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October 24, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, North Carolina 27603

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Post-Hearing Brief
Docket No. E-100, Sub 179

Dear Ms. Dunston:

Enclosed for filing in the above-referenced proceedings is Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress ("DEP" and, together with DEC, the "Companies") LLC's Post-Hearing Brief. Certain information in the Companies' Post-Hearing Brief is confidential based upon the record of this proceeding. Accordingly, the Companies are separately filing the confidential pages of the Post-Hearing Brief under seal.

If you have any questions, please do not hesitate to contact me. Thank you for your attention to this matter.

Sincerely ,

Enclosures

cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans And Carbon Plan	))))))	DUKE ENERGY CAROLINAS LLC'S AND DUKE ENERGY PROGRESS LLC'S POST-HEARING BRIEF

CARBON PLAN POST-HEARING BRIEF

NOW COME Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC" and together with DEP, "Duke Energy" or the "Companies"), by and through counsel, and submits this Post-Hearing Brief ("Brief") to the North Carolina Utilities Commission ("Commission") in the above-captioned docket. In parallel with this Brief, Duke Energy is also filing a Proposed Order that contains substantially more detailed Findings of Fact and Evidence and Conclusions of Law. This Brief is intended to provide a broad overview of the key issues for Commission determination in this initial Carbon Plan proceeding and reiterate the Companies' positions on certain key legal questions. For ease of reference, the Companies' Pre-Hearing Comments on Non-Expert Hearing Track Legal and Policy Issues are attached as **Appendix 1** and certain other legal issues are addressed in **Appendix 2** (as is further explained below).

I. INTRODUCTION AND OVERVIEW

Duke Energy's proposed Carolinas Carbon Plan ("Carbon Plan" or "Plan") presents a comprehensive and detailed analysis for the continued energy transition away from coal generation that provides a range of potential options for achieving the carbon dioxide ("CO_2") reductions targets established by North Carolina Session Law 2021-165, Section 1, as codified at N.C. Gen. Stat. § 62-110.9 ("HB 951"). Based on that detailed analysis, the Companies have proposed for Commission approval a set of balanced and reasonable near-term actions that are generally consistent with all of the initial portfolios and have been validated by both the supplemental portfolios produced during the proceeding in consultation with the Public Staff of the North Carolina Utilities Commission ("Public Staff") and in response to intervenor comments in this proceeding and by a wide range of sensitivities (including preliminary modeling analysis to assess the potential impacts of the recently enacted Inflation Reduction Act of 2022 ("IRA")).

The near-term actions proposed by the Companies represent a bold and decisive next step in the energy transition, placing the Companies on a trajectory that would allow for achievement of the 70% interim carbon emissions reduction target ("70% Interim Target") by 2030, while maintaining reliability and affordability, and mitigating the overall execution risks associated with over-reliance on any resource option. The Companies' Carbon Plan is built on the premise that the energy transition requires an "all of the above" strategy, which is reflected in the breadth of the tools proposed by the Companies to be utilized. The Companies' Carbon Plan proposes aggressive energy efficiency ("EE") and demand-side management ("DSM") planning assumptions and initiatives and other "Grid Edge" tools (including new customer renewable programs and innovative rate designs) to "shrink the challenge" and leverages existing supply-side resources and deployment of new supply-side resources through the pursuit of disciplined and balanced procurement and development activities in the near term (along with transmission grid investments needed to reliably integrate these new resources onto the Carolinas system). Under all portfolios, by the end of 2035, over 8,400 MW of coal capacity is projected to be retired, with only minimal differences in the projected retirement dates across the portfolios.

A Balanced, Reliable, and Executable Plan for the Carolinas

In developing and assessing the initial four portfolios presented in the Carbon Plan and additional supplemental portfolios modeled in consultation with the Public Staff, the Companies sought to balance four core objectives that are grounded in prudent utility planning and consistent with HB 951's overall framework to achieve an orderly energy transition: CO_2 reductions, affordability, reliability, and executability. The Carbon Plan is also informed by the Companies' extensive stakeholder engagement occurring both before and after the enactment of HB 951 and now continuing on in parallel with this proceeding and into the future.

Duke Energy recognizes the crucial importance of closely adhering to the primary policy guidance given by the General Assembly—finding the least-cost pathway to the targeted CO_2 reductions that maintains or improves reliability. Duke Energy's proposed Carbon Plan was built on the foundation of the most in-depth, detailed long-range planning ever conducted by the Companies, including a first-of-its-kind detailed Execution Plan that provides a roadmap for the many workstreams that will be implemented as the Companies pivot from analysis and planning to execution (and then back to planning in future proceedings, informed by the information gather through the execution process). The Companies' Carbon Plan, including the robust modeling and technical analysis, has been an "open book"—made available to all intervenors and subject to exhaustive discovery and analysis. In fact, the Companies have gone above and beyond even the Commission's directives to engage with stakeholders and intervenors, including to provide technical guidance to intervenor technical parties as such parties navigated use of new modeling tools that were being used in the North Carolina integrated resource planning process for the first time. The Companies appreciate and respect the wide range of opinions and perspectives that have been shared both by intervenors as well as the customers and communities that Duke Energy serves.

HB 951 establishes an iterative, biennial Carbon Plan process that will evolve over time as more information is gathered, market dynamics and technological breakthroughs are identified, national and state policies evolve, and customer behaviors change. The Companies view this current proceeding as the first step in a journey. Given the dynamic nature of the energy landscape, the Commission should remain focused on the steps necessary today to support the achievement of the emissions reduction targets, while retaining discretion to evolve the Carbon Plan and preserving all options needed to achieve an orderly energy transition and HB 951's objectives, with an eye toward future refinements to both planning and execution that will be made in the not-so-distant future.

A Decisive Plan of Action for Our Customers and Communities

The Carbon Plan proceeding has been unprecedented in many ways—from the number of intervening parties to the volume of information submitted and breadth of topics addressed by parties to the required pace of the proceeding in light of the statutory deadline. At various points in this proceeding, certain intervenors have strongly criticized certain aspects of the Companies' plan or operations and, in various ways, advocated for positions that are contrary to the well-established regulatory framework in North Carolina or inconsistent with HB 951 (some of which recommendations are not even relevant to the scope of this proceeding). While the Companies have responded to many such arguments in various ways in this proceeding and addressed many of those issues in their Proposed Order and this Brief, it is also worth stepping back and considering the big picture. Duke Energy, under the historically constructive regulation of this Commission and the Public Service Commission of South Carolina ("PSCSC"), is well-positioned as a strong and reliable utility that is delivering on the regulatory construct through reliable and affordable service to customers and has already made substantial strides in the energy transition for the benefit of customers. For evidence of the value of the regulatory construct, the

Commission need look no further than the slew of recent major economic development announcements in the state (for which the price, reliability, quality and declining carbon intensity of electrical service is a critical factor) or even to the testimony of industrial customers in this proceeding who stated that Duke Energy "should be applauded for presently being a low-cost, high-quality electricity supplier"[1] and "currently offers the most reliable, highest quality and least cost electricity compared with our suppliers in other states where we operate."[2] Under the Commission's oversight (along with that of the PSCSC), the Companies have already made substantial progress in the energy transition, having retired approximately 4,400 MW of coal-fired generation and converted approximately 3,150 MW of coal-fueled generating capacity to use natural gas as a fuel.[3] The Companies' existing emissions-free resources are significant. The six nuclear plants, 26 hydro-electric facilities, and hundreds of utility-scale solar facilities that are now online and serving customers are foundational to the Companies' orderly transition of its dual-state systems.

Duke Energy is continuing to lead the way in other areas for our customers and communities. Above and beyond the decisive next steps in the Companies' continued energy transition being considered in this proceeding, Duke Energy is evolving in every aspect of its business to facilitate the continued energy transition and provide the highest level of service to our customers. For instance, in the past two years alone, among other activities, Duke Energy has worked collaboratively with our customers to update our

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[1] Tr. vol. 25, 357.

[2] *Id.*

[3] Carbon Plan, Ch. 1, 2.

interconnection process to make it more efficient (even as other interconnection processes around the country encounter substantial challenges), engaged in a comprehensive and collaborative evaluation of all of our rate designs and developed a rate design study roadmap for future rate cases, pursued existing transmission planning processes to implement proactive transmission investments, pursued new electric vehicle ("EV") initiatives, including an innovative partnership with Ford, collaborated with stakeholders to consider opportunities to assist low-income customers, and much more.

The energy transition contemplated by HB 951 positions the Companies and the state to capitalize on evolving market factors, including federal policy. The clean energy tax credits in the recently enacted IRA will enhance the Companies' ability to develop and procure more clean energy in a least-cost manner, including by mitigating recent inflationary and supply-chain pressures facing the industry. The tax benefits for new generation resources will provide direct benefit to our customers. There is also significant funding for developing the hydrogen economy and other emerging technologies, and the IRA promotes EV adoption and EV infrastructure. The new law will enable investment in new infrastructure, supporting the communities that Duke Energy serves. Similarly, Duke Energy is actively engaged in the ongoing Infrastructure Investment and Jobs Act ("IIJA") implementation at the state and federal levels. Federal and state agencies are in the early phases of implementation, with many new programs still under development. Any DOE-approved funding received will ultimately be utilized to reduce rate impacts for our customers.

Key Differentiators Support Adopting Duke Energy's Proposed Carbon Plan

As the Commission deliberates to develop the initial Carbon Plan, there are a few key differentiators that are worth noting between the Companies' proposed Carbon Plan and alternate plans and modeling analyses submitted by certain other intervenors. First, the Companies' Carbon Plan maintains a core focus on reliability (consistent with HB 951) that is missing from the alternative plans submitted by certain intervenors. The Companies submitted extensive evidence concerning both the ways in which its modeling seeks to ensure reliability consistent with HB 951's requirements, including through detailed granular reliability-focused modeling (which was not performed by intervenors that submitted alternative analyses), as well as how the Companies' real world operational perspective was brought to bear on its Carbon Plan. Second, the Companies' Carbon Plan is carefully designed to be executable and presents detailed requests for relief and an Execution Plan that provides a clear roadmap across the entire spectrum of the Companies' operations, including optimization of existing generation and plans for new Grid Edge and customer renewable programs. In contrast, intervenors' alternative analysis in general did not demonstrate a similar level of rigor and depth of analysis concerning the full spectrum of risks or meaningfully focus on the execution side of the Carbon Plan. Third, the Companies' Carbon Plan was subject to a level of scrutiny in this proceeding far beyond the scrutiny applied to other proposed plans. For example, the Public Staff (which will make its own recommendations to the Commission) did not present any testimony analyzing the alternative modeling presented by other parties. To be clear, the Companies absolutely agree that its Carbon Plan should be closely evaluated by all parties. But it should not be lost that the level of scrutiny applied to the Companies' Carbon Plan exceeded by orders of magnitude the scrutiny applied to other plans. Duke Energy believes that it has more than rebutted the critiques of the Companies' Carbon Plan raised by some intervenors. Duke Energy has also identified numerous flaws and concerns in the alternative modeling analyses and resulting recommendations submitted by intervenors (although as acknowledged in testimony, it was simply not possible for the Companies to assess every aspect of all alternative analyses).[4] However, weight should be given to the fact that the Companies' Carbon Plan has withstood the asymmetric scrutiny applied in this proceeding (*e.g.,* more than 1,500 data requests issued to Duke Energy versus a few dozen to other parties).

Duke Energy also believes that its perspective in this proceeding is distinct from non-utility intervenors due to (1) the Companies' obligation under the North Carolina General Statutes and the Rules of the Commission to provide reliable electrical service to all customers, (2) the Companies' track record of providing reliable and affordable electricity, and (3) the broad, customer-focused perspective that guides everything we do, including the development of this initial proposed Carbon Plan for energy transition.

The Companies bear the responsibility for providing reliable service to all of our customers, a responsibility that drives everything we do. More than any other party in this proceeding, the Companies understand what it takes to deliver those results, as it is our technical experts and other dedicated professionals who have planned, constructed, and maintained our generating fleet and power delivery system, who sit in our operating control rooms and ensure reliability on the coldest winter mornings and the hottest summer days (and all times in between), and who have responded in the trenches to the challenges thrown

[4] *See* Tr. vol. 27, 35.

our way (*e.g.*, restoration of power after severe weather events). The Companies, under the historically constructive regulation of the Commission and the PSCSC, have delivered on these responsibilities by providing reliable service at rates that have been consistently below national average, taking steps to reduce the carbon intensity of our generating fleets, and contributing to the economic vitality and strength of our State. The Companies also engage with our customers on a regular basis to invite and better understand the wide range of customer concerns and priorities across all customer classes, from industrial and manufacturing customers focused on maintaining the state's economic competitiveness, to environmental advocates focused on the pace and approach to meeting CO_2 reductions and carbon neutrality requirements, to low-income customers and customer advocates seeking new and innovative customer-focused solutions that address affordability challenges and prioritize disadvantaged communities, and a myriad of customer perspectives in between.

<u>Focusing on the Key Issues in This Proceeding</u>

The Companies reiterate that the Commission need not determine every contested issue presented in this proceeding and should focus its efforts on approving near-term actions that are necessary to chart a course for achieving HB 951's CO2 emissions reductions targets in a manner that best achieves the core objectives of the law, as well as progressing the Companies' least cost Carolinas' system-wide energy transition objectives. The Commission and the Companies will then be able to "check and adjust" in future proceedings. In addition to the biennial Carbon Plan update, numerous additional proceedings will follow in the coming years that will give more opportunity for the Commission to evaluate the progress being made.

In weighing the substantial evidence presented in this proceeding, the Companies believe that balancing the four core Carbon Plan objectives—CO_2 emissions reductions, affordability, reliability, and executability—provides a reasonable and appropriate framework for assessing the varying positions of the parties. Taken together, these core objectives establish an orderly, reliable, and executable energy transition that balances affordability in developing the least-cost plan to retire the Companies' coal units and to meet HB 951's CO_2 emissions reduction targets. Based on these factors and the weight of evidence in this proceeding, the Companies believe that its Proposed Plan should be adopted by the Commission and that the Commission should grant all of the Companies' requested relief as set forth in the Companies' May 16, 2022 Verified Petition for Approval of Carbon Plan ("Petition").

II. ARGUMENT

A. The Companies Carbon Plan Presents a Balanced and Reasonable Roadmap for Achieving the 70% Interim Target and the Longer-Term Carbon Neutrality Target.

As described throughout the Carbon Plan and in Duke Energy's expert testimony, the Companies' Carbon Plan modeling framework was developed to achieve the energy transition and the CO_2 reduction targets outlined in HB 951 in the least cost manner for customers while ensuring system reliability is maintained or improved, and that the portfolios could be reasonably executed on the timelines presented by the Companies. As further validated through a variety of sensitivities, through supplemental modeling performed in consultation with Public Staff as well as additional IRA sensitivity analysis, the Companies' Carbon Plan is a reasonable and balanced roadmap for achievement of the 70% Interim Target and to plan for carbon neutrality by 2050 ("Carbon Neutrality Target").

B. The Companies' Supply Side Near-Term Action Plan is Reasonable and Should be Approved by the Commission.

Through the thousands of pages of comments and testimony in this proceeding, intervenors have introduced recommendations covering virtually every aspect of the regulatory construct. It is not feasible to resolve all such issues in this proceeding nor is it necessary or consistent with HB 951 to do so. Nor is it possible that every technical modeling issue can be resolved. Instead, the heart of this proceeding boils down to one single question: what are the near-term "reasonable steps" to be taken by Duke Energy to begin meaningful and substantial progress towards the 70% Interim Target on the path to Carbon Neutrality. Those parties that offered only critiques without a clear and readily identifiable set of alternative near-term actions should be discounted.

Duke Energy's position on this issue has been clear since its May 16th filing of the Carbon Plan—the Companies Petition presents a concise set of requests for relief including requests for Commission approval of the primary supply side near-term actions to be procured between now and 2024 when the Commission will again review the Companies' proposed Carbon Plan.

Supply-Side Resources: Near-Term Action Plan[5]

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2029		
Carbon Plan Solar	3,100 MW	• Begin Public Policy Transmission projects in 2022[6] • Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage
Battery Storage	1,600 MW	• Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar
Onshore Wind	600 MW	• Engage wind development community in preparation for procurement activities • Procure 600 MW in 2023-2024

[5] Tr. vol. 7, Bowman Ex. 3.

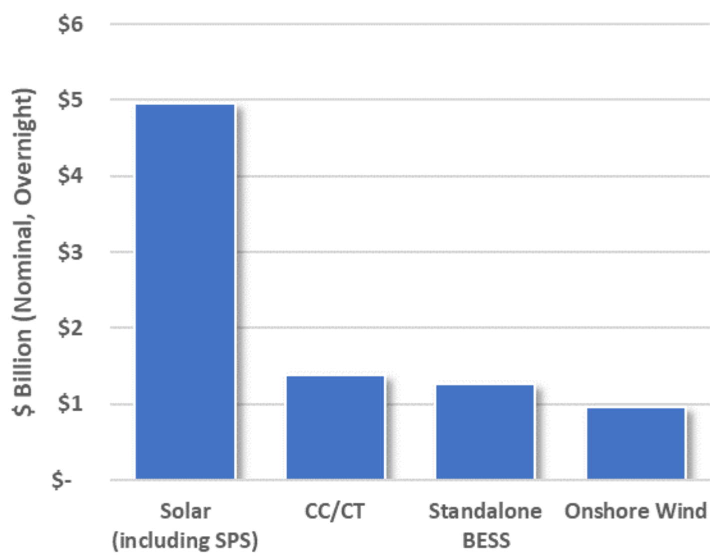
New CT[1]	800 MW	• Submit CPCN for 2 CTs totaling 800 MW in 2023
New CC[2]	1,200 MW	• Submit first CPCN for 1,200 MW in 2023 • Evaluate options for additional gas generation pending determination of gas availability
Proposed Resource Development: Options for 70% Interim Target		
Offshore Wind[3]	800 MW	• Secure lease • Initiate development and permitting activities for 800 MW[7] • Conduct interconnection study • Initiate preliminary routing, right-of-way acquisition for transmission
New Nuclear[4]	570 MW	• Begin new nuclear early site permit ("ESP") for one site • Begin development activities for the first of two SMR units
Pumped Storage Hydro[5]	1,700 MW	• Conduct feasibility study for 1,700 MW • Develop EPC strategy • Continued development of FERC Application for Bad Creek relicensing

Note 1: CPCN for two CTs (800 MW) estimated for in-service 2027-2028
Note 2: CPCN for one CC (1,200 MW) estimated for in-service 2027-2028, CPCN for second CC (1,200 MW) will be evaluated for submittal in 2024 with estimated in-service 2030 as fuel supply is determined.
Note 3: Retaining optionality through early development activities, in-service date assumption dependent upon portfolio.
Note 4: New nuclear capacity represents first two SMR units, planned in-service date through 2034.
Note 5: Pumped storage hydro capacity represents second powerhouse at Bad Creek, planned in-service 2033.
Note 6: Projects subject to North Carolina Transmission Planning Collaborative ("NCTPC") approval.
Note 7: Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan ("SAP"); or ii) a combined SAP and Commercial Operation Plan.

As shown in the table above, the Companies' primary supply-side near-term action plan consists of (1) a set of resources proposed for selection by the Commission (including related development and procurement activities) and (2) a set of initial development activities for the three long lead-time resources (offshore wind, small modular reactors ("SMRs") and Bad Creek II (together, the "Long Lead-Time Resources") that will preserve the potential for such unique resources to be utilized in achieving the 70% Interim Target and allow the Commission to consider in a more detailed fashion in future proceedings whether such resources should be selected as part of the Carbon Plan.

The Commission has heard a range of perspectives in this case, with some parties urging the most aggressive possible pace of execution focused on pursuing a narrow set of solutions, and others urging a more measured balanced approach involving a diverse set of resources in light of affordability and execution concerns. The Companies believe that the supply side near-term actions presented in its Carbon Plan strikes the right balance, involving decisive but reasonable first steps that includes investments in a diverse portfolio, weighted most significantly towards investment in solar and solar paired with storage, with additional smaller investments in standalone batteries, onshore wind and new natural gas as shown in the following figure:

Proposed Investment by Resource Type in the Companies' Near-Term Procurement and Development Activities[6]



Balancing affordability, reliability and executability are key considerations for setting the pace of energy transition. While certain parties suggest that the Commission should immediately take more aggressive action and commit to more significant development and procurements of solar and battery energy storage resources, customer

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[6] Tr. vol. 27, 48 (Modeling and Near-Term Actions Panel Rebuttal Figure 1).

groups such as CIGFUR and NCEMC, as well as the Public Staff, express support for the reasonable initial steps and the "check and adjust" strategy recommended by Duke Energy.[7]

- ***For more detailed discussion of the overall scope of the near-term development and procurement, see Duke Energy Proposed Order at Findings of Fact 25-33; Pages 107-120.***

1. Solar, Solar paired with Storage, and Standalone Storage

There is nearly unanimous support in this proceeding that some substantial amount of solar, solar paired with storage and standalone storage must be procured in the near-term. The only issue in dispute is the amount of such resources to be procured. The Companies' proposed amounts are aggressive but appropriately balance a range of risks, including executability, technology risk and price risk. The Companies' recommendations were validated by the supplemental modeling and largely align with the Public Staff's recommendation.[8] The limited other intervenors that made concrete proposals either recommend substantially more solar or substantially more storage (or both). The Companies believe that such recommendations are unreasonable, unnecessary at this time, potentially unexecutable and would impose substantial and unnecessary cost and technology risks for customers. For example, NCSEA, et al.[9] and Tech Customers[10] recommend near-term procurement of 4,000 MW and 3,900 MW of standalone storage, respectively. In addition to likely being unexecutable, this amount of storage represents an

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[7] Tr. vol. 25, 364; Tr. vol. 23, 305-06; Tr. vol. 21, 40-42.

[8] Tr. vol. 27, 41-42 (Modeling and Near-Term Actions Rebuttal Table 1).

[9] North Carolina Sustainable Energy Association together with the Sierra Club, and the Natural Resources Defense Council are collectively referred to herein as "NCSEA et al."

[10] Apple Inc., Google, LLC, and Meta Platforms, Inc. are collectively referred to herein as "Tech Customers."

approximately \$6 - \$7 billion investment in a technology that is still maturing both in design and operating experience and is projected to decline in price. Thus, while the Companies support substantial deployment of storage paired with solar and standalone storage resources in the near-term, a more measured pace than recommended by these parties would be more reasonable.[11]

The amount of solar, solar paired with storage and standalone storage proposed by the Companies' in the near-term is generally consistent with all of the Companies' portfolios and, contrary to assertions made by other parties, would not render achievement of the 70% Interim Target by 2030 unachievable.[12] It remains to be seen whether the market can deliver sufficient volumes of solar and storage resources below the modeled cost of these resources in the Carbon Plan to fully achieve the P1 volumes by 2030. However, the Commission will retain substantial discretion (consistent with HB 951) and can direct the Companies to procure more or less solar and solar paired with storage based on conditions at the time the Companies seek approval for future procurements and furthermore, can use volume adjustment mechanism to procure more when the market prices are lower than expected. Finally, there are numerous other considerations and aspects of an "all of the above" Carbon Plan that need to be considered to meet the carbon reduction targets while balancing the four core Carbon Plan objectives. As such, the pace

[11] *See* Tr. vol. 27, 272 (Snider responding to Chair Mitchell that "Q. What is number 1 [risk], in your opinion? A. I think number 1 [risk] is, if you were to go no gas and go concentrated I want 6-, \$7 billion worth of storage in the next few years, you're gonna wear a lot more risk than you're gonna wear by building a limited amount of hydrogen-capable gas. There's no getting around that. Twenty-five-year contracts on emergent technologies that don't have any operating experience for 20 years and chemistries are gonna stay perfect, you know, that's just unlikely, right?").

[12] *See* Tr. vol. 27, 58-60.

of solar and storage procurements must be viewed in the broader context of other resources and infrastructure needed in conjunction with the new solar and storage resources to achieve the targeted carbon reductions in an orderly fashion.[13]

Contrary to the assertions of some intervenors, there are, in fact, risks to "over-procurement" of solar, solar paired with storage and standalone storage in the near-term. Those risks include foregoing the potential for declining future costs (which most parties in this proceeding project will occur) and losing out on technology maturation (which is a more significant concern for battery storage but also exists for solar). Battery technology is advancing rapidly and solar paired with battery storage is not as mature as standalone solar, especially in the Carolinas. To "frontload" the procurement of developing resources in this manner would increase the risk that the Companies and their customers miss the technologies and resource advancements and price declines that are likely to occur over the coming years.[14]

The Companies' application of real-world annual interconnection limits for solar also received substantial attention in the proceeding (primarily from solar developer trade associations). In assessing the reasonableness of this assumption, it is initially important to recognize that the Carbon Plan modeling necessarily utilizes all manner of "constraints" to model the least cost portfolios of supply-side and demand-side resources, such as CO_2 emissions reductions, capacity planning reserve margins and operating reserve requirements, as well as "when and how much" of all resources can feasibly be integrated

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[13] *See id*. at 60.

[14] *See id.* at 59-60.

into the portfolio.[15] Consistent with the other aspects of Duke Energy's modeling, the Carbon Plan utilizes reasonable base planning as well as high solar interconnection assumptions that were developed based on Duke Energy's engineering judgement and take into account a variety of factors informing Duke Energy's "real-world" capability to interconnect new solar resources.[16] Significant amongst these factors are the increasingly complex transmission level interconnections that will be required in the future as well as Duke Energy's nation-leading success interconnecting solar resources to date, which has resulted in significant "Red Zone" areas of constraints on the transmission system.[17] Contrary to arguments by Clean Power Suppliers Association ("CPSA") and certain other parties, the Companies' solar forecasting and transmission planning witnesses explain in detail that Duke Energy's base solar interconnection limit assumption is a reasonable but aggressive target. In contrast, they explain that the significantly increased levels of interconnections recommended by other parties would likely be unachievable in the near-term (2026-2027) but that Duke Energy is planning for increased solar interconnections over time as new transmission projects are completed.[18] The Public Staff also agrees with the Companies' base solar interconnection limits as reasonable for modeling purposes, while expressing serious concerns about the Companies' ability to interconnect significantly greater solar by 2030.[19] The Companies are also recommending a 2022 Solar Procurement target volume and adjustment mechanism that aligns with the Public Staff

[15] *See* Carbon Plan, App'x E, 27.

[16] *See* Tr. vol. 7, 353.

[17] *See* Carbon Plan, App'x I, 6-8; Tr. vol. 7, 349-50; Tr. vol. 27, 65-67.

[18] *See* Tr. vol. 28, 144-46.

[19] *See* Tr. vol. 21, 41, 97.

and are not constrained by the solar interconnection limit.[20] Accordingly, both Duke Energy's solar interconnection modeling assumptions as well as near-term solar procurement plans are reasonable and should be approved by the Commission. Further issues related to the Companies' interconnection practices are addressed below in Section (E)(2).

- ***For more detailed discussion of the recommended volume of solar, see Duke Energy Proposed Order at Findings of Fact 17, 27-28; Pages 70-79, 108-120.***
- ***For more detailed discussion of the recommended volume of solar paired with storage and standalone storage, see Duke Energy Proposed Order at Findings of Fact 15-17, 28-30; Pages 67-79, 108-120.***
- ***For more detailed discussion of the annual solar interconnection limits, see Duke Energy Proposed Order at Finding of Fact 17; Pages 67-79.***

2. Onshore Wind

Among the parties recommending concrete supply side near-term actions, there is nearly unanimous support for the Companies' plan to attempt to procure 600 MW of onshore wind. The Companies recognize that substantial work is needed to assess establish a framework for such procurement and will undertake those activities in 2022-2023, targeting a procurement event in 2024 (given the lack of a mature market for onshore wind in the Carolinas, the Companies do not believe it would be prudent to target a procurement event in 2023). All information gained through those efforts will be used to inform the 2024 biennial Carbon Plan update.

3. New Natural Gas Generation

One of the issues garnering the most attention in this proceeding is the Companies' request that the Commission select 800 MW of new combustion turbines ("CTs") and

[20] *See* Tr. vol. 27, 56-60.

1,200 MW of new combined cycle ("CC"). Limited amounts of new flexible and dispatchable hydrogen-capable gas generation is essential to an orderly, reliable and least cost energy transition.[21] Failing to have such flexible resources on the system as the Companies move forward with retiring 8,400 MW of coal unit capacity jeopardizes achieving the emissions reductions target, increases cost of operating the system, and increases risk of a disorderly or delayed transition. Selecting limited amounts of new gas generation at this time provides system flexibility, supports grid reliability as higher levels of intermittent renewables and storage resources are interconnected, and importantly provides significant carbon reductions needed to achieve the 70% Interim Target.[22] Further delays in moving forward with a limited amount of hydrogen-capable natural gas resources will either present reliability challenges or delay achievement of the 70% Interim Target and retirement of existing coal resources or both.[23]

The Public Staff recognizes the need for limited new CC and CT capacity as part of the near-term action plan. Numerous other parties also recognize that some limited amount of CC and/or CT capacity is needed to reliably transition the system.[24] Only the results-oriented analysis and testimony presented by NCSEA et al., North Carolina Waste Awareness and Reduction Network ("NC WARN"), and Environmental Working Group

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[21] *See* Tr. vol. 27, 81.

[22] *See id*. at 80.

[23] *See id*. at 94.

[24] *See* Tr. vol. 25, 409-10, 446. Similarly, while CPSA does not directly opine on near-term activities related to new hydrogen-capable gas, each of the CPSA portfolios modeled by the Brattle Group includes two new CCs by 2030, implicitly recognizing that new gas is a necessary part of an orderly energy transition. CPSA July 15 Comments Exhibit A at Slide 30-32.

("EWG") oppose any development of even limited, hydrogen-capable new gas resources in the near term.[25]

There is a misconception that the Companies can proceed with all other elements of the Carbon Plan but defer action on gas and still meet emissions reductions targets along the least cost path.[26] To the contrary, flexible hydrogen-capable natural gas resources play an essential role in decreasing CO_2 emissions, while simultaneously providing reliable replacement capacity that enables the deployment of significant renewable resources. In the case of the new CCs, these resources emit about 60% less carbon per MWh basis than the coal generation they are replacing. Being the newest and most efficient resource on the system, with access to the lowest cost gas on the system, these resources would offset higher carbon emitting resources over the life of the assets. As an example, delaying (or removing) a single gas CC in the plan and keeping an equivalent amount of coal online resulted in an increase of nearly 2 million tons of CO_2 on the system in the year 2030. This is roughly 2.5% of the 2005 baseline. Furthermore, peaking CTs allow for more flexibility in system operations to meet high load requirements, while providing operators the ability to turn these units on and off, reducing CO_2 emissions compared to longer required online and offline time for retiring coal, or, when needed, to run them for extended periods during high load events.[27]

Without adequate replacement resources, including peaking CT and baseload CC resources, the Companies cannot retire coal, compounding the difficulty in achieving the

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[25] Tr. vol. 27, 37.

[26] *See id.* at 79-80.

[27] *See id*. at 80.

emissions reduction targets. Additionally, if retiring coal is replaced with natural gas resources at retiring coal sites, these resources maybe able to avoid transmission investments and take advantage of other existing infrastructure.[28]

There was substantial focus in the proceeding on the availability of natural gas transportation, the cost of natural gas, and the stranded asset risk. With respect to natural gas transportation, the Companies' Carbon Plan supports planning for accessing limited Appalachian Gas as the most appropriate base gas supply assumption for least cost planning purposes.[29] The Carbon Plan also reasonably recognizes that current uncertainty regarding access to gas from the Appalachia region presents a future "pivot point," meaning the Companies will refine resource decisions over the near-term depending on the Companies' ability to access Appalachian gas supply.[30] The Companies' analysis also presents reasonable and defendable Firm Transportation ("FT") cost assumptions and executable plans to obtain additional interstate FT fuel supply in 2022-2023 to support any new CC generation.[31]

With respect to natural gas price forecasts, numerous parties pointed to current market prices to suggest that the Companies' longer term forecasts used in the Carbon Plan modeling were incorrect. As pointed out by Public Staff witness Thomas, while current (balance of 2022) natural gas market prices are elevated, and above the Companies' base projected 2050 natural gas price, the market projects natural gas costs will recede in the

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[28] *See id*.

[29] *See* Tr. vol. 7, 254

[30] Carbon Plan, Ch. 3, 13, App'x E, 32.

[31] *See* Tr. vol. 7, 367-71; Tr. vol. 27, 88-91.

coming years as global production increases, recovering from impacts from the COVID-19 pandemic and geo-political instability impacting the cost and availability of natural gas.[32] Witness Thomas further noted that all four of the Carbon Plan portfolios significantly *decrease* the total amount of natural gas burned annually, while remaining critical to the system on peak days and in extreme weather.[33] As a result, customer exposure to volatile natural gas prices will significantly decrease over time. The selection of resources utilizing natural gas up until 2050 is more significantly impacted by longer-term fundamental-based natural gas projections, along with other requirements of the system to reduce CO_2 emissions and maintain reliability. Furthermore, the Companies conducted high-gas sensitivities (which assumed prices that exceeded current market prices) in both their initial portfolios as well as the IRA sensitivity and natural gas generation was still selected. Even in the preliminary IRA modeling, and in a high natural gas price scenario, with the inflationary costs of resources and responsive tax incentives, the capacity expansion model continued to select CC capacity in the near term.[34]

Finally, the Companies offered extensive testimony regarding the future potential outcomes that substantially mitigate stranded asset risk, which include the potential future use of hydrogen (which the Companies believe to be a reasonable planning assumption), the use of carbon offsets (if needed) up to the amounts permitted by HB 951 or continued operation to maintain reliability (as permitted under HB 951).[35]

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[32] *See* Tr. vol. 21, 70; Tr. vol. 27, 82-83.

[33] *See* Tr. vol. 21, 70.

[34] *See* Tr. vol. 27, 79.

[35] *See id*. at 271.

In summary, the limited CC and CT resources identified by the Companies in the near-term action plan are essential to achieving the emissions reduction target, while maintaining or improving reliability, and doing so along the least cost path.[36] Based on all of the Companies' modeling, including the numerous sensitivities, the supplemental modeling (Supplemental Portfolio 5 (no App gas)), and the IRA sensitivities, the Companies continue to believe that the Commission should select the limited hydrogen-capable new natural gas generation recommended in the near-term action plan. This generation is essential both for reliability and for CO_2 reductions.

As the Companies have previously acknowledged, the Commission's selection of natural gas in this proceeding does not obviate the need for the Companies to obtain a certificate of public convenience and necessity ("CPCN") under N.C. Gen. Stat. § 62-110.1 prior to the commencement of construction. As the Companies note below (and in their Sept. 9th Pre-Hearing Comments),[37] the Commission should exercise its delegated authority to select new generating facilities and other resources in the Carbon Plan in a thoughtful and flexible manner. In the case of new natural gas generation, the Companies agree that a future CPCN application will include, in addition to the site-specific information required by law, a more detailed discussion of interstate gas transportation and updated modeling analysis (taking into account even more updated information concerning the impacts of the IRA) to demonstrate that the specific resource selected continues to be

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[36] Tr. vol. 30, 106; Tr. vol. 27, 80-81.

[37] *See* Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Pre-Hearing Comments on Non-Expert Hearing Track Legal and Policy Issues filed on September 9, 2022 ("Sept. 9th Pre-Hearing Comments").

part of the least cost path.[38] However, the Commission's findings in this proceeding related to the value of and need for natural gas generation will be taken into account in any such future CPCN proceeding and provide strong evidence of public convenience and necessity.

- ***For a more detailed discussion of the need for new natural gas generation, see Duke Energy Proposed Order at Findings of Fact 19-22, 32-33; Pages 83-99; 107-120.***

4. Near-Term Initial Development Activities

The Companies' request for approval of initial development activities for the three Long Lead-Time Resources is unique (though not unprecedented). The requested relief is appropriate given the nature of the Carbon Plan and, in particular, the substantial action needed to achieve the 70% Interim Target. What is clear from the weight of the evidence in this proceeding is that one or more of three Long Lead-Time Resources will be needed to achieve the 70% Interim Target and likely all three will be needed over the long-term to achieve the Carbon Neutrality Target.[39] Bad Creek II is required under all of the Companies' four initial portfolios and two supplemental portfolios, and SMRs are similarly required under all portfolios, in some cases as early as 2032 and in others not until slightly later in time. While offshore wind is not selected in every portfolio for the 70% Interim Target, the Companies nevertheless believe that it is prudent to proceed with near-term development activities at this time to maintain it as an option given its technological maturity and ability to provide resource diversity.[40]

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[38] Tr. vol. 27, 78.

39 *See* Tr. vol. 17, 84-85; Tr. vol. 27, 115.

40 *See* Tr. vol. 17, 84-85.

What has also not been disputed is that substantial development work is needed on each of three Long Lead-Time Resources in the near term in order to preserve the potential that one or more of such resources could be relied on to achieve the 70% Interim Target. That is, for any of the three Long Lead-Time Resources to play a role in achieving the 70% Interim Target, work must begin now and cannot be delayed until after the 2024 Carbon Plan update.[41] Therefore, the question before the Commission is whether it agrees that it is reasonable and appropriate to direct Duke Energy to pursue development activities for the Long Lead-Time Resources in order to preserve the potential for these resources to be available for the 70% Interim Target and to allow for a more meaningful detailed consideration of the resources in the 2024 Carbon Plan or other future proceedings. Importantly, the Companies believe that none of this identified initial development work will be "wasted" in that all three of the Long Lead-Time Resources will likely be needed over the longer-term.[42] Specific support for the initial development of each of the three Long Lead-Time Resources are addressed below and legal issues related to the Commission's authority to grant this requested relief are addressed later in this Brief.

5. Bad Creek II

Pumped storage hydro is a proven long-duration storage technology that will enable more efficient use of other renewable and carbon-free resources. Bad Creek II in particular is a unique opportunity for the Companies to add new long-duration, large-scale pumped storage hydro at an existing facility.[43] Any other additional pumped storage hydro at a

41 *See* Tr. vol. 17, 128-29.

42 *See* Tr. vol. 29, 93.

43 *See* Tr. vol. 17, 85-87.

location other than the existing Bad Creek facility would likely be substantially more costly, take longer to permit with more possible opposition and a longer time to construct. Bad Creek II will allow the Companies to integrate more renewable and low-carbon generation to the grid and provide customers savings by storing excess generation during low demand and producing generation quickly and nimbly when demand is high. All of the Companies' portfolios rely on Bad Creek II and no party to this proceeding has even attempted to model a plan that does not rely Bad Creek II.[44]

The Companies have proposed a discrete set of development activities in the near-term that will allow Bad Creek II to remain on a development schedule that is consistent with the timelines assumed in the Companies' Carbon Plan. The Public Staff notes that, given the modeling results and the long development time for Bad Creek II, it is reasonable for the Companies to perform further near-term evaluation and initial development activities to seek initial permitting, refine the timeline of commercial operation, identify risk factors, and determine more accurate cost estimates.[45] As a result of these development activities, the Companies will be positioned to provide in future proceedings a more firm cost estimate and other technical details in order to allow the Commission to determine whether it is appropriate to select Bad Creek II as part of the Carbon Plan.[46]

- ***For a more detailed discussion of the benefit of Bad Creek II, see Duke Energy Proposed Order at Findings of Fact 34-35; Pages 121-124, 138-141, 145-147.***

6. SMRs

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44 *See id*. at 87-93.

45 *See* Tr. vol. 21, 49.

46 *See* Tr. vol. 17, 92-93.

There is simply no doubt that new nuclear generation will be needed as part of the Carbon Plan. SMRs are identified as being needed in all of the Companies' modeling analysis, with the exact first date of need shifting slightly between each of the portfolios.[47] Modeling and analysis supported by the Public Staff and other parties validates the need for SMRs.[48] Pursuit of SMRs will also allow the Carbon Plan to leverage the nation-leading nuclear operations expertise of the Companies. Duke Energy has the largest regulated nuclear fleet in the country, operating eleven large light-water reactors at six sites across the Carolinas. The nuclear fleet provides approximately 10,773 MW of capacity, which provides over 50% of the electricity used by Duke Energy's customers in the Carolinas, and 35% of Duke Energy's overall generation. This generation is approximately 83% of the zero-carbon energy produced by Duke Energy overall. Duke Energy's strong nuclear operational experience positions the Companies to add SMRs in the 2030s as the remaining coal units are retired and to achieve a reliable and balanced portfolio of new generation resources.[49]

SMRs have significant advantages over their historical counterparts. The modular design of these new reactors allows for more off-site construction and decreases production timelines. Designs have become smaller, meaning units require less capital investment and are more flexible, allowing for greater ability to match power output to system loads. In addition, the new generation of nuclear plants are significantly safer. Inherent safety

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47 *See* Tr. vol. 7, 251-52.

48 *See, e.g.*, Tr. vol. 21, 76.

49 *See* Tr. vol. 17, 93-95.

features, such as passive shut down and self-cooling through natural circulation, mean that the system can turn off and cool indefinitely with no operator intervention.[50]

The development work proposed for SMRs primarily involves pursuit of an early site permit ("ESP"). An ESP would allow Duke Energy to make progress in deploying advanced nuclear while the state of technology advances and the detailed designs are completed. An ESP allows the NRC to review and approve the environmental impacts and site safety analysis associated with nuclear deployment before a technology is selected or a decision to build has been made. ESPs can be used to avoid delays from siting issues that could adversely impact the construction schedule after significant capital has been invested. Given the near certainty that SMRs will be needed in the Carbon Plan combined with the fact that an ESP can be approved for up to 20 years and renewed for an additional 20 years, the pursuit of an ESP at this time is a no-regrets strategy.[51]

A number of parties raised concerns regarding the schedule and construction cost risk associated with nuclear generation.[52] Duke Energy understands these concerns but reminds the Commission that the Companies are not requesting approval to begin construction of SMRs at this time.[53] More detailed consideration of any potential schedule and construction cost risk can be more fully considered at the point in time at which the Companies seek authorization to proceed with construction, which will

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50 *See id.* at 96; Tr. vol. 29, 106-07.

51 *See* Tr. vol. 17, 100, 104-05.

52 *See, e.g.*, Tr. vol. 21, 76-77.

53 *See* Tr. vol. 29, 92-94.

occur in a future Carbon Plan-related proceeding.[54] However, from a schedule perspective, a mid-2032 in-service date requires an aggressive timeline, but is feasible based upon information known today if Duke Energy accelerates actions to start the licensing process, including primarily pursuit of the ESP in the near-term.[55]

- ***For a more detailed discussion of the benefit of SMRs, see Duke Energy Proposed Order at Findings of Fact 34, 36; Pages 124-129, 138-140, 144-145.***

7. Offshore Wind

Finally, the Companies have requested approval to move forward with initial development activities for offshore wind in the near-term. These proposed development activities are necessary to preserve the potential that offshore wind will be available on the timelines contemplated in the Carbon Plan, as well as to have a more refined cost estimate for the Commission to consider in the 2024 Carbon Plan update in order to determine at that time whether offshore wind should be selected as part of the Carbon Plan.[56]

The majority of the offshore wind development activities must be performed on a specific offshore wind lease (including work on transmission from the projected landing site to the point of interconnection ("POI")).[57] At the time of the initial filing of the Carbon Plan, the Companies were still in the process of assessing the potential options for offshore wind development and had not yet identified the particular offshore wind lease for which development activities would be pursued.[58] As this proceeding has progressed and more

54 *See id*. at 98.

55 *See* Tr. vol. 17, 101.

56 *See* Carbon Plan, App'x J, 6; Tr. vol. 29, 96.

57 See Tr. vol. 17, 115.

58 *See* Carbon Plan, Ch. 4, 21.

information has been gathered, the Companies are now recommending (as was explained in the rebuttal testimony of the Long Lead-Time Resources Panel) that the near-term development activities for offshore wind should occur specifically for the offshore wind lease currently held by the Companies' unregulated affiliate, Duke Energy Renewables Wind, LLC for one of the two lease areas in the Carolina Long Bay ("DERW" and such lease the "DERW Lease").[59] In order for DEP to pursue such development activities, the DERW Lease must be transferred to DEP, with such transfer occurring at cost[60] and upon notice to the Commission of the transfer itself (in a manner consistent with applicable law including the Regulatory Conditions).

The transfer of the DERW Lease and commencement of development activities for the DERW Lease is the only option that allows the Commission and the Companies to remain in control of the development of offshore wind. All other pathways introduce substantial uncertainty regarding whether offshore wind will be available at all or available on a timeline and at a cost that is consistent with the Carbon Plan and HB 951.[61]

One of the aspects that makes offshore wind unique is that there are a limited number of offshore wind leases available to serve the Carolinas in the near-term. In addition to the DERW Lease, there are two additional offshore wind lease areas potentially available to serve the Carolinas—one lease held by Avangrid Renewables, LLC ("Avangrid") and one lease held by TotalEnergies Renewables USA, LLC

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[59] *See* Tr. vol. 29, 95.

[60] *See* Tr. vol. 29, 103-04. Transfers from an unregulated affiliate to a regulated utility are required to be made at the lesser of cost or market. In this case, the cost of the lease is equal to the market price, as the market price was established through an open bidding process that occurred approximately six months. Therefore, the DERW Lease would be transferred at cost.

61 *See* Tr. vol. 29, 101-04.

("TotalEnergies"). Substantial uncertainty exists regarding whether, on what timeline, and at what cost such other leases may be available as part of the Carbon Plan.[62]

Given the timing of the BOEM auction for the Carolina Long Bay onshore wind energy area lease and the approaching moratorium, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. To ensure the availability of a wind lease option, Duke Energy Corporation, the parent company of DEP, determined a risk-adjusted price it believed was reasonable to bid into the auction, which resulted in the acquisition of the DERW Lease by DERW.[64]

The Companies are not suggesting that the other offshore wind leases will be precluded from incorporation in the Carbon Plan in the future, but simply that the prompt transfer of the DERW Lease and development by DEP is the only avenue that provides certainty to the Commission and the Companies that offshore wind could potentially be available on a timeline consistent with the timelines assumed in the Carbon Plan, at a known price and from a willing seller.[65] Similarly, ownership and development by the Companies provides the ability to control the pace of development at a rate that is

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62 *See id*.

63 *See id*. at 158, 160-63.

64 *See id*. at 103.

65 *See* Tr. vol. 29, 95:12-15.

consistent with future Commission direction. For example, ownership by the Companies, coupled with guidance from the Commission on the desired timeframe for an offshore wind resource to support the Carbon Plan would enable the Companies to either accelerate development to as early as late 2030,[66] or even suspend the lease under 30 C.F.R. § 585.415(b) to slow development if the Commission desires.

A number of parties have recommended that a procurement event be conducted (and potentially administered by a third-party) to assess which of the three leases will provide the best value for customers.[67] Such a procurement, with a broad range of project differences and uncertainties, would be challenging to construct and evaluate. In addition to uncertain parameters and timeline for any such procurement event, this approach also carries with it the same risk discussed above—that is, the possibility that none of the three leases are ultimately bid into such procurement event or, in the case of the Avangrid or TotalEnergies' lease, are bid at unreasonable prices,[68] thereby leaving customers without any viable offshore wind option to meet the 70% Interim Target. Absent approval of the decision to incur development costs and a transfer of the DERW Lease to the Companies, any of the three entities that are not regulated by the Commission could choose to hold or dispose of their lease rights as they see fit.

In contrast, the DERW Lease can be transferred promptly and at cost (which is equal to market in this case), and the Commission can then directly oversee and be kept

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[66] *See* Tr. vol. 18, 98:4-100:13.

[67] *See, e.g.*, Tr. vol. 23, 164:21-165:3, 183:6-11.

[68] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

apprised of the development activities for the DERW Lease. Furthermore, there is already ample evidence that the DERW Lease provides the best value for customers, particularly because it must be transferred at the lower of cost or market. In contrast, the TotalEnergies' lease, which had a higher lease cost, would almost certainly involve some amount of markup.[69] And evidence from the proceeding indicated that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

During the expert witness hearing, a number of lines of cross examination centered on the view that the Commission should simply allow the three wind lease areas to be developed outside of the supervision of the Commission and that this approach would provide the least "risk" for customers. However, this argument ignores the very material risk that accompanies this approach—namely that none of these three leases are ultimately made available to serve the Companies' customers (i.e., if the facilities are ultimately not constructed or are constructed but dedicated to customers outside of the Carolinas) or none of the three leases are developed on a timeline consistent[70] with the Carbon Plan.

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69 *Compare* TotalEnergies Lease No. OCS-A 0545, available at https://www.boem.gov/renewable-energy/state-activities/commercial-lease-ocs-0545 (stating a total acquisition fee of $160 million); *with* DERW Lease No. OCS-A 0546, available at https://www.boem.gov/renewable-energy/state-activities/commercial-lease-ocs-0546 (stating a total acquisition fee of $155 million).

70 Any leaseholder may seek a suspension of the lease under 30 C.F.R. § 585.415(b) by setting forth "(a) the reasons for requesting a suspension and the length of additional time requested; and (b) an explanation of why the suspension is necessary in order to ensure full enjoyment of the lease and why it is in the government's interest to approve the suspension." The lack of a certain off-taker for the offshore wind

Offshore wind is identified in the short-term to achieve the 70% Interim Target in three out of the Companies' four initial portfolios and in the long-term in five out of six portfolios and supplemental portfolios. Therefore, the Companies' proposed offshore wind development activities are prudent and reasonable and a no-regrets strategy.

Importantly, as was made clear by the Long Lead-Time Resources Panel, Commission approval at this time to proceed with the transfer and development the DERW Lease does not foreclose the potential that any of the other leases could ultimately be included as part of the Carbon Plan in the future if determined to be beneficial for customers.[71] And the Companies are not asking for selection of offshore wind at this time. Instead, approval of the development activities will allow the Companies to provide a more refined cost estimate for offshore wind on the DERW Lease to the Commission in the 2024 Carbon Plan update and the Companies will also update the Commission regarding whether any new information has been made available regarding the potential availability and cost of the other offshore wind leases.

- ***For a more detailed discussion of the benefit of Offshore Wind, see Duke Energy Proposed Order at Findings of Fact 37-38; 129-140, 142-147.***

C. The Companies' Carbon Plan Modeling is Reasonable

The Carbon Plan was developed through a sophisticated and comprehensive analytical process using a suite of advanced technical models that was largely supported

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generation could form a basis for this suspension request. In addition, Dominion Energy took approximately seven years to submit their COP from the time they secured their WEA lease to COP submittal. *See* Tr. vol. 29, 133-34 (stating that Dominion acquired its lease in 2013 and did not file a COP until 2020). Avangrid, also, has developed their lease on timelines longer than it claimed. *See* Tr. vol. 23, 178 *compared with* Duke Energy Avangrid Direct Cross Examination Exhibits 1 and 2.

[71] *See* Tr. vol. 29, 94:19-23, 101:13-102:8, 104:4-11, 165:14-167:16.

by Public Staff and was presented in an unprecedented level of detail and transparency to ensure that the resulting portfolios and the proposed near-term actions support all four core Carbon Plan energy transition objectives.[72] The Companies' inputs, assumption and forecasts were reasonable and also largely supported by Public Staff (with a handful of noted differences in opinion).

As described in Chapter 3 and Appendix E, the Companies' modeling process involves significant sensitivity analysis on many input variables to test the robustness of the modeling under various changes or sensitivities to inputs.[73] In addition, the Companies exerted substantial effort to identify areas of consensus by working with the Public Staff to identify appropriate and potentially impactful modeling functionality and input assumptions through supplemental modeling that was performed within the very tight timelines for this proceeding.[74] In light of recent upward inflationary pressures on technology costs and the significance of the newly passed IRA, Duke Energy also performed preliminary modeling sensitivity analysis based on an initial review of the IRA to test the robustness of the Companies' proposed near-term actions. This IRA modeling sensitivity further validated the near-term actions.[75]

Duke Energy continues to support the comprehensive multi-step modeling process used to develop the Carbon Plan as reasonable and appropriate. Though certain intervenors criticized certain "out of model" steps, the Companies strongly believe that it is not

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[72] *See* Tr. vol. 7, 224-33.

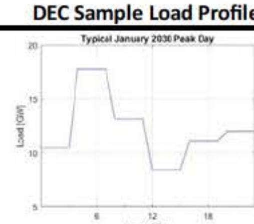
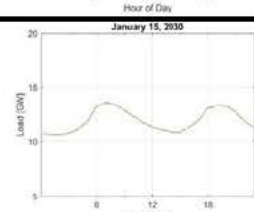
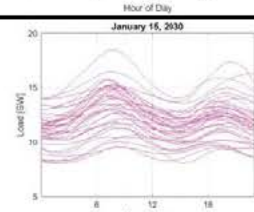
[73] *See* Carbon Plan, Ch. 3, 12-15; App'x E, 84-102.

[74] *See* Tr. vol. 7, 245-56

[75] *See* Tr. vol. 27, 70-73; Duke Energy Late-Filed Exhibit 1.

reasonable to rely entirely on capacity expansion model results for economic selection of energy storage or for reliability validation.[76] The Companies appreciate the focus on ensuring that Duke Energy's enhanced modeling steps—which, while necessary, are admittedly not as transparent to stakeholders as the EnCompass capacity expansion modeling process—are reasonable. Overall, the Companies' multi-step modeling framework, as described in detail in Appendix E and further addressed in testimony, was reasonable and appropriate for planning purposes and achieved reasonable results. The progression of the Companies' modeling analysis is shown in the figure below, which illustrates and describes how each step increases in depth in order to ensure that the resulting portfolio will maintain or improve reliability as required by HB 951.

Scope and Purpose of the Models Used in the Carbon Plan Analysis

Model	Purpose	Scope	DEC Sample Load Profile
Capacity Expansion (EnCompass)	Initial screening of thousands of possible portfolios	• All resource options • All years • 2 "typical" days/month • Four-hour time blocks	
Production Cost (EnCompass)	Detailed operational and economic analysis of a single portfolio	• Fixed portfolio • Every hour of every year • Single weather scenario • Single outage scenario	
SERVM	Detailed reliability analysis under a variety of conditions	• Fixed portfolio • Every hour of a single study year • 41 weather scenarios • 50 outage scenarios	

[76] *See* Tr. vol. 27, 100-102.

As the figure shows, the Companies used the EnCompass capacity expansion model to screen resource options and develop initial Carbon Plan portfolios. The Companies then used the EnCompass production cost model to evaluate hourly portfolio operations, and then SERVM to assess whether each portfolio could be expected to maintain or improve system reliability in the future.[77]

The Battery-CT Optimization step was a reasonable economic assessment in advance of the reliability validation step. This least cost portfolio verification step was not "out of model" but utilized more detailed production cost modeling within EnCompass to confirm economic selection of battery resources by the capacity expansion model. The Modeling and Near-Term Actions Panel explains that this step was necessary and appropriate to address the simplified simulations used in capacity expansion modeling, which cannot effectively evaluate in-depth economic operation of resources to ensure economic resource selection, especially in the case of energy-limited resources such as storage.[78] Duke Energy's decision to use more detailed production cost modeling more accurately accounts for the cost to operate the system with battery resources versus CTs. Through this analysis, the Companies' production cost modeling identified that capital cost savings for a limited amount of CTs offset the system production (fuel) cost increase and further determined that CO2 reduction targets can still be met, thereby demonstrating that limited replacement of batteries with CTs is the more cost-effective resource.[79] Importantly, energy storage will play an important role in the energy transition, and the

[77] *See* Tr. vol. 27, 99.

[78] *See* Tr. vol. 7, 227-28.

[79] *See* Tr. vol. 7, 230.

Companies reiterate that this process is evaluating a small portion of the overall planned energy storage on the system, to ensure its economic inclusion in the portfolios.[80]

The Companies also reasonably performed a final Portfolio Verification and reliability validation step using both EnCompass's production cost module and the SERVM to validate that the adequacy and reliability of the Companies' systems was maintained or improved under each of the Carbon Plan portfolios. SERVM is widely utilized in the utility industry to assess reliability standards and quantify the reliability requirements for large, complex power systems including determining planning reserve margin requirements and effective load carrying capability (ELCC) or capacity values.[81] The Modeling and Near-Term Actions Panel explains that this enhanced reliability validation modeling analysis is especially important for portfolios with high reliance on variable energy and energy-limited resources, which presents risks that planning reserve margins alone do not adequately address, especially in severe and prolonged weather events.82

There was substantial focus in the proceeding on whether and to what extent particular intervenors were able to replicate the Companies' modeling results. As an initial matter, the Companies do not believe that 100% replication is an appropriate standard or expectation, particularly given the scope and complexity of the Companies' modeling, along with the compressed timelines under which all parties were working. Importantly, however, Public Staff was able to work with Anchor Power Solutions and confirm the

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[80] *See* Tr. vol. 7, 229.

[81] Tr. vol. 7, 227.

[82] *See* Tr. vol. 7, 228-32; Tr. vol. 27, 98-99.

Companies' supplemental modeling with "very slight deviations" that, in the Companies' opinion, were inconsequential differences over the longer-term.[83] Public Staff witness Thomas suggested during the hearing that many of the challenges faced were due to the compressed timeframe for the proceeding.[84] NCSEA et al. witness Fitch also testified that he viewed intervenors challenges initially validating Duke Energy's modeling to be "growing pains" in the process that should be expected, as the models are complex and "the validation issue could likely be from some other input problem . . . deep inside the model[]" and "chalk[ed] it up to . . . the compressed timeline" of the proceeding.[85] Finally, as discussed above regarding the asymmetric scrutiny applied in this proceeding, no parties have attempted to 100% replicate the results of any of the other alternative analyses.

The Companies look forward to continuing to work with the Public Staff and other stakeholders to further improve and refine the process in advance of the 2024 Carbon Plan update. The Companies are hopeful that, having now been through this process a first time, future proceedings may avoid certain technical misunderstandings that were largely the product of using a new model combined with a compressed timeline for this proceeding.

- ***For a more detailed discussion of modeling framework and analytical approach issues, see Duke Energy Proposed Order at Findings of Fact 3-13; Pages 23-55.***

[83] Tr. vol. 21, 367-370.

[84] *See* Tr. vol. 23, 53 (Public Staff witness Thomas explaining "in full, you know, transparency, I think a lot of some of the issues may have arised simply because of the compressed timeframe that Duke had to perform all this modeling with EnCompass and share this data in a way that is not really precedented in terms of sharing modeling inputs like they have.").

[85] Tr. vol. 24, 249-250.

D. Consistent with HB 951's Requirements, the Companies' Carbon Plan Appropriately Focused on Improving or Maintaining Reliability in Ways that Many Intervenors Failed to Do.

Executing the Carbon Plan will be transformative to the Companies' generation fleets and underlying grid, connecting unprecedented amounts of new supply-side resources and leveraging demand-side tools necessary to retire significant amounts of coal-fired generation and achieve the carbon emission reduction targets important to the Companies, their customers in the Carolinas, and established by HB 951. DEC and DEP system operations functions must maintain a secure and reliable electric grid every minute of every day through this transformative period of energy transition, while meeting the Companies' core obligations as an electric service provider and the provisions of HB 951 to maintain or improve upon the adequacy and reliability of the existing grid.[86] Duke Energy believes that certain intervenors in this proceeding failed to appropriately focus on or consider reliability and that, in contrast, the Companies reasonably and necessarily brought to bear reliability considerations on both the modeling process and their consideration of the overall operations implications of the execution plan specifically and the energy transition generally.

Specifically, from a modeling perspective, none of the intervenors conducted any reliability validation step similar to that performed by the Companies, described in Appendix E and discussed in the Companies' Modeling and Near-Term Panel testimony, which are necessary to ensure the Companies can reliably serve load under real world conditions. Failure to perform these reliability verification steps—and relying solely

[86] *See* Tr. vol. 19, 116.

on the planning reserve margin to ensure system reliability—ignores the reality of a changing resource mix and substantially increases the risk that, if the resulting portfolio were implemented, the Companies would be unable to maintain system reliability as mandated by HB 951.[87] The continuing transition to greater reliance on variable energy and energy-limited resources makes the inclusion of enhanced reliability verification methods a vital part of a robust Carbon Plan analysis. The capacity expansion model's reliance on a static reserve margin and a limited set of resource ELCC values makes it an inadequate tool for ensuring system reliability across a wide range of forced outage and weather scenarios, particularly for portfolios that contemplate a transition away from firm, dispatchable resources and towards substantially higher levels of variable energy and energy-limited resources.[88] Similarly, the deterministic, hourly production cost model that relies on weather-normal load and renewable energy generation forecasts is a necessary step, but it is not sufficient for ensuring system reliability for Carbon Plan portfolios across a range of potential real-world conditions. The Companies' operational experience with exceptional weather and outage patterns informed and guided the reliability validation step as part of Carbon Plan modeling and was crucial to ensure portfolio reliability performance required by HB 951. Going forward, the Companies will continue to integrate operational experience into Carbon Plan modeling validations, and reliability analysis and metrics will evolve in step with industry experience and North American Electric Reliability

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[87] *See* Tr. vol. 7, 393.

[88] *See* Tr. vol. 7, 391.

Corporation ("NERC") Reliability Standards—understanding that a model cannot feasibly capture all operational conditions.[89]

From an operations perspective, the Companies' witnesses provided real-world perspective on the challenges system operations functions will face maintaining adequacy and reliability through this grid transformation and planned greater reliance on low carbon resources during the transition.[90] Fundamentally, the results of portfolio planning, modeling, analysis and validation must have a connection to the real world of system operators who manage anticipated, unanticipated and emergent events.

The Companies are in the unique role of owning the obligation to serve customers securely and reliably, every minute of the day in all operating and weather conditions and meeting NERC reliability obligations to ensure the stability of the Bulk Electric System and broader Eastern Interconnection electric grid—no intervenors have this responsibility.[91] The Companies are accountable to the Commission and their customers for ensuring the adequacy and reliability of the existing grid is maintained or improved, and the Carbon Plan approved by the Commission must be executable and appropriately manage operating and reliability risks.

The Companies' system operator witnesses, Sam Holeman and Sammy Roberts (Reliability Panel), identified two key elements necessary to their ongoing ability to reliably serve customers as the Companies consider the industry perspective of grid transformation and plan to execute the Carbon Plan to reduce CO_2 emissions. First, it is

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[89] *See* Tr. vol. 30, 96-97.

[90] *See* Tr. vol. 19, 196.

[91] *See id*.

critical to have a robust and diverse resource mix to ensure system operators have multiple tools in their generation adequacy and reliability toolbox to deal with expected and unexpected operational conditions.[92] There should not be an overreliance on any single technology, as all technologies—renewables, demand-side resources, batteries, nuclear, flexible gas resources—will be necessary to both reduce CO2 emissions and maintain or improve upon reliability of the grid. Second, as the Companies retire over 8,400 MW of coal-fired generation by the end of 2035—representing approximately 20% of existing winter capacity for the combined systems[93]—and rely more on the sun to shine, the wind to blow, and batteries to be charged, system operators must have access to enough flexible, dispatchable replacement capacity with similar operational capabilities as coal units to meet NERC Reliability Standards, particularly in seasonal and extreme events.[94]

NERC has acknowledged that traditional resource planning methods may no longer be sufficient to consider the real-world grid impacts and interactions of an evolving resource mix with less baseload generation and more variable generation, inverter-based resources, storage, and distributed energy resources, leading to potential generation or transmission insufficiencies.[95] For example, resource adequacy has traditionally been assumed through verifying capacity with appropriate planning reserves to serve peak demand in long-term resource planning. However, recent industry events have highlighted that the changing resource mix performing in real-world situations can result in energy

[92] *See id.* at 118.

[93] *See* Carbon Plan Executive Summary at 17.

[94] Tr. vol 19, 118.

[95] *See id.* at 133.

inadequacy. NERC also identified that fuel disruptions from weather events or extreme natural events may not be fully accounted for in resource adequacy assessments, particularly as more resources with weather-dependent fuel, such as the sun and wind, are integrated in high amounts into the system as grid connected or distributed resources.[96] Another risk component that NERC identified was the sequencing of resource transitions so they do not negatively impact resource adequacy, such as timing coal unit retirements with the full assurance of timely replacement with a mix of resources that have an operational profile complementary to those retiring units.[97] Finally, NERC highlighted the risk component of not having adequate flexible resources that are dispatchable to meet demand when less flexible resources, such as solar and wind, are unavailable.[98]

NERC asserts the ongoing need for dispatchable resources to mitigate potential capacity and energy shortfalls due to changing resource mixes by stating that "[u]ntil storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain a necessary balancing resource to provide increasing flexibility needs"[99] and that "[r]esource planning and policy decisions must ensure that sufficient balancing resources are developed and maintained for reliability."[100] To manage the risk of variability, adequate risk margins in the form of flexible operating reserves will be required to meet demand over both shorter operational periods and for prolonged extreme events—ensuring both capacity and energy adequacy.

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[96] *See id.*

[97] *See id.* at 134.

[98] *See id.*

[99] 2022 State of Reliability Report at 26.

[100] *Id*. at 27.

As the Companies consider system resource mix changes through decarbonization, electric systems become more complex, layered, and interdependent when meeting a variety of operational conditions. In context of a storm like the recent winter storm Uri in Texas, a resource mix that relies on significant levels of solar capacity may have little generation for days due to precipitation and cloud cover. A system that relies on energy efficiency and demand response to reduce demand may lose margin as customers need more energy in severe winter conditions. Likewise, a system that relies heavily on batteries would need to carefully plan and coordinate energy balance and replenishment of energy-limited batteries to span a multi-day event, particularly if those batteries are charged from solar. These events highlight how the Companies must evaluate future resource mixes in the context of extreme seasonal events, including understanding both man-made and natural fuel dependencies, operating parameters of all resources, availability of demand response and distributed resources, reliance on storage, and how all the various resources in a new resource mix may be impacted during similar prolonged extreme operating conditions and time periods.[101]

As the Companies' Reliability Panel explained, gas resources (CT and CC units and dual fuel conversions) are a necessary reliability "bridge" on the path to achieving Carbon Neutrality to fill part of the resource adequacy needs created by the retirement of coal units.[102] In all Plan portfolios, based on coal retirement and generation replacement concerns, additional gas generation capacity is a necessary complement to renewables and storage to provide dispatchable capacity and ensure energy adequacy during winter months

[101] *See* Tr. vol. 19, 151-52.

[102] *Id.* at 177.

when solar output is not well correlated to the Companies' early morning peak load shapes and overall energy demands can remain high for extended periods of time.[103] Not only is solar not well correlated to the Companies' winter load shape, as mentioned previously, winter is the time where solar capacity factors can vary drastically. This day-to-day change would make it difficult, if not impossible, to reliably depend on significant solar energy to store for peaking capacity needed to ensure reliability during an extended cold weather period. Gas technology options have the key reliability advantage of controllable output and sustained output when needed, over long durations, and are additionally more efficient than coal units.[104]

A number of intervenors highlighted the critical importance of planning for continued reliability and resource adequacy as the Companies execute the Carbon Plan and integrate higher levels of renewable and intermittent resources. CUCA,[105] CIGFUR,[106] and Person County[107] reinforced the need to ensure adequate dispatchable resources as increasing levels of renewable and intermittent resources are added to the grid. NCEMC agreed with Duke Energy that "generation resource diversity provides flexibility and mitigates the risk of implementation failure that could otherwise result from overreliance on any one technology to meet reliability and resilience requirements as the energy

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[103] *Id.* at 183.

[104] *Id.* at 173-74.

[105] *See* CUCA July 15th Initial Comments at 13-14.

[106] *See* CIGFUR July 15th Initial Comments at 3-4.

[107] *See* Person County July 15th Initial Comments at 16-25.

transition evolves"[108] and that DEC and DEP forming a single balancing authority area will improve reliability.[109]

The alternate plans proposed by certain other intervenors did not adequately take into account the critically important requirement under HB 951 that the Carbon Plan must maintain or improve the adequacy and reliability of the grid during this accelerated period of system transformation. Such other plans provided no additional analysis, quantitative or qualitative, assessing adequate power supply and Bulk Electric System reliability considerations that the Companies identified in the Carbon Plan through Appendix Q (Reliability and Operational Resilience Considerations) and through enhanced reliability validation modeling efforts used in the portfolio development process.[110]

For instance, the Companies' Reliability Panel provides actual customer demand and irradiance experience during January 2018 applied to additional solar in the Carolinas. As shown in Figure 13 of the Reliability Panel's Direct Testimony, certain of the alternative plans presents by intervenors would not have provided energy adequacy for reliably serving this real world 3-day winter high customer demand event, as they are over-reliant on the weather-dependent solar and wind resources, and the associated storage of energy from these weather-dependent resources.[111] Furthermore, these proposed portfolios retire coal early without effectively providing replacement generation or resources that can

[108] NCEMC July 15th Initial Comments at 16.

[109] *See id.* at 9.

[110] *See* Tr. vol. 19, 196.

[111] *See id.* at 199-200.

achieve high capacity factors for extended periods when needed as demonstrated by Duke Energy's coal generation in January 2018.

In conclusion, maintaining reliability of the system is a core objective of the HB 951 framework and the Companies' Carbon Plan was appropriately informed by Duke Energy's real-world experience in operating the system, utilizing appropriately granular modeling refinements and continually assessing the Plan from an operator perspective and leveraging a national perspective on the energy transition.

- ***For a more detailed discussion of reliability issues, see Duke Energy Proposed Order at Findings of Fact 53-54; Pages 200-212.***

E. The Commission should approve the Companies' other requests for relief

As discussed above, the Companies' Petition includes a comprehensive set of requests for relief that cover a wide range of issues, all of which are essential to the continued energy transition and achievement of the CO_2 reduction goals established under HB 951. The following addresses certain of the additional key requests.

1. Grid Edge

The Companies' Carbon Plan included extensive details regarding the Companies' Grid Edge plans, as further explained in the testimony of the Grid Edge Panel. The Companies are on the forefront of innovative Grid Edge activities and initiatives.[112] Indeed, as explained in the Carbon Plan Executive Summary, the first pillar of energy transition and the Carbon Plan process is to "shrink the challenge" by reducing energy

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[112] *See* Tr. vol. 13, 30-31.

requirements and modifying load patterns through Grid Edge customer programs, allowing more tools to respond to fluctuating energy supply and demand.[113]

All of the work needed to advance new Grid Edge programs will occur outside of this Carbon Plan proceeding in separate dockets to be initiated in the coming months and years. The Companies' only Grid Edge related request for relief is that the Commission signal some level of support for the Companies' plan to update the underlying determination of the utility system benefits in the Companies' approved EE/DSM Cost Recovery Mechanism. This support is obviously directional only, as the actual updates will need to be fully detailed and considered in future dockets.[114]

From a Carbon Plan modeling perspective, substantial attention was focused on the Companies' EE/DSM assumptions that were embedded in the load forecast. For purposes of Carbon Plan modeling, the Companies assumed an aggressive but reasonable annual reduction of 1% of eligible load from EE programs. This assumption is built on the Companies' extensive, real-world experience in the Carolinas and detailed engagement in the Carolinas EE/DSM Collaborative ("Collaborative") and is an aggressive but achievable target.[115] Various intervenors assert that substantially higher amounts of energy efficiency and DSM and customer programs can be achieved but the Companies do not believe that such assumptions are reasonable or justified at this time under existing legal frameworks

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[113] *See* Carbon Plan, Exec. Summary, 9.

[114] *See* Tr. vol. 13, 31-32.

[115] *See id.* at 35-38.

and market conditions.[116] Importantly, however, due to the iterative, biennial nature of the Carbon Plan process, it is not necessary to have the perfect projection of future EE/DSM.

While a number of intervenors advocated for substantially higher assumed levels of EE/DSM, Public Staff asserted that the 1% of eligible load assumption was too aggressive.[117] The unrealistic intervenor EE assumptions substantially reduced the amount of load to be served, which in turn, artificially reduces the amount of supply-side resources needed and skewing the validity of any resulting proposed plan.[118] Despite predicating their model result on these unrealistic assumptions, such intervenors provided no meaningful roadmap for how such levels of EE would be achieved. Several intervenors that advocated for substantially higher amounts of forecast EE savings based such forecast on industry reports but ignored the ways in which such reports do not accurately represent realistically achievable results in the Carolinas. The Grid Edge Panel demonstrated the ways in which a comparison of energy efficiency as a percentage of the retail sales against other utilities is misleading given the wide variety of factors that directly impact such amounts but that are outside of the Companies control, such as the reality that electric usage and electric rates differ significantly between states and that states have substantially divergent laws, regulations and policies and substantially different methodologies for assessing what can be accounted for as EE savings.[119]

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[116] *See id.* at 48-52.

[117] *See id.* at 52-53.

[118] *See* Tr. vol. 7*,* 381.

[119] *See* Tr. vol. 13, 49-52.

The Companies' use of an annual energy efficiency forecast of 1% reduction of eligible load strikes the appropriate balance between reaching beyond the reasonable assumptions in the approved 2020 IRP to ensure the Companies are aggressively pursuing energy efficiency and demand-side measures to benefit customers and assuming an unattainable target. In the Carbon Plan or other resource plans, it is risky to assume an unachievable level of energy savings which could result in not planning for additional supply-side resources. As the Companies work to implement the identified enablers and new programs, it may be appropriate to update and refine the EE forecast in the Carbon Plan biennial updates to continue to ensure the appropriate balance is maintained and any needed changes to planned supply-side resource needs can be effectuated. [120]

As discussed above, the first step in achieving the energy transition in a least-cost manner is to reduce and manage load at the edge of the grid, with a suite of grid-edge customer programs that include energy efficiency, DSM, customer self-generation, voltage management, and other distributed energy resources. The Companies intend to offer a compelling menu of pricing options to customers to reach the adoption levels necessary for a material impact on peak loads. The enablers identified will help the Companies develop cost-effective programs that will empower our customers to reduce their energy usage and achieve the 1% energy efficiency target.[121]

Additionally, tariff-on-bill programs are not yet before the Commission; once approved, they will be important components of the Companies' energy transition and implementation of the Carbon Plan. To that end, the Companies request that the

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[120] *See id.* at 55.

[121] *See id.* at 73-74.

Commission acknowledge those programs as such during the tariff-on-bill proceedings. Finally, the Companies also recommend that the Commission consider an expedited regulatory process for innovative new pilot programs will be essential to enabling more innovation with respect to Grid Edge activities.[122]

- ***For a more detailed discussion of Grid Edge, see Duke Energy Proposed Order at Finding of Fact 46; Pages 162-172.***

2. Transmission Planning, the Red Zone Expansion Projects, Offshore Wind Interconnection and Interconnection Generally

The Commission also received extensive evidence regarding transmission planning generally and the need for the Red Zone Transmission Expansion Projects ("RZEP") more specifically. Executing the energy transition away from coal generation will require a transformation of and investment in the DEC and DEP transmission systems to interconnect and safely and reliably deliver the unprecedented amounts of new supply-side resources that will be needed to retire significant amounts of coal-fired generation and achieve the carbon emission reduction targets established HB 951. The Companies' Transmission and Solar Procurement Panel provided an overview of this significant transmission system transformation and investment associated with executing the Companies' proposed near-term plan for coal retirements and interconnecting incremental resources, as well as enabling execution of the intermediate-term to long-term plans associated with the Carbon Plan portfolios.[123] In addition, the Companies provided an overview of Companies' transmission planning processes for ensuring a reliable system compliant with NERC Reliability Standards and Federal Energy Regulatory Commission

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[122] *See id.* at 74.

[123] *See* Tr. vol. 16, 53-55; *see also* Carbon Plan, App'x P, 12-15.

("FERC") orders, including processes for evaluating the interconnection facilities and network upgrades necessary for integrating incremental resources.[124]

The Companies support transitioning to a more proactive transmission planning process and are committed to working through the FERC approved NCTPC local transmission planning process to collaboratively assess and plan for the transmission projects that will be needed to interconnect new generation identified as needed in the Plan and to achieve HB 951's emission reduction targets. The RZEP projects represent the first significant step in this proactive approach, which will enable the interconnection of large amounts of solar needed to execute the energy transition and Carbon Plan successfully and also provide other benefits to customers. The RZEP projects are a prudent and necessary first step to interconnect to the DEC and DEP systems the volume of solar needed to execute the Carbon Plan.[125] Under the Carbon Plan, up to 5.4 GW of additional solar will need to be interconnected to the DEC and DEP systems by 2030 for Carbon Plan execution. Based on numerous transmission planning studies, the high solar viability region located in the red zones will need to have the associated transmission constraints relieved to enable interconnecting this volume of solar within the timeframes necessary to meet carbon reduction objectives.

Furthermore, there will be additional benefits from these RZEP projects. The increase in transmission capability will help to enable solar located in the red zones to charge stand-alone battery storage that is located closer to load centers. During high solar capacity factor, blue-sky days when solar energy is creating excess energy on the system,

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[124] *See* Tr. vol. 16, 56-57; *see also* Carbon Plan, App'x P, 2-4, 8-10.

[125] *See* Tr. vol. 16, 66-67.

rather than curtail solar output this excess energy can be used to charge stand-alone battery storage located closer to load centers.[126] This carbon-free energy can be discharged to meet load center demand during the winter and summer net demand peak periods. Another benefit resulting from the RZEP projects is that they will replace aging, less resilient equipment with new, more resilient equipment such as replacing wood poles with steel poles.[127]

The Companies exerted considerable effort to produce supplemental studies during the Carbon Plan proceeding in consultation with Public Staff that further validated the need for the RZEP. Specifically, the companies conducted supplemental cluster-type studies of the most recent generator interconnection requests for 5.4 GW, which aligns with the level of solar identified by the Carbon Plan Portfolio 1 as needed to meet a 70% CO_2 reduction objective by 2030. The supplemental study scope and criteria were discussed and agreed upon with the Public Staff in advance of performing the study.

Based on the foregoing, the Companies reiterate their request that the Commission acknowledge that HB 951 supports the energy transition and need to interconnect new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the Open Access Transmission Tariff and direct the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the NCTPC and other appropriate forums.[128]

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[126] *See* Tr. vol. 16, 78-79.

[127] *See id.*

[128] *See* Duke Energy Verified Petition, at 12, 17.

Certain parties raised a recommendation that the Commission hire a third party, assisted by an independent technical advisory committee to study the achievability of higher solar interconnection rates.[129] The Companies strenuously object to this recommendation due to the fact that is based on a faulty premise that the Companies' historic interconnection accomplishments are somehow deficient or that the Companies are somehow failing to continually pursue opportunities to further improve its interconnection process—nothing could be further from the truth. The Companies have been a national leader in solar interconnection for many years. While there has been a recent decrease in the amount of annual solar interconnection in the past few years, the primary driver of such amounts were factors outside of the Companies' control.[130] In actuality, the Companies proactively implemented queue reform even while interconnection processes in other markets around the country have encountered substantial challenges and delays.[131] The Companies have also proactively sought to identify new practices to expedite interconnection, and the assumed annual interconnection amounts in the Companies modeling compare very favorably to the interconnection amounts achieved in other states (when compared on an apples to apples basis).[132] In sum, there is simply no factual basis on which to conclude that there is a "problem" to be solved, let alone one that requires the involvement of a third party, which would introduce a burdensome and potentially expensive new layer of oversight.

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[129] *See* Tr. vol. 26, 45-46

[130] *See* Tr. vol. 7, 348-49, 353.

[131] *See* Tr. vol. 25, 122-125.

[132] *See* Tr. vol. 16, 88.

Finally, the Companies have determined that based on the 2020 NCTPC Offshore Wind Study and additional Duke Energy cost analysis, considering cost effectiveness, reliability, and interconnectivity, the New Bern point of interconnection ("POI") is the most appropriate for importing up to 1,600 MW of offshore wind into the DEP system. New Bern is the most feasible and economic POI for injecting 800 MW to 1,600 MW of offshore wind, with capability to inject even more offshore wind energy. In addition to the 2020 NCTPC Offshore Wind Study, Duke Energy performed a cost analysis to determine the most cost-effective transmission path including the POI for importing up to 1,600 MW of offshore wind into the DEP system. This cost analysis, which included both offshore and onshore transmission costs (network transmission and interconnection facilities), revealed that the New Bern POI was approximately $700 million less compared with other potential POIs. The New Bern POI also allows the Companies to utilize existing right-of-way for the network transmission and will reduce risk and cost for an offshore wind project. The Companies need to immediately start preliminary routing, scoping, siting, and right-of-way acquisition for offshore wind transmission projects to deliver power from the onshore landing site to the point of interconnection at the New Bern Substation consistent with an in-service date that facilitates commercial operation of offshore wind energy on the DEP system by 2030. Delaying these activities to 2024 or beyond means the transmission infrastructure will have a later in-service date and the ability to bring offshore wind energy into the DEP system will be delayed beyond 2030. To be clear, constructing the transmission needed to interconnect offshore wind has substantial execution risk and 2030 is already expected to be very challenging to achieve.[133]

- ***For a more detailed discussion of transmission planning, see Duke Energy Proposed Order at Finding of Fact 47; Pages 172-178, 187-193.***

- ***For a more detailed discussion of RZEP, see Duke Energy Proposed Order at Finding of Fact 48; Pages 178-193.***

- ***For a more detailed discussion of offshore wind transmission, see Duke Energy Proposed Order at Pages 136-138.***

3. Disciplined and Orderly Pursuit of Subsequent License Renewals ("SLRs") for the Companies' Existing Nuclear Fleet and Modifications to Expand Flexibility of Existing Gas Resources

In its requests for relief, the Companies requested that the Commission approve the Companies' proposed actions with respect to existing supply-side resources, including through expanding flexibility of the existing gas fleet and continued disciplined pursuit of SLRs for the Companies' existing nuclear fleet.[134] Public Staff supports pursuing these actions and no intervenor has meaningfully opposed.[135] Continued operation of the Companies' existing nuclear fleet is a foundational component of the Companies' Carbon Plan and planning for continued operation of these low-priced, 24/7 emission free resources will provide substantial benefits to customers. Expanding the flexibility of existing natural gas units will also benefit customers by ensuring the system is able to accommodate the increased amounts of intermittent generation.

- ***For a more detailed discussion of development plans for enhancing the capabilities of existing supply-side nuclear and gas resources, see Duke Energy Proposed Order at Findings of Fact 41-45; Pages 147-153, 160-162.***

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[133] *See* Tr. vol. 28, 137.

[134] *See* Duke Energy Verified Petition, at 10-11, 16.

[135] *See* Public Staff July 15th Initial Comments at 159-60; Tr. vol. 21, 132-34.

4. Many Important Issues Raised in this Proceeding Cannot be Fully Resolved in the Carbon Plan but have been adequately addressed and should not delay Commission action on the Companies' proposed Carbon Plan.

There were a range of important issues raised in the proceeding relating to the Companies' Carolinas utilities operations that will continue to be crucial going forward but are not susceptible of resolution at this time. The Companies believe that such issues have been addressed appropriately in this proceeding and should not delay or impact the Commission's actions in this proceeding. The Companies are committed to getting to work on these issues in the near-term and acknowledge that such issues are important and will require further Commission attention in future proceedings at the appropriate time.

5. Rate Differences, Merger and North and South Carolina Alignment.

The Commission received very important testimony concerning three crucial issues for the future of the energy transition: existing and future rate differences between DEP and DEC, a potential merger of DEP and DEC, and continuation of dual-state planning operation through North and South Carolina alignment.[136] These issues are distinct but related, and the Companies have provided the Commission with a road map for how these issues will be addressed going forward.

With respect to rate differences, the Companies explained the historic factors that led to the current rate differences and importantly, why such rate differences are to be expected between two different utilities with different systems that have been planned and developed separately over many decades.[137] As the Public Staff acknowledged, these types

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[136] *See generally* Tr. vol. 15, 22-35 (Carolinas Utilities Operations Panel Direct); Tr. vol. 23, 91-102 (Public Staff McLawhorn Direct); Tr. vol. 28, 54-60 (Bateman Rebuttal).

[137] *See* Tr. vol. 28, 54.

of differences can be expected based on unique characteristics of each utility, and while DEP's rates are higher than DEC's, they still have been consistently below the national average.[138]

Looking forward, the Companies agree that the costs of the Carbon Plan that is to be executed jointly across the two utilities should be fairly allocated. However, the Companies have identified that, in addition to other potential benefits, a merger is the most straightforward method to addressing the potential for growing rate differences that are projected to occur under the Carbon Plan absent a merger. The projected impact of the Carbon Plan investments on current rate differences prior to the targeted merger is minimal to non-existent (depending on the portfolio assumed).[139] Therefore, the Companies believe that attention and resources should be devoted towards pursuing a potential merger rather than developing a "stop-gap" method to cost allocation that is not needed at this time. If stakeholders agree upon and regulators approve an equitable approach to a merger, once accomplished, it would allocate the Carbon Plan costs to customers of both legacy utilities. Finally, the Companies note that, in the currently pending DEP rate case, DEP has provided at the request of Public Staff, a proposal to allocate RZEP costs to DEC, though DEP does not support that approach at this time.[140]

The Companies have provided a detailed timeline for achieving a merger and intend to continue to pursue the merger.[141] The Companies believe that a merger of DEP and

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[138] *See* Tr. vol. 28, 54, 100-01.

[139] *Id.* at 56.

[140] *Id.* at 113.

[141] *See* Tr. vol. 15, Carolinas Utilities Operations Panel Direct Exhibit 1.

DEC would be in the long-term best interest of customers from an overall efficiency perspective. However, the Companies cannot accomplish a merger unilaterally, but instead must work with all applicable regulators and stakeholders to identify an equitable merger pathway, recognizing that any merger will necessarily and unavoidably result in cost shifts.

The Companies have also offered extensive evidence regarding the benefits of dual-state planning and operation, as well as the importance of maintaining the dual-state system over the long term.[142] Maintaining a dual-state system will continue to deliver benefits for customers, provide the most efficient pathway for the energy transition, and allowing the Companies to pursue all available avenues to ensure ongoing alignment. The Companies remain convinced that a larger, combined system with scale, generation diversity, and operational flexibility provides substantial value and limits additional risk to customers and that the energy transition is ultimately consistent with prudent utility planning and in customers' best interest.[143] Importantly, the timeline for Carbon Plan implementation and the 2024 biennial Carbon Plan update provides a sufficient runway to continue to evaluate these issues and allow for modification of the Carbon Plan if needed. Importantly, the near-term actions proposed in this Carbon Plan are "no regrets" actions that will be needed no matter how alignment is ultimately maintained. Furthermore, the Companies are also exploring alternative approaches that could facilitate continued state alignment, such as a framework pursuant to which the costs and benefits of new resources added to the system would be allocated between the states based each state's respective decisions.[144]

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[142] *See* Carbon Plan, Ch. 1; Tr. vol. 14, 32-37.

[143] *See* Tr. vol. 15, 35.

[144] *See* Tr. vol. 16, 19; Tr. vol. 28, 61.

In conclusion, these important issues need not delay or alter the Commission's decision in this Carbon Plan and the Companies acknowledge the importance of the issues and will remain committed to continued engagement with regulators and stakeholders to ensure fair and appropriate solutions.

- ***For a more detailed discussion of Carolinas utilities operations issues, see Duke Energy Proposed Order at Findings of Fact 49-52; Pages 193-200.***

6. Affordability and Low-Income Affordability Collaborative

The Companies understand the critical importance of maintaining affordable and competitive rates, and we are focused on continuing to achieve efficiencies across the business to maintain our affordable rates. Most importantly, the Carbon Plan requires identification of the least-cost pathway consistent with the requirements of HB 951. Affordability was a core objective of assessing each of the four portfolios, and cost was an important consideration in developing the varying timelines the portfolios presented. Those portfolios that extend the interim target beyond 2030 are both more affordable and carry less execution risk than Portfolio 1. In its consideration of the Carbon Plan, the Commission must weigh these factors and determine the least-cost path to compliance.[145]

The Companies are very attuned to the concerns about rate impacts from our commercial and industrial customers. While there is upward pressure on rates from a variety of factors, including many beyond the control of the utilities and being experienced across the country, like commodities prices, supply chain and labor shortages, and inflation, the Companies believe that achieving the carbon reduction targets will make the State more attractive to business and will lead to new opportunities for economic

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[145] *See* Tr. vol. 7, 55.

development. Furthermore, the Companies believe that the energy transition has and will continue to mitigate potential bill impacts on customers by introducing generation resources with lower or no fuel costs and decreasing dependence on coal generation (which faces increasingly challenged supply chains).[146] Finally, in response to stakeholder feedback and consistent with HB 951, the Companies will be proposing in the near future new customer renewable programs that the Companies believe, when combined with continued affordable and competitive rates, will continue to contribute to successful economic development in the State.

A number of intervenors have raised concerns specifically regarding low-income affordability. To ensure we are helping customers most in need now and in the future, we are taking steps with the input of the Low-Income Affordability Collaborative ("LIAC") to advance new proposals that will help our residential customers that may be struggling to pay their bills. The LIAC final report, filed with the Commission on August 12, 2022, details 22 proposals submitted and assessed by LIAC members. The proposals detail recommended solutions to address electric energy affordability by implementing energy efficiency programs, providing bill payment assistance, and potential policy changes to reduce electric energy burden and energy intensity. The LIAC research findings identified partnership opportunities with organizations that provide state-wide support for low-income customers will maximize savings for those customers and increase program participation.[147] Finally, DEP has proposed a new program in the pending rate case to assist low-income customers, which will be considered further in that docket.

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[146] *See id.*

[147] *See* Tr. vol. 7, 56-57.

7. Environmental Justice and Impacted Communities

Duke Energy believes that environmental justice is a business imperative, fundamental to operations and a pillar of meaningful stakeholder engagement. The Companies recognize and understand the importance of both the impact of Duke Energy's work on communities and early engagement with those impacted. In response to stakeholder feedback, the Companies convened a small group of environmental justice-focused stakeholders on May 3, 2022 and August 2, 2022, to discuss how to engage North Carolina communities and understand what issues are important to low-income customers and communities of color. Each meeting included about ten stakeholders, representing a variety of interests, including health, environmental, and economic impact of the Carbon Plan.[148] The Companies shared their commitment to environmental justice as a business imperative that is fundamental to the Companies' business operations and committed to take meaningful action to address these issues. This stakeholder engagement effort will be ongoing and will involve a select number of individuals committed to working together with the Companies to explore these complex issues and identify areas for potential partnership and progress. The Companies also held an Impacted/Frontline Communities stakeholder meeting on May 5, 2022 to initiate engagement with communities that are expected to be impacted by future coal retirements.[149] Many of these issues will emerge with more specificity as the Companies transition into the execution phase and begin considering some of the key procurement and siting decisions that will be required in the near-term action plan.

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[148] Tr. vol. 7, 49.

[149] *Id.*

F. Stakeholder Engagement and Third-Party Oversight

The Companies have engaged stakeholders in unprecedented ways both in connection with the Carbon Plan, as well as in connection with other ongoing separate regulatory processes and initiatives. Indeed, stakeholder engagement has become an integral component driving Duke Energy's business strategy and initiatives, particularly over the past several years. Underpinning recent key regulatory initiatives, such as generator interconnection queue reform and the Competitive Procurement of Renewable Energy Program, has been effective engagement with stakeholders.

In initiating the development of the stakeholder process for the Carbon Plan, the Companies sought the expertise of a third-party facilitator, the Great Plains Institute ("GPI"), to advise the Companies in their efforts to create a process through which robust and meaningful collaboration with stakeholders could occur. Together with GPI, the Companies dedicated significant time and attention to creating an environment that encouraged open, constructive dialogue among a diverse group of stakeholders representing all segments of the energy industry as well as local communities. It is important to recognize that the stakeholder engagement specifically dedicated to the Carbon Plan represents only a portion of the Companies' holistic stakeholder engagement activities. The Carbon Plan was informed not only by the specific Carbon Plan stakeholder engagement, but by other subject matter-specific related stakeholder engagement efforts that pre-dated the Carbon Plan process.

However, it is also important to note that stakeholder processes are not a panacea for achieving consensus and should be employed thoughtfully and strategically. As it relates to an issue as broad and multi-faceted as the Carbon Plan involving an immensely wide range of stakeholder perspectives, stakeholder engagement is more appropriately focused on dialogue and sharing of perspectives. Achieving consensus on the Carbon Plan was challenging given the breadth of issues as well as, in the case of some stakeholders, the magnitude of the differences of opinion.

It is also true that stakeholder processes require substantial time and investment of resources—both from the Companies and from the stakeholders themselves. Therefore, the Companies believe that as the Commission considers various requests in this proceeding for new additive stakeholders processes, the Commission should think strategically about the value and benefit and, importantly, the intended outcomes of future stakeholder processes and also weigh the costs (in dollars, time and resources) of such processes.

The Commission also heard perspectives from certain intervenors as it relates to stakeholder engagement related to resource planning modeling and, in fact, the Commission denied a motion during the proceeding that would have forced the Companies to perform modeling on behalf of an intervenor party. As discussed above, the Companies did engage with stakeholders in an unprecedented way concerning the Companies modeling. Going forward, the Companies anticipate more engagement in advance of future Carbon Plan modeling and are hopeful that there will more efficient opportunities to share perspective as a result of having more time and based on lessons learned from this first proceeding. However, once again, the Companies would urge the Commission to be thoughtful in considering further structured stakeholder engagement on the Companies' modeling process. Similar to the discussion above, there will always be differences of opinion on modeling issues due to fundamental differences of opinion about planning objectives, real world operations, system constraints and other factors. Stakeholder engagement, even regarding modeling, should be balanced and thoughtful and should set realistic expectations. And as was the case in this Carbon Plan, the Companies would strenuously object to any structure in which the Companies were forced to accept alternative modeling recommendations or assumptions with which they fundamentally disagree or to be the modeling consultant for intervenors. However, as demonstrated through the supplemental portfolios produced by the Companies during the Carbon Plan, the Companies are open to input and, in certain circumstances, willing to perform alternative analysis that is informed by other parties' perspectives, even where the Companies are not in 100% agreement with all parameters.[150] But that approach is far different than a top-down approach in which the Companies' finite resource become consumed by performing modeling for other parties based on assumptions or parameters that the Companies simply cannot support because they are not reasonable for planning purposes, do not result in grid adequacy and reliability, or are not executable in the real world.

Finally, in a similar vein, the Companies caution against approving or requiring third-party oversight of the Companies' core business functions. In a few cases in this proceeding, parties have recommended third-party oversight or consultation. For instance, the Companies addressed above the recommendation for third party consultation regarding the Companies' interconnection timelines. As explained above, the Companies believe that there has been insufficient justification for such an imposition on the Companies' management of its transmission construction operations and processes. More generally,

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[150] *See* Tr. vol. 7, 254-255.

the Companies note that, consistent with the Commission's well-established precedent, the Companies should be given wide latitude to operate its business through prudent and reasonable management. Absent clear evidence of failure or obvious shortcoming in the Companies' performance, third party consultation or oversight is likely not needed and, in fact, the recent past has shown that third party oversight does not even necessarily guarantee outcomes that are more efficient or free of controversy.

1. All In Bill Impacts

The Companies also strongly object to any requirement to provide "all in" bill impact projections for the entirety of the period covered by the Carbon Plan, as recommended by CIGFUR.[151] This request should be rejected because (1) the Companies simply to do not have the information required to perform such an estimate, (2) if forced to do so, the estimate would be so speculative as to be meaningless, (3) such an estimate could be used in ways that are harmful, and (4) no other utilities are require to produce a similar estimate over such a period of time.[152]

The financial analysis produced as part of the Carbon Plan is distinct and is intended solely to compare and contrast, using a very simplified set of assumptions, the projected relative differences between each of the portfolios. As background, the Companies' Integrated Resource Plans ("IRPs") have historically shown Present Value of Revenue Requirements ("PVRR") for costs of the resource plan and used this metric as a valuable tool to compare one portfolio to other alternatives. These PVRRs have never included all future revenue requirements of the utility, but only those caused by the resource plans. In

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[151] *See* Tr. vol. 25, 355.

[152] *See* Tr. vol. 28, 59-60, 68.

the Companies' 2020 IRP, based on feedback from the Public Staff, the Companies, for the first time, included average annual customer rate impacts by 2030 and by 2035.[153] The rate impacts used the same revenue requirement inputs that were used in the PVRRs and should be used in combination with the PVRRs to compare one portfolio to another in terms of cost to customers. The Companies continued this approach in the Carbon Plan. These rate impacts were never intended to try to predict exactly what a customer's all-in rate will be in 10 or 15 years, but instead were meant to be a valuable tool for comparing alternative resource plans.[154]

However, the Companies would need an immense amount of information (information that it does not possess) to calculate an all-in bill impact over the entirety of the Carbon Plan. For instance, the Companies do not prepare a forecast that includes all costs and revenues that goes out for 10 or 15 years. Even if the Companies were to try to produce such a forecast, it would inevitably be wrong due to the number of different factors that impact rates—interest rates, inflation, fuel costs, government regulations, amortization periods for deferred costs, etc., over many of which the Companies have no or limited control.[155] For example, several witnesses suggest that the Companies include storm securitization impacts. The Companies would have to try to predict the timing and magnitude of future storms, the cost of restoration, and timing of securitization in order to project a future rate impact from storm securitization. This is obviously impossible.

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[153] *See id.* at 58.

[154] *See id.* Tr. vol. 7, 289.

[155] *See* Tr. vol. 28, 58.

In terms of grid investments, the Companies have worked diligently to develop detailed three-year grid investment plans. DEP presented its plan to the Commission in its July 25, 2022, Technical Conference (Docket E-2, Sub 1300). DEC will be presenting its plan in its Technical Conference (Docket E-7, Sub 1276). The rate impacts of these plans will be included in the Companies' upcoming rate cases. However, the Company does not have similarly detailed grid investment plans for the next 10 or 15 years upon which to base a rate projection, as some interveners seem to assume.

G. Legal Issues

The most substantial legal issues raised in this proceeding were previously addressed in detail in the Companies' Sept. 9th Pre-Hearing Comments, which are attached as Appendix 1 to this Brief for ease of Commission reference. For the benefit of the Commission, the following subsections provides a brief overview and excerpts from the Companies' Sept. 9th Pre-Hearing Comments.

The Companies' Sept. 9th Pre-Hearing Comments addressed certain relevant intervenor positions raised in the Carbon Plan proceeding prior to September 9, 2022. Public Staff and certain intervenors also filed comments on September 9, 2022 addressing certain non-hearing track issues that were primarily legal in nature. For the benefit of the Commission, Appendix 2: Targeted Additional Responses provides targeted responses to specific positions set forth in the comments filed by certain intervenors on September 9, 2022 to the extent that any such positions were not already preemptively addressed by the Companies in their Sept. 9th Pre-Hearing Comments.

1. HB 951 Grants the Commission Discretion With Respect to the 70% Interim Target Achievement Date and the Companies Have Reasonably Presented Analysis That Contemplates Such Extensions. However, The Companies' Near-Term Action Plan is Generally

Consistent with All Portfolios and the Commission Need Not Rely on any Extension at This Time.

The Companies have proposed decisive near-term actions that are generally consistent with all portfolios and represent the initial "reasonable steps" that are required by HB 951. The Near-Term Actions proposed by the Companies are significant and place the Companies on a trajectory that would allow for achievement of the 70% Interim Target by 2030, while maintaining reliability and affordability, and mitigating the overall execution risks associated with over-reliance on any resource option. Nevertheless, HB 951 provides broad authority to achieve the 70% Interim Target by 2032 and more narrow authority to achieve the 70% Interim Target after 2032 and it is reasonable for the Commission to be presented with and consider for planning purposes analysis that leverages such extensions.

Specifically, N.C.G.S. § 62-110.9(4) provides the Commission with substantial discretion to extend the target date ("Interim Target Achievement Date") for achieving the 70% Interim Target beyond to 2030, requiring that the Commission retain its discretion to select the optimal timing and resource mix that achieves least-cost compliance with HB 951's carbon reduction goals even where such timing and resource mix extends the Interim Target Achievement Date to 2032. This discretion allows the Commission to use its judgment to select a compliance pathway that takes into account a variety of critical factors, including the four core Carbon Plan objectives identified by the Companies,[156] all of which are grounded in prudent utility planning and operation. In addition, N.C.G.S. § 62-110.9(4)

[156] *See* Carbon Plan, Exec. Summary, 15-16.

expressly defines further discrete circumstances under which the Commission is authorized to extend the Interim Target Achievement Date beyond 2032.

The Companies' proposed Carbon Plan and its requested relief are consistent with the Commission's timing authority and allows the Commission to "retain discretion" looking towards future biennial Carbon Plan updates as the Companies make substantial near-term progress towards the 70% Interim Target. Moreover, the Commission need only spend limited time considering this argument as, ultimately, it has no impact on the decisions to be made in this initial Carbon Plan proceeding. This is because the Companies are not asking the Commission to select a single portfolio. As described in the Carbon Plan and further explained by Witness Bowman and the Modeling and Near-Term Actions Panel, the near-term actions presented in the Carbon Plan are generally consistent with both P1 enabling Duke Energy to meet the 70% Interim Target in 2030, as well as the other portfolios that achieve the 70% Interim Target after 2030.[157] Said differently, the resources that the Companies are requesting the Commission select in this initial Carbon Plan represent the "reasonable steps" to be executed in the near term toward achieving the least-cost path to compliance with the 70% Interim Target by 2030, and the Commission should retain discretion to assess in the future the optimal path to achieve the 70% Interim Target. The Commission, in future proceedings, can determine whether to exercise the discretion to select a path for compliance beyond 2030, including by authorizing construction of a wind or nuclear facility.

[157] *See* Carbon Plan, Exec. Summary, 24; Carbon Plan, Ch. 4, 8; Tr, vol. 7, 48, 242.

In summary, the Commission should select the near-term actions presented in the proposed Carbon Plan while retaining discretion to "adjust" in future proceedings and to consider the optimal timing and generation resource mix to achieve the least-cost path to compliance. This necessarily should include discretion to consider future Carbon Plan proceedings portfolios that achieve the 70% Interim Target beyond 2030, consistent with authority delegated by the General Assembly under HB 951.

- ***For more detailed analysis of this issue, please see the Companies' Sept. 9th Pre-Hearing Comments (Pp. 4-17).***

2. The Commission Is Not Obligated to Select a Single Portfolio

The Companies have requested the Commission affirm that the Companies' Carbon Plan modeling across all portfolios is reasonable for planning purposes and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning. This approach is consistent with the Commission's historic approach to long-range planning, and HB 951 does not impose upon the Commission an obligation to select at a single portfolio. The Commission should adopt the near-term actions and enable the Commission and the Companies to check and adjust the longer-term plan in future Carbon Plan updates.

- ***For more detailed analysis of this issue, please see Companies' September 9th Comments (Pgs. 17-18).***

3. HB 951 Mandates Clear, Unambiguous Ownership Requirements that Must be Applied in Harmony with All Other Requirement of HB 951 and Existing Law

There is no ambiguity in HB 951 with respect to ownership of new generating facilities and other resources (collectively, "Facilities") selected by the Commission in the Carbon Plan: third parties shall own 45% of new solar and solar paired with energy storage

("SPS"), and Duke Energy shall own all other Facilities selected by the Commission to achieve the Carbon Plan (collectively, the ownership requirements in HB 951 applicable to Duke Energy and third parties are referred to herein as the "Ownership Requirements").[158] These Ownership Requirements could not be clearer or more unambiguous, and the Commission need not look elsewhere for the General Assembly's intent.[159]

Most parties do not challenge the Ownership Requirements and Public Staff concludes that HB 951 mandates "Duke ownership of new generation facilities for purposes of Carbon Plan compliance."[160] However, a handful of intervenors engage in tortured interpretive gymnastics to avoid the plain reading of the HB 951's Ownership Requirements.

Duke Energy believes that the General Assembly was clear and meant what it said in HB 951: the Commission should develop a plan to retire Duke Energy's owned coal-fired generation and other carbon-emitting resources to achieve carbon neutrality and should select new Facilities as part of a State-wide plan to reliably replace these resources which shall be subject to HB 951's Ownership Requirements.

Intervenors' reading, which ignores the General Assembly's plain language and effectively adds language not included, is impermissible under well-established principles of statutory interpretation in North Carolina. When interpreting statutes, North Carolina

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[158] *See* N.C. Gen. Stat. §§ 62-110.9(2), (2)(b).

[159] *See State v. Jackson*, 353 N.C. 495, 501, 546 S.E.2d 570, 574 (2001) (courts "are without power to interpolate, or superimpose, provisions and limitations not contained" in "clear and unambiguous" legislative enactments) (quoting *In re Banks*, 295 N.C. 236, 239, 244 S.E.2d 386, 388-89 (1978).

[160] Public Staff Thomas Testimony at 34 ("Section 110.9(2) requires Duke ownership of new generation facilities for purposes of Carbon Plan compliance").

courts may not "ignore or amend legislative enactments" that are "clear and unambiguous."[161] With respect to general interpretation, the North Carolina Court of Appeals has affirmed that "a statute must be considered as a whole and construed, if possible, so that none of its provisions shall be rendered useless or redundant."[162] Furthermore, "[i]t is presumed that the legislature intended each portion to be given full effect and did not intend any provision to be mere surplusage."[163] North Carolina courts also adhere "to the long-standing principle that when two statutes arguably address the same issue, one in specific terms and the other generally, the specific statute controls."[164]

HB 951's Ownership Requirements are clear and unambiguous and those few intervenors challenging the Ownership Requirements have failed to articulate an interpretation that is remotely consistent with well-established principles of statutory interpretation under North Carolina law. Intervenors CUCA, Tech Customers, and Kingfisher take the position that these express ownership mandates are merely discretionary.[165] In fact, these intervenors argue that HB 951's utility ownership requirement actually means the opposite of what it says: the Commission must consider

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[161] *Orange County ex rel. Byrd v. Byrd*, 129 N.C. App. 818, 822, 501 S.E.2d 109, 112 (1998) (citing *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451, 465, 232 S.E.2d 184, 192 (1977)).

[162] *R.J. Reynolds Tobacco Co. v. N.C. Dep't of Envtl. and Natural Res.*, 148 N.C. App. 610, 616, 560 S.E.2d 163, 168 (2002) (quoting *Porsh Builders, Inc. v. City of Winston–Salem*, 302 N.C. 550, 556, 276 S.E.2d 443, 447 (1981) (internal quotations and citations omitted))

[163] *Id.* at 616, 560 S.E.2d at 168.

[164] *High Rock Lake Partners, LLC v. N.C. Dep't of Transp.*, 366 N.C. 315, 322, 735 S.E.2d 300, 305 (2012) (citations omitted).

[165] *See* CUCA July 15th Initial Comments at 2-3 ("If utility ownership is not the least-cost option, then Duke should be required to . . . consider[ ] purchases from third-party energy suppliers."); Tech Customers July 15th Initial Comments at 18 ("[T]he omission of purchased power as an alternative to new-build generation is contrary to the expectations of [HB 951]."); Kingfisher Comments at 3 ("Kingfisher believes that the use of competitive bidding would best effectuate the legislative intent behind . . . House Bill 951.").

third-party non-utility ownership when selecting new generation resources under the Carbon Plan. Intervenors' position stretches the statute's plain language beyond any reasonable interpretation and rests on a fundamental misapplication of statutory construction principles. Their errors include ignoring or disregarding plain language in HB 951, ingrafting language into the law that was omitted, manufacturing – rather than avoiding – conflicts within the legislation and advocating for interpretations that would have absurd results. Therefore, such intervenors' erroneous and impermissible reading of HB 951 should be rejected.

Finding no express language to support their reading, certain intervenors argue that the Commission's authority to disregard the Ownership Requirements should be implied from the references to "least cost" in HB 951.[166] In asserting such positions, such intervenors do not even attempt to wrestle with North Carolina's well-established principles of statutory interpretation.

More specifically, such intervenors effectively attempt to impermissibly "amend legislative enactments" and "add to…language of the statute." Had the General Assembly intended to allow third-party ownership of new, non-solar/SPS Facilities, it would have said so. The General Assembly instead expressly required utility ownership of all new, non-solar/SPS generation without exception. Indeed, the General Assembly clearly considered third-party ownership and, in fact, made the express decision to authorize third

[166] *See* CUCA July 15th Initial Comments at 3 (stating that "least-cost planning requires consideration of purchases from third-party energy suppliers"); Tech Customers Comments at 19 (HB 951 "directs the commission to select the 'least cost path'—not the least-cost assets owned by the utility."); CIGFUR Comments at 26 ("CIGFUR suggests, among other recommendations, that to the extent new natural gas assets are determined to be the least-cost, most reliable increment of new generation, power purchase agreements (PPAs) with third parties should be, at a minimum, evaluated as a potentially more cost-effective alternative.").

party ownership of 45% of new solar resources. Alternatively, the General Assembly could have specified that new resources must adhere to the Ownership Requirement, but only if utility ownership represents the least cost option.[167] But once again, the General Assembly did not so state, and these intervenors may not add language to the statute.

Intervenors also ignore inconvenient language in Section 1 that provides essential context for understanding "least cost" planning under the Carbon Plan. The General Assembly directs the Commission to achieve the "least cost path *consistent with this section*."[168] The purpose of this provision is to make clear that "least cost path" must be determined within the context of other provisions in Section 1.[169] The primary Ownership Requirement mandate is provided in the very next subsection. Therefore, the "least cost path" must account for and be "consistent with" the Ownership Requirement.

Finally, intervenors' argument that the general "least cost" planning requirements is controlling over and negates specific utility ownership mandates flips statutory interpretation principles on their head.[170] As is further explained below, the Companies do not believe there is a conflict between the "least cost" planning and the Ownership requirements, but even if there is perceived conflict, the express and "specific"[171] Ownership Requirements are controlling.

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[167] *See* CUCA July 15th Initial Comments at 2.

[168] N.C. Gen. Stat. § 62-110.9(1) (emphasis added); *Cf.* Tech Customers July 15th Initial Comments at 19 (asserting that "Section (1)(2) directs the Commission to select the 'least cost path'").

[169] As enacted, all of the Carbon Plan related provision were in the same section of the law—Section 1.

[170] *See High Rock*, 366 N.C. at 322, 735 S.E.2d at 305.

[171] *Id*.

In effect, such intervenors are asking the Commission to repeal by implication the Ownership Requirements altogether. North Carolina law holds that "[i]nterpretations that would create a conflict between two or more statutes are to be avoided, and statutes should be reconciled with each other whenever possible."[172] When determining whether legislative provisions are in conflict,

> [R[epeals by implication are not favored . . . and *the presumption is always against implied repeal* . . . Instead, repeal by implication results only when the statutes are inconsistent, necessarily repugnant, utterly irreconcilable, or wholly and irreconcilably repugnant[.][173]

The requirement to "comply with current law and practice with respect to least cost planning for generation, pursuant to G.S. 62-2(a)(3a)" in Subsection 1(2), as well as other references to "least cost" in Section 1, are not inconsistent with the express Ownership Requirement in HB 951. There is a simple and straightforward way to read and interpret in harmony the various requirements imposed by the General Assembly under HB 951. That is, there are a series of core requirements imposed under HB 951, all of which have been given "full effect"[174] in Duke Energy's proposed Carbon Plan in a manner that avoids conflict[175] and "implied repeal."[176] The General Assembly has directed that the Carbon Plan must (1) achieve targeted CO_2 reductions, (2) utilize the "least cost path consistent with this section," (3) comply "current law and practice with respect to the least cost

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[172] *Velez v. Dick Keffer Pontiac GMC Truck, Inc.*, 144 N.C. App. 589, 593, 551 S.E.2d 873, 876 (2001).

[173] *State ex rel. Utils. Comm'n v. Town of Kill Devil Hills*, 194 N.C. App. 561, 567, 670 S.E.2d 341, 345, *writ allowed*, 636 N.C. 583, 681 S.E.2d 344 (2009), *aff'd*, 363 N.C. 739, 686 S.E.2d 151 (2009) (citations and quotations omitted) (emphasis in original).

[174] *R.J. Reynolds*, 148 N.C. App. at 616, 560 S.E.2d at 168.

[175] *Velez,* 144 N.C. App. at 593, 551 S.E.2d at 876.

[176] *Kill Devil Hills*, 194 N.C. App. at 567, 670 S.E.2d at 345.

planning for generation," (4) ensure that reliability is maintain or improved, and (5) adhere to the Ownership Requirements. The Companies' Carbon Plan incorporates and balances all requirements, charting a course that gives full effect to clear and unambiguous statutory directives and ensuring that no provision is rendered useless or surplusage.[177]

Legislation must be construed "so as to avoid absurd consequences."[178] Intervenors' interpretation should also be rejected because it would yield absurd results. No intervenor disputes that the General Assembly has expressly imposed the Ownership Requirements. However, if the utility ownership requirement can simply be ignored for allegedly conflicting with the least cost requirement, then so too would the mandated third-party ownership of 45% of solar and solar/SPS. Once again, this interpretation repeals by implication an express General Assembly directive when such an outcome is not necessary. In fact, taken to its logical extreme, such intervenors' interpretation could actually be used to negate even the CO_2 emissions reduction targets contained in HB 951. That is, if the clear and unambiguous Ownership Requirements can be ignored based on the alleged application of "least-cost" principles, then it would also be similarly possible to override the CO_2 emission reduction targets if achievement of such targets were shown to be allegedly inconsistent with least cost planning. This would be an absurd result. Rather, it is necessary for the law to be applied in a manner that gives logical and balanced effect to all of its provisions, which is what the Companies have done through their Carbon Plan.

The General Assembly did not prescribe clear Ownership Requirements only to have them ignored or bypassed under the guise of applying least cost principles to devise

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[177] *R.J. Reynolds*, 148 N.C. App. at 616, 560 S.E.2d at 168.

[178] *Nationwide Mut. Ins. Co. v. Mabe*, 342 N.C. 482, 494, 467 S.E.2d 34, 41 (1996) (citation omitted).

a new ownership allocation. Nor did the General Assembly establish specific carbon reduction goals only to have them discarded based on alleged least cost planning. Rather, the General Assembly directed that least cost principles be applied within the context of all of the requirements of HB 951 to select the appropriate mix of supply-side resources (utilizing the Ownership Requirements) and demand-side resources that will enable Duke Energy to achieve the targeted emissions reductions.

Finally, setting aside statutory interpretation, it is essential to note that the Ownership Requirements in HB 951 are not arbitrary but instead represent sound and reasonable policy that is beneficial to customers. The State's transformational emission reduction targets can only be achieved by replacing emission-intensive generation resources with new, lower- or lower-and zero-carbon emitting resources. Given the magnitude of the task and the central role that Duke Energy plays in both accomplishing the transition and maintaining reliability, it is reasonable for the General Assembly to conclude that the utility should have a substantial ownership interest in the new Facilities required. The reasonableness of this policy decision is only highlighted when one considers that many of the new Facilities are simply replacing retiring facilities that Duke Energy previously owned, managed, operated and relied upon to provide reliable electric service to the citizens of North Carolina for decades.

Requiring utility ownership through Commission-supervised least-cost planning also embodies the regulatory compact between Duke Energy and the State. The General Assembly has recognized that rates, services and operations of public utilities are affected with the public interest and has declared it to be the "policy of the State of North Carolina

. . . to promote the inherent advantage of regulated public utilities."[179] Doing so allows for the "availability of an adequate and reliable supply of electric power . . . to the people, economy and government of North Carolina[.]"[180] This declaration "clearly reflects the policy adopted by the legislature that a regulated monopoly best serves the public, as opposed to competing suppliers of utility services."[181] It is not surprising that the General Assembly would turn to traditional cost-of-service regulation principles when enacting such transformative energy legislation.

The General Assembly has placed ownership of new generation resources selected by the Commission under the Carbon Plan in the hands of the same regulated utility that is legally obligated to maintain a continuous supply of adequate and reliable electricity to serve North Carolina.[182] Therefore, the utility ownership mandate is consistent with North Carolina's policy that utility ownership of generating resources best serves the public interest.[183] Indeed, the General Assembly's reaffirmation of its policy promoting Duke Energy's ownership of utility resources is especially compelling in this instance, where it has directed Duke Energy to achieve Carbon Neutrality and to transform nearly every aspect of its regulated electric utility system in just 30 years by 2050.

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[179] N.C. Gen. Stat. § 62-2(a)(2).

[180] *State ex rel. Utils. Comm'n v. N. Carolina Waste Awareness & Reduction Network*, 255 N.C. App. 613, 619, 805 S.E.2d 712, 716 (2017), *aff'd*, 371 N.C. 109, 812 S.E.2d 804 (2018) ("NC WARN") (quoting N.C. Gen. Stat. § 62-2(b)).

[181] *Id.* (quoting *State ex rel. Utils. Comm'n v. Carolina Tel. & Tel. Co.*, 267 N.C. 257, 271, 148 S.E.2d 100, 111 (1966)).

[182] *See* N.C. Gen. Stat. § 62-110.9(2); *see generally* N.C. Gen. Stat. §§ 62-2(a), (3a).

[183] *See NC WARN*, 255 N.C. App. at 619, 805 S.E.2d at 716.

Certain intervenors express concern that mandated utility ownership will give Duke Energy a blank check to meet the emissions reduction targets by any means and at any cost.[184] Such hyperbole has no basis in the law or the Commission's long-standing regulation of the Companies for two obvious reasons. First, HB 951's least-cost planning requirement will guide reasonable and prudent planning decisions, and all new Facilities must be approved by the Commission. In its selection of new Facilities, the Commission must choose the least-cost path to achieve the emissions reduction targets while not sacrificing system adequacy and reliability. Duke Energy's commitment to ensuring the least-cost path is reflected in its Execution Plan, which contemplates the use of competitive processes to acquire the most cost-effective resources for the benefit of customers. These strategies allow Duke Energy to leverage its economies of scale to minimize costs. Second, the Commission will continue to apply its traditional regulatory scrutiny to all costs incurred by the Companies and will deny cost recovery of any costs that are determined to be unreasonable or imprudent.

In sum, HB 951's clearly stated utility ownership requirement aligns with the regulatory compact and vertically-integrated regulated utility model that has long served Duke Energy's customers and communities in the State of North Carolina well through provision of affordable, reliable and increasingly cleaner energy in the Carolinas.[185]

- ***For more detailed analysis of this issue, please see the Companies' Sept. 9th Pre-Hearing Comments (Pp. 19-36).***

[184] *See* CIGFUR II and III July 15th Initial Comments at 25-26 (asserting that "the energy transition does indeed present a ripe opportunity for Duke to gold-plate its generation and transmission plant.").

[185] Carbon Plan, Exec. Summary, 1.

4. The Commission Has Authority to and Should Provide Duke Energy Reasonable Assurances that Engaging in Initial Project Development Activities for Long Lead-Time Resources Identified in the Near-Term Execution Plan is a Reasonable and Prudent Step and that Any Such Prudently Incurred Development Costs will be Recoverable in the Future.

The Companies' request for cost recovery assurance in connection with its proposed near-term initial development activities for the Long Lead-Time Resources is reasonable and appropriate in light of the framework of the Carbon Plan and the magnitude of the costs required. To be clear, the Companies are not asking the Commission to rubber stamp that all specific future-incurred project development costs are reasonable and prudent. Neither are the Companies seeking authorization today to defer extraordinary costs in a regulatory asset account under the Commission's well-established two-pronged test, as these types of project development costs generally qualify for balance sheet accounting under FERC Account 183, Preliminary survey and investigation charges. Rather, the Companies are seeking assurances from the Commission that (1) engaging in initial project development activities, in advance of receiving any required CPCN, for these significant Long Lead-Time Resources is a reasonable and prudent step in executing the Carbon Plan to enable potential future selection of Bad Creek II, new nuclear and offshore wind on the timeline required to meet HB 951 goals; (2) to the extent the Commission later finds the individual costs incurred to be reasonable and prudent, they will be recoverable in rates; and (3) that such reasonable opportunity for recovery will be available to the Companies should the resource not ultimately be selected by the Commission and development activities abandoned in the future.

Pursuant to both statute and the Commission's general regulatory powers under N.C.G.S. §§ 62-2 & 62-30, the Commission has the power to grant Duke Energy the requested assurances that engaging in pre-CPCN initial project development activities is a reasonable and prudent step such that those costs will be recoverable in rates—assuming the specific development activities and associated costs are found in a future rate case or other appropriate proceeding to have been reasonably and prudently incurred—regardless of whether the project is ultimately completed or cancelled. The Companies acknowledge that N.C.G.S. § 62-110.7 codifies this authority with respect to project development costs for nuclear facilities. However, the Commission has previously acknowledged its authority to grant the requested relief even in the absence of an express statutory provision such as N.C.G.S. § 62-110.7. That is, the Commission has granted the exact relief requested by the Companies prior to the enactment of N.C.G.S. § 62-110.7, thereby demonstrating that the Commission has the authority to grant the requested relief outside of N.C.G.S. § 62-110.7 and for resources other than nuclear generation. Specifically, in 2006-2007, prior to N.C.G.S. § 62-110.7's enactment in Session Law 2007-397, the Commission affirmatively found it had legal authority to grant the requested assurances of future recovery of pre-CPCN development costs.[186]

The exact same rationale underlying the Commission's decision (which once again, pre-dated N.C.G.S. § 62-110.7) applies in the context of the Carbon Plan. That is, it is reasonable for the Commission to provide "general assurances" that the development activities are "appropriate activities" and it is in the "public interest" for these Long Lead-

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[186] *See In the Matter of Application of Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment*, Order issuing Declaratory Ruling, Docket No. E-7, Sub 819 (Mar. 20, 2007). Notably the assurances ultimately issued by the Commission did not track the exact same language requested by Duke Power, but are highly similar to what Duke Energy is requesting in this docket.

Time Resources "to be adequately considered to ensure that the most economical resources are *available to meet customers' needs* on a timely basis."

Therefore, contrary to the assertions of certain parties, the enactment of N.C.G.S. § 62-110.7 should not be interpreted as a constriction of the Commission's general regulatory authority but as needed policy direction given industry dynamics that existed at the time of enactment. And the fact that the General Assembly did not enlarge the scope of N.C.G.S. § 62-110.7 as part of HB 951 does not change the fact that the Commission previously assumed the ability to grant the Companies' requested relief without an express statute and does not indicate the negative—that the General Assembly believed that the Commission should not provide such cost recovery assurance for Long Lead-Time Resources other than nuclear.[187]

Importantly, HB 951 also provides the Commission additional authority to grant the relief requested, as the General Assembly directed the Commission to take "all reasonable steps" to achieve the least cost path towards carbon neutrality by the year 2050. A straightforward reading of this mandate counsels in favor of pursuing multiple pathways to potentially meet those new legislatively mandated planning goals, including by pursuing development activities for Bad Creek II, new nuclear and offshore wind at this early stage of Carbon Plan implementation to ensure those resources remain available for customers

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[187] Repeals of statutes by implication are disfavored, and "the presumption is always against implied repeal." *Kill Devil Hills*, 194 N.C. App. at 567, 670 S.E.2d at 345. Instead, where two statutes arguably address the same subject matter, one specifically and one generally, and appear incompatible, "the particular provision must be regarded as an exception to the general provision, and the general provision must be held to cover only such cases within its general language as are not within the terms of the particular provision." *State ex rel. Utils. Comm'n v. Carolina Coach Co.*, 236 N.C. 583, 588–89, 73 S.E.2d 562, 566 (1952). "This rule of construction is especially applicable where the specific provision is the later enactment[.]" *State ex rel. Utils. Comm'n v. Lumbee River Elec. Membership Corp.*, 275 N.C. 250, 260, 166 S.E.2d 663, 670 (1969) (internal citations omitted).

on the timeline needed to meet HB 951's targets. Assurances regarding cost recovery—whether or not the resource is ultimately determined to be needed and selected by the Commission as part of the least cost path—is critical to ensure the Companies can pursue the needed development steps, as discussed further *infra*. For all of these reasons, the Commission has clear legal authority to grant the Companies' requested relief and grant assurances regarding the potential for recovery of pre-CPCN expenses to ensure the Companies' customers retain access to the long lead-time resources identified in the Execution Plan.

Finally, the scale of the development costs required for Long Lead-Time Resources distinguishes them from other routine development work and justifies the Companies' requested treatment. Given the scale of such costs, it would be inconsistent with the regulatory compact to impose on the Companies a legal obligation to perform substantial development work (which is needed due to the timelines required under HB 951) while denying any assurance of cost recovery. To do otherwise would risk unlawfully permitting second guessing based upon future developments that are not reasonably known at this time. Recognizing the new paradigm of the Commission-developed Carbon Plan selecting resources as in the public interest and needed to meet HB 951's carbon emission reduction goals, providing the requested assurances for offshore wind, SMRs, and Bad Creek II is well supported by State policy set forth in the Public Utilities Act to provide fair regulation of public utilities in the interest of the public and to "assure that facilities necessary to meet future growth can be financed by the utilities operating in this State on terms which are reasonable and fair to both the customers and existing investors of such utilities[.]"[188]

For these reasons, the Companies respectfully ask the Commission to grant the requested assurances that the development activities costs incurred for Bad Creek II, new nuclear and offshore wind will be recoverable in rates whether or not the resource is ultimately completed. As is described in more detail by the Long Lead-Time Resources Panel, the Companies agree that the specified amount would serve as an appropriate cap of costs through 2024, and the Companies commit not to incur cost in excess of the identified amounts without further approval from the Commission.[189] The Companies also agree that a biannual reporting obligation would be appropriate so as to keep the Commission apprised of the progress and status of the development activities.[190]

The Public Staff suggests that the Companies should make a request for assurances regarding nuclear development costs pursuant to N.C.G.S. § 62-110.7 in a separate proceeding because "the parties have not had adequate time to review any request to incur nuclear development costs in sufficient detail while they reviewed the proposed Carbon Plan."[191] However, pursuant to the statute, a utility may make a request pursuant to N.C.G.S. § 62-110.7 "*at any time* prior to the filing of an application for a certificate to construct a potential nuclear electric generating facility[.]"[192] The Companies' plan for developing long lead-time resources is set out in detail both in the Carbon Plan's Execution

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[188] N.C.G.S. §§ 62-2(a)(1); (4a).

[189] *See* Tr. vol. 18, 23; *see also* Tr. vol. 19, 104.

[190] *See* Tr. vol. 29, 104-105.

[191] Public Staff July 15th Initial Comments at 156-57.

[192] N.C.G.S. § 110.7(b) (emphasis added).

Plan, Appendices J (Wind), K (Energy Storage) and L (Nuclear) as well as in the direct and rebuttal testimony of the Companies' Long Lead-Time Resources Panel. For comparison, the level of detailed support presented in the Companies' Carbon Plan and testimony regarding its planned development activities for Long Lead-Time Resources is materially greater than the information Duke Power provided with its application in the Lee Nuclear proceeding—basically reference to and summary of its discussion of new nuclear generating facilities development activities in its 2006 IRP short-term action plan.[193] Duke Power's 2006 application additionally provided an estimate of the anticipated development costs over a 15-month period. While the Companies did not provide that information in their Petition, as set forth *supra* Section II.C.2, they expect to incur approximately $440 million in initial development activity expenses for Long Lead-Time Resources through the end of 2024, when the Commission will have issued its next decision updating the Carbon Plan. Given that the details provided in the Carbon Plan and supporting testimony exceeds the level of specificity provided in Duke Power's previous cost recovery requests under Section 62-110.7 in the Lee Nuclear proceeding, it would be an inefficient use of regulatory resources to require the Companies to initiate a separate proceeding(s) for the purpose of seeking the ultimately-necessary assurances being requested here. Accordingly, the Companies renew their request for the Commission to approve the Request for Relief in the Petition for assurances relating to future recoverability.

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[193] *See In the Matter of Application of Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment*, Application for Authority to Recover Nuclear Generation Development Expenses, Docket No. E-7, Sub 819 (filed Sept. 20, 2006).

- ***For more detailed analysis of this issue, please see the Companies' Sept. 9th Pre-Hearing Comments (Pp. 36-50).***

5. The Commission's Obligation Under the Carbon Plan to Select Resources Should Be Exercised Thoughtfully and Flexibly Depending on the Circumstances.

HB 951 directs the Commission to develop a Carbon Plan and to "select" the "new generation facilities or other resources" needed "to achieve the authorized reduction goals." The Companies believe that the Commission should take a flexible approach to the selection of resources based on individual circumstances that will allow for regulatory efficiency. Such an approach will ensure appropriate checkpoints and scrutiny that account for the particular facts, circumstances and timing of each situation and comply with current law that requires a CPCN in order to construct a generation resource located in the state. Many parties advocate for a rigid approach that will not result in regulatory efficiency. To the contrary, the Commission should take a flexible approach that seeks to maximize regulatory efficiency based on the unique circumstances applicable to each decision.

It is important to note a number of considerations that do not make this issue susceptible of a "one size fits all" solution. First, not every resource that the Commission selects in a Carbon Plan requires a CPCN under North Carolina law. For instance, standalone battery storage, offshore wind facilities located outside of North Carolina territorial waters, acquisition of constructed out-of-state generation resources, and construction of new of out-of-state generating resources would not require CPCNs. However, in all cases, in order for such resources to be part of achieving the authorized reduction goals, the Commission must "select" the resource, and such selection would therefore most naturally occur within the context of the Carbon Plan process (*i.e.*, this proceeding or future biennial updates).[194] In another hypothetical scenario where a resource proposed for selection requires a CPCN, the Companies may be in a position to request the CPCN (*i.e.,* has prepared all of the information required to apply for a CPCN) at the same time as submitting a biennial update to the Carbon Plan, thereby effectively joining the two proceedings. The point of highlighting these examples is that the Commission should exercise its obligation to select resources flexibly and thoughtfully in ways that adapt to the particular of each situation.

As it relates to resources that the Commission might select in the Carbon Plan but that require a CPCN (and which were not situated so as to allow for a CPCN to be requested and issued in parallel with the Carbon Plan as discussed above), it is important to return to the theme of regulatory efficiency and consider the intersection of the Carbon Plan and the determination of need required in a CPCN. As the Companies have previously acknowledged, a CPCN is still required for generating assets located in North Carolina. But the Commission's selection of resources in a Carbon Plan should be deemed strong evidence of public convenience and necessity for purposes of any subsequent CPCN proceeding and, absent any material change in facts or circumstances, should be determinative in the CPCN proceeding. Stated simply, if the Commission has assessed the entirety of the Carbon Plan (including the exhaustive underlying analysis) and determined that a generation resource is needed to "achieve the authorized reduction goals," then such resource is, by definition, in the public interest.

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[194] There could also be a scenario where a resource that does not require a CPCN requires selection on a timeline that differs from the Carbon Plan biennial process, requiring a standalone Carbon Plan proceeding to allow the Commission to select the resource (e.g., a unique acquisition opportunity identified by the Companies that arises outside of the normal biennial Carbon Plan process).

Several intervenors argue that the selection of a resource in the Carbon Plan should have no bearing on a CPCN proceeding.[195] They contend that any resources selected in the Carbon Plan must be revisited anew and undergo the supposedly higher level of scrutiny and more exhaustive cost analysis that is provided in a CPCN proceeding.[196] Intervenors also wrongly frame Duke Energy's position as advocating that selection of a generating facility or other resource in the Carbon Plan effectively supplants or replaces a CPCN and makes it unnecessary.[197]

For the reasons explained above (and as further addressed in Duke Energy's Sept. 9th Pre-Hearing Comments), this inflexible approach is not the approach supported by Duke Energy and is neither necessary nor appropriate. Most fundamentally, it would be the height of regulatory inefficiency for the Commission to complete the exhaustive biennial Carbon Plan process only to have to fundamentally revisit the entirety of the Carbon Plan analysis with each and every CPCN process (particularly in those situations where the CPCN follows close on the heels of the Carbon Plan process). The Commission should not have to retread the same ground in a CPCN proceeding absent a compelling reason to do so. As addressed in the Companies' Sept. 9th Pre-Hearing Comments, the Commission has discretion to rely on findings in other dockets in rendering a decision in separate dockets and the Commission confirmed this in its recent order regarding the PBR process.

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[195] *See* CIGFUR July 15th Initial Comments at 41-42; CUCA July 15th Initial Comments at 5-6; Tech Customers July 15th Initial Comments at 13-14; EJCAN, *et al*. July 15th Initial Comments at 24, 29.

[196] *See id*.

[197] Intervenors' characterization of Duke Energy's position derives from a single discovery response. Asked how the Carbon Plan should impact CPCN proceedings, Duke Energy stated that the Commission's selection of a resource in the Carbon Plan "should be controlling in a CPCN proceeding absent a material change in facts and circumstances from Carbon Plan assumptions." *See* Tech Customers Comments at 14 (citing Duke Response to Public Staff Data Request 11-2).

Nor should a party displeased by the Carbon Plan be allowed to have a second bite at the apple and seek modification of the Carbon Plan's selection of a resource through a CPCN. At a minimum, the selection of resources in the Carbon Plan creates a strong presumption that the resource is required for the public convenience and necessity and needed to meet the energy transition and carbon emission reductions Plan dictated by the General Assembly in HB 951, Section 1.

- ***For more detailed analysis of this issue, please see the Companies' Sept. 9th Pre-Hearing Comments (Pgs. 50-57).***

III. CONCLUSION

Duke Energy appreciates the Commission's consideration of this Post-Hearing Brief as the Commission develops the initial Carbon Plan for North Carolina under HB 951. Duke Energy respectfully renews its request that the Commission grant the relief requested in its Petition and, further, adopt Duke Energy's Proposed Order as its own.

Respectfully submitted, this 24th day of October, 2022.

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September 9, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Pre-Hearing Comments on Non-Expert Track Legal and Policy Issues
Docket No. E-100, Sub 179

Dear Ms. Dunston:

Pursuant to the Commission's July 29, 2022 *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines,* enclosed for filing in the above-referenced docket, please find the Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Pre-Hearing Comments on Non-Expert Track Legal and Policy Issues.

If you have any questions, please do not hesitate to contact me. Thank you for your attention to this matter.

Sincerely,

Jack Jirak

Jack E. Jirak

Enclosure

cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Duke Energy Progress, LLC, and	)	DUKE ENERGY CAROLINAS LLC'S
Duke Energy Carolinas, LLC, 2022	)	AND DUKE ENERGY PROGRESS
Biennial Integrated Resource Plans	)	LLC'S PRE-HEARING COMMENTS
And Carbon Plan	)	ON NON-EXPERT HEARING TRACK
	)	LEGAL AND POLICY ISSUES

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Duke Energy Progress, LLC, and	)	DUKE ENERGY CAROLINAS LLC'S
Duke Energy Carolinas, LLC, 2022	)	AND DUKE ENERGY PROGRESS
Biennial Integrated Resource Plans	)	LLC'S PRE-HEARING COMMENTS
And Carbon Plan	)	ON NON-EXPERT HEARING TRACK
	)	LEGAL AND POLICY ISSUES

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies" or "Duke Energy"), pursuant to the Commission's July 29, 2022 *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Deadlines* (the "July 29 Order"), through counsel, and hereby respectfully submit these Comments on Non-Expert Witness Hearing Issues ("Comments").

I. <u>INTRODUCTION</u>

The Commission's July 29 Order granted parties the option to file comments on the specific topics and sub-issues identified in Ordering Paragraph 6, which includes any miscellaneous issues previously raised by any party but omitted from Duke Energy's July 22 Issues Report or not designated to the hearing track by the July 29 Order. Consistent with the Commission's directive, the Companies are hereby filing comments addressing the following issues:[1]

- **Issue No. 1:** The Commission's authority to extend the 70% interim carbon emissions reduction target ("70% Interim Target") beyond 2030 pursuant to N.C.G.S. § 62-110.9(4) and the permissible scope of the required Carbon Plan;[2]

  Duke Position: The Companies have proposed decisive near-term actions that are generally consistent with all portfolios and represent the initial "reasonable steps" that are required by Session Law 2021-165 ("HB 951").[3] Nevertheless, HB 951 provides general authority to achieve the 70% Interim Target by 2032 and more narrow authority to achieve the 70% Interim Target after 2032. The Companies' proposed Carbon Plan and its requested relief are consistent with the Commission's timing authority and allows the Commission to "retain discretion" looking towards future biennial Carbon Plan updates as the Companies make substantial near-term progress towards the 70% Interim Target.

- **Issue No. 2:** HB 951's requirements regarding ownership of new generation facilities or other resources selected by the Commission in order to achieve the authorized reduction goals resources;[4]

  Duke Position: The ownership requirements of HB 951 are clear and unambiguous and should be applied as directed by the General Assembly. The Companies' Carbon Plan is premised on a straightforward application of the ownership requirements that is consistent with well-established principles of statutory interpretation and gives full effect to all of the requirements of HB 951 and existing law. Certain intervenors urge interpretations that should be rejected because such interpretations fail to give full effect to HB 951's requirements, result in entire provisions being effectively nullified and, taken to their logical endpoint, would result in absurd interpretations. Finally, HB 951's ownership requirements are well supported by policy considerations and consistent with a least-cost planning framework.

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[1] The issues correspond to the issues identified by the Commission in Ordering Paragraph 6 of the July 29 Order, though are presented in a slightly different order. Section II of the Comments addresses the primary legal issues (Issue Nos. 1 – 4), Section III addresses procedural matters (Issue Nos. 5 – 6) and Section IV address additional miscellaneous issues (Issue Nos. 7 –8).

[2] July 29 Order, Ordering Paragraph 6. c.

[3] HB 951 was codified at Gen. Stat § 62-110.9. When referenced herein, HB 951 refers to Part 1, Section 1 of HB 951, which contains the Carbon Plan-related provisions of HB 951. In these comments, HB 951 and Gen. Stat § 62-110.9 are used interchangeably.

[4] July 29 Order, Ordering Paragraph 6(d).

- **<u>Issue No. 3</u>:** The Commission's authority to provide cost recovery assurance with respect to initial project development steps for longer lead-time resources outlined in the Companies' Near-Term Execution Plan;[5]

  <u>Duke Position</u>: The Companies' request for cost recovery assurance is reasonable and appropriate in light of the framework of the Carbon Plan and the magnitude of the costs required. The Commission has the authority to grant the requested relief for the three long lead-time resources and has previously unambiguously demonstrated its authority to grant the requested relief without express statutory authorization. The requested relief is in the public interest, as it will facilitate the execution of HB 951, and consistent with the regulatory compact between the Companies, the Commission, and customers.

- **<u>Issue No. 4</u>:** The impact of the Commission's selection of resources in this proceeding on future requests for a Certificate of Public Convenience and Necessity ("CPCN");[6]

  <u>Duke Position</u>: The Commission's new responsibility under the Carbon Plan to "select" resources should be exercised thoughtfully and flexibly, and the Commission should seek to maximize regulatory efficiency. In general, the Commission's selection of a resource in a Carbon Plan should provide strong evidence of public convenience and necessity and, absent a material change in facts or circumstances, should be determinative.

- **<u>Issue No. 5</u>:** Procedures and schedule for the next biennial Carbon Plan update proceeding and future IRP proceedings;[7]

  <u>Duke Position</u>: The Commission should direct Duke Energy to file a streamlined Carbon Plan update in 2023 and a comprehensive Carbon Plan update in 2024.

- **<u>Issue No. 6</u>:** Rulemaking procedures for revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan;[8]

  <u>Duke Position</u>: The Commission should direct the Companies and Public Staff to develop and propose for comment by April 28, 2023 revisions to

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[5] *Id*. at Ordering Paragraph 6(g).

[6] *Id*.

[7] *Id*. at Ordering Paragraph 6(a).

[8] *Id*. at Ordering Paragraph 6(b).

the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities.

- **Issue No. 7:** The proper analysis of the impacts of methane emissions from natural gas;[9] and

  Duke Position: The plain language of HB 951 provides no support for the recommendation for the Commission to consider methane emissions in the Carbon Plan.

- **Issue No. 8:** The appropriate forum for considering demand-side programs for wholesale customers.[10]

  Duke Position: The Commission does not have authority to require the Companies to modify their wholesale contracts in order to provide demand-side programs for wholesale customers.

II. LEGAL ISSUES APPLYING HB 951, SECTION 1

A. HB 951 Grants the Commission Authority to Determine Optimal Timing and Generation Resource Mix, Including "Retaining Discretion" to Extend the Target Date ("Interim Target Achievement Date") for Achieving the 70% Interim Target Beyond 2030

Duke Energy's proposed Carolinas Carbon Plan ("Carbon Plan" or "Plan"), together with Supplemental Portfolios 5 and 6, developed in consultation with the Public Staff, sets forth two pathways and six unique portfolios by which the Companies could meet the 70% Interim Target. As explained in the Companies' Carbon Plan and in the Direct Testimony of the Modeling and Near-Term Actions Panel,[11] the first compliance pathway is designed to achieve the 70% Interim Target by 2030. The second pathway evaluates various least-cost scenarios and resource planning options to achieve the 70% Interim Target beyond 2030. Of the six portfolios, one achieves the 70% Interim Target

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[9] *Id*. at Ordering Paragraph 6(e).

[10] *Id*. at Ordering Paragraph 6(g).

[11] Modeling and Near-Term Actions Panel Direct Testimony at 26-28.

by 2030 (P1), two achieve the 70% Interim Target by 2032 (P2 and SP5), and three achieve the 70% Interim Target by 2034 (P3, P4, and SP6).

The Companies certainly agree that the pace of CO_2 reduction is a critical objective to consider in developing a Carbon Plan and appreciate the perspective of those intervenors and customers that advocate for the fastest possible rate of reduction, including a resource plan that meets the 70% Interim Target by 2030. The Companies also believe that it is appropriate and consistent with HB 951 for the Commission to be able to consider a range of portfolios, all of which are compliant with HB 951's timing requirements.

Certain other parties have also indicated support for this approach generally and for the specific timing reflected in all of the Companies' portfolios. In its Initial Comments, the Public Staff does not take issue with the Companies' proposed pathways for meeting the 70% Interim Target, finding that P4—which delays compliance to 2034—"represents the most feasible portfolio."[12] In the Public Staff's view, "P4 relies upon a balance of resources and a slightly less aggressive interconnection schedule and may represent the most achievable portfolio, particularly given recent supply chain issues and inflationary pressures affecting the entire economy."[13] In pre-filed testimony, Public Staff witness Jeff Thomas supports near-term actions that align with a 2032 compliance target year.[14] CIGFUR likewise supports the potential to extend the Interim Target Achievement Date

[12] Public Staff Initial Comments at 19.

[13] *Id.*

[14] Public Staff Thomas Direct Testimony at 62.

beyond 2030, and its witness, Brad Muller, encourages the Commission to utilize the discretion delegated by the General Assembly.[15]

In contrast, several intervenors challenge the compliance timelines modeled by the Companies that extend beyond 2030 (which timelines vary slightly across the different portfolios) arguing that (1) there is no justification to extend the Interim Target Achievement Date beyond 2030 *at this time*; (2) the Commission's discretion to extend the Interim Target Achievement Date to 2032 is narrow; and (3) the Commission lacks the authority to select a portfolio that extends the Interim Target Achievement Date beyond 2032 in this proceeding. For all the reasons explained further below, the Companies' proposed Carbon Plan and the relief requested therein are consistent with the discretion provided to the Commission in HB 951, including the discretion possessed by the Commission with respect to the timing of achievement of the 70% Interim Target.

1. The Commission Has Broad Discretion to Extend the Interim Target Achievement Date to 2032.

In HB 951, the General Assembly provided that the Commission retained discretion regarding both the timing of compliance with the carbon reduction targets and the final generation mix identified to reduce CO_2 emissions. Indeed, while HB 951 directs the Commission to "take all reasonable steps" to achieve the 70% Interim Target by 2030 and carbon neutrality by 2050,[16] it also mandates that the Commission *must* "retain discretion to determine optimal timing and generation and resource-mix to achieve the least cost path

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[15] CIGFUR Comments at 8-9; CIGFUR Miller Direct Testimony at 16.

[16] N.C.G.S. § 62-110.9.

to compliance with the authorized carbon reduction goals[.]"[17] With respect to the 70% Interim Target, N.C.G.S. § 62-110.9 provides the Commission with discretion in two specific ways.

First, N.C.G.S. § 62-110.9(4) provides the Commission with substantial discretion to extend the Interim Target Achievement Date to 2032. Plainly, N.C.G.S. § 62-110.9(4) is broad—the plain language of the statute requires that the Commission retain its discretion to select the "optimal" timing and resource mix that achieves least-cost compliance with HB 951's carbon reduction goals even where such timing and resource mix extends the Interim Target Achievement Date to 2032. The General Assembly granted this discretion to the Commission in order to ensure that the Commission is able to use its judgment to select a Carbon Plan that takes into account a variety of critical factors, including the four core Carbon Plan objectives identified by the Companies (CO_2 reduction, affordability, reliability, and executability),[18] all of which are grounded in prudent utility planning and operation.

Second, N.C.G.S. § 62-110.9(4) expressly defines further discrete circumstances under which the Commission is authorized to extend the Interim Target Achievement Date beyond 2032:

- "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

[17] *Id.*

[18] *See* Carbon Plan, Executive Summary at 15-16.

factors beyond the control of the electric public utility[;]"[19] or

- "in the event necessary to maintain the adequacy and reliability of the existing grid."[20]

Pointing to the fact that the Companies' P1 portfolio achieves the interim CO_2 reduction target by 2030, the Attorney General's Office ("AGO") argues that the Commission may only delay meeting the 70% Interim Target beyond 2030 if the Companies show that another portfolio provides a "more significant and material impact on carbon reduction" than P1.[21] This interpretation is puzzling as it simply ignores the broad authority granted in HB 951 that precedes the provision cited by the AGO. Actually, N.C.G.S. §62-110.9(4) identifies "more significant and material impact on carbon reduction" as one of the factors the Commission may consider, but the Commission's discretion to allow for an extension of the Interim Target Achievement Date beyond to 2032 is broad—the Commission "[r]etains discretion to determine optimal timing and generation and resource-mix to achieve the least cost path."[22]

The AGO's interpretation effectively reads a key phrase—that the Commission has discretion "*including* discretion . . . to allow for implementation of solutions that would

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[19] *Id.* § 110.9(4).

[20] *Id.*

[21] AGO Initial Comments at 9-10 (*quoting* N.C.G.S. § 110.9(4)). NCSEA, *et al*. make a similar argument, stating that "it is clear that the General Assembly empowered the Commission to extend the deadlines for compliance with the law's carbon reduction requirements for up to two years only if doing so would obtain faster or deeper carbon reductions." NCSEA *et al.* Comments at 11. NCSEA, *et al*. similarly do not acknowledge or even attempt to address the "including" proviso that situates the HB 951's reference to "more significant and material impact on carbon reduction." *Id.*

[22] Gen. Stat. § 110.9(4) (directing that the Commission's discretion to "determine optimal timing . . . include[es] discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction").

have a more significant and material impact on carbon reduction"—out of the law."[23] Merriam-Webster defines the term "including" as "to take in or comprise as part of a whole."[24] The Fourth Circuit has similarly found that "the term 'including' is . . . more often than not the introductory term for an *incomplete list* of examples."[25] Accordingly, the Commission's discretion to extend the Interim Target Achievement Date to 2032 to implement solutions with a more significant impact on carbon reduction comprises an illustrative example or an "incomplete list" of the Commission's "discretion to determine optimal timing" for compliance with the authorized carbon reduction goals.[26]

Moreover, if the General Assembly intended to limit the Commission's discretion in the way the AGO suggests, it could have used more restrictive terminology like it did when directing that the Commission "shall not" extend the Interim Target Achievement Date beyond 2032 except in limited circumstances. The General Assembly's use of "including" was thus intended to provide the Commission broad, but temporally bounded, discretion to extend the Interim Target Achievement Date to 2032 and *not* to limit the Commission's discretion to consider an Interim Target Achievement Date beyond 2030

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[23] *Id.* § 110.9(3) (emphasis added).

[24] Merriam-Webster Dictionary, *available at* https://www.merriam-webster.com/dictionary/include.

[25] *Adams v. Dole*, 927 F.2d 771, 776–77 (4th Cir. 1991) (emphasis added) ("when we say that several colors, 'including red, blue and yellow' are in the rainbow, we are giving only examples and we do not mean that the rainbow does not include other colors"). In the limited circumstances where the term can be interpreted as restrictive, there must be an apparent inconsistency between the general principal and the specific, modifying phrase. *Id.* Here, there is no such inconsistency since the Commission's discretion to adjust achievement date for solutions that would result in a greater overall carbon reduction impact is not at odds with the general discretion to determine optimal timing.

[26] *See State ex rel. Utils. Comm'n v. Thornburg*, 316 N.C. 238, 245 (1986) ("When the language of a statute is clear and unambiguous, it must be accorded its clear meaning[.]").

only where such alternative resource plans would have a more significant and material impact on carbon reduction.

The AGO's interpretation also ignores other important factors HB 951 directs the Commission to consider, including least-cost planning, maintaining or improving the adequacy and reliability of the grid, considering the optimal mix of "power generation and transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs,"[27] all of which the Commission is required to consider to ensure selection of a prudent plan to meet HB 951's goals.

CPSA makes a similar attempt to narrow the Commission's post-2030 discretion, arguing that the Commission is not authorized to "delay compliance with the 70% reduction mandate past 2030 simply because it would cost less to do so."[28] However, with respect to this argument, CPSA does not appear to wrestle with the actual text of HB 951, which once again gives the Commission broad discretion prior to 2032 "to determine optimal timing and generation and resource-mix." Such broad discretion cannot be reasonably interpreted to foreclose the right of the Commission to pursue a pathway that achieves the 70% Interim Target beyond 2030 due solely or in part to the fact that such a pathway is more cost-effective.

Read together, these provisions of HB 951 provide the Commission broad discretion to extend the Interim Target Achievement Date to 2032.

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[27] N.C.G.S. § 110.9.

[28] CPSA Comments, at 37.

2. The Companies' Carbon Plan and Requests for Relief in this Initial Carbon Plan Proceeding are Consistent with the Commission's More Narrow Authority to Retain Discretion to Extend the Interim Target Achievement Date Past 2032.

As discussed above, N.C.G.S. § 62-110.9(4) grants the Commission express authority to extend the Interim Target Achievement Date beyond 2032 in two discrete scenarios: (1) in the event the Commission authorizes construction of a nuclear or wind facility that requires additional time for completion; and (2) in the event the Commission determines necessary to maintain the adequacy and reliability of the grid. Importantly, in this initial Carbon Plan proceeding, the Companies are not yet asking the Commission to select a portfolio or specific Interim Target Achievement Date based on future authorization of offshore wind or new nuclear facilities that could not be in service by 2032. Instead, the Companies are recommending that the Commission meet its obligation to "develop a plan" by finding the Companies' proposed Carbon Plan—including all portfolios reflecting a range of dates of achievement of the 70% Interim Target—to be reasonable for planning purposes and to specifically "select" and authorize the Companies to undertake near-term development and procurement activities in 2022-2024. This approach allows the Commission to direct decisive initial near-term actions—the near-term "reasonable steps" towards meeting the 70% Interim Target by 2030—while also allowing the Commission to retain discretion and preserve optionality to achieve all portfolios presented in the Carbon Plan, including the Supplemental Portfolios, in the future.

Accordingly, the Commission's ultimate determination of whether to "select" the addition of new nuclear or wind facilities and authorize their construction, thereby allowing an extension of the Interim Target Achievement Date beyond 2032 will occur in a later proceeding. The Companies' requested relief in this proceeding neither relies on nor forecloses the Commission's authority to extend the Interim Target Achievement Date beyond 2030 or 2032. Put another way, even though the Companies have not expressly asked the Commission to authorize construction of a nuclear or wind facility, the Commission can meet its planning responsibilities under HB 951 by selecting specific near-term actions and accepting as reasonable for planning purposes a range of intermediate- and longer-term portfolios, some of which would require the Commission to exercise its discretion and authority under HB 951 to achieve the 70% Interim Target beyond 2030 or 2032, if that is ultimately the path chosen.

This approach is supported by the plain language of HB 951, which confirms that the General Assembly intended the Commission to be nimble with its plans, adjusting as circumstances evolve, and "retain[ing] discretion to determine optimal . . . resource-mix[.]"[29] Specifically, the law expressly requires the Commission and the electric utilities to review the Carbon Plan "every two years and . . . adjust[ ] as necessary[.]"[30] The law also contemplates the Commission considering both existing generating technologies as well as "the latest technological breakthroughs to achieve the least cost path" as part of the energy transition.[31] This iterative development of the Plan supports the Commission setting a clear and executable near-term path while retaining optionality and discretion to evaluate the optimal least-cost path in the intermediate and long-term.[32]

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[29] N.C.G.S. § 110.9(4).

[30] *Id.* § 110.9(1).

[31] *Id.*

[32] This approach is wholly consistent with past integrated resource planning requirements under Rule R8-60, where the Companies submit short-term action plans for "specific actions currently being taken by the utility" while retaining flexibility to evolve its longer-term least cost planning as circumstances may change. *See* R8-60(h)(3).

Taken to its extreme, these intervenors' position would suggest that the Commission is somehow not permitted to even consider a compliance pathway that involves authorization of the construction of nuclear or wind generation prior to the point in time at which such authorization is actually granted. This would be an illogical result. The Commission is certainly free to accept as reasonable for planning purposes certain planning pathways that *may* ultimately rely on Commission authorization of nuclear and/or wind in the future and thereby retain discretion to actually utilize this plan to achieve the least-cost path for customers.

Importantly, the ultimate determination of whether the Companies have met the 70% Interim Target does not occur on December 31, 2022, but will instead be assessed on December 31, 2030. Pursuant to the biennial update process contemplated in HB 951, there will be at least three Carbon Plan update proceedings in the intervening years and, thus, three opportunities for the Commission and the utilities to "adjust" plans as necessary to meet the carbon reduction, least-cost, and reliability mandates given evolving procurement and development experience and other circumstances. Contrary to assertions by NCSEA *et al.*, Duke Energy is not "seeking to avail itself of an extension prospectively,"[33] but instead is providing a range of analysis in the form of multiple pathways and portfolios that appropriately allows the Commission to "[r]etain discretion to determine optimal timing and generation and resource-mix."

In fact, the Companies have requested selection of onshore wind generation in this initial proceeding. Through the onshore wind procurement process, the Companies will

[33] NCSEA *et al.* Comments at 14.

gather more information regarding project in-service dates for such resources, which will further inform the Commission's planning. Consistent with the plain language used by the General Assembly, the Commission should expressly state that it is retaining its discretion to adjust in the future so that it can better ensure that the least-cost plan to achieving the targeted carbon reduction milestones is achieved, as required by HB 951.

a. Presenting a range of portfolios is reasonable for planning purposes and the Companies' initial Carbon Plan also identifies the reasonable steps and decisive actions that the Commission should select towards achieving the 70% Interim Target.

Several parties, including AGO, CPSA, NCSEA *et al*., argue that the Companies should not assume an Interim Target Achievement Date beyond 2030 in any of their portfolios and suggest that an extension of the Interim Target Achievement Date was intended to serve only as a "safety valve" against unanticipated delays and would only be appropriate after the Commission issues a CPCN for a new nuclear or offshore wind facility.[34] This interpretation would both improperly limit the Commission's discretion and also force an absurd result, requiring the Companies to turn a blind eye to the realistic development timeline for resources like small modular reactors ("SMRs") that require further development. If the Commission were to accept intervenors' arguments, the Companies could likely not include SMRs in any of their plans to achieve the interim CO_2 reduction target—even though HB 951 expressly directs the Companies to consider "the latest technological breakthroughs" and provides a path to extending the Interim Target Achievement Date in the event such a technology is pursued.

[34] AGO Initial Comments at 10-12; CPSA Initial Comments at 35-37; NCSEA *et al*. Comments at 10-15; ECAN/DECAESIJC Initial Comments at 23-24; RHC/RCCSD Initial Comments at 26-30.

Moreover, the Commission need only spend limited time considering this argument as, ultimately, it has no impact on the decisions to be made in this initial Carbon Plan proceeding. This is because the Companies are not asking the Commission to select a single portfolio. As described in the Carbon Plan and further explained by the Modeling and Near-Term Actions Panel testimony, the near-term actions presented in the Carbon Plan are generally consistent with both P1 enabling Duke Energy to meet the 70% Interim Target in 2030, as well as the other portfolios that achieve the 70% Interim Target after 2030.[35] Said differently, the resources that the Companies are requesting the Commission select in this initial Carbon Plan represent the "reasonable steps" to be executed in the near term toward achieving the least-cost path to compliance with the 70% Interim Target by 2030, and the Commission should retain discretion to assess in the future the optimal path to achieve the 70% Interim Target. The Commission, in future proceedings, can determine whether to exercise the discretion to select a path for compliance beyond 2030, including by authorizing construction of a wind or nuclear facility.

b. <u>The Commission should also retain discretion to ensure the adequacy and reliability of the grid.</u>

Ensuring reliability is a core objective and requirement of the Carbon Plan to be developed by the Commission under HB 951. Continued planning flexibility is also key to ensuring that "any generation and resources changes [implemented as part of the Carbon Plan] *maintain or improve upon* the adequacy and reliability of the existing grid" as mandated by HB 951.[36] With this mandate, the General Assembly recognized the

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[35] Carbon Plan Executive Summary at 24; Chapter 4 Execution Plan at 8; Modeling and Near-Term Actions Panel at 50.

[36] N.C.G.S. § 110.9(3).

Companies' public service obligation to plan and operate their generating fleets and transmission and distribution systems to provide reliable electric service to customers at all hours of the day, every day of the year, in all weather and grid conditions. From a practical perspective, the Companies are planning to retire more than 8,400 MW of coal generating resources between now and 2035.[37] While the sophisticated modeling performed in the portfolio verification and reliability validation steps confirm that all proposed portfolios will meet the high standards for maintaining or improving reliability imposed by HB 951, the Commission should also recognize and retain its discretion to adjust the Plan in the future to ensure the adequacy and reliability of the grid is maintained as the Companies gain more clarity regarding the coal retirement schedule over the next decade.

In summary, the Commission should select the near-term actions presented in the proposed Carbon Plan while retaining discretion to "adjust" in future proceedings and to consider the optimal timing and generation resource mix to achieve the least-cost path to compliance. This necessarily should include discretion to consider future Carbon Plan proceedings portfolios that achieve the 70% Interim Target beyond 2030, consistent with authority delegated by the General Assembly under HB 951.

c. <u>CPSA incorrectly applies the extension authority granted to the Commission for the 70% Interim Target in the case of nuclear and wind generation.</u>

CPSA also attempts to narrow the Commission's discretion to extend the Interim Target Achievement Date on the basis of nuclear and wind generation, asserting that such an extension is only permitted where "<u>unanticipated</u> events beyond Duke's control result

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[37] Modeling and Near-Term Actions Panel Figure 11 shows that Duke Energy is reducing even more significant coal capacity by 2035 (9,247 MW) due eliminating the dual fuel capabilities at Cliffside Unit 6.

in delays on bringing wind or nuclear resources on-line once their construction has been authorized through the issuance of a CPCN."[38] This interpretation reflects two inaccuracies. First, there is nothing in the statutory language that suggests that the additional time must be required due to a factor that was "unanticipated." This assertion has no basis in the actual language of the statute.[39] Instead, an extension is permitted where the Commission authorizes nuclear or wind generation "that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility." These identified reasons are extremely broad, including the catch-all of "other factors," and there is no suggestion in the text that the factor giving rise to the necessary construction timeline must have been "unanticipated." Second, CPSA's statement seems to suggest that the factors pushing the construction timeline beyond 2032 must arise after the CPCN has been issued. Putting aside the fact that a CPCN is not required for offshore wind, CPSA's interpretation similarly has no basis in the text, as there is no language suggesting that the General Assembly intended to limit the extension only due to factors arising after a CPCN is issued.

3. The Commission Is Not Required to Select a Single Portfolio at This Time.

As explained in its Petition and Executive Summary and the Modeling and Near-Term Actions Panel,[40] the Companies have requested the Commission affirm that the Companies' Carbon Plan modeling across all portfolios is reasonable for planning purposes

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[38] CPSA Comments at 36 (emphasis in original).

[39] *See* Section II.B. *infra.* (explaining that the North Carolina Supreme Court has affirmed that courts have "no power to add to or subtract from the language of the statute[.]")

[40] *See* Petition at 15; Carbon Plan, Ch. 4 (Execution Plan) at 1; Direct Testimony of Snider, McMurry, Quinto & Kalemba at 17-23.

and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning. This approach is consistent with the Commission's historic approach to long-range planning, and there is no indication that the General Assembly intended a departure from such approach. Approving a single portfolio at this time is not only not required under law, it would also be premature before more information is gathered, including further information regarding market costs and information regarding the long lead-time supply-side resources that are projected to potentially be needed to execute the least-cost path to achieving the HB 951 goals.

NCSEA *et al*. assert that the "multi-pathway approach is not supported" by the law and that a single portfolio must be selected because HB 951 uses the "singular" plan.[41] This simplistic read is unreasonable and ignores the obvious fact that North Carolina law has long recognized that a long-range plan (singular) reasonably should include a range of potential future options (*see e.g.*, N.C.G.S. § 62-110.1 which requires development of the traditional long-range plan (singular), which the Commission has consistently affirmed can include a range of scenarios).[42]

[41] NCSEA *et al*. Comments at 15.

[42] *Id.* NCSEA *et al*. further engage in unsupported hyperbole, alleging that Duke Energy's position that the Commission need not select a single portfolio means that Duke Energy is seeking "not to be held accountable to a plan" or that somehow Duke Energy would thereby "be allowed to coach and referee a game in which it is a player, at once designing multiple play options, acting as quarterback to execute those options, and deciding whether a range of possible play options fall within the rules of the game." No explanation is provided as to why allowing the Commission to exercise its well-established historic practice of approving near-term actions followed by a range of longer-term planning portfolios means that Duke Energy is thereby the "coach" and the "referee" but, in any event, such baseless hyperbole is not grounded in anything Duke Energy has actually proposed in this proceeding.

B. HB 951 Mandates Clear, Unambiguous Ownership Requirements that Must be Applied in Harmony with All Other Requirement of HB 951 and Existing Law

There is no ambiguity in HB 951 with respect to ownership of new generating facilities and other resources ("Facilities") selected by the Commission in the Carbon Plan: third parties shall own 45% of new solar and solar paired with energy storage ("SPS"), and Duke Energy shall own all other Facilities selected by the Commission to achieve the Carbon Plan (collectively, the ownership requirements in HB 951 applicable to Duke Energy and third parties are referred to herein as the "Ownership Requirements").[43] These Ownership Requirements could not be clearer or more unambiguous, and the Commission need not look elsewhere for the General Assembly's intent.[44]

Duke Energy believes that the General Assembly was clear and meant what it said in HB 951: the Commission should develop a plan to retire Duke Energy's owned coal-fired generation and other carbon-emitting resources to achieve carbon neutrality and should select new Facilities as part of a State-wide plan to reliably replace these resources which shall be subject to HB 951's Ownership Requirements.

The Public Staff[45] and most other parties recognize or do not challenge the General Assembly's unambiguously stated intent in this regard. Several intervenors, however, contend that the General Assembly did not mean what it said. Instead, rather than applying HB 951 as drafted and applying all of its requirements in harmony, they argue that the

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[43] N.C.G.S. §§ 62-110.9(2), (2)(b).

[44] *State v. Jackson*, 353 N.C. 495, 501, 546 S.E.2d 570, 574 (2001) (courts "are without power to interpolate, or superimpose, provisions and limitations not contained" in "clear and unambiguous" legislative enactments) (quoting *In re Banks*, 295 N.C. 236, 239, 244 S.E.2d 386, 388-89 (1978).

[45] Public Staff Thomas Testimony at 34 ("Section 110.9(2) requires Duke ownership of new generation facilities for purposes of Carbon Plan compliance")

Ownership Requirements are subservient to the other requirements contained in HB 951, despite the lack of any statutory language or coherent interpretative principle to indicate that such outcome was intended by the General Assembly.[46]

Intervenors' reading, which ignores the General Assembly's plain language and effectively adds language not included, is impermissible under well-established principles of statutory interpretation in North Carolina. When interpreting statutes, North Carolina courts may not "ignore or amend legislative enactments" that are "clear and unambiguous."[47] The North Carolina Supreme Court has affirmed that courts have "no power to add to or subtract from the language of the statute . . . The question of the wisdom or propriety of statutory provisions is not a matter for the courts, but solely for the legislative branch of the state government."[48] With respect to general interpretation, the North Carolina Court of Appeals has affirmed that "a statute must be considered as a whole and construed, if possible, so that none of its provisions shall be rendered useless or redundant."[49] Furthermore, "[i]t is presumed that the legislature intended each portion to be given full effect and did not intend any provision to be mere surplusage."[50] North Carolina courts also adhere "to the long-standing principle that when two statutes arguably

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[46] *See e.g.*, Tech Customers' Comments at 18-20 (urging the Commission to reject HB 951's utility ownership mandate to authorize third-party power purchases).

[47] *Orange County ex rel. Byrd v. Byrd*, 129 N.C. App. 818, 822, 501 S.E.2d 109, 112 (1998) (citing *State ex rel. Utilities Comm'n v. Edmisten*, 291 N.C. 451, 465, 232 S.E.2d 184, 192 (1977)).

[48] *Ferguson v. Riddle*, 233 N.C. 54, 57, 62 S.E.2d 525, 528 (1950)

[49] *R.J. Reynolds Tobacco Co. v. N.C. Dep't of Envtl. and Natural Res.*, 148 N.C.App. 610, 616, 560 S.E.2d 163, 168 (2002) (quoting *Porsh Builders, Inc. v. City of Winston–Salem*, 302 N.C. 550, 556, 276 S.E.2d 443, 447 (1981) (internal quotations and citations omitted))

[50] *Id.* at 616, 560 S.E.2d at 168.

address the same issue, one in specific terms and the other generally, the specific statute controls."[51]

HB 951's Ownership Requirements are clear and unambiguous and those few intervenors challenging the Ownership Requirements have failed to articulate an interpretation that is remotely consistent with well-established principles of statutory interpretation under North Carolina law.

1. The Plain Language of HB 951 Clearly and Unambiguously Mandates the Ownership Requirements.

The Commission's role is to effectuate the purpose of the General Assembly in enacting HB 951.[52] To accomplish this objective, the Commission must first look to the plain language of the legislation.[53]

HB 951 charts a very clear and unambiguous pathway to the CO_2 emissions reduction targets. HB 951 directs the Commission to "take all reasonable steps" to achieve CO_2 emissions reduction targets by 2030 and 2050.[54] HB 951 tasks the Commission with developing a Carbon Plan, which "may, at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs to achieve the least cost path *consistent with this section* to achieve compliance with the authorized carbon

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[51] *High Rock Lake Partners, LLC v. N. Carolina Dep't of Transp.*, 366 N.C. 315, 322, 735 S.E.2d 300, 305 (2012) (citations omitted).

[52] *See State v. Hooper*, 358 N.C. 122, 125, 591 S.E.2d 514, 516 (2004).

[53] *Id*.

[54] N.C.G.S. § 110.9.

reduction goals."[55] It is in the very same section[56] where the General Assembly mandated the Ownership Requirements of Facilities selected in the Carbon Plan.

The first sentence of N.C.G.S. § 62-110.9(2) requires the Commission to "[c]omply with current law and practice with respect to the least cost planning for generation, pursuant to G.S. 62-2(a)(3a)" for new generation resources. Then N.C.G.S. § 62-110.9(2) goes on to require that "[*a*]*ny new generation facilities or other resources selected by the Commission* in order to achieve the authorized reduction goals for electric public utilities *shall be owned and recovered on a cost of service basis by the applicable electric public utility*[.]"[57] There could be no clearer manifestation of the General Assembly's intent to require utility ownership than actually using the words "shall be owned . . . by the applicable electric public utility."[58] North Carolina courts have affirmed that "[t]he use of the word 'shall' in a statute is mandatory."[59]

Then, N.C.G.S. § 62-110.9(2) goes on to provide one—and only one—exception within the Ownership Requirements for new facilities: "[t]o the extent that *new solar*

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[55] N.C.G.S. § 110.9(1)(emphasis added).

[56] As enacted, all of the Carbon Plan related provision were in the same section of the law—Section 1.

[57] N.C.G.S. § 110.9(1) (emphasis added).

[58] *Id*.

[59] *In re Cline*, 230 N.C. App. 11, 19, 749 S.E.2d 91, 97 (2013) ("The use of the word "shall" in a statute is mandatory.") (citing *Multiple Claimants v. N.C. Dep't of Health & Human Servs.*, 361 N.C. 372, 378, 646 S.E.2d 356, 360 (2007) (citations omitted)).

The requirement that these new resources be "recovered on a cost of service basis" further confirms utility ownership is required. Cost of service regulation is the process by which public utilities are allowed a reasonable opportunity to recover their investments in Facilities that are used and useful in the provision of public utility service. *See* N.C.G.S. § 62-133(b)(1); *State ex rel. Utilities Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 348 N.C. 452, 467, 500 S.E.2d 693, 704 (1998). HB 951's requirement that new generation resources be recoverable by utilities in cost of service-based rates could only mean one thing: the utility tasked with executing the Carbon Plan developed by the Commission—which necessitates retiring significant utility-owned carbon emitting generation—shall own the Facilities selected by the Commission as enabling the least cost path to achieve the State's emissions reductions goals.

generation is selected by the Commission, in adherence with least cost requirements," 45% shall be owned by third parties and 55% shall be owned by the utility.[60] The remaining 55% of new solar "shall be . . . *owned* and *operated* and *recovered on a cost of service basis*" by the utility. *Id*. (emphasis added). Importantly, Gen. Stat. § 62-110.9(2)(b) demonstrates that where the General Assembly wanted to authorize power purchases from third parties as resources selected in the Carbon Plan, it used express, precise language to do so.

2. Intervenors' Interpretation is Impermissible Under Traditional Principals of Statutory Construction.

Intervenors CUCA, Tech Customers, and Kingfisher take the position that these express ownership mandates are merely discretionary.[61] In fact, these intervenors argue that HB 951's utility ownership requirement actually means the opposite of what it says: the Commission must consider third-party non-utility ownership when selecting new generation resources under the Carbon Plan. Intervenors' position stretches the statute's plain language beyond any reasonable interpretation and rests on a fundamental misapplication of statutory construction principles. Their errors include ignoring or disregarding plain language in HB 951, ingrafting language into the law that was omitted, manufacturing – rather than avoiding – conflicts within the legislation and advocating for

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[60] N.C.G.S. § 62-110.9(2)(b). As specified therein, this allocation also applies to solar energy facilities (i) paired with energy storage and (ii) procured in connection with any voluntary customer program.

[61] *See* CUCA Comments at 2 ("If utility ownership is not the least-cost option, then Duke should be required to . . . consider[ ] purchases from third-party energy suppliers."); Tech Customers' Comments, at 18 ("[T]he omission of purchased power as an alternative to new-build generation is contrary to the expectations of [HB 951]."); Kingfisher Comments at 3 ("Kingfisher believes that the use of competitive bidding would best effectuate the legislative intent behind . . . House Bill 951.").

interpretations that would have absurd results. Therefore, such intervenors' erroneous and impermissible reading of HB 951 should be rejected.

a. Intervenors ignore HB 951's plain language and there is no conflict between the Ownership Requirements and the least cost planning requirement in HB 951.

Finding no express language to support their reading, certain intervenors argue that the Commission's authority to disregard the Ownership Requirements should be implied from the references to "least cost" in HB 951.[62] In asserting such positions, such intervenors do not even attempt to wrestle with North Carolina's well-established principles of statutory interpretation.

More specifically, such intervenors effectively attempt to impermissibly "amend legislative enactments" and "add to…language of the statute." Had the General Assembly intended to allow third-party ownership of new, non-solar/SPS Facilities, it would have said so. The General Assembly instead expressly required utility ownership of all new, non-solar/SPS generation without exception. Indeed, the General Assembly clearly considered third-party ownership and, in fact, made the express decision to authorize third party ownership of 45% of new solar resources. Alternatively, the General Assembly could have specified that new resources must adhere to the Ownership Requirement, but

[62] *See* CUCA Comments at 3 (stating that "least-cost planning requires consideration of purchases from third-party energy suppliers"); Tech Customers Comments at 19 (HB 951 "directs the commission to select the 'least cost path' – not the least-cost assets owned by the utility."); CIGFUR Comments at 26 ("CIGFUR suggests, among other recommendations, that to the extent new natural gas assets are determined to be the least-cost, most reliable increment of new generation, power purchase agreements (PPAs) with third parties should be, at a minimum, evaluated as a potentially more cost-effective alternative.").

only if utility ownership represents the least cost option.[63] But once again, the General Assembly did not so state, and these intervenors may not add language to the statute.

Furthermore, these intervenors do not appear to consider how their interpretation would render the Ownership Requirements meaningless. These intervenors' interpretation would render everything after the first sentence of N.C.G.S. § 62-110.9(2) as mere surplusage, which is clearly not what the General Assembly intended nor consistent with established statutory interpretation principles.[64]

Moreover, intervenors ignore inconvenient language in Section 1 that provides essential context for understanding "least cost" planning under the Carbon Plan. The General Assembly directs the Commission to achieve the "least cost path *consistent with this section*."[65] The purpose of this provision is to make clear that "least cost path" must be determined within the context of other provisions in the section.[66] The primary Ownership Requirement mandate is provided in the very next subsection. Therefore, the "least cost path" must account for and be "consistent with" the Ownership Requirement.

Finally, intervenors' argument that the general "least cost" planning requirements is controlling over and negates specific utility ownership mandates flips statutory interpretation principles on their head.[67] Assuming *arguendo* that the Commission has traditionally considered resource ownership issues as part of "least cost" resource planning,

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[63] *See* CUCA Comments at 2.

[64] *See R.J. Reynolds Tobacco Co.*, 148 N.C. App. at 616, 560 S.E.2d at 168.

[65] N.C.G.S. § 62-110.9(1) (emphasis added); *Cf.* Tech Customers Comments at 19 (asserting that "Section (1)(2) directs the Commission to select the 'least cost path'").

[66] As enacted, all of the Carbon Plan related provision were in the same section of the law—Section 1.

[67] *See High Rock Lake Partners*, 366 N.C. at 322, 735 S.E.2d at 305.

there is no indication on the face of N.C.G.S. § 62-2(a)(3a) or otherwise that the General Assembly expected third-party market alternatives to be selected in the Carbon Plan beyond solar and SPS. As is further explained below, the Companies do not believe there is a conflict between the "least cost" planning and the Ownership requirements, but even if there is perceived conflict, the express and "specific"[68] Ownership Requirements are controlling.

In effect, such intervenors are asking the Commission to repeal by implication the Ownership Requirements altogether. North Carolina law holds that "[i]nterpretations that would create a conflict between two or more statutes are to be avoided, and statutes should be reconciled with each other whenever possible."[69] When determining whether legislative provisions are in conflict,

> [R[epeals by implication are not favored . . . and *the presumption is always against implied repeal* . . . Instead, repeal by implication results only when the statutes are inconsistent, necessarily repugnant, utterly irreconcilable, or wholly and irreconcilably repugnant[.][70]

The requirement to "comply with current law and practice with respect to least cost planning for generation, pursuant to G.S. 62-2(a)(3a)" in Subsection 1(2), as well as other references to "least cost" in Section 1, are not inconsistent with the utility ownership requirement. There is a simple and straightforward way to read and interpret in harmony the various requirements imposed by the General Assembly under HB 951. That is, there

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[68] *Id*.

[69] *Velez v. Dick Keffer Pontiac GMC Truck, Inc.*, 144 N.C. App. 589, 593, 551 S.E.2d 873, 876 (2001).

[70] *State ex rel. Utilities Comm'n v. Town of Kill Devil Hills*, 194 N.C. App. 561, 567, 670 S.E.2d 341, 345, writ allowed, 636 N.C. 583, 681 S.E.2d 344 (2009), and aff'd, 363 N.C. 739, 686 S.E.2d 151 (2009) (citations and quotations omitted) (emphasis in original).

are a series of core requirements imposed under HB 951, all of which have been given "full effect"[71] in Duke's proposed Carbon Plan in a manner that avoids conflict[72] and "implied repeal."[73] The General Assembly has directed that the Carbon Plan must (1) achieve targeted CO_2 reductions, (2) utilize the "least cost path consistent with this section," (3) comply "current law and practice with respect to the least cost planning for generation," (4) ensure that reliability is maintain or improved, and (5) adhere to the Ownership Requirements. The Companies' Carbon Plan incorporates and balances all requirements, charting a course that gives full effect to clear and unambiguous statutory directives and ensuring that no provision is rendered useless or surplusage.[74] For instance, when selecting the future mix of Facilities to achieve HB 951's carbon reduction goals, the Commission should be guided by least cost principles, and should also plan for the least cost mix of generation and demand-reduction measures which is achievable, pursuant to G.S. 62-2(a)(3a). Thus, when faced with two or more portfolios of generating facilities and other resources designed to meet the State's carbon emission reduction goals that reflect the Ownership Requirements, the Commission should apply least cost planning principles, including full consideration of demand-side measures and EE, to select amongst these alternate portfolios of potential resources.[75] Such application of least cost principles is

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[71] *R.J. Reynolds Tobacco Co.*, 148 N.C. App. at 616, 560 S.E.2d at 168.

[72] *Velez,* 144 N.C. App. at 593.

[73] *Kill Devil Hills*, 194 N.C. App. at 567.

[74] *R.J. Reynolds Tobacco Co.*, 148 N.C. App. at 616, 560 S.E.2d at 168.

[75] Under North Carolina law and practice, cost is not the only factor the Commission considers for least cost planning of generation resources. Instead, "[N.C.]G.S. [§] 62-2(a)(3a) requires evaluation of the full spectrum of DSM and EE, the goal of such an analysis is to ensure that energy planning results in the least cost mix of generation and demand reduction that also serves the utility's requirement to provide adequate and reliable service." Order Issuing Certificate of Public Convenience and Necessity, at 11, Docket No. E-2, Sub 1066 (Aug. 3, 2015).

entirely consistent with historic practice and yet still gives full effect to the Ownership Requirements.

In contrast, these intervenor arguments would effectively "repeal by implication"[76] nearly the entirety of subsection (2). This outcome is not necessary because the statute can easily be read in harmony and is therefore not "utterly irreconcilable."[77]

b. Intervenors' interpretation would yield absurd results.

Legislation must be construed "so as to avoid absurd consequences."[78] Intervenors' interpretation should also be rejected because it would yield absurd results. No intervenor disputes that the General Assembly has expressly imposed the Ownership Requirements. However, if the utility ownership requirement can simply be ignored for allegedly conflicting with the least cost requirement, then so too would the mandated third-party ownership of 45% of solar and solar/SPS. Once again, this interpretation repeals by implication an express General Assembly directive when such an outcome is not necessary.

In fact, taken to its logical extreme, such intervenors' interpretation could actually be used to negate even the CO_2 emissions reduction targets contained in HB 951. That is, if the clear and unambiguous Ownership Requirements can be ignored based on the alleged application of "least-cost" principles, then it would also be similarly possible to override the CO_2 emission reduction targets if achievement of such targets were shown to be allegedly inconsistent with least cost planning. This would be an absurd result. Rather, it

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[76] *Kill Devil Hills*, 194 N.C. App. at 567.

[77] *Id.*

[78] *Nationwide Mut. Ins. Co. v. Mabe*, 342 N.C. 482, 494, 467 S.E.2d 34, 41 (1996) (citation omitted).

is necessary for the law to be applied in a manner that gives logical and balanced effect to all of its provisions, which is what the Companies have done through their Carbon Plan.

The General Assembly did not prescribe clear Ownership Requirements only to have them ignored or bypassed under the guise of applying least cost principles to devise a new ownership allocation. Nor did the General Assembly establish specific carbon reduction goals only to have them discarded based on alleged least cost planning. Rather, the General Assembly directed that least cost principles be applied within the context of all of the requirements of HB 951 to select the appropriate mix of supply-side resources (utilizing the Ownership Requirements) and demand-side resources that will enable Duke Energy to achieve the targeted emissions reductions.

c. The Ownership Requirements applicable to Carbon Plan are not altered by N.C.G.S. § 62-110.1 or the Commission's Rules.

Several intervenors assert that pre-HB 951 references in N.C.G.S. § 62-110.1 to "other arrangements with other utilities and energy suppliers" and the directive to "take into account the applicant's arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power" nullifies the Ownership Requirements. Similarly, certain intervenors assert that the requirement in Rule R8-60 to consider purchases of power from "wholesale suppliers and power marketers" negates the Ownership Requirements.

Once again, these interpretations are inconsistent with well-established principles of statutory construction. The flaw lies in intervenors' reliance on broad language and general grants of authority in Sections 62-3(a)(3a) and 62-110.1 related generally to long-range planning, and rules promulgated thereunder, in an attempt to undermine the

Legislature's specific intent in the later enacted and narrowly focused Section 1 of HB 951. Thus, "when there are two statutes, one dealing specifically with the matter in issue and the other being in general terms which, nothing else appearing, would include the matter in question, the specific statute controls" over the general statute and its corresponding regulations.[79] "Moreover, just as it 'is true a fortiori' that a specific statute prevails over a general one 'when the special act is later in point of time,' the later addition of a specific provision to a pre-existing more general statute indicates the General Assembly's most recent intent."[80]

Here, the General Assembly has clearly and unequivocally asserted that the Ownership Requirements should apply to all new resources selected as part the Carbon Plan and, to the extent that there is a conflict, which the Companies do not believe to be the case, that more specific directive should control over the more general directive. To do otherwise would lead to the absurd results articulated above, since for instance, the historic planning practices applied under N.C.G.S. § 62-2(a)(3a) similarly did not contemplate or allow for system planning designed to reduce CO_2 emissions. Allowing the provisions of N.C.G.S. §§ 62-110.1 to render the Ownership Requirements meaningless is inconsistent with North Carolina law.

Moreover, the Companies' Carbon Plan does take into account other energy suppliers and the purchase of *non-firm* power through the reliance on substantial amounts of emergency import power and the potential availability of short-term sales under the

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[79] *Edmisten*, 291 N.C.at 465, 232 S.E.2d at 192; *High Rock Lake Partners, LLC v. N. Carolina Dep't of Transp.*, 366 N.C. 315, 322, 735 S.E.2d 300, 305 (2012).

[80] *LexisNexis Risk Data Mgmt. v. N.C. Admin. Office of the Courts*, 368 N.C. 180, 187, 775 S.E.2d 651, 656 (2015) (citation omitted).

Southeast Energy Exchange Market, currently effective third-party purchase arrangements and power purchased at wholesale from qualifying facilities. The General Assembly has further directed that Duke Energy is required to purchase power from third-party providers in the case of solar generation (up to the allocated 45%). But when it comes to all other "new generation facilities or other resources selected by the Commission in order to achieve the authorized reduction goals," the General Assembly has unambiguously required that utility ownership apply.

3. HB 951's Utility Ownership Mandate Represents Sound and Reasonable Policy That is Beneficial to Customers.

Setting aside statutory interpretation, it is essential to note that the utility ownership requirements in HB 951 are not arbitrary but instead represent sound and reasonable policy that is beneficial to customers. The State's transformational emission reduction targets can only be achieved by replacing emission-intensive generation resources with new, lower- or lower-and zero-carbon emitting resources. The Companies' proposed Carbon Plan demonstrates that this complex energy transition will require the execution of interdependent actions that must be synchronized across near- and long-term planning horizons. Consider, for example, some of the unprecedented tasks facing Duke Energy. The Companies are planning to retire over 8,400 MW of coal generation capacity currently owned by the Companies – approximately one-fourth of DEC's and DEP's system capacity. In order to maintain reliability, this capacity must be retired in a carefully coordinated and sequential manner through investments in a wide variety of new resources. All of this must be accomplished by Duke Energy—under the oversight of this Commission and the Public Service Commission of South Carolina. Given the magnitude of the task and the central role that Duke Energy plays in both accomplishing the transition and maintaining reliability, it is reasonable for the General Assembly to conclude that the utility should have a substantial ownership interest in the new Facilities required. The reasonableness of this policy decision is only highlighted when one considers that many of the new Facilities are simply replacing retiring facilities that Duke Energy previously owned, managed, operated and relied upon to provide reliable electric service to the citizens of North Carolina for decades.

Requiring utility ownership through Commission-supervised least-cost planning also embodies the regulatory compact between Duke Energy and the State. The General Assembly has recognized that rates, services and operations of public utilities are affected with the public interest and has declared it to be the "policy of the State of North Carolina . . . to promote the inherent advantage of regulated public utilities."[81] "Doing so allows for the 'availability of an adequate and reliable supply of electric power . . . to the people, economy and government of North Carolina[.]'"[82] This declaration "clearly reflects the policy adopted by the legislature that a regulated monopoly best serves the public, as opposed to competing suppliers of utility services."[83]

It is not surprising that the General Assembly would turn to traditional cost-of-service regulation principles when enacting such transformative energy legislation.[84] HB

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[81] N.C.G.S.§ § 62-2(a)(2).

[82] *State ex rel. Utilities Comm'n v. N. Carolina Waste Awareness & Reduction Network*, 255 N.C. App. 613, 619, 805 S.E.2d 712, 716 (2017), aff'd, 371 N.C. 109, 812 S.E.2d 804 (2018) ("NC WARN") (quoting N.C.G.S. § 62-2(b)).

[83] *Id.* (quoting *State ex rel. Utils. Comm'n v. Carolina Tel. & Tel. Co.*, 267 N.C. 257, 271, 148 S.E.2d 100, 111 (1966)).

[84] The regulatory compact has allowed utilities to "offer their most essential contribution to the health and growth of our economy, and it has provided utility customers with the most reliable and most economic utility

951 introduces a new carbon emissions reduction planning objective that must be satisfied and balanced with other crucial customer interests. The State has mandated the Commission to develop a plan to transition the Companies' system on an aggressive schedule both to meet the 70% Interim Target and by 2050 to achieve carbon neutrality. Successful integration of new generation resources selected under the Carbon Plan will require prudent planning and execution and a laser focus on ensuring reliability is maintained or improved. These deadlines give Duke Energy a narrow window to develop new generation resources capable of replacing its remaining coal units and meeting future demand.

Further, as it replaces old resources and integrates new resources one by one, Duke Energy must also maintain or improve the overall reliability and adequacy of its electric system. The utility ownership mandate reflects the General Assembly's conclusion that investing in, developing, and executing the significant generation resource transition and power system transformation required to execute the Carbon Plan is best accomplished through Duke Energy's vertically-integrated operations under the comprehensive and constructive regulatory oversight of the Commission and PSCSC.

The General Assembly has placed ownership of new generation resources selected by the Commission under the Carbon Plan in the hands of the same regulated utility that is legally obligated to maintain a continuous supply of adequate and reliable electricity to

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service available anywhere in the world." Robert L. Swartwout, *Current Utility Regulatory Practice from a Historical Perspective*, 32 Nat. Res. J. 289, 313 (1992).

serve North Carolina.[85] Therefore, the utility ownership mandate is consistent with North Carolina's policy that utility ownership of generating resources best serves the public interest.[86] Indeed, the General Assembly's reaffirmation of its policy promoting Duke Energy's ownership of utility resources is especially compelling in this instance, where it has directed Duke Energy to transform nearly every aspect of its regulated electric utility system in just 30 years by 2050.

Certain intervenors express concern that mandated utility ownership will give Duke Energy a blank check to meet the emissions reduction targets by any means and at any cost.[87] Such hyperbole has no basis in the law or the Commission's long-standing regulation of the Companies for two obvious reasons.

First, HB 951's least-cost planning requirement will guide reasonable and prudent planning decisions, and all new Facilities must be approved by the Commission. In its selection of new Facilities, the Commission must choose the least-cost path to achieve the emissions reduction targets while not sacrificing system adequacy and reliability. Duke Energy's commitment to ensuring the least-cost path is reflected in its Execution Plan, which contemplates the use of competitive processes to acquire the most cost-effective resources for the benefit of customers. These strategies allow Duke Energy to leverage its economies of scale to minimize costs. Second, the Commission will continue to apply its

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[85] N.C.G.S. § 62-110.9(2).

[86] *See NC WARN*, 255 N.C. App. at 619, 805 S.E.2d at 716.

[87] *See* Comments of CIGFUR I and II at 25-26 (asserting that "the energy transition does indeed present a ripe opportunity for Duke to gold-plate its generation and transmission plant.").

traditional regulatory scrutiny to all costs incurred by the Companies and will deny cost recovery of any costs that are determined to be unreasonable or imprudent.

In addition, there are a wide range of operational and other benefits of utility ownership. A complete recitation of such benefits is beyond the scope of these Comments but include the following:

- **Responsibility, Reliability and Control**—Because Duke Energy is responsible for ensuring reliability, it is appropriate for the Companies to have ownership level control over a substantial portion of generation on which it will depend to provide reliability. Contractual-based generation arrangements involving third parties are complex and imperfect and do not always result in the right incentives over the short or long term with respect to reliability. A utility is able to exert more direct control over a generating facility under ownership than under third-party ownership. Even under the perfect contract, there will be limits on the Companies' ability to control the generating asset, and there may be circumstances that prevent the utility from maximizing that asset for the benefit of customers. Furthermore, it is much more complex to administer a fleet of generating assets where the utility must navigate scores or even hundreds (in the case of solar) different power purchase agreements, all of which are executed at different times and reflect different terms and conditions.

- **Price Certainty; End of Life Value Mitigates Future Price Risk**—Cost-of-service ownership of assets provides more price certainty and mitigates future price risk. As utility assets approach the end of useful life, capital costs to customers trend towards zero. This can provide substantial benefit to customers where assets exceed expected useful life (*see e.g.*, the Companies' nuclear units) and also provide risk mitigation against future market price increases (utility-owned assets have a future known capital cost to customers whereas market prices in those years are uncertain and could increase substantially, particularly if federal carbon restrictions or prices are eventually mandated).

- **Future Technology Evolution and Future System Changes**—There will always be future technology and system evolutions that are not foreseeable today. In the case of utility-owned assets, such technology evolutions can be assessed by the regulator and implemented on a comprehensive and efficient basis. In the case of third-party owned assets, such technology evolutions might not be able to be implemented efficiently where the operation of the assets are governed by contract, many of which will have different terms and conditions. A simple example is where capacity needs, forecasts of commodity costs or pricing periods established at a particular

> point in power purchase agreement eventually fail to coincide with actual system conditions at some future point in time. No contract can perfectly anticipate future system conditions over a 15-25 year period.

In sum, HB 951's clearly stated utility ownership requirement aligns with the regulatory compact and vertically-integrated regulated utility model that has long served Duke Energy's customers and communities in the State of North Carolina well through provision of affordable, reliable and increasingly cleaner energy in the Carolinas.[88]

C. **The Commission Has Authority to and Should Provide Duke Energy Reasonable Assurances that Engaging in Initial Project Development Activities for Long Lead-Time Resources Identified in the Near-Term Execution Plan is a Reasonable and Prudent Step and that Any Such Prudently Incurred Development Costs will be Recoverable in the Future.**

In its Verified Petition for Approval of Carbon Plan (the "Petition"), the Companies requested that the Commission make a number of determinations to provide Duke Energy reasonable assurance that reasonable and prudently incurred project development costs associated with long lead-time resources (offshore wind, SMRs, new pumped storage hydro at Bad Creek) identified in Table 3 of the Carbon Plan Executive Summary, if approved by the Commission, would be recoverable. Specifically, the Companies asked the Commission to determine that:

> (i) Engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;
>
> (ii) To the extent not already authorized under applicable accounting rules, that the Companies are authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies then authorized, net-of-tax,

[88] Carbon Plan Executive Summary at 1.

> weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and
>
> (iii) That in the event the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO2 emission reduction targets of HB 951, 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[.][89]

Several intervenors objected to this request, citing concerns that, in their view, (1) it would be inappropriate for the Commission to make any determination at this time regarding the reasonableness or prudence of the costs associated with project development activities or otherwise pre-determine that such costs shall be recoverable in rates;[90] and (2) it is premature for the Commission to authorize deferral accounting for costs incurred to develop long lead-time resources as the Companies have not shown that such costs meet the Commission's two-pronged test for authorizing deferral of extraordinary costs outside of a rate case.[91]

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[89] Petition at 16.

[90] Public Staff Initial Comments at 155-159 ("The Public Staff does not recommend that the Commission approve [project development] actions for ratemaking or other purposes prior to the time that the same or similar actions would normally be approved under existing statutory authority or Commission practices."); NCSEA *et al.* Initial Comments at 20-21, 35 ("The Commission need not . . . approve of any costs related to project development activities in order to develop a Carbon Plan[.]"); Tech Customers Comments at 2, 15-18 ("There is no statutory basis for the preordained recovery of these costs."); CIGFUR Comments at 35 ("Any determination at this time regarding whether DEC and/or DEP acted reasonably and prudently in developing, constructing, and placing into service new electric generating facilities at some future date would be premature."); Walmart Initial Comments at 5-10 ("Allowing cost recovery of costs for projects that may never go into service is contrary to typical FERC accounting rules; CUCA Initial Comments at 5-6 ("N. .C. Gen. Stat. § 62-110.7 addresses special accounting treatment/recovery for nuclear-generation projects only, not for offshore wind and pumped-storage development costs; nor does the statute allow for a return on costs for cancelled projects.").

[91] Public Staff Initial Comments at 155-159 ("It is premature at this time to authorize any deferrals related to the Carbon Plan."); Tech Customers Initial Comments at 2, 15-18 (arguing that Duke Energy could not show that costs are "extraordinary," unanticipated, or unplanned because the Companies had already voluntarily adopted its own carbon-reduction goals."); NCSEA *et al.* Comments at 21, 35; CIGFUR Initial Comments at 22-24, 27; CUCA Initial Comments at 5-6.

These criticisms, however, misconstrue key aspects of the Companies' intended requests. First, the Companies are not asking the Commission to rubber stamp that all of their specific future-incurred project development costs are reasonable and prudent. Second, the Companies are not seeking authorization today to defer extraordinary costs in a regulatory asset account under the Commission's well-established two-pronged test,as these types of project development costs generally qualify for balance sheet accounting under FERC Account 183, Preliminary survey and investigation charges. Rather, the Companies are seeking assurances from the Commission that (1) engaging in initial project development activities, in advance of receiving any required CPCN, for these significant long lead-time resources is a reasonable and prudent step in executing the Carbon Plan to enable potential future selection of Bad Creek II, new nuclear and offshore wind on the timeline required to meet HB 951 goals; (2) to the extent the Commission later finds the individual costs incurred to be reasonable and prudent, they will be recoverable in rates; and (3) that such reasonable opportunity for recovery will be available to the Companies should the resource not ultimately be selected by the Commission and development activities abandoned in the future. As described below, these types of assurances are consistent with the Commission's past practice as well as reasonable and necessary to ensure that the Companies can prudently invest in the initial development activities necessary to ensure these significant longer lead-time zero-carbon emitting resources are available on the timelines contemplated in the proposed Carbon Plan portfolios

1. The Commission Has Legal Authority to Grant the Companies' Requested Relief for Bad Creek II, New Nuclear and Offshore Wind.

Pursuant to both statute and the Commission's general regulatory powers under N.C.G.S. §§ 62-2 & 62-30, the Commission has the power to grant Duke Energy the requested assurances that engaging in pre-CPCN initial project development activities is a reasonable and prudent step such that those costs will be recoverable in rates—assuming the specific development activities and associated costs are found to have been reasonably and prudently incurred—regardless of whether the project is ultimately completed or cancelled.

First, for new nuclear facilities, N.C.G.S. § 62-110.7 codifies this authority with respect to project development costs, creating a statutory framework whereby utilities may apply to the Commission for an order approving as prudent the utility's decision to incur project development costs for nuclear electric generating facilities.[92] The statute authorizes the Commission to approve the decision to incur costs and then affirmatively provides that all reasonable and prudent nuclear project development costs incurred pursuant to such authority shall be "fully recoverable through rates in a general rate case proceeding."[93] In the event the utility is allowed to cancel the project, reasonable and prudently incurred nuclear development costs are recoverable subject to amortization over a period equal to the greater of 5 years or the period during which the costs were incurred.[94]

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[92] N.C.G.S. § 62-110.7(b).

[93] *Id.* § 62-110.7(c).

[94] *Id.* § 62-110.7(d).

Duke Energy recognizes that N.C.G.S. § 62-110.7 applies only to potential nuclear generating facilities. However, the Commission has previously recognized its authority to grant the Companies' requested relief without reliance on N.C.G.S. § 62-110.7. That is, the Commission has granted the exact relief requested by the Companies prior to the enactment of N.C.G.S. § 62-110.7, thereby demonstrating that the Commission has the authority and precedent to grant the requested relief outside of N.C.G.S. § 62-110.7 and for resources other than nuclear generation.

Specifically, in 2006-2007, the Commission considered Duke Power's[95] request for "authority to recover the North Carolina allocable portion of necessary costs and obligations related to the development of the Company's proposed [Lee Nuclear facility]" as the utility expected to incur significant pre-CPCN development work in the foreseeable future to develop the Lee Nuclear Facility. At that time, prior to N.C.G.S. § 62-110.7's enactment in Session Law 2007-397, the Commission affirmatively found it had legal authority to grant the requested assurances of future recovery of pre-CPCN development costs.[96]

The Commission's analysis considered whether Duke Power's requested relief was consistent with North Carolina's stated public policy under N.C.G.S. § 62-2(4a) to "assure that facilities necessary to meet future growth can be financed by the utilities operating in this State on terms which are reasonable and fair to both the customers and existing

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[95] Duke Power was the predecessor utility to DEC prior to the merger of Duke Energy and Progress Energy.

[96] *In the Matter of Application of Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment*, Order issuing Declaratory Ruling, Docket No. E-7, Sub 819 (Mar. 20, 2007). Notably the assurances ultimately issued by the Commission did not track the exact same language requested by Duke Power.

investors of such utilities; and to that end to authorize fixing of rates in such a manner as to result in lower costs of new facilities[.]" Finding in the affirmative, the Commission held that the identified pre-CPCN development work was "generally consistent with the promotion of adequate, reliable, and economical utility service to the citizens of North Carolina and the policies expressed in G.S. 62-2" and that it is "in the public interest for the Commission to issue a declaratory ruling which gives Duke a general assurance that its activities in assessing the development of the proposed Lee Nuclear Station . . . are appropriate activities."[97] Expounding on that concept, the Commission more specifically held that "it is in the public interest for all potential resource options . . . to be adequately considered to ensure that the most economical resources are *available to meet customers' needs* on a timely basis."[98]

The exact same rationale underlying the Commission's decision (which once again, pre-dated N.C.G.S. § 62-110.7) applies in the context of the Carbon Plan. That is, it is reasonable for the Commission to provide "general assurances" that the development activities are "appropriate activities" and it is in the "public interest" for these long lead-time resources "to be adequately considered to ensure that the most economical resources are *available to meet customers' needs* on a timely basis."

Importantly, the Commission granted the precise relief in the Lee Nuclear proceeding that the Companies are requesting in this proceeding, finding that (1) it was appropriate for Duke Power to pursue preliminary development of the proposed Lee Nuclear facility through December 2007 "to ensure that nuclear generation remains an

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[97] *Id.* Order at 22.

[98] *Id.* (emphasis added).

available resource option for Duke's customers[;]" and (2) to the extent those expended costs were found to be prudently and reasonably incurred, Duke could recover the costs in rates whether or not Lee Nuclear is constructed.[99] Like Duke Power more than a decade ago, the Companies are now seeking general assurances that the preconstruction development costs of the significant long lead-time carbon-free resources will not be disallowed because the act of incurring them in the first place was not prudent and, importantly, if development is abandoned, that the reasonable and prudent costs incurred in furtherance of executing the Carbon Plan can be recovered.

Therefore, contrary to the assertions of certain parties, the enactment of N.C.G.S. § 62-110.7 should not be interpreted as a constriction of the Commission's general regulatory authority but as needed policy direction given industry dynamics that existed at the time of enactment. And the fact that the General Assembly did not enlarge the scope of N.C.G.S. § 62-110.7 as part of HB 951 does not change the fact that the Commission previously assumed the ability to grant the Companies' requested relief without an express statute and does not indicate the negative—that the General Assembly believed that the Commission should not provide such cost recovery assurance for long lead-time resources other than nuclear.[100]

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[99] *Id.*

[100] Repeals of statutes by implication are disfavored, and "*the presumption is always against implied repeal.*" *Kill Devil Hills*, 194 N.C. App. at 567, 670 S.E.2d at 345. Instead, where two statutes arguably address the same subject matter, one specifically and one generally, and appear incompatible, "the particular provision must be regarded as an exception to the general provision, and the general provision must be held to cover only such cases within its general language as are not within the terms of the particular provision*.*" *State ex rel. Utils. Comm'n v. Carolina Coach Co.*, 236 N.C. 583, 588–89, 73 S.E.2d 562, 566 (1952). "This rule of construction is especially applicable where the specific provision is the later enactment[.]" *State ex rel. Utils. Comm'n v. Lumbee River Elec. Membership Corp.*, 275 N.C. 250, 260, 166 S.E.2d 663, 670 (1969) (internal citations omitted).

Importantly, HB 951 also provides the Commission additional authority to grant the relief requested, as the General Assembly directed the Commission to take "all reasonable steps" to achieve the least cost path towards carbon neutrality by the year 2050. A straightforward reading of this mandate counsels in favor of pursuing multiple pathways to potentially meet those new legislatively mandated planning goals, including by pursuing development activities for Bad Creek II, new nuclear and offshore wind at this early stage of Carbon Plan implementation to ensure those resources remain available for customers on the timeline needed to meet HB 951's targets. Assurances regarding cost recovery—whether or not the resource is ultimately determined to be needed and selected by the Commission as part of the least cost path—is critical to ensure the Companies can pursue the needed development steps, as discussed further *infra*. For all of these reasons, the Commission has clear legal authority to grant the Companies' requested relief and grant assurances regarding the potential for recovery of pre-CPCN expenses to ensure the Companies' customers retain access to the long lead-time resources identified in the Execution Plan.

2. It is Inconsistent with the Regulatory Compact to Expect or Require the Companies to Incur Hundreds of Millions of Dollars of Development Costs Without Reasonable Assurance of Recovery.

The cost-of-service regulatory model has served customers in North Carolina well for more than a century through the provision of reliable service at affordable rates.[101] The

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[101] *See e.g.,* CIGFUR Direct Testimony of Bradford D. Muller at 9 ("Duke should be applauded for presently being a low-cost, high-quality electricity supplier. Charlotte Pipe operates seven plants around the United States. Duke Energy currently offers the most reliable, highest quality and least cost electricity compared with our suppliers in other states where we operate.).

State's regulatory model is based on a regulatory compact under which the utility is obligated to provide reliable service to all customers and the business decisions of the utilities' management are subject to regulatory oversight by the Commission. In return, the utilities are provided the right to recover the costs of reasonable and prudently incurred investments along with a reasonable opportunity to recover its financing costs through an approved rate of return. Such construct is both stable and nimble and assures that the utilities (and, by extension, their customers) have access to capital at reasonable rates in order to finance the investments needed to serve customers.

While it is true that Duke Energy has historically incurred modest amounts of development costs prior to Commission approval (which approval, in the case of generating assets and certain transmission assets, comes in the form of a CPCN), Duke Energy has never been required to incur the development costs of the magnitude that are required to ensure the availability of the long lead-time resources on the timelines contemplated by the Carbon Plan without some form of cost recovery assurance. The scale of the development costs required for these long lead-time resources distinguishes them from other routine development work and justifies the Companies' requested treatment. Given the scale of such costs, it would be inconsistent with the regulatory compact to impose on the Companies a legal obligation to perform substantial development work (which is needed due to the timelines required under HB 951) while denying any assurance of cost recovery.

Recognizing the new paradigm of the Commission-developed Carbon Plan selecting resources as in the public interest and needed to meet HB 951's carbon emission reduction goals, providing the requested assurances for offshore wind, SMRs, and Bad Creek II is well supported by State policy set forth in the Public Utilities Act to provide fair regulation of public utilities in the interest of the public and to "assure that facilities necessary to meet future growth can be financed by the utilities operating in this State on terms which are reasonable and fair to both the customers and existing investors of such utilities[.]"[102]

No party has set forth a coherent argument as to why the Companies and the investors that provide equity and debt financing to ensure reliable service should bear the full and substantial financial risk of pursuing the considerable development activities necessary to ensure these significant longer lead-time resources remain available on the timeline required to facilitate the Commission's selection of these carbon-free technologies as part of the least cost path to achieving HB 951's carbon reduction goals for the long-term benefit of customers. Executing the Carbon Plan on the timelines mandated by the General Assembly implicates numerous significant risks to the Companies' respective systems (reliability, executability, cost) that could impact whether these longer lead-time resources are ultimately needed in the future. It is conceivable that market developments (*e.g.*, changes in technology costs/risks or alternative breakthrough technologies becoming available), regulatory developments or other circumstances beyond Duke Energy's control could result in a future determination that Bad Creek II, new nuclear or offshore wind should not be selected as needed under the Carbon Plan, despite the prudent decision to pursue initial development work for all three longer lead-time resources today.

North Carolina's policy is clear on this issue: resource development activities should be financed on "terms which are reasonable and fair to *both the customers and*

[102] N.C.G.S. §§ 62-2(a)(1); (4a).

existing investors of . . . utilities[.]"[103] Intervenors' proposal would have the Companies bear all of the risk, and this proposal is not equitable to either the utilities—who would risk significant financial loss to pursue development—or customers—who would risk losing the benefit of any resources the Companies chose not to develop.

The same general facts and circumstances that necessitated Duke Power seeking similar assurances in the Lee Nuclear proceeding and that underlie the adoption of N.C.G.S. § 62-110.7 exist today for Bad Creek II, new nuclear and offshore wind. Specifically, the long lead-time resources that are the subject of the Companies' request for development cost recovery assurances require Duke Energy to incur significant initial development costs—just like the nuclear development costs in the Lee Nuclear proceeding. The need for assurances here is, perhaps, even more critical than in the Lee Nuclear proceeding as HB 951 sets express carbon reduction goals that must be reached on a specific timeline, and the identified long lead-time resources are likely to be required to achieve those goals in a least-cost manner. As described in the testimony filed by the Long Lead-Time Panel, each of these long lead-time resources will require extensive development activities prior to securing selection by the Commission in a future Carbon Plan or other required construction authorization to ensure that the resource remains available on the timelines required by the Carbon Plan.

For these reasons, the Companies respectfully ask the Commission to grant the requested assurances that the development activities costs incurred for Bad Creek II, new nuclear and offshore wind will be recoverable in rates whether or not the resource is

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[103] *Id.* § 62-2(4a) (emphasis added).

ultimately completed. Duke Energy estimates that its development activities, through the end of 2024 (the point in time at which the Commission will issue an update to the Carbon Plan), to ensure these resources remain available for selection and the benefit of customers will be approximately as follows. Note, these amounts have been rounded from Tables 1, 2 and 3 from the Long Lead-Time Panel's direct testimony for purposes of establishing cost caps:

Resource	Proposed Development Cost Cap (2022-2024)
Offshore Wind	$325 million[104]
Nuclear	$75 million[105]
Bad Creek II	$40 million

3. The Companies Support Application of a Cap and Biennial Reporting Obligations

As is described in more detail in the Long Lead-Time Resources Panel Rebuttal Testimony filed concurrently with these Comments, the Companies agree that the amounts set forth in the table above would serve as an appropriate cap of costs through 2024, and the Companies commit not to incur cost in excess of the identified amounts without further approval from the Commission. The Companies also agree that a biennial reporting obligation would be appropriate so as to keep the Commission apprised of the progress and status of the development activities.

[104] Includes estimated cost of obtaining an offshore wind lease.

[105] Costs associated with development work needed to obtain an Early Site Permit for a single site.

4. Deferring a Commission Determination to Provide Assurances under Section 62-110.7 for New Nuclear or Under its General Authority for Offshore Wind and Bad Creek II is Unnecessary and Inefficient.

The Public Staff suggests that the Companies should make a request for assurances regarding nuclear development costs pursuant to N.C.G.S. 62-110.7 in a separate proceeding because "the parties have not had adequate time to review any request to incur nuclear development costs in sufficient detail while they reviewed the proposed Carbon Plan."[106] However, pursuant to the statute, a utility may make a request pursuant to N.C.G.S. 62-110.7 "*at any time* prior to the filing of an application for a certificate to construct a potential nuclear electric generating facility[.]"[107] The Companies' plan for developing long lead-time resources is set out in detail both in the Carbon Plan's Execution Plan, Appendices J (Wind), K (Energy Storage) and L (Nuclear) as well as in the direct and rebuttal testimony of the Companies. For comparison, the level of detailed support presented in the Companies' Carbon Plan and testimony regarding its planned development activities for long lead-time resources is materially greater than the information Duke Power provided with its application in the Lee Nuclear proceeding—basically reference to and summary of its discussion of new nuclear generating facilities development activities in its 2006 IRP short-term action plan.[108] Duke Power's 2006 application additionally provided an estimate of the anticipated development costs over a 15-month period. While

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[106] Public Staff Initial Comments at 156-57.

[107] N.C.G.S. § 110.7(b) (emphasis added).

[108] *In the Matter of Application of Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment*, Application for Authority to Recover Nuclear Generation Development Expenses, Docket No. E-7, Sub 819 (filed Sept. 20, 2006).

the Companies did not provide that information in their Petition, as set forth *supra* Section II.C.2, they expect to incur approximately $440 million in project development expenses for long lead-time resources through the end of 2024, when the Commission will have issued its next decision updating the Carbon Plan. Given that the details provided in the Carbon Plan and supporting testimony match the level of specificity provided in Duke Power's previous cost recovery requests under Section 110.7 in the Lee Nuclear proceeding, it would be an inefficient use of regulatory resources to require the Companies to initiate a separate proceeding(s) for the purpose of seeking the ultimately-necessary assurances being requested here. Accordingly, the Companies renew their request for the Commission to approve the Request for Relief in the Petition for assurances relating to future recoverability.

5. The Companies are Not Requesting Deferral Authority or Any Finding that Specific Costs are Reasonable and Prudent.

The Companies' Petition asked the Commission for authority to "defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies then authorized, net-of-tax, weighted average cost of capital)." Nevertheless, this request was made "[t]o the extent not already authorized under applicable accounting rules," and the Companies have determined that Commission approval to defer pre-CPCN development costs in a regulatory asset account is not needed at this time. To the extent the Commission (like the Public Staff and certain other parties) interprets the Companies' Petition as seeking that relief, the Companies expressly withdraw the request and represent that they will not place project development costs for long lead-time resources in a regulatory asset account unless otherwise authorized by applicable accounting regulations or future Commission Order to do so. In addition, the Companies acknowledge that consideration of the reasonableness and prudence of specific costs will be decided by the Commission in a future general rate case proceeding. The Commission's ruling in this case, to the extent it grants the relief requested, will be limited to finding that it is generally reasonable and prudent for the Companies to undertake development activities for the long lead-time resources identified in their near-term action plan and to provide assurances that such reasonable and prudent costs will be recoverable if one of these long lead-time projects is not selected by the Commission in a future update to the Carbon Plan, and development is abandoned.

D. <u>The Commission's Obligation in the Carbon Plan to Select New Generation Facilities or Other Resources to Achieve the Authorized Reduction Goals is a New Paradigm.</u>

Least-cost resource planning proceedings have traditionally been viewed as forward-looking and legislative in nature, gathering facts and focusing on the Companies' long-range needs and plans for their systems to ensure adequate and reliable service is maintained. However, recognizing that HB 951 now directs the Commission to develop a Carbon Plan and to "select[]" resources in that Plan that are needed to meet the State's CO_2 emission reductions targets on a schedule prescribed by State law, the Carbon Plan is now something more significant than a traditional IRP in this respect.

1. The Commission's Obligation Under the Carbon Plan to Select Resources Should Be Exercised Thoughtfully and Flexibly Depending on the Circumstances.

As an initial matter, the Companies believe that the Commission should take a flexible approach based on individual circumstances that will allow for regulatory efficiency while ensuring appropriate checkpoints and scrutiny that account for the particular facts, circumstances and timing of each situation. As was the case in related comments in Docket No. E-100, Sub 178,[109] many parties advocate for a rigid approach that will not result in regulatory efficiency. To the contrary, the Commission should take a flexible approach that seeks to maximize regulatory efficiency based on the unique circumstances applicable to each decision.

It is important to note a number of considerations that do not make this issue susceptible of a "one size fits all" solution. First, not every resource that the Commission selects in a Carbon Plan requires a CPCN under North Carolina law. For instance, standalone battery storage, offshore wind facilities located outside of North Carolina territorial waters, acquisition of existing out-of-state generation resources, and construction of new of out-of-state generating resources would not require CPCNs. However, in all cases, in order for such resources to be part of achieving the authorized reduction goals, the Commission must "select" the resource, and such selection would therefore most naturally occur within the context of the Carbon Plan process (*i.e.*, this proceeding or future biennial updates).[110] In another hypothetical scenario where a resource proposed for selection requires a CPCN, the Companies may be in a position to request the CPCN (*i.e.,* has prepared all of the information required to apply for a CPCN) at the same time as

[109] *See* the Companies' Initial Comments (March 16, 2022) and Reply Comments (April 13, 2022) in Docket No. E-100, Sub 178. The issues raised in this case bear some relationship to the issues considered by the Commission in comments regarding the intersection of the multi-year rate plan ("MYRP") process and the CPCN requirement. As noted in those comments, in some cases the Carbon Plan will serve as justification of the need for generation resources for purpose of both the MYRP and for CPCNs. *See* Initial Comments at 7-8; Reply Comments at 13-14 ("the Commission's Carbon Plan (the initial one of which will be issued prior to an initial PBR decision) will provide even more definitive regulatory guidance regarding the "reason" and "need" for projected solar generating facilities—that is, where the Commission has through a Carbon Plan decision determined the "reason" and "need" for a projected solar generating facility, such decision should guide and, in many cases, simplify both the PBR and CPCN processes.").

[110] There could also be a scenario where a resource that does not require a CPCN requires selection on a timeline that differs from the Carbon Plan biennial process, requiring a standalone Carbon Plan proceeding to allow the Commission to select the resource (e.g., a unique acquisition opportunity identified by the Companies that arises outside of the normal biennial Carbon Plan process).

submitting a biennial update to the Carbon Plan, thereby effectively joining the two proceedings. The point of highlighting these examples is that the Commission should exercise its obligation to select resources flexibly and thoughtfully in ways that adapt to the particular of each situation.

2. Where Applicable, the Commission's Selection of Resources in the Carbon Plan Should be Deemed to Provide Strong Evidence of Public Convenience and Necessity and Absent a Material Change in Facts or Circumstances Should be Determinative.

As it relates to resources that the Commission might select in the Carbon Plan but that require a CPCN (and which were not situated so as to allow for a CPCN to be requested and issued in parallel with the Carbon Plan as discussed above), it is important to return to the theme of regulatory efficiency and consider the intersection of the Carbon Plan and the determination of need required in a CPCN. The purpose of a CPCN proceeding is to assess whether "public convenience and necessity requires, or will require, such construction"[111] and for the Commission to consider whether "construction [of the generation resource] will be consistent with the Commission's plan for expansion of electric generating capacity."[112] All new generation resources in North Carolina to be constructed through 2050 will be resources that are selected by the Commission as part of the Carbon Plan—therefore the assessment of necessity in a CPCN will be coterminous with the Commission's Carbon Plan, and any resource selected by the Commission as part of the Carbon Plan is, by definition, part of the "Commission's plan for explanation of electric generating capacity."

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[111] N.C.G.S. § 62-110.1(a).

[112] *Id.*. § 62-110.1(e).

As the Companies have previously acknowledged, a CPCN is still required for generating assets located in North Carolina. But the Commission's selection of resources in a Carbon Plan should be deemed strong evidence of public convenience and necessity for purposes of any subsequent CPCN proceeding and, absent any material change in facts or circumstances, should be determinative in the CPCN proceeding. Stated simply, if the Commission has assessed the entirety of the Carbon Plan (including the exhaustive underlying analysis) and determined that a generation resource is needed to "achieve the authorized reduction goals," then such resource is, by definition, in the public interest.

The CPCN process will provide a forum in which the Commission can review the site-specific plans and ensure the more detailed projected construction cost is consistent with the cost assumed in the Carbon Plan modeling that supported the Commission's prior selection. And, once again, it will be necessary to assess each situation based on the unique facts and circumstances. In some cases, it may be that the assessment underlying the Commission's selection in a Carbon Plan is timed such that requiring further updated modeling for purposes of the CPCN proceeding is not necessary. In other cases, timing consideration may dictate that slightly updated modeling is required and in other cases, it may be the case that completely updated modeling is required. In still other cases, the cost of the proposed resource may be so far below the price assumed in the modeling as to allow a more expedited determination without updating the modeling. In the case of solar resources specifically, many such resources (if not nearly all) are likely to be procured through Commission-established procurement processes. In those situations, the combination of a prior "selection" of the resource in a Carbon Plant and a procurement event overseen by the Commission establishes a strong foundation on which the Commission's CPCN determination can be substantially streamlined.

Several intervenors argue that the selection of a resource in the Carbon Plan should have no bearing on a CPCN proceeding.[113] They contend that any resources selected in the Carbon Plan must be revisited anew and undergo the supposedly higher level of scrutiny and more exhaustive cost analysis that is provided in a CPCN proceeding.[114] Intervenors also wrongly frame Duke Energy's position as advocating that selection of a generating facility or other resource in the Carbon Plan effectively supplants or replaces a CPCN and makes it unnecessary.[115]

For all of the reasons explained above, this inflexible approach is not the approach supported by Duke Energy and is neither necessary nor appropriate. Most fundamentally, it would be the height of regulatory inefficiency for the Commission to complete the exhaustive biennial Carbon Plan process only to have to fundamentally revisit the entirety of the Carbon Plan analysis with each and every CPCN process (particularly in those situations where the CPCN follows close on the heels of the Carbon Plan process). The Commission should not have to retread the same ground in a CPCN proceeding absent a compelling reason to do so. The Companies have previously explained that the Commission has discretion to rely on findings in other dockets in rendering a decision in

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[113] *See* CIGFUR Comments at 41-42; CUCA Comments at 5-6; Tech Customers Comments at 13-14; EJCAN, *et al*. Comments at 24, 29.

[114] *Id*.

[115] Intervenors' characterization of Duke Energy's position derives from a single discovery response. Asked how the Carbon Plan should impact CPCN proceedings, Duke Energy stated that the Commission's selection of a resource in the Carbon Plan "should be controlling in a CPCN proceeding absent a material change in facts and circumstances from Carbon Plan assumptions." *See* Tech Customers Comments at 14 (citing Duke Response to Public Staff Data Request 11-2).

separate dockets[116] and the Commission confirmed this in its recent order regarding the PBR process[117]

Nor should a party displeased by the Carbon Plan be allowed to have a second bite at the apple and seek modification of the Carbon Plan's selection of a resource through a CPCN. At a minimum, the selection of resources in the Carbon Plan creates a strong presumption that the resource is required for the public convenience and necessity and needed to meet the energy transition and carbon emission reductions Plan dictated by the General Assembly in HB 951, Section 1.

As for intervenors' characterization of Duke Energy's position, the Companies have never suggested that the Carbon Plan is a substitute for or should eliminate the requirement to obtain a CPCN. To the contrary, Duke Energy has repeatedly acknowledged the importance of CPCN proceedings in implementing the Carbon Plan. For example, later in the same discovery response cited by intervenors, Duke Energy confirmed

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[116] Reply Comments, Docket No. E-100, Sub 178, at 16-18 ("Such arguments [that Commission cannot take into account decisions from other dockets] are without legal basis and appear to ignore the innumerable ways in which the Commission has historically taken judicial notice of prior decisions and, in many cases, expressly relied on evidence and findings of fact from prior proceedings. To require duplication of an already established record supporting project need and cost…would be contrary to established practice and a waste of administrative time and resources. Contrary to intervenor's arguments, the Commission has historically elected to rely on prior decisions and has done so specifically in the context of CPCN proceedings and need-making determinations. For example, in Docket No. E-2, Sub 1257, the Commission relied in part on the Western Carolinas Modernization Project ("WCMP") Order and DEP's 2018 Integrated Resource Plan ("IRP") and 2019 IRP in finding a CPCN need for a 5 MW solar photovoltaic facility to be constructed in Buncombe County, North Carolina. This approach of taking judicial notice of its prior decisions and reliance upon such decisions in determining whether a proposed facility was in fact needed would also be appropriate in a CPCN case involving a facility that was previously approved…Similarly, in the context of the Companies' Competitive Procurement of Renewable Energy ("CPRE") Program, the Commission codified an "expedited" CPCN review of renewable energy facilities owned by an electric utility and procured under the CPRE Program. Pursuant to NCUC Rule R8-71(k), such projects can receive expedited CPCN approval and are not otherwise required to comply with the requirements of N.C. Gen. Stat. §§ 62-82 or 62-110.1, or NCUC Rules R8-61 or R8-64, further evidencing that need determinations in certain instances can be and are appropriately streamlined in certain circumstances.")

[117] Order Approving Template Notice and Providing Initial Guidance on Issues Related to CPCN Process and Cost Recovery Under PBR, Docket No. E-100 Sub 178 (September 8, 2022)

that "the Commission will have a further opportunity to approve [new generating resources] through any necessary CPCN proceeding."[118] The Companies' Verified Petition for Approval of Carbon Plan ("Petition") also acknowledged that CPCN proceedings are still required by law and should occur:

> CPCN proceedings for resources selected by the Commission will provide opportunities for the Commission to assess more detailed market information to ensure alignment with the Carbon Plan trajectory presented in this initial Plan. [119]

Further confirming its position, Duke Energy's request for approval of certain "near-term supply-side development and procurement activities" explicitly states that resources selected under the Carbon Plan should "in all cases [be] subject to the obligation to obtain a CPCN (where applicable)[.]"[120]

As should be clear, Duke Energy agrees with intervenors that CPCN proceedings to authorize construction of new generating facilities are still required under the Public Utilities Act. However, Duke Energy believes that the scope of the disputed issues in CPCN proceedings should be limited to only those issues that are not fully addressed, or which could not have been addressed, in the Carbon Plan. For example, where the cost assumptions that underlie the Commission's selection of a particular resource have materially changed following a Carbon Plan ruling, a CPCN proceeding would be the appropriate venue to decide whether those changes should prevent the Companies from developing that resource. Duke Energy's position promotes regulatory efficiency, prevents

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[118] *Id*.

[119] Petition ¶ 21.

[120] *Id*. at 15 ¶¶ 2, 2(a).

inconsistent rulings on the same issues, and gives the Carbon Plan process the weight it deserves. Simply put, the General Assembly's directive for the Commission to "consider power generation . . ." and to "select[] generating facilities" as part of the Carbon Plan should establish the need for such resources and inclusion of resources in the Carbon Plan should be viewed as a strong indication of public convenience and necessity for purposes of a CPCN, subject to any material change in costs or circumstances identified in CPCN proceeding.

III. PROCEDURAL MATTERS FOR FUTURE CARBON PLANS

A. The Commission Should Direct Duke Energy to File a Carbon Plan Update in 2023 and a Comprehensive Carbon Plan Update and Next Biennial IRP in 2024

The Commission's Initial Scheduling Order recognized the significant overlap between the analyses required to prepare a proposed Carbon Plan under HB 951 and development of the Companies' biennial IRP and indicated an intent to "sync, eventually, the Carbon Plan proceedings with the IRP proceedings."[121] In doing so, the Commission delayed DEC's and DEP's next biennial IRP filings required by Commission Rule R8-60(h)(1) to September 2023. To achieve the Commission's goal of syncing the biennial IRP and Carbon Plan proceedings and in light of the fact that the Companies' initial Carbon Plan reflects a planning document that is at least as comprehensive as a biennial IRP filing, the Companies' Verified Petition for Approval of Carbon Plan requested that the Commission hold the Companies' next biennial IRPs in abeyance to 2024 to align with the next Carbon Plan proceeding as contemplated under HB 951. No party opposed this

[121] Initial Scheduling Order at 1.

proposal; however, the Public Staff recommended that the Companies should file an IRP update pursuant to Commission Rule R8-60(h)(2) and (j) in 2023. In an effort to achieve consensus, the Companies agree to comply with the Public Staff's recommendation and will plan to file IRP Updates for the DEC and DEP systems in 2023. The 2023 update will further serve the purpose of apprising the Commission on the status of the near-term execution plan as well as longer-term development activities.

In light of the agreement between the Companies and the Public Staff, and in the absence of opposition from any other party, the Companies respectfully request that the Commission order the Companies to file IRP updates in 2023 and a joint updated Carbon Plan and comprehensive IRPs in 2024.

B. **The Commission Should Direct the Companies and Public Staff to Develop and Propose for Comment by April 28, 2023 Revisions to the Commission's IRP Rule R8-60 and Related Rules for Certificating New Generating Facilities**

The Commission's Initial Scheduling Order also indicated that the Commission "will initiate, by separate order . . . a rulemaking proceeding to revise Commission Rule R8-60 to reflect the approach of syncing the Carbon Plan with the IRP proceedings."[122] To ensure that the necessary revisions to R8-60 can be developed and implemented in advance of the proposed 2024 joint Carbon Plan / IRP proceeding, the Companies' Verified Petition requested that the Commission direct the Companies and Public Staff to, by January 31, 2023, develop and propose for comment revisions to Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan. The Public Staff generally agreed with the Companies' proposal but recommended that the deadline

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[122] *Id.* at 1-2.

for filing proposed revised rules should be extended to April 28, 2023.[123] The Companies do not oppose this proposal and note that the extended deadline will allow more time for all parties to engage and develop draft rules.[124]

IV. ADDITIONAL MISCELLANEOUS ISSUES RAISED BY INTERVENORS

A. Upstream Methane Emissions Are Not Relevant to this Proceeding

Intervenors NC WARN and Charlotte Mecklenburg NAACP ("NAACP") fault the Companies for not analyzing the impacts of methane emissions from natural gas.[125] Intervenors acknowledge that "HB 951 is tailored to the reduction of carbon dioxide emissions and *arguably* does not address the emission of other greenhouse gases, such as methane."[126] Yet they contend that the Commission is nevertheless "empowered" to consider methane emissions in the Carbon Plan.[127]

HB 951 addresses carbon dioxide and *only* carbon dioxide. The plain meaning of "carbon dioxide (CO_2)" is not "arguable."[128] Carbon dioxide and methane are distinct chemical compounds. Had the General Assembly intended to reduce methane emissions

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[123] Public Staff Comments at 163.

[124] NCSEA *et al*. objects to this request on a number of grounds, including that (1) the timeline the Companies originally proposed would require development of the proposed rule contemporaneous with the Commission's consideration of the Carbon Plan; (2) "it is inappropriate for Duke and the Public Staff to develop changes to Rule R8-60 behind closed doors and without input of other stakeholders[;]" and (3) there is no need for a change to the Commission's rules regarding CPCNs. NCSEA *et al*. Comments at 33-34. However, as NCSEA et al. acknowledges, the relief the Companies are requesting is consistent with the Commission's stated intent to initiate a rulemaking proceeding to revise Commission Rule 8-60. Initial Scheduling Order at 1-2.

[125] *See* Joint Comments of NC WARN and NAACP at 6 ("The Companies should provide updated analyses which encompass the significance of methane emissions from natural gas-fired generation[.]").

[126] *Id*. at 20.

[127] *Id.* (Emphasis added).

[128] *See Edmisten*, 291 N.C. at 465, 232 S.E.2d at 192 ("[C]lear and unambiguous" language "must be given effect and clear meaning.").

in HB 951, it could have done so.[129] Intervenors may certainly petition the legislature for a methane plan, but that is beyond the planning criteria and policy goals prescribed by the General Assembly to be considered in this proceeding.

Since the plain language of HB 951 provides no support for NCWARN/NAACP's recommendation for the Commission to consider methane emissions in the Carbon Plan, intervenors look elsewhere to circumvent the General Assembly's express intent. They rely on three sources for the Commission's purported authority: Executive Order No. 246, Executive Order No. 80, and N.C.G.S. § 62-2(a)(5). Joint Comments of NC WARN and NAACP at 21. None give the Commission the authority that intervenors desire.

As an initial matter, and as discussed extensively above, HB 951's plain language precludes a search for legislative intent outside of the statute.[130] Even if that were permissible, which it is not, intervenors' reliance on two Executive Orders and N.C.G.S. § 62-2(a)(5) are misplaced. The Commission's authority does not derive from the Governor. "The Commission is a creation of the Legislature and . . . [i]t has no authority except that given to it by statute."[131] Therefore, the Executive Orders cannot and do not grant authority to the Commission that the General Assembly did not grant in HB 951. Regardless, a closer examination of the Executive Orders reveals that the Governor never intended to usurp the General Assembly's authority as intervenors suggest. Only one, Executive Order No. 246, even references the Commission. Because the Commission is not a cabinet agency, the

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[129] *See Ferguson*, 233 N.C. at 57, 62 S.E.2d at 528 (courts have "no power to add to or subtract from the language of the statute").

[130] *See Edmisten*, 291 N.C. at 465, 232 S.E.2d at 192 ("clear language . . . may not be evaded by an administrative body or a court under the guise of construction").

[131] *Id*. at 464, 232 S.E.2d at 192.

Governor "encourage[s]" the Commission to incorporate the social cost of greenhouse gas emissions ("SC-GHG") in its decision-making processes.[132] Cabinet agencies, on the other hand, were directed to "actively support" SC-GHG initiatives. *Id*. An 'encouragement' is certainly not an attempt to grant authority. Moreover, to the extent that SC-GHG does contemplate methane emissions, the Commission has no authority to "incorporate the SC-GHG into" its Carbon Plan decision for the reasons discussed above[133].

Intervenors' reliance on Section 62-2(a)(5) is problematic for different reasons. This provision in the Public Utilities Act provides that it is the State's policy "to encourage and promote harmony between public utilities, their users and the environment."[134] From this broad policy, intervenors somehow divine the Commission's express authority to expand the scope of the Carbon Plan to include methane emissions. Again, the analysis should end with HB 951's plain language. Since HB 951 is clear that the Commission should only consider "emissions of carbon dioxide," it is improper to look beyond this legislation to determine whether the Commission has the authority to consider methane and other emissions.[135] Moreover, under long-standing Supreme Court precedent, "when two statutes arguably address the same issue, one in specific terms and the other generally, the specific statute controls."[136] HB 951 establishes the State's "carbon dioxide" emissions

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[132] Executive Order No. 246, § 6.

[133] The Modeling and Near-Term Actions Panel testimony does note that the Companies did consider SC-GHG in developing a sensitivity analysis demonstrating the impact that an explicit federal cost of CO2 could have on cost to customers.

[134] N.C.G.S. § 62-2(a)(5).

[135] *High Rock Lake Partners*, 366 N.C. at 322, 735 S.E.2d at 305 (where a "statute is clear and unambiguous" it is impermissible to "construe that statute in pari materia with any other statutes, including those that treat the same issues generally").

[136] *Id*.

reduction goals and directs the Commission to develop the Carbon Plan to achieve these "authorized carbon reduction goals." On the other hand, N.C.G.S. § 62-2(a)(5) generally promotes "harmony" with the "environment," but does not establish any legislative directive or make any express delegation of authority to reduce emissions of carbon dioxide, methane, or otherwise. To the extent that HB 951 and N.C.G.S. § 62-2(a)(5) overlap at all, HB 951 is the more specific statute and must control.

While HB 951 only addresses emissions of one greenhouse gas – carbon dioxide, Duke Energy shares iIntervenors' attention to reducing methane emissions. That is why Duke Energy set a company-wide goal to achieve net-zero methane emissions from natural gas distribution by 2030 and net-zero methane by 2050 for upstream emissions related to purchased natural gas.[137] The first step in this process is to measure methane emissions from the Companies' natural gas operations and eliminate leaks in the system.[138] Duke Energy has partnered with Microsoft and Accenture to develop a technology platform that will allow the Companies to rapidly detect and repair methane leaks.[139] In addition, in February of this year the Companies updated their 2050 net-zero goals to include scope 2 and scope 3 emissions, which include upstream methane and carbon dioxide emissions. These efforts demonstrate Duke Energy's commitment to a clean energy transformation of its Carolinas operations including focus on methane emissions.

B. <u>The Commission Does Not Have Authority to Approve Demand-Side Programs for Wholesale Customers</u>

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[137] Duke Energy, *2021 ESG Report* at 23 (2022), *available at*, https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/esg/2021-esg-report-full.pdf?la=en&rev=19532a880c3a47ee868fb43cb087c369.

[138] *Id*. at 28.

[139] *Id*.

Electricities of North Carolina, Inc. ("Electricities"), North Carolina Eastern Municipal Power Agency ("NCEMPA"), and North Carolina Municipal Power Agency Number 1 ("NCMPA1" and, together with Electricities and NCEMPA, the "Power Agencies") argue that the Carbon Plan is deficient because Duke Energy "fail[s] to consider the benefit of load management efforts that wholesale customers could provide" and recommends NCUC "direct Duke to take full advantage of as much load side management as its wholesale customers can possibly provide."[140] However, in making this recommendation, the Power Agencies ask the Commission to extend the Carbon Plan proceeding well beyond its statutorily prescribed purpose. As the North Carolina Court of Appeals has recognized, "exclusive jurisdiction over interstate wholesale electric power transactions is conferred upon [the Federal Energy Regulatory Commission]."[141] Duke Energy's wholesale requirements contracts with multiple entities in the Carolinas are on file with FERC and subject to it jurisdiction, including as it relates to how the wholesale customers' demand side management or energy efficiency programs interact with wholesale charges. Accordingly, the issue raised by the Power Agencies is not properly before the Commission in this proceeding.

V. <u>CONCLUSION</u>

The Companies request the Commission take these comments into consideration in their deliberations and development of the Carbon Plan in this proceeding.

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[140] Power Agencies Filing Regarding Significant Carbon Plan Issues to be Considered At Expert Witness Hearing ("Power Agencies Comments") at 5.

[141] *State ex. rel. Utils. Comm'n v. N.C. Electric Membership Corp.*, 105 N.C. App. 136, 142 (1992) (affirming that issues affecting wholesale rates were appropriately not addressed in IRP proceeding as "such an issue is more appropriately addressed to FERC"); *see also Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 964 F.3d 1177, 1181 (2020).

Appendix 2: Targeted Additional Responses

As noted in the body of the Companies' Post-Hearing Brief, the most substantial legal issues raised in this proceeding were previously addressed in substantial detail in the Companies' Pre-Hearing Comments on Non-Expert Hearing Track Legal and Policy Issues filed on September 9, 2022 ("Sept. 9th Pre-Hearing Comments"), attached as Appendix 1 to the Post-Hearing Brief for ease of Commission reference.

The Companies' Sept. 9th Pre-Hearing Comments addressed certain relevant intervenor positions raised in the Carbon Plan proceeding prior to September 9, 2022. The Public Staff and certain intervenors also filed comments on September 9, 2022 addressing certain non-hearing track issues that were primarily legal in nature. For the benefit of the Commission, this Appendix 2 provides targeted additional responses to specific arguments set forth in the comments filed by certain intervenors on September 9, 2022 to the extent that any such positions were not already preemptively addressed by the Companies in their Sept. 9th Pre-Hearing Comments.

These targeted additional responses are provided with respect to only three issues. The Companies have thoroughly addressed these issues in both the Companies' Sept. 9th Pre-Hearing Comments as well as the Post-Hearing Brief. Nevertheless, out of an abundance of caution, the Companies are including these targeted additional responses to ensure clarity of the record.

- ***Commission Discretion with Respect to Interim Target Achievement Date***
- ***HB 951's Ownership Requirements***
- ***Wholesale Power Contract Issues***

1) Commission Discretion with Respect to Interim Target Achievement Date

Attorney General's Office Comment:

The Attorney General's Office ("AGO") argues that a plain reading of N.C.G.S. § 62-110.9(4) "shows that the provision was meant to allow the Commission to delay achieving the carbon reduction goals by more than two years in the event ***an unforeseen event*** makes achievement impossible." AGO Sept. 9th Pre-Hearing Comments at 10 (emphasis added). Duke, intervenors, and AGO have provided portfolios that maintain the adequacy and reliability of the grid. Therefore, the AGO argues that no delay is necessary based on any exception to the Interim Target of 2030. *Id*. at 11.

Targeted Additional Response:

- The Companies reiterate that Duke Energy is not asking for, and it is not necessary for the Commission to preemptively approve, a delay of the Interim Target Achievement Date in this initial Carbon Plan proceeding.
- The Companies' proposed near-term actions reflect the initial reasonable steps required by HB 951 towards achieving CO_2 emissions reductions targets and the Commission can check and adjust in future Carbon Plan update proceedings, as contemplated by N.C.G.S. § 62-110.9(1). *See* Sept. 9th Pre-Hearing Comments, at 14-15. The near-term actions are generally consistent with all portfolios and preserve the potential to achieve the 70% Interim Target in 2030.
- However, there is no basis in HB 951 to support the AGO's argument that the event or fact giving rise to any future Commission-authorized extension beyond 2032 must be "unforeseen". Clean Power Suppliers Association ("CPSA") makes a similar argument in its September 9th Pre-Hearing Comments, arguing that the trigger for the extension must be "unanticipated." What Section 62-110.9(4) actually requires is that the event triggering the extension be "beyond the control of the electric public utility." Nowhere does the statute require the triggering event or factor be "unforeseen" or "unanticipated."

Clean Power Suppliers Association Comment:

CPSA argues that it would be improper for the Commission to approve any portfolio that extends the Interim Target Achievement Date to 2034 in order to accommodate new nuclear and wind generation resources. CPSA Sept. 9th Pre-Hearing Comments at 2.

Targeted Additional Response:

- The Companies are not requesting the Commission select a portfolio that requires a preemptive extension of the Interim Target Achievement Date in this proceeding. Duke Energy has proffered a Carbon Plan with multiple portfolios that reflect different generation mixes for the Commission's consideration, which the Public Staff determined to be a reasonable approach. Tr. vol. 21, 38.

- As explained in the Companies' Sept. 9th Pre-Hearing Comments, CPSA's interpretation is inconsistent with HB 951 and would seem to absurdly seek to prevent Commission consideration of portfolios that rely on nuclear and wind generation in direct contravention of the HB 951's direction to consider all technologies. *See* Sept.

9th Pre-Hearing Comments at 11-12 ("the Commission's ultimate determination of whether to 'select' the addition of new nuclear or wind facilities and authorize their construction, thereby allowing an extension of the Interim Target Achievement Date beyond 2032 will occur in a later proceeding. The Companies' requested relief in this proceeding neither relies on nor forecloses the Commission's authority to extend the Interim Target Achievement Date beyond 2030 or 2032.").

2) <u>HB 951's Ownership Requirements</u>

Attorney General's Office Comment:

The AGO argues that the General Assembly's use of the term "other resources" in Section 62-110.9(2) "is broad enough to include wholesale third-party purchases." AGO Sept. 9th Pre-Hearing Comments at 11. "[O]nce energy is purchased from a third party, it is by definition owned by the utility and may be recovered in rates on a cost of service basis[.]" *Id*. at 11-12.

Targeted Additional Response:

- The AGO's interpretation simply contradicts the plain reading of the statute. Section 62-110.9(2) states that "[a]ny new generation facilities or other resources selected by the Commission…shall be owned and recovered on a cost of service basis by the applicable electric public utility." Here, the General Assembly is imposing a straightforward directive that "new generation resources" should be owned by the utility. But the AGO's baseless interpretative expansion of the phrase "other resources" would essentially fully negate the unambiguous directive of utility ownership of generation resources. It strains credulity to suggest that the General Assembly would direct utility ownership of "generation resources" and then completely eviscerate the requirement in the very next phrase—since all third-party owned generators produce electricity that can be sold to the Companies, the AGO's interpretation would have the effect of negating the clear ownership generation ownership requirement. Instead, the more natural reading is that "other resources" was simply intended to refer to resources that are not technically generation resources, such as standalone storage and make clear the utility ownership requirement also extends to such non-generation resources.
- AGO's interpretation would essentially turn HB 951's Ownership Requirement provision into a meaningless restatement of existing law. As the franchised retail electric service provide, Duke Energy is required to "own" all of the electricity that is used to serve its retail customers. AGO's interpretation would essentially just turn the provision in question into a restatement of a fact that is already well-established under

North Carolina law, rendering the entire provision surplusage in contravention of well-established principles of statutory construction.

- Duke Energy agrees with the Public Staff that purchased power agreements are not recovered on a cost of service basis. *See* Public Staff Sept. 9th Pre-Hearing Comments, at 8 ("traditional utility-owned resources are the only resources that are recovered on a cost-of-service basis"), 11 ("The difference in cost recovery treatment between utility-owned assets and purchased power, and the statutory language in Section 110.9(2), seems to intentionally preclude purchased power from being considered in the Carbon Plan."). If the General Assembly intended to broadly allow PPAs, there would have been no need to specifically authorize PPAs for 45% of solar.
- See generally the Companies' Sept. 9th Pre-Hearing Comments at 19-36 for further discussion of this issue.

Avangrid Renewables, LLC Comment(s):

Avangrid Renewables, LLC ("Avangrid") takes the position that HB 951's ownership requirements are ambiguous when considering offshore wind facilities sited in federal waters. Avangrid Sept. 9th Pre-Hearing Comments at 9. "[T]raditional cost recovery mechanisms in North Carolina have not had to deal with resources sited in non-state territory." *Id*. Avangrid notes that HB 951 does not address or prohibit joint ownership. *Id*. at 10. Avangrid therefore argues that "[i]t seems better policy, and is consistent with much of the existing U.S. offshore wind industry, to allow partnerships or other joint ownership structures that permit the sharing of the capital expenses and risks associated with their development and construction." *Id*. Allowing third party ownership of offshore wind resources would "present an opportunity to provide out-of-state bulk clean electric generation to North Carolina, replacing the need for some in-state assets, and effectively "shrinking the problem" of in-state carbon emissions." *Id*. at 11. Further, "[r]equiring Duke ownership of offshore wind facilities sited in federal waters would not result in a least path cost of compliance, particularly if that ownership is further limited to Duke's preferred Carolina Long Bay lease area that is currently owned by a Duke affiliate." *Id*. at 13.

Targeted Additional Response:

- The Ownership Requirements are clear and unambiguous. *See generally* Sept. 9th Pre-Hearing Comments at 19-36.
- The Ownership Requirements in HB 951 make no distinction between in and out of state resources. Whether located in North Carolina or outside or in "non-state territory," "*[a]ny* new generation facilities or other resources selected by the

Commission in order to achieve the authorized reduction goals for electric public utilities" is subject to the Ownership Requirements. N.C.G.S. § 62-110.9(2).

- Avangrid admits that its concerns could be addressed if Duke Energy were to purchase its wind lease area, thereby achieving the ownership requirements of the law. *See* Avangrid Sept. 9th Pre-Hearing Comments at 15.
- Duke Energy agrees that certain forms of joint ownership may be permissible under the Ownership Requirements and Duke Energy will explore such opportunities where applicable and beneficial to customers.

Carolinas Clean Energy Business Association Comment:

Intervenor Carolinas Clean Energy Business Association ("CCEBA") admits, "[t]aken at face value, [Section 62-110.9(2)] can certainly be read to prevent the Commission from approving a Carbon Plan that relies in any way on energy other than solar energy or solar + storage that is purchase from third parties through Power Purchase Agreements. ***CCEBA concedes that the language of the statute reads as it reads.***" CCEBA Sept. 9th Pre-Hearing Comments at 4 (emphasis added). Unable to dispute the plain language of the statute, CCEBA makes a policy argument that the ownership requirement should not be "an impenetrable barrier to development of offshore wind resources in North Carolina." *Id*. at 5. CCEBA further argues that HB 951 allows the Companies to continue to purchase energy from third parties under existing PPAs, and Duke may enter into new PPAs. *Id*. at 6. Additionally, regarding new offshore wind resources, CCEBA contends that "a restriction on the rights of parties in federal waters outside of the territorial jurisdiction of North Carolina would be of dubious Constitutionality." *Id*.

Targeted Additional Response:

- CCEBA reasonably acknowledges that Section 62-110.9(2) is unambiguous (*i.e.*, the statute should be applied as written, at "face value"). CCEBA does not offer a coherent argument for ignoring plain meaning of the statute.
- Duke Energy disagrees that the Ownership Requirement is an "impenetrable barrier" to offshore wind development.
- Duke Energy disagrees that new PPAs that involve new generation facilities are permissible as "resources selected by the Commission in order to achieve the authorized reduction goals" under N.C.G.S. § 62-110.9(2). HB 951 is clear that new generation facilities and other resources must be owned by Duke Energy and recovered on a cost of service basis, with the exception of the specified allocation for solar generation.

- HB 951 makes no "restriction on the rights of parties in federal waters." HB 951 simply makes a policy determination that resources "selected" in the Carbon Plan to serve retail customers are subject to the Ownership Requirements.

Clean Power Suppliers Association Comment:

CPSA argues that HB 951 "prohibit[s] this Commission from approving a Carbon Plan that relies on new non-utility-owned generating resources, other than solar and solar-plus-storage, in order to meet the decarbonization mandates[.]" CPSA Sept. 9th Pre-Hearing Comments at 7. HB 951 does not purport to give the Commission regulatory authority over any generating resource located outside of North Carolina. Rather, "[i]t is simply placing limitations on what kind of resources Duke Energy . . . may rely on in its plan for meeting the requirements of HB 951. This is not dissimilar from G.S. § 62-110.6, which establishes requirements for North Carolina utilities' rate recover [sic] for construction costs of out-of-state generating facilities." *Id*. at 6 n.14.

Targeted Additional Response:

- Duke agrees with CPSA's above comments with respect to the Ownership Requirements.

Kingfisher Comment:

Kingfisher Energy Holdings, LLC ("Kingfisher") attempts to invent a new category of resource under the Carbon Plan – generating facilities that are "not selected" by the Commission, yet that are nevertheless "needed" to achieve the carbon reduction goals. *Id*. at 3-4. Kingfisher argues that this "not selected" but "needed" resource could be owned by third parties under Section 62-110.9(2). *Id*.

Targeted Additional Response:

- This argument is illogical. If a resource is "needed to achieve the carbon reduction goals," then that resource must be planned for and selected by the Commission in the Carbon Plan and, therefore, be subject to the Ownership Requirements established by N.C.G.S. § 62-110.9(2). [See the Companies' response Avangrid's similar comment above.]

NCSEA et al. Comment:

NCSEA et al. argue that the utility ownership language in Section 62-110.9(2) is seemingly at odds with North Carolina's law and practice with respect to "least cost" planning. *Id*. at 10. If there is a conflict, the Commission should allow purchases from third parties. *Id*. NCSEA also notes that the Companies allowed EnCompass to model purchases of offshore wind from third parties, which suggests that the Companies believe that Section 62-110.9(2) allows third party ownership. *Id*. at 9.

Targeted Additional Response:

- NCSEA is incorrect that the Companies modeled purchases of offshore wind from third parties. *See* Tr. vol 22 316-317; *see* Duke Energy Proposed Order, at 84-85.
- The Companies' Sept. 9th Pre-Hearing Comments explain how Commission should reconcile the Ownership Requirements and least cost requirements to achieve legislative intent; however, the Companies do not believe such construction is necessary because the Ownership Requirements are clear and unambiguous and creates no conflict with traditional least cost requirements.

Public Staff Comment:

The Public Staff agrees that Section 62-110.9(2) requires utility ownership of new generation and other resources selected in the Carbon Plan. The Public Staff reasoned that "[t]he difference in cost recovery treatment between utility-owned assets and purchased power, and the statutory language in Section 110.9(2), seems to intentionally preclude purchased power from being considered in the Carbon Plan." Public Staff Sept. 9th Pre-Hearing Comments at 11. Purchased power has traditionally been treated as an Operation and Management expense; so, if a PPA is selected as a resource in the Carbon Plan, then the Public Staff would oppose including PPA in the rate base. *Id*.

Targeted Additional Response:

- Duke agrees with the Public Staff's Sept. 9th Pre-Hearing Comments in this respect.

Tech Customers Comment:

Tech Customers make several arguments opposing the requirement in Section 62-110.9(2) that utilities own new generation and other resources selected in the Carbon Plan. Tech Customers argue that, as part of the Duke-Progress merger in 2012, Duke agreed to pursue least cost planning, including consideration of purchased power and, therefore, this commitment should supersede the Ownership Requirement. Tech Customers Sept. 9th Pre-Hearing Comments at 5.

Targeted Additional Response:

- To the extent there is a conflict (which Duke Energy does not concede), the new statutory Ownership Requirements of HB 951 override pre-existing regulatory requirements.

Tech Customers Comment:

Tech Customers argue that purchased power is an "other resource" not "new generation." When purchased by the utility, it is "owned" by the utility. Therefore, purchased power fits squarely within the reasonable interpretation of 62-110.9(2). *Id*. at 5-6.

Targeted Additional Response:

- The power that is purchased comes from a generation facility, and Duke Energy would have to enter into a new agreement for the purchase of capacity and energy to secure delivery of the power. Tech Customers cannot rely on the "other resources" language as an end around the plain language of the statute. *See* Duke Energy's response above to the AGO's comments on the Ownership Requirements. Duke Energy would not own the generating facility from which power is purchased and this interpretation eviscerates the legislative intent. This interpretation is also not compatible with statutory language also requiring recovering of cost on a cost of service basis. *See* Public Staff Sept. 9th Pre-Hearing Comments at 8, 11 ("traditional utility-owned resources are the only resources that are recovered on a cost-of-service basis").

Tech Customers Comment:

Tech Customers suggest that, because the Companies' proposed Carbon Plan relies on the DEP/DEC Joint Dispatch Agreement ("JDA") - which facilitates the sale of power generated by one affiliate to the other, the Companies are acknowledging that third party ownership is authorized under Section 62-110.9(2). Tech Customers Sept. 9th Pre-Hearing Comments at 8. Tech Customers further note that several of the Companies' portfolios include existing PPAs and purchased wind power from other jurisdictions. *Id*. at 9.

Targeted Additional Response:

- The JDA is not a "new generation facilities or other resource[]…[being] selected by the Commission" as part of the Carbon Plan. Therefore, the Companies' assumption regarding the continued operation of the JDA is not relevant to this issue.
- HB 951 is prospective ("*new* generating facilities and other resources) and does not impair or propose to modify terms of existing PPAs.
- Tech Customers' assertion that Duke modeled purchases of onshore or offshore wind from third parties is not accurate. See Tr. vol 22 316-317; *See* Response to NCEA et al. comment on Ownership Requirement above.

Tech Customers Comment:

Tech Customers argue that an interpretation of Section 62-110.9(2) that prohibits access to out of state third party resources and interstate wholesale markets would violate the dormant Commerce Clause. *Id*. at 13.

Targeted Additional Response:

- It is well established under North Carolina law that the Commission does not have authority to determine the constitutionality of legislative enactments.[1]
- Putting aside this threshold issue, the Tech Customers' argument is fatally flawed. The plain language of HB 951 straight-forwardly mandates that "[a]ny new generation facilities or other resources selected by the Commission in order to achieve … [the Carbon Plan's] carbon reduction goals for electric public utilities *shall be owned and recovered on a cost of service basis by the applicable public utility* …." N.C. Gen. Stat. § 62-110.9(2) (emphasis added).[2] The statute's ownership mandate goes hand-in-glove with the General Assembly's declaration of policy in the Public Utility Act that the "rates, services, and operations of public utilities … are affected with the public interest and that the availability of an adequate and reliable supply of electric power … to the people, economy and government of North Carolina is a matter of

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[1] *State ex rel. Utilities Comm. v. CUCA*, 336 N.C. 657, 673-4 (1994) ("As an administrative agency created by the legislature, the Commission has not been given jurisdiction to determine the constitutionality of legislative enactments."); *Order on Public Staff Motion for Order Directing Amendment*, Docket No. E-7, Sub 700 (Nov. 7, 2001) (recognizing that "[t]he Commission has no jurisdiction to determine the constitutionality of a statute. The Commission must interpret the statute according to its terms and in light of the regulatory responsibilities assigned to the Commission[.]")

[2] This mandate is subject to exceptions, including the provision in Section 62-110.9(2)(b) that requires 45% of new solar or solar plus storage generation *not* be owned by the "applicable public utility."

public policy." N.C.G.S. § 62-2. The General Assembly expanded upon this articulation of the public policy in its enumeration of specific policy declarations, including that the policy of the State is to "promote the inherent advantages of regulated public utilities." N.C.G.S. § 62-2(2). The "inherent advantages" of regulation are furthered by the ownership mandate.

- The Tech Customers have a different vision for public utility regulation in North Carolina—***de***regulation. They advocate alternatives to North Carolina's long-standing approach, and disregard the "inherent advantages of regulated public utilities" that North Carolina's Public Utilities Act champions. N.C.G.S. § 62-2(a)(2) Their expert report (the Gabel Report) puts forth a "Preferred Portfolio" including features such as "expanding options for consumers to contract directly with renewable energy suppliers" (Gabel Report at 2), and notes that the State could "amplify the value" of such strategies by "joining a wholesale power market like PJM." (*Id*. at 3). Ignoring the plain language of HB 951, their Preferred Portfolio includes new wind generation owned by third-parties and imported into North Carolina. (*Id*. at 7).

- But the Tech Customers may not ignore the plain language of the statute; nor can they, under the guise of "interpretation," turn that plain language on its head. The Tech Customers clearly understand this—so in order to evade HB 951's Ownership Requirements mandate, they suggest to the Commission that HB 951 somehow "implicates" scrutiny under the dormant Commerce Clause of the United States Constitution. It does not, and the Commission should reject this argument.

- First, the Tech Customers' suggestion is couched as an invitation to the Commission to "avoid" constitutional issues by interpreting HB 951 in harmony with the restrictions imposed upon state law by the dormant Commerce Clause. But the Tech Customers do not proffer any such "harmonious" interpretation – they simply read the Ownership Requirement out of the statute altogether. This is patently an ***un***reasonable "interpretation" of HB 951, in that statutory interpretation properly applied may not simply ignore express statutory language. As the Tech Customers note,[3] avoiding constitutional issues when a case can be resolved on other grounds is certainly the preferred approach, but the premise underlying such avoidance when undertaking statutory construction is that "[w]here one of two *reasonable* constructions of a statute will raise a serious constitutional question … our courts should adopt the construction that avoids the constitutional question." *State v. T.D.R.*, 347 N.C. 489, 498 (1998) (emphasis added).[4] The Tech Customers simply have not proffered a "reasonable"

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[3] *See* Tech Customers' Comments on Non-Hearing Issues Relating to Duke's Proposed Carbon Plan, filed September 9, 2022 ("Tech Customer Comments"), at 11.

[4] Tech Customers cite *State v. China*, 370 N.C. 627, 640 (2018) for this proposition. *See* Tech Customers Comments, at 11. However, in *China*, the quotation appears in the dissenting opinion of then-Chief Justice Beasely, not in the majority opinion.

interpretation of HB 951 so as to trigger avoidance of a constitutional issue. And, in any event, no "serious" dormant Commerce Clause question with respect to HB 951 exists.

- The Constitution reserves to Congress the power to "regulate Commerce … among the several States" (U.S. Const. art. I, § 8, c. 3), and inherent in this grant of power is a limitation upon the power of the States to erect barriers to interstate commerce. This limitation upon the States is referred to as the "dormant" aspect of the Commerce Clause, *see Colon Health Centers of America, LLC v. Hazel*, 813 F. 3d 145, 154 (4th Cir. 2016) ("*Colon Centers II*"), and the focus of dormant Commerce Clause jurisprudence is to strike down state laws that "*discriminate* against interstate commerce." *Id*. (citing cases, emphasis in original). "Discrimination" for dormant Commerce Clause purposes "simply means differential treatment of in-state and out-of-state interests that benefits the former and burdens the latter." *Id*. (citing cases). A discriminatory measure is "virtually *per se* invalid," and will survive strict scrutiny only if it "advances a legitimate local purpose that cannot be adequately served by reasonable nondiscriminatory alternatives." *Id*. (citing cases).

- As the Fourth Circuit has held, "A state statute may discriminate against interstate commerce in one of three ways: 'facially, in its practical effect, or in its purpose.'" *Id.* at 152. The Tech Customers do not even suggest that HB 951 discriminates against interstate commerce in "practical effect" or that the statute is discriminatory in purpose.[5] Insofar as "facial" discrimination is concerned, the Tech Customers assert that "a law [HB 951] that would prohibit North Carolina public utilities from purchasing power would limit access to the North Carolina market, protecting the incumbent utilities from price competition to the detriment of power generators in the interstate electricity market." Tech Customer Comments, at 11-12. But this is patently wrong—by requiring (with the notable exception of solar or solar plus

[5] Determining whether a challenged statute has a discriminatory purpose or discriminatory practical effect is a fact intensive inquiry. *Colon Health Centers of America, LLC v. Hazel*, 733 F. 3d 535, 545 (4th Cir. 2013). The Tech Customers present no facts to support either proposition. Even had they attempted to do so, prevailing dormant Commerce Clause jurisprudence easily disposes of the notion that HB 951 is subject to attack as discriminatory in purpose or effect. "Regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States." *Baltimore Gas & Elec. Co. v. Heintz*, 760 F.2d 1408, 1424 (4th Cir. 1985) ("*BG&E*") (quoting *Arkansas Electric*, 461 U.S. 375, 377, 76 L. Ed. 2d 1, 103 S. Ct. 1905 (1983)). North Carolina's police power interest would decisively tip the scales in any dormant Commerce Clause analysis to preclude findings of discriminatory purpose or effect. *See LSP Transmission Holdings, LLC v. Sieben*, 954 F. 3d 1018, 1030 (8th Cir. 2020), *cert. denied*, __U.S. __, 141 S.Ct. 1510 (2021) (Minnesota statute conferring the right of first refusal ("ROFR") upon incumbent transmission owners in connection with building new transmission lines survives dormant Commerce Clause challenges asserting discriminatory purpose and effect because state's police power interest in regulation of utilities rendered the discriminatory impact (if any) of Minnesota's ROFR statute an "incidental" hurdle not invalidated by the dormant Commerce Clause). North Carolina's interest in maintaining its traditional role in the regulation of utilities, enshrined as a specific policy choice in the Public Utilities Act, is no less important to this State as Minnesota's ROFR statute is to Minnesota.

storage) utility ownership of new generation or other resources, HB 951 prevents third-party ownership of such resources no matter where those resources originate—*either* in-state *or* out-of-state. There is simply no discrimination against out-of-state resources. The Fourth Circuit recognized this in *Colon Centers II*, a case in which out-of-state medical providers challenged Virginia's Certificate of Need law: "The [CON] program applies to all firms establishing or expanding covered health care operations within the state, and makes no distinction between in-state and out-of-state service providers." 813 F. 3d at 152. A merchant gas plant (not utility owned) located in Kings Mountain, NC is just as precluded from being included as a "resource" for Carbon Plan purposes as a Midwest wind farm selling into the PJM market.

- Accordingly, the Tech Customers' attempt to create doubt regarding HB 951's validity under the dormant Commerce Clause is without merit and should be rejected.
- Notably, the Commonwealth of Virginia has prescribed very similar ownership requirements in the Virginia Clean Economy Act of 2020. *See* Tr. vol. 16, Va. Code § 56-585.1(6) (providing that ". . . new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from onshore wind with an aggregate capacity of 16,100 megawatts . . . [and] ". . . utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than 3,000 megawatts, are in the public interest."

3) <u>Wholesale Power Contract Issues</u>

Electricities[6] Comment:

Intervenor Electricities argues that "Duke's failure to consider the benefit of load management efforts that wholesale customers could provide is a fatal omission from the Proposed Plan. For that reason, when the Commission develops a Carbon Plan this year, it should limit the amount of new generation investment it would find prudent, and thus recoverable from retail customers to reflect the load side management Duke could benefit from if it acted to incentivize or at least permit greater investment in DER by Duke's wholesale requirements customers." Electricities Sept. 9th Pre-Hearing Comments at 5. Load and demand reduction could eliminate the need for a portion of more expensive offshore or SMR. *Id*. at 6. If adequately incentivized, wholesale customers could add Battery Energy Storage Systems and other DSM/DR programs. *Id*. at 7.

[6] Electricities September 9th Pre-Hearing Comments addressed several hearing topics in addition to non-hearing topics.

Targeted Additional Response:

- Rates, terms, and agreements for the provision of demand response by wholesale customers is a FERC-jurisdictional issue and the Commission does not have authority to approve demand-side programs for wholesale customers. *See* Duke Energy's September 9th Pre-Hearing Comments, at 62-63.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Post-Hearing Brief, Confidential Version, submitted in Docket No. E-100, Sub 179, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid, to parties of record who have entered into a nondisclosure agreement.

This the 24th day of October, 2022.

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