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NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

October 24, 2022

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

Re: Docket No. E-100, Sub 179
Duke Energy Progress, LLC's and Duke Energy Carolinas, LLC's
2022 Biennial Integrated Resource Plans and Carbon Plan

Dear Ms. Dunston:

Attached for filing is the Proposed Order of the Public Staff in the above-referenced docket.

By copy of this letter, I am forwarding a copy to all parties of record by electronic delivery.

Sincerely,
Electronically submitted
/s/ Nadia L. Luhr
Staff Attorney
nadia.luhr@psncuc.nc.gov

cc: Parties of Record

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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	)))	**PROPOSED ORDER OF THE PUBLIC STAFF**

HEARD: Monday, July 11, 2022, at 7:00 p.m., in Courtroom D7, Durham County Courthouse, 510 S. Dillard Street, Durham, North Carolina

Tuesday, July 12, 2022, at 7:00 p.m., in Courtroom 317, New Hanover County Courthouse, 316 Princess Street, Wilmington, North Carolina

Wednesday, July 27, 2022, at 7:00 p.m., in Courtroom 1-A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina

Thursday, July 28, 2022, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 E. 4th Street, Charlotte, North Carolina

Tuesday, August 23, 2022, at 1:30 p.m. and 6:30 p.m., held via Videoconference

Tuesday, September 13, 2022, at 9:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland; Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, Floyd B. McKissick, Jr., and Karen M. Kemerait.

Based upon the foregoing and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

General

1. The Commission has the discretion to extend the interim 70% carbon emission reduction target past 2030.

2. It is appropriate for Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (together, Duke) each to file an Integrated Resource Plan (IRP) Update in 2023, and to include in the 2023 IRP Update milestones and development activities associated with the 2022 Carbon Plan.

3. It is appropriate to delay Duke's next comprehensive IRP filing to 2024, and for Duke to combine its comprehensive 2024 IRP and 2024 Carbon Plan Update filings.

4. It is appropriate for Duke and the Public Staff to work together to develop proposed revisions to Commission Rule R8-60, and to then convene a stakeholder process by which interested parties can provide feedback on those proposed revisions before they are filed with the Commission on or before April 28, 2023. It is also appropriate for interested parties to have the opportunity to submit comments on the proposed revisions, as well as alternative proposals.

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Modeling

5. Duke has appropriately established the 2005 baseline level of carbon dioxide (CO_2) emissions from its facilities for purposes of tracking compliance with N.C. Gen. Stat. § 62-110.9 (Section 110.9).

6. It is appropriate for the 2023 IRP Update and the 2024 Carbon Plan Update/IRP to incorporate the impacts of the Inflation Reduction Act of 2022 (IRA).

7. Supplemental Portfolio 5 (SP5) is reasonable for planning purposes and as a foundation for the 2022 Carbon Plan and associated near-term procurement and development activities.

8. It is appropriate to assume, for modeling purposes, that all new carbon-emitting resources selected in the Carbon Plan would be located in North Carolina and that Duke's total system carbon emissions would count against the interim and 2050 emission reduction targets.

9. It is appropriate for Duke's modeling for the 2024 Carbon Plan Update/IRP proceeding to utilize a dynamic dispatch of solar plus storage (S+S) resources and, to the extent feasible, to incorporate bi-directional inverter capability.

10. It is appropriate for Carbon Plan modeling to avoid the use of cumulative resource addition limits in the absence of known and measurable technical limitations on resource potential. With respect to battery storage resources, it is appropriate for Duke's modeling for the 2024 Carbon Plan

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Update/IRP proceeding to utilize declining Effective Load Carrying Capability (ELCC) curves rather than cumulative capacity limits.

11. It is appropriate for Duke, in the 2024 Carbon Plan Update/IRP proceeding, to address the operable lives of its battery storage resources and the reasonableness of an assumption of continual replacement of capacity with identical resources.

12. It is appropriate for the 2022 Carbon Plan to exclude the use of hydrogen blending. It is appropriate for the 2024 Carbon Plan Update/IRP to include hydrogen blending only if such blending can be reasonably supported by advancements in the green hydrogen industry. If hydrogen blending is included in the 2024 Carbon Plan Update/IRP, it is appropriate to endogenously evaluate whether it is economical to retire any natural gas assets as an alternative to converting them to run on 100% hydrogen.

13. It is appropriate for the 2022 Carbon Plan to assume that no Appalachian gas will be available to Duke for its natural gas facilities. It is appropriate for the 2023 IRP Update and the 2024 Carbon Plan Update/IRP to utilize natural gas pricing and supply assumptions that reflect the most recent developments that would impact natural gas access in North Carolina, including developments regarding natural gas pipeline projects.

14. It is appropriate for the 2022 Carbon Plan to utilize a natural gas price forecasting methodology that consists of five years of natural gas market-based pricing and three years of transitioning from market-based pricing before fully

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utilizing fundamentals-based natural gas pricing forecasts beginning in year nine. In the 2024 Carbon Plan Update/IRP proceeding, it is appropriate to generate natural gas pricing forecasts that correspond to Duke's actual fuel procurement practices.

15. It is appropriate for the 2024 Carbon Plan Update/IRP to include an endogenous retirement analysis of operational coal units, subject to certain adjustments reflecting constraints that are not able to be represented in the model.

16. It is appropriate for the 2022 Carbon Plan to utilize an eight-year optimization period for the capacity expansion modeling. It is appropriate to ensure that the optimization period utilized in the 2024 Carbon Plan Update/IRP appropriately balances model run times against the challenges associated with limited model foresight.

17. It is appropriate for the 2023 IRP Update and the 2024 Carbon Plan Update/IRP to utilize a transmission tariff between DEC and DEP that simulates the non-firm service tariff in Duke's Open Access Transmission Tariff (OATT) approved by the Federal Energy Regulatory Commission (FERC).

18. It is appropriate for Duke to incorporate the results of the 2022 Solar Procurement in its 2024 Carbon Plan Update/IRP filing, and to utilize the results of the 2022 Solar Procurement to identify any material distinctions in solar capital costs, transmission upgrade costs, and operational characteristics between resources located in DEC territory and those located in DEP territory that reflect

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the variance in bid prices received. It is also appropriate for Duke to incorporate any variations in bid prices in the modeling for the 2024 Carbon Plan Update/IRP.

19. It is appropriate for pricing information from future Requests for Proposals (RFPs) in Duke's territories, particularly for solar and S+S, to be reflected in the inputs in the modeling for the 2024 Carbon Plan Update/IRP.

20. Based on Duke's modeling and SP5, it is reasonable and appropriate for the 2022 Carbon Plan to achieve interim compliance no later than 2032.

21. It is appropriate for Duke's filing in the 2024 Carbon Plan Update/IRP proceeding to include modeled portfolios that reach interim compliance in 2030, 2032, and 2034.

22. It is appropriate for Duke, at the time it makes its filing in the 2024 Carbon Plan Update/IRP proceeding, to concurrently provide all intervenors and the Public Staff with all modeling files, spreadsheets, and process documentation necessary to validate the modeling inputs and results filed by Duke, subject to any non-disclosure agreements.

Near-Term Actions

23. The appropriate target procurement volume for the 2022 Solar Procurement is 1,200 megawatts (MW), at least one-third of which is to be procured in DEC, one-third in DEP, and the final one-third in either utility territory.

24. It is appropriate for Duke to engage with interested stakeholders and market participants in advance of the 2023 S+S Procurement to develop

commercial terms and conditions, operational conditions, and a *pro forma* power purchase agreement (PPA) to be used for S+S resources.

25. The preliminary Target Volumes for future RFPs shall be 950 MW for the 2023 Solar Procurement and 1,150 MW for the 2024 Solar Procurement. A minimum of 400 MW of at least 2-hour co-located storage shall be procured in each RFP, subject to the terms of this order.

26. It is appropriate for Duke to seek to procure 600 MW of onshore wind.

27. It is appropriate for Duke to plan to include 800 MW of Combustion Turbines (CTs) and 1,200 MW of Combined Cycle plants (CCs) in its economically selected resource mix.

28. It is appropriate for the ultimate determination of the need for a CT or CC to be made by the Commission upon the facility's application for a certificate of public convenience and necessity (CPCN).

Transmission

29. It is appropriate for Duke to upgrade the transmission lines enumerated in Duke Transmission Panel Rebuttal Testimony Exhibit 3 except for the Clinton 100 kilovolt (kV) (Bush River-Laurens) and the Erwin – Fayetteville 115 kV Line.

30. It is appropriate for Duke to include any future proactive transmission upgrade projects in its future Carbon Plan Update/IRP filings, and for the Commission to approve those projects prior to the North Carolina Transmission

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Planning Collaborative (NCTPC) or Southeastern Regional Transmission Planning (SERTP) process including those projects in their Local or Regional Transmission Plans.

31. It is appropriate for Duke to update its transmission cost adders using the results of the most recently available interconnection cluster study for the 2024 Carbon Plan Update/IRP.

32. A transmission planning horizon of 20 years is appropriate, and plans should incorporate the resource additions identified in the Commission's Carbon Plan into its transmission expansion plans filed with the NCTPC and SERTP.

33. It is appropriate for Duke, in the 2024 Carbon Plan Update/IRP proceeding and future Definitive Interconnection System Impact Study (DISIS) cluster studies and resource procurement solicitations, to provide updated locational guidance maps which identify any new proactive transmission upgrades planned to be included in the study baseline. It is also appropriate for Duke's filing in the 2024 Carbon Plan Update/IRP proceeding to explicitly identify such proactive transmission upgrades and include information regarding cost, need, and estimated in-service dates.

Long Lead-Time Resources

34. It is appropriate for Duke to proceed with the activities related to obtaining subsequent license renewals (SLRs) for its existing nuclear fleet.

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35. It is appropriate for Duke to proceed with the activities related to developing small modular reactor (SMR) capabilities as outlined in Duke's Petition; provided, however, that it is not appropriate at this time for Duke to select a particular SMR technology vendor, given the state of Nuclear Regulatory Commission (NRC) design approvals.

36. It is appropriate for Duke to proceed with the initial development activities necessary to advance the Bad Creek II pumped storage hydro project as outlined in Duke's Petition for Approval, and to provide updates on its progress in the 2023 IRP Update and 2024 Carbon Plan Update/IRP filing.

37. It is not appropriate at this time for Duke to proceed with its proposed initial development activities related to offshore wind, including procurement of the Carolina Long Bay offshore wind lease area through an affiliate transfer, initiation of permitting and development activities, or initiation of the interconnection process.

38. It is appropriate for Duke to engage an independent third party to study and analyze all the potential offshore wind sites off the coast of North Carolina to enable more accurate modeling of offshore wind in the 2024 Carbon Plan Update proceeding.

Grid Edge

39. The Companies' Grid Edge forecasts associated with demand response, net energy metering, electric vehicles, and dynamic rate designs are appropriate for planning purposes.

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40. The use of one percent of prior-year-available retail sales as the modeling assumption for the Utility Energy Efficiency (UEE) forecast is not reasonable for planning purposes. It is appropriate for Duke in its 2024 Carbon Plan Update/IRP to utilize the most recent market potential study (MPS) base scenario, adjusted for any market or EE adoption trends reflected in the Companies' recent DSM/EE riders, as the modeling assumption in its base case for modeling the impacts of UEE.

41. It is appropriate for the 2024 Carbon Plan Update/IRP proceeding to use the following UEE forecast sensitivities: (1) the achievable utility EE potential as set forth in the most recent MPS; (2) Duke's proposal of one percent of eligible retail sales; (3) one percent of total system retail sales; and (4) 1.5% of total system retail sales.

42. It is not appropriate in this proceeding to approve Duke's proposals to: (1) update the underlying determination of the utility system benefits in the Companies' approved DSM/EE mechanisms; (2) adopt an "as-found" savings baseline methodology; or (3) expand the pool of customers eligible to participate in Duke's low-income DSM/EE programs to households with gross incomes up to 300% of the federal poverty guideline.

43. It is appropriate to conduct a full review of the Companies' currently approved mechanisms to begin within 90 days of this Order. In addition to consideration of the proposed enablers, the appropriate percentage of PPI and PRI, the impact of on-bill financing, the inclusion of a cost of carbon or non-energy

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benefits, whether NLR should continue to be collected through the DSM/EE riders if residential decoupling is approved in a MYRP, and other matters discussed herein, it is appropriate that the parties consider whether the mechanisms should provide a utility incentive for achieving energy savings at or below the target level of EE savings approved for use in the Carbon Plan or to only incentivize the achievement of energy savings over and above the target.

44. For any DSM/EE program approval or modification filing, it is appropriate for the respective company to identify the methodology (traditional baseline or as-found) for calculating energy savings it intends to apply to each measure included in the program.

45. It is appropriate to distinguish the energy savings that can be recognized for use in DSM/EE proceedings from savings used for Carbon Plan compliance purposes.

46. It is appropriate for the 2024 Carbon Plan Update/IRP proceeding to include a transparent analysis that clearly illustrates the impact on the UEE forecast of: (1) each enabler described in Proposed Carbon Plan Appendix G if adopted, as well as any additional approved or proposed enablers; (2) the effects of market transformation; (3) rate impacts; and (4) any other changes that might be considered in the context of a future multi-year rate plan (MYRP).

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Reliability

47. It is appropriate for Duke's modeling in the 2024 Carbon Plan Update/IRP proceeding to calculate Loss of Load Expectation (LOLE) for each portfolio as a key metric for system reliability.

48. SP5 passed Duke's resource adequacy validation testing through the year 2035 and demonstrates reliability over that period.

Cost Recovery

49. The reasonableness and prudence of specific costs associated with the 2022 Carbon Plan will be determined by the Commission in future cost recovery proceedings.

50. It is premature in this proceeding to authorize any deferrals related to the 2022 Carbon Plan.

51. The ratemaking treatment specified in N.C.G.S. § 62-110.7 is only applicable to nuclear facilities and does not apply to other resource types such as offshore wind and new pumped storage hydro.

52. It is not appropriate for the Commission to consider in this Carbon Plan proceeding or future IRP or Carbon Plan proceedings whether any costs for nuclear facilities are eligible for ratemaking treatment pursuant to N.C.G.S. § 62-110.7. It is appropriate for the capital costs associated with nuclear facilities to be considered on a case-by-case basis in a separate proceeding pursuant to N.C.G.S. § 62-110.7.

53. It is premature in this proceeding to authorize any potential recovery of abandoned plant costs related to the 2022 Carbon Plan. It is appropriate for any request for recovery of abandoned plant to be handled on a case-by-case basis in a future general rate case proceeding.

Coal Unit Securitization

54. It is appropriate for Duke to assess whether it would be in the interest of ratepayers to securitize additional coal generation assets above the 50% required by Session Law 2021-165 (HB 951) and Commission Rule R8-74, including supercritical coal units.

Bill Impacts, Rate Disparity, and Merger

55. It is appropriate for Duke to calculate the relative cost impact to ratepayers of each Carbon Plan portfolio regardless of whether costs are common among all portfolios.

56. It is appropriate for Duke, in its 2024 Carbon Plan Update filing, to provide a bill impact analysis of each portfolio that includes all known and measurable costs, and to indicate the amount of costs common across all portfolios.

57. It is appropriate for Duke to proceed with pursuing a full merger of DEC and DEP and to immediately begin taking the steps outlined in Carolinas Utilities Operations Panel Exhibit 1.

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58. Until a merger of DEC and DEP is consummated, it is appropriate for Duke to propose jurisdictional cost allocation methodologies that equitably allocate the costs of new generation and transmission between DEC and DEP proportionate to the benefits received by each utility's customers in its current MYRP proceedings (Docket Nos. E-2, Sub 1300 and E-7, Sub 1276) and in future proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the initial and responsive comments of the Public Staff, intervenors, and Duke, and the entire record in this proceeding.

Section 110.9 requires the Commission to "take all reasonable steps" to ensure that statewide carbon dioxide emissions from electric generating facilities serving at least 150,000 North Carolina retail jurisdictional customers are reduced by 70% from 2005 levels by 2030, and to achieve carbon neutrality[1] by 2050. Section 110.9 also states that, in achieving the authorized carbon reduction goals, the Commission shall:

> [r]etain discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals, including 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

[1] Section 110.9(a) defines "carbon neutrality" as follows: "for every ton of CO_2 emitted in the State from electric generating facilities owned or operated by or on behalf of electric public utilities, an equivalent amount of CO_2 is reduced, removed, prevented, or offset, provided that the offsets are verifiable and do not exceed five percent (5%) of the authorized reduction goal."

> impact on carbon reduction; provided, however, the Commission shall not exceed the dates specified to achieve the authorized carbon reduction goals by more than two years, except in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility, or in the event necessary to maintain the adequacy and reliability of the existing grid. In making such determination, the Utilities Commission shall receive and consider stakeholder input.

N.C.G.S. § 62-110.9(4) (2021).

No party argued that the Commission lacked the discretion to extend the interim compliance deadline past 2030. Public Staff Initial Comments, 28; Attorney General's Office (AGO) Initial Comments, 8-9; AGO Responsive Comments, 7-11; Clean Power Suppliers Association (CPSA) Initial Comments, 34-37; CPSA Responsive Comments, 2-5; Clean Energy Buyers Association (CEBA) Initial Comments, 4-5; North Carolina Sustainable Energy Association (NCSEA), Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club (together, "NCSEA *et al.*") Initial Comments, 10-15; NCSEA *et al.* Responsive Comments, 6-8; CCEBA Initial Comments, 6-8; CCEBA Responsive Comments, 2-4; Avangrid Initial Comments, 11-12; Avangrid Responsive Comments, 2-9; City of Asheville and County of Buncombe Initial Comments, 4; Carolina Industrial Group for Fair Utility Rates II and III (CIGFUR) Responsive Comments, 6-7.

Several intervenors did, however, express that the 2022 Carbon Plan should aim to comply with the 2030 interim deadline, or that the requirements for an extension laid out in Section 110.9 have not been met. For example, the AGO

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cited to the Commission's authority to extend the interim compliance deadline past 2030 but stated that the Commission may only include a portfolio that delays compliance with the statutory deadline in the 2022 Carbon Plan if it determines that it provides a "more significant and material impact on carbon reduction" than Duke's Portfolio 1, which does meet the 2030 interim deadline. AGO Initial Comments, 8-9.

In the responsive comments of the Public Staff addressing non-expert hearing issues, the Public Staff stated that while meeting the interim compliance goal of 2030 is a priority, Section 110.9(4) explicitly grants the Commission the authority to extend the 2030 carbon emission reduction target. The Public Staff further stated that while it is not recommending that the Commission preemptively authorize a delay in meeting the interim compliance goals, the Commission has the statutory authority to do so if it finds that it is in the public interest to extend the compliance deadlines set forth in Section 110.9 under one or more of the three specific circumstances enumerated therein. Public Staff Responsive Comments, 4-6.

In its responsive comments, Duke stated that the Commission has broad discretion to extend the interim 70% carbon emission reduction target to 2032, and that Duke's Proposed Carbon Plan and requests for relief are "consistent with" the Commission's authority to retain discretion to extend the interim target date past 2032. Duke Responsive Comments, 4-16.

It is well settled that "[l]egislative intent controls the meaning of a statute" and is "found first from the plain language of the statute." *N.C. Farm Bureau Mut. Ins. Co. v. Dana*, 379 N.C. 502, 510 (2021) (internal citation omitted); *see also State v. Bates*, 348 N.C. 29, 34 (1998) (stating that "[t]he meaning of any legislative enactment is controlled by the intent of the legislature and that legislative purpose is to be first ascertained from the plain language of the statute"). "When the language of a statute is clear and unambiguous, there is no room for judicial construction, and the courts must give it its plain and definite meaning." *State v. Jones*, 358 N.C. 473, 477 (2004); *see also Nance v. Southern R. Co.*, 149 N.C. 366, 371 (1908) (stating that "if the Legislature has used language of clear import, the court should not indulge in speculation or conjecture for its meaning"). Further, courts and quasi-judicial bodies such as the Commission should "give effect to the words actually used in a statute and should neither delete words used nor insert words not used in the relevant statutory language during the statutory construction process." *Midrex Techs., Inc. v. N.C. Dep't of Revenue*, 369 N.C. 250, 258 (2016).

The language in Section 110.9(4) granting the Commission the authority to extend the 2030 carbon emission reduction target is clear and unambiguous, and the Commission is charged with giving such language its plain and definite meaning. Accordingly, the Commission concludes, as is uncontested by any party, that it would be acting in accordance with its statutory authority should it extend the compliance deadlines set forth in Section 110.9 under one or more of the three specific circumstances enumerated therein. Specifically, the Commission has the discretion to extend the 2030 interim deadline to allow for "implementation of

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solutions that would have a more significant and material impact on carbon reduction." The Commission may only extend the deadline by two years, unless: (1) the Commission authorizes the construction of a nuclear or wind energy facility "that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility;" or (2) a longer extension is necessary to maintain the adequacy and reliability of the existing grid.

Moreover, "statutes should be construed so that the resulting construction 'harmonizes with the underlying reason and purpose of the statute.'" *N.C. Farm Bureau*, 379 N.C. at 510 (internal citation omitted). Section 110.9 requires least-cost planning,[2] and Section 110.9(3) provides that the Commission shall "[e]nsure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid." Likewise, the overarching declaration of policy in N.C.G.S. § 62 requires least-cost planning and promotes adequate and reliable utility service. N.C.G.S. § 62-2(a). The Commission is of the opinion that Section 110.9's explicit grant to the Commission of authority to extend the 2030 carbon emission reduction target directly supports these overarching provisions insofar as an extended compliance deadline would result in least-cost planning or improved adequacy and reliability of the grid. The Commission concludes that Section 110.9 provides for a balancing between the 2030 interim compliance timeline, least-cost planning, and adequacy and reliability.

[2] *See, e.g.*, Section 110.9(2) (providing that the Commission shall "[c]omply with current law and practice with respect to the least cost planning for generations . . . in achieving the authorized carbon reduction goals and determining generation and resource mix for the future").

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Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that it has the discretion to extend the interim 70% carbon emission reduction target past 2030. Whether there is support in the record for extending the deadline past 2030 in accordance with Section 110.9(4) is addressed later in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-3

The evidence supporting these findings of fact is contained in Duke's Petition for Approval, the initial and responsive comments of the Public Staff, intervenors, and Duke, and the entire record in this proceeding.

In Duke's Petition for Approval filed with its Proposed Carbon Plan on May 16, 2022, the Companies requested, in part, that the Commission hold the next comprehensive IRP in abeyance until September 2024 in order to synchronize the Carbon Plan and IRP proceedings. Duke Petition for Approval, 17.

In its comments addressing non-expert hearing issues, the Public Staff stated that it agreed with the Commission's statement in its November 19, 2021 Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines that the biennial IRP proceedings should be adjusted to align with the biennial Carbon Plan updates. The Public Staff stated that there is significant overlap between the Carbon Plan and the IRP, and that undertaking the two proceedings at different points in time would result in a substantial duplication of efforts. The Public Staff recommended that the next biennial IRP be held in abeyance until September 2024, and that the first biennial Carbon Plan update proceeding should begin in

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sync with the 2024 IRP filing. The Public Staff emphasized that the Carbon Plan update proceeding should take place on a timeline that allows for: (1) discovery; (2) the filing of testimony (and comments as appropriate); (3) an evidentiary hearing; (4) public hearings; and (5) stakeholder engagement. The Public Staff noted that under such a timeline, an adjusted Carbon Plan adopted pursuant to the 2024 Carbon Plan Update proceeding would be adopted in 2025. The Public Staff added that it is crucial that intervenors and the Public Staff have sufficient time to review and work with the data and inputs used by Duke in its modeling. Lastly, the Public Staff commented that holding the next biennial IRP in abeyance until September 2024 would also allow more time for a full review of any necessary revisions to Commission Rule R8-60. Public Staff Responsive Comments, 1-3.

Several intervenors also expressed support for synchronizing the IRP and Carbon Plan proceedings and for holding the next biennial IRP proceeding in 2024. NCSEA *et al.* Initial Comments, 32; Walmart Responsive Comments, 2; CIGFUR Responsive Comments, 2. NCSEA *et al.* however, in its responsive comments, stated that in light of the passage of the Investment Reduction Act (IRA), the Commission should allow for the possibility of supplemental modeling to make adjustments to the short-term action plan prior to the commencement of the 2024 Carbon Plan process. NCSEA *et al.* recommended that, to the extent that the 2022 Carbon Plan's short-term action plan does not take policies under the IRA into account, parties should have the opportunity to provide supplemental modeling to update the Carbon Plan in early 2023 for the limited purpose of determining whether any modifications to the short-term action plan would be in the public

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interest. NCSEA *et al.* Responsive Comments, 1-3. Similarly, the AGO stated that while it supports eventual coordination of the IRP and Carbon Plan proceedings, postponing further planning review is not appropriate given the substantial impact of the IRA. The AGO commented that once the IRA's impact is evaluated and addressed in the Carbon Plan, it will be more appropriate to sync up the timing of the IRP and Carbon Plan proceedings. AGO Responsive Comments, 4-5.

In addition, like the Public Staff, several intervenors specified that the timeline for the first Carbon Plan update proceeding should allow time for stakeholder engagement and more collaboration and sharing on modeling efforts. For example, NCSEA *et al.* commented that the 2024 update proceeding should begin with a stakeholder process that seeks to align parties as to the inputs, assumptions, and modeling best practices that will create a shared foundation for developing the Carbon Plan and enable meaningful review and critique. NCSEA *et al.* further stated that the Commission's procedural order in the 2024 update proceeding should establish deadlines for the sharing of EnCompass modeling inputs as all parties work to develop plan updates. NCSEA *et al.* Responsive Comments, 2-4.

Duke again requested in its responsive comments that the Commission hold the Companies' next biennial IRPs in abeyance to 2024 to align with the next Carbon Plan proceeding, noting that no party opposed this proposal. Duke also noted that the Public Staff had recommended the filing of an IRP update in 2023, and stated that, in an effort to achieve consensus, the Companies agreed to comply with the Public Staff's recommendation and will plan to file IRP updates for

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DEC and DEP in 2023. Duke commented that the 2023 IRP 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. Duke Responsive Comments, 57-58.

Section 110.9 states that the Carbon Plan must be "reviewed every two years and may be adjusted as necessary in the determination of the Commission and the electric public utilities." Similarly, Commission Rule R8-60 requires that all electric public utilities develop an IRP and provide details of that IRP to the Commission with a biennial report in even-numbered years. The Commission agrees with the Public Staff, intervenors, and Duke, that it is appropriate to begin the next biennial IRP proceeding in 2024, and that alignment of the IRP and Carbon Plan update proceedings will create efficiencies and avoid duplication of efforts. The Commission also finds and concludes that it is appropriate for Duke to combine its comprehensive 2024 IRP and 2024 Carbon Plan Update filings. There is significant overlap between the two proceedings, and combining the two matters into a single, comprehensive filing is reasonable and appropriate, and will result in reduced administrative burden.

Further, it is appropriate for Duke to file an IRP update in 2023, consistent with the requirements in Commission Rule R8-60(h)(2) and (j). The most recent IRP filing made by DEC and DEP before the Commission was filed in Docket No. E-100, Sub 165 in September 2021, and the Commission emphasizes the importance of receiving updated information from the Companies before their comprehensive IRP filing in 2024, including information regarding milestones and

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development activities associated with the 2022 Carbon Plan. As discussed later in this Order, the near-term activities approved by the Commission require diligent efforts and monitoring, and the Commission expects to receive detailed information on Duke's implementation of the 2022 Carbon Plan in a frequent manner, including in each IRP or IRP Update filed by DEC and DEP. Notably, as discussed later in this Order, the filing of an IRP Update in 2023 will incorporate the IRA, therefore providing the Commission, the Public Staff, and interested parties with information on how the new federal legislation is impacting the energy policy landscape in Duke's service territories, the Company's resource planning, and the Carbon Plan.

With respect to timing, the Commission agrees with the Public Staff that syncing the two proceedings would result in a 2024 Carbon Plan Update being adopted in 2025. However, the Commission is persuaded that this timing is reasonable, as it will allow for enough time to pass following the adoption of the initial 2022 Carbon Plan for the gathering of sufficient information and data to allow the Commission, Duke, the Public Staff, and interested parties to assess the progress of Duke's implementation and any updates in cost, load projections, technologies, and other factors relevant to whether revisions to the 2022 Carbon Plan are appropriate. In addition, the Commission notes that such a timeline will also allow for a full review of the 2024 Carbon Plan Update/IRP filings made by Duke, including discovery, stakeholder engagement, public and expert hearings, and the filing of testimony and comments.

Based on the foregoing and the entire record in this proceeding, the Commission concludes that it is appropriate for Duke to file an IRP Update in 2023,

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and to include in the 2023 IRP Update milestones and development activities associated with the 2022 Carbon Plan, as well as impacts of the IRA. The Commission further concludes that it is appropriate to delay Duke's next comprehensive IRP filing to 2024, and for Duke to combine its comprehensive 2024 IRP and 2024 Carbon Plan Update filings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is contained in Duke's Petition for Approval, the initial and responsive comments of the Public Staff, intervenors, and Duke, and the entire record in this proceeding.

In its Petition for Approval, Duke asked that the Commission direct the Companies and the Public Staff to develop and propose for comment by January 31, 2023, revisions to Commission Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan adopted by the Commission. Duke Petition for Approval, 17.

In its Initial Comments, the Public Staff agreed that revisions to Commission Rule R8-60 are necessary but requested that the deadline for the filing of proposed revisions be April 28, 2023, to allow more time for all parties to develop draft rules. Public Staff Initial Comments, 162-63. The Public Staff reiterated that request in its responsive comments, also recommending that, in the interest of efficiency, the Commission direct the Companies and the Public Staff to work together to develop proposed rule revisions, and then to convene a stakeholder process by which interested parties can provide feedback on those proposed revisions before they

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are filed with the Commission on or before April 28, 2023. The Public Staff also recommended that interested parties have the opportunity to submit comments on the proposed revisions, as well as alternative proposals. Public Staff Responsive Comments, 3.

In its responsive comments, Duke stated that the Companies do not oppose the Public Staff's recommendation that the deadline for filing proposed revised rules should be extended to April 28, 2023. Duke noted that the extended deadline would allow more time for all parties to engage and develop draft rules. Duke Responsive Comments, 58-59. CIGFUR also supported the proposed April 28, 2023 deadline. CIGFUR Responsive Comments, 3-4.

NCSEA *et al.* commented that they agreed that all parties should be afforded more time to develop draft rules, and that, prior to any party proposing rule revisions, the Commission should appoint an independent third party or Commission staff to facilitate a collaborative process for interested parties to propose revisions to Rule R8-60. NCSEA Responsive Comments, 4-5. Similarly, the AGO commented that any schedule for modifying the Commission's rules should allow sufficient time for input, and that all interested parties should be encouraged to participate. AGO Responsive Comments, 5-6. CCEBA also noted in its responsive comments that any rule revision process should be conducted with full involvement of stakeholders and the public. CCEBA Responsive Comments, 1.

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In its November 19, 2021 Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines, the Commission indicated that it will initiate, by separate order and subsequent to undertaking the development of the initial Carbon Plan, a rulemaking proceeding to revise Commission Rule R8-60 to reflect the approach of syncing the Carbon Plan with the IRP proceedings. First, to the extent that Duke and the Public Staff determine that revisions to rules other than Commission Rule R8-60 are necessary to sync the Carbon Plan with the IRP proceedings, they may propose such revisions for Commission consideration. The Commission also finds the proposed deadline of April 28, 2023, for the filing of proposed rule revisions to be reasonable and expects that such a timeframe will allow for substantial and meaningful engagement with interested stakeholders.

Based on the foregoing and the entire record in this proceeding, the Commission concludes that is appropriate for Duke and the Public Staff to work together to develop proposed revisions to Commission Rule R8-60, and to then convene a stakeholder process by which interested parties can provide feedback on those proposed revisions before they are filed with the Commission on or before April 28, 2023. It is also appropriate for interested parties to have the opportunity to submit comments on the proposed revisions, as well as alternative proposals. The Commission declines at this time to appoint an independent third party or Commission staff to facilitate a collaborative rule drafting process for stakeholders.

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EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is contained in Duke's Proposed Carbon Plan, Duke's Petition for Approval, the testimony of Public Staff witnesses Dustin R. Metz, Jeff Thomas, and David Williamson, the direct and rebuttal testimony of Duke witnesses Snider, McMurry, Quinto, and Kalemba (Modeling Panel), and the entire record in this proceeding.

In its Proposed Carbon Plan, Duke explained that Section 110.9 requires the Commission to take all reasonable steps to achieve a 70% reduction in carbon emissions from electric generating facilities owned or operated by electric public utilities in North Carolina by 2030 from 2005 levels, and carbon neutrality by 2050. Duke further explained that a prerequisite to determining how to meet those targets is a clear understanding of the baseline for measuring progress toward meeting the goals. Duke's Proposed Carbon Plan, Executive Summary, 7-8.

Duke explained its methodology for determining the 2005 CO_2 emissions baseline in Appendix A of its Proposed Carbon Plan. It explained that the CO_2 emissions regulated under Section 110.9 fall into three categories: (1) electric generation facilities owned by the electric public utility; (2) electric generation facilities operated by the electric public utility; and (3) electric generation facilities operated on behalf of the electric public utility. Duke then described the sources of the CO_2 emissions data it used in its analysis, as well as the methodology it used to calculate the 2005 baseline. As a result of its calculations, Duke estimated the 2005 emissions baseline to be 75,865,188 short tons of CO_2, compared to a total of 41,003,085 short tons of CO_2 emitted in 2021. Duke's Proposed Carbon Plan, Appendix A, 2-7. In its Petition for Approval, Duke asked that the Commission approve the Companies' methodologies outlined in Appendix A of the Proposed Carbon Plan for tracking compliance with the emission reduction targets in Section 110.9. Duke Petition for Approval, 17.

Public Staff witness Metz testified that the Public Staff had multiple meetings with the North Carolina Department of Environmental Quality and Duke's staff to review historical emissions data and related information prior to Duke's filing of its Proposed Carbon Plan. He explained that, based on the Public Staff's review, Duke has correctly accounted for the level of carbon output from its facilities in 2005 for purposes of complying with Section 110.9. Tr. vol. 21, 108.

No party disputed the 2005 baseline emissions calculation or methodology used by Duke to perform the calculation. Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that Duke has appropriately established the 2005 baseline level of CO_2 emissions from its facilities for purposes of tracking compliance with Section 110.9.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the direct testimony of Duke witness Kendal Bowman, the direct and rebuttal testimony of the Duke Modeling Panel, the testimony of Public Staff witnesses Jeff Thomas and David Williamson, the testimony and responsive comments of Redtailed Hawk

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Collective *et al.*, Brad Rouse, NCSEA *et al.*, Tech Customers, AGO, CPSA, and CCEBA, and the entire record in this proceeding.

In her direct testimony, Duke witness Bowman stated that the IRA was enacted on August 16, 2022. She explained that the Companies are actively continuing their analysis of the IRA, which contains many incentives associated with clean energy resources and electrification technologies. Tr. vol. 7, 57-58. The Duke Modeling Panel also addressed the IRA in their direct testimony, stating that implementation of the IRA will be one of the key developments that will be influential in updating the Carbon Plan for the 2024 update proceeding. *Id.* at 215. They explained that Duke did not account for the IRA in its original load forecast because the IRA was not passed until after Duke's initial modeling had been completed. Tr. vol. 8, 215.

Public Staff witness Thomas, discussing more generally the appropriateness of updating commodity and generation resource price forecasts after the initial Carbon Plan modeling has been performed, stated that modeling inputs must be finalized at some point, lest the biennial IRP proceeding devolve into an endless cycle of updating assumptions and re-running the models. He further stated that the consequences of this reality are tempered by procedural schedules that allow for frequent IRP updates and a reliance on robust portfolios that cover a range of scenarios. With respect to the IRA specifically, witness Thomas stated that while the IRA has extended the Investment Tax Credit (ITC) for renewables and included energy as a qualifying resource for the ITC, the tax credits are dependent on new factors (such as industry prevailing wages, siting,

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and source of raw materials), can be replaced with a Production Tax Credit (PTC) once energy production begins, and may eventually become technologically neutral. He also stated that financing for new nuclear development, including PTCs for nuclear resources, also appears to be included in the legislation, but the capital costs for new nuclear facilities are speculative at best. Tr. vol. 21, 72.

In sum, witness Thomas argued that incorporating the impacts of the IRA into Duke's models would be complex, as it is dependent upon Internal Revenue Service guidance and renewable developers and utilities being able to capture bonus tax incentives to the benefit of ratepayers. Witness Thomas also acknowledged that the IRA could have an impact on the supply chain for solar. However, he did not take the position that Duke should be directed to update its Carbon Plan with the impacts of the IRA because the Public Staff's modeling suggests that the resource selection within the timeframe of the near-term action plan is less sensitive to capital costs and is largely dependent upon model constraints, such as the first available selection year, the amount that can be interconnected annually, and annual carbon dioxide limits. Witness Thomas further described how the IRA would not only have an impact on the cost of certain renewable and energy storage resources, but could also impact electrification and energy efficiency, and that the net impact on load is complicated and would need to be studied by load forecasting experts. Tr. vol. 21, 82, 242. Public Staff witness Williamson stated that when Duke begins to prepare for its 2024 Carbon Plan Update/IRP, it will incorporate these effects on load. Tr. vol. 22, 381.

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Several intervenors emphasized that the IRA will have a significant impact on resource costs, least cost determinations, technologies, and other factors that impact Carbon Plan considerations. Redtailed Hawk Collective *et al.* Responsive Comments, 2-5; Tr. vol. 22, 88-89, 114; Tr. vol. 23, 236, 240-250; Tr. vol. 24, 179-181; Tr. vol. 25, 67-68, 241-247, 274-75, 293-94; Tr. vol. 26, 37, 248-49. For example, in their responsive comments, NCSEA *et al.* noted that the IRA has dramatically altered the policy landscape in ways that will significantly reduce the costs of resources that can help the Companies achieve the state's carbon reduction requirements. They therefore recommended that, to the extent the 2022 Carbon Plan's short-term action plan does not take policies under the IRA into account, there be an opportunity to provide supplemental modeling to update the Carbon Plan in early 2023 for the limited purpose of determining whether any modifications to the short-term action plan would be in the public interest. NCSEA *et al.* Responsive Comments, 1-2. Likewise, the AGO argued that the Commission should update the 2022 Carbon Plan to incorporate the impact of the IRA before syncing the timing of the Carbon Plan update proceedings and the Companies' IRP proceedings. AGO Responsive Comments, 4-5.

In their rebuttal testimony, the Duke Modeling Panel stated that the Companies agree that the tax credits and other incentives in the IRA will be beneficial for customers and may offset recent upward pressures on technology costs that have occurred since the development of the Proposed Carbon Plan. They added that the IRA incentives will lower costs for solar, storage, wind, and nuclear, and that in order to provide some preliminary high-level insight into the

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impact of the IRA and test the robustness of the Companies' proposed near-term actions, they have conducted additional sensitivity analyses. The Duke Modeling Panel also stated that the Companies must "snap a chalk line" at a specific point in time for purposes of fixing the modeling inputs and assumptions so that they can move forward with developing a plan. They argued that the modeling and analysis provided thus far in this proceeding are sufficient to support the Companies' near-term actions. The Duke Modeling Panel also testified that the IRA is very complex, and that the Companies are continuing to evaluate tax implications and the applicability of the new law and are confirming initial interpretations of the incentives for each resource. Tr. vol. 27, 48-50, 70-71. Lastly, the Modeling Panel provided a description of the preliminary modeling sensitivity analysis they conducted based on their initial review of the IRA, as well as a description of the results of that preliminary modeling. *Id.* at 27, 72-75.

While the Commission agrees with the parties that the IRA will likely have a significant impact on the Carbon Plan, including resource costs and the development of new and emerging technologies, it is also cognizant that the IRA was passed by Congress on August 16, 2022, three months after Duke completed its initial modeling in this proceeding, less than one month before the beginning of the evidentiary hearing, and a little over four months before the Commission's deadline for adopting the 2022 Carbon Plan. Such a timeline simply does not allow for the incorporation of the IRA into Duke's modeling or for a full review of the potential impacts of the legislation. The Commission further agrees with the Public Staff and Duke that modeling inputs must be finalized at some point, lest a

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proceeding "devolve into an endless cycle of updating assumptions and re-running the models." Tr. vol. 21, 72. Therefore, the Commission determines that it is appropriate for Duke to incorporate the impacts of the IRA into the 2023 IRP Update and the 2024 Carbon Plan Update/IRP, and any CPCN applications filed in the interim, so that Duke, the Public Staff, interested parties, and the Commission will have more comprehensive information on the impacts of the IRA on the Carbon Plan. If such information necessitates an adjustment to the Carbon Plan in the 2024 Carbon Plan Update/IRP, the Commission will make an adjustment at that time.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that it is appropriate for the 2023 IRP Update and the 2024 Carbon Plan Update/IRP to incorporate the impacts of the IRA.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-19

The evidence supporting these findings of fact is contained in the initial comments of the Public Staff, the testimony of the Duke Modeling and Transmission Panels, the testimony of Public Staff witnesses Jeff Thomas and Dustin R. Metz, the testimony of NCSEA *et al.* witness Tyler Fitch, and the entire record in this proceeding.

In its initial comments, the Public Staff recommended that Duke develop a new portfolio incorporating 13 specific changes to its modeling. The Public Staff further stated that the intent of this additional model run is to validate the short-term execution plan proposed by Duke. Public Staff Initial Comments, 20-23.

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In its direct testimony, the Duke Modeling Panel explained that it had worked with the Public Staff to incorporate its suggested changes to the modeling and developed two supplemental portfolios, SP5 and SP6. Duke also explained that it had incorporated additional changes requested by CPSA, and that several of the changes made to the modeling aligned with the those recommended by the AGO and CCEBA, as well as other intervenors. Tr. vol. 7, 244-53. The Duke Modeling Panel also provided a comparison of the assumptions used in SP5 and SP6, versus those used in P1 through P4. *Id.* at 248-50. The Duke Modeling Panel explained that, at a high level, the development of SP5 and SP6 most closely aligned with the development of P2 and P3, respectively. They stated that SP5 targets achieving the interim CO_2 emissions reduction goals in 2032, similar to P2, and that SP6 targets meeting those goals in 2034. *Id.* at 250. The details of the supplemental modeling and the results of that modeling are provided in Modeling and Near-Term Actions Panel Exhibit 1.

The Duke Modeling Panel described some of the key input assumption changes between the Companies' Proposed Carbon Plan portfolios and SP5 and SP6. They explained that SP5 and SP6: used a no-Appalachian gas scenarios as the base planning assumption, with Transco Zone 4 supply to existing CC units and enough firm supply for two large or three small CC units; removed hydrogen as a fuel; and assumed that the last 5% of the 2050 carbon neutrality target would be met with carbon offsets. In addition, SP5 allowed the first SMR to be selected in June 2032. *Id.* at 250-52.

In their testimony, the Duke Modeling Panel also explained that SP5 and SP6 incorporated modeling assumption changes recommended by other intervenors. For example, CPSA had recommended the High Solar Interconnection Sensitivity, and the AGO and other intervenors recommended incorporating modeling functionality allowing the capacity expansion and production cost models to determine the dispatch of batteries paired with solar, a change which the Duke Modeling Panel found had merit, as well as an additional S+S configuration that includes a battery with higher energy capacity than was included in P1 through P4. *Id.* at 253. The Duke Modeling Panel also testified regarding the modeling and assumption changes in SP5 and SP6 with which the Companies disagreed, as well as several recommendations from intervenors that Duke chose not to include in the supplemental portfolios. *Id.* at 254-57. Lastly, they listed several additional modeling updates and updates to inputs that were included in SP5 and SP6. *Id.* at 257-60. Overall, the Duke Modeling Panel concluded that the supplemental modeling results supported the near-term actions that were outlined in the Proposed Carbon Plan. *Id.* at 260-61, 266-68, 344.

Public Staff witness Thomas testified that Duke's supplemental portfolios addressed the majority of the Public Staff's recommendations in its initial comments, and that the Public Staff recommends that the Commission incorporate the changes reflected in SP5 and SP6 into its 2022 Carbon Plan. He explained that the supplemental portfolios included the following changes recommended by the Public Staff: (1) variations on interim compliance, with SP5 achieving the interim compliance goal by 2032, and SP6 by 2034, and availability of SMRs and

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offshore wind; (2) optimized S+S modeling and one additional S+S configuration; (3) removal of cumulative limits on battery storage; (4) removal of hydrogen fuel and associated costs; (5) no access to Appalachian gas, limited incremental gas from existing sources, and other natural-gas-related assumptions; and (6) an energy hurdle transfer rate between DEC and DEP imposed during capacity expansion modeling. Tr. vol. 21, 35-36. Witness Thomas emphasized that SP5 and SP6 generally added more solar and batteries than Duke's original portfolios, with significantly less offshore wind, and provided a comparison of the cumulative system resource additions for each portfolio by 2035. *Id.* at 36-37.

Witness Thomas next testified regarding the out-of-model steps taken by Duke to override the endogenous selection of resources in EnCompass. For example, he discussed the battery/CT optimization step (Battery Replacement step) used by Duke, wherein Duke removed 35% of the economically selected battery storage in all portfolios, replacing it with CTs. He explained that the Battery Replacement step may not be reasonable for planning purposes and stated that Duke should have allowed the model to economically select battery storage without replacing 35% of battery capacity with CTs, and if reliability issues were identified during the LOLE Validation step, CTs could be added at that point to meet LOLE thresholds. *Id.* at 43-47. Regarding whether the Battery Replacement step results in cost savings for ratepayers, as argued by Duke, witness Thomas stated that he found that the overall cost savings are relatively minor and are sensitive to assumptions regarding natural gas prices and battery storage capital costs. He further stated that the Public Staff tested the robustness of Duke's

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savings estimates under two sensitivities: a 30% reduction to battery storage capital costs, representing the investment tax credit that is now available to standalone energy storage systems; and the use of Henry Hub natural gas prices forecasted in the 2022 Annual Energy Outlook, Low Oil and Gas Supply case. He stated that the Present Value of Revenue Requirement (PVRR) savings were dramatically reduced for each portfolio, and that in P2 and P3 the replacement of 35% of battery storage with CTs resulted in a cost increase under these assumptions. *Id.* at 47-49.

Public Staff witness Thomas then discussed the CTs that were forced into the model by Duke to replace batteries and S+S in the Battery Replacement step. He stated that it does not appear that the CTs are necessary, explaining that they are largely capacity-only resources, and that, except for a spike in 2028 after the first CT is constructed in SP5, the capacity factor for either class of CTs never reaches above 2% until 2049. He added that the production cost model runs indicate that new CTs tend to operate in only one or two months each year, typically only in the winter, and are not regularly called upon to provide system flexibility. Witness Thomas also stated that this is particularly concerning because the reserve margins for both DEC and DEP in SP5 are quite elevated relative to Duke’s 17% planning reserve margin, and that this elevated reserve margin is likely the reason why the economic analysis favored CTs over batteries and S+S in Duke’s Battery Replacement step. According to witness Thomas, because the forced-in CTs generate almost no energy and consume very little natural gas in the model, the expected production cost increase associated with additional CTs

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is very low, tilting the economic analysis toward replacing more batteries and S+S with CTs. He added that if the forced-in CTs were to increase their capacity factors relative to what is modeled, the economic analysis supporting the Battery Replacement step becomes even more questionable as production costs increase. *Id.* at 49-51. Witness Thomas argued that Duke should have allowed the model to economically select battery storage without replacing 35% of battery capacity with CTs, and that if reliability issues were identified during the LOLE Validation step, CTs could be added at that point to meet LOLE thresholds. He testified that this would be similar to the process followed by Duke while evaluating alternative plans submitted by NCSEA *et al.* and Tech Customers. Tr. vol. 21, 46-47.

Witness Thomas summarized his concern that the Battery Replacement step: (1) produces minimal ratepayer savings; (2) is not robust to changes in capital costs, fuel prices, or natural gas consumption relative to Duke's assumptions; (3) forces in CTs to serve as essentially capacity-only resources, resulting in elevated reserve margins; and (4) is potentially redundant to the more detailed LOLE Validation analysis. *Id.* at 51-52.

With respect to other out-of-model steps, Public Staff witness Thomas and Public Staff witness Metz both discussed the endogenous selection of coal retirement dates. *Id.* at 52, 116-17. Witness Metz testified that he generally does not support maintaining the operation of any generation unit beyond its economic life and stated that not all system operational factors can be captured within a model. As a result, the retirement schedule may need to reflect impacts on the transmission system, modifications to the existing transmission system, coal inventory and supply, and maintenance of system reserves to account for system abnormalities that occur outside of a model. *Id.* at 116-17. Witness Thomas testified that the LOLE Validation step appears reasonable and is consistent with the requirements of Section 110.9 regarding system reliability. *Id.* at 52.

Public Staff witness Thomas also discussed the eight-year optimization period used in Duke's modeling. He explained that the optimization period is the length of time over which the model optimizes resource selection and dispatch, and that an eight-year optimization period indicates the model can only "see" costs and system conditions over an eight-year period (with a one-year extension) and is blind to any model inputs beyond the optimization period. He stated that an eight-year optimization period is problematic, particularly due to the hydrogen conversion costs in later model years. Witness Thomas explained that the Tech Customers' Gabel Report and NCSEA *et al.*'s Synapse Report used 28-year and 15-year optimization periods, respectively, and that both intervenors were able to complete their model runs by adjusting other settings to reduce run times, such as by increasing the Mixed Integer Programming (MIP) Stop Basis (a measure of how accurate the model results are relative to the optimal result). Witness Thomas recommended that in future Carbon Plan proceedings, the Commission direct Duke to utilize an initial optimization period of no less than 15 years and relax the MIP Stop Basis as necessary and within reason to reduce model run times. *Id.* at 53-54.

With respect to the annual interconnection limits for solar and storage resources, witness Thomas stated that Duke, in its Proposed Carbon Plan, limited

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the economic selection of most resources to 2027 at the earliest, including onshore wind, solar, and S+S, and put annual limits on the amount of each resource that could be added to the grid. He testified that he agreed with Duke that the question is not whether a limitation or constraint is appropriate, but instead what specific limitation is the most reasonable forecast of Duke's ability to interconnect resources in the future. Witness Thomas testified that the Public Staff views the base projected annual solar interconnections used by Duke in P2 through P4, and in SP5 and SP6, to be reasonable for modeling purposes; in fact, he testified that meeting this baseline would be a "huge challenge" coinciding with the interconnection of other resources as well as constructing required transmission upgrades. He further noted that Duke will update future Carbon Plans based on the results of the 2022 Solar Procurement and future DISIS clusters. He also stated that it is unlikely that substantial amounts of solar procured through the 2022 Solar Procurement will come online prior to 2026 due to required transmission upgrades but added that it is possible that some competitive projects located outside of the Red Zone Transmission Expansion Plan (RZEP) could achieve operation in 2025. He explained that while Duke prevented the addition of economically selected solar prior to 2027, it forced solar into the model between 2023 and 2026, based upon projections of solar currently in the interconnection queue successfully interconnecting and through ongoing programs such as the Competitive Procurement of Renewable Energy (CPRE) and Green Source Advantage. He noted that the Public Staff expects that the bulk of the solar capacity procured through the 2022 Solar Procurement will come online in late 2026 and 2027, and

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that the Public Staff therefore finds it reasonable for Duke to force in expected solar capacity from 2022 through 2026 and allow EnCompass to economically select solar beginning in 2027. *Id.* at 54-58, 318.

In its capacity expansion models, Duke placed limits on the amount of battery storage that could be added over the planning horizon. Specifically, Duke limited the amount of four-hour battery capacity that can be added over the entire planning horizon to 1,500 MW in DEC and 1,800 MW in DEP. The Public Staff proffered that Duke stated that these limits were put in place to reflect the declining effective load carrying capability (ELCC) of battery storage. Duke confirmed that this was the reasoning behind the cumulative limit. Tr. vol. 11, 66. In the final capacity expansion model run for each portfolio, this project limit is reached in 2035 (P1) or 2038 (P2 through P4). In later post-processing steps, Duke removed at least 35% of four-hour battery storage capacity and replaced it with CTs, as described in the Proposed Carbon Plan Battery-CT Optimization Step. *Id*. at 128-29. Therefore, in its Initial Comments the Public Staff recommended that Duke remove or increase the cumulative limits on four-hour battery storage and include this modification in the SP5 model run requested by the Public Staff, as well as in all future Carbon Plan filings. The Public Staff also recommended that in the absence of known technical limits, Duke should avoid the use of cumulative limits on any resources in future Carbon Plan filings. *Id*. at 130.

Witness Thomas also testified that the Public Staff did not find the cumulative limits on S+S and standalone storage resources to be reasonable for modeling purposes, arguing that a more appropriate assumption would be to utilize

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declining ELCC curves that reflect the addition of solar and storage capacity. He stated that SP5 and SP6 removed the cumulative limitation on battery storage and extended the ELCC curve in this manner. He emphasized that Duke should avoid the use of cumulative resource limits that do not reflect known and measurable technical limits. *Id.* at 58. In addition, the Public Staff noted that for battery storage resources with operable lives shorter than the planning horizon, Duke's model essentially assumed they would be replaced in-kind in perpetuity. The Public Staff recommended that Duke address in its 2024 Carbon Plan whether this assumption is appropriate or if such resources should potentially be retired and replaced with different resources at the end of their useful life. Public Staff Initial Comments, 134.

With respect to model constraints placed on wind resources by Duke, witness Thomas testified that there are currently two onshore wind farms in North Carolina – the operational 208 MW Amazon Wind facility in Perquimans and Pasquotank Counties, and the planned 189 MW Timbermill Wind facility in Chowan County, both of which are in PJM's territory. He gave the history of the projects and described the timelines under which they became permitted and, in the case of Amazon Wind, operational, and stated that given this history and the absence of any wind projects in Duke's interconnection queues, it is unlikely that any onshore wind projects in Duke's territory will be able to achieve operation prior to 2029. He added that onshore wind imported from PJM or other neighboring areas would require firm point-to-point transmission service and would be subject to the appropriate border or wheeling charge. He concluded that, absent convincing evidence that large quantities of onshore wind will be available to Duke earlier than

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2029, or that more than 300 MW can be interconnected annually, the Public Staff finds Duke's assumptions with respect to onshore wind to be reasonable for the development of the Carbon Plan. He added that because the near-term action plan calls for the procurement of 600 MW of onshore wind, if the Carbon Plan adopted by the Commission includes onshore wind, Duke should be in a position to provide updated assumptions in the 2024 Carbon Plan proceeding. Tr. vol. 21, 59-61.

Public Staff witness Thomas also discussed offshore wind, explaining that Duke had prevented the selection of offshore wind prior to 2030. He discussed the lease areas owned by Avangrid, TotalEnergies Renewables USA, LLC, and Duke Energy Renewables Wind, LLC. He stated that, at this time, given the substantial uncertainties regarding offshore wind in the Carolinas, the Public Staff views 2029 as a reasonable first year for offshore wind for modeling purposes. He noted that SP5 and SP6 do not economically select offshore wind until the 2040s, which would provide the Commission with additional time relative to a 2029 in-service date to evaluate the least-cost offshore wind resource. *Id.* at 61-62.

Regarding the configurations of S+S resources selected by Duke, Public Staff witness Thomas explained that because all models are approximations of reality and there are essentially infinite configurations of S+S available during project design, some approximations must be made to reduce model complexity. He noted, however, that intervenors involved in the development of S+S resources have stated that more than two configurations should be included. Witness Thomas stated that the Public Staff found these suggestions reasonable and noted that SP5 and SP6 include one additional configuration of S+S requested by

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intervenors. He recommended that Duke file preliminary 2023 Solar Procurement results in the 2024 Carbon Plan Update proceeding and explain how its S+S modeling is influenced by the results of the 2023 Solar Procurement. He added that the Public Staff also supports CCEBA and CPSA's recommendation that Duke begin working with stakeholders in advance of the 2023 DISIS to develop appropriate S+S PPA structures that can appropriately value third-party S+S resources. *Id.* at 63-64.

Public Staff witness Thomas testified further that Duke did not appropriately model S+S resources. The AGO, CCEBA, CPSA, and the Tech Customers also identified this issue in their initial comments. Witness Thomas explained that the fixed output profile used by Duke to model S+S resources results in a less flexible S+S resource, as the storage dispatch behavior is determined outside of the model and is based on rate periods established in the 2018 avoided cost proceeding. He noted that this issue was addressed in SP5 and SP6, resulting in significantly increased levels of S+S being selected by the model. He argued that the results in SP5 and SP6 support the Public Staff's recommendation that Duke should model S+S resources in such a way as to allow EnCompass to optimize the storage component and not use a fixed dispatch profile based on historical avoided cost rate periods. Witness Thomas acknowledged Duke's concerns regarding model run times and complexity and stated that longer model run times are a reasonable tradeoff for more accurate S+S resource dispatch in this proceeding. He also encouraged Duke to explore other methodologies for simplifying S+S dispatch or otherwise controlling model run times, as long as it will continue to allow the model to utilize the full benefit of S+S resources. He added, however, that using a fixed dispatch profile that is based on historical avoided cost pricing periods is inappropriate for modeling purposes and should not be permitted in the 2024 Carbon Plan Update. Witness Thomas also testified on cross examination that he saw value in potentially modeling S+S resources as alternating current (AC)-coupled, or as direct current (DC)-coupled with bidirectional inverters, which would allow them to charge from the grid. *Id.* at 64-67, 233.

The Public Staff stated that in addition to the lack of flexibility modeled for these S+S resources, Duke assumed that all S+S resources will have DC-coupled battery storage and that the storage resource will be unable to charge from the grid. This assumption further limited the flexibility of S+S resources in the model and was particularly questionable given that S+S resources can still access some or all of the federal solar photovoltaic (PV) investment tax credit, so long as at least 75% of the battery's energy input is from the solar PV system. Public Staff Initial Comments, 123-24. Witness Thomas stated that he saw value in having bidirectional inverters, which would allow a DC-coupled battery storage resource charge from both the DC solar output and the grid. He also noted, in response to concerns of CCEBA and CPSA, that the Public Staff believes that the 2023 Solar Procurement will reveal what S+S configurations are economical for developers, and that the 2024 Carbon Plan Update/IRP should reflect this variety. *Id.* at 64-67, 233.

Regarding natural gas prices, Public Staff witness Thomas testified that he found the natural gas price forecasting methodology used in the Proposed Carbon

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Plan to be reasonable. He stated that, generally, the Public Staff finds Duke's methodology of using five years of forward market prices, followed by a three-year transition to an average of multiple fundamental forecasts, to be an improvement over past IRPs. He concluded that the Public Staff is not recommending any changes to natural gas forecasting methodologies at this time. *Id.* at 67-68.

Witness Thomas also described rate increases occurring in Dominion Energy North Carolina's territory as a result of natural gas commodity price spikes and stated that the Public Staff is concerned that significantly increasing Duke's natural gas fleet, particularly its high-capacity factor CCs, creates substantial risk that Duke ratepayers may experience similar rate increases. He added, however, that the risk of overreliance on natural gas may be overstated by only reviewing installed capacity, and that while all four of Duke's portfolios maintain roughly the same percentage of natural gas capacity by 2040, they all significantly decrease the total amount of natural gas burned annually. He stated that natural gas fuel consumption peaks around 2026 in all portfolios and steadily declines through the remainder of the planning period, reducing ratepayers' exposure to volatile natural gas prices over time. Witness Thomas also stated that this reduction should mitigate some of the concerns regarding natural gas price volatility in the long run, although it does raise the issue of whether natural gas plants built prior to 2030 will become underutilized, and potentially stranded, in later years as they become primarily capacity resources. He noted that Duke's use of an eight-year optimization period may have caused its models to select natural gas in 2028 and

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2029, without considering the stringent carbon reduction targets and higher gas prices in later years. *Id.* at 67-70.

Also regarding natural gas prices, witness Thomas testified that Duke should not update its natural gas prices used in the model in the current proceeding, and that the Carbon Plan should utilize the most recent estimates of commodity prices that are available at the time the modeling is performed. He stated that modeling for the Carbon Plan is a complex task, and, as in the IRP dockets, typically begins six to nine months in advance of any filing, at which time fuel price forecasts are typically "locked in." He noted that none of the fundamental forecasts anticipated the elevated prices that occurred in 2022, and the forward markets also failed to anticipate this increase. He stated that the Public Staff recognizes that modeling inputs must be finalized at some point, lest the biennial IRP proceeding devolve into an endless cycle of updating assumptions and re-running the models, and that the consequences of this reality are tempered by procedural schedules that allow for frequent IRP updates, and a reliance on robust portfolios that cover a range of scenarios. He added that, if fundamental natural gas price forecasts of falling average gas prices between 2023 and 2027 prove correct, updating the model to reflect current high prices would have a minor, and likely immaterial, effect on resource selection, as new natural gas resources are generally not selected prior to 2027. *Id.* at 71-72.

Witness Thomas also noted that the 2024 Carbon Plan Update proceeding will utilize updated natural gas price forecasts, and that if future gas prices appear elevated, this forecast will be reflected in revised near-term action plans. Likewise,

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he testified that Duke must seek a CPCN prior to construction of any natural gas generation, and that the reasonableness of a proposed natural gas plant, including an analysis of the most recent gas price forecasts and market conditions, will be evaluated in detail after the CPCN application is filed. *Id.* at 72-73.

Public Staff witness Thomas testified that Duke's assumptions regarding natural gas supply were not reasonable and emphasized its concerns regarding the availability of Appalachian gas to natural gas facilities in North Carolina. He noted that SP5 and SP6 included natural gas assumptions recommended by the Public Staff, and that the changes modeled in SP5 have resulted in a shift of the location of CC plants. In the original four portfolios, one CC was selected in DEC and one in DEP, both in 2029. In SP5, both CCs are located in DEC's territory, and one CC is delayed until 2030. He stated that even if Appalachian gas is made available to North Carolina via the Mountain Valley Pipeline (MVP) and the MVP Southgate Pipeline, it is unclear whether this gas will have a firm pathway to locations in DEC's territory. Witness Thomas concluded that the Public Staff supports the "No App Gas" supply assumptions used in SP5 and SP6, and noted that developments related to the MVP and MVP Southgate projects would be a matter of debate in future CPCN proceedings and Carbon Plan updates. *Id.* at 73-74.

The Public Staff identified in its initial comments concerns with Duke's use of Henry Hub Zone 4 and Zone 5 pricing in the EnCompass model. The Public Staff requested that future EnCompass model runs use an average of Zone 4 and 5 pricing for existing and future CCs, rather than the current practice of assigning the cheapest gas to the most efficient new generators. Assignment of the lowest cost natural gas to a generator has the effect of making a new natural gas generation facility appear more favorable relative to how natural gas prices will be assigned in annual fuel rider cost recovery proceedings, and relative to how the system is actually dispatched. The Public Staff stated that it believes this modeling change will more accurately reflect how average costs are recovered in annual fuel riders and would not provide new natural gas fired CCs with an unwarranted advantage over other generation sources. *Id*.

With respect to assumptions regarding green hydrogen, witness Thomas stated that while the Public Staff found Duke's assumptions to be reasonable from a methodology perspective, it is premature to include hydrogen in the model due to uncertainty around development risk, deliverability, and cost. He recommended that hydrogen not be included in the 2022 Carbon Plan adopted by the Commission and noted that SP5 and SP6 have removed hydrogen entirely from the Carbon Plan modeling, pursuant to the Public Staff's recommendations. *Id.* at 75.

Witness Thomas testified that the Public Staff finds Duke's assumptions regarding non-commercialized technologies, particularly new nuclear resources, to be reasonable for planning purposes. He explained that Duke's assumption that new nuclear resources will be available in the future is not unreasonable, and that he expects assumptions related to new nuclear resources to be updated with new information in future Carbon Plan proceedings. *Id.* at 76-77.

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Witness Thomas also testified that the Public Staff agrees with multiple intervenors that competitive procurement should be utilized to procure resources approved in the Carbon Plan, and that competitive procurement is consistent with least cost planning principles. He further stated that while solar, wind, and battery storage will be needed in great quantities over the next ten to 15 years, and Duke should procure these resources via competitive procurements, it is not clear if ratepayers would benefit from having a single all-source procurement to meet these goals, or whether resource-specific competitive procurements should be utilized. He added that the Public Staff intends to be closely involved in the development of future RFPs to ensure that ratepayers benefit from a competitive market and are protected from cost overruns. *Id.* at 79-81.

Public Staff witness Thomas found Duke's assumptions regarding resource costs and technological characteristics to be reasonable in this proceeding. He stated that the costs for all resources are in a state of flux in the current environment, with global inflation and supply chain constraints causing significant price increases for many technologies, particularly those dependent on imported raw materials or components. He added that the costs of specific resources are generally an important factor in determining the least-cost plan in a capacity expansion model, but that, given the limited types of low-carbon resources available in the near term and the urgency of the 2030 interim compliance target, model constraints are driving much of the new resource selection identified in the near-term action plan. He explained that modeling performed by the Public Staff suggests that resource selection in the near-term is not particularly sensitive to

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resource prices, particularly for renewables and storage. For example, Witness Metz testified that the Public Staff modeled an increase of the capital costs of nuclear by 18% and found nuclear was still economically selected, and witness Thomas testified that they modeled a downward adjustment of 30% to all renewable resources and found that it did not materially change the quantity of solar and storage being procured in the near term. Witness Thomas concluded that the resource costs used by Duke in its modeling are reasonable for planning purposes and based on reasonable assumptions. He further recommended that pricing information from future RFPs in Duke's territories, particularly for solar and S+S, should be used as inputs to future Carbon Plan updates. *Id.* at 81-83. Public Staff witness Thomas stated that Duke's transmission cost adders are reasonable for planning purposes and noted that some specific transmission costs were derived from historical interconnection studies. *Id.* at 83-84, 307-09.

The Public Staff stated in its initial comments that it believed the implementation of a transmission tariff, or hurdle rate, between DEC and DEP would be appropriate in the Capacity Expansion modeling to reflect costs associated with exporting power from DEP to DEC. Public Staff Initial Comments, 125.

In his testimony, Public Staff witness Metz explained that, for modeling purposes, Duke had assumed that all new carbon-emitting resources would be located in North Carolina and that its total system carbon emissions would count against the interim and 2050 emissions reduction targets. He stated that the Public Staff agrees with this approach. Tr. vol 21, 108. He also testified that, from a

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modeling standpoint, currently all new generation resources built to serve DEC or DEP load have all associated carbon emissions counted toward the emission targets, and that this appears to be appropriate given the uncertainty of where new generation resources will be built. He added that this approach reduces speculation regarding future asset locations and reduces modeling complexities. In addition, he testified that if Duke were to build new gas-fired generation resources in South Carolina or any non-North Carolina jurisdiction and exclude those carbon emissions in the capacity expansion models in future Carbon Plans, the model could select additional natural gas resources merely because of the emission headroom created by locating them out of the state. *Id.* at 110.

Duke acknowledged that its methodology for modeling S+S resources had the effect of limiting the effectiveness of S+S resources in the capacity expansion model. Tr. vol. 9, 51. Duke stated that allowing the model to independently dispatch the energy storage component of S+S resources is something it had been investigating during the development of the Proposed Carbon Plan, but found it added an extensive amount of time to the modeling. Duke went on to acknowledge that in a perfect world, it would model S+S resources as recommended by the Public Staff. Duke also stated that the dynamic dispatch utilized in the supplemental portfolios increased the amount of S+S that was selected. Duke witness McMurry testified in response to Commission questions that he believed it would become practical to allow dynamic dispatch in the model in the future. Tr. vol. 12, 20; Tr. vol. 8, 46-47.

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The Public Staff acknowledged the increased run times associated with dynamic dispatch but stated that the longer model run times were a reasonable tradeoff for the improved S+S benefit. The Public Staff urged Duke to explore other methodologies for simplifying S+S dispatch or otherwise controlling model run times but cautioned that Duke should avoid using a fixed dispatch profile based on historical avoided cost pricing periods for the duration of the planning period. Tr. vol. 21, 65-66. In response to cross examination questions from CCEBA, witness Thomas stated that in SP5 and SP6, solar and storage were modeled as two separate resources, allowing the EnCompass algorithm to dispatch storage according to the system needs in real time, which he believed was a contributing factor for the model's shift from standalone solar to S+S compared to P1 through P4. Tr. vol. 21, 231-32.

In response to testimony regarding the ability of DC-coupled storage to charge from the grid, Duke stated that the EnCompass model at the time the Proposed Carbon Plan was developed did not allow for bidirectional charging of storage, and that Duke had to choose to model S+S resources as either: (1) DC-coupled, capable of capturing clipped energy but unable to charge from the grid; or (2) AC-coupled, capable of charging from the grid but unable to capture clipped energy. Tr. vol. 8, 49-50. Duke further acknowledged that the recently released EnCompass version 6.2 does add this functionality, which Duke would review, test, and potentially utilize in future proceedings. Tr. vol. 28, 45.

NCSEA *et al.* witness Fitch testified that had the Companies utilized dynamic dispatch for S+S resources, it would likely have made an improvement to

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the economic value of those resources and would likely lead to more procurement of those resources. Witness Fitch went on to testify that the eight-year optimization period used by Duke results in choosing resources for the years 2022 through 2030 without looking into the future, and not accounting for costs or benefits for any of the resources selected in each eight-year optimization period. Witness Fitch also stated that the Companies' adjustments to the endogenously selected coal retirement dates were not sufficiently justified. Tr. vol. 24, 203, 209, 231, 270.

The Commission notes the complexity and technical nuances associated with the modeling in Duke's Proposed Carbon Plan and the alternate modeling conducted by intervenors. Because of the complexities associated with variables such as fuel costs, supply chains, capital costs, technology availability, load forecasts, and interconnection ability, some of which is discussed elsewhere in this Order, the Commission agrees with Duke, the Public Staff, and a number of intervenors that it is not necessary to select a portfolio at this time. However, the Commission is of the opinion that it is critical to refine modeling methodologies and inputs so that the Commission, the Public Staff, intervenors, and Duke can be assured that the 2022 Carbon Plan and each iteration moving forward will be based on the best information possible, despite the abundant uncertainties that arise from resource planning 28 years into the future.

Based on the record herein, the Commission concludes that SP5 is reasonable for planning purposes and as a foundation for the 2022 Carbon Plan and associated near-term procurement and development activities. In determining that SP5 is reasonable for planning purposes and that it should serve as the

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foundation for the 2022 Carbon Plan, the Commission is also determining that the modeling assumptions and methodologies encompassed in SP5 are appropriate. In addition, the Commission directs Duke to use the assumptions and methodologies in SP5 in its modeling for the 2024 Carbon Plan Update/IRP proceeding, unless significant developments occur in the interim which require certain assumptions be revisited, as provided for in this Order. As we progress through the decade and then beyond the interim goal, the objective for each iteration of the Carbon Plan and the modeling underpinning of that Carbon Plan is to develop best practices and remain open to changing our modeling practices if doing so will result in more accurate and useful information.

At this time, as shown in the testimony of the Public Staff, SP5 demonstrates that Duke's proposed near-term procurement and development activities are appropriate and that Duke should proceed with them as outlined in its Proposed Carbon Plan, with the exception of offshore wind and specific solar and S+S quantities, as discussed later in this Order.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that SP5 and the modeling assumptions therein are reasonable for planning purposes and as a foundation for the 2022 Carbon Plan and associated near-term procurement and development activities. The Commission also concludes that it is appropriate to assume, for modeling purposes, that all new carbon-emitting resources would be located in North Carolina and would count against the interim and 2050 emission reduction targets.

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In addition, it is appropriate for Duke to incorporate the results of the 2022 Solar Procurement in the 2024 Carbon Plan Update/IRP filing.

The Commission also finds that it is appropriate for Duke to incorporate the following recommendations in its modeling for the 2024 Carbon Plan Update/IRP proceeding, as well as the IRP Update if applicable: (1) utilize a dynamic dispatch of S+S resources and, to the extent feasible, incorporate bi-directional inverter capability; (2) avoid the use of cumulative resource addition limits in the absence of known and measurable technical limitations on resource potential; (3) utilize declining ELCC curves rather than cumulative capacity limits for battery storage resources; (4) address the operable lives of battery storage resources and the reasonableness of using an assumption of continual replacement of capacity with identical resources; (5) include hydrogen blending only if it can be reasonably supported by advancements in the green hydrogen industry; if hydrogen blending is included, endogenously evaluate whether it is economical to retire any natural gas assets as an alternative to converting them to run on 100% hydrogen; (6) utilize natural gas pricing and supply assumptions that reflect the most recent developments that would impact natural gas access in North Carolina, including developments regarding natural gas pipeline projects; (7) generate natural gas pricing forecasts that correspond to Duke's actual fuel procurement practices; (8) include an endogenous retirement analysis of operational coal units, subject to certain adjustments reflecting constraints that are not able to be represented in the model; (9) utilize an optimization period that balances model run times against the challenges associated with limited model foresight; (10) utilize a transmission tariff

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between DEC and DEP that simulates the non-firm service tariff in Duke's FERC-approved OATT; (11) incorporate any variances in solar bid prices, as identified in the 2022 Solar Procurement, between DEC territory and DEP territory; and (12) reflect pricing information from any RFPs in Duke's territories, particularly for solar and S+S resources, in the modeling inputs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

The evidence supporting these findings of fact is contained in Chapter Three of Duke's Proposed Carbon Plan, the initial comments of intervenors, the responsive comments of Duke and intervenors, the testimony of the Duke Modeling Panel, the testimony of Public Staff witness Jeff Thomas, the testimony of NCSEA *et al.* witness Tyler Fitch, and the entire record in this proceeding.

Chapter Three of Duke's Proposed Carbon Plan details the four portfolios initially developed by the Companies. Of those four portfolios, P1 alone meets interim compliance by 2030, while P2 meets interim compliance by 2032, and P3 and P4 meet interim compliance by 2034. The supplemental portfolios modeled by Duke after its initial filing, SP5 and SP6, met interim compliance by 2032 and 2034, respectively. Tr. vol. 21, 35-36.

In their comments, a number of intervenors expressed that the Commission should not delay the interim compliance date past 2030, or that a delay past 2032 was not yet warranted. *See, e.g.*, AGO Initial Comments, 9-13; AGO Responsive Comments, 7-11; CCEBA Initial Comments, 4-5; NCSEA *et al.* Initial Comments, 10-15; NCSEA *et al.* Responsive Comments, 6-8; CCEBA Initial Comments, 6-10;

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CCEBA Responsive Comments, 2-4; CPSA Initial Comments, 36-39; CPSA Responsive Comments, 2-5; Avangrid Responsive Comments, 5-9; Durham County Initial Comments, 2-3. For example, the AGO stated in its comments that Duke has failed to show that P2, P3, and P4, which extend compliance past 2030, are within the Commission's discretion to include in its 2022 Carbon Plan. It added that the construction of a wind or nuclear facility has not been authorized, precluding the discretion of the Commission to extend the compliance deadline past 2032, and that Duke has not shown that an extension past 2030 would "result in a more significant and material impact on carbon reduction." AGO Initial Comments, 9-13.

In its responsive comments, CIGFUR stated its position that the plain language of HB 951 treats the 2030 interim compliance target as an aspirational goal, not a mandate. CIGFUR added that HB 951 clearly requires that carbon reductions be accomplished on a least-cost basis and without compromising existing reliability, and that requiring strict adherence to the 2030 compliance deadline would be inconsistent with the least-cost mandate and also potentially with the requirement to maintain or improve existing reliability. CIGFUR therefore concluded that extending compliance beyond 2030 is allowable and would likely result in the least-cost, most reliable pathway for accomplishing the required carbon emissions reductions. CIGFUR Responsive Comments, 6-7.

In his testimony, Public Staff witness Thomas stated that while meeting the interim compliance goal by 2030 should be a priority, the Public Staff also believes it is appropriate for Duke to model multiple portfolios with different interim

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compliance dates in order to evaluate the costs and generation resource mixes that would result. He argued that without this information, it would be impossible for the Commission to evaluate whether a delay would be in the best interest of ratepayers and whether the adopted Carbon Plan meets statutorily mandated "least cost" principles. He reiterated that the Public Staff believes it is appropriate to model a delay in this 2022 Carbon Plan proceeding and in future Carbon Plan updates. Tr. vol. 21, 39-40.

Public Staff witness Thomas also testified that while the Public Staff is not recommending that the Commission preemptively authorize a delay in the meeting the interim compliance goals, it must also consider the "optimal timing and generation and resource mix" and comply with current law and practice with respect to the least-cost planning for generation. He explained that to the extent that a two-year delay allows for more achievable targets for solar, wind, and battery storage interconnections while significantly reducing costs for Duke ratepayers, the Commission should consider exercising the discretion afforded it by Section 110.9. Witness Thomas added that such a determination should be made only after Duke has demonstrated that the interconnection of sufficient resources to meet the interim compliance date by 2030 is not possible, ideally through the results of the 2022 and 2023 DISIS cluster studies. According to witness Thomas, a delay beyond two years should not be preemptively authorized in this proceeding, as the Commission has not authorized the construction of a nuclear or offshore wind facility that would require additional time to construct, and Duke has not demonstrated that achieving compliance by 2030 or 2032 would result in

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unacceptable declines in grid reliability. He concluded that delaying the compliance deadline to 2032 may allow the Commission to develop a Carbon Plan with lower costs and lower execution risk. *Id.* at 40-41.

More specifically, witness Thomas testified that the Public Staff has serious concerns about Duke's ability to interconnect the amount of renewable generation that must be installed by 2030 to meet the targets, particularly given the challenges associated with the required major transmission network upgrades, which will almost certainly involve more than only the 18 specific projects identified in the RZEP. In addition, he stated that the Public Staff is concerned that P1 is the most vulnerable to cost overruns related to delayed schedules and material price increases, as it relies heavily on aggressive additions of solar and storage, both of which are experiencing substantial near-term cost increases related to global inflation and supply chain issues. He stated that the Public Staff also found that the cost per ton of carbon abatement associated with implementing P1 relative to Duke's other portfolios exceeded the per ton Social Cost of Carbon (SCC), suggesting that the carbon reduction benefits encapsulated by the SCC would not exceed the incremental costs of 2030 interim compliance under Duke's initial assumptions. *Id.* at 41-42.

In sum, witness Thomas argued that significant uncertainty currently exists within each portfolio regarding interconnection ability, resource costs, and operational characteristics of new resource additions. He explained that execution risk is the failure to achieve modeled results in the real world due to a variety of risk factors, and that an assessment of execution risk examines whether the

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timeline for construction and commercial operation dates envisioned in the Carbon Plan are realistic. He recommended that the Commission direct Duke to take all reasonable steps to streamline its interconnection processes and procure sufficient renewable resources to meet the interim compliance date by no later than 2032. Witness Thomas further stated that if the Commission approves the Public Staff's recommended volume for the 2022 Solar Procurement, this volume would put Duke on a path toward compliance no later than 2032. *Id.* at 42-43, 236-37, 293.

NCSEA *et al.* witness Fitch stated in his testimony that a delay in the projected achievement of the emissions reduction requirement reduces flexibility if unforeseen delays occur and increases the risk of noncompliance with HB 951. He added that the Carbon-Free by 2050 analysis conducted by Synapse maintains the 2030 interim compliance deadline and allows for flexibility in later planning proceedings in the event that the Commission determines that a delay is warranted. Tr. vol. 24, 157, 159-160.

In their responsive comments, the Companies state that while they agree that the pace of CO_2 reduction is a critical objective to consider in developing a Carbon Plan, they also agree that it is appropriate and consistent with HB 951 to consider a range of portfolios. Duke commented that 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 beyond 2032, will occur in a later proceeding. The comments added that the iterative nature of the Carbon Plan supports the Commission setting a clear and

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executable near-term path while retaining optionality and discretion to evaluate the optimal least-cost path in the intermediate and long-term, including discretion to extend the interim deadline beyond 2030 or 2032. According to Duke, the ultimate determination of whether the Companies have met the 70% interim compliance target does not occur on December 31, 2022, but will instead be assessed on December 31, 2030. Duke added that, pursuant to the biennial update process, there will be at least three Carbon Plan update proceedings in the intervening years and, thus, three opportunities for the Commission and the Companies to "adjust" plans as necessary to meet the carbon reduction, least-cost, and reliability mandates. Duke Responsive Comments, 5, 11-13.

Similarly, Duke responded to intervenors' arguments that the Companies should not assume an interim compliance date beyond 2030 in any of their portfolios, and that an extension would only be appropriate after the Commission issues a CPCN for a new nuclear or offshore wind facility. Duke argued that this interpretation would improperly limit the Commission's discretion and force an absurd result, requiring the Commission to ignore the timeline for the development of resources like SMRs that require a long lead time. The Companies also reiterated that the near-term actions presented in their Proposed Carbon Plan are generally consistent with both P1, enabling interim compliance by 2030, and the other portfolios that achieve interim compliance at a later date. In addition, Duke stated that the Commission should retain its discretion to adjust the Carbon Plan in the future to ensure that the adequacy and reliability of the grid is maintained, and to consider the optimal timing and generation resource mix to achieve the

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least-cost path to compliance, including the discretion to consider portfolios that achieve the interim compliance target after 2030. *Id.* at 14-16.

During cross examination, Duke witness Snider stated that Section 110.9(4) allows for consideration of whether it is in the interest of customers to allow more time to pursue wind and nuclear resources. He raised the issue of whether a delay in the interim deadline to allow for development of those resources would result in a more meaningful contribution from those sources relative to a more expedited adoption of the emission reduction goal, with the limitations on development of any wind or nuclear resources by 2030. He added that one of the considerations that must be balanced, along with affordability, reliability, and executability, is the determination of whether allowing more time for wind and nuclear to come online is in the interest of the consumer. Tr. vol. 12, 37-39.

Duke witness McMurry also testified that Duke used different interim compliance dates in its modeling for P1 through P4 because there is risk associated with every technology. He explained that Duke did not pick one technology over another, but instead provided a suite of options for achieving the emission reduction goals, with identification of the risks for each resource. Tr. vol. 27, 258-59.

As the Commission concluded earlier in this Order, the Commission has the discretion to extend the 70% interim compliance deadline past 2030. As many parties have highlighted, the Commission's discretion to extend the deadline to 2032 is not unbounded. The Commission has the discretion "to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with 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." Section 110.9(4). Further, the Commission can extend the deadline to 2032 without utilizing the provisions in Section 110.9(4) regarding nuclear or offshore wind resources or grid reliability.

The Commission agrees with the Public Staff and intervenors that a delay beyond 2032 is premature in this proceeding, as the Commission has not authorized the construction of a nuclear or offshore wind facility that would require additional time to construct, and Duke has not demonstrated that achieving compliance by no later than 2032 would result in unacceptable declines in grid reliability. The Commission also notes that no party in this proceeding has advocated for such a delay at this time.

With respect to extending the compliance deadline to 2032, the Commission concluded earlier in this Order that SP5, which includes a 2032 interim compliance deadline, is reasonable for planning purposes and as a foundation for the 2022 Carbon Plan and associated near-term procurement and development activities. As discussed in the testimony of the Public Staff cited herein, and in the Evidence and Conclusions associated with Finding of Fact No. 7 (finding SP5 to be reasonable for planning purposes), delaying the compliance target to 2032 may lower execution risk and result in substantially lower costs to ratepayers, particularly in the short term. The Commission is committed to achieving the emission reduction requirements set forth in Section 110.9, but also finds critical

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the need to consider cost, reliability, and executability in developing the 2022 Carbon Plan. The Commission is persuaded that extending the compliance deadline to 2032 for purposes of the 2022 Carbon Plan is consistent with its authority under Section 110.9(4), is warranted based on a consideration of cost, reliability, and executability, and will likely "result in a more significant and material impact on carbon reduction."

The Commission also agrees with the Public Staff and Duke that it is appropriate for Duke to model interim compliance dates of 2030, 2032, and 2034 in the 2024 Carbon Plan Update/IRP proceeding. Such information is necessary in order for the Commission, Duke, the Public Staff, and intervenors to evaluate the costs and generation resource mixes that would result, and to assess whether a delay would be in the best interest of ratepayers, comply with the provisions of Section 110.9, and meet statutorily mandated "least cost" principles.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that it is reasonable and appropriate for the 2022 Carbon Plan to achieve interim compliance no later than 2032. The Commission further concludes that it is appropriate for Duke's filing in the 2024 Carbon Plan Update/IRP to include modeled portfolios that reach interim compliance in 2030, 2032, and 2034.

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EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact is contained in the April 5, 2022 Duke Energy Plans for Sharing of Carbon Plan Inputs and Assumptions and Further Stakeholder Engagement (Duke Plans for Sharing), the July 8, 2022 Informational Filing of NCSEA *et al.* (NCSEA *et al.* Informational Filing), the July 8, 2022 Duke Update Letter on Carbon Plan Modeling, Intervenor Engagement, and Discovery Status (Duke Update Letter), the initial comments of the Public Staff, the testimony of the Duke Modeling Panel, Public Staff witness Jeff Thomas, NCSEA *et al.* witness Tyler Fitch, and Tech Customers witness Maria Roumpani, and the entire record in this proceeding.

In its March 22, 2022 Order Regarding Data Inputs and Assumptions, and Scheduling Additional Update on Stakeholder Process Sufficiency, the Commission ordered Duke, as soon as practicable but no later than five business days after the filing of Duke's Proposed Carbon Plan, to provide complete EnCompass input and output data files to intervenors upon request and subject to any necessary confidentiality agreements. On April 5, 2022, Duke filed its Plans for Sharing in this docket. In its letter, Duke stated that it would make available to intervenors on May 16, 2022 (the date of filing of its Proposed Carbon Plan), the final EnCompass model dataset used to develop the portfolios included in its Proposed Carbon Plan.

On July 8, 2022, NCSEA *et al.* filed in this docket an informational filing regarding the EnCompass modeling datasets produced by Duke pursuant to the

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Commission's March 3, 2022 Order. In their filing, NCSEA *et al.* stated that the firm they had jointly retained, Synapse Energy Economics, Inc. (Synapse), had encountered discrepancies and difficulties in performing EnCompass modeling using the datasets produced by Duke. They further stated that these discrepancies and difficulties presented technical challenges that significantly slowed the progress of Synapse's analysis. According to NCSEA *et al.*, Synapse was unable to validate the model using the datasets provided by Duke, and it was not until June 8, 2022, that Duke confirmed the problem and provided guidance on how to work around it. Therefore, between May 16 and June 8, intervenors had access to a set of inputs and outputs that were incapable of being reconciled. NCSEA *et al.* Informational Filing, 1-3.

NCSEA *et al.* further stated that after fixing that discrete issue and following instructions for initializing the database from Duke, Synapse's EnCompass modeling continued to produce significantly different results from those provided by Duke, even though Synapse was using the same inputs. They stated that the long validation process inhibited Synapse's ability to conduct a substantive modeling analysis. NCSEA *et al.* also noted that Duke confirmed on June 8, 2022, that specific manual changes were required in order for the database originally provided to intervenors to be able to produce Duke's outputs, contrary to the intervenors' expectation that those steps would be transparent in the EnCompass database. Lastly, NCSEA *et al.* stated that unexplained discrepancies between the database provided to intervenors and the database used to generate the Carbon Plan remain, and that Synapse is unaware of any intervenor that has been able to successfully replicate the outcomes provided by Duke. NCSEA *et al.* Informational Filing, 3-4.

Also on July 8, 2022, Duke filed a letter to update the Commission and intervenors on Carbon Plan modeling and data. The letter stated that Duke had made available the final EnCompass model datasets used to develop the portfolios presented in the Proposed Carbon Plan. Duke also stated that the Companies had held informational meetings on May 19, 2022, and June 14, 2022, to provide a forum in which Public Staff and intervenor technical experts could discuss the EnCompass modeling process and best practices for utilizing the files with Duke's technical model experts. The letter further stated that the Companies had responded to an "immense" amount of written discovery, nearly 1,400 questions as of the date of the letter, from Public Staff and intervenors, including substantial questions regarding technical modeling data and assumptions. Duke Update Letter, 1-2.

In its initial comments, the Public Staff stated that it had encountered difficulties with the modeling files provided by Duke, consistent with the summary provided in the NCSEA *et al.* Informational Filing. The Public Staff stated that with support from Anchor Power Solutions (APS), the creator of the EnCompass software, the Public Staff loaded Duke's EnCompass input files into its own databases and attempted to re-run the capacity expansion and production cost models to validate that they produced the same output values Duke obtained. However, the Public Staff was unable to directly validate the output from Duke's models. The Public Staff stated that, while some slight differences might be

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expected due to variance in generator outage timing, particularly in generator dispatch, results should align closely. The Public Staff's initial attempts to run the capacity expansion models failed, and differences in dispatch decisions, emissions, and system costs were found in the production cost models. The Public Staff further commented that on June 8, 2022, Duke provided a document identifying the aforementioned issue as well as an additional issue with capacity expansion plans. However, after resolving both issues, the Public Staff re-ran the models and produced results that were closer to Duke's, but still not exactly the same. The Public Staff noted that the deviation occurred in later years, 2040 and beyond, and the Public Staff was therefore comfortable using EnCompass as a tool to determine the relative impact of some of Duke's assumptions. Public Staff Initial Comments, 36-37.

The Public Staff also stated in its initial comments that Duke utilized a series of modeling steps to arrive at the final capacity expansion plan. Some of these steps, such as estimating system reliability using the Strategic Energy and Risk Valuation Model (SERVM), require external modeling or analysis that is performed outside of the EnCompass model. The Public Staff noted that, given the complex nature of these additional steps, the novelty of the EnCompass software to the Public Staff, the delay caused by the capacity expansion model error and production model issues, and the compressed time period for these detailed and complex proceedings, the Public Staff was not able to submit its own carbon plan in this proceeding. Instead, the Public Staff used EnCompass as a tool in its investigation. Public Staff Initial Comments, 37.

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During cross examination, Public Staff witness Thomas elaborated on the issues he had experienced with the supplemental portfolio EnCompass files provided by Duke along with its direct testimony. He explained that after the Public Staff had reached out to APS regarding the data input failure, APS determined that a duplicated line in the dataset provided by Duke was causing the error, and that the Public Staff was then able to go through a several-step process to load the dataset. Witness Thomas also explained again that the Public Staff was not able to exactly replicate the outputs provided by Duke, and that he continued to see slight deviations and differences in the resources selected that were very minor, particularly by 2035, and some differences in the dispatch of resources. He noted that they mostly saw the same results through 2040, and therefore found them to be reasonable for use in the Public Staff's analysis. Witness Thomas added, however, that he was surprised that the capacity additions over time were not identical to the output files provided by Duke. Tr. vol. 21, 366-371.

On redirect examination, Public Staff witness Thomas explained that Duke had performed additional analysis, both on the front and the back end of its modeling, that made both modifying the inputs and validating the outputs challenging. He provided several examples of steps that were taken outside the model, either in proprietary tools or spreadsheets, rather than in EnCompass. For example, he stated that Duke did not calculate the revenue requirement for capital investments based upon the model's financial outputs. He explained that instead, Duke took the capacity that was built and then plugged it into an external spreadsheet that would calculate the revenue requirement of these resources

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based upon a real levelized fixed charge calculation that is external to the model. He emphasized that he did not believe this would materially affect the model, but that it certainly made it harder for the Public Staff and other intervenors to validate both inputs and output calculations for present value of revenue requirements. Tr. vol. 22, 355-56.

In addition to Public Staff witness Thomas, NCSEA *et al.* witness Fitch and Tech Customers witness Roumpani also testified regarding the issues they experienced with Duke's input and output files and with replicating their modeling steps. Tr. vol. 24, 215-17, 249-51; Tr. vol. 25, 104-05, 115-16.

During the Modeling Panel's direct testimony, Duke witness McMurry acknowledged that Duke did not, prior to posting its modeling files, take the inputs that were provided to the intervenors and run them again to make sure that they produced the outputs that were also provided to intervenors. Tr. vol. 10, 102-03. When asked why Duke thought the intervenors were not able to replicate Duke's model results, Duke witness Snider testified that this was an extraordinarily complex modeling exercise, and that Duke did not have the time to further investigate the issues intervenors may have been having. Tr. vol. 10, 103. Duke witness Snider further acknowledged that no party had been able to replicate the modeling Duke performed based on the inputs and outputs they had been provided, adding that "much of that may have been on their side." Tr. vol. 10, 105-06.

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Upon a review of the evidence, the Commission is persuaded that the errors, delays, and incomplete information encountered by intervenors hindered their efforts to conduct modeling with their own experts, independent of Duke. The Commission understands that this initial Carbon Plan proceeding has been conducted on a short timeline, thereby increasing opportunities for error and reducing the amount of time in which to correct such errors, but the Commission also stresses the importance of intervenors having access to the data used by Duke in its modeling, so that they can conduct their own modeling and present alternative analyses. It is also important for Duke to establish internal processes, which should be in place in time for the 2024 Carbon Plan Update/IRP proceeding, for validating its inputs and outputs before sharing files with intervenors. Such processes should reduce the possibility that intervenors will spend weeks troubleshooting errors that should have been corrected by Duke before sharing the inputs and outputs.

The Commission further notes the difficulties the Public Staff and intervenors experienced with modeling steps performed outside of EnCompass and concludes that it is appropriate for Duke to provide documentation of these steps to intervenors when it shares its modeling files and spreadsheets so that intervenors can validate the modeling inputs and results filed by Duke. Duke has expressed frustration with the amount of discovery it received in the present docket, and it is apparent to the Commission from the filings and testimony of the Public Staff and intervenors, that Duke may be able to reduce the amount of

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discovery it receives in future proceedings by providing more complete and transparent documentation.

The Commission finds and concludes that it is appropriate for Duke, at the time it makes its filing in the 2024 Carbon Plan Update/IRP proceeding, to concurrently provide all intervenors and the Public Staff with all modeling files, spreadsheets, and process documentation necessary to validate the modeling inputs and results filed by Duke, subject to any non-disclosure agreements. The Commission also finds and concludes that it is appropriate, prior to the 2024 Carbon Plan/IRP proceeding, for Duke to establish internal processes to test EnCompass model input files to ensure that they can be imported into a new database and reproduce Duke's output files to a reasonable degree of accuracy prior to sharing them with intervenors. These internal processes should be tested and verified prior to the submission of the 2024 Carbon Plan Update/IRP.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting this finding of fact and conclusions is contained in Duke's Proposed Carbon Plan, the Initial Comments of the Public Staff, the direct testimony of Public Staff witness Thomas, the testimony of Public Staff Panel 1 on cross examination, the direct testimony of NCSEA *et al.* witness Tyler Fitch, the direct testimony of CPSA witness Tyler Norris, the direct and rebuttal testimony of the Duke Modeling Panel, the rebuttal testimony of the Duke Transmission Panel, and the entire record in this proceeding.

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In Chapter 4 of the Proposed Carbon Plan, Duke proposes to procure 750 MW of new solar resources through the 2022 Procurement Program. Duke states that it anticipates multiple rounds of solar procurements will be needed to meet the significant expansion of new solar and S+S resources on the DEC and DEP system. Section 110.9 requires that 55% of the total solar capacity be utility-owned and 45% be procured through third-party PPAs.

Duke originally planned to seek 750 MW of solar in the 2022 Procurement but as indicated in the Modeling Panel's direct testimony, it revised that target to 1,200 MW of new solar resources, consisting of 750 MW of solar selected in its Proposed Carbon Plan (HB 951 MW) and 441 MW remaining from the CPRE Program (CPRE Shortfall). Duke stated that it would: (1) contract solely with third-party PPA proposals in the 2022 Solar Procurement to the extent they meet the avoided cost requirements; (2) not count the CPRE Shortfall procured towards HB 951 ownership requirements; and (3) not count the CPRE Shortfall procured towards the calculation of the volume adjustment mechanism (VAM), which compares the weighted average bid prices received against the levelized cost of solar used in the Carbon Plan models and adjusts the procurement volume up or down by as much as 20%, based on how unfavorable or favorable the comparison is. Witness Kalemba of Duke's Modeling Panel testified that the CPRE Shortfall would be included in the 2022 Procurement because the Carbon Plan's renewable energy baseline assumed that the entire CPRE target volume would be interconnected. Tr. vol. 11, 69. It would not be used to determine if the VAM would be triggered, because those CPRE Shortfall MW would not be part of the 2022

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Procurement under HB 951. *Id.* at 71. Witness Kalemba admitted that any MW procured to satisfy the CPRE Shortfall would probably be among the most competitive bids, because in order to satisfy the CPRE Program those bids would have to be at or below avoided cost inclusive of network upgrades. *Id*. at 70. Witness Kalemba also agreed that if Duke were to exclude the bids that were selected for the CPRE Shortfall from the determination of the VAM, the price of the bids would likely rise in comparison to the Carbon Plan's solar reference cost, potentially reducing the volume of solar procured. *Id.* at 73-74.

The Modeling Panel also acknowledged that the original 750 MW target for the 2022 Solar Procurement is determined by the Proposed Carbon Plan and assumptions regarding the annual limit on solar interconnection capacity used in the model. Tr. Vol. 7, 355. The Modeling Panel discussed the fact that the annual interconnection limit is a forecast based on the best information available at the time the analysis is conducted. *Id*.

Public Staff witness Thomas stated that the interconnection constraint is binding as the model economically selected 750 MW in 2026 and reached its interconnection limits in most subsequent years. Tr. vol. 8, 314. Witness Thomas explained that if the constraint in the model limited solar to 750 MW in a given year, it caused the cost of solar above 750 MW to rise in the model. *Id*.

The Public Staff, in its initial comments, explained that the interconnection limit is an engineering judgment based on several factors outlined in Duke's Proposed Carbon Plan, and that the best way to challenge those estimated limits

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is to attempt to interconnect more than 750 MW through the 2022 Procurement. Public Staff's Initial Comments 146. Public Staff witness Thomas stated that it is not appropriate to use historical interconnections as a gauge or limit on future interconnections because in the last several years solar facilities have increased in size and have begun to impact the transmission system, which requires expensive and time-consuming upgrades. Tr. vol. 21, 313. According to the Public Staff, Duke is no longer interconnecting the large quantities of 5 MW facilities to the distribution system that currently make up a majority of DEP's operational solar capacity. Public Staff Initial Comments, 146. The Public Staff stated that while larger projects can be more complex and trigger larger transmission system upgrades, a lower number of projects could also free up labor and material constraints. *Id.* For reference, witness Thomas indicated that in North Carolina alone, Duke interconnected an average of 72 solar projects per year from 2015 to 2020 but only approximately 300 MW of solar projects from 2019 through 2021 across its system. Public Staff Initial Comments, 146-147, Tr. vol 21, 317. The Public Staff noted that interconnecting between 10 and 15 larger projects a year through iterative competitive procurements will represent a significant decrease in the number of projects that require interconnection facilities and contractual obligations. Public Staff Initial Comments, 147.

Further, the Public Staff asserted that the 2022 Procurement is the first time Duke has performed the DISIS, which is the cluster study process adopted within the Commission-approved queue reform, which was implemented by Commission order in August 2021. Public Staff Initial Comments, 147. The Public Staff stated

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that it understands the technical challenges associated with interconnecting large quantities of solar capacity, but also believes that a larger and more robust solar procurement in 2022 will both increase the likelihood that the 70% CO_2 reduction target will be met and help serve as validation that the RZEP Duke has identified in Proposed Carbon Plan Appendix P is part of a no-regrets proactive approach to transmission planning. Public Staff Initial Comments, 148.

Witness Thomas emphasized that the Public Staff seeks balance between robust market participation in the 2022 Solar Procurement and the risk that procuring too much solar this year could result in higher prices for ratepayers, given the unprecedented supply chain challenges facing the industry. Tr. vol. 21, 310.

The Public Staff also stated, in its Initial Comments, that the increasing number of net transfers from DEP to DEC is indicative of DEC load that is served by DEP generation and transmission resources. Public Staff Initial Comments, 97. The Public Staff also noted that absent a change to how rate-based costs are allocated, this increase in DEC load served by DEP will exacerbate the existing rate disparity. The Public Staff identified the 2022 Solar Procurement as one of several instances where this issue has arisen. *Id.*

Witness Thomas testified that the Public Staff is skeptical that high levels of annual solar interconnections are achievable in the short term, and that Duke's interconnection limits are generally reasonable. Tr. vol. 21, 97. However, witness Thomas stated that given the large quantity and geographic diversity of projects

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that have bid into the 2022 Solar Procurement and the terms of the 2022 Solar Procurement RFP, the Public Staff believes it likely that capacity procured will come online between 2025 and 2027. *Id*. According to witness Thomas, some projects may already have completed Facilities Studies or signed Interconnection Agreements, or may have minimal transmission upgrades, and may be able to interconnect in 2025 or early 2026. *Id.* Further, the 2022 Solar Procurement RFP allows projects to interconnect as late as November 30, 2027, or later, if certain conditions are met. *Id.* Thus, the Public Staff believes that the 1,200 MW target will likely be spread out over three years, depending on project characteristics, costs, and transmission upgrade timelines. *Id.* at 97-98.

NCSEA *et al.* witness Fitch stated that 7,200 MW of solar should be interconnected by 2030, 4,000 MW of which should be procured from 2022 to 2024 and in-service between 2025 and 2028. Tr. vol. 24, 177-178. CPSA witness Norris requested that the Commission require an even larger target volume of solar for the 2022 Procurement and beyond. CPSA proposed a total of 4,800 MW of solar from 2022-2024, allocated as 1,500 MW in 2022, 1,500 MW in 2023, and 1,800 MW in 2024. Tr. vol 26, 52.

Public Staff witness Thomas argued that intervenors such as CPSA and NCSEA *et al.* are requesting solar procurement targets that rely on unrealistic near-term annual interconnection limits and interconnection costs. Witness Thomas agreed that all the portfolios eventually call for the interconnection of 10 gigawatts (GW) of solar with different completion dates but cautioned the Commission against procuring large amounts too quickly. Tr. vol. 21, 320-321.

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Witnesses Thomas and Metz agreed that there must be an orderliness to the transition from fossil fuels to renewables and that CPSA and Brattle modeling did not take into account transmission upgrades that might require larger increases in cost as they start to trigger affected system studies and create more wide-ranging impacts beyond the local network. *Id*. at 319.

Witness Thomas stated that the near-term procurement, and particularly the 2022 Solar Procurement volume that the Public Staff recommended, appropriately balances the risks of waiting and the risks of moving too early. *Id.* at 320. He went on to state that portfolios that require the selection of significant amounts in the 2022 Procurement run the risk of over-procuring and potentially result in higher costs as the less cost-effective projects from the 2022 Solar Procurement are selected; while waiting too long could increase the risk of non-compliance and subject the procurement to market uncertainties that may drive prices up. He reiterated that the Public Staff's recommendation and the VAM included in the 2022 Solar Procurement RFP for ratepayer protection adequately balance these factors by procuring more if RFP prices are low, and less if RFP prices are high. Tr. vol. 21, 322. Witness Thomas discussed that the Public Staff presented a more holistic view of the S+S procurement amounts to be procured over the next four years to be in-service by 2030, which should help shape the procurement targets for 2022. Tr. vol. 22, 293-95. Witness Thomas further testified that the Public Staff tried to average out the overall procurement but front-load the procurements to determine the capability of the interconnection process and perhaps reach compliance earlier than 2032, recognizing certain constraining factors such as

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locating some projects in DEC due to where the CPRE Shortfall MW was assumed to be located, and acknowledging that the RZEP projects have not been constructed. Tr. vol. 22, 293.

The Commission finds the testimony of Public Staff witnesses Thomas and Metz convincing in determining the target volume for the 2022 Solar Procurement. The Commission is of the opinion that Duke's stated interconnection limits must be challenged responsibly. While 1,200 MW is significantly more than the annual interconnection limits that Duke has testified are reasonable, the Commission believes that the 2022 Procurement will be unique due to several factors, including the number of projects that could be selected that are more fully developed due to the past interconnection queue backlogs, allowing interconnections to start earlier. Additionally, the 2022 Procurement RFP allows selected projects to interconnect late into 2027, giving the Companies more time to interconnect these initial projects as the RZEP upgrades are completed.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that Duke shall seek to procure 1,200 MW of solar resources inclusive of the CPRE Shortfall volume of 441 MW. In addition, to address concerns about location, one third of the final capacity procured through the 2022 Solar Procurement after the VAM adjustment shall be located in DEC's territory, one third in DEP's territory, and the remaining one third comprised of the remaining most competitive bids in either DEC or DEP. Further, the Commission concludes that the CPRE Shortfall MW shall be subject to the avoided cost cap and pursuant to the requirements of N.C.G.S § 62-110.8 (Section 110.8) and

Commission Rule R8-71 with the exceptions established in the Commission's Order in Docket Nos. E-2, Sub 1297 and E-7, Sub 1268 establishing the 2022 Procurement target. The remaining 759 MW of solar resources shall be procured subject to Section 110.9 and its 55%/45% ownership requirements. All MW procured through the 2022 Procurement process subject to either Section 110.8 or Section 110.9 will be included in the comparison of the weighted average bid price and the Carbon Plan's solar reference cost to determine if the VAM will be used to adjust the target volume up or down.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-25

The evidence supporting these findings of fact and conclusions is contained in Duke's Proposed Carbon Plan, the Initial Comments of the Public Staff, the direct testimony of Public Staff witness Thomas, the testimony on cross-examination of Public Staff Panel 1, the testimony of CCEBA witness Ron DiFelice, the direct and rebuttal testimony of Duke's Modeling Panel, and the entire record in this proceeding.

The Public Staff discovered during its investigation that Duke did not allow EnCompass to dispatch the storage component of the S+S resource. Public Staff, Initial Comments, 125. Public Staff witnesses Metz and Thomas indicated that its modeling suggests that the way Duke modeled S+S may have led to material impacts on resource selection, as discussed in the evidence and conclusion section to Findings of Fact 7-19. Witness Metz recommended that commercial

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terms be created so dispatch of storage can occur and that those terms fairly compensate owners and protect ratepayers. Tr. vol. 21, 234-35.

CCEBA witness Ron DiFelice testified that contract structures that allowing the utility full control over third-party energy storage assets, within certain technical parameters, currently exist in jurisdictions such as the Tennessee Valley Authority, where a S+S procurement is underway. Tr. vol. 26, 278.

Regarding witness Metz' recommendation for the development of commercial terms for solar plus storage facilities, Duke testified that it is striving to replicate the same flexibility it has with utility-owned S+S assets with PPAs, to have the same operational flexibility for the people that are actually operating the grid. Tr. vol. 12, 22. Duke witness Farver further testified that it is important to develop contracts for the provision of S+S resources that allow the utility control over the timing and use of the storage component in order to provide flexible uses beyond capacity, and that third party developers should be appropriately compensated for the value they provide. Tr. vol. 16, 130-131, 133.

Public Staff witness Thomas indicated that he expects that S+S resources will be competitively procured through annual procurements that are similar to the 2022 Solar Procurement, albeit expanded to procure S+S resources in addition to standalone solar. Tr. Vol. 21, 63. During these future procurements, witness Thomas testified that he expects a wide variety of S+S configurations will be submitted for evaluation. *Id.* at 64. Witness Thomas opined that assuming the first S+S procurement will take place during the 2023 DISIS, there should be sufficient

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time to incorporate common configurations and costs into the 2024 Carbon Plan. *Id.* As such, witness Thomas recommended that Duke file preliminary 2023 Solar Procurement results in the 2024 Carbon Plan proceeding and explain how its S+S modeling is influenced by the results of the 2023 Solar Procurement. *Id.* Witness Thomas stated that the Public Staff also supported CCEBA and CPSA's recommendation in their Initial Comments that Duke begin working with stakeholders in advance of the 2023 DISIS to develop appropriate S+S PPA structures that appropriately value third-party S+S resources, to which Duke agreed. Tr. vol. 7, 264.

Public Staff witness Thomas indicated that he believed 4,250 MW of solar and S+S should be procured in the near-term action plan, including 1,225 MW of batteries. Tr. vol. 21, 91. He recommended that 1,125 MW of standalone battery storage be procured as part of the SP5-compliant near-term action plan. *Id*. On cross examination, witness Thomas acknowledged that the near-term action plan presented in his direct testimony is not an "apples-to-apples" comparison with the near-term action plan presented by Duke in its Proposed Carbon Plan. Tr. vol. 22, 294. He explained that rather than simply looking at the quantity of resources expected to be in-service by 2028 and that would be procured in the 2022, 2023, and 2024 Solar Procurements, the Public Staff took a more holistic approach. *Id.* This approach involved looking at the total quantity necessary to be in-service by 2029 and averaging that quantity over the next solar procurement cycles, with minor adjustments for certain constraining factors and potentially front-loading the procurement to attempt to reach compliance earlier than 2032. *Id.* at 295.

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Duke presented its analysis of the various parties' near-term procurement plans in its Modeling Panel rebuttal testimony. The Modeling Panel Rebuttal Table 1 showed that by year end 2028, Duke recommended the procurement of 3,100 MW of solar and S+S; 600 MW of batteries paired with solar; and 1,000 MW of standalone storage. Tr. vol. 27, 41. The Public Staff recommended 2,630 MW of solar and S+S; 820 MW of batteries paired with storage; and 1,130 MW of standalone storage. *Id*. However, the Public Staff noted that by year end 2029, its near-term action plan called for 4,250 MW of solar and S+S, including 1,225 MW of paired storage, approximating 1,100 MW per year. Tr. vol. 22, 295-96.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that it is appropriate for Duke to set a preliminary procurement target in the amounts of solar, S+S, and standalone battery storage as recommended by the Public Staff's near-term action plan. Specifically, the Commission finds merit in the Public Staff's "averaging out" approach and believes taking a longer-term perspective and front-loading the procurement appropriately balances execution risk, cost, and interim compliance. Duke shall engage with stakeholders to develop an RFP to procure the required amounts of solar, S+S, and standalone storage in 2023 and 2024. Based upon the average of 1,100 MW of solar and S+S that must be procured over the next four procurement cycles, and the 1,200 MW to be sought in the 2022 Solar Procurement, the remaining capacity shall be approximately evenly divided between the 2023 and 2024 Solar Procurement cycles. Specifically, the preliminary target amounts shall be 950 MW for the 2023 Solar Procurement and 1,150 MW for the 2024 Solar Procurement.

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This should provide ample time for Duke to complete its RZEP upgrades and facilitate higher levels of interconnection in the 2024 cycle. To meet the estimated 1,225 MW of batteries paired with solar, the Commission further directs that a minimum of 400 MW of at least 2-hour storage shall be procured in the 2023 and 2024 RFP cycles. Accordingly, Duke shall hold stakeholder discussions and shall file an update outlining areas of agreement and disagreement, and including proposed terms and conditions, operational conditions, and a *pro forma* PPA, by no later than February 1, 2023. Duke shall incorporate these terms and conditions in its 2023 Solar Procurement, which shall be filed no later than March 1, 2023. The Commission notes that battery storage projects do not currently require a CPCN. Whether a CPCN is appropriate for battery storage resources will be determined by the Commission in an appropriate proceeding.[3]

<u>EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26</u>

The evidence and conclusions for this finding of fact can be found in Duke's Proposed Carbon Plan, the direct and rebuttal testimony of the Duke's Modeling Panel, the direct testimony of Duke's Carolina Utilities Operations Panel (Operations Panel), the direct testimony of Duke's Transmission Panel, the direct

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[3] In its November 19, 2021 Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning issued in Docket No. E-100, Sub 165 (Order Accepting IRPs), the Commission noted that it appreciated the Public Staff's suggestion that it would be appropriate and useful for the Commission to initiate a proposed rulemaking to determine the circumstances, if any, under which a CPCN should be required for an energy storage facility. In that Order, the Commission determined that it would address the suggestion by separate order at a later time. Order Accepting IRPs at 21-22.

testimony of Public Staff witnesses Thomas and Metz, and the entire record in this proceeding.

Every portfolio in Duke's Proposed Carbon Plan and both supplemental portfolios selected 600 MW of onshore wind by 2030. Tr. vol. 12, 66. The Operations Panel stated that if onshore wind was ultimately selected by the 2022 Carbon Plan, the Companies would consider whether DEP and DEC could jointly own wind generation. However, they indicated that the Companies modeled the onshore wind assuming it would be owned by DEP and paid for by DEP customers. Tr. vol. 15, 33.

Absent convincing evidence that large quantities of onshore wind will be available to Duke earlier than 2029, or that more than 300 MW could be interconnected annually, Public Staff witness Thomas found Duke's assumptions with respect to onshore wind interconnections to be reasonable for the development of the Carbon Plan. Tr. vol. 21, 59. As the Near-term Action Plan calls for the procurement of 600 MW of onshore wind in DEP's territory, witness Thomas testified that should the 2022 Carbon Plan include onshore wind, Duke should work to procure these resources in accordance with the Commission's interpretation of the statute and be in a position to provide updated assumptions in the 2024 Carbon Plan Update proceeding. *Id.* at 61. Public Staff witness Thomas further recommended that the 2022 Carbon Plan and Near-term Action Plan include 600 MW of onshore wind, consistent with SP5. *Id.* at 63.

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Duke witness Snider stated that there are a limited number of sites in North Carolina with significant onshore wind resource potential. Tr. vol. 11, 97. He further stated that Duke must work with the communities and wind developers to see if those sites are actually viable. *Id.* If those sites are determined to be viable, Snider added that Duke must determine the transmission plan to bring those resources to load centers. *Id.* Witness Snider stated that while Duke has a proxy interconnection cost in the model for onshore wind, that price does not have the transmission study history that the solar interconnection cost does. *Id*. at 97-8. He indicated that it is important for Duke to strive to procure onshore wind in the Near-term Action Plan, as it has synergies with solar because the wind blows at different times than solar is available, such as winter mornings and at night. *Id.* at 100. He also stated that developing onshore wind assets would provide additional diversification benefits from a technological, load profile, and supply chain perspective. *Id.* He went on to state that Duke would need to report to the Commission in the 2024 Carbon Plan Update proceeding about its efforts to procure onshore wind, and potentially adjust the amount of onshore wind that could be added at that time. *Id. a*t 101-02.

Duke's Transmission Panel testified that Duke considered importing Midwest onshore wind for meeting the Carbon Plan unfeasible at this time due to the needed transmission system upgrades, the costs of those upgrades, and the time needed to complete the upgrades. Tr. vol. 16, 104. Duke indicated that it has submitted a 1,000 MW first transmission service request to PJM to validate these results, which will be considered in future Carbon Plan iterations. *Id.* The Transmission Panel further stated that the Proposed Carbon Plan considered

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importing Midwest onshore wind onto the Duke system and used the PJM border rate for the transmission cost adder. *Id.* Duke had PJM conduct a feasibility study in 2019 for importing 300 MW into DEC, and the upgrades needed on the PJM side of the system were $411 million and expected to take up to 84 months to complete. Tr. vol. 16, 104-05. Witness Roberts further testified that if Duke were to import onshore wind from the Midwest, it would have to pay wheeling charges to PJM and potentially MISO, depending on where the resources were sited. Tr. vol. 17, 28. Public Staff witness Thomas testified on cross that Duke modeled onshore wind as a utility-owned resource that meets the ownership requirements of Section 110.9. Tr. vol. 22, 316.

Duke witness Pompee, with the Long-Lead Time Panel, testified that onshore wind is considered a mature technology and that the only emerging technologies he is aware of that would increase the potential for onshore wind in North Carolina are "high hub height wind," which allows developers to place the wind turbines higher to get a bigger wind profile. Tr. Vol. 18, 92. He admitted that the siting limitations in North Carolina would not necessarily change if the geographical area where a commercially viable wind turbine could be built were expanded. *Id.*

Duke witness Farver, part of the Transmission Panel, testified that Duke is excited about the opportunity to include onshore wind in its generation mix, but recognizes that there are challenges, particularly with siting. Tr. Vol. 18, 125. She stated that Duke is ramping up internal preparations and capabilities for self-development and is also starting informal conversations with the onshore wind

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development community. *Id.* Witness Farver explained that onshore wind is nascent in North Carolina and Duke is attempting to gather more information to determine if there is a pipeline of projects that would be interested in a 2023 RFP opportunity for acquisition, but there have not yet been any formal stakeholder meetings to gather that information. *Id.* As such, she concluded that Duke does not have sufficient market intelligence to believe that the expense of an RFP would be worthwhile. *Id*.

Witness Roberts of Duke's Transmission panel testified that given Carteret County is the area with the greatest onshore wind potential, there would most likely be transmission constraints that would need to be resolved due to the aggregation of solar, offshore wind, and onshore wind resources that could influence power flows in the area. While the main transmission line in Carteret County is not currently constrained, witness Roberts did not know how much headroom was available on that line. *Id.* at 127-28.

The Public Staff testified that Duke placed the following limitations on onshore wind in its modeling: (1) first selectable by 2029; (2) annual limits of 300 MW each in DEC and DEP; and (3) cumulative limits of 600 MW in DEC and 1,200 MW in DEP. Tr. vol. 21, 59. The AGO's Strategen Analysis of Duke Energy 2022 Carbon Plan also indicated that the typical wind project development timeline is two to three years. AGO Initial Comments, 22, Attachment 1, 21. Public Staff witness Thomas commented that he could not speak to onshore wind development timelines in PJM but noted that there are two onshore wind farms in North Carolina – the operational 208 MW Amazon Wind facility in Perquimans and Pasquotank

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Counties, and the planned 189 MW Timbermill Wind facility in Chowan County, both within PJM's territory. Tr. vol. 21, 59 Witness Thomas also noted that both facilities had long development timelines, at least six or seven years from early permitting efforts to commercial operation or expected commercial operation. *Id.* at 59-60.

Given this history and the absence of any wind projects in Duke's interconnection queues, the Public Staff witness Thomas indicated that it believes it is unlikely that any onshore wind projects in Duke's territory would be able to achieve operation prior to 2029. In addition, it noted that onshore wind imported from PJM or other neighboring areas would require firm point-to-point transmission service and would be subject to the appropriate border or wheeling charge. Tr. vol. 21, 60-61. Public Staff witness McLawhorn also testified that the Public Staff is concerned about the transmission development required to interconnect onshore wind in DEP's service territory without a plan to allocate some of the costs to DEC. Tr. vol. 23, 96-97.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that it is appropriate to include 600 MW of onshore wind in the 2022 Carbon Plan for planning purposes at this time. Duke shall continue gathering information as stated by witness Farver on the possible market for an onshore wind RFP and its ability to procure and place into service 600 MW of onshore wind capacity by 2030. Within 60 days of the issuance of this order, Duke shall file a report detailing its plan to engage market participants and onshore wind stakeholders to gauge interest in an onshore wind RFP, determine

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the potential locations and timelines for procuring and placing into service onshore wind facilities, address whether out-of-state wind resources should be included in the future RFP, and estimate the potential transmission upgrade projects necessary to interconnect the facilities. If Duke determines that an onshore wind RFP would attract sufficient bids for a competitive procurement, Duke shall submit a timeline for submitting the RFP to the Commission for approval and provide a cost allocation methodology for sharing the costs of the facilities and the requisite transmission upgrades between DEP and DEC.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27-28

The evidence supporting these findings of fact and conclusions is contained in Duke's Proposed Carbon Plan, the Initial Comments of the Public Staff, the direct testimony of Public Staff witnesses Thomas and Metz, the cross-examination testimony of Public Staff Panel 1, the direct testimony of NCSEA *et al.* witness Tyler Fitch, the direct testimony of Tech Customer witness Michael Borgatti, the direct testimony of AGO witness Edward Burgess, the direct and rebuttal testimony of the Modeling Panel, and the entire record in this proceeding.

Duke's Proposed Carbon Plan included two types of natural gas-fired CTs and two types of natural gas-fired CCs. All portfolios in the Proposed Carbon Plan included the selection of 1,200 MW of CC capacity and 800 MW of new CTs placed in-service by 2029, and Duke's verified Petition for Relief requests Commission authorization to move forward with the development of these assets.

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Public Staff witness Thomas testified that supplemental portfolios SP5 and SP6 also selected 1,200 MW of CCs and 800 MW of CTs, although one additional CC was delayed relative to Duke's original portfolios. Tr. vol. 21, 91. Witness Thomas stated that the CCs were selected across a "wide range of portfolios and sensitivities," and that demonstrated that some natural gas capacity might be necessary. *Id.* at 344.

Public Staff witness Thomas indicated that the Public Staff found Duke's assumptions regarding resource costs to be reasonable, while CPSA, NCSEA *et al.*, NC WARN, the Tech Customers, and Avangrid stated in their respective Initial Comments that Duke underestimated costs for natural gas and overestimated costs for solar, wind, and energy storage. Tr. vol. 21, 81; CPSA Initial Comments, 26; NCSEA *et. al*. Initial Comments, Synapse Report, 10, A-5; NC WARN Initial Comments, 24; CCEBA Initial Comments, 39; Tech Customers Initial Comments, 10, Gabel Report, 8; Avangrid Initial Comments, 3; and TotalEnergies Initial Comments, 8. Witness Thomas stated that the Public Staff did not take issue with any specific resource costs in Duke's model because the costs for all resources are in a state of flux in the current environment, with global inflation and supply chain constraints causing significant price increases for many technologies, particularly those dependent on imported raw materials or components. Tr. vol. 21, 81-82. In evaluating the reasonableness of Duke's assumptions, the Public Staff noted that it reviewed two sets of data: Duke's supply-side data manual, which contained its confidential estimates of capital costs, and compared that with

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publicly available data such as National Research Energy Laboratory and Energy Information Administration capital cost assumption data. *Id.* at 378.

Public Staff witness Thomas stated that the Public Staff is concerned that significantly increasing Duke's natural gas fleet, particularly its high-capacity factor CCs, creates substantial risk that Duke ratepayers may experience similar rate increases related to future natural gas commodity price spikes as is occurring in Dominion's territory this year. *Id.* at 69. He noted that the potential cost increases associated with Duke's High Gas price sensitivity were more than double the potential cost savings associated with the Low Gas price sensitivity. However, witness Thomas surmised that the risk of over-reliance on natural gas may be overstated by only reviewing installed capacity, as all of Duke's portfolios significantly decrease the total amount of natural gas burned annually after a peak in approximately 2026. *Id* at 68-70. The Public Staff believes that while this reduction should mitigate some of the concerns regarding natural gas price volatility in the long run, it does raise the issue of whether natural gas plants built prior to 2030 will become underutilized, and potentially stranded, in later years as they become primarily capacity resources. *Id*. at 70. According to witness Thomas, Duke's use of an eight-year optimization period caused its models to select natural gas in 2028 and 2029, without considering the stringent carbon reduction targets and higher gas prices in later years. *Id.*

As already discussed in this Order, the Public Staff and other intervenors have concerns regarding the ability of Duke to obtain incremental firm natural gas capacity for future CC generation facilities that depend upon access to the MVP

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and MVP Southgate projects. Due to the uncertainty, the Public Staff supports the no Appalachian gas supply assumptions used in SP5 and SP6 and expects that the availability of Appalachian gas and its delivered price will be a significant matter of debate in future CPCN proceedings, if any, for natural gas plants. *Id*. at 74. Witness Thomas also acknowledged that there was a risk that natural gas supply, even with ongoing expansion projects, would be insufficient for new combined cycle plants in Duke's territories, stating that intervenors who made the conclusion that supply constraints would prohibit the construction of new CCs were not necessarily unreasonable. Tr. Vol 22, 313.

Public Staff witness Thomas indicated that the Public Staff did, however, find that Duke's natural gas combined cycle configurations and operable life assumptions were reasonable. He noted that SP5 and SP6 allowed the selection of both the advanced J-Class and the smaller F-Class CTs, which the Public Staff finds reasonable for planning purposes. In SP5 and SP6, only J-Class CCs were selected. Much like S+S configurations, witness Thomas indicated that there are many different specific configurations for a natural gas CC that cannot all be reasonably modeled. He stated that the appropriate specific CC configuration will be determined during future CPCN proceedings. Tr. vol. 21, 74-75.

Public Staff witness Metz testified that SP5, which allows no Appalachian gas, was below Duke's threshold for LOLE, indicating that the SP5 with no Appalachian gas portfolio will adequately address system reliability concerns at the generation level while mitigating fears about execution risk and compliance with Section 110.9 requirements. Tr. vol. 21, 159.

Public Staff witness Thomas testified that his recommendation for and the Commission's approval of the Near-term Action Plan would not constitute the Commission's approval of construction of generation plants or be otherwise controlling in a CPCN proceeding. *Id.* at 98. Witness Thomas stated that while approval of the near-term action plan provides clarification on what steps should be taken or are likely to be needed in the planning horizon, it should not be controlling. *Id.* Witness Thomas also testified that selection of a resource in the Commission's Carbon Plan is one factor the Public Staff would consider in a CPCN proceeding, but that it would likely require an updated model run at the time of the application, particularly for natural gas resources. *Id.* The Public Staff also contended that the ultimate review of the reasonableness and prudence of the costs of the Commission's Carbon Plan would be decided in a general rate case proceeding or, in some cases, the annual fuel rider. *Id*.

Witness Metz stated that the Public Staff based its assumptions that the new CCs would receive supply from pipeline expansion projects, like the Transco Southside Reliability Expansion Project. Tr. vol. 21, 261. Witness Thomas added that the Public Staff made a reasonable assumption that the gas pipeline system needs expansion, and there are significant needs for natural gas. *Id.* at 262. He testified that therefore, it was reasonable to limit access to natural gas to acknowledge that there are limits and challenges associated with building gas plants. He also stated that a CPCN application docket would be the proper place to evaluate pipeline costs, the route of the pipeline, the ability to actually construct the gas plant, and whether the CPCN would be in the best interest of ratepayers.

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Witness Thomas stated that natural gas has an important role to play in serving as a transitional bridge for reliability purposes. Tr. vol. 22, 275. He further noted that while natural gas is not the only thing that can act as a firm dispatchable resource (e.g., batteries and solar and a combination of intermittent resources can provide system reliability if properly designed), cost must be considered. Tr. vol. 22, 256-61.

Witness Fitch stated that Duke's plans to build new gas plants are based on the assumption that low cost Appalachian gas will become available and that it will be economically viable in the future to convert these plants to run on hydrogen, both of which are high risk assumptions. Tr. vol 24, 158. Tech Customer witness Michael Borgatti also points to fuel risk as a primary concern, noting that natural gas fuel delivery issues are often responsible for generator outages and derates. Witness Borgatti further highlights that Duke has acknowledged there is insufficient firm transportation on the system to supply their existing CC fleet, let alone new gas generators proposed in this proceeding, and he proposes that the Commission defer a decision on new natural gas units until these risks can be thoroughly evaluated and managed. Tr. vol 25, 57. AGO witness Edward Burgess also discusses Duke's reliance on key assumptions to support the natural gas assets identified in the Carbon Plan, including the assumption that a robust hydrogen market will develop, and that Duke's natural gas fleet can operate on 100% hydrogen by 2050. He concludes that while hydrogen combustion may ultimately become feasible, planning based on today's technologies suggests that the natural gas plants identified in Duke's near-term action plan would likely need to be retired

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early and would impose significant stranded costs on Duke's customers. Tr. vol. 25, 272.

Duke witness Snider testified that Duke has contract positions to get gas from the MVP line if it comes online but also has contingency plans if MVP does not come online. He stated that Duke is looking into bringing in gas from both the north and the south off of the Transco line but would need to discuss additional upgrade projects with Transco. Using Piedmont's experience with Transco as an example, Duke would be required to show a need for the gas, at which point the Companies would have Transco upgrade the line in order to support additional capacity. Tr. vol. 27, 189-190.

Based on the foregoing and the entire record in this proceeding, the Commission concludes that Duke should assume that no Appalachian gas will be made available to Duke until there is more certainty about the MVP project's in-service date. Future Carbon Plan proposals shall incorporate the most recent developments to ongoing natural gas pipeline projects that would expand natural gas access in North Carolina, and natural gas pricing and supply assumptions shall reflect those developments.

The Commission concludes that planning for approximately 800 MW of CTs and a CC of up to 1200 MW is a reasonable step for Duke to take at this time, and therefore the Commission is including that capacity in its Carbon Plan. Section 110.9 states that Duke must maintain or improve reliability while meeting the carbon reduction targets. CTs and CCs, at this point in time, ensure that Duke's

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customers will continue to have adequate and reliable service as the Companies retire their coal plants and add a significant number of intermittent resources to their generation portfolios. While there are questions about where the supply of natural gas will come from and when it may be available, the Commission believes at this time that it is appropriate for Duke to continue to evaluate the best way to incorporate the natural gas capacity the Commission has approved for planning purposes in this Carbon Plan.

The Commission is also sensitive to the risk of natural gas plants becoming stranded in later years, as raised by the Public Staff and intervenors. At the time Duke determines it is appropriate to seek the construction of a CT or CC, it is required under current law and regulations to apply for a CPCN from the Commission. Once Duke applies for a CPCN, the Commission will evaluate the need for the facility, using this 2022 Carbon Plan as one factor in determining the need. The Commission will also evaluate the current costs of the facility, including all the costs associated with construction of the facility itself and any necessary pipeline expansion projects to provide the facility with fuel. The Commission further finds that due to the significant uncertainty around natural gas supply, pricing, and the renewable incentives included in the IRA, Duke shall be prepared to demonstrate the need for new natural gas capacity through updated modeling in future CPCN applications.

The Commission has also found in its Order Denying Certificate of Public Convenience and Necessity for Merchant Generating Facility, Docket No. EMP-105, Sub 0 (Friesian Order) that “it is appropriate for the Commission to consider

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the total construction costs of a facility, including the cost to interconnect and to construct any necessary transmission network upgrades, when determining the public convenience and necessity of a proposed new generating facility." The Friesian Order was affirmed by the North Carolina Court of Appeals, holding that neither the Federal Power Act nor any precedent would preclude the Commission from considering the cost of network upgrades in determining if the generating facility is in the public convenience and necessity.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 29-33

The evidence for these findings of fact and conclusions of law are found in Duke's Proposed Carbon Plan, the direct testimony of Public Staff witnesses Thomas and Metz, the testimony on cross examination of Public Staff Panel 1, the direct and rebuttal testimony of Duke's Modeling and Transmission Panels, and the entire record in this proceeding.

The Transmission Panel testified that Appendix P of Duke's Proposed Carbon Plan explains that the transition from traditional generation planning to what is contemplated in Duke's Proposed Carbon Plan will require significant investment in the transmission system on an aggressive timeline to interconnect the significant amounts of incremental new solar, S+S, stand-alone storage, wind, SMRs, and new natural gas generation resources identified as needed in the Carbon Plan and to reliably retire the coal units that currently support the grid. Tr. vol. 16, 65-66. The Panel stated that the Companies will not be able to wait on solar procurements, associated DISIS timelines, and associated resource

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interconnection agreements to drive the start of transmission network upgrade projects that could take three to five years to construct and still meet the timeline for aggressive CO_2 reduction requirements outlined in Section 110.9. *Id.* at 65. To meet this need, the Panel indicated that DEC and DEP have been engaged in the Local Transmission Planning process through the NCTPC in 2022 with respect to introducing the RZEP projects for inclusion in a Local Transmission Plan that includes the necessary transmission upgrades to accommodate timely integration of a significant amount of additional solar in high solar viability areas of the DEC and DEP systems. *Id* at 66. According to the Transmission Panel, the RZEP projects will unlock high solar viability areas where numerous generator interconnection studies have shown that solar resources desire to interconnect. *Id*. The Transmission Panel stated that the history of solar generator interconnection requests in DEC and DEP show that solar facilities continue to request interconnection in these red zones, despite published guidance from DEC and DEP stating that locating solar in the red zones will require significant network upgrades. *Id.* Further, the panel stated that developers have continued to submit interconnection requires in the red zones, and then to withdraw from the interconnection queue when the cost allocation for transmission upgrades necessary to enable interconnection of their resource is determined. *Id.* The panel argued that this piecemeal approach to transmission planning and generator interconnection presents a significant challenge to Carbon Plan and energy transition execution. *Id.* at 67.

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The Companies contend that their Proposed Carbon Plan reflects the need for proactive consideration of the RZEP projects to enable successful interconnection of significant incremental resources, primarily solar resources, as identified in the Proposed Carbon Plan portfolios. *Id.* The panel explained that the Companies planned to follow the required Attachment N-1 planning process for NCTPC Transmission Advisory Group (TAG) stakeholder input and coordination and to seek Oversight/Steering Committee (OSC) approval with the goal of incorporating the RZEP projects into the update of the 2021 Local Transmission Plan by mid-year 2022. *Id.*

The Transmission Panel noted that prior to the Companies' Proposed Carbon Plan filing, in March 2022, the Companies introduced to the NCTPC OSC the RZEP projects as generator interconnection study informed solutions to common transmission constraints that had been increasingly defined by DEC and DEP transmission planners since May 2018 and that were repeated impediments to solar interconnections in the red-zone areas. *Id.* In April 2022, the Companies shared with the OSC initial mapping of generator interconnection studies to RZEP projects identified as necessary upgrades in the studies. *Id.* at 68. According to the panel, after the Carbon Plan filing, in June 2022, the Companies provided updated information on the number of times interconnection studies identified the RZEP projects as necessary upgrades to enable interconnection. *Id.* Also in June 2022, the NCTPC distributed a draft of the 2021 Mid-year Update Report to the TAG for review prior to the June TAG meeting. In addition to other updates to the Local

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Transmission Plan approved at the end of 2021, the draft 2021 Mid-Year Update Report proposed adding the RZEP projects to the Local Transmission Plan. *Id*.

The Transmission Panel further testified that on June 27, 2022, the Companies presented the 2021 Plan Mid-Year Update Report to the TAG. *Id.* The Mid-Year Update Report included several slides reflecting the reasons the RZEP projects are needed to enable solar interconnections to integrate significant amounts of generation and for executing the Carbon Plan. *Id.* The Transmission Panel explained that the plan at that time was to seek approval of the 2021 Plan Mid-Year Update Report from the OSC by mid-August pending feedback and additional input received from TAG stakeholders. *Id.* Based on current estimated construction schedules, which would be re-evaluated upon OSC approval, certain RZEP projects have lead times of up to four and a half years. *Id.* Aside from preliminary engineering work on the RZEP projects, which has been conducted primarily as a result of legal obligations from interconnection requests where RZEP projects were previously identified, no significant development work has been completed for the RZEP projects in order to provide sufficient time to construct them. *Id.* The Transmission Panel stated that in order to provide sufficient time to construct the RZEP projects necessary to integrate over 4,500 MW of incremental solar generation between 2026 and 2030, as identified in the Companies' IRP, DEC and DEP believed at the time, and continue to believe, that expeditious action by the NCTPC and approval by the OSC is necessary for Carbon Plan execution. *Id.* at 69.

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However, the Transmission Panel stated that based on feedback and additional input received from TAG stakeholders and the Commission's directive in the 2022 Solar Procurement dockets for the Companies to exclude the RZEP projects from being considered in the baseline for the 2022 DISIS Phase 1 Study, the NCTPC communicated that the RZEP projects would be removed from consideration to be included in the 2021 Plan Mid-Year Update Report. *Id*.

The Transmission Panel testified that the Companies and many TAG participants continue to recognize the need for these projects to interconnect new solar generating facilities and to support the energy transition and achieving Carbon Plan objectives. *Id.* According to the panel, the Companies also recognize that the accelerated pace for presenting the RZEP projects to the TAG presented limited opportunities for engagement and understanding of the need for the RZEP, although the transmission needs addressed by the RZEP have been known for several years. *Id.*

Through subsequent engagement with Public Staff after the June TAG meeting and the Commission directive in the 2022 Solar Procurement dockets, the Transmission Panel testified that DEC and DEP agreed to perform supplemental planning studies. The Transmission Panel stated that the supplemental study scope and criteria were discussed and agreed upon with the Public Staff in advance of performing the study. *Id*. at 70, 73.

The Transmission Panel testified that the purpose of the supplemental studies was to further analyze the need for proactive transmission upgrades to help Duke meet Carbon Plan and IRP goals in the Carolinas. *Id.* at 73. According to the Transmission Panel, prior studies in the serial generator interconnection process and the Transitional Cluster Study have demonstrated the need for transmission upgrades that mitigate common constraints but cannot be financed by solar generation developers. *Id.* In these studies, the panel stated that prior solar generation interconnection requests that withdrew from the queue were studied with the latest Duke transmission power flow models, using cluster study methods, to determine overloaded transmission facilities, appropriate upgrades, and contributions to the overloads by the studied solar generators. *Id.*

The Transmission Panel stated that DEC and DEP 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. *Id.* To conduct a forward-looking study of this type, assumptions about the MW size and location of future generation are necessary. *Id.* The panel testified that using the most recent generator interconnection requests as the basis for generator MW size and location assumptions is a non-discriminatory and objective approach to the selection of the 5.4 GW used in the supplemental studies. *Id.* The panel testified that from the most recent generator interconnection requests, DEC studied 41 solar projects representing 1,937 MW, and DEP studied 45 solar projects representing 3,527 MW. In DEC, only one request was considered for interconnection to a 44 kV line due to the significant local impact of more than one request on a 44 kV line. *Id* at 74. DEC and DEP did not study solar projects greater

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than 175 MW due to the localized impact that these projects have on network upgrades needed for interconnection. *Id*.

The results of the supplemental study, according to Duke's Transmission Panel, support all four RZEP projects identified in DEC. For solar projects requesting interconnection to 44 kV circuits, even though DEC is limiting to one solar project for a given 44 kV circuit, overloads are still reflected in the results. *Id.* This result may be mitigated by limiting the aggregate size of solar (transmission, distribution) on the 44 kV circuit. The DEC study results reflect that the four RZEP projects are needed to enable 981 MW of solar projects to be interconnected in the red zones. *Id.*

The Transmission Panel testified that the DEP study results reflect 11 RZEP projects are needed to enable 2,778 MW of solar projects to be interconnected in the red zones. *Id.* at 75. As reflected in the supplemental study results, additional network upgrades were identified as necessary to interconnect 5.4 GW or more of solar inside and outside the red zones. *Id.* However, the panel stated that the majority of these additional network upgrades identified are not projected to be as extensive, or should receive as high a priority, as compared with the identified RZEP projects and thus should not present a Carbon Plan execution risk. *Id.*

According to the Transmission Panel, the study results reflect that three of the DEP RZEP projects could be delayed until future studies again show a reliability need or generation addition need for the project. *Id.* Even though the Erwin-Milburnie 230 kV, the Rockingham-West End 230 kV West, and the Sutton-

Wallace 230 kV lines were not identified as network upgrades necessary for interconnecting the solar projects studied, past transmission planning studies have shown these upgrades to be needed for interconnecting solar projects. *Id.*

Based on the scope of the study, the Transmission Panel stated that DEC and DEP did not need to utilize the historical generator interconnection requests that had previously been mapped to the Erwin-Milburnie 230 and Sutton-Wallace 230 upgrade to get the 5.4 GW needed to meet the study requirements. *Id.* Economic development load may require the upgrade of the Rockingham-West End 230 kV West line. *Id.* The three network upgrades not identified by the study are all pole replacement upgrades, with the exception of the Erwin-Milburnie 230 kV line that additionally requires replacement of blades on four-line switches, with all projects requiring only a single outage/maintenance season to implement the upgrades, although coordination with other transmission work will dictate the schedule needed. *Id.* Once these network upgrades are identified as necessary for interconnecting solar projects in future studies, these projects should not present a Carbon Plan execution risk due to the single season required to implement the upgrade. *Id.*

The Transmission Panel stated that these supplemental planning studies, reinforce the need for the majority of the RZEP projects, and the Companies' current plan is to reintroduce the RZEP projects into the NCTPC process, supported by multiple transmission planning studies and the supplemental planning studies, as necessary to integrate anticipated future generation and execute the Carbon Plan. *Id*. at 69. The panel stated that these RZEP projects will

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be reintroduced through recommended inclusion in the 2022 Local Transmission Plan that will be reviewed by the TAG and considered for approval by the OSC later this year. *Id. at* 70. According to the panel, the Companies anticipate additional TAG meetings from now until the end of the year to review the need, benefits, and estimated costs of the RZEP projects. *Id*.

Public Staff witness Metz testified that the Red Zone for DEP is generally in southeastern North Carolina, which is highly suitable for solar development due to its flat terrain, relatively low land costs, and relatively high solar insolation; however, the transmission in this area is also highly constrained due to historical load requirements and, more recently, increased solar development. Tr. vol. 21, 140. According to witness Metz these transmission constraints were major issues in the Commission's review of two solar CPCN applications – Friesian Holdings, LLC, in Docket No. EMP-105, Sub 0 and Juno Solar, LLC, in Docket No. EMP-116, Sub 0. *Id*. at 141. Witness Metz described the RedZone in DEC as generally in the northwest part of South Carolina, near the North Carolina border. *Id.* According to witness Metz, both DEC's and DEP'S Red Zones have relatively high solar insolation. *Id.* He stated that the historic success of solar development interconnected to Duke's distribution and transmission systems in these areas has contributed to the transmission system reaching a saturation point, i.e., the system has too much generation and not enough load in discrete line segments of the distribution and transmission system. *Id.* Witness Metz stated that each utility's unique electric circuit configuration, such as the use of lower voltage transmission,

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has also created challenges for further large-scale adoption in specific areas of the system. *Id.* at 141.

Witness Metz agreed with Duke's Transmission Panel's testimony that while the fewer number of Red Zone requests in recent years may be due to the well-known congestion and upgrade costs in the Red Zones, elimination of Red Zone congestion with proactive upgrades may incentivize a higher concentration of Red Zone requests than seen in recent years. *Id.* at 149.

Witness Metz believes that Interconnection requests are likely to increase in the Red Zone after Duke completes proactive upgrades of the transmission system and that the increase could create congestion again. Based on this determination, witness Metz requested Duke to evaluate future proactive upgrades to reflect anticipated interconnections over at least a ten-year horizon and potentially a twenty-year horizon, as recommended by the Public Staff in its Initial Comments, while creating milestone provisions to measure the need to move forward to the design and, if justified, construction of the projects. *Id.*

Witness Metz stated that the supplemental planning process listed in the Issues Report Submitted on Behalf of DEC and DEP on July 22, 2022, is a valid effort to refine the study process to determine potential proactive upgrades. *Id.* at 141. This proactive study approach, according to witness Metz, identifies areas of transmission lines that have been targeted by previous interconnection requests (including transmission projects that are currently outside the red zones and not currently under consideration but may be candidates for future proactive transmission plans), highlighting that the study results could be (and likely would be) an identification of common upgrades. *Id.* He pointed out that the study centered on historic interconnection requests and was not a least-cost analysis. *Id. at* 141-42. Witness Metz stated that he was not aware of the existence of any other alternate analysis that was completed to compare or contrast the line upgrades Duke selected. *Id.* This does not imply, according to witness Metz, that Duke's solution is not least cost, as it is not clear whether there were other alternatives that could have achieved the same mitigation, such as alternate line analysis and non-wires alternatives. *Id.* Witness Metz further acknowledged the timing constraints of Duke's study in order to include it in testimony. *Id.* Witness Metz continued by stating that, as the Public Staff stated in its Initial Comments, proactive transmission upgrades require a balance of least-cost and least-regrets planning, coupled with a robust, forward looking planning process. *Id.* Undoubtedly, Section 110.9 compliance will require more solar generation, and all portfolios filed in this docket require interconnection of at least 5 GW of solar (including solar plus storage) over the next decade. Some intervenors, according to witness Metz, have stated this amount should be much higher over the next several years based on alternative modeling results. *Id.* Therefore, witness Metz believes a least-regrets approach for proactive transmission is reasonable because Duke will add solar and other low or no carbon resources in later years, likely exceeding the 5 GW amount by the late 2030s. *Id*.

Witness Metz stated that the modified transmission study addressed some of the Public Staff's concerns. Duke used realistic assumptions regarding circuits

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of certain voltages (e.g., limited amounts of generation can interconnect onto 44 kV lines) to minimize the likelihood that a large number of projects could interconnect on a part of the system where such growth would not be reasonable. *Id.* The study assumptions also addressed concerns around speculative generation of solar facilities and changing land availability. *Id.* The study went further to isolate solar facilities that were extraneous and required substantial line upgrades that mostly benefited one interconnection request. *Id.* at 142-43. The amount of solar MWs studied was the same amount identified in Duke's proposed Carbon Plan, and the study attempted to maintain the solar allocations used in Duke's proposed Carbon Plan. For modeling purposes, no more than 60% of new solar generation for DEP and DEC combined may be located in the current DEP balancing area. *Id.*

Witness Metz further testified that Duke's overall study methodology addressed the Public Staff's issues regarding the reasonableness of the projects sampled to evaluate the transmission impacts. *Id.* at 144. Witness Metz, however, did state that while the study included approximately the same capacity of solar resources as identified in the Proposed Carbon Plan, it was based on historic queue information, and future generation may have different technical characteristics or points of interconnection. *Id.* In addition, he stated that the study did not include significant levels of storage or solar plus storage, despite the large quantity of these resources that are also likely to be procured over the next several years to meet the carbon reduction targets of Section 110.9. Witness Metz testified that the results of this evaluation in combination with the current Definitive

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Interconnection System Impact Study (DISIS) project locations, which are shown as Figure 2 in the Transmission Panel's pre-filed direct testimony, continue to support constructing upgrades that are likely or common to multiple solar projects. Witness Metz pointed out that while the results were similar to those in previous studies, the new study had a few discrete changes and supported a delay of some upgrades. *Id.*

Witness Metz stated that the Public Staff supported the majority of the RZEP projects in DEC, stating that three of the four projects would facilitate the interconnection of over 80% of all generation facilities seeking to interconnect, providing a positive correlation of potential upgrades in DEC to likely areas of interconnection. *Id.* at 145. However, witness Metz argued that based on the information known to date, he would not recommend DEC build the Clinton 100 kV Line upgrade at this time, based on the relatively few generator facilities impacting that line and the unclear causal relationship between future solar generation and this upgrade. Witness Metz also contended that based on his review of a transmission map, he understood that the Clinton 100 kV Line upgrade will likely be needed in the near future if solar generation continues to attempt to interconnect in this area given its proximity to the other transmission projects in question. *Id*.

The Public Staff requested that Duke address whether exclusion of the Clinton 100 kV Line upgrade would challenge the reliability of the existing transmission system or if it is more cost effective to perform the upgrades at the same time as the other RZEP projects in rebuttal. The Public Staff further asked

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Duke to explain why the Clinton 100 kV Line is needed based on more than just historic interconnection requests, such as the 2022 DISIS results and if there is any potential that further development of solar plus storage would mitigate the need for the Clinton 100 kV Line. *Id.* at 145-146.

After reviewing the DEP study, witness Metz recommend that the Erwin-Fayetteville 115 kV Line and the Camden-Camden Dupont 115 kV Line be removed from the RZEP at this time. *Id. a*t 147. The Erwin-Fayetteville 115 kV Line and the Camden-Camden Dupont 115 kV Line have approximately 25% of all common upgrades affecting the proposed transmission projects in the study (24% and 26%, respectively). *Id.* The Camden-Camden Dupont 115 kV Line appears relatively small in scope compared to the other transmission upgrades. Removal of the Erwin-Fayetteville 115 kV Line and the Camden-Camden Dupont 115 kV Line are separate from the results of a power-flow analysis (or equivalent) or project estimated completion timeline. *Id.* Witness Metz requested that Duke address in rebuttal whether exclusion of the Erwin-Fayetteville 115 kV Line and the Camden-Camden Dupont 115 kV Line would challenge the reliability of the existing transmission system or if it is more cost effective to perform the work at the same time as the other red zone Projects in the general vicinity. *Id.* Witness Metz further requested that Duke explain how the Erwin-Fayetteville 115 kV Line is needed based on more than just historic interconnection requests. *Id.* at 147.

Public Staff Witness Metz expressed concerns over the accuracy of Duke's cost assumptions in the supplemental transmission study, as almost all estimates were Class 5 estimates with an expected accuracy range of between -50% to -

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20% on the low end and +30% to +100% on the high end, and the effect of current inflationary pressures, which are unknown. *Id.* at 148. Witness Metz stated that the costs listed in the study may change given their preliminary nature and the scope of work, which will take years to complete. *Id.* Witness Metz stated that cost over-runs are not necessarily the result of imprudence, but he raised this concern given the potential uncertainty and cost exposure of ratepayers. *Id.*

Witness Metz clarified that while the Public Staff supports the proactive upgrades in this instance, the Public Staff's support should not be construed as precedent or indicative of future Public Staff recommendations. *Id.* Witness Metz stated that proactive upgrade planning can be a tool used for efficient planning of the electrical system while ensuring system reliability and achieving policy goals. *Id.* He further stated that the Commission should direct Duke to adopt the transmission planning-related recommendations in the Public Staff's Initial Comments. He also testified that the Public Staff is not making recommendations at this time on whether the costs are reasonable and prudent, stating that the Public Staff will make those recommendations when Duke seeks cost recovery. *Id.* at 149.

Witness Metz stated that mitigating execution risk to achieve Section 110.9 compliance requires proactive transmission planning and proactive upgrades. The Commission should acknowledge the public policy goals for North Carolina as part of its 2022 Carbon Plan, as requested by Duke. *Id.* at 149-50.

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Witness Metz testified that the Public Staff contends if the Commission acknowledges the need for proactive transmission upgrades in its Carbon Plan, the Commission should require Duke to file a report on the status of the upgrades in a dedicated docket or sub-docket to include current project timing milestone completion and cost estimates on a semi-annual basis. *Id*. at 150. In addition, witness Metz argued that the Commission should require and approve a cost allocation or cost sharing mechanism for DEC and DEP to share the cost of the proactive upgrades. *Id.* Witness Metz stated that the Public Staff expressed its concern with the flow of power from DEP-located generation to serve DEC load as DEC's customers should pay their fair share of the DEP transmission and plant investments that serve DEC's load so that DEP customers do not disproportionately bear the burden of statewide carbon reduction. *Id*. at 151.

In its rebuttal testimony, witness Roberts of Duke's Transmission Panel stated that even if the Commission were not to acknowledge the need for the RZEP projects, Duke would continue to iteratively evaluate through the NCTPC the need for and benefits of proactive transmission planning projects to interconnect new generation, enable coal unit retirements as part of the system-wide Carolinas energy transition and to implement the public policy requirements of HB 951. In doing so, the Companies will continue to follow the procedures in its OATT for approval of transmission projects for inclusion in its Local Transmission Plan. Tr. vol. 16, 163.

Witness Roberts also stated that one of the RZEP projects, the Camden-Camden Dupont 115 kV Line opposed by the Public Staff, could be postponed at this time, but Duke would continue to evaluate it through the 2022 DISIS Phase 1 Study. Tr. vol. 28, 128-29. Witness Roberts did contest the other two projects that the Public Staff opposed, stating that the Clinton 100 kV Line would aid in interconnecting 740 MW of solar facilities considered in the supplemental study and the Erwin-Fayetteville 115 kV Line would aid in the interconnection of over 625 MW of solar considered in the supplemental study. *Id. a*t 131. Further, witness Roberts stated that the Clinton 100 kV Line would take 48 months to construct, and the Erwin-Fayetteville 115 kV Line would take approximately 54 months to construct. Witness Roberts, however, did not testify about the need for the upgrades other than the historical interconnection requests. *Id*. at 132.

At the hearing, witness Roberts could not give a definitive answer as to how much headroom any particular RZEP projects would provide for the interconnection of solar facilities, stating that a study must be conducted using input from the solar developers on location and size of projected interconnected facilities or take some information from the 2022 DISIS. Tr. vol. 16, 163.

Witness Roberts also described the RZEP projects as generator addition projects/public policy projects, whose costs ultimately will be borne by the wholesale and retail ratepayers of the Duke subsidiary that constructs the upgrades. Tr. vol. 17, 33, 36.

Also, during the hearing witness Roberts explained how the OSC is comprised, and that DEP and DEC constitute half of the voting members. *Id.* at 45. He also stated that, to his knowledge, DEC and DEP had never voted against one

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another and that the OSC has never been unable to come to a unanimous decision. *Id.* He also acknowledged that the OSC guidelines state that an investor-owned utility shall not be bound by the decisions of the OSC to the extent that the utility reasonably determines such decisions as related to reliability planning are inconsistent with good utility practice, SERC or NERC established criteria, or least cost integrated resource planning principles. *Id.* at 46.

Based on the foregoing and the entire record in this proceeding, the Commission concludes that the RZEP projects generally are necessary to help meet the requirements of Section 110.9. The Commission has seen the issues that the congestion on the transmission system in the southeastern part of the state has caused over the last five years and believes that the most efficient and effective path toward the State's carbon reduction goals is to incorporate proactive transmission planning. The Commission is satisfied that the Public Staff has properly investigated the need for the individual projects in the RZEP and therefore adopts the Public Staff's position that the RZEP projects should be constructed except for the Clinton 100 kV Line in DEC and the Camden-Camden Dupont Line in DEP. The Commission also concludes that Duke shall update its transmission cost adders using the results of the most recently available interconnection cluster study for future Carbon Plans/IRP Updates.

The Commission also believes that the future of generation and transmission planning will be more interrelated than ever before due to the requirement for transmission upgrades to be placed into service prior to the interconnection of generation. While this has always been the case, traditionally

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generation, or load, determined where transmission needed to be constructed. In this situation, while currently generation, in the form of solar facility interconnection requests, is determining what transmission projects are being constructed, the Commission can foresee a time in the near future where transmission projects could determine where generation is located. If DEP or DEC were to announce that certain transmission lines will be upgraded in the future, it is likely that, as long as the area was topographically appropriate, the generation would follow.

FERC Order 1000 was issued, in part, to require each local and regional transmission planning process to allow transmission providers the opportunity to consider transmission needs driven by public policy requirements in order to support more efficient and cost-effective achievement of those requirements.[4] FERC stated that other inadequacies were transparency and the lack of a requirement that the overall transmission planning process be open to customers, competitors, and state commissions.[5]

FERC stated in the recent Transmission Notice of Proposed Rulemaking (NOPR) that it is attempting to build off its previous orders, including Order No. 1000.[6] The FERC NOPR proposes to require public utility transmission providers to include in their Open Access Transmission Tariffs a Long-Term Transmission

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[4] Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils., Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), order on reh'g, Order No. 1000-A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132, order on reh'g and clarification, Order No. 1000 -B, 141 FERC ¶ 61,044 (2012), aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41 (D.C. Cir. 2014).

[5] *Id*. at 17.

[6] *Id*. at 2.

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Planning Process that would include transparent and not unduly discriminatory criteria to maximize benefits to consumers over time without over-building transmission facilities.[7] FERC also stated that it seeks to include in the Long-Range Transmission Planning "a process to coordinate with the relevant state entities in developing criteria."[8]

The Commission believes that FERC Order No. 1000, does not preclude this Commission from participating more fully in the local and regional transmission planning process. Further, the current FERC transmission NOPR states that FERC would like more state oversight into these long-term transmission planning processes. Therefore, the Commission requires all proactive public policy transmission upgrades to be in a Commission approved Carbon Plan/IRP prior to being included in the NCTPC's local transmission plan or the SERTP regional transmission plan to ensure that there is transparency in which projects will be included in the local transmission plan in order to ensure consumers realize the maximum benefits over time without over-building these transmission facilities. The Commission is not attempting to supersede the NCTCP process, but this will provide the Commission with a better understanding of where generation is likely to be built in the future and will allow the Commission to have more insight into the costs that DEP and DEC are incurring to interconnect generating facilities as they implement the Commission's Carbon Plan. Further, the Commission and the

[7] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, RM21-17-000 at 241.

[8] *Id.*

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Public Staff, which are both members of the TAG will continue to monitor the NCTPC process. For each proactive transmission project presented to the Commission for consideration of adoption into the Carbon Plan, Duke shall provide justification for the project and the lead time to construct the project.

Further, Duke shall expand its internal transmission planning horizon to 20 years. Duke shall also continue to provide updated locational guidance maps in future DISIS processes and procurement solicitations, and to show any proactive transmission upgrades expected to be in service within the locational guidance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-38

The evidence for these findings of fact is found in Duke's Proposed Carbon Plan and Petition for Approval, the initial comments of the Public Staff, the direct and rebuttal testimony of Duke witnesses Regis Repko, Steve Immel, Chris Nolan, and Clift Pompee (Long Lead-Time Resources Panel), the testimony of Public Staff witnesses Dustin R. Metz and Jeff Thomas, the direct and rebuttal testimony of Duke witnesses Glen Snider, Bobby McMurry, Michael Quinto, and Matt Kalemba (Modeling and Near-Term Actions Panel, or MNTA Direct Panel), the testimony of CIGFUR witnesses Michael P. Gorman and Bradford D. Muller, the testimony of NC WARN *et al.* witness William E. Powers, the testimony of EWG witness Arjun Makhijani, the testimony of AGO witness Edward Burgess, the testimony of Duke witnesses Dewey S. Roberts II and John Samuel Holeman III (Reliability Direct Panel), the testimony of Tech Customers witness Michael Borgatti, the initial comments of Avangrid, the testimony of Avangrid witnesses Michael Starrett and

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Becky Gallagher, the testimony of TotalEnergies Renewables USA witness Nicholas Prokopuk, the testimony of Duke witnesses Dewey S. Roberts II and Maura Farver (Transmission Direct Panel), and the entire record in this proceeding.

As part of complying with the requirements of HB 951, Duke contemplated utilizing a variety of low or zero carbon-emitting electric generating resources. Some of the contemplated resources will either take several years to develop or will require further evaluation. In particular, Duke focused on three categories of resources: (1) SLRs for its existing nuclear fleet and development of new SMRs; (2) additional pumped storage hydro; and (3) offshore wind. Petition for Approval, 9. These resources are referred to by Duke as "long lead-time resources."

Duke did not request that the Commission "select" long lead-time resources under HB 951 at this time. Tr. vol. 17, 78. Instead, Duke proposed to begin development activities with respect to those resources in the near-term, and to provide the Commission with additional information and more refined cost estimates regarding these resources in future proceedings. *Id.* at 79. Duke also stated that, with respect to long lead-time resources, the Commission's approval of development activities would have no impact on any future required regulatory approvals for such projects, including, where applicable, a CPCN.

With respect to the Companies' statement regarding regulatory approvals, the Commission agrees and emphasizes that its approval of any development

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activities in this proceeding shall not obviate in any way the obligation for Duke to seek required regulatory approvals including, where applicable, a CPCN.

Nuclear Resources

Duke's Proposed Carbon Plan relies on both continuing to operate its current nuclear fleet and on constructing new SMRs.

SLR for Duke's Existing Nuclear Fleet

Duke has the largest regulated nuclear fleet in the country and utilizes those generation resources to provide approximately 10,773 MW of capacity, which is over 50% of the electricity used by Duke's customers in the Carolinas. This generation is approximately 83% of the zero-carbon energy produced by Duke overall. Tr. vol. 17, 93. In 2021, Duke's nuclear fleet operated with a combined capacity factor of 95.72%. Tr. vol. 17, 93-94. The current nuclear fleet provides power to more than eight million homes in the Carolinas. Tr. vol. 17, 95.

Duke has announced plans to pursue SLR for all 11 of its operating nuclear units. The licenses for the 11 units are presently scheduled to expire over the course of the years 2030 to 2046. SLRs, if granted, would extend the operating life of the plants for an additional 20 years, which would move the range of retirement dates to the years 2050 to 2064. Continued use of existing nuclear generation is an essential component of Duke's Proposed Carbon Plan. Tr. vol. 95, 25. In 2021, Duke filed its first SLR application. According to Duke, the regulatory approval process may take up to four years per SLR application. Petition for Approval, 11.

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All six portfolios modeled by Duke (P1 through P4, SP5, and SP6) rely on the continued use of the existing nuclear fleet. MNTA Direct Panel, Exhibit 1, 12, Section V.A. The costs associated with seeking SLR were not included as a separate category of expenses in rate impact estimates. CIGFUR Initial Comments, 13, Attachment G. Duke estimated the SLRs to cost between $45,000,000 and $50,000,000 per site. Tr. vol. 17, 204. This would involve a total expense for the entire nuclear fleet of between $240,000,000 and $300,000,000. Tr. vol. 18, 18. CIGFUR witness Gorman believed obtaining SLRs would likely incur a significant and material cost. Tr. vol. 22, 38.

Some intervenors were strongly in favor of, or opposed to, nuclear energy. Others faulted Duke for not including an itemization of the costs of SLR in its rate impact analysis. However, no intervenor who addressed SLR on the merits was opposed to Duke's stated intention to pursue SLR for its current nuclear fleet. Tr. vol. 21, 135. Although the Public Staff was not opposed to Duke's pursuit of SLRs, both the Public Staff and other intervenors testified that the following should be required of Duke in future proceedings: (1) identifying the actions necessary to continue safe and reliable plant operations; (2) demonstrating that SLR activities and costs incurred are reasonable and prudent; (3) providing details regarding the scheduling for pursuing SLRs for each existing nuclear plant; (4) modeling a contingency in the event any nuclear plant does not succeed in obtaining an SLR or its operation becomes no longer economically prudent; and (5) providing cost estimates and projected rate impacts associated with SLRs. *See, e.g.*, Tr. vol. 21, 133-34; Tr. vol. 25, 354-55.

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The Commission finds and concludes that Duke's pursuit of SLRs for its existing nuclear fleet is appropriate. Duke has experience with the operation of its current nuclear fleet and has previously successfully obtained extensions for its licensure. Further, based on the record, the Commission is of the opinion that existing nuclear generation is a critical component of Duke's carbon reduction goals.

However, the Commission desires greater transparency into SLRs. Therefore, the Commission finds and orders that Duke should provide additional information regarding SLRs in the 2024 Carbon Plan Update/IRP proceeding to enable an analysis of the associated activities and costs. This would include, but not necessarily be limited to, the following: (1) identifying actions necessary to continue safe and reliable plant operations; (2) providing details regarding the scheduling for pursuing an SLR for each existing nuclear plant; (3) modeling a contingency in the event any nuclear plant does not succeed in obtaining an SLR or its operation becomes no longer economically prudent; and (4) providing cost estimates and projected rate impacts associated with SLRs.

<u>New SMRs</u>

The nuclear generation discussed in the section immediately above results from electric production at traditional, large-scale nuclear power plants typically with a nameplate capacity of approximately 1,000 MW or more. In the United States, new construction of traditional, large nuclear facilities has proven to be logistically problematic and has resulted in significant cost overruns and even

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cancellations of projects. Tr. vol. 21, 130-31. However, there are two additional types of nuclear generation addressed in Duke's Proposed Carbon Plan: advanced reactors and SMRs.

Advanced reactors are nuclear generation facilities that do not use water as the primary coolant. Such advanced reactors use liquid metal, molten salts, or high-temperature gas for cooling. *Id.* at 131. There are currently no commercially operating advanced reactor generating facilities in the United States. Tr. vol. 17, 183-84.

SMRs are described by their name. They are physically smaller and generate less electricity than traditional nuclear plants, are modular in the sense that much of the construction can be completed offsite and rely on nuclear reactors to generate electricity. Tr. vol. 21, 128. SMRs are smaller scale in terms of size, cost, and construction time due to their modular characteristics. In addition, the size and modularity provide for more flexibility in terms of siting and land requirements. Tr. vol. 21, 131. SMRs use water for cooling, just like the traditional nuclear fleet presently operated by Duke. SMRs therefore are based on well-known and proven technology and as such should both have a more readily available supply chain and a less challenging licensing path. Tr. vol. 29, 97.

Duke is experienced with storing used nuclear fuel through its operation of its large, traditional nuclear fleet. Duke testified it is reasonable to expect that used nuclear fuel resulting from future operations of SMRs would be handled similarly to Duke's current practices. Tr. vol. 29, 108.

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SMRs are present in all six portfolios modeled by Duke, including SP5. Some portfolios selected SMR generation as early as 2032, but by 2035 all six portfolios include approximately 600 MW of power supplied by SMRs. By 2050, new nuclear resources are modeled to provide generation comparable to that currently provided by Duke's traditional nuclear fleet. Duke Proposed Carbon Plan, Appendix E, 54-55, 86; Tr. vol. 7, 262.

Although there is much interest in the utility sector in SMRs, Duke acknowledges they are not a mature technology. Tr. vol. 18, 33-34. Presently, there are no SMRs in operation that are generating power and providing it for commercial operation. Tr. vol. 17, 183. Duke concedes that having SMRs in commercial operation by 2032 represents an "aggressive" schedule. Tr. vol. 17, 36.

Some intervenors expressed opposition to Duke's future use of SMRs, arguing that the technology is unproven, expensive, unlikely to be available, and will generate radioactive waste. *See, e.g.*, Tr. vol. 22, 154-214; Tr. vol. 24, 68-121. According to AGO witness Burgess, "[t]he Commission should use extreme caution in approving any development activities for new nuclear." Tr. vol. 25, 301.

Although SMRs are not a mature technology, they represent one of the "breakthrough technologies" contemplated by HB 951. Section 110.9(1). Several SMR projects are expected to be operating in North America over the next decade. Tr. vol. 17, 98-99. More than a dozen utilities across the country are planning to incorporate SMRs into their future generation plans. Tr. vol. 21, 77. The Public

Staff testified that it is reasonable to include SMRs as a potential future generation resource since it is highly likely it will be approved and deployed. Tr. vol. 21, 258-59.

The Public Staff is technology agnostic in terms of new nuclear technologies, Tr. vol. 21, 130, and Duke has not selected a preferred new nuclear technology. Duke is reviewing potential new nuclear power generation resources (SMRs and advanced reactors) to determine the most viable and cost-effective technologies. Tr. vol. 17, 100.

Duke proposes to take certain near-term development activities between now and 2024 related to SMRs, as follows: (1) organize nuclear development staff for new nuclear builds; (2) perform new nuclear alternative siting study; (3) perform new nuclear technology selection; (4) begin new nuclear early site permit development; (5) choose the advanced nuclear technology/company to build the first plant(s); and (6) develop a new nuclear construction and operating license application. The projected cost of the near-term development activities for new nuclear generation is $72,000,000. Tr. vol. 17, 31-32.

The focus of the near-term development activities is to pursue siting for an SMR by developing an early site permit. The multi-year process of obtaining such permits allow time for the reactor technologies to develop. Moreover, such permits can be renewed for up to 20 years. Tr. vol. 29, 107. Duke testified that it intends to be a "second mover" in the SMR field in an attempt to avoid first-of-a-kind costs. Tr. vol. 17, 105, 211.

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The Commission finds and concludes that Duke's limited development activities for SMRs are appropriate, and notes that SMR technology is relied upon in all of Duke's modeled portfolios. Although new, commercial SMR technology is based on existing technology and represents an important developing field that has the potential to be executable and provide carbon-free, reliable power at least cost. This is the type of "breakthrough" technology contemplated by HB 951. The Commission recognizes the risks to ratepayers of pursing breakthrough technologies, but risk associated with SMRs is mitigated by Duke's experience with existing nuclear technology, especially operating water-cooled nuclear reactors and disposing of spent nuclear fuel. Risk is further mitigated by the fact that Duke will review potential nuclear generation resources to determine the most viable and cost-effective technologies and provide the Commission with additional information and more refined cost estimates regarding SMRs in future proceedings.

The Commission notes Duke's proposed near-term development activities could be read to involve the "selection" and "choos[ing]" of a technology before the end of 2024. The Commission places great weight on Duke's pledge to be a "second mover" and allow time for reactor technology to develop and complete the Nuclear Regulatory Commission licensing phase. The Commission cautions Duke against incurring the risk associated with picking a specific SMR technology too soon.

The Commission is mindful of the importance of monitoring the development activities related to this breakthrough technology. Accordingly, the

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Commission orders Duke to provide updates on its progress, and any significant developments in the industry impacting Duke's plans, in the 2023 IRP Update and 2024 Carbon Plan Update/IRP filing.

Additional Pumped Storage Hydro

Since 1991, Duke has successfully operated the Bad Creek I energy generation facility. Bad Creek I stores and generates energy by moving water between two reservoirs at different elevations. During times of low electricity demand, surplus energy is used to pump water to an upper reservoir while during periods of high demand, the stored water is released down through turbines – hence the appellation "pumped storage hydro." As with traditional hydroelectric stations, the flow of water through turbines generates electricity. Bad Creek I provides 1,360 MW of capacity. Presently, upgrades are being made to Bad Creek I that will permit it to provide approximately 1,700 MW of capacity in 2023. Tr. vol. 21, 124; Tr. vol. 17, 85-86.

Duke has benefited greatly from the operating reserves and flexibility provided by pumped storage hydro. Tr. vol. 19, 176. Duke has determined that an additional 1,700 MW of capacity can be added to the Bad Creek station through the addition of four new generating units and other improvements. Hereinafter, this pumped storage hydro resource expansion project is referred to as "Bad Creek II." Tr. vol. 17, 87.

Duke has already undertaken some development activities related to Bad Creek II, including retaining an engineering firm to perform a feasibility study

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scheduled for completion this year. Tr. vol. 21, 125-26; Tr. vol. 17, 89. Duke has projected $35,855,000 in expenses related to Bad Creek II near-term development activities. Given the anticipated time involved in obtaining licensure and then completing construction, Duke projects Bad Creek II will be in service in 2033. Tr. vol. 17, 90. The Public Staff has noted this timeline may not be realistic and requests that periodic reporting on the project's status be made. Public Staff Initial Comments, 98-99.

All six portfolios modeled by Duke (P1 through P4, SP5, and SP6) include 1,700 MW of capacity from Bad Creek II coming online in the mid-2030s and remaining in service through at least 2050. Duke Proposed Carbon Plan, Appendix E, 86; Tr. vol. 7, 262.

Duke opined that there appears to be substantial support for Bad Creek II. Tr. vol. 29, 91. Duke is correct that intervenors largely did not take issue with the near-term Bad Creek II development activities proposed by Duke. Many included Bad Creek II's capacity in their own proposals. *See, e.g.*, Tr. vol. 25, 47; Tr. vol. 27, 94-95. AGO witness Burgess found pumped storage hydro to have "the most certainty" of the long lead-time resources. Tr. vol. 25, 300.

The Commission finds and concludes that Duke's limited development activities related to Bad Creek II are appropriate, as Bad Creek II would serve as a valuable system resource. The Commission notes that Bad Creek II's pumped storage hydro is relied upon in all modeled portfolios. Duke has experience with

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the operation of its hydroelectric stations, including pumped storage hydro. There was no substantial opposition to Bad Creek II among intervenors.

The Commission also concludes that Duke shall file a quarterly report on the timeline of the project along with expected project spend. The Commission further orders Duke to provide updated expected project costs in the 2024 Carbon Plan Update/IRP filing.

Offshore Wind

Duke testified that offshore wind's benefits include carbon emission reductions, fuel cost savings, and resource diversity. Tr. vol. 17, 112. In May 2020, Duke Energy Renewables Wind LLC (DERW), an unregulated affiliate of Duke, entered into a lease for the Carolina Long Bay wind lease area, approximately 20 miles from Cape Fear. This wind lease area consists of approximately 55,000 acres and cost $155,000,000. Tr. vol. 17, 111; Tr. vol. 29, 103. The Bureau of Ocean Energy Management (BOEM) is the federal agency that regulates offshore wind development in federal waters.

Duke testified that a variety of obligations and timing requirements accompany holders of leases for offshore wind energy areas. Duke agreed that under the applicable law and lease, DERW would be required to submit a site assessment plan before June 1, 2023, and a construction operations plan before either December 2026 or June 2027, unless DERW seeks and is granted additional time from BOEM. Tr. vol. 17, 113-14; Tr. vol. 29, 127, 133. If DERW fails to comply with these obligations (in the absence of the grant of additional time),

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Duke agreed that DERW runs the risk of having its Carolina Long Bay lease cancelled by BOEM. Tr. vol. 29, 129-30.

Duke testified that after obtaining a lease for an offshore wind energy area, it can take eight to ten years to get to the point where electric power is commercially available. Tr. vol. 18, 80. In order to achieve offshore wind generation in this eight-to-ten-year timeframe, Duke outlined a series of steps that would be necessary, including: (1) obtaining BOEM's approval of a site assessment plan by 2024 for the Carolina Long Bay wind lease area; and (2) submitting a construction and operations plan to BOEM by 2027. Duke's Proposed Carbon Plan, Chapter 4, 20-21.

Obtaining approval of a site assessment plan and submitting a construction and operations plan do not necessarily have to be performed by Duke in order to keep offshore wind on the eight-to-ten-year timeframe. If DERW complies with the applicable law (without seeking extensions), it would meet the timeframe proposed by Duke. The Companies agreed that if DERW moved expeditiously, DERW's actions would keep Duke on the same timeframe as outlined in its near-term action plan. Tr. vol. 29, 134.

In fact, Duke believes its affiliate DERW is currently working on a site assessment plan that is targeted for completion by mid-2023. Tr. vol. 17, 120; Tr. vol. 18, 121. When asked if DERW would sell to Duke in five years, Duke testified: "I don't know. I presume so." Tr. vol. 18, 83.

Under the rules governing affiliates, Duke's purchase from DERW would be made at either the lower of cost or market. Duke asserts that because the auction was an independent, third-party process, the May 2022 auction necessarily set the market price. Duke's Proposed Carbon Plan, Chapter 4, 19; Tr. vol. 29, 103. Duke testified that its assertion regarding market price has not accounted for the recently passed IRA's impact on the offshore wind moratorium. Tr. vol. 18, 83.

Duke projects the near-term costs associated with offshore wind development to be $317,400,000. Approximately half of the funds would be used to purchase DERW's Carolina Long Bay lease. Tr. vol. 17, 119. Duke was unaware of whether DERW would purchase its lease back in the event Duke acquired it from DERW and then did not move forward with offshore wind generation. Tr. vol. 18, 83-84.

Two intervenors in this case, TotalEnergies and Avangrid, have also leased offshore wind lease areas. TotalEnergies has leased approximately 55,000 acres in the Carolina Long Bay offshore wind lease area that is adjacent to that of DERW. Tr. vol. 17, 111. Avangrid has leased 122,405 acres approximately 27 miles from the Outer Banks (the Kitty Hawk lease area). Avangrid Initial Comments, 5.

Avangrid testified that it "is open to any manner of transaction that is on reasonable terms and fairly values the Kitty Hawk lease area, including PPA transactions, or a sale of the lease area, in whole or in part." Tr. vol. 23, 173.

Avangrid stated that the Kitty Hawk lease area is on a much earlier permitting timeline than that of DERW. Additionally, Avangrid stated that the Kitty

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Hawk lease area is superior to Carolina Long Bay in wind speed, location, and anticipated cost, among other points. Avangrid Initial Comments, 15-17.

P1 includes 800 MW of offshore wind being added to the generation mix in 2030 with no increase through 2050. P2 includes 800 MW of offshore wind being added to the generation mix in 2030, 800 MW added in 2032, and the total offshore wind capacity climbing to 3,200 MW by 2050. P3 includes no offshore wind as part of the generation mix through 2050. P4 includes 800 MW of offshore wind being added to the generation mix in 2032 with no increase through 2050. SP5 and SP6 did not select offshore wind as part of the generation mix until the 2040s but include at least 1,600 MW of capacity by 2050. Duke's Proposed Carbon Plan, Exhibit E, 73-77; Tr. vol. 10, 133; Tr. vol. 7, 262. Offshore wind is therefore only selected in half of the portfolios before the year 2040. Tr. vol. 18, 81.

Offshore wind development in the United States on the scale proposed by Duke is nascent. Tr. vol. 21, 127. Duke concedes that offshore wind has not been deployed at a large scale in the United States. Tr. vol. 7, 222. Presently, other hurdles exist with offshore wind, including the lack of Jones Act-compliant seagoing ships and the risk of strong hurricanes in the area. Public Staff Initial Comments, 91-92.

Offshore wind generation requires undersea cabling, landfall facilities, and overland routing to the point of interconnection to Duke's grid. A 2020 NCTPC Offshore Wind Study was performed which provided a comprehensive screening analysis for several potential points of interconnection. However, that study was

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not an official generator interconnection study responding to an interconnection request being submitted to the DEP Transmission Provider in accordance with the FERC-approved process in the OATT. In order for offshore wind to be appropriately connected to the grid, official generator interconnection studies would have to be conducted. Tr. vol. 16, 100.

Public Staff witness Metz recommended that at this time the Commission deny the request to begin the near-term development activities sought by Duke, especially the affiliate transfer from DEWR to DEP. Tr. vol. 21, 127. Duke testified that the Public Staff's position "would effectively eliminate the ability to keep offshore wind as an option to meet the 70% Interim Target of the Carbon Plan." Tr. vol. 29, 96.

The Commission finds and concludes that Duke's request for an affiliate transfer and for DEP to be solely responsible for development activities related to offshore wind is neither appropriate, reasonable, nor prudent at this time. The Commission concludes that: (1) Duke should not take steps to procure or transfer DERW's Carolina Long Bay offshore wind lease, including through an affiliate agreement; and (2) Duke should not initiate permitting or development activities, including work on a site assessment plan or construction operations plan, related to offshore wind. DERW was not a party to this proceeding, and it is not clear what actions DERW can or will take with respect to development of the Carolina Long Bay lease. The Commission notes for clarity that this Order in no way applies to DERW or any other wind lease holder that is not regulated by the Commission and

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does not prevent their undertaking of any work on or development of an offshore wind lease.

The Commission notes that offshore wind is not selected until the 2040s in SP5 and SP6 and is not selected at all in P3. Given Duke's testimony that offshore wind can be developed in eight to ten years, the Commission sees no need at this time to move forward with any of the near-term development activities related to offshore wind set forth in Duke's Proposed Carbon Plan.

The Commission rejects Duke's assertion that a failure by Duke to acquire DERW's lease in the near term will "effectively eliminate" offshore wind as an option for interim compliance. The Commission finds that the offshore wind lease areas may be developed in the absence of Duke's ownership. In fact, such activities are required by both the applicable law and provisions of the BOEM lease. Should holders of offshore wind leases fail to move forward with the development of their areas for generation, they run the risk of cancellation. Bolstering the Commission's finding, Duke has testified that it believes its unregulated affiliate DERW is currently working on the required site assessment plan. Moreover, Duke's assertion ignores the existence of two other offshore wind leaseholders off the coast of North Carolina – Avangrid and TotalEnergies – who both testified that they were willing to engage in discussions with Duke. In fact, Avangrid is already further along in the development process of its offshore wind lease than DERW.

As provided above, not moving forward with Duke's proposed near-term development activities at this time will not impair carbon reduction goals and will permit this nascent technology to mature in the United States. Additional time will also allow for further analysis and study. The Commission has heard no compelling reason to shift development risks and costs from Duke's unregulated affiliate to Duke's ratepayers at this time.

In addition, the Commission is of the opinion that a study of the three wind lease areas off the coast of North Carolina would permit more accurate modeling in the 2024 Carbon Plan Update/IRP proceeding and enable the Commission to better understand the costs, potential, and timing of offshore wind resources. This study, to be performed by an independent third party, shall review differences in cost, performance, location, interconnection, timeframes, experience, and other factors that would enable a comparison and analysis of the three offshore wind lease areas.

Accordingly, the Commission finds and orders that Duke shall retain an independent third party to conduct the study and analysis referenced in this order. Duke shall work with that independent third party to obtain information that will enable more accurate modeling in the 2024 Carbon Plan Update/IRP proceeding. Duke shall assist the independent third party in obtaining information. Duke's assistance shall include Duke's requesting, on a voluntary basis, information (especially performance and cost information) from all lease holders of areas near the North Carolina coast where offshore wind generation may be sited. The

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independent nature of the third party and its work shall be maintained and respected by all parties.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 39-41

The evidence supporting these findings and conclusions is contained in the Companies' Proposed Carbon Plan; testimony and exhibits of Company witnesses Tim Duff and Lon Huber, Appalachian Voices witnesses Rory McIlMoil and Yunus Kinkhabwala, NCSEA, *et al.* witness Tyler Fitch, and Public Staff witness David Williamson; the Initial Comments of the AGO, Appalachian Voices, CIGFUR, the City of Charlotte, NCSEA, *et al.*, Durham County, EWG, NC WARN, *et al.*, and the Public Staff; and the entire record in this proceeding.

Duke's Grid Edge Forecasts

Appendix F to the Companies' Proposed Carbon Plan sets forth Duke's forecast assumptions regarding the growth of its Grid Edge initiatives. These Grid Edge initiatives include net energy metering (NEM), electric vehicles (EV), dynamic rate designs, demand response (DR), and UEE, as described in more detail below. The Grid Edge initiatives reduce the gross load forecast over the Companies' planning horizon to determine the net load forecast.

Net Energy Metering

Appendix E to the Companies' Proposed Carbon Plan states that the base NEM growth reflects the currently approved net metering rate designs as of January 1, 2022. Appendix E also indicates that investment tax credits and the

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cost of rooftop panels were considered in the low load forecast. Appendix F discusses the development of modeling assumptions and inputs related to NEM. Much of the Companies' forecasting relies on the current state of NEM in North Carolina, including growth of new solar customers, and currently approved rate designs. In Appendix G to their Proposed Carbon Plan, the Companies further explained that, if approved, DEC's and DEP's proposed Solar Choice Net Metering options (initially filed in Docket Nos. E-7, Sub 1214, and E-2, Sub 1219, and transferred to Docket No. E-100, Sub 180) will include dynamic pricing rate designs that vary based upon the time of day and peak demand and will integrate with other EE and DR measures to offer customers additional participation incentives. Appendix G highlights DEC's and DEP's proposed Smart $aver Solar Programs (Docket Nos. E-7, Sub 1261, and E-2, Sub 1287) that will offer eligible residential customers an upfront incentive associated with investment in rooftop solar. Duke further anticipates that bundling behavioral DR programs with rate design options to encourage adoption and enable additional responsiveness will likely lead to a greater uptake of behind-the-meter solar throughout the mid and latter half of the decade than that which is reflected in the base net energy metering forecast. Proposed Carbon Plan, Appendices E, 17; F, 8; and G, 17-19.

Electric Vehicles

Duke stated in Appendix E that the base EV load forecast was developed using trends and assumptions as of Fall 2021. The base forecast did not include specific projections of future growth from policies or trends from federal government incentive programs. The Companies' EV forecast as described in

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Appendix F stated that Duke incorporated recent goals from the Biden Administration that provide that 50% of new United States passenger car and light truck sales will be electric by 2030. Additionally, major automakers have announced a goal of 40% to 50% of new vehicle sales being electric by 2030. Additionally, North Carolina Executive Order 246 directs the North Carolina Department of Transportation to develop a plan to achieve 1.25 million registered zero-emission vehicles on the road by 2030. Applying these assumptions, the Companies used the Vehicle Analytics and Simulation Tool to produce hourly load shapes to determine the demand and energy requirements needed to forecast the EV potential for the system over the planning horizon. Proposed Carbon Plan, Appendices E, 18; F, 11.

Dynamic Rate Design

Chapter 4 of the Companies' Proposed Carbon Plan briefly discusses some of the near-term rate design actions considered to encourage customers to change their load profiles to better support lower- and zero-carbon resources. This includes updating pricing structures for distributed solar resources, development of new real time pricing tariffs for large business customers, and piloting subscription rates to encourage customers to actively manage their charging behaviors. Rate programs such as the critical peak pricing and peak-time programs are intended to send signals to customers to incentivize reduction of their energy consumption during peak hours. The effects of these and other rate programs are captured in the load forecast and modeled as a reduction in load. Proposed Carbon Plan, Ch. 4, 32; Appendix E, 24.

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Demand Response

Appendix G discussed the Companies' shift from historically focusing on peak shaving capability to looking instead at load shaping capability, with the Companies being able to load shape to maximize renewables available at any given moment, thereby reducing steep ramping of central generation as the sun sets and taking advantage of over-supply scenarios. Duke suggests that load shaping capability would be used both for emergencies (e.g., large customer participants occasionally shut down their manufacturing lines or reschedule workers to ensure system reliability conditions during an emergency) and to provide more flexibility (more frequent but minor inconveniences to customers). Duke explained that it is shifting its focus to reducing the winter peak demands due to the large increase of intermittent solar generation during the summer, and that strategies to flatten peak demand must include a focus on residential customers, thereby making residential customer engagement critical to DR's ability to reduce the winter peak. Proposed Carbon Plan, Appendix G, 25-31.

Utility Energy Efficiency

In Chapter 2 of its Proposed Carbon Plan, Duke described the key inputs it used in its Carbon Plan modeling process. With respect to the electric load forecast, the Companies stated that their UEE savings reflected an incremental annual reduction of 1% of each year's eligible retail sales (1% annual target). The EE savings accounted for in the forecast modeling includes naturally occurring savings (occurring independently of UEE, such as market transformation), as well as historical impacts of prior utility programs and new and existing programs. The Companies noted that this 1% annual target was based upon an aspirational goal emerging from Duke's ongoing engagement with the Carolinas DSM/EE Collaborative. The Companies further explained that achievement of annual savings of this magnitude will require substantial customer participation and regulatory support. Proposed Carbon Plan, Ch. 2, 7-9.

In Appendix G to its Proposed Carbon Plan, Duke described its suite of existing Grid Edge programs and identified a number of risks in reaching the 1% annual target, including the need to timely obtain a variety of regulatory approvals and the significant barriers to customer participation in EE programs, such as inflation, supply chain risks associated with obtaining necessary supplies, potential economic downturns, and the inconvenience of DR programs to customers. Proposed Carbon Plan, Appendix G, 1-5.

In their direct testimony, Company witnesses Duff and Huber described the 1% annual target as appropriately aggressive yet achievable and stated that this modeling assumption was based upon "extensive, real-world experience in the Carolinas and detailed engagement in the Carolinas DSM/EE Collaborative," as well as historical levels of achievements, the forecast of UEE incorporated into the most recently approved IRPs, the performance targets built into the Mechanisms,[9] and the potential impact of some enablers. Witnesses Duff and Huber stated that

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9 The Companies' most recent Cost Recovery and Incentive Mechanisms for DSM/EE Programs were approved by the Commission's Order Approving Revisions to Demand-side Management and Energy Efficiency Cost Recovery Mechanism, issued on October 20, 2020, in Docket Nos. E-2, Sub 931 and E-7, Sub 1032.

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it is not necessary to have the perfect projection of future DSM/EE at this time and that the Companies focused on near term procurement and development, noting that the gap is smaller in the near term and the Companies can check and adjust continually moving forward. Accordingly, witnesses Duff and Huber requested that the Commission approve the modeling assumption that 1% of eligible retail load is a reasonable and prudent assumption for annual EE that can be achieved. Tr. vol. 13, 31, 73.

According to witnesses Duff and Huber, Duke does not believe that higher assumptions are reasonable or justified at this time under existing legal frameworks and market conditions. They cautioned that it is risky to assume an unachievable level of energy savings which could result in not planning for additional supply-side resources, and that any understatement of load would lead the optimization model to underbuild new supply-side resources or retire existing resources prematurely, thereby compromising system reliability. Witnesses Duff and Huber further testified that the success of the DSM/EE programs and magnitude of the resulting energy savings ultimately depends on customers electing to participate, and that the 1% annual target – which will deliver approximately a 5% cumulative reduction in total retail load by 2030 – is significant for a time period when many of the historic savings associated with the non-specialty lighting measures are rolling-off and shifting to being reflected as historic EE savings in the load forecast rather than UEE. Witnesses Duff and Huber also explained that the DSM/EE forecast included in Carbon Plan did not increase the amount of behavioral-based program savings beyond what was included in the

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Companies' approved 2020 IRPs, and that, to the extent the additional energy savings were needed to meet the 1% annual target, the equipment-based – as opposed to behavioral-based – measures were increased proportionally (based on residential and non-residential load growth) to reach the targeted energy savings levels in future years. Tr. vol. 13, 31, 50-55.

In response to the Public Staff's questions on questions from Commissioners Hughes and McKissick concerning the energy savings target, witness Duff testified that increasing the energy savings target to 1.5% or higher would not be least cost and that cost-effectiveness would "erode under the existing counting provisions." Tr. vol. 14, 105-07.

In rebuttal testimony, witnesses Duff and Huber acknowledged that achieving higher levels of EE savings, beyond the "low-hanging fruit" that has gone through market transformation and rolled off, will require new approaches and innovative efforts. Tr. vol. 28, 182-83.

Intervenors' Perspectives

<u>Net Energy Metering</u>

In its Initial Comments, the Public Staff stated that it did not take issue with the Companies' underlying forecast regarding NEM. The Public Staff requested that the Commission take judicial notice of its comments filed in the Solar Choice Net Metering and Smart $aver Solar dockets, and stated that, while it supports approval of the Solar Choice Net Metering proposal as described in its comments

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in that docket, it recommends that the Commission deny approval of the Smart $aver Solar program as an EE program, while noting its proposal that Duke review the potential of providing a rebate for the installation of residential solar if it is a resource that could assist Duke in achieving a least cost Carbon Plan. Public Staff Initial Comments, 62-63.

The AGO in its Initial Comments stated that Duke placed arbitrary limits on NEM and recommended that Duke model residential rooftop solar and analyze differing levels of residential rooftop solar adoption and how they are impacted by varying incentives. AGO Initial Comments, 23-24.

CIGFUR critiqued Duke's NEM load forecast for the Companies' failure to analyze or model the cost effects concerning NEM reform. CIGFUR Initial Comments, 15.

NCSEA, *et al.* also found Duke's projections for future NEM adoption to be too conservative, particularly when viewed in light of the number of the Companies' new NEM customers in 2021. As such, NCSEA, *et al.* stated that it is not reasonable to expect residential solar adoption rates to decline over the immediate Carbon Plan planning horizon and recommended that Duke adopt more reasonable assumptions for customer adoption of NEM for Carbon Plan purposes and continue to offer reasonable support for private investments in distributed renewable energy resources. NCSEA, *et al.* Initial Comments, 28-36.

NC WARN, *et al.* took issue in its Initial Comments with the fact that the NEM load forecast included in Duke's Proposed Carbon Plan is lower than the forecast that was provided in the Companies' 2020 IRP, with no explanation justifying this decline. NC WARN, *et al.* contended that the Companies' NEM tariff proposals in Docket No. E-100, Sub 180, will materially harm the value of rooftop solar systems. NC WARN, *et al.* therefore recommended that the Companies be required to correct their proposed NEM tariffs as discussed in NC WARN, *et al.*'s comments in Docket No. E-100, Sub 180. NC WARN, *et al.*'s Initial Comments, 32-34.

Electric Vehicles

The Public Staff in its Initial Comments stated that it did not take issue with the Companies' underlying forecast regarding EVs. The Public Staff acknowledged the nascent nature of the EV market, as well as the Companies' current efforts to research the EV market through EV-specific programs and the EV market's potential to introduce significant amounts of additional load in the coming years. The Public Staff noted that rates and programs that Duke is implementing now can shape customers' charging behaviors and habits, rather than waiting to implement new rates after EV adoption is more mature and customers have established charging behaviors. Although the Public Staff did not find it unreasonable that Duke did not include the impacts of EV-specific programs and rate schedules in its EV load forecast due to the uncertainty of customer response to these programs, it cautioned that failure to properly manage new EV load could result in increased system peaks and acceleration of the need for new system resources in the future. Public Staff Initial Comments, 64-65.

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The City of Charlotte commented on the importance of ensuring that load growth forecasts reflect known and emerging trends in transportation and building electrification. The City of Charlotte suggested that the impacts of electrification on the electric system should be fully analyzed and that the Companies should implement best practices for managing load growth and matching increased demand with zero-carbon generation should be fully analyzed. Finally, the City of Charlotte stated that Duke should further optimize charging behaviors through rate design that incentivizes behaviors beneficial to grid operation such as off-peak charging and Vehicle-to-Grid services. City of Charlotte Initial Comments, 10-11.

Durham County recommended that the Commission adjust load forecasts to account for changes due to beneficial electrification and decreases due to DSM and technological advances to improve utility planning and load management. Durham County Initial Comments, 6.

EWG cautions that Duke's Proposed Carbon Plan likely underestimates demand growth due to electrification of transportation and of non-electric energy uses in the residential and commercial sectors. EWG Initial Comments, 3.

Dynamic Rate Design

On the subject of dynamic rate design, the Public Staff further recommended that the proposals stemming from the Comprehensive Rate Design Study should be explored and, if shown to improve system efficiency and avoid significant cost shifts between customer classes, they should be offered on a pilot basis at a minimum. The Public Staff also discussed its concern that subscription-

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based or fixed bill rate designs have previously resulted in an increase in consumption and were eventually terminated by the Commission, citing the Commission's Order Ruling on Fixed Payment Programs dated March 14, 2008, in Docket Nos. E-2, Sub 847, and E-7, Sub 710. The Public Staff noted that it does not oppose any proposals at this time but also does not recommend any of the specific rate design proposals in the Proposed Carbon Plan in light of its view that any such proposals should be fully reviewed as part of a program application. Public Staff Initial Comments, 67-68.

Demand Response

Regarding the Companies' DR forecast, the Public Staff observed that stakeholders in the EE Collaborative have expressed interest in developing new DR programs and rate designs that provide a level of flexibility. The Public Staff stated its support for pilot programs to test the validity of factors such as the level of participant incentives needed to increase participation, the frequency and degree of using DR resources, and the level of discomfort participants are willing to tolerate but noted that support for pilot programs must be grounded in a firm understanding that any new pilot must eventually demonstrate long-term cost effectiveness potential before becoming a permanent program offering. In addition, the Public Staff stated that it did not foresee any significant change in customer acceptance and behavior regarding DR, noting that balancing Duke's need for DR with the need for maintaining and increasing participation is critical to any program's success – particularly with respect to Duke's efforts to increase winter-oriented DR where customers are unlikely to tolerate significant inconvenience

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resulting in cold indoor temperatures or limited hot water supply. As such, the Public Staff stated that it did not take issue with any of the Companies' DR enablers, but that none of the specific DR proposals outlined in Duke's Proposed Carbon Plan should be approved outside of the individual program approval process, in pilot programs submitted for approval based upon sound estimates of cost-effectiveness and of sufficient scale and scope to provide meaningful data for Duke to develop a full-scale program. Public Staff Initial Comments, 59-62.

Appalachian Voices stated in its Initial Comments that the Companies' DR forecasting greatly underestimates its potential and that DR does not play a significant role in Duke's Proposed Carbon Plan. Appalachian Voices recommended that expanding DR can play a significant role in reducing the need for gas CTs and help improve affordability for low-income residential customers. Appalachian Voices Initial Comments, 22-23.

CIGFUR stated in its Initial Comments that Duke did not analyze how implementation of new non-residential DR programs might be leveraged to provide system and ratepayer benefits. CIGFUR Initial Comments, 14.

NCSEA, *et al.* suggested that making certain DR programs "the default option," rather than requiring customers to sign up, may increasingly be necessary and that Duke could experiment with third-party aggregators to recruit customers to participate in DR programs. NCSEA, *et al.* Initial Comments, 27-28.

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Utility Energy Efficiency

While the Public Staff did not take issue with the Companies' forecasts concerning NEM, EV, dynamic rate design, or DR, the Public Staff did take issue with the Companies' hard-coding of a UEE forecast of 1% of prior-year-available retail sales, bypassing the Companies' most recent MPS. In his testimony, Public Staff witness Williamson explained that the Companies have traditionally relied upon, and the Commission has accepted, utility specific MPS to establish a benchmark for new EE measures and savings in IRP proceedings, and that the approach taken by the Companies in the Proposed Carbon Plan of applying a hard-coded aspirational UEE savings target as the modeling assumption in the UEE forecast deviated significantly from the Companies' use of achievable savings projected in its MPS for measure/program development. In witness Williamson's view, the Companies have failed to justify their 1% energy savings target, opining that the Companies are advocating for a UEE forecast that is neither based upon accepted practice nor approved in the DSM/EE rider proceedings, the Mechanisms, or the most recent IRPs. Instead, the Public Staff advocates that the Companies model the UEE forecast using their "low EE case assumption" as set forth in the most recent MPS. Tr. vol. 21, 172-85.

Witness Williamson explained that the Companies have struggled in recent years to maintain or increase cost-effective EE savings for some individual programs, as well as the overall EE portfolio, due to factors such as updates to codes and appliance standards, market transformation, and decreasing avoided cost rates which have lowered the economic value of EE benefits on a system basis. While the Public Staff noted that it has never objected to the use of the 1% savings target as a "stretch goal" for the Companies, the Public Staff recommends that the Companies rely on the most realistic and achievable energy savings assumptions to ensure that the load forecast, which ultimately drives statutorily mandated least cost resource planning decisions, is as accurate and reasonable as possible. Witness Williamson agreed with Company witnesses Duff and Huber that any overstatement of attainable EE savings results in an understatement of load that will lead to the optimization model under-building new supply-side resources or retiring existing resources prematurely, thereby compromising system reliability. The Public Staff further warned that if the Companies rely upon a hard-coded target of 1% prior-year-retail sales EE savings, every MWh of energy not reduced as projected must be served in some form, likely in a manner that is not least cost. In response to questions from NCSEA, *et al.*, Witness Williamson elaborated, testifying that hoping that savings will appear should not be a plan and that when it comes to reliability and operating the grid, we should be planning as realistically as possible. Tr. vol. 21, 365.

Witness Williamson further stated that Section 110.9 does not change any aspect of how UEE should be defined or modeled, nor does it alter the process for recovery of DSM/EE costs that has previously been approved pursuant to N.C.G.S. §§ 62-133.8 and 133.9, and, instead, Section 110.9(2) states explicitly that "[e]xisting law shall apply with respect to energy efficiency measures and demand-side management." As such, according to the Public Staff, until the Commission rules upon the Companies' proposed regulatory changes, which

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would change the methodology for counting DSM/EE savings and the calculation of cost-effectiveness; or until the General Assembly enacts a law directing how UEE should be handled or modified, it is unreasonable to advocate for such aggressive targets that go well beyond what is considered achievable in the current MPS. The Public Staff therefore recommended that the Commission find that the Companies' 1% energy savings assumption is not reasonable and prudent for purposes of modeling UEE, and that, instead, the Companies utilize the most recent MPS base scenario in its 2024 Carbon Plan Update. Tr. vol. 21, 185-91.

A number of other intervenors took issue with the Companies' 1% annual target, suggesting that this target was too low. For instance, the AGO stated in its Initial Comments that the Companies placed arbitrary limits on DSM/EE, with Duke having claimed that the 1% annual target is "very ambitious" despite other utilities across the country already exceeding this target. In addition, the AGO suggested that, as DSM/EE programs have the potential to be cost-effective means of offsetting additional generation, rather than assuming a set level of DSM/EE savings, Duke should allow increased levels of DSM/EE savings to be selected by the EnCompass model. AGO Initial Comments, 22-23.

Appalachian Voices witnesses McilMoil and Kinkhabwala compared Duke's 1% annual target to other states' achievements and testified that "higher targets are clearly achievable." Tr. vol. 24, 48-51.

NCSEA, *et al.* stated in their Initial Comments that, despite Duke's contention in its Proposed Carbon Plan that the Companies are national leaders in energy savings, the American Council for Energy Efficient Economy's 2020 Scorecard demonstrates that, when ranked against their peer utilities, neither company substantially exceeds the national average for energy savings. NCSEA, *et al.* stated that Section 110.9 provides the Commission with the authority to drive higher savings as integral to a least-cost pathway for achieving long-term carbon reductions. NCSEA, *et al.* therefore requested that the Commission find that a 1.5% savings of total load is a reasonable UEE target, with NCSEA, *et al.* witness Tyler Fitch opining in his direct testimony that a savings target of 1.5% of total retail load is the appropriate long-term savings target. NCSEA, *et al.* Initial Comments, 24-25; Tr. vol. 24, 183-84.

Commission Conclusions

The Commission appreciates the parties' attempts to promote and improve each of the Companies' Grid Edge programs that can cost-effectively achieve carbon reductions through reduced energy consumption. The Commission acknowledges that the effects of the Companies' Grid Edge programs have marginal but important impacts on the overall carbon reduction goal.

It is widely recognized that EE can be one of the least cost actions that customers and utilities can take to reduce consumption and thus reduce carbon emissions. Duke has worked to improve its EE potential by working through its EE Collaborative to develop cost-effective programs, improve participation in those programs, and work toward developing programs for low-income customers. However, the Commission also recognizes that, as Company witnesses Duff and

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Huber stated in their direct testimony, the 1% annual target is significant when many of the historic savings associated with the non-specialty lighting measures are rolling-off and shifting to being reflected as historic EE savings in the load forecast rather than UEE.

The Commission further acknowledges that Duke's achievements have come close to achieving 1% energy savings based upon eligible load, with only having an aspirational goal established. While the 1% annual target is a focal point of Duke's energy savings efforts, NEM, EV, dynamic rates, and other DR programs also present opportunities for the utility to optimize the load shape of the grid to reduce carbon emissions.

The Commission also recognizes that there are a number of actions Duke could take to further improve participation and energy savings in its EE programs, such as offering larger incentives to participants. This could be counter-intuitive because if participation does not increase despite the increased incentive, each unit of energy savings would come at greater cost overall (e.g. lower cost-effective), and would cause customers to pay higher rates for each kWh saved. The Commission believes that it is important to find the appropriate balance between lowering cost-effectiveness and the costs of pursuing greater energy savings. Given the marginal impacts of these Grid Edge programs, the Commission encourages Duke to continue working with stakeholders to develop programs to produce as much cost-effective savings as achievable. However, it is important to keep least-cost principles in mind in this analysis and, as Company witness Duff acknowledged in response to the Public Staff's question on questions

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from Commissioners Hughes and McKissick concerning the energy savings target, increasing the energy savings target to 1.5% or higher would not be least cost and cost-effectiveness would "erode under the existing counting provisions." Tr. vol. 14, 105-07.

At this time, the Commission does not believe that planning to achieve 1% of eligible retail load is a reasonable and prudent assumption for purposes of planning and declines to approve Duke's use of its proposed 1% target goal of energy savings. Although stated in response to a question specific to the Companies' proposal to expand the threshold for low-income programs, the Commission finds persuasive in the context of the 1% annual target the logic expressed by Company witness Duff that a specific numeric target is unnecessary where "the target is to do as much as we can."

Based on the foregoing and the entire record in this proceeding, the Commission concludes that the Companies' Grid Edge forecasts associated with NEM, EVs, dynamic rate designs, and DR are reasonable for planning purposes. For the assumption related to the Companies' UEE forecast, the Commission is not persuaded that Duke's 1% of prior-year-available retail sales target is appropriate for planning purposes. Instead, the base scenario from the most recent MPS, adjusted for any market or EE adoption trends reflected in the Companies' most recent DSM/EE riders, shall be the modeling assumption used for planning purposes. The Commission further concludes, in light of the many suggestions of the parties for increasing energy savings, that in Duke's 2024 Carbon Plan Update proceeding, it is appropriate for the Companies to use the following UEE forecast

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sensitivities: (1) the achievable utility EE potential as set forth in the most recent MPS; (2) Duke's proposal of 1% of eligible retail sales; (3) 1% of total system retail sales; and (4) 1.5% of total system retail sales.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42-46

The evidence supporting these findings and conclusions is contained in the Companies' Proposed Carbon Plan; testimony and exhibits of Company witnesses Tim Duff and Lon Huber and Public Staff witness David Williamson; Initial Comments of the AGO, NCSEA, *et al.*, and the Public Staff; and the entire record in this proceeding.

Duke's Proposed Enablers

Company witnesses Duff and Huber explained that Duke worked to identify enablers which, when considered along with new DSM/EE programs, would potentially allow them to achieve more EE reduction than what was included in the IRPs. According to witnesses Duff and Huber, the approval of these enablers is necessary for the Companies to achieve its 1% of prior year available sales annual target (1% annual target), although Duke acknowledges that the Companies have yet to model the cost impacts of the proposed enablers. While the Companies believe that the proposed enablers will increase the benefits, witness Duff testified that there will likely be corresponding cost increases, particularly with regard to increasing customer incentives. Tr. vol. 13, 38-39, 56-58, 71-73; Tr. vol. 14, 51-52.

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These enablers are as follows: (1) updating the inputs underlying the determination of the utility system benefits in the Companies' Mechanisms; (2) moving to an "as-found" baseline methodology to calculate energy savings; and (3) expanding the definition of low-income to include customers with gross household incomes under 300% of the federal poverty level (FPL). Witnesses Duff and Huber also advocate for implementing a cost recovery mechanism that will enable utility accounts to effectively finance efficiency upgrades in the form of a charge on the monthly bill and for an expedited Commission approval process for new customer pilot programs needed to accomplish energy transition required by the Carbon Plan. Tr. vol. 13, 38-39, 56-58, 71-73; Tr. vol. 14, 51-52.

Updating Mechanism Inputs

Witnesses Duff and Huber testified that Section 110.9 specifically contemplates the Companies' plan to update – in future proceedings – the underlying determination of the utility system benefits in the Companies' DSM/EE Cost Recovery Mechanisms. Although they assert that the current Mechanisms reflect the 1% annual target through their incentive and penalty structures, witnesses Duff and Huber testified that adjusting the Mechanisms will allow for appropriate valuation of demand-side distributed energy resources so that DSM/EE programs are evaluated on par with zero-carbon supply-side alternatives. In addition, witnesses Duff and Huber explained that modifying the Mechanisms could help increase incentive levels and participation while maintaining cost-effectiveness in existing programs and potentially allow for new programs and measures that would not otherwise have been cost-effective. Witnesses Duff and

Huber testified that the modifications sought by the Companies will likely specify that the per kW avoided capacity benefits and per kWh avoided energy benefits used will be derived from levelized average marginal supply-side resource costs utilized in the most recently approved Carbon Plan production cost model. Tr. vol. 13, 31, 57-59.

As-Found Baseline Methodology

Concerning the Companies' proposal to move to an as-found baseline methodology – which they describe as the promotion of early replacement rather than replacement upon failure – witnesses Duff and Huber testified that it is appropriate to recognize the amount of carbon being reduced associated with the old equipment compared to the new equipment. In Duke's view, the early replacement of inefficient equipment creates savings compared to the equipment being replaced at the end of its measure life, not the efficiency standard in place at the time of replacement. Witnesses Duff and Huber testified that the existing Mechanisms have the necessary protections built in, as they place a cap on the return on cost that the Companies may earn through their Portfolio Performance Incentive (PPI). Tr. vol. 13, 58-62.

Low-Income Eligibility Threshold

Witnesses Duff and Huber support the Companies' proposal to increase the threshold for participation in low-income EE programs so that the pool of eligible customers is larger. They testified that, because in many cases programs targeting low-income customers are not cost effective, the Companies will fully vet any new

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programs or modifications to existing programs with the EE/DSM Collaborative before filing for Commission approval. Tr. vol. 13, 57.

On cross-examination of their direct testimony, when asked by the Public Staff about the Companies' low participation in existing EE programs, witness Duff acknowledged that, despite the fact that 33% of DEC's residential customers at or below 200% of the FPL are eligible for its Weatherization and Equipment Replacement Program (Docket No. E-7, Sub 1032, approved October 29, 2013), only 0.068% percent of eligible customers have participated in the programs; and that, although 33% of the Companies' North Carolina residential customers are eligible for the Neighborhood Energy Savings programs (Docket Nos. E-7, Sub 1230, and E-2, Sub 1252), only 7.8% of eligible DEC customers and 10% of eligible DEP customers have participated in these low-income programs. Witness Duff also testified that increasing the threshold for low-income programs to include customers with gross household incomes up to 300% of the FPL would increase savings, but not cost-effectiveness. Tr. vol. 14, 45-46.

Tariffed-On-Bill Financing

Witnesses Duff and Huber further testified that the Companies' forthcoming tariff-on-bill program proposals,[10] once approved, will be important components of the Companies' energy transition and implementation of the Carbon Plan. In their

[10] At the time that Company witnesses Duff and Huber filed their testimony, Duke had not yet proposed any tariff-on-bill programs. However, since their testimony has been filed, both companies have filed numerous tariff-on-bill proposals. See Docket Nos. E-7, Subs 1278 and 1279; and E-2, Subs 1307, 1308, and 1309.

view, tariff-on-bill financing will serve as a cost recovery mechanism that will enable utility accounts to effectively finance efficiency upgrades in the form of a charge on the monthly bill which will reduce upfront financial barriers to EE investments. As such, the Companies requested that the Commission acknowledge – during the forthcoming tariff-on-bill proceedings – that tariff-on-bill programs are important components of Duke’s energy transition and implementation of the Carbon Plan. Tr. vol. 13, 56-57, 74.

Expedited Program Approval

Witness Huber testified that new technology and clean energy mandates and goals across the United States are driving utilities to rapidly innovate their customer programs and service offerings and that, on a national level, the regulated community is considering what changes to the existing regulatory process are needed to ensure that innovative solutions are identified, tested, deployed, and scaled at pace to meet these goals. Witness Huber suggested that flexible and expedited Commission approval processes that embrace a less formal and more collaborative process than the current Commission approval process are needed, and that collaborative regulatory processes will spur innovation needed to meet clean energy goals. As an example of an expedited approval process, witness Huber cites to the Flexibility Guidelines that the Commission has approved as part of the Companies’ currently approved Mechanisms, stating that the

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Flexibility Guidelines[11] have allowed for more streamlined minor modifications to existing DSM/EE programs so that the Companies can meet the need for program changes more quickly. The Companies believe that a similar expedited approval process for new customer pilots would better allow each company to innovate and timely implement the Carbon Plan. Accordingly, witness Huber testified that the Companies "plan to consider this issue further and may file a formal proposal with the Commission after it issues its Carbon Plan." Tr. vol. 13, 71-73.

Intervenors' Perspectives

Generally, the Public Staff's position was that it is not appropriate or necessary for the Commission to acknowledge, at this time, that the enablers identified by the Companies are necessary to achieve targeted EE savings, as acceptance thereof would require either public policy decisions by the Commission, legislative action, or a proceeding separate from this docket to investigate the impacts of any proposed enablers. Tr. vol. 21, 208-09.

More specifically, with regard to the updating the mechanism inputs, the Public Staff asserted that, with the Companies not having proposed a preferred portfolio (and having provided no details around avoided cost benefits) and the Commission not having approved a Carbon Plan that would use specific assumptions at this time, it is unable to assess the reasonableness of using specific inputs within a particular portfolio as the foundation for determining the

[11] DEC's Flexibility Guidelines were developed and filed with the Commission on February 6, 2012, in Docket No. E-7, Sub 831, and were approved on July 16, 2012. DEP's Flexibility Guidelines were approved on January 20, 2015, in Docket No. E-2, Sub 931.

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avoided cost benefits associated with UEE – a determination which the Public Staff contended is essential to the valuation of benefits and cost-effectiveness of DSM/EE. Instead, the Public Staff suggested that an update to the inputs underlying the determination of the utility system benefits, and modifications made to any of the individual components of the Mechanisms, must take place in the context of a full, formal review of the entire Mechanisms, with involvement from all interested parties, so that any impacts on other components of the Mechanisms can be analyzed at the same time. Tr. vol. 21, 194-96. In response to a question from Commissioner Hughes on this topic, witness Williamson elaborated that a full review would be a better use of everyone's time. He went on to discuss a recent endeavor to modify specific pieces of the EE Mechanisms and how it required three DSM/EE rider proceedings to finalize the changes, where a full Mechanism review would take one to two years. Tr. Vol. 22, 382-83.

Concerning the Companies' proposed as-found baseline methodology, the Public Staff stated that it does not object to the Companies claiming naturally occurring savings for purposes of Carbon Plan compliance, but that it does object to counting these same energy savings for DSM/EE cost recovery purposes. Witness Williamson described the Companies' as-found proposal as a combination of both naturally occurring EE savings and the incremental EE savings that are above equipment baselines or standards. Witness Williamson further described naturally occurring EE savings as energy savings that happen outside of a UEE program. The Public Staff expressed concern over the potential for the Companies to receive financial rewards with PPI, Program Return Incentive

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(PRI), and net lost revenues (NLR) for energy reductions that do not originate from, or have exceeded the life of, the EE measures that comprise their DSM/EE portfolios. The Public Staff stated that failing to properly account for these energy savings for cost recovery purposes could result in a financial windfall to the Companies. Tr. vol. 21, 195-99.

Moreover, the Public Staff explained that the Companies' proposed as-found baseline methodology for counting energy savings is not appropriate for any EE measure with an identified baseline efficiency, and that the Companies' new proposed methodology has generally been used to address measure installations that are custom or unique and do not have codes or standards upon which to base savings. Witness Williamson also explained that, under the new construct of performance-based ratemaking (PBR), the Companies should not receive credit for naturally occurring EE savings of residential customers as a result of switching to an as-found baseline methodology while also recouping fixed cost recovery erosion through the residential decoupling mechanism that will be part of future PBR/general rate case applications, as decoupling creates the potential for double counting between the DSM/EE rider proceedings' NLR calculations and the residential revenue decoupling mechanism in a PBR application. Tr. vol. 21, 195-99.

As such, the Public Staff recommended that the Commission distinguish the energy savings that can be used for DSM/EE cost recovery purposes from those savings that are used for Carbon Plan compliance purposes; that, if the Companies' as found methodology is approved for Carbon Plan compliance

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purposes, the Commission hold in abeyance the use of such methodology for cost recovery purposes until a full and comprehensive DSM/EE Mechanism review takes place and that, in the meantime, for any program approval or modification filed before the next Mechanism reviews, the Companies identify which methodology (traditional baseline or as-found) they intend to apply to each measure included in the program. Tr. vol. 21, 191-200.

The Public Staff stated that it did not support Duke's proposal to expand the definition of "low-income" to include those who have household incomes up to 300% of the federal poverty guidelines, noting that the Low Income Affordability Collaborative (LIAC) had expressly rejected the idea of an increased threshold because it encompassed too many customers, would increase costs and the potential for cross-subsidy that would accompany any expanded assistance program, and would dilute any mitigation efforts from those who were most vulnerable to falling behind on their bills and risking disconnection. The Public Staff also stated that it was not clear that this change would increase the EE savings potential of the Companies. In addition, the Public Staff noted that, typically, low-income programs are not cost-effective as they are designed to be delivered at no, or very low, cost to the participant, and that, while participants benefit from reduced bills, all customers bear the costs of programs that are not cost-effective and would do so to an even greater extent if eligibility were broadened. Rather than increasing the threshold, the Public Staff suggests that the Companies increase participation by better targeting its programs to the customers most in need by using information such as that produced by the LIAC, and by lowering costs and increasing benefits to all customers by increasing the cost-effectiveness of its low-income programs. Tr. vol. 21, 200-07.

Given the lack of specific information provided concerning tariff-on-bill programs or the idea of an expedited regulatory process for new programs, the Public Staff also disagreed with the Companies that it is appropriate or necessary for the Commission to acknowledge at this time, or in this proceeding, that tariff-on-bill programs are important components of the Companies' energy transition and implementation of the Carbon Plan or that an expedited regulatory process for new pilot programs is needed. The Public Staff noted that the Flexibility Guidelines were developed following consideration of the amount of notice parties should receive of modifications to DSM/EE measures or programs based upon the modifications' impacts on cost-effectiveness, costs, and savings. According to the Public Staff, allowing the Company to introduce new DSM/EE pilots, DSM/EE programs, and rate designs without a full review will jeopardize the Commission's ability to ensure that the pilots are reasonable and prudent before costs are incurred and that the pilots are being pursued in a manner that aligns with state policy, laws, and Commission rules. Accordingly, and in light of the fact that no specific proposal is before the Commission at this time, the Public Staff recommended that the Commission deny the Companies' requests related to tariff-on-bill programs and expedited regulatory approval in this Carbon Plan proceeding. The Public Staff further recommended that the process for pilot program approval is an appropriate topic for discussion in a comprehensive review of the current Mechanisms. Tr. vol. 21, 208-11.

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To a more limited extent, other intervenors also weighed in on the Companies' proposed enablers. The AGO stated in its Initial Comments that it did not support Duke's proposal to move to an as-found baseline. In doing so, it relied upon Strategen's analysis of the proposal which stated that, by setting an obsolete appliance as the baseline, Duke would be able to claim UEE savings for installing the most inefficient appliances the market has to offer – appliances which only meet the bare minimum of prevailing standards. Additionally, while Duke claims that the as-found approach will increase the overall amount of UEE savings achieved, the Strategen report stated that Duke would be artificially inflating the amount of savings counted for each measure by simply increasing the kWh savings attributable to each measure but not actually increasing the efficiency of the measures being installed. As such, according to the Strategen report, Duke would be able to reach its 1% annual target with fewer overall measures being deployed than it would have needed under the traditional baseline accounting method. AGO Initial Comments, 23; AGO Initial Comments, Attachment 1, 44.

NCSEA, *et al.* supported Duke's proposal to update the inputs underlying the benefits to the utility system in the DSM/EE cost-recovery mechanism so that those customer-sited programs are evaluated on par with zero-carbon supply-side alternatives, and so that a carbon price can be included in the avoided cost calculation. NCSEA, *et al.* also supported the Companies moving toward an as-found baseline for certain programs, such as tariffed-on-bill financing, which have the promise to unlock significant capital to finance deep retrofits at scale for residential customers who otherwise would not have been able to invest in such

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upgrades. NCSEA, *et al.* did not support Duke's proposals to expand the definition of low-income eligibility, noting that there remains much work to be done to reach the existing income-eligible customers who are most energy-burdened. NCSEA, *et al.* Initial Comments, 26.

Commission Conclusions

Based on the foregoing and the entire record in this proceeding, the Commission declines to acknowledge at this time or in this proceeding that the following changes need to be made as enablers to achieving the targeted EE savings: (1) updating the underlying determination of the utility system benefits in the Companies' approved DSM/EE Mechanisms; (2) adopting an "as-found" baseline methodology; or (3) expanding the pool of low-income customers to households with gross incomes up to 300% of the federal poverty guideline. Such proposals are better suited for discussion within the Companies' DSM/EE Mechanism reviews. The Commission is persuaded that it is appropriate to conduct a full review of the currently approved Mechanisms to begin within 90 days of this Order. In addition to consideration of the proposed enablers, the appropriate percentage of PPI and PRI, the impact of on-bill financing, the inclusion of a cost of carbon or non-energy benefits, whether NLR should continue to be collected through the DSM/EE riders if residential decoupling is approved in a MYRP, and other matters discussed herein, the Commission directs the parties to consider whether it is appropriate for the Mechanisms to provide a utility incentive for achieving energy savings at or below the target level of EE savings approved for use in the Carbon Plan or to only incentivize the achievement of energy savings over and above the target.

The Companies have not sought specific action in this docket concerning tariff-on-bill proceedings, and, as such, the Commission will address tariff-on-bill programs in their individual dockets. Similarly, when the Companies have a detailed proposal to expedite the regulatory approval process of new programs and pilots, this proposal should first be considered by the parties in the review of the Mechanisms.

The Commission further concludes that, while naturally occurring EE savings are appropriate for determining Carbon Plan compliance, the nature of these savings falls outside of savings eligible to be counted toward savings used in the DSM/EE cost recovery riders and that, going forward, for any program approval or modification filing, the respective company shall identify the methodology (traditional baseline or as-found) for calculating energy savings it intends to apply to each measure included in the program. In addition, the Commission concludes that it is appropriate to distinguish in program approvals and DSM/EE cost recovery proceedings the energy savings that can be used for DSM/EE cost recovery purposes from those savings that are to be observed for Carbon Plan compliance purposes.

In addition, the Commission concludes that it is appropriate for the 2024 Carbon Plan Update/IRP proceeding to include a transparent analysis that clearly illustrates the impact on the load forecast of: (1) each enabler described in

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Proposed Carbon Plan Appendix G if adopted, as well as any additional approved or proposed enablers; (2) the effects of market transformation; and (3) any other changes that might be considered in the context of a future MYRP. Additionally, the 2024 Carbon Plan Update/IRP should also include the individual rate impact of each enabler.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 47-48

The evidence supporting these findings and conclusions is contained in Duke's Proposed Carbon Plan, the testimony of Public Staff witness Dustin R. Metz, and the direct testimony of Duke's Modeling and Near-Term Actions Panel.

HB 951 requires that any generation and resource changes maintain or improve upon reliability. N.C.G.S. § 62-110.9(3). To test reliability, Duke performed an LOLE analysis on each of the portfolios. Duke used an industry standard one-day-in-ten-years LOLE, expressed as "0.1 LOLE." A 0.1 LOLE is interpreted as one firm load shed event every ten years due to a shortage of generating capacity. LOLE is an accepted metric for testing system reliability. Duke Proposed Carbon Plan, Appendix E, 9, 62.

Duke explained that, for each of the six primary portfolios (P1 through P4, SP5, and SP6), it used "SERVM," a program used to develop Duke's planning reserve margins, to test the portfolios across 41 weather years and a range of forced outage scenarios to ensure the EnCompass-generated models can maintain a 0.1 LOLE. If SERVM identifies deficiencies, alterations are made in EnCompass and the results are re-modeled and re-tested until there are adequate

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resources. Duke further explained that resource adequacy is a key ensurer of reliability. Tr. vol. 7, 231-33, 394.

All six primary portfolios passed the resource adequacy validation testing for both years 2030 and 2035 and therefore demonstrate reliability over that period. In addition, the testimony of Public Staff witness Metz notes that utilization of Duke's LOLE threshold highlights that the SP5 No App Gas portfolio's LOLE adequately addressed system reliability concerns at the generation level while mitigating concerns about execution risk and compliance with Section 110.9 requirements. Tr. vol. 21, 159; Tr. Vol. 20, 82; Tr. vol. 7, 394.

Based on the foregoing and the entire record in this proceeding, the Commission concludes that the LOLE calculation is an appropriate measure for testing reliability, and that Duke shall, in the 2024 Carbon Plan Update/IRP proceeding, calculate LOLE for each portfolio as a key metric for system reliability. The Commission also notes, in support of its earlier finding in this Order that SP5 is reasonable for planning purposes and as a foundation for the 2022 Carbon Plan and associated near-term procurement and development activities, that SP5, as discussed herein, demonstrates reliability through the year 2035.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-53

The evidence supporting these findings of fact is contained in Duke's Petition for Approval of Carbon Plan (Petition for Approval) and Proposed Carbon Plan, the Initial Comments of the Public Staff and intervenors, the testimony of Duke witness Laura Bateman, the testimony of Public Staff witnesses Michelle M.

Boswell, Jeff Thomas, and Dustin R. Metz, the responsive comments of Duke and intervenors, and the entire record in this proceeding.

Duke's Petition for Approval asks the Commission to determine, with respect to Duke's proposed project development activities, that:

> 1. 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;
>
> 2. 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, 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
>
> 3. 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.

Petition for Approval, 16.

In Chapter Four of Duke's Proposed Carbon Plan, Duke argues that such forward-looking approval is necessary and appropriate in this context where substantial development activities are needed in advance of final selection by the Commission to ensure that those resources can achieve commercial operation in a timely manner. Duke also stated that such forward-looking approval is consistent with N.C.G.S. § 62-110.7, which contemplates pre-approval of project

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development costs in connection with a potential nuclear electric generating facility. On Duke's request that the Commission determine that the initial project development activities associated with long-lead time resources are reasonable and prudent, Duke stated that it believes such activities are reasonable and prudent because they are necessary to keep long-lead time resources on a timeline that is consistent with the portfolios in the Proposed Carbon Plan and HB 951. With respect to the deferral request, Duke explained that while many of the project development costs to be incurred can be capitalized under applicable accounting rules, the Companies believe that it is appropriate to "ensure full clarity" that any such project development costs that are not capitalizable will be deferred for future recovery. Lastly, with respect to its request regarding abandoned projects, Duke stated that a predetermination of recoverability through base rates is consistent with N.C.G.S. § 62-110.7(d), which mandates that, after pre-approval of the incurrence of project development costs, the utility is entitled to recover such costs in the event a project is ultimately not required. Proposed Carbon Plan, Ch. 4, 7-8.

The Public Staff and a number of intervenors argued consistently that nothing in this proceeding should supplant the evaluation of the reasonableness and prudence of costs in a future general rate case. Tr. vol. 21, 98, 121, 129-30; AGO Initial Comments, 29-30; EWG Initial Comments, 20-23; NCSEA *et al.* Initial Comments, 20-21; Walmart Initial Comments, 2-10; CIGFUR Initial Comments, 23; CUCA Initial Comments, 5-7. For example, when discussing near-term resource development activities associated with both near-term resources and long lead-

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time resources, Public Staff witness Metz stated that "[a] review of the reasonableness and prudence of the costs incurred will be determined in the context of a general rate case proceeding, including a multiyear rate plan and, in some cases, in an annual fuel rider proceeding." Tr. vol. 21, 121.

With regard to Duke's deferral request, Public Staff witness Boswell testified that it is premature at this time to authorize any deferrals related to the Carbon Plan, and that deferral requests should be handled on a case-by-case basis, include full and detailed costing, including cost breakdowns between operations and maintenance (O&M) and capital costs, and be subject to the two-prong test of extraordinariness and magnitude, or such other criteria that the Commission considers relevant and important. Witness Boswell also stated that Duke had been unable to provide a breakdown of estimated costs between O&M and capital costs for the projects for which it is seeking deferral treatment. Further, she argued that Duke has an obligation to meet the carbon reduction requirements of Section 110.9 and has not shown how the projects depicted in Duke's Proposed Carbon Plan are outside the normal course of business. Tr. vol. 23, 119-20; Public Staff Initial Comments, 157-58. Relatedly, Public Staff witness Metz testified that Duke had begun planning and incurring costs for the Bad Creek II pumped storage hydro project before the enactment of Section 110.9 and without any preauthorization, including completion of a Pre-Feasibility Study in January 2020. Tr. vol. 21, 125.

Public Staff witness Thomas testified that the approval of certain actions by the Commission, such as procurement of S+S resources and construction of the RZEP upgrades, should in no way constitute approval of cost recovery. He

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emphasized that this proceeding is not a cost recovery proceeding and added that cost recovery is appropriately addressed in a general rate case, an MYRP proceeding, or another cost recovery proceeding where the appropriate investigation would take place on prudence and reasonableness. Tr. vol. 22, 325.

Several intervenors also stated in their comments that a deferral or any approval of costs related to project development activities for the 2022 Carbon Plan is inappropriate in this proceeding. CUCA Initial Comments, 4-7; NCSEA *et al.* Initial Comments, 20-21; Tech Customers Initial Comments, 15-18; Walmart Initial Comments, 5-10; CIGFUR Initial Comments, 23; CIGFUR Responsive Comments, 9. According to Tech Customers, Duke has not satisfied the test for deferral accounting, which is warranted only if the costs are extraordinary in nature and magnitude. Tech Customers explained that costs are extraordinary in nature when they are "unanticipated, unplanned, beyond the control of the utility, and of an infrequent, non-recurring nature." Tech Customers Responsive Comments, 17.[12] Tech Customers then argued that Duke's development costs do not fit any of these criteria, stating that Duke had already voluntarily adopted its own carbon reduction goals and identified SMR, offshore wind, and pumped storage as a potential resource in its 2020 IRP filings. Tech Customers further explained, with respect to the magnitude of costs, that Duke has not provided evidence that, absent deferral, these development costs would have a material impact on its

[12] Quoting Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Docket No. E-7, Sub 1214 (March 31, 2020), 138.

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financial condition. Tech Customers added that Duke has not in fact provided any evidence on financial impact because its Proposed Carbon Plan did not disclose expected development costs. Tech Customers Initial Comments, 17-18.

Witness Boswell also explained that the only existing statute that prescribes special ratemaking treatment for project development costs is N.C.G.S. § 62-110.7, which only applies to capital costs (plus allowance for funds used during construction) associated with nuclear facilities. Tr. vol. 23, 120. In its Initial Comments, the Public Staff excerpted the following language from a Duke response to Public Staff discovery:

> [T]he Companies' request in this proceeding for approval of certain development costs (including development costs for SMRs) is functionally the same as Commission pre-authorization to incur project development costs under N.C. Gen. Stat. 62-110.7 (and the Commission is free to deem such approval for SMR development costs as occurring under N.C. Gen. Stat. 62-110.7). The Companies believe a Commission determination on this issue is appropriate at this time, which would obviate a need for any subsequent application under N.C. Gen. Stat. 62-110.7.

Public Staff Initial Comments, 156.

Witness Boswell testified that N.C.G.S. § 62-110.7 applies specifically to nuclear facilities and should not be expanded to apply to the other resources included in Duke's deferral request, such as offshore wind and new pumped storage hydro. She also stated that the General Assembly could have expanded the project development statute to cover technologies other than nuclear facilities but did not do so when it enacted either N.C.G.S. §§ 62-110.7 or 62-110.9. Moreover, witness Boswell emphasized in her testimony that decisions regarding

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project development cost deferral for nuclear resources should be made on a case-by-case basis and reiterated that initial project development costs for the remaining resources identified in Duke's request for deferral do not meet the specific criteria set out in N.C.G.S. § 62-110.7. She explained that Duke has been unable to identify the breakdown of costs between capital costs and O&M costs, and that the Public Staff therefore does not have the information necessary to determine which initial project development costs might be eligible for special treatment under N.C.G.S. § 62-110.7. Witness Boswell consequently did not recommend approval of any nuclear project development costs at this time. Tr. vol. 23, 120, 122-23.

Likewise, several additional intervenors also argued in their comments that N.C.G.S. § 62-110.7 is only applicable to nuclear resources, and that a determination regarding special ratemaking treatment for new nuclear resources associated with the 2022 Carbon Plan under N.C.G.S. § 62-110.7 is inappropriate at this time. AGO Initial Comments, 29-30; Tech Customers Initial Comments, 16-17; Walmart Initial Comments, 6-7; CUCA Initial Comments at 6. For example, Tech Customers explained that N.C.G.S. § 62-110.7 authorizes the recovery of project development costs for "a potential nuclear electric generating facility,"[13] not the recovery of costs for offshore wind or pumped-storage resources. They further stated that N.C.G.S. § 62-110.7 requires the utility to provide "such information and documentation as is necessary" to "demonstrate by a preponderance of the evidence" that it is prudent to incur the development costs in question.[14] They

[13] N.C.G.S. § 62-110.7(a), (b).

[14] N.C.G.S. § 62-110.7(b).

commented that Duke had offered only its Proposed Carbon Plan, which does not establish prudence of near-term SMR, offshore wind, and pumped-storage projects. Tech Customers Initial Comments, 17.

Regarding Duke's request to prospectively authorize the recovery through base rates of abandoned plant costs associated with long-lead time resources in the event that those resources are "ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951," Public Staff witness Boswell testified that it is premature to authorize any potential recovery of abandoned plant costs related to the 2022 Carbon Plan. She stated that prospective authorization would remove critical checks on the Companies' spending that have historically helped ensure that capital expenditures are reasonable and prudent throughout the life of a project. She added that requests for recovery of abandoned plant should be handled on a case-by-case basis and held to similar historical standards of treatment of abandoned plant. Witness Boswell therefore recommended that the Commission forbear from determining the ratemaking treatment for such costs until the time a project ceases construction, and that the Commission not predetermine recovery timeframe, allocation, cost category, or the appropriateness of a return on the unamortized costs. Tr. vol. 23, 123-24.

In its comments addressing non-expert hearing legal and policy issues, Duke stated that the Companies are not requesting deferral authority or any finding that specific costs are reasonable and prudent. Duke expressly withdrew its request to defer, to the extent not already authorized under applicable accounting

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rules, associated project development costs for recovery in a future rase case. According to Duke, the Companies had determined that Commission approval to defer pre-CPCN development costs in a regulatory asset account is not needed at this time. Duke further represented that it would 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. Duke also acknowledged that the reasonableness and prudence of specific costs will be determined by the Commission in a future general rate case proceeding. Lastly, Duke stated that the Commission's ruling in this case, to the extent it grants the relief requested by Duke, would 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." Duke Responsive Comments, 49-50.

Duke's comments also reiterated its request in its Petition for Approval for assurances from the Commission that: (1) engaging in initial project development activities for 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 in a timely manner; (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) reasonable opportunity for recovery will be available

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to the Companies should the resource not ultimately be selected by the Commission and development activities are abandoned in the future. *Id.* at 38.

Duke argued that for new nuclear facilities, N.C.G.S. § 62-110.7 authorizes the Commission to approve the decision to incur project development costs and provides that all reasonable and prudent nuclear project development costs thereby incurred shall be fully recoverable in a general rate case proceeding. Duke added that in the event of cancellation of a project, reasonable and prudently incurred nuclear development project costs are also recoverable pursuant to N.C.G.S. § 62-110.7(d). With respect to the application of this special ratemaking treatment to other resources, the Company acknowledges that the statute only applies to nuclear facilities, but states that the Commission has previously 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. The Company explained that in 2006, Duke Power requested special ratemaking treatment for the proposed Lee Nuclear facility in Docket No. E-7, Sub 819. Duke Power expected to incur significant pre-CPCN development costs to develop the Lee Nuclear plant, and the Commission, prior to enactment of N.C.G.S. § 62-110.7, found that it had the legal authority to grant the requested assurance of future recovery of pre-CPCN development costs. Duke discussed the Commission's decision in the Lee Nuclear proceeding and stated that "[t]he exact same rationale underlying the Commission's decision . . . applies in the context of the Carbon Plan." *Id.* at 39-41.

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More specifically, Duke argued that, as with the Lee Nuclear decision, "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.'" (Emphasis in original) Duke stated that the fact that the General Assembly did not expand the scope of N.C.G.S. § 62-110.7 does not change the fact that the Commission previously granted the Companies' requested relief without express statutory authority and does not indicate that the General Assembly believed the Commission should not have that authority for resources other than nuclear. Lastly, Duke points to the language in HB 951 that directs the Commission to take "all reasonable steps" to achieve the emission reduction targets in the legislation, and argues that this should include pursuing new nuclear, offshore wind, and new pumped storage hydro at this early stage to ensure that these resources will be available when needed to meet the HB 951 targets. *Id.* at 41-43.

Relatedly, the Company argued in its non-expert hearing legal and policy comments that Duke has never been required to incur, prior to Commission approval, 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 Company argues that this justifies its requested treatment, and states that it would be inconsistent with the regulatory compact to impose on the Companies a legal obligation to perform substantial development work while denying any assurance of cost

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recovery, including in the event that a future determination is made that a long-lead time resource is not needed under the Carbon Plan, despite the prudent decision to pursue initial development work for those resources today. Duke stated that denial of its request would place all the risk on Duke, and would not be equitable to either the Companies, who would risk significant financial loss to pursue development, or to customers, who would risk losing the benefit of any resources the Companies chose not to develop. *Id.* at 43-46.

In discussing its request for cost recovery assurances related to project development activities, the Companies stated that their current cost estimates for offshore wind, nuclear, and Bad Creek II project development activities through the end of 2024, $325 million, $75 million, and $40 million, respectively, would serve as an appropriate cap of costs through 2024, and the Companies would commit not to incur cost in excess of those amounts without further approval from the Commission. Duke also proposed a biennial reporting obligation to keep the Commission apprised of the progress and status of development activities. *Id.* at 47.

In response to the Initial Comments of the Public Staff recommending that any request for assurances regarding nuclear development costs be addressed in a separate proceeding, Duke stated that N.C.G.S. § 62-110.7 allows utilities to request special ratemaking treatment at any time prior to the filing of a CPCN application, and that the level of detail provided in Duke's Proposed Carbon Plan and the Companies' testimony regarding its planned development activities for long lead-time resources is "materially greater" than that provided by Duke Power

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in the Lee Nuclear proceeding. Duke explained that the information provided in the Lee Nuclear request merely referenced and summarized its discussion of new nuclear generating facility development activities in its 2006 IRP short-term action plan. Duke added that it would be an inefficient use of regulatory resources to require the Companies to initiate a separate proceeding to address the assurances being requested here. *Id.* at 48-49.

In her rebuttal testimony, Duke witness Bateman confirmed that the Company has modified its Petition for Approval and is not seeking deferral of costs related to long lead-time resources. She also stated, in response to questions by Commissioner Duffley, that she does not consider the current proceeding to be a N.C.G.S. 110.7 proceeding or equate it to such a proceeding. She then stated the following: "it goes back to that basic ratemaking principle. If it's reasonable and prudent for the utility to pursue these development activities and we execute them in a reasonable and prudent manner, then we should be allowed an opportunity to recover those costs." Tr. vol. 28, 88-90.

The Commission first notes that Duke has acknowledged that the reasonableness and prudence of specific costs will be determined by the Commission in a future general rate case proceeding, and that the Companies have withdrawn their request for the authorization of deferrals related to project development activities associated with the 2022 Carbon Plan. Regardless, out of an abundance of caution, the Commission declines to make any determinations as to the reasonableness and prudence of costs associated with the 2022 Carbon Plan until such time that those specific costs are presented to the Commission in

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a cost recovery proceeding. The Commission emphasizes that approval of near-term development activities in the 2022 Carbon Plan does not constitute a determination as to reasonableness and prudence.

The Commission also agrees with the Public Staff and intervenors that such authorization of deferrals in this proceeding would be premature and inappropriate. Indeed, this is not a cost recovery proceeding. As noted by the Public Staff and Tech Customers, deferrals are appropriately handled on a case-by-case basis in a cost recovery proceeding such as a general rate case, and only after the receipt and consideration of detailed cost information and facts relevant to the criteria used by the Commission to approve a deferral, including the extraordinariness and magnitude of the costs incurred. In addition, as stated by Public Staff witness Boswell and Tech Customers, Duke has not shown how the projects in its Proposed Carbon Plan are outside the normal course of business. The Commission concludes that it is premature in this proceeding to authorize any deferrals related to the 2022 Carbon Plan, and therefore declines to do so.

The Commission further concludes that any decisions regarding the ratemaking treatment for long lead-time resources should be made on a case-by-case basis in an appropriate cost recovery proceeding. Duke argues that its request is consistent with N.C.G.S. § 62-110.7, which states:

> (a) For purposes of this section, "project development costs" mean all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs

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of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs.

(b) At any time prior to the filing of an application for a certificate to construct a potential nuclear electric generating facility, either under G.S. 62-110.1 or in another state for a facility to serve North Carolina retail customers, a public utility may request that the Commission review the public utility's decision to incur project development costs. The public utility shall include with its request such information and documentation as is necessary to support approval of the decision to incur proposed project development costs. The Commission shall hold a hearing regarding the request. The Commission shall issue an order within 180 days after the public utility files its request. The Commission shall approve the public utility's decision to incur project development costs if the public utility demonstrates by a preponderance of evidence that the decision to incur project development costs is reasonable and prudent; provided, however, the Commission shall not rule on the reasonableness or prudence of specific project development activities or recoverability of specific items of cost.

(c) All reasonable and prudent project development costs, as determined by the Commission, incurred for the potential nuclear electric generating facility shall be included in the public utility's rate base and shall be fully recoverable through rates in a general rate case proceeding pursuant to G.S. 62-133.

(d) If the public utility is allowed to cancel the project, the Commission shall permit the public utility to recover all reasonable and prudently incurred project development costs in a general rate case proceeding pursuant to G.S. 62-133 amortized over a period equal to the period during which the costs were incurred, or five years, whichever is greater.

No party disputes that this statutory provision is limited to nuclear resources, and Public Staff witness Boswell testified that the General Assembly declined to expand this ratemaking treatment to other resources in its enactment of both N.C.G.S. §§ 62-110.7 and 62-110.9. Duke, however, argues that the Commission has the authority to nevertheless provide the same treatment to other resources, and that it has done so in the past. The Commission notes, however, that even if the Commission were to determine that it had the authority to provide Duke with assurances regarding costs associated with project development activities for long lead-time resources, it can still find that such assurances are inappropriate in the current proceeding.

In its comments, Duke laid out similarities between the current Carbon Plan proceeding and the Lee Nuclear proceeding, arguing that project development costs associated with the 2022 Carbon Plan should be afforded the same treatment as those costs that were projected to be incurred for the Lee Nuclear plant. Here, however, the Commission agrees with the Public Staff and intervenors that Duke provided insufficient information concerning costs for the project development activities proposed by the Companies. The Commission is presented with a suite of resource options that could potentially form a future resource mix intended to comply with emission reduction targets—the long lead-time resources proposed by Duke are not specific project proposals, and Duke's filings lack the information necessary to determine which initial project development costs might be eligible for special treatment under N.C.G.S. § 62-110.7. Without more information, including more detailed cost information, providing assurances regarding cost recovery for those projects at this time is inappropriate. In addition, as discussed earlier in this Order, the Commission has found and concluded that

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it is not appropriate at this time for Duke to proceed with its proposed initial development activities for offshore wind, and it is therefore inappropriate to provide any assurances regarding development activities for offshore wind, specifically, at this time.

It is also worth noting that the Lee Nuclear docket was opened specifically to address the question of cost recovery for that project. Here, the Companies are requesting assurances for cost recovery in a general proceeding that is more akin to an IRP proceeding. In fact, Duke noted in its comments that the Lee Nuclear request was made *subsequent to and based on* an IRP proceeding—not in the IRP proceeding itself. This Carbon Plan proceeding is not the appropriate forum for cost recovery determinations or assurances that require detailed information and analysis.

The Commission also emphasizes, regarding Duke's comments concerning the regulatory compact, that the Commission is not making a finding in this Order that Duke will not be able to recover costs in the future, or that the Commission will not provide cost recovery assurances in the future—this Order is simply concluding that such determinations are premature, and that this is not the appropriate proceeding for such matters. Relatedly, the Commission declines to adopt or approve a cost cap at this time for the project development activities associated with long lead-time resources; all associated costs will be reviewed at the appropriate time in a cost-recovery proceeding. In addition, the Commission notes that even in the Lee Nuclear proceeding, which was referenced by Duke in its

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responsive comments, the Commission was able to review costs associated with the project before approving cost caps.

As noted by the Public Staff and intervenors, a utility seeking special ratemaking treatment under N.C.G.S. § 62-110.7 must provide such information and documentation as is necessary to support approval of the decision to incur proposed project development costs, including information necessary to demonstrate by a preponderance of the evidence that it is prudent to incur the costs in question. Those conditions have not been satisfied in this proceeding.

Regarding Duke's request for cost recovery of long-lead time resources ultimately determined not to be necessary to achieve the energy transition and CO_2 emission reduction targets of HB 951, the Commission agrees with the Public Staff and other parties that any potential recovery of abandoned plant costs related to the Carbon Plan is premature and inappropriate in the current proceeding. While Duke withdrew its request related to the deferral of costs associated with long-lead time projects, it maintained in its comments that it is requesting that the Commission find 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."

The Commission has historically made determinations regarding abandoned plant costs on a case-by-case basis after cancellation of a project, and no aspect of the 2022 Carbon Plan warrants or necessitates a deviation from this practice. The Commission's consideration of cost recovery for abandoned plant costs is appropriately conducted at such time a project ceases construction, and in an appropriate cost recovery proceeding. Such consideration includes a thorough and detailed evaluation of the reasonableness and prudence of capital expenditures throughout the life of the project—none of which can be predetermined. Therefore, it would be inappropriate at this time for the Commission to predetermine any aspect of cost recovery for abandoned plant costs, including a recovery timeframe, cost category, cost allocation, or whether a return on the unamortized costs is appropriate.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that the reasonableness and prudence of specific costs associated with the 2022 Carbon Plan, including those associated with long-lead time resources, will be determined by the Commission in future proceedings. The Commission also finds and concludes that it is premature in this proceeding to authorize any deferrals related to the 2022 Carbon Plan. Further, the Commission finds and concludes that the ratemaking treatment specified in N.C.G.S. § 62-110.7 is only applicable to nuclear facilities and does not apply to other resource types such as offshore wind and new pumped hydro, and that it is not appropriate in this proceeding to consider whether any costs for nuclear facilities are eligible for ratemaking treatment pursuant to N.C.G.S. § 62-110.7;

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rather, any such ratemaking treatment should be considered on a case-by-case basis in a separate proceeding. Lastly, the Commission finds and concludes that it is premature in this proceeding to authorize any potential recovery of abandoned plant costs related to the 2022 Carbon Plan, and that any request for recovery of abandoned plant should be handled on a case-by-case basis in a future proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 54

The evidence supporting these findings of fact and conclusions is contained in Duke's Proposed Carbon Plan, the direct testimony of Duke witnesses Snider, McMurry, Quinto, and Kalemba, the direct testimony of Public Staff witnesses Boswell and Metz, the Initial Comments of CIGFUR, the direct testimony of CIGFUR witnesses Michael Gorman and Brad Muller, the Initial and Supplemental Joint Comments of NCSEA *et al*., the direct testimony of NCSEA *et al.* witnesses Dr. Uday Varadarajan and Tyler Fitch, the Initial Comments of the Redtailed Hawk Collective and Robeson County Cooperative for Sustainable Development, and the Initial Comments of the Environmental Justice Community Action Network and Down East Coal Ash Environmental and Social Justice Coalition.

Pursuant to HB 951 and Commission Rule R8-74, Duke is required to securitize 50% of the remaining net book value of all subcritical coal-fired electric generating facilities to be retired to achieve the carbon reduction goals set forth in Section 110.9.

Duke indicated in its Proposed Carbon Plan that HB 951 recognized the importance of coal retirements to meet CO_2 emissions reduction targets by including provisions to facilitate securitization of subcritical coal assets that are retired early. Duke Proposed Carbon Plan, Appendix B, 19. Duke further stated that the modeling approach to coal securitization was one of the topics covered in Stakeholder Meeting 2. *Id.* at 9.

In addition, Duke indicated that the Companies previously performed retirement analyses "agnostic of remaining net book value of units at the time of modeled retirement," and that, for the Proposed Carbon Plan, the Companies have "factored into the coal retirement analysis, the benefits associated with securitization of the remaining net book value of subcritical coal at time of modeled retirement." Duke Proposed Carbon Plan, Appendix E, 46-49.

According to Duke, "[t]he accelerated retirement of these units allows for lower costs to customers associated with the securitized portion of the remaining net book value of the units if retirement is to achieve the authorized emissions reductions targets," and that "[t]o capture this benefit in the coal retirement analysis, the Companies modeled a securitization benefit for subcritical coal units that would have to be forgone if the unit were modeled to continue to be operated each successive year." *Id.* at 46-47.

Duke indicated that "[o]nce the cost projections for each coal unit for each portfolio development scenario had been input into the capacity expansion model, the Companies conducted the 'Coal Unit Retirement Runs,'" and that "[t]hese

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model runs allowed the capacity expansion model to retire the coal units alongside continuing to allow the model to select new resources, while maintaining achievement of the emissions reductions targets." *Id.* at 47.

Finally, Duke's Proposed Carbon Plan indicated that "endogenous capacity expansion modeling was used in the identification of coal retirement dates." However, Duke views the endogenously selected dates as "representative and directional in nature," and adjusted them to account for certain factors not considered by the screening model. Ultimately, Duke states that the retirement dates in the Carbon Plan will also be directional, and will depend on the procurement of replacement resources.

In its initial comments, CIGFUR indicated that while the accelerated retirement of subcritical units allows for lower costs to customers, Duke's retirement analysis was performed before the Commission issued its coal plant retirement securitization rules such that Duke's modeling might be considered somewhat conservative toward retirement. CIGFUR Initial Comments 17-18. CIGFUR recommended that the Commission require Duke to securitize the remaining net book value of each subcritical coal plant at the time of its retirement, if it is found by the Public Staff and the Commission to be in the economic interest of ratepayers. *Id*. at 39. CIGFUR believes that Duke's proposal fails to satisfy the least-cost requirement in that it does not "guarantee it will utilize and maximize securitization of early-retired coal assets for the benefit of ratepayers to the extent required by HB 951." *Id*. at 40-41.

In their initial comments, both the Environmental Justice Community Action Network and Down East Coal Ash Environmental and Social Justice Coalition and the Redtailed Hawk Collective and Robeson County Cooperative for Sustainable Development indicated that securitization is the most economic path to the early retirement of coal assets. EWG Initial Comments, 2.

In their initial comments, NCSEA *et al*. indicated that securitization helps mitigate costs to ratepayers, but that Duke's "artificially slow coal retirement plan risks leaving substantial securitization benefits untapped, which, if leveraged sooner, would realize significant savings for ratepayers, helping to offset some of the energy transition costs." NCSEA *et al*. Initial Comments, 6.

NCSEA *et al*. pointed to Rocky Mountain Institute's (RMI's) modeling of an MYRP and stated that an analysis of residential decoupling in Optimus, a utility finance model, shows that the Duke Resources scenario exposes customers to risks of steep rate hikes in a scenario with quicker than expected load growth (for example, from faster adoption of EVs or building electrification than Duke anticipates) coupled with higher-than-expected gas prices. RMI hypothesizes that this risk would be mitigated under an alternative resource scenario with a higher penetration of solar, battery storage, and wind resources "because a greater portion of demand would be satisfied with capital assets that are essentially fixed in cost and independent of the generation output." *Id.*

In their initial comments, NCSEA *et al*. also provided a report by RMI (Exhibit 1) entitled "Analyzing the Ratepayer Impacts of Duke Energy's Carbon

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Plan Proposal." In the report, RMI stated that Duke's Proposed Carbon Plan "underutilizes securitization as a source of ratepayer relief to mitigate rate spikes from early retirement of coal." NCSEA *et al*. Initial Comments, Exhibit 1, ii-iii. RMI estimated that Duke's proposal will result in approximately $14.1 million in savings for ratepayers as a net present value (NPV) in 2022 dollars. RMI also modeled the securitization of 50% of all unrecovered balances following a retirement of all subcritical Duke coal plants at the end of 2022 and estimated an additional $446 million in savings (NPV, 2022$) for ratepayers. *Id.*

RMI suggested that, from its perspective, Duke captures only 3% of the ratepayer savings available from securitization under HB 951. RMI modeled a securitization scenario outside the limits of HB 951 in which, "if all unrecovered balances from all Duke coal plants, including the supercritical Cliffside 6 and the recently retired G.G. Allen units, were securitized at the end of 2022, ratepayer savings from such a refinancing could reach $1.26 billion (NPV, 2022$)." *Id.*

In its report, RMI concluded that it would be unwise to adopt a Carbon Plan without "[e]xamining the impact of a fully economic retirement schedule (such as a scenario that allows EnCompass to select the economic retirements without exogenous limitations) inclusive of and considering the associated benefits of securitization." *Id.* at Exhibit 1, 26.

RMI recommended that the Commission require Duke to "use the full revenue requirement to estimate ratepayer costs (instead of just the forward-looking incremental costs, which treats expenses associated with the existing electric fleet as a foregone conclusion)" to "better reflect the cumulative impact on ratepayers and help the utility, the Commission, and intervening parties identify opportunities to reduce the cumulative costs of each portfolio scenario, including early retirement with refinancing options such as securitization or depreciation schedule adjustments of regulatory assets." *Id.* RMI also recommended that the Commission require Duke to provide "disaggregated cost projections associated with both existing assets and incremental additions for each portfolio scenario" and that such "disaggregation must differentiate maintenance capital expenditures and transmission-related levelized fixed charge rates from fixed O&M costs" to allow everyone to "understand and accurately reflect projected rates and bills trajectories, as well as the full potential benefits of mechanisms such as securitization." *Id.*

In supplemental comments, NCSEA *et al*. indicated that their analysis showed that Duke's plan would result in coal generation staying online for up to six years longer than necessary, thereby reducing the securitization benefits to ratepayers. NCSEA *et al*. Supplemental Joint Comments, 6. They attached to their supplemental comments a Synapse Energy report entitled "Carbon-Free by 2050: Pathways to Achieving North Carolina's Power Sector Carbon Requirements at Least Cost to Ratepayers." In this report, Synapse's EnCompass analysis projected that keeping coal units online to meet Duke's proposed retirement dates (rather than those selected by EnCompass) would cost ratepayers an additional $1.4 billion, even before accounting for fuel costs or variable operation and

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maintenance costs, which increase costs to ratepayers and diminish the value of securitizing the assets. *Id.* at Synapse Report, 29.

In its initial comments, CUCA requested that the Commission ensure that all sub-critical coal plants that are retired are subject to securitization. CUCA Initial Comments, 4. CUCA indicated that, if a sub-critical coal plant's retirement results in lower carbon emissions ("which seems inescapable"), the plant should be subject to securitization. CUCA expressed concern that Duke might attempt to exclude a retired plant from securitization by arguing that the plant was retired for economic reasons instead of to reduce carbon emissions. *Id.*

In response to CUCA's request that the Commission ensure all sub-critical coal plants that are retired are subject to securitization, Duke witnesses Snider, McMurry, Quinto, and Kalemba indicated in their direct testimony that Duke included securitization in the retirement analysis for all sub-critical coal plants. The Duke witnesses indicated that "[t]he securitization opportunity value was added to the fixed operations and maintenance (FOM) cost stream provided to EnCompass for its consideration in the coal unit economic retirement analysis. To the extent FOM is an avoidable cost with retirement, adding the securitization opportunity value to FOM enables EnCompass to consider it. To the extent the securitization opportunity is a declining stream, EnCompass has to incrementally choose year-after-year to continue to operate the unit and incur the securitization opportunity value as a cost (or rather in the inverse, choose to retire and take the securitization opportunity value as a benefit). As the value gets lower with time, it has less and less effect over time on that decision being made by the model." Tr. vol. 7, 331.

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In response to CIGFUR's recommendation that Duke consider converting existing coal units to run on gas rather than retiring the units, witnesses Snider, McMurry, Quinto, and Kalemba indicated that the Companies evaluated the high-level business case of expansions of gas cofiring beyond the current 50% at Belews Creek Units 1 and 2 and Marshall Units 3 and 4. The Duke witnesses indicated that, while the expansions were potentially feasible, Duke's evaluation did not show favorable economics. *Id.* at 332.

In direct testimony, Public Staff witness Metz indicated that the Public Staff was still reviewing the results of the additional model filed by Duke with its testimony on August 19, 2022. Tr. vol. 21, 112-18. Witness Metz recommended, and the Commission is persuaded, that Duke should continue to update the Commission and stakeholders of any changes to the current retirement schedule in an annual filing and in the 2024 Carbon Plan Update/IRP proceeding. *Id*. at 117.

Public Staff witness Boswell indicated that securitization of the Company's sub-critical coal-fired units that are retiring early to meet the carbon reduction goals of HB 951 must be conducted in a timely manner and maximize benefits to customers. She indicated that the Public Staff would continue to engage with the Companies to ensure compliance with Commission Rule R8-74. She recommended that Duke maximize cost savings by assessing whether it would be in the interest of ratepayers to securitize additional coal generation assets, including non-sub-critical coal units. Tr. vol. 23, 118. The Commission finds

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persuasive Public Staff witness Boswell's recommendation that it is appropriate for Duke to assess whether it would be in the interest of ratepayers to securitize additional coal generation assets, including non-sub-critical coal units.

In the direct testimony of NCSEA *et al*. witness Varadarajan, he stated that the "Duke Resources" scenario underutilizes securitization as a source of ratepayer relief to "mitigate rate spikes from early retirement of coal," and recited the savings discussed in the RMI report. Witness Varadarajan also discussed possible benefits associated with the recently passed IRA. Witness Varadarajan indicated that the new Section 1706 loan program "opens the way for low-cost financing for fossil asset transition without the restrictions on securitization in H951, in particular the 50% limit on retired plant balances eligible for securitization." He further stated that, "[w]ith Section 1706, plant balances could be refinanced in full using debt backed by the guarantee of the federal government with interest rates similar to, and potentially lower than, those achievable with securitization, and over longer tenors (up to 30 years)." He also testified that, "[a]s with securitization under H951, ratepayer savings under Section 1706 would tend to increase in line with the size of the plant balances refinanced and duration of the refinancing period, with earlier retirements yielding larger consumer benefits." Tr. vol. 24, 235-53. The Commission finds persuasive the testimony of witness Varadarajan and finds it appropriate for the Companies to assess possible benefits associated with the recently passed IRA to the benefit of ratepayers.

In his direct testimony, NCSEA *et al*. witness Fitch incorporated cites to the Synapse report "Carbon-Free by 2050" that provided that maintaining coal units past their economic retirement dates could cost Duke ratepayers $1.4 billion, "before accounting for fuel costs, variable operations & maintenance costs, or lost securitization benefits." Tr. vol. 24, 174-77.

In his direct testimony, CIGFUR witness Gorman indicated that "securitization bonds may be useful for reducing costs to customers for recovery of abandoned coal plant early retirement costs, and the securitization bond proceeds will enhance utility cash flows and support financial integrity during the development of low carbon replacement resources." Tr. vol. 22, 31. Witness Gorman also indicated that providing "accelerated recovery of early retirement cost of coal plants, particularly if DEC and DEP are refinanced using securitization bonds, will provide an immediate injection of cash to the utilities that may support any potentially weakened financial positions of the utilities as they move into major construction programs." *Id.* at 41.

In his direct testimony, CIGFUR witness Muller recommended that the Commission require Duke to affirmatively assure the Commission and ratepayers of Duke's intent to "securitize — for the benefit of ratepayers — 50% of the costs associated with the early, uneconomic retirement of its still serviceable coal fleet, which will come at a substantial cost to ratepayers and is another cost driver that Duke did not sufficiently quantify or otherwise account for in its cost estimates and projected rate impacts in its proposed Carbon Plan." Tr. vol. 25, 356.

Based on the foregoing and the entire record in this proceeding, the Commission concludes that securitization is an invaluable tool for the benefit of

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ratepayers in Duke's transition from fossil fuels and in its implementation of the Carbon Plan.

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EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 55-56

The evidence supporting these findings and conclusions is contained in the direct testimony of Duke's Modeling Panel and the Carolinas' Utilities Operations Panel, the rebuttal testimony of Duke witness Laura Bateman, the testimony of Public Staff witnesses Metz and McLawhorn, CUCA witness O'Donnell, and CIGFUR witnesses Gorman and Muller, the initial comments of the Public Staff, CIGFUR, and CUCA, and the entire record in this proceeding.

The Modeling Panel explained that its bill impact analysis shows the difference in incremental costs between the Proposed Carbon Plan portfolios, rather than the all-in costs of each portfolio. Tr. vol. 7, 289-90. They contended that including all costs to customers through 2050, including those unrelated to the Carbon Plan, would offer "no additional information or insight," and would be unnecessary and potentially counter-productive if it obscured the impact of differing investments. Tr. vol. 7, 290. Duke witness Bateman testified that Duke's presentation of the rate impacts with only revenue requirements caused by the individual portfolios was consistent with how it had traditionally presented PVRRs in its IRPs. She also noted that all-in forecasts of future bill impacts would inevitably be incorrect due to the many factors beyond Duke's control. Tr. vol. 28, 57-60.

Public Staff witness Metz disagreed with the exclusion of SLR costs from the calculation of bill impacts as the calculation does not represent the total cost impact to customers. He recommended that Duke provide an additional analysis that shows the total expected bill impact. Tr. vol. 21, 138-39. Public Staff witness McLawhorn testified that because costs that are common across all portfolios were not included in the rate impact analysis, he believed it likely that the rates were substantially understated. As such, he argued that Duke did not provide the actual costs ratepayers will bear. Mr. McLawhorn concurred that Duke should in the future provide bill impacts in two ways – a comparative analysis between portfolios as Duke has provided, as well as "all-in" bill impacts. He noted that, as stated in the Public Staff's initial comments, excluding fixed costs from the costs of existing generation plants artificially suppresses operational costs in the near term and prevents an analysis of the tradeoff between capital and production costs associated with renewable resources. Tr. vol. 23, 106-09. CUCA witness O'Donnell and CIGFUR witnesses Gorman and Muller echoed the Public Staff's request for an all-in bill analysis. Tr. vol. 25, 220; Tr. vol. 22, 43-44; Tr. vol. 25, 352-56.

The Commission finds that it was appropriate for Duke to calculate bill impacts showing the incremental differences between the portfolios in its Proposed Carbon Plan. Further, the Commission agrees with Duke witness Bateman that there are substantial uncertainties associated with projecting costs into the future, especially when the horizon for the projections is extended to 2050. Nonetheless, as discussed by the Public Staff, CUCA, and CIGFUR, ratepayers must have a clear picture of the cost of electricity they will pay as the Carbon Plan is implemented, including non-Carbon Plan costs. In its filing in the 2024 Carbon Plan

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Update/IRP proceeding, Duke should calculate two sets of bill impacts – one using the traditional methodology showing the incremental differences between portfolios, and a second that includes all known and measurable projected costs common across the portfolios. Duke should explain its assumptions used to make the projections and provide the amount of non-Carbon Plan costs it has included in its calculation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 57-58

The evidence supporting these findings and conclusions is contained in the direct testimony of Duke's Carolinas' Utilities Operations Panel, the rebuttal testimony of Duke witness Laura Bateman, the testimony of Public Staff witness McLawhorn, NCEMC witness Fall, CUCA witness O'Donnell, and CIGFUR witnesses Gorman and Muller, the initial comments of the Public Staff, CIGFUR, and CUCA, and the entire record in this proceeding.

Duke witness Peeler testified regarding the many benefits, efficiencies, and cost savings that would accrue from either consolidated system operations (CSO) or a merger of DEC and DEP and stated that merger is the preferred path because it would resolve rate disparity issues over time, spread costs over a larger number of customers, allow the development of a single IRP, and provide for joint unit commitment. Tr. vol. 15, 24-25. He noted that a merger of DEC and DEP would require regulatory approvals from the Commission, the South Carolina Public Service Commission, and FERC, and would result in a shift of cost responsibility from wholesale to retail jurisdictions. *Id.* at 26-27. Mr. Peeler said that to

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accomplish a merger, first Duke would seek to combine the DEC and DEP Balancing Authorities and the two companies' OATTs. It would require a study of the costs and benefits of a merger and the development of strategies to mitigate cost shifts, standardization of certain functions, and rate designs. Mr. Peeler projected that a merger could be accomplished by the end of 2026, including all regulatory approvals, and set out the timeline in his Exhibit 1. *Id.* at 27-28. Ms. Bateman acknowledged the rate disparities between DEC and DEP but stated that she did not foresee material widening of the gap from 2023 to 2026. *Id.* at 28-29. In her rebuttal testimony, Ms. Bateman contended there was no need at this time to develop a plan for allocating Carbon Plan costs due to the timing of the Carbon Plan investments and the proposed merger. She stated that if the merger was not achieved, after 2026, Duke would look at implementing other alternatives for solving the allocation issue. Tr. vol. 28, 56-57.

Public Staff witness McLawhorn discussed the rate disparity between DEP and DEC that has grown since 2012 such that DEP customers pay approximately 20% more than DEC customers for the same electric service. Tr. vol. 23, 91-92. He attributed the disparity in part to the greater solar development and the requisite transmission upgrades in the DEP territory and noted that DEP territory would be the likely location for any onshore or offshore wind transmission, as well as for increased solar and S+S development required by the Carbon Plan, further exacerbating rate disparities. *Id.* at 95-96. Mr. McLawhorn recommended that the costs of the Carbon Plan be allocated based on the benefits received by DEP and DEC customers as the Carbon Plan is mandated for the two companies on a

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combined basis, and that Duke begin working with the Public Staff to develop an allocation methodology at once. *Id.* at 97-98, 102. Mr. McLawhorn testified that a merger would be the best way to achieve a least cost Carbon Plan and that he found the merger timeline proposed by Mr. Peeler to be reasonable. *Id.* at 91, 102. However, he noted that it was incumbent on Duke to develop an allocation methodology now, as achievement of a merger was not certain and would not occur in any case for a number of years. *Id.* at 137. Mr. McLawhorn suggested that the Commission could set deadlines for development of the allocation methodology. *Id.* at 139. NCEMC witness Fall also testified as to the benefits a merger between DEC and DEP. *Id.* at 308-09. He noted that the proposed RZEP upgrades would be allocated to DEP customers despite their benefit to DEC customers and supported development of mitigation measures for the inequitable allocation of costs. *Id.* at 309-10.

The Commission agrees with Duke and the Public Staff that a merger of DEC and DEP would result in a number of benefits, including cost reductions and operational efficiency. Moreover, it would allow for the equitable allocation of the costs of the Carbon Plan and the gradual resolution of rate disparities. The Commission is aware of the regulatory hurdles Duke must scale before achieving a merger and understands that approval is not certain. Indeed, while the Commission is hopeful that the four-year timeline proves to be accurate, the Commission finds it necessary for the Companies to propose a method to allocate the costs of the Carbon Plan equitably between DEP and DEC customers in their current rate cases in the event a merger is not approved by a regulatory body or

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is not achieved in the projected timeline. The Commission disagrees with Duke witness Bateman that a methodology to allocate Carbon Plan costs between DEC and DEP is not necessary at this time. As witness McLawhorn noted, rates set in the Companies' next general rate cases may be in place for three to four years, and costs will be incurred during that time to meet Carbon Plan requirements. The Commission agrees with witness McLawhorn that it is imperative to have cost allocation methodologies established sooner rather than later to address costs incurred that benefit both DEC and DEP ratepayers. *Id.* at 139-40. Additionally, the Companies should file a report every 90 days detailing their progress in achieving a merger of DEC and DEP.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke shall file an IRP Update in 2023, and that the 2023 IRP Update shall provide information on milestones and development activities associated with the 2022 Carbon Plan.

2. That Duke's next comprehensive IRP shall be filed in 2024, and that the 2024 IRP and 2024 Carbon Plan Update shall be combined as a joint filing.

3. That Duke and the Public Staff shall work together to develop proposed revisions to Commission Rule R8-60 and convene a stakeholder process by which interested parties can provide feedback on those proposed revisions before they are filed with the Commission on or before April 28, 2023.

4. That the 2023 IRP Update and the 2024 Carbon Plan Update/IRP shall incorporate the impacts of the IRA.

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5. That Duke shall incorporate the recommendations specified in the Evidence and Conclusions corresponding to Findings of Fact Nos. 7-19 in its modeling for the 2024 Carbon Plan Update/IRP proceeding, as well as the IRP Update if applicable.

6. That Duke's filing in the 2024 Carbon Plan Update/IRP shall include modeled portfolios that reach interim compliance in 2030, 2032, and 2034.

7. That Duke shall, at the time it makes its filing in the 2024 Carbon Plan Update/IRP proceeding, concurrently provide all intervenors and the Public Staff with all modeling files, spreadsheets, and process documentation necessary to validate the modeling inputs and results filed by Duke, subject to any non-disclosure agreements.

8. That Duke shall set the 2022 Solar Procurement target amount at 1,200 MW, a maximum 441 MW of which will be used to fulfill the remaining CPRE Shortfall. All the MW procured for the CPRE Shortfall will be included in determining whether the VAM is triggered. One-third of the 1,200 MW procured shall be procured in DEC, one-third shall be procured in DEP, and the final one-third shall be comprised of the remaining most competitive bids in either DEC or DEP.

9. That Duke shall hold stakeholder discussions regarding a 2023 Solar Procurement and shall file, no later than February 1, 2023, an update outlining areas of agreement and disagreement, including proposed terms and conditions, operational conditions, and a *pro forma* PPA. Duke shall incorporate these terms

and conditions in its 2023 Solar Procurement to be filed no later than March 1, 2023.

10. That within 60 days of the issuance of this order, Duke, in conjunction with the Public Staff, shall file a plan for Commission approval containing all the information stated in the Evidence and Conclusions for Finding of Fact No. 26 of this Order, addressing onshore wind.

11. That Duke shall incorporate the most recent developments to ongoing natural gas pipeline projects that would expand natural gas access in North Carolina in the 2023 IRP Update and 2024 Carbon Plan Update/IRP proceeding. Natural gas pricing and supply assumptions contained within those proposals shall reflect those pipeline projects.

12. That all proactive public policy transmission upgrades must be included in a Commission approved Carbon Plan, or Carbon Plan Update/IRP, prior to being included in the NCTPC's local transmission plan or the SERTP regional transmission plan.

13. That Duke shall provide justification and lead time for construction of each proactive transmission project presented to the Commission for inclusion in the 2023 IRP Update and 2024 Carbon Plan Update/IRP.

14. That Duke shall expand its internal transmission planning horizon to 20 years.

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15. That Duke shall continue to provide updated locational guidance maps in future DISIS processes and procurement solicitations, which should include any proactive transmission upgrades and their expected in-service dates.

16. That Duke shall proceed with the near-term development activities outlined in its Proposed Carbon Plan for SLRs for its existing nuclear fleet, SMRs, and Bad Creek II.

17. That Duke, as detailed earlier in this Order, shall provide updates and additional information regarding SLRs, SMRs, and Bad Creek II in the 2023 IRP Update and 2024 Carbon Plan Update/IRP proceeding.

18. That Duke shall file quarterly reports on the timeline and expected project costs of the Bad Creek II project.

19. That Duke shall retain an independent third party to conduct an offshore wind study as detailed in this Order. Duke shall assist the independent third party with obtaining information that will enable more accurate modeling in the 2024 Carbon Plan Update/IRP proceeding. Duke's assistance shall include Duke's requesting, on a voluntary basis, information (especially performance and cost information) from all lease holders of areas near the North Carolina coast where offshore wind generation may be sited.

20. That Duke shall, in the 2024 Carbon Plan Update/IRP proceeding, utilize the most recent MPS base scenario, adjusted for any market or EE adoption

trends reflected in the Companies' recent DSM/EE riders, as the modeling assumption in its base case for modeling the impacts of UEE.

21. That Duke shall, in the 2024 Carbon Plan Update/IRP proceeding, use the following UEE forecast sensitivities: (1) the achievable utility EE potential as set forth in the most recent MPS; (2) Duke's proposal of one percent of eligible retail sales; (3) one percent of total system retail sales; and (4) 1.5% of total system retail sales.

22. That Duke shall, within 90 days of this Order, begin a full review of the Companies' currently approved DSM/EE cost recovery and incentive mechanisms.

23. That Duke shall, in future DSM/EE program approval or modification filings, identify the methodology (traditional baseline or as-found) for calculating energy savings it intends to apply to each measure included in the program.

24. That Duke shall, in future DSM/EE program approval, program modification, and cost recovery proceedings, distinguish the energy savings that can be used for DSM/EE cost recovery purposes from savings used for Carbon Plan compliance purposes.

25. That Duke shall, in the 2024 Carbon Plan Update/IRP proceeding, include a transparent analysis that clearly illustrates the impact on the UEE forecast of: (1) each enabler described in Proposed Carbon Plan Appendix G, if adopted, as well as any additional approved or proposed enablers; (2) the effects

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of market transformation; (3) rate impacts; and (4) any other changes that might be considered in the context of a future MYRP.

26. Duke's modeling in the 2024 Carbon Plan Update/IRP proceeding shall calculate LOLE for each portfolio as a key metric for system reliability.

27. That Duke shall assess whether it would be in the interest of ratepayers to securitize additional coal generation assets above the 50% required by HB 951 and Commission Rule R8-74, including supercritical coal units.

28. That in its filing in the 2024 Carbon Plan Update/IRP proceeding, Duke shall calculate two sets of bill impacts – one using the traditional methodology showing the incremental differences between portfolios, and a second that includes all known and measurable projected costs common across the portfolios. Duke shall explain its assumptions used to make the projections and provide the amount of non-Carbon Plan costs it has included in its calculation.

29. That Duke shall develop cost allocation methodologies to allocate Carbon Plan costs equitably between DEC and DEP and propose such methodologies to the Commission in the current DEC and DEP general rate cases.

30. That the Companies shall file a report every 90 days from the date of this Order detailing their progress in achieving a merger of DEC and DEP.

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ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of ___________________ 2022.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston, Chief Clerk

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