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October 24, 2022

VIA ELECTRONIC FILING

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

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Proposed Order
Docket No. E-100, Sub 179

Dear Ms. Dunston:

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

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

Sincerely ,

Enclosures

cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, Sub 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan	))))	DUKE ENERGY PROGRESS, LLC, AND DUKE ENERGY CAROLINAS, LLC, PROPOSED ORDER ADOPTING CARBON PLAN

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

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

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

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

Tuesday, August 23, 2022, at 1:30 p.m., held via video conference

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

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

APPEARANCES:

For Duke Energy Carolinas, LLC and Duke Energy Progress, LLC:

Jack E. Jirak, Deputy General Counsel; Kendrick C. Fentress, Associate General Counsel; Jason A. Higginbotham, Associate General Counsel; and Kathleen Hunter-Richard, Associate, Duke Energy Corporation, Post Office Box 1551, Raleigh, North Carolina 27602

E. Brett Breitschwerdt; Andrea R. Kells; and Tracy S. DeMarco, McGuireWoods LLP, 501 Fayetteville Street, Suite 500, Raleigh, North Carolina 27601

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For North Carolina Sustainable Energy Association:

Taylor Jones, Regulatory Counsel, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Southern Alliance for Clean Energy, Natural Resources Defense Council, and The Sierra Club, and:

Gudrun Thompson, Senior Attorney; David L. Neal, Senior Attorney; and Nicholas Jimenez, Senior Attorney, Southern Environmental Law Center, 200 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For Carolina Industrial Group for Fair Utility Rates II and III:

Christina D. Cress, Partner; and Douglas E. Conant, Associate, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For Carolina Utility Customers Association, Inc., and Tech Customers:

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Craig D. Schauer, Brooks Pierce, 1700 Wells Fargo Capitol Center, 150 Fayetteville Street, Raleigh, North Carolina 27601

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For Brad Rouse:

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For Clean Power Suppliers Association:

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For Environmental Working Group:

Andrea C. Bonvecchio, The Law Offices of F. Bryan Brice, Jr., 127 West Hargett Street, Suite 600, Raleigh, North Carolina 27601

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For Walmart, Inc.:

Carrie H. Grundmann, Spilman Thomas & Battle, PLLC, 110 Oakwood Drive, Suite 500, Winston-Salem, North Carolina 27103

For City of Charlotte:

Karen Weatherly, Senior Assistant City Attorney, 600 East Fourth Street, Charlotte, North Carolina 28202

For Appalachian Voices:

Catherine Cralle Jones, The Law Offices of F. Bryan Brice, Jr., 127 West Hargett Street, Suite 600, Raleigh, North Carolina 27601

For RedTailed Hawk Collective, Robeson County Cooperative for Sustainable Development, Environmental Justice Community Action Network, and Down East Ash Environmental and Social Justice Coalition:

Ethan Blumenthal, ECB Holdings, LLC, 1624 Nandina Corners Alley, Charlotte, North Carolina 28205

For NC WARN and for Charlotte-Mecklenburg NAACP:

Matthew D. Quinn, Lewis & Roberts, PLLC, 3700 Glenwood Avenue, Suite 410, Raleigh, North Carolina 27612

For Broad River Energy, LLC:

Patrick Buffkin, Buffkin Law Office, 3520 Apache Drive, Raleigh, North Carolina 27609

For Kingfisher Energy Holdings, LLC, and for Person County, North Carolina:

Patrick Buffkin, Buffkin Law Office, 3520 Apache Drive, Raleigh, North Carolina 27609

Kurt J. Olson, The Law Office of Kurt J. Olson, PLLC, Post Office Box 10031, Raleigh, North Carolina, 27605

For North Carolina Electric Membership Corporation:

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For City of Asheville and County of Buncombe:

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Curtis Euler, Senior Attorney II, Buncombe County, 200 College Street, Suite 100, Asheville, North Carolina 28801

For MAREC Action:

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For TotalEnergies Renewables USA, LLC, and for Clean Energy Buyers Association:

Joseph W. Eason, Nelson, Mullins, Riley & Scarborough, LLP, 4140 Parklake Avenue, Suite 200, Raleigh, North Carolina 27612

Weston Adams, Nelson, Mullins, Riley & Scarborough, LLP, 1320 Main Street, Suite 1700, Columbia, South Carolina 29201

For Pork Council:

Kurt J. Olson, Law Office of Kurt J. Olson, PLLC, Post Office Box 10031, Raleigh, North Carolina, 27605

For Council of Churches:

James P. Longest, Jr., Duke University School of Law, Box 90360, Durham, North Carolina 27708

For Avangrid Renewables, LLC:

Benjamin W. Smith, Todd S. Roessler, and Joseph S. Dowdy, Kilpatrick Townsend & Stockton, LLP, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For Sean Lewis:

Sean Lewis, Pro se, 640 Firebrick Drive, Cary, North Carolina 27519

For the Using and Consuming Public:

Margaret A. Force, Special Deputy Attorney General and Tirrill Moore, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

Lucy Edmondson, Chief Counsel, Robert Josey, Nadia L. Luhr, Anne Keyworth, William E.H. Creech, and William Freeman, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On October 13, 2021, Governor Cooper signed into law House Bill 951 ("HB 951" or "S.L. 2021-165"), directing the Commission to take all reasonable steps to achieve reductions in the emissions of carbon dioxide in this State from electric generating facilities owned or operated by certain electric public utilities. The Commission is directed to take all reasonable steps to achieve a reduction of 70% from 2005 levels by the year 2030 and carbon neutrality by the year 2050. Session Law 2021-165 limits the applicability of this requirement to Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC, and together with DEP, Duke Energy or the Companies). The Commission is directed to develop a plan (Carbon Plan) by no later than December 31, 2022, with the Companies and including stakeholder input, to achieve the least-cost path to compliance with the carbon dioxide emissions reductions in HB 951 and to review the plan every two years thereafter.

The findings and conclusions and ordering paragraphs presented in this Order represent the Commission's initial Carbon Plan for North Carolina under S.L. 2021-165. The Commission has developed this Carbon Plan with the Companies and including stakeholder input, and determines that it is a reasonable, least-cost and reliable plan for Duke Energy to achieve the authorized carbon emissions reduction goals established by the General Assembly. The directives presented in this Order represent the initial reasonable steps towards achieving the interim 70% Interim Target by 2030 and appropriately retains discretion for the Commission to determine optimal timing and generation and resource mix to achieve compliance with HB 951's carbon reduction goals. The Commission will exercise its authority under the Public Utilities Act, Chapter 62 of the General Statutes, to supervise Duke Energy's execution of this initial Carbon Plan, including through the various Carbon Plan-related filings and proceedings that will occur in 2023 (including the 2023 IRP update discussed above) and provide further direction on an as-needed basis. The Plan will be reviewed again in 2024 and every two years thereafter to ensure that the Companies remain on the least cost path consistent with HB 951 to achieve compliance with the State's authorized carbon reduction goals.

PROCEDURAL HISTORY AND JURISDICTION

Procedural History

The Commission has issued a multitude of procedural orders in this docket, all of which are a matter of record herein. The following is a summary of the most pertinent filings by the parties and the Commission's procedural orders.

On various dates petitions to intervene were filed[1] by the following parties and were granted by orders of the Commission: Carolina Industrial Group for Fair Utility Rates II and the Carolina Industrial Group for Fair Utility Rates III (collectively, CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); the North Carolina Sustainable Energy Association (NCSEA"); the Fayetteville Public Works Commission (FPWC); the North Carolina Electric Membership Corporation (NCEMC); ElectriCities of North Carolina, Inc., North Carolina Eastern Municipal Power Agency, and North Carolina Municipal Power Agency 1 (collectively, the Power Agencies); Apple Inc., Google, LLC, and Meta Platforms, Inc. (collectively, Tech Customers); Clean Power Suppliers Association (CPSA); the Carolinas Clean Energy Business Association (CCEBA); the Pork Council (Pork Council); Appalachian Voices (Appalachian Voices); Southern Alliance for Clean Energy (SACE), the Sierra Club, and the Natural Resources Defense Council (NRDC) (collectively, SACE et al." and together with NCSEA, NCSEA et al.); Broad River Energy, LLC (Broad River); the Clean Energy Buyers Association (CEBA); Walmart, Inc. (Walmart); Person County (Person County); NC WARN; the Environmental Working Group (EWG); Avangrid Renewables, LLC (Avangrid Renewables); the City of Charlotte; Kingfisher Energy Holdings, LLC (Kingfisher); Harold Bradley Rouse (Brad Rouse); the North Carolina Council of Churches (Council of Churches); the RedTailed Hawk Collective and the Robeson County Cooperative for Sustainable Development (RTHC and RCCSD); TotalEnergies Renewables USA, LLC (TotalEnergies); the Charlotte Mecklenburg branch of the National Association for the Advancement of

[1] RWE Offshore Wind Holdings, LLC (RWE) filed a Petition to Intervene on April 14, 2022, which was subsequently withdrawn by RWE's Motion for Leave to Withdraw filed on June 2, 2022. The Commission issued an *Order Granting Motion of RWE for Leave to Withdraw* on June 3, 2022. Additionally, the John Locke Foundation (JLF) filed a Petition to Intervene on July 15, 2022, which was subsequently withdrawn by JLF's Notice of and, in the Alternative, Motion to Withdraw Petition to Intervene. No Commission orders were issued related to this intervention.

Colored People (NAACP Charlotte-Mecklenburg); the Environmental Justice Community Action Network (EJCAN) and Down East Coal Ash Environmental and Social Justice Coalition (DECAESJC) (collectively, EJCAN et al.); Sean Lewis; 350 Triangle; the North Carolina Alliance to Protect our People and the Places We Live (NC-APPPL); MAREC Action (MAREC); and the City of Asheville and Buncombe County (Asheville et al.). In addition, a Notice of Intervention was filed by the North Carolina Attorney General's Office (AGO). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On November 19, 2021, the Commission issued an *Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines* (November 19, 2021 Order) directing Duke to conduct at least three stakeholder meetings before March 31, 2022, specifically for the purpose of gathering and incorporating stakeholder input on the Carbon Plan, and to file a summary report identifying the participating stakeholders, outlining the process employed and identifying points of consensus after each of the three meetings. Duke was also directed to file a proposed Carbon Plan with the Commission by April 1, 2022. Additionally, this Order directed the Public Staff to participate in the stakeholder process and to file a separate report after each stakeholder meeting, providing an overview of each of those stakeholder meetings. This Order also made clear that the stakeholder process should take into account and reflect the collaborative work and outputs of the stakeholder efforts associated with the 2019 North Carolina Clean Energy Plan along with the 2020 Integrated Resource Plan, and that this process should build off the consensus achieved and resources expended during those efforts. Lastly, the Order established additional procedural processes and deadlines.

On November 23, 2021, Duke Energy filed a Motion to Extend Time to File Carbon Plan, requesting a 45-day extension of time to file the proposed Carbon Plan and a corresponding extension of time to conduct the stakeholder meetings required by the November 19, 2021, Order. On November 29, 2021, the Commission issued an *Order Granting Extension of Time*, granting Duke Energy's requested extensions of time and extending additional procedural deadlines.

On January 21, 2022, February 22, 2022, and March 22, 2022, Commission Orders were issued requiring Duke Energy and the Public Staff, and allowing other parties, to provide updates to the Commission after each of the three stakeholder meetings. On February 7, 2022, March 7, 2022, and April 4, 2022, Duke Energy and the Public Staff, along with certain parties to this proceeding, provided those updates to the Commission.

On March 9, 2022, the Commission issued an *Order Scheduling Public Hearings and Requiring Public Notice* for the purposes of receiving public comment on the Carbon Plan. These hearings were held as scheduled in Durham, Wilmington, Asheville, and Charlotte. A virtual hearing was also held for the purpose of receiving public comment on the Carbon Plan. The Commission has also received numerous statements of position from consumers.

On May 16, 2022, Duke Energy filed its proposed Carbon Plan.

On July 15, 2022, intervening parties filed comments on Duke's initial Carbon Plan filing.

On July 29, 2022, the Commission issued an *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines*, setting an expert witness hearing to begin on September 13, 2022, establishing deadlines for prefiling testimony on certain specific issues, and allowing responsive comments to be filed on those specified issues.

On August 5, 2022, the AGO filed a Motion to Direct Duke to Perform Additional Modeling, requesting that the Commission require Duke Energy to run additional modeling scenarios to address issues raised in the AGO's Initial Comments. Duke Energy filed a Response opposing the Motion on August 8, 2022, and the Commission issued an Order denying the AGO's Motion on August 17, 2022.

On August 19, 2022, Duke Energy filed its direct testimony and exhibits.

On September 2, 2022, intervenors filed their testimony and exhibits.

On September 9, 2022, Duke Energy filed its rebuttal testimony and exhibits. Also on this date, parties filed responsive comments pertaining to topics not designated for the expert witness hearing (non-hearing track issues).

This matter came on for expert witness hearing as scheduled, beginning September 13, 2022, and concluding on September 29, 2022.

On October 18, 2022, CPSA, CCEBA, and NCSEA et al. filed a Joint Motion to Reopen Record to Receive Late Filed Exhibit or in the Alternative for Judicial Notice, requesting that the Commission receive into the record, either by late-filed exhibit or judicial notice, the report prepared by the National Renewable Energy Laboratory (NREL) under contract with Duke Energy that was published in October 2022. On October 21, 2022, the Commission issued an *Order Denying Motion to Reopen Record to Receive Late-Filed Exhibit*, denying the Joint Motion.

Jurisdiction

No party has contested the fact that DEC and DEP are public utilities subject to the Commission's jurisdiction pursuant to the Public Utilities Act, Chapter 62 of the North Carolina General Statutes. The Companies are also "electric public utility[ies] as defined in G.S. 62-3(23) serving at least 150,000 North Carolina retail jurisdictional customers as of January 1, 2021[,]" and, therefore, are subject to HB 951, Part 1. The Commission concludes that it has personal jurisdiction over the Companies and subject matter jurisdiction over the matters presented in this proceeding.

Whole Record

The Commission held five public witness hearings, as noted above. The following public witnesses appeared and testified:

Durham: Gordon Phillip Allen, David Sokal, Tobin Freid, William Terry, Lieceng Zhu, Russ Outcalt, Jason Torian, Jessica Rowe, Montravias King, Bobby Jones, Hope Gattis, Aaron Hope, Robby Phillips, Peter Morcombe, Scott Cline, Rachel Woods, Katie Craig, William Scott, Dan Figgins, Dale Evarts, Lois Nelson, Daksh Arora, Denise Frizzell, Lib Hutchby, Claudia Berry Hill, Thomas Carlyle Dowd, Ziyad Habash, Betsy Bickel, Lauren Nadine Martin, Barry Strock, Michael Audie, Keval Khalsa, Maple Mary Ann Osterbrink, David Allen Kirkpatrick, Geraldine Nelson, and Gary Nelson

Wilmington: Alexander Brown, Esther Murphy, Ivan Bartley, Beth Hansen, Carl Parker, Deborah Dicks Maxwell, Rachel Mitchell, Robert Parr, MD., Isabella Peadon, Lindsey Hallock, Paul Summers, Andy Wood, and Marcel McFadden

Asheville: Sherry Vaughan, Steven Norris, Lauren Steiner, Pam Brown, Rob Denton, Melanie Chopko, Gray Jernigan, Carlton Angell, Maggie Ullman Berthiaume, Shannon Bodeau, Steffi Rousch, Anne Craig, Clare Hanrahan, Phil Bisesi, Melody Shank, Elsa Enstrom, Shelby Cline, Maureen Linneman, Tim Birthisel, Sawyer Bryan, Cathy Scott, John Ager, Kendall Hale, Jodi Lasseter, Rachel Bliss, Mary Olson, Patrick Sawyer, Richard Fireman, Joe Beckham, Judy Mattox, Farah Ogletree, Michael Churchman, Ken Brame, Drew Ball, Ruffin Shackleford, Bruce Santorini, Don Nicholson, Holly Beveridge, Sophie Loeb, and Sara Tew

Charlotte: Billie Anderson, June Blotnick, Majeed Ederer, Babak Mokari, Karen Hodges, Amy Brooks Paradise, Jennifer Roberts, Tina Katsanos, Hannah Stephens, Lisa Huntting, Tom Lannin, Meg Houlihan, Donna Durfee, Lawrence Toliver, Brenda Gasior, Faith Silva, Michelle Carr, Jill Palmer, Debbie Foster, Beth Henry, Susan Tompkins, Janet Palmer, John Gaertner, Matthew Withrow, Jeff Robbins, Keith Banner, Mary Jo Klingel, David Walsh, Nancy Neely, Skip Hudspeth, John Rochester, Maria Portoue, Jerome Wagner, Martin Fiedler, and Bailey Scarlet

Virtual: William McNeil, Mary Abrams, David McGowan, Jane Barnett, Pam Hemminger, Kathleen Liebowitz, Jean Pudlo, Kay Reibold, Katherine Wyszkowski, Michael Totten, Barron Northrup, John Wait, Maren Mahoney, Peter Krull, and Nancy Carter

In addition to the public witness testimony, the Commission received numerous written consumer statements of position, all of which were filed in the docket. *See generally*, Docket No. E-100, Sub 179CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on Duke's proposed Carbon Plan as the Commission develops the initial Carbon Plan as required by Section 62-110.9(1).

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order. Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

REQUIREMENTS FOR COMMISSION TO DEVELOP CARBON PLAN UNDER HB 951

On October 13, 2021, Governor Roy Cooper signed S. L. 2021-165 into law. HB 951 enacts a Commission-supervised framework by which to continue a reasonable and orderly transition of the Companies' generation resource mix towards carbon neutrality by the year 2050, while ensuring high quality, adequate and reliable electric service is maintained for customers in the State.

Historically, the State's least-cost resource planning process has been forward-looking and legislative in nature, gathering facts and overseeing Duke Energy's long-range needs and plans for its systems to ensure adequate and reliable service is maintained. *See* N.C.G.S. § 62-110.1(c). With the enactment of HB 951, N.C.G.S. § 62-110.9 sets prescriptive new carbon emission reduction goals and requirements for resource planning that the Commission must work with Duke Energy to achieve. Section 62-110.9 directs that the Commission must "[d]evelop a plan, . . . with the electric public utilities, including stakeholder input, for the utilities to achieve the authorized [carbon] reduction goals[.]" N.C.G.S. § 62-110.9(1). This legislative mandate marks an evolution in the Commission's traditional resource planning role, as it is now tasked with "selecting"[2] resources and taking "all reasonable steps" to meet the specified carbon reduction goals while complying with all other requirements set forth in N.C.G.S. § 62-110.9.

Section 62-110.9 mandates that the Commission must "take all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO_2) emitted in the State from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 [(70% Interim Target)] and carbon neutrality by the year 2050 [(Carbon Neutrality Target)]." N.C.G.S. § 62-110.9. While the legislature left discretion to the Commission to determine what steps are "reasonable," it did prescribe specific additional requirements that any approved Carbon Plan must meet. First, the Carbon Plan must "[c]omply with current law and practice with respect to the least cost planning for generation . . . in achieving the authorized carbon reduction goals and determining the generation and resource mix for the future." N.C.G.S. § 62-110.9(2).

[2] Section 62-110.9 contemplates that the Commission will "select" "new generation facilities or other resources . . . in order to achieve the authorized reduction goals." N.C.G.S. § 62-110.9(2).

In doing so, the General Assembly specifically identified that current law and practice should be informed by the State's energy policy, N.C.G.S. § 62-2(a)(3a), which requires the Commission to pursue energy planning to "result in the least cost mix of generation and demand-reduction measures which is achievable," and to include "use of the entire spectrum of demand-side options" in determining resources necessary to meet future growth through the provision of adequate, reliable utility service. Thus, the Commission must ensure that the Carbon Plan includes robust consideration of both supply-side and demand-side resources to achieve a reliable least cost plan for the future. The General Assembly further emphasized that in developing the plan, the Commission "may, at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs to achieve the least cost path" again highlighting the transformational, "all-of-the-above" approach to reducing carbon emissions from electric generating facilities in North Carolina. N.C.G.S. § 62-110.9(1).

Second, the approved Carbon Plan must ensure generation and resource mix changes included in the Carbon Plan "maintain or improve upon the reliability of the existing grid." N.C.G.S. § 62-110.9(3). The Commission has always viewed system reliability as a critical component of a utility's integrated resource planning as reliable electric service is essential to the well-being of each electric utility customer, including families, businesses and communities across North Carolina. This directive to "maintain or improve" reliability represents a legislative imperative to collectively plan and execute a transition of Duke Energy's Carolinas electric systems and resource mixes in a way that, at a minimum, preserves the highly reliable service Duke Energy's customers currently receive.

Third, the General Assembly expressly determined that "new generation facilities or other resources selected by the Commission in order to achieve the authorized reduction goals for electric public utilities shall be owned and recovered on a cost of service basis by the applicable electric public utility" with two limited exceptions. To the extent the Commission selects new solar generation as part of the Carbon Plan, forty-five percent (45%) of the total megawatts must be supplied through the execution of power purchase agreements (PPAs) with third parties and fifty-five percent (55%) must be supplied by facilities that are utility-owned and operated. N.C.G.S. § 62-110.9(2)(b). The General Assembly further mandated that "[e]xisting law shall apply with respect to energy efficiency measures and demand-side management." N.C.G.S. § 62-110.9(2)(a).

The General Assembly also expressly recognizes the ongoing, iterative nature of resource planning by mandating that the Carbon Plan shall be reviewed every two years and may be adjusted as necessary in the determination of the Commission and the electric public utilities. N.C.G.S. § 62-110.9(1). Importantly, Section 62-110.9(4) also grants the Commission discretion to extend the date for achieving compliance with the interim 70% carbon emissions reduction goal (Interim Target Achievement Date). First, the Commission has broad discretion to extend the Interim Target Achievement Date to 2032, if determined necessary to achieve a more "optimal timing and generation and resource-mix." The plain language of the statute places no prescriptive limits on the

Commission's ability to exercise its authority to determine "optimal timing" for Carbon Plan implementation before 2032, and, in addition, identifies the potential of "implement[ing] solutions that would have a more significant and material impact on carbon reduction" as one basis for doing so. This flexibility is critical to ensuring the Commission is able to use its judgment to select a Carbon Plan that takes into account a variety of critical factors, including carbon reduction, affordability, reliability, and executability, all of which are grounded in prudent utility planning and operation. Second, the statute expressly defines further discrete circumstances under which the Commission is authorized to extend the Interim Target Achievement Date *beyond* 2032. Such additional extension is permissible (1) "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 (2) "in the event necessary to maintain the adequacy and reliability of the grid." N.S.G.S. § 62-110.9(4). As discussed further in this Order, the Commission need not exercise its discretion to extend the Interim Target Achievement date in this proceeding. Rather, the near-term actions the Commission is selecting will support a range of portfolios and represent "reasonable steps" toward achieving the least-cost path, placing the Companies on a trajectory that would allow for achievement of the 70% Interim Target by 2030 while retaining discretion for the Commission to assess in the future the optimal path to achieve the 70% Interim Target.

Consistent with this statutory framework, the Commission views development of the Carbon Plan as an iterative process that will be refined every two years to reflect the most current data, inputs, technological advancements, market information, and general evolving knowledge regarding the ongoing energy transition.

FINDINGS OF FACT

Carbon Accounting Methodology

1. Carbon Plan Appendix A (Carbon Baseline and Accounting) presents the Companies' proposed carbon baseline and accounting methodologies required by paragraph 3 of the Commission's Carbon Plan Procedural Order.

2. The methodologies and data sources presented in Carbon Plan Appendix A are reasonable and appropriate for calculating the Companies' in-State baseline 2005 CO_2 emissions from their electric generating facilities and for calculating the 70% Interim Target and Carbon Neutrality Target.

Carbon Plan Approach and Modeling Framework

3. The Companies' Carbon Plan approach of seeking to balance the four core objectives of CO_2 reduction, affordability, reliability, and executability to develop the least cost path to achieve HB 951's authorized CO_2 emissions reductions targets is reasonable for planning purposes.

4. The Companies' Carbon Plan modeling approach complies with current law and practice with respect to least cost planning for generation to achieve HB 951's carbon reduction goals based upon the least cost mix of generation and achievable demand-reduction measures. The Companies' proposed Carbon Plan first seeks to "shrink the challenge" by using the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions.

5. The Companies' initial Carbon Plan modeling developed two pathways and four portfolios that are reasonable for planning purposes and enable the Commission with the Companies to plan for achieving HB 951's authorized CO_2 emissions reductions targets and support planning the continued system-wide energy transition in a manner consistent with HB 951's requirements and prudent utility planning.

6. The Companies' Carbon Plan provides a robust modeling framework and sensitivity analyses to establish least cost portfolios of supply-side and demand-side resources required to meet HB 951's goals.

7. The Companies' supplemental modeling analysis and supplemental portfolios 5 and 6 further validate the reasonableness of the Companies' initial Carbon Plan modeling and resulting portfolios based upon a necessary snapshot in time in which the modeling was performed.

8. The Companies' preliminary Inflation Reduction Act of 2022 (IRA) sensitivity analysis is informative and its results were generally consistent with the results of initial Carbon Plan modeling. Further modeling and analysis of the impacts of the IRA should be completed in the 2024 Carbon Plan update. Future Carbon Plan modeling will incorporate changing circumstances over time such as inflationary impacts on resources' costs as well as offsetting technology cost impacts of the IRA.

9. The Companies' Carbon Plan provides an unprecedented level of detail to the Commission and intervenors regarding the modeling process. The Companies should continue to promote transparency regarding the modeling inputs, assumptions and analytical steps used in future Carbon Plan updates.

10. The Companies' decision to use a mass cap modeling approach to model CO_2 emissions reductions is reasonable and appropriate for planning purposes.

11. The Companies' use of Encompass capacity expansion and production cost modeling framework as well as the battery/CT Optimization and Reliability Verification steps the Companies took to ensure compliance with the least cost and reliability requirements of HB 951 are reasonable for planning purposes.

12. All of the Companies' Carbon Plan portfolios maintain or improve upon the reliability of the grid as required by HB 951.

13. The Companies should continue to evaluate the capabilities of the EnCompass modeling platform and assess whether modeling improvements and other adjustments to the optimization periods can be incorporated in future Plan updates.

Consideration of Modeling Critiques by Other Parties and Review of Alternative Modeling Recommendations and Analysis

14. The Companies' projected load forecast is reasonable for planning purposes and reflects reasonable projections of achievable demand-side management/energy efficiency (DSM/EE), behind the meter solar installations, and other resources impacting the load forecast at this time.

15. The solar paired with storage configuration assumptions the Companies used to model the Carbon Plan portfolios and supplemental portfolios are reasonable for planning purposes.

16. The Companies' fixed dispatch approach to modeling solar paired with storage is not unreasonable in this initial Carbon Plan proceeding; however, the Companies should continue to evaluate the more flexible approach used in supplemental modeling in future Carbon Plan proceedings.

17. The Companies' assumptions regarding the Companies' ability to interconnect new solar generating facilities to the transmission system are reasonable for planning purposes. More aggressive solar interconnection assumptions that would exceed the volume of solar that the Companies can interconnect to the transmission system would unreasonably increase execution risks and result in missed opportunity for technology maturation and development and declining prices, especially for storage paired with solar resources.

18. The Companies' assumptions regarding the cost and availability of onshore wind are reasonable for planning purposes.

19. The Companies' natural gas pipeline supply assumptions that plan for limited access to Appalachian gas or a potential pivot if future transportation of Appalachian gas to DEC's and DEP's service territories in the Carolinas does not materialize are reasonable for planning purposes.

20. The Companies' assumptions regarding a 35-year operable life as well as capital costs for new natural gas CC and CT resources are reasonable for planning purposes.

21. Duke Energy's proposed Carbon Plan is reasonably developed to identify a least cost portfolio of resources to be selected by the Commission and owned by Companies, including potential new gas CC and CT resources. It is not reasonable or consistent with HB 951 to assume reliance on future purchases of dispatchable capacity from natural gas facilities beyond what is under contract today.

22. Substantial uncertainty remains regarding the long-term potential of hydrogen fuel to replace natural gas; however, it is not unreasonable at this time to plan for hydrogen fuel and/or the potential for limited carbon offsets as allowed under HB 951.

23. The modeling analysis and alternative portfolios presented by intervenors was considered and weighed by the Commission but, on balance, the Commission finds DEC's and DEP's Carbon Plan portfolios (including the Supplemental Portfolios developed by the Companies in consultation with the Public Staff) to be more reasonable for planning purposes.

24. The Companies' PVRR and bill impact analyses are reasonable for planning purposes and allow for portfolio comparison to assist the Commission in developing a reasonable Carbon Plan. While outside the scope of this proceeding, the Commission declines to adopt "all-in cost" bill impact analyses given that the Companies do not have the information that would be needed to produce such analyses.

Selecting Near-Term Supply-Side Development and Procurement Activities

25. Duke Energy's proposed Carbon Plan presents initial reasonable steps towards achieving the interim 70% Interim Target by 2030 and appropriately retains discretion for the Commission to determine optimal timing and generation and resource mix to achieve compliance with HB 951's carbon reduction goals. At this time, the Commission need not determine whether to authorize a delay in meeting interim 70% target beyond 2030 and can check and adjust progress in 2024 and beyond.

26. It is reasonable and prudent for the Companies to undertake development and procurement activities to develop the supply-side resources identified in the Near-Term Action Plan presented in Carbon Plan Executive Summary Table 3 and Bowman Direct Exhibit 3 and selected by the Commission in this Order.

27. The Commission selects 3,100 MW of solar resources as part of the Carbon Plan subject to the obligation to obtain a CPCN and the further guidance in this order addressing the Commission's expectations regarding the contents of such CPCN applications. It is reasonable and prudent for the Companies to undertake development and procurement activities for 3,100 MW of solar generation in the 2022-2024 timeframe targeting such projects being placed into service by 2028.

28. As directed in the Commission's [Nov. 1, 2022] order in Docket Nos. E-2, Sub 1159, E-7, Sub 1156, E-2, Sub 1297 and E-7, Sub 1268, it is reasonable and prudent for the Companies' 2022 Solar Procurement Program to procure approximately 1,200 MW of new standalone solar resources including a minimum of 750 MW of new HB 951 standalone solar and the 441 Competitive Procurement of Renewable Energy (CPRE) Program remainder MW. It is reasonable and prudent for the Companies to target procuring a minimum of 400 MW of new solar resources in DEC and 400 MW in DEP as part of an overall least cost portfolio of new solar resources. It is reasonable and prudent for the Companies to target a minimum of 2,350 MW of solar in 2023-2024 and determine the optimal timing and mix of new standalone solar and solar paired with storage. It is

also appropriate for the Companies to consider volume adjustments or other mechanisms similar to the 2022 Solar Procurement during this period to competitively procure additional solar at least cost.

29. The Commission selects 600 MW of storage paired with the new solar resources identified in the Findings of Fact 27-28 to be procured in the 2023-2024 timeframe. It is reasonable and prudent for the Companies to undertake development and procurement activities for 600 MW of storage paired with the solar, targeting such projects being placed into service by 2028.

30. The Commission selects 1,000 MW of stand-alone storage to be developed in the 2022-2024 timeframe. It is reasonable and prudent for the Companies to undertake development and procurement activities for 1,000 MW of stand-alone storage, targeting such projects being placed into service by 2029.

31. The Commission selects 600 MW of onshore wind to be developed in the 2022-2024 timeframe. It is reasonable and prudent for the Companies to undertake development and procurement activities for 600 MW of onshore wind, targeting such projects being placed into service by 2029. Onshore wind resources are selected as part of the Carbon Plan subject to the obligation to obtain a CPCN and the further guidance in this order regarding the Commission's expectations regarding the contents of such CPCN applications.

32. The Commission selects 800 MW of combustion turbine units (CTs) to be developed in the 2022-2024 timeframe. It is reasonable and prudent for the Companies to undertake development and procurement activities for 800 MW of CTs, targeting such projects being placed into service by 2029. CT resources are selected as part of the Carbon Plan subject to the obligation to obtain a CPCN and the further guidance in this order regarding the Commission's expectations regarding the contents of such CPCN applications.

33. The Commission selects 1,200 MW of combined cycle units (CCs) to be developed in the 2022-2024 timeframe. It is reasonable and prudent for the Companies to undertake development and procurement activities for 1,200 MW of CCs targeting such projects being placed into service by 2029. CC resources are selected as part of the Carbon Plan subject to the obligation to obtain a CPCN and the further guidance in this order regarding the Commission's expectations regarding the contents of such CPCN applications.

Approval of Near-Term Initial Development Actions to Support Future Availability of Long Lead-Time Resources (Bad Creek II, SMR, and Offshore Wind)

34. It is reasonable and prudent for the Companies to pursue near-term (through EOY 2024) initial development activities for new pumped storage hydro (i.e., Bad Creek II), SMRs, and offshore wind (collectively, Long Lead-Time Resources) because they are necessary initial development and permitting activities that retain value even if any one of these resources is not pursued in the short-term, and all three

resources will likely be needed for HB 951 compliance either for the 70% Interim Target or 2050 compliance as well as the promotion of adequate, reliable, and economical utility service to the citizens of North Carolina and the policies expressed in N.C.G.S. § 62-2. These initial development activities will also allow the Companies and the Commission to develop more refined cost estimates that can be used to more fully evaluate the potential selection of those resources in future Carbon Plan proceedings. The Commission believes it is reasonable and prudent to take action to preserve the potential that one or more of the Long Lead-Time Resources could be utilized in achieving the 70% Interim Target.

35. It is reasonable and prudent for DEC to engage in near-term (through EOY 2024) development activities for Bad Creek II to ensure that it remains an available resource option for the Companies' customers, including expending no more than $40 million, to conduct a feasibility study, develop an engineering, procurement and construction (EPC) strategy, and continue to develop the application to the Federal Energy Regulatory Commission (FERC) to relicense the Bad Creek I facility to incorporate the future operation of Bad Creek II.

36. It is reasonable and prudent for the Companies to engage in near-term (through EOY 2024) development activities for SMRs to ensure that new nuclear generation remains an available resource option for the Companies' customers, including expending no more than $75 million, to begin work on an early site permit (ESP) and perform a due diligence review to identify a nuclear technology for the SMRs.

37. It is reasonable and prudent for DEP to engage in near-term (through EOY 2024) development activities for offshore wind to ensure that offshore wind remains an available resource option for the Companies' customers, including expending no more than $325 million, to acquire the Duke Energy Renewables Wind, LLC's (DERW) Carolina Long Bay Wind Energy Area (WEA), effectuated by a future affiliates transfer pursuant to N.C.G.S. § 62-153, develop, submit and obtain approval of a Site Assessment Plan (SAP) from the Bureau of Ocean Energy Management (BOEM), begin development of a Construction and Operation Plan (COP), engage in development work for the onshore tie-line, and initiate an interconnection study process.

38. Avangrid's proposal to initiate a third-party WEA comparison process is not reasonable as it is unlikely to identify a WEA that is more cost-effective than the DERW WEA for DEP to develop offshore wind.

39. To the extent the Commission finds, in a future general rate case proceeding, the specific activities involved in, and the costs of pursuing development activities for Long Lead-Time Resources to be reasonable and prudent, whether or not the Long Lead-Time Resources are ultimately constructed, it is appropriate for the Companies to recover in rates the North Carolina allocable portion of DEC's and/or DEP's respective shares of such costs at the time(s) and in the manner determined to be appropriate by the Commission consistent with the policies set forth in N.C.G.S. § 62-2

and, for SMRs, the project development cost review provisions set forth in N.C.G.S § 62-110.7.

40. It is reasonable for the Companies to file biannual reports with the Commission detailing their Long Lead-Time Development activities and costs incurred in pursuing such activities and to adhere to the approved cost caps.

Near-Term Actions for Existing Supply-Side Resources

41. It is reasonable and prudent for the Companies to pursue the near-term actions for existing supply-side resources to ensure system reliability is maintained or improved upon as coal units are retired.

42. It is reasonable and prudent for the Companies to increase flexibility of the existing gas fleet, including gas unit control upgrades and equipment changes and seeking regulatory approvals for operational and air permit changes.

43. It is reasonable and prudent for the Companies to continue to develop and submit 20-year subsequent license renewals (SLRs) for existing nuclear facilities.

Planning for Coal Retirements

44. The Companies' assumptions and modeling process regarding planning coal retirements are reasonable for planning purposes.

45. It is reasonable and appropriate for the Companies to continue to analyze planned retirement dates for the Companies' coal units, including the transmission impact analysis presented in Execution Plan Table 4-13 and provide an update to the Commission in 2024.

Grid Edge and Customer Programs

46. It is reasonable for the Companies to advance the Grid Edge and Customer Programs identified in Appendix G of the Carbon Plan and to initiate further proceedings at the Commission to update the underlying inputs used in determination of the utility system benefits in the Companies' approved EE/DSM Cost Recovery Mechanism.

Transmission Development Activities

47. It is reasonable for the Companies to study future transmission needs to reliably implement the Carbon Plan through the NCTPC.

48. The Commission acknowledges that the Red Zone Transmission Expansion Plan projects identified in Transmission and Solar Procurement Rebuttal Exhibit 3 are necessary transmission upgrades to achieve the objectives of the Carbon Plan and will provide system benefits such as reliability, resiliency, and lower transmission losses and the Companies should pursue approval of these projects through the NCTPC.

Planning for Consolidated Carolinas Utilities and Potential Merger of DEC and DEP

49. DEC and DEP have successfully planned and operated dual-state systems across North Carolina and South Carolina for more than a century, and the Commission supports the continued their historical practice of dual-state system operation and planning for the benefit of customers.

50. The Companies' Near-Term Actions are "no regrets" actions regardless of ultimate outcome in terms of dual-state planning alignment.

51. It is reasonable and appropriate for DEC and DEP to continue to pursue a potential merger of the utilities, which provides the most straightforward and direct path to resolving rate differences, as well as greater operational efficiencies.

52. Given that there is projected to be little to no increase in rate differences resulting from Carbon Plan investments prior to the targeted merger date, there is no need to pursue any alternative pre-merger interim Carbon Plan cost allocation approach.

Ensuring System Reliability

53. The Carbon Plan is reasonably designed to maintain or improve upon the adequacy and reliability of the existing grid.

54. Ensuring ongoing system reliability and compliance with mandatory NERC Reliability Standards during the ongoing energy transition is consistent with prudent utility planning and the requirements of HB 951 and non-negotiable for the Companies and for customers.

Pursuing Overall Execution Plan in Near-Term

55. The Carbon Plan Execution Plan provides reasonable details and an appropriate framework for presenting near-term and intermediate-term actions as well as prudent longer-term strategies to monitor risks and signposts across all planning horizons in order to meet the interim CO_2 emissions reductions target and to achieve carbon neutrality by 2050.

56. The near-term planning, development and procurement activities presented in the proposed execution plan set forth in Chapter 4 of the Carbon Plan are reasonable initial steps in executing the Carbon Plan and the Companies should commence all near-term activities needed to progress the Carbon Plan.

57. It is appropriate and consistent with N.C.G.S. § 110.9(2) for Duke Energy to own any new generation facilities or other resources selected by the Commission excepting energy efficiency measures and demand-side management, for which existing law applies, and in the case of controllable solar generation and solar paired with storage,

for which ownership is to be allocated according to the percentages specified in N.C.G.S. § 110.9(2)(b).

58. It is reasonable and appropriate for Duke Energy to explore with stakeholders new contract structures for solar paired with storage to be developed in advance of a 2023 procurement. It is reasonable and appropriate for Duke Energy to develop with stakeholders contract terms and pricing to enable Duke Energy to maximize the benefits of solar paired with storage facilities over the full contract term.

59. Reporting on the Companies' progress in executing the Carbon Plan is appropriate as part of the interim 2023 IRP update to enable the Commission to monitor progress and to check and adjust the Carbon Plan in the next biennial Carbon Plan update

FERC-Jurisdictional Power Contract Considerations

60. Proposals regarding coordination with wholesale customers on load side management issues are beyond the scope of this proceeding and more appropriately addressed before FERC. The Companies are encouraged to continue to look for opportunities to engage with wholesale customers on distribution system coordination and cost-effective programs to enable CO_2 reductions as they implement the Carbon Plan.

Procedural Matters for Future Carbon Plans

61. It is reasonable for Duke Energy to file an IRP update on September 1, 2023 and a comprehensive Carbon Plan Update and IRP on September 1, 2024.

62. It is reasonable for the Companies and the Public Staff to develop and propose for comment by April 28, 2023, revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities.

EVIDENCE AND CONCLUSIONS

CARBON ACCOUNTING METHODOLOGY (Findings of Fact Nos. 1-2)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings of fact are found in the Companies' proposed Carbon Plan, the direct testimony and exhibits of witnesses Snider, McMurry, Quinto and Kalemba (Modeling and Near-Term Actions Panel), and the testimony and exhibits of Public Staff witness Dustin Metz.

Summary of the Evidence

In order to track compliance with HB 951's CO_2 emissions reduction targets, the Commission directed the Companies to file a Carbon Plan that addresses: "(1) the methodology used to determine the baseline 2005 level of carbon dioxide emitted in North Carolina by their electric generating facilities; (2) the methodology used to calculate the reduction in carbon dioxide emitted from their electric generating facilities; and (3) the methodology used to quantify the reduction associated with any offset proposed and the methodology for verifying any such offset." *Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines*, Docket No. E-100, Sub 179, at 3 ¶ 3 (Nov. 19, 2021) (*Carbon Plan Procedural Order*).

The Carbon Plan explains that the Companies are committed to system-wide CO_2 emissions reductions, targeting carbon neutrality for their entire system by 2050. The Companies affirmed during the stakeholder process that, for modeling compliance with HB 951, they would assume that any new CO_2-emitting resources selected in the model would be sited in North Carolina. Carbon Plan, Exec. Summary, 8.

Appendix A to the Carbon Plan presents the Companies' proposed methodologies for setting the 2005 baseline and for tracking achievement with HB 951's CO_2 emission reduction targets. *Id.* Specifically, Appendix A includes "the methodology used to determine the baseline 2005 level of [CO_2] emitted in North Carolina by their electric generating facilities" and "the methodology used to quantify the reduction associated with any offset proposed and the methodology for verifying any such offset." Carbon Plan, App'x A, 1.

The Companies' methodology for determining a baseline 2005 level of CO_2 relies on the Environmental Protection Agency's (EPA) Emissions and Generation Resource Integrated Database (eGRID), which contains reliable, auditable, and publicly available emissions reporting data for the electric utility sector. Tr. vol. 7, 272. Using eGRID, the Companies calculated that they emitted 75,865,188 short tons of CO_2 in 2005. Carbon Plan, App'x A, 5. The Companies then calculated that "achieving the interim target would require that the Companies limit CO_2 emissions from electric generation facilities owned, operated by or operated on behalf of, the Companies located in the State to 22,759,556 short tons of CO_2 in the compliance year." *Id*. at 6.

Appendix A does not include a methodology for quantifying emission reductions from offsets but explains that the proposed Carbon Plan did not assume utilizing offsets to achieve the interim or carbon neutrality targets. Carbon Plan, Exec. Summary, 7. Appendix A explains that the Companies have no definitive plans at this time to utilize offsets in the achievement of the HB 951 Carbon Neutrality Target and before using any carbon offsets, a calculation methodology would be presented for regulatory approval. As the execution of the Carbon Plan progresses and offset usage and calculation methodologies evolve, the Companies will revisit this topic. Carbon Plan, App'x A, 8.

The Carbon Plan explains that the Companies' compliance methodology does not account for CO_2 emissions resulting from energy generated out of State and imported into the State. Carbon Plan, App'x A, 2. HB 951 only addresses CO_2 emissions within North Carolina's geographic boundary. *Id.* For modeling purposes, the Companies assume that all new CO_2 emitting resources will be located in North Carolina. *Id*. The Companies request that the Commission (1) approve the methodologies outlined in

Appendix A, and (2) determine whether CO_2 emissions from out-of-state generating resources ultimately selected to be part of the Plan should be accounted as if such emissions occurred in the State.

Public Staff witness Metz agrees with the Companies' calculation of the carbon baseline and agrees with the Companies' modeling approach that assumes all new carbon emitting resources would be located in North Carolina. Tr. vol. 21, 108. He testifies that the Public Staff met with the North Carolina Department of Environmental Quality (DEQ) and the Companies' staff multiple times to review historical emissions data and related information. *Id*. Witness Metz opines that the Companies correctly accounted for the level of carbon output from their facilities in 2005 for purposes of complying with Section 62-110.9. *Id*. Moreover, witness Metz agrees with the Companies' interpretation of Section 62-110.9 that only emissions from in-state (North Carolina) generation sources should be included when calculating interim compliance and carbon neutrality. *Id*. at 109. However, he also recognizes concerns that HB 951's emissions boundary could lead to locating carbon-emitting resources outside of North Carolina as an end around to the emissions reduction targets and agrees with the Companies that the system-wide approach reduces speculation regarding future asset locations and reduces modeling complexities. *Id*. Public Staff witness Metz encourages the Commission to exercise oversight in further iterations of the Carbon Plan, IRP, and CPCN dockets, and other proceedings to guard against this possibility. *Id*.

Discussion and Conclusions

The Commission directed the Companies to explain the methodology they used to evaluate compliance with HB 951's requirement to reduce CO_2 emissions in the State by 70% from 2005 levels by 2030 and carbon neutrality by 2050. *Carbon Plan Procedural Order* at 3 ¶ 3. The starting point for measuring compliance is the 2005 baseline level of CO_2 "emitted in the State by electric generating facilities owned or operated by" the Companies. N.C.G.S. § 62-110.9. With a baseline number in hand, the amount of CO_2 reduction needed to satisfy the 70% interim target can then be calculated.

The Commission concludes that the Companies' methodology for determining 2005 baseline CO_2 emissions reasonably and appropriately relies on credible, widely used data on emissions from the electric power sector. The Commission further concludes that the Companies have correctly calculated the 2005 baseline CO_2 emissions from the Companies' North Carolina electric generating facilities and have correctly calculated the interim CO_2 emissions target.

In response to the Companies' request for guidance on the treatment of CO_2 emissions from out-of-state generating resources, the Commission agrees with Public Staff witness Metz that the General Assembly intended for the emissions reduction targets to include only CO_2 "emitted in the State." N.C.G.S. § 62-110.9. The Commission is not, however, unmindful of concerns expressed by stakeholders and intervenors that the Carbon Plan could potentially achieve the emissions reduction goals by siting new carbon emitting resources out of the State. The Commission confirms that ultimate siting of new resources optimally inside or outside of North Carolina must be based on several factors, such as appropriateness of the site for the type of generation, access to fuel, ability to leverage existing infrastructure to reduce costs, and evaluation of community impacts. However, for purposes of this proceeding, which is to approve an initial Carbon Plan and not to make specific siting decisions, the Commission accepts the Companies' approach to modeling compliance that assumes that any new CO_2 emitting resources would be sited in North Carolina.

CARBON PLAN APPROACH AND MODELING FRAMEWORK (Findings of Fact Nos. 3-13)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-9

The evidence in support of these findings of fact is found in the Companies' proposed Carbon Plan, the testimonies and exhibits of witnesses Snider, McMurry, Quinto and Kalemba (Modeling and Near-Term Actions Panel), Public Staff witness Thomas, AGO witness Burgess, CPSA witness Haggerty, NC WARN witness Powers, and the entire record in this proceeding. The evidence in support of these findings of fact is found in the Companies' proposed Carbon Plan, the testimonies and exhibits of Modeling and Near-Term Actions Panel, Public Staff witness Thomas, AGO witness Burgess, CPSA witness Haggerty, NC WARN witness Powers, and the entire record in this proceeding.

Summary of the Evidence

General Description of Carbon Plan Modeling Approach

The Companies' Three-Pronged Approach to Planning

In the Carbon Plan, the Companies take a three-pronged approach to maintaining reliable service while also meeting CO_2 emissions reductions targets: (1) shrink the challenge; (2) add carbon-free resources; and (3) ensure reliability. The Companies propose first to shrink the challenge by reducing and modifying system annual energy and peak-demand requirements through grid edge and customer programs that allow more tools to respond to fluctuating energy supply and demand. Second, the Companies created several diverse portfolios that include increasing amounts of carbon-free resources to meet the emissions reduction targets in HB 951. Finally, the Companies included flexible, dispatchable capacity resources in their portfolios in order to ensure reliability of the power system. Carbon Plan, Exec. Summary, 9; Ch. 2, 1-2.

The direct testimony of Duke Energy's Modeling and Near-Term Actions Panel provides additional detail on this three-pronged approach. With respect to shrinking the challenge, the Modeling and Near-Term Actions Panel explains that every incremental megawatt-hour of load the Companies need to serve increases both the cost and CO_2 emissions of the system. The Modeling and Near-Term Actions Panel states that to the extent the grid edge and customer programs can reduce system annual energy and peak-demand requirements in a cost-effective manner, the Companies plan to prioritize deployment and usage of such resources. Tr. vol. 7, 221-22.

Regarding the second prong—to add and utilize zero-carbon emitting resources to replace retiring coal generation and meet new load—the Modeling and Near-Term Actions Panel explains that the Companies first leverage zero-carbon renewable resources that are available today by continuing to programmatically add significant solar to the system over time, integrate available onshore wind resources, and maintain existing zero-carbon resources such as the Companies' hydroelectric facilities. The Panel explains that for the mid- to long-term, this prong means continuing development activities of emerging renewable and other zero-carbon resources such as small modular reactors (SMRs) and advanced nuclear reactors, while pursuing subsequent license renewals (SLR) for the Companies' existing nuclear fleet. The Panel states that pursuing a wide range of advanced technologies is prudent given the risk that not all of these resources will be technically or economically viable. Tr. vol. 7, 222-23.

Finally, the Modeling and Near-Term Actions Panel explains that the third prong—ensuring reliability of the system—represents a minimum standard for all portfolios and is given special recognition and attention in HB 951. Specifically, in developing the Carbon Plan, the Commission must "[e]nsure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid." N.C.G.S. § 62-110.9(3). The Panel states that the Carbon Plan modeling robustly assesses potential reliability risks in developing the portfolios, and that Carbon Plan Appendix Q (Reliability and Operational Resilience Considerations) addresses how the Companies are planning to meet the evolving challenges of a transitioning resource mix and grid. Tr. vol. 7, 223-24.

Duke Energy's proposed Carbon Plan explains that HB 951 sets out an interim target of taking all reasonable steps to achieve 70% CO_2 emissions reductions from a 2005 baseline level by 2030 while achieving carbon neutrality by 2050, subject to specific discretion afforded to the Commission by HB 951 to adjust the timeline for achieving the 70% interim target, including as may be needed to accommodate development of wind or new nuclear resources. The Modeling and Near-Term Actions Panel explains that using the three-pronged approach described above, the Companies' Carbon Plan presents two pathways and four portfolios that meet HB 951's 70% Interim Target in either 2030 (Portfolio 1 (P1)), 2032 (Portfolio 2 (P2); adding OSW), or 2034 (Portfolio 3 (P3); adding SMR; Portfolio 4 (P4; adding OSW and SMR). With respect to the two pathways, the Panel explains that one pathway achieves the Interim Target by 2030 (*i.e.,* P1), utilizing the available technology at that time, and the other pathway achieves the Interim Target once additional nuclear and offshore wind resources would be available for deployment at scale (*i.e.,* P2, P3, and P4). Consistent with HB 951, the Companies state that these portfolios and pathways afford the Commission the flexibility to determine the optimal timing of resources to achieve the least cost path in compliance with the CO_2 reduction goals. Finally, the Panel makes clear that regardless of the timeframe for achieving the interim reduction targets, each of the four portfolios keeps the Companies on the longer-term path to achieving Carbon Neutrality by 2050, albeit at differing projected costs and levels of execution risk. Carbon Plan, Ch. 2, 2-4; Tr. vol. 7, 218-20. Under all portfolios, by the end of 2035, over 8,400 MW of coal capacity is projected to be retired, with only minimal differences in the projected retirement dates across the portfolios. Carbon Plan, App'x E, 46; Tr. vol. 7, 68, 335-36; Tr. vol. 27, 81.

Balancing the Four Core Carbon Plan Objectives

The Modeling and Near-Term Actions Panel states that the Carbon Plan is designed to balance the four core planning objectives in pursuing all reasonable steps towards achieving the requirements of HB 951: (1) CO_2 reductions; (2) affordability; (3) reliability; and (4) executability. When assessing each of the portfolios against these core objectives, the Panel explains that the Carbon Plan utilizes a comprehensive set of modeling tools within an analytical framework designed to fully assess the operational, economic, and reliability implications of resources within a set of planning portfolios. The Panel states that the Carbon Plan takes an "all of the above" strategy that allows for diverse resources to assess a range of options to achieve the emissions reductions requirements while ensuring reliability is maintained or improved for the Companies' customers and communities, with all of the portfolios assessed against the four core objectives. The Modeling and Near-Term Actions Panel also notes that HB 951 ultimately tasks the Commission with developing a Carbon Plan that meets HB 951's goals and balances the four core Carbon Plan objectives. Tr. vol. 7, 43, 205.

The Carbon Plan provides additional detail on how the Companies analyzed these core objectives throughout the modeling process. For CO_2 reductions, the Carbon Plan explains that all four portfolios continue the energy transition and result in substantial CO_2 emissions reductions consistent with the targets set forth in HB 951 but notes that the pace of the CO_2 emissions reductions in each portfolio varies, with P1 reducing emissions at a faster pace than the other three portfolios. For affordability, the Carbon Plan states that cost for customers remains a critically important consideration as HB 951 requires the least-cost pathway for achieving the CO_2 emissions reduction goals. The Companies provide projected long-term present value of revenue requirements (PVRR) across their combined Carolinas service territory, as well as separate estimates of average residential monthly bill impacts for DEC and DEP. For reliability, the Carbon Plan explains that all portfolios must maintain or improve system reliability consistent with sound resource planning principles and as required by HB 951. The Carbon Plan explains that the Companies must continue to maintain adequate day-to-day operating reserves and long-term planning reserves to meet customer needs during peak demand periods, such as cold winter mornings and hot summer afternoons. Finally, the Carbon Plan highlights the importance of executability, noting that maintaining reliability while executing an orderly transition away from more carbon-emissions intensive resources requires that all portfolios are not only carefully planned but also prudently executed. To ensure executability, the Companies perform a thorough evaluation of interdependent retirements and resource needs, timing, and related risk analysis around near-term activities such as regulatory review, interconnection, and supply chain considerations. Carbon Plan, Ch. 3, 16-18.

Unprecedented Level of Detail Provided to Commission and Intervenors on Planning

The Modeling and Near-Term Actions Panel states that the Carbon Plan provides the Commission and interested parties with unprecedented detail and insight into the Companies' modeling and portfolio development process in Carbon Plan Chapters 2 and 3, as well as in Appendix E (Quantitative Analysis). The Panel explains that the Carbon Plan utilizes sophisticated modeling and planning techniques, including the EnCompass modeling platform and a suite of portfolio verification and reliability validation modeling tools the Companies used to develop least cost pathways to achieving CO_2 emissions reduction targets while ensuring prudent planning for a reliable system. As the Panel notes, Appendix E provides a substantial amount of detail on the modeling software and assumptions of the system, load, resources, and other inputs used in the Carbon Plan modeling. Tr. vol. 7, 224-26.

The Modeling and Near-Term Actions Panel further explains that while the Carbon Plan is most comparable to the Companies' integrated resource planning process, the Carbon Plan includes a number of differences in terms of objectives, scope, and level of detail. The Panel first notes that traditional integrated resource planning includes developing a forecast of native load requirements and comprehensive analysis of resource options to reliably satisfy the same in a least cost manner over a 15-year planning horizon. The Carbon Plan, on the other hand, requires the Companies to maintain or improve the reliability of the system while also meeting specified CO_2 emissions reductions targets by 2050 (initially a 28-year planning horizon) while also meeting an interim CO_2 emissions reduction target. The Panel also notes that the Carbon Plan provides more detail on modeling methodology and key assumptions (Carbon Plan Chapter 2), development of the four portfolios and two pathways (Carbon Plan Chapter 3), and detailed quantitative analysis (Carbon Plan Appendix E) used to develop the Carbon Plan portfolios and sensitivities pursuant to the four core objectives. Tr. vol. 7, 216-17.

The Modeling and Near-Term Actions Panel also highlights the Carbon Plan's "enhanced focus on executability" as a core objective, as the assumptions made to develop the Carbon Plan must ultimately be executable. The Panel notes that the Public Staff also identified the importance of executability, as the Public Staff states that "[e]xecution risks will likely pose the most significant challenge to achieving the CO_2 reduction goals" in HB 951. Tr. vol. 7, 217. In response, the Panel explains that Carbon Plan Chapter 4 (Execution Plan) provides the Commission unprecedented detail on the Companies' execution plans, including near-term supply-side development and procurement activities to achieve the interim emissions reduction targets and ensure that selected and long lead-time resources are available options for the Companies' customers on the timelines identified within the portfolios if selected in future Carbon Plan updates. Tr. vol. 7, 217-18.

Description of the Four Carbon Plan Portfolios

The Carbon Plan and the Modeling and Near-Term Actions Panel's testimony explain that each of the four Carbon Plan portfolios are designed to provide the Commission with the flexibility to determine the appropriate pace and resource mix to achieve the interim 70% CO_2 emissions reduction target, as well as target carbon neutrality by 2050, as required by HB 951, while balancing the four core objectives.

Specifically, Chapter 3 of the Carbon Plan provides a detailed discussion of the four Carbon Plan portfolios. As summarized in the Modeling and Near-Term Actions Panel's testimony, P1 contemplates a 70% CO_2 emissions reduction by 2030, and therefore is largely limited to currently available resource types, with the first 800 MW block of offshore wind coming online by the end of 2029. Portfolio 2 delays the 70% CO_2 emissions reduction to 2032, allowing time for a second 800 MW block of offshore wind to be deployed to contribute to the interim target. Portfolio 3 and Portfolio 4 achieve a 70% CO_2 emissions reduction in 2034 by incorporating the first SMR on the system. Portfolio 3 represents a path that does not include offshore wind, while Portfolio 4 presents a hybrid approach, using both offshore wind and SMR to achieve the interim target. The Panel states that the four portfolios provide a broad set of options across which the Commission can weigh tradeoffs with respect to factors such as emissions reductions, costs, portfolio diversity, and execution risks. Tr. vol. 7, 237-39.

The Modeling and Near-Term Actions Panel's testimony includes the following table as a summary comparison of the key differences between the four Carbon Plan portfolios to meet the 70% Interim Target. Carbon Plan, Ch. 3, 2-3.

<table>
<tr><th colspan="3">PORTFOLIOS</th><th>Grid Edge</th><th>Coal Retirements</th><th>New Solar</th><th>Battery</th><th>Onshore Wind</th><th>Offshore Wind</th><th>New Nuclear</th><th>New Pumped Storage</th><th>New CC</th><th>New CT</th></tr>
<tr><td>2030</td><td>P1</td><td>70% by 2030</td><td rowspan="4">EE 1% of eligible retail sales
IVVC growing to 96% (DEC) and 97% (DEP) circuits
Winter DR & CPP</td><td rowspan="2">(-4.9 GW)</td><td>5.4 GW</td><td>2.1 GW</td><td>0.6 GW</td><td>0.8 GW</td><td></td><td></td><td rowspan="4">2.4 GW</td><td rowspan="3">1.1 GW</td></tr>
<tr><td>2032</td><td>P2</td><td>70% 2032 OSW</td><td>5.6 GW</td><td>1.7 GW</td><td rowspan="3">1.2 GW</td><td>1.6 GW</td><td></td><td></td></tr>
<tr><td>2034</td><td>P3</td><td>70% 2034 SMR</td><td rowspan="2">(-6.2 GW)</td><td>7.7 GW</td><td>2.2 GW</td><td></td><td rowspan="2">0.3 GW</td><td rowspan="2">1.7 GW</td></tr>
<tr><td>2034</td><td>P4</td><td>70% 2034 OSW + SMR</td><td>6.8 GW</td><td>1.8 GW</td><td>0.8 GW</td><td>0.8 GW</td></tr>
</table>

Note 1: Gray blocks denote coal retirements, which are dependent on addition of resources shown.
Note 2: Remaining coal planned to be retired by year end 2035.
Note 3: New Solar includes solar + storage, excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage.
Note 4: Capacities as of beginning of the target year of 70% reduction.
Note 5: IVVC = Integrated Volt/Var Control.
Note 6: CPP = Critical Peak Pricing.
Note 7: Battery includes batteries paired with solar.

The Modeling and Near-Term Actions Panel notes that while all of the portfolios achieve carbon neutrality by 2050, the primary differentiator across them is the pace of the energy transition, which creates differences in relative costs and risks to successful plan execution. As an example, the Modeling and Near-Term Actions Panel notes that the more rapid transition contemplated in P1 comes at greater cost ($2 billion more than P2 and approximately $6 billion more than P3 and P4 in PVRR terms) and carries more exposure to execution risks associated with a more concentrated portfolio and more aggressive resource deployment in the near-term. Tr. vol. 7, 239-40.

Sensitivity Analyses Used to Test Different Assumptions and Develop Supplemental Portfolios

The Modeling and Near-Term Actions Panel also explains that Chapter 3 and Appendix E of the Carbon Plan include significant sensitivity analyses on many of the input variables in order to test the robustness of the Carbon Plan under various changes or sensitivities to inputs. The Companies conducted sensitivity analyses including those related to (1) natural gas supply and natural gas price, (2) capital cost sensitivity analysis, (3) adjusted load forecast, (4) federal carbon tax policy, and (5) hydrogen fuel supply. Carbon Plan, Ch. 3, 12-15; App'x E, 84-102. Generally, the Panel states that the sensitivity analysis affirms the reasonableness of the proposed near-term action plan while highlighting specific areas where there still exists a level of uncertainty that may need to be checked and adjusted in future Carbon Plan updates, such as the availability and access to gas from the Appalachia region. Tr. vol. 7, 208.

The Modeling and Near-Term Actions Panel also emphasizes that the Commission will have the opportunity to check and adjust assumptions made in the initial Carbon Plan based on future changes during the biennial Carbon Plan update proceedings. The Panel also emphasizes that one of the largest potential barriers to establishing the most prudent and reasonable least cost pathway to accomplish an orderly Carolinas energy transition and to meet HB 951's goals may be the paralysis that can result from the desire for endless additional analysis and planning prior to execution. The Panel instead states that robust planning informed and updated by robust execution in a sequential and complementary manner will best serve to balance the core objectives discussed above and to achieve the emissions reduction targets envisioned in HB 951. Tr. vol. 7, 208-09.

Background and Development of Supplemental Modeling Based on Public Staff Recommendations

The Modeling and Near-Term Actions Panel explains that in response to recommendations by the Public Staff, and reflective of certain comments of other intervenors, the Companies exerted extraordinary effort to conduct full supplemental modeling during the Carbon Plan proceeding to further assess the reasonableness of the Carbon Plan modeling and the Companies' proposed near-term actions. The Panel presents a detailed analysis of this supplemental modeling as Exhibit 1 to its direct testimony. The Panel states that the Companies worked with the Public Staff to evaluate the impact of increased modeling functionality, such as (1) allowing the EnCompass model to endogenously dispatch storage resources that are paired with solar and address key uncertainties to the overall near-term execution plan, (2) fuel supply, both natural gas and hydrogen, and resource technology options and configurations, and (3) more solar paired with storage combinations and multiple CCs and CTs available for the model to select. Tr. vol. 7, 245-56.

Through the supplemental modeling, the Companies developed two additional portfolios, Supplemental Portfolio 5 (SP5) and Supplemental Portfolio 6 (SP6), each with two fuel supply assumption scenarios. The Modeling and Near-Term Actions Panel explains that per the Public Staff's recommendation, the "primary" natural gas supply assumption used in the supplemental modeling analysis is a "no Appalachian gas" assumption, whereas the "limited Appalachian gas" assumption is considered the "alternate" fuel supply scenario. SP5 represents the no Appalachian gas supply scenario and targets a 2032 interim 70% compliance year, and Supplemental Portfolio 5 with Alternate Fuel (SP5***A***) represents a fuel supply scenario that envisions limited access to Appalachian gas with the same compliance year. Similarly, SP6 targets a 2034 interim 70% compliance year with the no Appalachian gas supply assumption, and like SP5***A***, Supplemental Portfolio 6 with Alternate Fuel (SP6***A***) represents the fuel supply scenario with limited access to Appalachian gas and 2034 as the compliance year. The Modeling and Near-Term Actions Panel also states that the Companies performed the same portfolio verification steps and reliability modeling in EnCompass and in SERVM as the four Carbon Plan portfolios to evaluate each supplemental portfolio's loss of load expectation. Finally, the Panel explains that the Companies also developed PVRR and customer bill impacts analyses for the supplemental portfolios. Tr. vol. 7, 245-47.

The Modeling and Near-Term Actions Panel notes that while it conducted the supplemental modeling in coordination with Public Staff to test the robustness of the Carbon Plan and the proposed near-term actions, the Companies do not agree with all of the Public Staff's recommendations used in the supplemental modeling. Specifically, the Panel states that: (1) unlike the Public Staff, the Companies continue to support using the Carbon Plan's limited Appalachian gas assumption as the appropriate base fuel supply assumption; (2) the Companies disagree with the Public Staff's recommendation to delay the retirement of Belews Creek past 2035; (3) the Companies disagree with the Public Staff's approach to only use the capacity expansion model to select the optimal configuration of storage resources given implications to the load shape at this step in the analysis framework; and (4) the Companies do not support the removal of hydrogen fuel from the development of the supplemental portfolios as the Companies continue to believe the development of future hydrogen fuel sources is likely while also recognizing in the Carbon Plan that there is uncertainty around its development. Tr. vol. 7, 254-56.

The Modeling and Near-Term Actions Panel explains that the supplemental modeling does, however, include a limited number of modeling updates and assumptions changes that were appropriate to include in the supplemental portfolio analysis. Specifically these limited changes include: (1) updating EnCompass to version 6.1.3, which addresses several issues identified by intervenors in their ability to replicate the Companies' modeling results; (2) addressing an issue where EnCompass was not properly recognizing declining capital costs for certain emerging resources; (3) correcting an error, immaterial to resource selection, to more accurately reflect the transmission cost adder in the supplemental portfolios; (4) changing the new nuclear maintenance from discrete maintenance outage days to maintenance rates which allowed the model to more closely reflect real-world dispersed maintenance outages; (5) properly reflecting the fixed operations and maintenance (FOM) costs for combined solar sites, which resulted in a low FOM for all solar paired with storage resources; and (6) properly capturing the degradation of new solar resources to accurately model the generation output over the life of the asset. The Panel summarizes that, overall, the modeling improvements and minor corrections to data incorporated into the supplemental portfolio analysis would not have resulted in material differences in the selection of resources in the four Carbon Plan portfolios, especially with respect to the near-term action plan. Tr. vol. 7, 257-60.

Differences in Inputs and Assumptions between P1-P4 and SP5 & SP6

In order to explain the key differences in inputs and assumptions between the original four portfolios (P1-P4) in the Carbon Plan and the supplemental portfolios (SP5 and SP6), the Modeling and Near-Term Actions Panel provides a summary table. The comparison table shows as follows:

	Portfolios 1 - 4	Supplemental Portfolios 5 - 6
First SMR Availability	EOY* 2032	Mid-year 2032
Belews Creek Retirement	Retired EOY 2035	Retired EOY 2037
Solar Plus Storage (SPS) Battery Dispatch Optimization	Fixed battery dispatch profile	Model optimized battery dispatch
Available SPS Battery Configurations	▪ 4-hr, 25% battery to solar ratio ▪ 2-hr, 50% battery to solar ratio	▪ 4-hr, 25% battery to solar ratio ▪ 2-hr, 50% battery to solar ratio ▪ 4-hr, 50% battery to solar ratio
Cumulative Battery Limits	▪ 4-hr battery capped at 1500 MW in DEC and 2300 MW in DEP ▪ 6-hr battery capped at 1800 MW in DEC and 2000 MW in DEP	▪ 4-hr and 6-hr battery not capped, but continue to decline in capacity value at higher penetrations
Inclusion of Hydrogen Fuel	Yes	No
Limited Appalachian Fuel Supply Case	Existing CC fleet fueled in part by App Gas, FT for two new CCs, no CC on ULSD** backup	Existing CC fleet fueled in part by App Gas, FT for two new CCs, no CC on ULSD backup

	Portfolios 1 - 4	Supplemental Portfolios 5 - 6
No Appalachian Fuel Supply Case	Existing CC fleet fueled Transco Zone 4, no incremental FT for new CCs, new CC configured with ULSD backup	Existing CC fleet fueled Transco Zone 4, FT for two new CCs, no CC on ULSD backup
Back-up Fuel Supply	CTs operate on ULSD for entire month of January	CTs operate on ULSD for two weeks in January
Availability of F-Class and J-Class CCs and CTs	Smaller F-Class CC available in no Appalachian fuel supply case. Larger J-Class CC available in limited Appalachian supply case. Only J-Class CTs available.	Both J-Class and F-Class CCs and CTs available in both fuel supply scenarios.
DEC/DEP Energy Transfer Hurdle Rate	No energy hurdle rate imposed on DEC/DEP transfers	Energy hurdle rate imposed on DEC/DEP transfers included for resource selection

Notes:
*EOY = End of Year
**ULSD = Ultra Low Sulfur Diesel

The Modeling and Near-Term Actions Panel states that the development of SP5 and SP6 most closely align to the development of P2 and P3, respectively. SP5 targets achieving the 70% Interim Target in 2032, similar to P2. SP6 conversely targets achieving the 70% Interim Target in 2034. Because SP6 does not prescribe into the resource portfolio any offshore wind resources, it more closely parallels P3 than P4, which integrates offshore wind into the portfolio for resource diversity benefits and cost comparisons. Tr. vol. 7, 247-51.

The Modeling and Near-Term Actions Panel highlights that the supplemental modeling also includes some of the recommendations made by other intervenors. For example, the Panel notes that the AGO and other intervenors recommended incorporating modeling functionality that allows the capacity expansion and production cost models to determine the dispatch of batteries paired with solar, as well as an additional solar paired with storage configuration that includes a battery with higher energy capacity than was included in P1 through P4. Also similar to the Public Staff, several intervenors expressed concern with the risk of relying on hydrogen for CO_2

emissions reductions and risk of long-lived natural gas assets. The Panel states that these concerns were addressed in the supplemental modeling. Tr. vol. 7, 253.

The Modeling and Near-Term Actions Panel also provides additional detail on the key differences between the original Carbon Plan portfolios and the supplemental portfolios. The Panel first identifies that the Public Staff wanted to assess a no-Appalachian gas scenario as the base planning assumption, which allows for Transco Zone 4 supply to all existing combined cycle units while allowing for the additional procurement of up to 400,000 dekatherms/day incrementally. This assumed incremental Transco firm transportation is enough firm supply for two large, or three small, CC units, which allows for a limited amount of additional firm transportation capacity relative to the Carbon Plan portfolios' alternate fuel supply cases, but still overall constrains fuel supply. Second, the Panel identifies that the Public Staff's supplemental portfolios remove hydrogen as a fuel whereas in the Carbon Plan, the Companies assume the development of a clean hydrogen market with hydrogen fuel blending starting in 2035. The Public Staff did agree, however, to plan the system to 5% or less of CO_2 emissions compared to the 2005 baseline, by 2050, assuming the remaining emissions will be accounted for with carbon offsets, as permissible in HB 951. The final key assumption difference the Panel identifies is the accelerated implementation of the SMR in the modeling. The Panel explains that implementation of the first SMR unit is feasible for June 2032 and with SP5 targeting a 2032 compliance year, accurately modeling the deployment of a nuclear unit in mid-year 2032 could have a material impact on meeting the CO_2 emissions reductions target. The Panel further explains that the model, however, retires and brings new resources on at the end of the year to meet the following year's winter peak capacity needs; thus, the first SMR in the Carbon Plan modeling was available at the end of 2032. The Panel states that due to these potential material impacts that a half year of a nuclear SMR can have on CO_2 emissions, the Companies and the Public Staff agreed to allow the first SMR to be brought online in June 2032 for purposes of this supplemental modeling analysis. Tr. vol. 7, 250-52.

Supplemental Portfolio Analysis Also Included Additional "Low EE" and "High Solar Interconnection" Sensitivity Analyses

The Modeling and Near-Term Actions Panel also explains that the Companies undertook additional sensitivity analyses as part of the supplemental modeling and in response to recommendations from intervenors. First, the Companies included a "Low EE" sensitivity, which the Public Staff describes as "a better estimation of the impacts to future load" based on legislative and regulatory barriers to achieving the load reductions projected in the Carbon Plan's utility energy efficiency (UEE) forecast. Public Staff July 15th Initial Comments at 69. The Panel explains that the Carbon Plan's base UEE forecast is an aggressive target, but states that Duke Energy continues to believe it is important to aggressively pursue the first prong of the Companies' strategy for meeting the objectives of HB 951 by "shrinking the challenge." For purposes of the supplemental analysis, however, the Companies included a Low EE sensitivity. Second, the Panel explains that the Companies conducted a "High Solar Interconnection" sensitivity that assumes for modeling purposes that the Companies are able to interconnect a larger amount of solar in the near-term and throughout the planning horizon. The High Solar

Interconnection sensitivity was recommended by CPSA and is also responsive to comments by multiple intervenors, including the AGO and CCEBA, that advocate for relaxing the solar selection constraints in the model to assess whether the model would economically select higher levels of solar in the near-term. This sensitivity raises the solar interconnection constraint to 1,500 MW per year for 2026 and 2027, which is above the High Solar Interconnection limit used in the development of Portfolio 1, and to 1,800 MW per year for 2028 and for every year thereafter, which is equal to the High Solar Interconnection limit used in the development of Portfolio 1 for 2028 and beyond. The Panel refers to Carbon Plan Appendix I and notes that interconnecting this significantly higher level of solar generation to the Companies' systems is actually unlikely to be achievable, but this sensitivity satisfies the hypothetical question of how much solar might be economically selected at the capital cost assumed in the Carbon Plan without these real-world constraints. Tr. vol. 7, 246-48.

Supplemental Modeling Results Present Reasonable Validation for Initial Carbon Plan Portfolios and Generally Support Near-Term Actions

The Modeling and Near-Term Actions Panel states that the Supplemental Portfolio analysis further validates the Companies' proposed near-term actions by confirming the resources that Duke Energy is requesting the Commission select for near-term procurement, as well as the long lead-time resources for which the Companies are requesting approval of development activities. The Panel explains that in the Supplemental Portfolios, solar continues to be selected at an aggressive pace to comply with the interim CO_2 emissions reduction compliance year and onshore wind continues to be selected as soon as it is available. The Panel also notes that natural gas CC units continue to be selected to help replace coal capacity and energy, despite the removal of hydrogen fuel in the long-term, and that new nuclear continues to be selected as soon as it is available for the model and deployed at significant scale across the planning horizon. Finally, the Panel identifies that offshore wind is not selected for compliance with the interim emissions reduction target in any of the Supplemental Portfolios, but it is selected in all portfolios in the 2040s. Tr. vol. 7, 260-61.

While explaining how the supplemental analysis generally supports the Companies' near-term action plan, the Modeling and Near-Term Actions Panel also notes that the supplemental modeling did impact the model selection of resources in the near-term and long-term. First, the Panel states that including the additional solar paired with storage option with a 50% battery-to-solar ratio with 4-hour duration, along with the revised solar paired with storage modeling, resulted in more storage paired with solar and less standalone storage being selected in SP5 and SP5$_A$. The Panel explains that most of the increase is due to a shift from standalone storage and standalone solar to solar paired with storage as the model recognizes some synergistic capital cost benefits of pairing larger storage with solar versus standalone storage. Overall, however, the Panel notes that the supplemental portfolios validate the total storage needs identified in the Companies' proposed near-term actions and the Panel still supports the initial standalone storage and storage paired with solar targets in the Companies' proposed near-term actions as reasonable. Tr. vol. 7, 263-65.

Companies Undertook Additional Preliminary Modeling of IRA Impacts to Carbon Plan

The Modeling and Near-Term Actions Panel also discusses the IRA, which was recently enacted in August 2022 and includes approximately $370 billion in incentives in climate and energy-related provisions to counteract impacts of inflation. The Panel notes that the IRA is very complex with a multitude of incentive options for supply-side resources, generally solar, wind, storage, and nuclear including potential stackable incentives based on other factors such as siting. The Panel states that Duke Energy is continuing to evaluate tax implications and applicability of the IRA and how the incentives offset the inflationary impacts to the cost of resources such as solar, wind, and storage. Tr. vol. 27, 70-71.

Several intervenor witnesses also discuss the IRA and point to the potential benefits customers will see with increased tax incentives primarily for solar, storage and wind resources. Tr. vol. 23, 241-243; Tr. vol. 25, 245-246, 442-443.

In rebuttal testimony, the Modeling and Near-Term Actions Panel points out, and agrees with, Public Staff witness Thomas' testimony that the near-term inflationary cost impacts caused by global and domestic supply-chain issues have caused current technology costs to rise above those assumed at the time the Carbon Plan was prepared offsetting some of the beneficial cost impacts of the IRA. Tr. vol. 21, 41-42; Tr. vol. 27, 70-72.

The Modeling and Near-Term Actions Panel explains that the Companies' preliminary IRA modeling demonstrates that customers will benefit from increased tax incentives for solar, storage, and wind resources but these benefits do not have a material impact on resources selected in Carbon Plan modeling. Specifically, the Companies conducted a preliminary modeling sensitivity analysis based on an initial review of the IRA, which involved, first, updating technology costs for CC/CT, solar, storage, and onshore wind to account for recent inflationary pressures, and then, second, applying an estimate of applicable tax incentives allowed under the IRA to these resources. The Panel states that the Companies also then reoptimized SP5 (no Appalachian gas) using these updated cost and tax incentive inputs in the capacity expansion model to evaluate the initial selection of economic resources. Tr. vol. 27, 72-73.

The Modeling and Near-Term Actions Panel describes the results of this IRA sensitivity analysis by first noting that significant quantities of solar (standalone and solar paired with storage) and standalone battery storage continue to be selected and the capacity expansion model also continued to select CC and CT capacity by the end of 2030. The Panel states that this generally supports the Companies' near-term actions, including with respect to gas resources. The Panel also explains that based on the preliminary modeling, the IRA will likely reduce costs for customers relative to current pricing and supports including new hydrogen-capable gas resources in the near-term action plan. *Id.*, 73-74.

The Modeling and Near-Term Actions Panel highlights that the IRA sensitivity analysis also recognizes near-term fuel price impacts in addition to capturing the inflationary impacts on technology costs and tax benefits. The Panel states that while current natural gas market prices are elevated, the market projects natural gas costs will recede in the coming years as global production increases, recovering from impacts from the COVID-19 pandemic and geo-political instability impacting the cost and availability of natural gas. The Panel explains that while the near- and mid-term natural gas prices impact the overall cost of the system, the selection of resources utilizing natural gas up until 2050 is more significantly impacted by longer-term fundamental-based natural gas projections, along with other requirements of the system to reduce CO_2 emissions and maintain reliability. Tr. vol. 27, 74-75. Furthermore, the Companies conducted a sensitivity to the IRA analysis that showed, using the Carbon Plan's "high" natural gas price forecast, that natural gas CC continued to be selected consistent with the Companies' proposed near-term actions. Duke Energy Late-Filed Exhibit 1, 8. When questioned if CTs were still validated in this high natural gas price forecast sensitivity to the IRA analysis, Duke Energy witness Quinto stated the Companies did not have sufficient time to conduct the additional portfolio verification steps for this sensitivity to see if CTs were economic replacements for batteries. The Panel suggests, however, that the additional verification steps likely would have validated its inclusion. *Id.*, 191-93.

The Modeling and Near-Term Actions Panel explains that resource planning analyses rely heavily upon inputs, assumptions, and forecasts about future conditions that are based on a "snapshot in time" at the time the plan is developed, and the Carbon Plan reflects cost inputs and assumptions that were available in late 2021 through spring 2022. The Panel notes that since the Carbon Plan was developed, economic conditions and other external factors have changed, which impacts a number of inputs into the planning process, such as those underlying the forecasts for customer annual energy requirements and seasonal peak demand needs. Tr. vol. 7, 206-07.

The Modeling and Near-Term Actions Panel ultimately states that the Companies agree with all parties that the IRA will be beneficial for customers by lowering costs for solar, storage, wind, and nuclear, with potential compounding benefits if such resources can be optimally sited. The Companies also state, however, their support for the Public Staff testimony that the modeling provided thus far in the docket is sufficient to support proposed near-term actions. The Panel states that it is not necessary to delay the Commission's selection of resources from the Carbon Plan at this time. The Companies reiterate that more thorough analysis of the IRA and updates to Carbon Plan modeling can be incorporated into the 2024 update. The Panel explains this these changes are unavoidable and that this is recognized in HB 951 as the Commission has the opportunity to check and adjust the Carbon Plan every two years. Carbon Plan, Ch. 2, 1; Tr. vol. 7, 206-07.

Based on this base planning analysis, sensitivity analysis, and supplemental modeling analysis conducted throughout this proceeding, the Modeling and Near-Term Actions Panel states that the Companies' proposed near-term actions represent the "reasonable steps" contemplated by HB 951 to decisively move forward in this next major phase of the energy transition and should be approved by the Commission. *Id.*, 208-09.

Intervenor Concerns Regarding Ability to Validate Carbon Plan Modeling

The Commission's March 22, 2022, *Order Regarding Data Inputs and Assumptions, and Scheduling Additional Update on Stakeholder Process Sufficiency* (Order Requiring Data Inputs) directed Duke Energy, amongst other requirements, to provide the complete EnCompass input and output data files to intervenors who so request subject to any necessary confidentiality agreements, ideally contemporaneously with the filing but no later than five business days after the filing its initial Carbon Plan. *Order Regarding Data Inputs*, at 2. Mr. McMurry explained that the Companies produced the EnCompass dataset to a confidential datasite and provided access to all intervenors with confidentiality agreements on May 16, 2022, contemporaneous with filing the Carbon Plan with the Commission. Tr. vol. 11, 81-82. After May 16, the Companies engaged with intervenors through hosting a technical conference as well as answer significant modeling-specific discovery. *Id.*, 83-84. During that same timeframe, after validation concerns were raised by intervenors, the Companies performed a validation in a developmental server to confirm that using the input files provided, the Companies could still replicate the output files for P1 through P4. *Id.*, 82-83.

During the evidentiary hearing, Mr. Snider explained that the Companies went to extraordinary efforts to help intervenors with replicating the modeling performed by the Companies including both through the technical conferences as well as answering at least a couple hundred modeling-oriented data requests, but also suggested that there was only so much the Companies could do based on the timeline of the proceeding. *Id.*, 84. Mr. Snider noted that the intervenors also reached out to the EnCompass vendor, Anchor Power Solutions (Anchor Power), to try and get some of their model issues resolved and some intervenors were close to fully replicating the modeling while others were not, but ultimately it is not entirely the Companies' responsibility to ensure the intervenors are able to fully replicate the modeling. Tr. vol. 10, 102-04, 107. Mr. Snider also explained that the Companies do not believe 100% replication is an appropriate standard or expectation, particularly given the scope and complexity of the Companies' modeling, along with the compressed timelines under which all parties were working. Tr. vol. 11, 85.

Public Staff witness Thomas testifies that Public Staff was initially unable to download the EnCompass files and the import failed. Tr. vol. 21, 37. However, after working with Anchor Power, witness Thomas explained at the hearing that the Public Staff was able to confirm the Companies' supplemental modeling with "very slight deviations" amounting in roughly 50 MW differences, which he stated is expected given the way certain things like forced outages are handled in EnCompass. *Id.* at 367-70. Witness Thomas suggested during the hearing that many of the challenges faced were due to the compressed timeframe for the proceeding. Tr. vol. 23, 53.

NCSEA et al. witness Fitch also testifies that he viewed intervenors' challenges initially validating Duke Energy's modeling to be growing pains in the process that also should be expected, as the models are complex and "the validation issue could likely be from some other input problem . . . deep inside the model[]" and "chalk[ed] it up to . . . the compressed timeline" of the proceeding. Tr. vol. 24, 249-50. Witness Fitch continued that "[Synapse] and the intervenors got very close, very, very close to validating and getting exactly the same result" while still noting that the inability to entirely replicate the Companies' modeling "creates a risk that there's some tiny piece of this that's working in a way that's not expected." *Id.*, 250-51.

Tech Customers witness Roumpani testifies that one of the modeling issues encountered during her review of the Carbon Plan was the failure to fully validate the results despite fixes from Anchor Power. Witness Roumpani claims that she believes this means the output files posted by the Companies are inconsistent with the posted input files. Witness Roumpani, however, states that she was "eventually successful in overcoming these issues." Tr. vol. 25, 105.

Specifically in response to Tech Customers, during the evidentiary hearing Mr. Snider noted that in the time between when the Companies filed the Carbon Plan on May 16 and when the intervenors filed their alternative plans on July 15, the Companies responded to six sets of discovery to the Tech Customers. Yet during that same time frame neither the Tech Customers nor their experts Gabel & Associates contacted the Companies to explain that they were not able to use the files provided by the Companies on May 16 to produce their own report. Tr. vol. 11, 84-85. Regardless, as Mr. Snider explains, the Companies' modeling process is highly complex, involves a very large data set, and new model versions were released over the course of the modeling process, so it is not surprising that the intervenors could not exactly replicate the modeling given the time constraints and complexity. Mr. Snider states that the fact that the intervenors could not entirely replicate the Companies' modeling should not have "any bearing in this proceeding" as the modeling is robust and supports the near-term action plan. *Id.*, 85-86.

Discussion and Conclusions

The Commission finds that the Companies' approach of balancing the four core Carbon Plan objectives of affordability, reliability, and executability to develop the least cost path to achieve HB 951's authorized CO_2 emissions reductions targets is reasonable for planning purposes.

The Commission determines that it was reasonable for the Companies to develop multiple portfolios and sensitivity analyses that recognize the flexibility afforded to the Commission under HB 951 to determine the optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals. The Commission also finds that the Companies made reasonable efforts to develop the supplemental portfolios in collaboration with the Public Staff, and inclusive of appropriate recommendations from other intervenors, to consider the impact of alternative assumptions—some of which the Companies did not agree with. The Commission particularly acknowledges, and agrees with, the Companies' and Public Staff's testimony that modeling must necessarily be completed using assumptions that reflect a snapshot in time in which the Plan is developed. The Commission agrees with the Companies that the biennial process established by the General Assembly will allow the Companies to check and adjust assumptions made in this first Carbon Plan in future biennial Carbon Plan updates and IRP proceedings. Relatedly, the Commission also gives some weight to the preliminary IRA modeling performed by the Companies and expects that the new incentives in the IRA as well as other changing market conditions will be more fully incorporated into future Carbon Plan modeling updates. As discussed in further detail and approved later in this Order, Duke Energy's robust and thorough modeling process and analysis presented in the proposed Carbon Plan, supplemental modeling, and the IRA sensitivity analysis has informed a reasonable set of near-term actions for the development and procurement of supply-side resources, initial development activities for longer-lead time resource that are expected to be needed in the future, as well as demand side grid edge proposals to "shrink the challenge," each of which the Commission finds appropriate to include as part of this initial Carbon Plan. The Commission finds that the Companies' robust modeling process and "all of the above" resource planning approach recommending deployment of both supply-side and demand-side resources to achieve HB 951's goals align with and are supported by current law and practice with respect to the least cost planning for generation, pursuant to N.C.G.S. § 62-2(a)(3a), in achieving the authorized carbon reduction goals and determining generation and resource mix for the future. N.C.G.S. § 62-110.9(2).

Specific to intervenor challenges validating Duke Energy's Carbon Plan EnCompass modeling, the Commission finds that there is no indication in the record that Duke Energy acted unreasonably or in any way failed to adhere to the Commission's directives in the *Order Requiring Data Inputs*. The hearing testimony by Public Staff witness Thomas and NCSEA et al. witness Fitch as well as the Modeling and Near-Term Actions Panel all suggest that the accelerated pace of the proceeding as well as the complexity of the Carbon Plan modeling were primary contributors to the challenges initially experienced by intervenors and the Public Staff. The record also suggests that parties were ultimately able to achieve very close results to the modeling results produced by Duke Energy and the Commission accepts the Modeling and Near-Term Actions Panel's uncontroverted testimony that changes in model versions or other factors could contribute to minor discrepancies when the model is run. The record suggests that Duke Energy witness McMurry and the Duke Energy modeling team acted in good faith and made unprecedented efforts to address intervenor challenges, when raised, and the Commission also agrees with Duke Energy that the Commission's expectation for meaningful stakeholder engagement on modeling does not mean that Duke Energy should become a modeling consultant to intervenors or be required to undertake alternative modeling on their behalf. As addressed elsewhere in this Order, the Commission is directing Duke Energy to engage with stakeholders in advance of filing the 2024 Carbon Plan update and the Commission encourages the Companies to discuss intervenors' modeling validation concerns raised in this proceeding as part of that process.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-13

The evidence in support of these findings of fact is found in the Companies' proposed Carbon Plan, the testimonies and exhibits of the Modeling and Near-Term

Actions Panel, Public Staff witnesses Thomas and Metz, AGO witness Burgess, NCSEA et al. witness Fitch, Tech Customers witness Roumpani, and the entire record in this proceeding.

Summary of the Evidence

Chapter 2 of the Carbon Plan details the methodology and key assumptions the Companies used in the modeling process, while Carbon Plan Appendix E (Quantitative Analysis) provides a detailed explanation of each of the modeling steps Duke Energy performed to develop the proposed Carbon Plan. The Modeling and Near-Term Actions Panel provides an overview of the Companies' modeling framework and process. The Panel describes its approach to the Carbon Plan and how it expands on the requirements of traditional IRP planning. Tr. vol. 7, 216-18. The panel goes on to explain how the modeling was performed with sophisticated modeling and planning techniques including the EnCompass modeling platform and a suite of portfolio verification and reliability validating modeling approaches utilizing IRP models. *Id.*, 224-25. The panel explains that this overall modeling framework is essential to a complete Carbon Plan analysis that develops least cost pathways to achieving CO_2 emissions reduction targets while ensuring prudent planning for a reliable system. *Id.*, 225.

Encompass Modeling Platform

The portfolios that the Companies presented in the Carbon Plan that achieve the CO_2 emissions reduction targets were initially developed using the capacity expansion model within EnCompass, an economic resource screening modeling tool. The Companies explain how this model utilizes simplified load and system operations assumptions to quickly assess a wide range of resource portfolio combinations and permutations to identify an initial set of resources. This initial identification of resources must then be validated and refined based on more detailed planning tools to confirm the least cost set of resources are included and reliability is maintained or preserved. Tr. vol. 7, 216-18, 24-26, 29, 85-86; Tr. vol. 27, 101-03.

Public Staff witness Thomas and other parties to the proceeding do not raise issues with the Companies' general use of EnCompass as the primary modeling tool in this proceeding for the purpose of capacity expansion and production cost modeling. Tr. vol. 21, 31-32.

"Mass Cap" Approach to Modeling Emission Reductions

The Modeling and Near-Term Actions Panel describes how the Companies conducted the capacity expansion modeling using a CO_2 emission "mass cap." As further detailed in Carbon Plan Appendix E, this modeling technique puts a limit on the amount of CO_2 a candidate resource portfolio is allowed to emit through the economical simulation of system operations. Using this approach, the model must select resources, which, when integrated in the portfolio, result in CO_2 emissions that are less than the specified limit. The Companies used annual CO_2 limits that decreased along a linear reduction trajectory between 2025 and the 70% interim target year. Thereafter the limit continues to be reduced along a linear trajectory between the 70% interim year and 2050 when net zero emissions is achieved. The Modeling and Near-Term Actions Panel states that modeling the system in this way allows for an orderly transition with the addition of resources throughout the planning horizon rather than waiting until the compliance target years to add in significant amounts of zero-carbon resources. Tr. vol. 7, 236; Carbon Plan, App'x E, 5-6.

The Carbon Plan explains that to model the achievement of the CO_2 emissions reductions, the Companies imposed a system-wide mass cap on CO_2 emissions. This effectively reduced CO_2 emissions of the entire system, regardless of generator location, such that when the system cap was achieved, the emissions from the generators located in the State would achieve the emission reductions targets for HB 951. The Carbon Plan conservatively assumed that all new resources would count towards the in-State CO_2 reduction target for modeling purposes, even though some future generating facilities and other resources may ultimately be sited outside of North Carolina. The model then selects resources to meet the emissions reduction targets regardless of where the new resources were located. For purposes of modeling achievement of the Carbon Neutrality Target, the Companies elected to model a system that achieved zero CO_2 emissions, rather than relying on "net-zero" goal, which would allow the system up to 5% CO_2 emission, relative to the 2005 baseline. Carbon Plan, App'x E, 7.

In his testimony, Public Staff witness Metz acknowledges that the approach the Companies took correctly accounted for the level of carbon output from their facilities in 2005 for purposes of complying with HB 951. Witness Metz also agrees with the Companies' approach to conservatively assume all new CO_2 emissions would be included in the achievement of the CO_2 emissions reductions targets, recognizing the concern associated with locating carbon-emitting resources outside of North Carolina to make an end-run around the spirit of the emissions reduction targets set out in HB 951. Tr. vol. 21, 108, 110.

Portfolio Verification - Battery-CT Economic Evaluation

Carbon Plan and Companies' Direct Testimony

Carbon Plan Appendix E describes the portfolio verification steps the Companies undertook in modeling the Carbon Plan to ensure the portfolios are least cost and ensure the adequacy and reliability of the grid are maintained or improved upon. The Modeling and Near-Term Actions Panel further explains that, as part of the overall modeling framework, the Companies included a portfolio verification step, which included production cost modeling within the EnCompass model to confirm economic selection of resources by the capacity expansion model. The Panel explains that due to the simplified simulations used in capacity expansion modeling, the capacity expansion model alone cannot evaluate in-depth economic operation of resources to ensure economic resource selection, especially in the case of energy-limited resources such as storage. Therefore, the production cost model is used for a more detailed and realistic simulation of the system to more accurately account for the cost to operate the system with these resources. Tr. vol. 7, 227-28.

The Modeling and Near-Term Actions Panel describes this process as necessary to ensuring the inclusion of a least cost set of resources. To quickly assess a wide range of resource options, the capacity expansion resource screening model makes necessary simplifications in hourly loads and system operations to find potential least cost resource portfolios that will minimize the cost of the system. Due to these simplifications, resources are evaluated against load shapes that account for monthly peak and low load conditions for each "typical day," while maintaining total average daily energy to ensure resources are selected that can meet these crucial planning requirements. The Panel explains that this simplification (while necessary in the capacity expansion resource screening model) has the side effect of distorting the load shape in a way that does not reflect actual hourly needs on the system, which results in the capacity expansion model over-valuing short-duration energy storage. Because the capacity expansion model over-ascribes value to energy storage resources, the Panel explains that it is important to use additional analysis to verify if at least a portion of the energy storage, especially in the near term, included in the initial capacity expansion results is economic relative to other peaking resources, in this case CTs. Tr. vol. 7, 229.

As the Modeling and Near-Term Actions Panel explains, to assess this issue, the Companies ran the initially identified expansion plans through the detailed production cost model, which more accurately and thoroughly simulates hourly load shapes as well as the hourly operation of the system, dispatching economically among all units of the resource portfolio in every hour of every day of the planning horizon. This gives the Companies a more accurate reflection of actual production cost impacts of these resources on the system. Tr. vol. 7, 229.

Next, the Modeling and Near-Term Actions Panel states that the Companies replaced approximately 35% of the batteries selected by the capacity expansion model with CTs and re-ran the detailed production cost model with the adjusted resource mix. The Panel explains that removing batteries and adding CTs typically increases modeled production costs, but because CTs are lower capital cost ($/kW) to build than batteries, this adjustment reduces the total capital costs of the portfolio. The Panel explains that so long as the capital cost savings are more than enough to offset the production cost increase and CO_2 reduction targets can still be met, the CTs are the more cost-effective resource. Tr. vol. 7, 230.

The Modeling and Near-Term Actions Panel cautions that omitting this step could result in the inclusion in the portfolio of greater amounts of energy storage than is cost-effective. The necessary simplification of the hourly load shape in the capacity expansion model exaggerates the magnitude and duration of the maximum peak-valley spread. This similarly exaggerates the value of energy storage resources, which is heavily influenced by that spread. As a consequence of this inherent bias in the simplified load shape, the capacity expansion model will tend to select more than the cost-effective amount of energy storage resources, which is why verification in the more detailed production cost model is required. Tr. vol. 7, 390.

The Companies see energy storage playing an important role in the energy transition and reiterate that this process is evaluating a small portion of overall energy storage on the system, to ensure its economic inclusion in the portfolio. Tr. vol. 7, 229.

Public Staff and Intervenor Testimony

Public Staff witness Thomas, NCSEA et al. witness Fitch and AGO witness Burgess raise various concerns with the battery-CT economic evaluation and portfolio verification step.

Public Staff witness Thomas agrees with the Companies that the resulting simplified load shape has a deep, midday valley, as described in the Companies' proposed Carbon Plan. This load profile would allow batteries to fully charge in a way that may not be possible in actual system operations and accordingly creates a wide gap between the peak and valley of the interval load. Tr. vol 21, 45-46. Witness Thomas describes the resulting "Typical peak/off-peak day" load shape as six four-hour intervals and hourly output from wind and solar facilities is similarly aggregated to these interval blocks. Tr. vol. 21, 44. However, he questions the need for this verification step. He states that Duke Energy performed the battery replacement step, in part, to ensure system resource adequacy and reliability taking into account the possibility of extreme weather days that have much longer duration peaks with minimal low load periods to allow for battery charging. However, he confirms this step was performed prior to the Portfolio Loss of Load Expectation (LOLE) and Resource Adequacy Validation (LOLE Validation) step, where capacity expansion plans were run through the Companies' Strategic Energy Risk Valuation Model (SERVM) to ensure that the LOLE targets are maintained. Tr. vol. 21, 46. Witness Thomas further states that while such deep midday valleys are suitable to charge the batteries, there also exists a four-hour morning peak that must be met by the model. Witness Thomas concludes that the rationale provided by the Companies for performing this step, in part, to address resource adequacy renders it potentially redundant with the more detailed quantitative LOLE validation step, which was performed after the battery replacement step. Tr. vol. 21, 51-52.

Public Staff witness Thomas goes on to suggest that the economic evaluation is sensitive to various modeling parameters and that the overall cost savings are relatively minor and are sensitive to assumptions regarding natural gas prices and battery storage capital costs. The Public Staff tested the robustness of these savings estimates under two sensitivities: (1) a 30% reduction to battery storage capital costs, representing the investment tax credit that is now available to standalone energy storage systems; and (2) the use of Henry Hub natural gas prices forecasted in the 2022 Annual Energy Outlook, Low Oil and Gas Supply case. Witness Thomas testifies that the PVRR savings are dramatically reduced for each portfolio, and in P2 and P3 the replacement of 35% of battery storage with CTs results in a cost increase under these assumptions based on his analysis. Tr. vol. 21, 48.

Witness Fitch on behalf of NCSEA, et al. also critiques the Companies' battery-CT economic evaluation step for reasons similar to Public Staff and raises two additional arguments in his sponsored report. First, witness Fitch states that this economic replacement is directly counter to resource planning principles of allowing all resources to compete and choosing the most economical portfolio. Tr. vol. 24, 139-40. Second, he states that Duke Energy is unable to test whether these resources endanger compliance with carbon requirements or determine whether these resources are cost-effective when planning for a de-carbonized grid. *Id.*,135, 155-56.

AGO witness Burgess also cautions against post capacity expansion modeling evaluation and adjustments. Witness Burgess states that while not all out-of-model adjustments are necessarily unwarranted, these kinds of additional steps can introduce a new potential "black box" that is non-transparent and can be difficult for stakeholders to independently assess. Thus, witness Burgess believes it is generally preferable to minimize these additional steps. Tr. vol. 25, 257. Specifically with respect to the Companies' CT-Battery economic evaluation, witness Burgess opines that the simultaneous equations of the optimization algorithm are solved as a set, not in isolation from each other. He clarifies that this means that if changes to certain variables are made after the optimization is completed, they may no longer represent the optimal solution without additional re-optimization. Witness Burgess also recommends minimizing the adjustments needed to ensure economically optimal resources mixes. *Id*.

Duke Energy Rebuttal Testimony

In their rebuttal testimony, the Modeling and Near-Term Actions Panel responds to witness Thomas' concern that the CT-Battery economic evaluation step is not necessary because it is performed prior to the Portfolio LOLE and LOLE Validation steps. The Panel acknowledges that Appendix E raises resource adequacy concerns over short duration battery being able to cover extended extreme weather days, but the discussion in that Appendix goes on to reinforce that this is an economic evaluation of cost effectiveness. The Companies initially describe the distortion of the load shape in the capacity expansion model as a "needle peak" followed by a deep, midday valley in the simplified load shape that creates an optimal daily shape for energy storage resources. However, the Panel acknowledges in rebuttal testimony that the resulting simplified load shape generated in the capacity expansion model is not a "needle" peak but creates perhaps an even more favorable proposition for batteries. Carbon Plan, App'x E, 58; Tr. vol. 27, 103.

The Modeling and Near-Term Actions panel states that the use of the simplified "typical day" load shape, with creates a situation in which the capacity expansion model "thinks" that a four-hour battery could be fully charged at the minimum load for the month, could fully discharge to serve the peak load for the month, and that this could be repeated for every weekday of the month. Because the capacity expansion model has such an inaccurate and imprecise view of daily battery operations, it is essential to validate battery selection with a more granular tool such as in the production cost models, which model realistic load shapes across every hour of the planning horizon. Tr. vol. 27, 103.

The Modeling and Near-Term Actions panel addresses witness Thomas's critiques that the battery-CT economic evaluation step is centered around factors that affect resource selection in general, rather than on whether the capacity expansion model can appropriately value energy storage. The Panel believes the concerns expressed by witness Thomas reinforce the need to validate capacity expansion model results rather than undermine this reasonable and necessary verification step. Tr. vol. 27, 104.

The Companies, as they state in their IRA analysis, note that it is crucial to first recognize inflation impacts on these resources before applying an incentive. Tr. vol. 27, 71. Furthermore, Public Staff witness Thomas testifies that while the Companies projected cost of storage going down in the Carbon Plan, there is no certainty that such costs will actually decrease in light of increased demand for lithium for both utility-scale storage and the EV sector. Tr. vol. 23, 362-63.

In response to NCSEA, et al. witness Fitch's claim that the CT-Battery economic evaluation step is counter to best practices in resource planning, the Companies contend that while each model has a role in resource planning, the capacity expansion model has the broadest analytical cost, but the least accurate representation of the operation of the system, which is critical to evaluating the value of batteries. Tr. vol. 27, 100. The Companies state that the capacity expansion model provides a guide to the portfolio that could best meet planning objectives, but subsequent verification and validation is absolutely required. *Id*. at 101. Simplification made in these models may not reflect real-world operations that dictate adjustment to capacity expansion results, and more detailed analysis of the initial portfolio is required to assess system production costs and resource adequacy using tools designed for those purposes. Because the production cost model evaluates unit dispatch in each hour sequentially over the full planning period (rather than against a simplified "typical day" load shape), it produces a much more accurate estimate of total system operating costs than the capacity expansion model. Iterative production cost model runs can be used to evaluate the impact of adjustments to the portfolio on total system operating costs. The operating cost changes, together with the associated capital cost changes, can be used to calculate the PVRR impact of the adjustment. The Companies therefore conclude that an adjustment that lowers total PVRR can be considered an improvement to the portfolio, assuming the change does not jeopardize other planning objectives or violate any known real-world constraints. *Id*. at 101-02.

In response to NCSEA et al.'s critique that the Companies did not consider the impact to CO_2 emissions of the system when performing the CT-Battery evaluation, the Companies state that they did in fact consider the impact to CO_2 emissions. Appendix E states that the Companies were careful to observe the impact to system CO_2 emissions in this optimization analysis. Replacing more batteries with CTs may have economic benefits, but the replacements have the potential to inhibit the system from meeting its CO_2 emissions reduction targets. When performing the analysis, the Companies were careful not to replace battery capacity that caused the system to exceed the CO_2 reduction targets by the year the interim target is achieved. Carbon Plan, App'x E, 59. Moreover, in the Modeling and Near-Term Actions Panel direct testimony, the Companies state that as long as the capital cost savings are more than enough to offset the production cost increase and CO_2 reduction targets can still be met, the CTs are the more cost-effective resource, alluding to the fact that this consideration was verified before completing the economic change out of resources. Tr. vol. 7, 230. The Companies directly address this fact stating that following the CT-Battery economic evaluation step, a final production cost model run on the adjusted portfolio confirms that CO_2 emissions targets are met. *Id*. at 284-85. The Panel reiterates this sentiment in rebuttal testimony stating an adjustment that lowers total PVRR can be considered an improvement to the portfolio, assuming the change does not jeopardize other planning objectives such as CO_2 emissions reduction constraints. Tr. vol. 27, 102.

Regarding AGO witness Burgess's stance that adjustments made after completion of capacity expansion modeling result in suboptimal portfolio optimization, the Modeling and Near-Term Actions Panel explains that such adjustments are economically justified because they appropriately account for changes in capital and system production costs as determined by the detailed production cost model and therefore result in lower PVRRs. According to witness Burgess, instead of including the battery-CT economic evaluation step, the "typical day" profile should have been adjusted within EnCompass to more accurately represent daily load shapes. The Modeling and Near-Term Actions Panel explains that the Companies agreed that many modeling techniques proposed by intervenors and the Public Staff should be considered for further process improvements and plan to continue to assess modeling improvements such as these and commit to engage with the Public Staff and stakeholders in advance of the 2024 Carbon Plan update to discuss modeling process improvements that will be utilized in that proceeding. Tr. vol. 27, 102.

Overall, the Companies believe this additional analysis is also necessary understanding that overall battery energy storage contemplated in the Carbon Plan analysis is largely untested at scale, and existing planning tools are still being updated and enhanced to better assess the complexities of this dynamic resource. Tr. vol. 27, 104.

Portfolio Verification - Bad Creek II Validation

Carbon Plan and Companies' Direct Testimony

Carbon Plan Appendix E explains the role of the Bad Creek and Jocassee pumped storage hydro facilities in providing long-duration storage to the DEC system and identifies that DEC has a unique opportunity to construct a second 1,680 MW powerhouse at the Bad Creek facility. As explained in Appendix E, the Companies performed additional comparative economic analysis of this long-duration storage to confirm Bad Creek II as an economic inclusion in the portfolios. In the initial development of portfolios in the capacity expansion model, Bad Creek II was prescribed into each of the portfolios. To confirm the inclusion was economic, the Companies compared the project's cost effectiveness to other longer-duration storage options. Carbon Plan, App' E, 26-7; Tr. vol. 7, 230.

The Modeling and Near-Term Actions Panel explains that, similar to the battery-CT economic evaluation, the Companies ran the detailed production cost model including Bad Creek II and then replaced the project with the equivalent amount of 8-hour lithium-ion batteries and ran the detailed production cost model again. The Panel explains that the differences in production cost and new project costs were compared and the Companies determined the inclusion of Bad Creek II was economic. Tr. vol. 7, 231.

Public Staff and Intervenor Testimony

Public Staff witness Metz affirms the Companies' modeling results and states that given the long development time for Bad Creek II and the favorable economics, it is reasonable for Duke Energy to perform further near-term evaluation to refine the timeline of commercial operation, identify risk factors, and determine more accurate cost estimates of this resource. Tr. vol. 21, 124.

Similarly, AGO witness Burgess points to pumped storage as a mature technology with a proven track record. When viewed against other long lead time resources, from an execution risk standpoint, pumped storage may make sense to approve further development activities for this resource. Tr. vol. 25, 300-01.

Portfolio Verification - Resource Adequacy and Reliability Validation

Carbon Plan and Companies' Direct Testimony

Carbon Plan Appendix E also introduces the resource adequacy and reliability validation step performed in developing the proposed Carbon Plan. Carbon Plan, App'x E, 60-65. The Modeling and Near-Term Actions Panel explains that the Companies performed this final Portfolio Verification step using both EnCompass's production cost module and the SERVM to validate that the adequacy and reliability of the Companies' systems was maintained or improved under each of the Carbon Plan portfolios. The Panel explains that the production cost module can analyze the operations of a portfolio of resources in every hour of every year across the entire planning horizon, ensuring the portfolio over time can reliably meet customer load and maintain stability of the grid. The Panel also explains that SERVM is a state-of-the-art reliability and hourly production cost simulation tool used to analyze a portfolio's ability to reliably serve system load in a particular year across a wide range of weather and outage uncertainty. SERVM is widely utilized in the utility industry to assess reliability standards and quantify the reliability requirements for large, complex power systems including determining planning reserve margin requirements and effective load carrying capability (ELCC) or capacity values. The Panel explains that this enhanced reliability validation modeling analysis is especially important for portfolios with high reliance on variable energy and energy-limited resources, which presents risks that planning reserve margins alone do not adequately address, especially in severe weather events. Tr. vol. 7, 228-32; Tr. vol. 27, 98-99.

The Modeling and Near-Term Actions Panel explains how this additional modeling, using both the EnCompass production cost model and SERVM, was performed to ensure that each portfolio would maintain the reliability of the system. The SERVM model was used to verify that the portfolios maintain resource adequacy in 2030 and 2035 as the system undergoes significant changes, while the production cost model was used to verify that portfolios could reliably meet the energy and CO_2 reduction requirements through 2050. Tr. vol. 7, 227.

The Panel highlights the requirement in HB 951 to maintain or improve on the adequacy and reliability of the system as supporting the need for this additional analysis along with the transformational nature of resources expected to come onto the system that will transition the fleet away from large quantities of firm dispatchable resources to greater reliance on variable energy and energy limited resources. Because planning parameters such as a reserve margin requirement and resource specific ELCC values used in the capacity expansion model in actuality can change over time, more sophisticated tools and techniques are required to ensure reliability is maintained. Tr. vol. 7, 231.

The Panel explains that this additional reliability validation modeling step was designed to take the Carbon Plan portfolios, including adjustments resulting from the previous portfolio verification steps, load them into SERVM, and analyze the performance of the portfolio in this wide range of weather and forced outage simulations to measure LOLE and ensure the reliability benchmark was met. In cases where the reliability benchmark was not met, the Companies added “reliability CTs” to the portfolios until the LOLE benchmark was met, indicating that the newly adjusted portfolio could maintain system reliability. Tr. vol. 7, 232. Through this detailed reliability validation process, the Panel states that the Companies were able to confirm that each of the Carbon Plan portfolios have the necessary resources to meet the LOLE benchmark and are therefore able to show that these portfolios maintain or improve upon the reliability of the existing grid. Carbon Plan, App’x E, 65.

Finally, for the last step of the portfolio verification process, the Companies ran the detailed production cost model again with any necessary reliability CTs added to the portfolios to ensure that hourly load throughout the planning horizon could be served while meeting CO_2 reduction targets. Tr. vol. 7, 232-33.

The Companies state that SERVM is a state-of-the-art reliability and hourly production cost simulation tool managed by Astrapé Consulting who provides consulting services and/or licenses the model to its users. The model is also the same model the Companies used to develop the planning reserve margin and effective load carrying capabilities of energy limited and variable energy resources such as solar, wind and batteries. SERVM is widely used in the utility industry as a tool to ensure reliability. Tr. vol. 7, 227.

Public Staff and Intervenor Testimony and Comments

Public Staff witness Thomas agrees that the process the Companies undertook to validate portfolios’ LOLEs appears to be reasonable but could be considered redundant with the battery-CT economic evaluation step and would capture the economic replacements found in the preceding portfolio verification step. Tr. vol. 21, 51-52. During the hearing, witness Thomas testified that the reliability validation modeling was a reasonable step to make sure the modeled portfolios meet the reliability requirements of HB 951. Tr. vol. 22, 374.

Public Staff witness Metz acknowledges that reserve margins can potentially change over time or be influenced by external factors. He does not take issue with the Companies' analysis and uses the analysis as evidence that Supplemental Portfolios 5 and 6 also adequately address system reliability. Tr. vol. 21, 242, 248.

AGO witness Burgess also recognizes that reliability must be evaluated comprehensively to ensure that any simplifications in models like EnCompass do not overlook any potential gaps. Witness Burgess agrees that a reliability modeling step similar to the validation step performed by the Companies may be necessary. Nevertheless, witness Burgess expresses concerns regarding transparency of the analysis as the Companies performed the LOLE step outside of Encompass. For the instant proceeding, witness Burgess does not recommend removing this reliability adjustment step because the adjustments made by the Companies appear relatively limited and well into the next decade. Tr. vol. 25, 261-62.

Tech Customers witness Roumpani states that intervenors could not verify the Companies' reliability validation because they did not have the capability to run SERVM. Tr. vol. 25, 89.

NCSEA, et al. witness Fitch states that the reliability validation step does not align with industry best practices and is a meaningful departure from resource adequacy studies. According to Witness Fitch, the fact that the Companies did not run the Resource Adequacy and Reliability Verification step in preparing their 2020 IRPs demonstrates that the process is not necessary, and the Companies can rely on the planning reserve margin alone. Witness Fitch also argues that the one other utility that the Companies found that performs a similar resource adequacy step—the Public Service Company of New Mexico (PNM)—runs SERVM in a much different manner that is not comparable to the Companies. Tr. vol. 24, 142-43.

Companies' Rebuttal Testimony

In response to Public Staff witness Thomas's argument that the LOLE would capture the battery-CT economic evaluation step, the Modeling and Near-Term Actions Panel states that the battery-CT economic evaluation step was performed before the Resource Adequacy and Reliability Validation step. The battery-CT evaluation is an economic analysis to assess whether replacing a portion of model-selected batteries with CTs results in overall PVRR savings, while the Resource Adequacy and Reliability Validation step is designed to ensure resource adequacy across a range of possible weather years and outage scenarios. Batteries that are economically justified in the battery-CT economic evaluation contribute to lowering the overall cost of the plan, while the LOLE validation ensures resource adequacy of the system. The Panel summarizes that justification in economic evaluation step does not necessarily mean it would be required in the reliability step and vice versa. Tr. vol. 27, 105.

In response to Tech Customers witness Roumpani's argument that intervenors could not verify the Resource Adequacy and Reliability Step because they lacked access to SERVM, the Panel explains that SERVM is required to properly assess resource adequacy and perform an in-depth analysis of portfolio operations across a wide range of conditions. The Panel reiterates that SERVM is the state-of-the-art reliability and production cost model used to assess the carbon plan portfolios across a wide range of forced outage and weather scenarios to ensure the portfolio resource adequacy. Tr. vol. 27, 112.

In response to witness Fitch's claim that the Resource Adequacy and Reliability Step was not necessary because the Companies did not use it to develop their 2020 IRPs, the Companies state that witness Fitch's critique presupposes that the "correct" reserve margin for satisfying the 0.1 LOLE standard is fully known prior to capacity expansion modeling. According to the Panel, initial reserve margin and ELCC values are dependent on many factors including system peak demand and load shape to be served, the existing resource mix, as well as the expected adoption level of different renewable and energy storage resource technologies. The capacity expansion model introduces changes in the resource mix, which can impact ELCC values, reliability, and operational reserve requirements. Since it is not practical to determine these values for infinite combinations of resources, nor are such inputs easily integrated into the capacity expansion model, the "correct" reserve margin for the portfolio initially produced by the capacity expansion model cannot be definitively known in advance. Accordingly, the Panel explains, the Resource Adequacy and Reliability Validation step is necessary to ensure the reliability of initial capacity expansion results maintain or improve on system reliability. Tr. vol. 27, 114-15.

Responsive to witness Fitch's argument that the Companies did not use SERVM to validate reliability in the same way as PNM, the Panel explains that the analyses performed by the two utilities are solving for the same reliability risks. According to the Panel, as the electric generation system transitions generally toward variable energy and energy-limited resources and away from firm, dispatchable resources, DEC and DEP are concerned about energy imbalances due to the diurnal nature of solar and resource availability during peak load conditions, especially at winter peak, when solar generation is in low supply and during long duration events when energy limited resources are not able to be recharged to ensure reliability, consistent with PNM's justification for an LOLE validation process. Tr. vol. 7, 287.

Capacity Expansion Segmentation

Carbon Plan and Companies' Direct Testimony

The Modeling and Near-Term Actions Panel explains that the Companies modeled prospective resource portfolios that achieve the targeted CO_2 emissions reductions using a CO_2 "mass cap." This modeling approach influences the selection of resources which when dispatch economically with the rest of the system resulting in the system emitting less than the annual cap. Tr. vol. 7, 236. The Panel explains that this was a new approach to modeling the transition of the DEC and DEP systems than previously used by the Companies, in addition to the transition to EnCompass, and results in a more complex analytical solution. *Id.* at 281. The Companies found early in the development of the Carbon Plan that the capacity expansion model would not solve the complex problem using a "partial commitment" condition and imposing a reasonable convergence tolerance. Working with the EnCompass vendor, Anchor Power Solutions, the Panel explains that the Companies found that the same run would solve if the problem was broken into smaller pieces. The Companies determined that using eight-year segments with a 25 Mixed Integer Program (MIP) basis, or "convergence tolerance," allowed the model to solve while considering the complex array of resource options available. Tr. vol. 27, 108.

The Companies explain that the use of this eight-year period was appropriate as it accounted for all available resources in developing the expansion plans and allowed for more detailed commitment logic and better solution with a lower convergence tolerance. The Modeling and Near-Term Actions Panel notes that this eight-year segmentation was identified because it allowed for "Partial Commitment" to ensure system reliability was considered in the development of the expansion plan within Encompass and a convergence tolerance of 0.25%. The unit commitment option in EnCompass considers the unit operational parameters such as ancillaries, reserves, startup/shutdown cost, ramp rates and unit operational requirements. The Partial Commit option considers all these operational constraints but with partial units by bypassing the step in the optimization which searches the best way to commit whole units, thus reducing run time. Tr. vol. 7, 281-82. In contrast, the Panel explains, other commitment options such as "No Commitment" ignores most of these constraints and simplifies many others, which in turn runs the system with unrealistic flexibility. The Companies note that with increasing levels of system variable energy resources, the need to incorporate system reliability in the selection of resources will only increase. Tr. vol. 27, 106-07.

Public Staff and Intervenor Direct Testimony and Comments

The Synapse Report, prepared on behalf of NCSEA, et al., suggests that eight-year optimization segments are within the reasonable range of planning horizons used in capacity expansion modeling, but also suggests that this approach introduces risks that resources selected in the earliest segments may not be economical resource choices when viewed over the long term. Tr. vol. 25, Carbon-Free by 2050 Report, B-16. NCSEA witness Fitch specifically addresses this risk stating it is a short-term approach that will not integrate long-term planning dynamics, including carbon reduction requirements. Tr. vol. 24, 158. Tech Customers witness Roumpani states that the optimization period may bias results, especially with near term decisions, while the Gabel Report on behalf of Tech Customers also highlights costs such as the hydrogen conversion costs that would not be considered when making the original resource selection. Tr. vol. 25, 94; Tr. vol. 25, Tech Customers - Gabel Report, 49.

Public Staff witness Thomas agrees with Synapse's and Gabel Associates' observations that an eight-year optimization period could be problematic, particularly due to future hydrogen conversion costs being excluded from the resource selection analysis of new CCs and CTs selected in the near-term. However, Public Staff witness Thomas points out that because hydrogen as a fuel was excluded from the Supplemental Portfolio Analysis, conversion costs for CC and CTs were also excluded from Supplemental Portfolios 5 and 6. Because these portfolios continued to select CC and CT resources in the Supplemental Portfolio Analysis, the Public Staff was satisfied with an eight-year optimization period for purposes of the supplemental portfolios. Tr. vol. 21, 53-54.

In alternative modeling proposed by Synapse on behalf of NCSEA, et. al., longer segments were used. Synapse used one 15-year segment and one 14-year segment (i.e., 2022-2036, 2037-2050). The Synapse report states that this strikes a balance between resource efficiency while allowing economic optimization to make a decision that takes a long-term view of emissions and technology prices trajectories. Tr. vol. 15, Carbon-Free by 2050 Report, B-16. NCSEA, et al. witness Fitch adds lengthening optimization horizon as a recommendation to minimize the risks of negative impacts of path dependence. Tr. vol. 24, 162. Gabel Associates on behalf of Tech Customers used a 28-year optimization period covering the entire planning horizon, but Public Staff Thomas points out that these modeling approaches were achieved by increasing the MIP Stop Basis and altering commitment setting. Tr. vol. 25, Tech Customers - Gabel Report, 48-50.

Public Staff witness Thomas also suggests that Duke Energy did not provide sufficient explanation as to why a relaxed MIP Stop Basis of 0.5% instead of 0.25% is inadequate for determining the least-cost plan while reducing model run times. Tr. vol. 21, 53-54.

Public Staff witness Thomas also recommends that in future Carbon Plan proceedings the Commission direct Duke Energy 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. Tr. vol. 21, 54.

Companies' Rebuttal Testimony

In response to Public Staff witness Thomas's recommendation of longer optimization periods with lower convergence tolerance, the Modeling and Near-Term Actions Panel states in its rebuttal testimony that convergence tolerance measures are essentially the degree of accuracy required of the model in selecting the least cost portfolio. The Companies provide the example that convergence tolerance of 200 would allow the model to “stop” iterating to find a better solution once the identified resource portfolio is within 2% of the optimal solution. To put this into context the Companies highlight the PVRR of Portfolios 1-4, approximately $100 billion. Therefore, a convergence tolerance of “200” would allow the model to stop trying to find a better solution when it was within $2 billion (2%) of the optimal (least cost) solution. As a comparison, the Companies point to the PVRR difference between Supplemental Portfolios with and without offshore wind in 2031 at only $0.3 billion. With a convergence tolerance that allows for $2 billion of “wiggle room” around the optimal solution could result in a portfolio with very significant resource differences from a more optimal solution. The Companies state they typically use a convergence tolerance of 25 to 50 (equivalent to deviations of $0.25 billion to $0.5 billion from the optimal solution for a $100 billion portfolio) depending on model run times for a given analysis. Tr. vol. 27, 107.

The Modeling and Near-Term Actions Panel maintain that the use of eight-year optimization periods is reasonable in accordance with the appropriate system operational conditions and convergent tolerances used in the initial development of expansion plans in the capacity expansion model in the Carbon Plan. Tr. vol. 27, 105-06. The Companies explain that using eight-year segments allowed the model to solve while considering the complex array of resource options available with realistic operating simulations. The first segment (2023-2030) evaluated resources needed to meet a 2030 target, the most stringent CO_2 mass cap scenario. New nuclear and additional offshore wind resources were evaluated in the second eight-year segment (2031-2038) as options to meet the interim targets in P2-P6 and continue on the path toward zero CO_2 emissions. The final segments could then further weigh nuclear, offshore wind, and 100% hydrogen resources for achieving the 2050 zero CO_2 emission cap. *Id.* at 108.

The Panel explains that the Companies reviewed the modeling files used to prepare the Synapse Report and Gabel Report modeling files and found that the 15-year segmented solution used a MIP basis of 200, which witness McMurry explains is not precise enough for resource planning. The Panel also confirms that the modeling presented in the Gabel Report did not use segmentation, optimizing resources over the entire planning horizon and a more stringent MIP basis of 60, compared to the Synapse modeling. However, Strategen also used the unrealistic “no commitment” operational condition in the capacity expansion model. Witness McMurry expresses concern over the illogical and erroneous selection of resources under such a modeling setting. Tr. vol. 9, 82-87; Tr. vol. 25, 109.

Generally, the Modeling and Near-Term Actions Panel explains that NCSEA et al., the AGO, and the Public Staff suggest modeling approaches that are likely to be more computationally intensive. The Panel explains that there are trade-offs for increasingly complex analytical challenges associated with the energy transition that can influence the setup and time to development of resource plans. For example, the Panel explains that implementing the Public Staff’s proposal regarding solar paired with storage—allowing the capacity expansion model to optimize the charging and discharging of batteries paired with solar rather than using a fixed generation profile for solar paired with storage resources—in modeling the Supplemental Portfolios increased capacity expansion model run times to nine hours or more per solution, with some runs exceeding 48 hours. Tr. vol. 27, 109-10.

The Panel states that in response to Public Staff and intervenor recommendations to use longer optimization periods, the Companies have committed to testing longer segmentation periods as new versions of the model are implemented and will continue to engage with the Public Staff and other parties in advance of the 2024 Carbon Plan but continue to caution the Commission that it would be overly restrictive and problematic for the Commission to dictate detailed model settings such as convergence tolerance and commitment settings. Tr. vol. 27, 110-11.

The Companies state that this duration of run time presents an untenable result in developing IRPs and the Carbon Plan with hundreds of required runs. The Companies note that as more complex modeling is undertaken, including strict emissions caps and complex fuel logic, they must be careful to set up the capacity expansion model in a way that allows for reasonable processing time while ensuring reliable results. Tr. vol. 27, 110. The Companies contend that due to the complex, technical nature of model settings in modeling for Carbon Plans and IRPs, along with potentially more computationally intensive modeling approaches, imposing prescriptive requirements in a regulatory proceeding could unnecessarily confine the Companies' efforts to address these challenges in the future. These complexities can be discussed with the Public Staff and other interested stakeholders in advance of the development of the 2024 Carbon Plan. *Id.*

Discussion and Conclusions

The Commission finds that Duke Energy's modeling framework, including the detailed approach it took to assess least cost and system reliability used to develop the proposed Carbon Plan, is reasonable for planning purposes. The Commission recognizes that the complexity associated with new modeling approaches as presented in the Carbon Plan will require the use of more complex analytical tools to answer important questions of reliability and cost. The Companies' approach of detailed analytics to ensure least cost planning and maintaining or improving the reliability of the system are fully consistent with the requirements of N.C.G.S. § 62-110.9.

As an initial matter, the Commission finds the Companies' use of the EnCompass model to be reasonable and appropriate. No party challenged the Companies' use of EnCompass and the evidence in the record demonstrates that EnCompass is a sophisticated and detailed capacity expansion and production cost modeling platform that continues to evolve and improve. Similarly, no party took issue with the Companies' mass cap approach to modeling CO_2 emission reductions over time and the Commission similarly finds it to be a reasonable approach for planning purposes.

Turning to the battery-CT economic evaluation process, the Commission concludes that utilizing a capacity expansion screening model, which uses necessary simplifications to quickly assess a wide range of resource portfolio, is useful as an initial guide to resource selection. However, to the extent that a more detailed modeling approach that more realistically simulates system operations proves that limited adjustments result in a lower cost resource mix, such adjustments are reasonable, appropriate, and necessary for ensuring a least cost portfolio, while continuing to maintain reliability and meeting other planning factors, including CO_2 emission targets. The Commission places substantial weight on the Companies' uncontroverted testimony that each of the portfolios continued to meet the carbon reduction targets even after the battery-CT economic evaluation step replaced a portion of battery storage resources initially selected in the capacity expansion step with CTs. It is also uncontroverted that the more detailed production cost modeling analysis demonstrated that this limited adjustment to the capacity expansion portfolios to add CTs reduced the PVRR of the portfolios. The Commission also recognizes the concerns identified by the Public Staff and other parties that the battery-CT economic evaluation process may ultimately not achieve lower costs in future modeling and may also overlap with the reliability validation steps performed at the end of the modeling process. The Commission acknowledges that the reduction in the cost of batteries in this analysis may be much more impactful than an increased natural gas price. Additionally, when reducing the cost of the batteries to represent the investment tax credit now available to the resources, the Public Staff also did not factor in near term inflation impacts that drove the federal government to enact such incentives. Ultimately, however, the Companies should continue to assess the potential improvements to the modeling process in an effort to minimize the need for adjustments to resources identified by the capacity expansion model.

The Commission also finds the Bad Creek II validation step reasonable. Numerous parties including the Public Staff, AGO, NCSEA et al., and others support inclusion of this significant long-duration storage resource as part of the least cost portfolio. The Commission also notes that we are only approving initial procurement and development activities for Bad Creek II as the Companies have not requested the Commission select Bad Creek II as part of the Carbon Plan in this proceeding. Accordingly, the Commission will have future opportunities to further evaluate the need for and selection of Bad Creek II in future updates to the Carbon Plan.

The Commission also finds the final reliability validation step performed in the Carbon Plan modeling process to be reasonable for planning purposes. This step is appropriately designed to ensure reliability is maintained during the energy transition now underway to achieve net zero emissions and furthers the General Assembly's express directive for the Commission in developing the Carbon Plan to "[e]nsure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid." The Commission recognizes that as the system evolves from reliance on firm and dispatchable resources to increasingly rely upon variable energy and energy limited resources, the ability for these resources to maintain a reliable system is important for the Companies to verify. The Commission finds use of the industry-recognized SERVM model—which is also used to develop ELCCs and the Companies' planning reserve margins—to verify the LOLE of the portfolios is appropriate. While the Commission acknowledges that the Carbon Plan portfolios were demonstrated to maintain or improve on resource adequacy and reliably serve energy throughout the planning horizon, the Commission supports the Companies' efforts to evolve its modeling regarding the critically important issues of resource adequacy, especially as the Companies and neighboring utilities continue to transition to higher variable energy resource and energy limited resource reliance.

The Commission declines to impose prescriptive requirements on the highly technical modeling set up to be used in future Carbon Plans based on the record in this proceeding. The Commission appreciates the Public Staff's practical concerns that unreasonably short model optimization periods could result in the model not "seeing" a potential future cost such as hydrogen fuel conversion at the time the resource is selected by the model. However, the Modeling and Near-Term Actions Panel's rebuttal and hearing testimony demonstrates that there are a number of highly complex convergence tolerance and commitment settings and likely other factors that impact the balance between precision and efficiency in the modeling process. The Commission recognizes the need to balance computational time with modeling accuracy and representation of real-world operating conditions. Absent significant advancements in computation ability to optimize to a mass cap over the entire planning horizon while maintaining realistic and reasonable system conditional constraints, the Commission recognizes the segmentation the Companies relied to appropriately balance resource decisions while fairly representing the operational constraints and conditions of a real-world system.

Finally, the Commission notes that the Companies and the Public Staff through constructive engagement were able to agree on supplemental modeling that addressed the Public Staff's main concern about the costs of hydrogen conversions occurring in a later optimization period. The Modeling and Near-Term Actions Panel also committed on behalf of the Companies to testing longer segmentation periods as new versions of the EnCompass model are implemented and to engage with the Public Staff and other parties in advance of the 2024 Carbon Plan to further discuss these issues. Accordingly, the Commission finds and concludes that such complex and technical model settings are best addressed through future engagement with the Public Staff and other interested stakeholders ahead of the development of the 2024 Carbon Plan, providing the Companies the flexibility and latitude to determine the best and most effective use resources and modeling approaches to model the system.

CONSIDERATION OF MODELING CRITIQUES BY OTHER PARTIES AND ALTERNATIVE MODELING RECOMMENDATIONS AND ANALYSIS (Findings of Fact Nos. 14-24)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence in support of this finding of fact is found in the Companies' proposed Carbon Plan, the testimonies and exhibits of the Modeling and Near-Term Actions Panel, witnesses Huber and Duff (Grid Edge Panel), the comments and testimony of Public Staff witness David Williamson, AGO witness Burgess, NC WARN witness Powers, CPSA, NCSEA, et al., Brad Rouse, the City of Asheville and Buncombe County, the City of Charlotte and the entire record in this proceeding.

Summary of the Evidence

Development of the Load Forecast and Modifiers

Appendix F of the Carbon Plan (Electric Load Forecast) explains that the load forecasts used in the Carbon Plan cover the years 2023-2037 and are geared toward assessing the energy needs of the residential, commercial, and industrial, street lighting customer classes. The Companies explain that this data set allows the Companies to analyze the impact of varying inputs on sales and customer growth, including substitution of different economic or weather inputs. Carbon Plan, App'x F, 1-2.

The Modeling and Near-Term Actions Panel's testimony summarizes and describes how the Companies developed the load forecast using four steps. First, the Companies obtained a service area economic forecast using economic and demographic projections from Moody's Analytics that includes economic forecasts for the Carolinas. Second, the Companies prepared an energy forecast by estimating statistical models based on these economic conditions. The Companies further explain that preparing the energy forecast involves a mix of Statistical Adjusted End-Use Model techniques and traditional economic models, which calculate how variation in energy volumes can be explained by variations in weather and economic data. Third, the Companies perform ex-post modifications to account for the growth in electric vehicle, solar, and energy efficiency programs. Finally, using the energy forecast, the Companies developed summer and winter peak demand forecasts. Tr. vol. 7, 306-07.

Once the gross load forecast is developed, the Modeling and Near-Term Actions Panel explains that several load modifiers are applied to arrive at the net load forecast used in the Carbon Plan modeling. The Panel states that these modifiers are necessary to account for load projections that either increase or decrease the load the Companies must serve and include modifiers such as EV load, additional wholesale load, and expected line losses and Company use (which may increase the load forecast) and Utility Energy Efficiency (UEE), behind-the-meter renewables or net energy metering (NEM), Peak Time Rates (PTR), and Integrated Volt-Var Control (IVVC) (which may decrease the load forecast). Tr. vol. 7, 308; Carbon Plan, Ch. 2, Tables 2-1 to 2-4.

UEE Savings of 1% of Eligible Load

The Modeling and Near-Term Actions Panel provides additional detail on some of these modifiers, beginning with a discussion of how the Companies incorporated EE/DSM into the Carbon Plan modeling process. The Panel explains that the Companies sought to incorporate an aggressive, yet attainable, modeling assumption regarding the amount of load reduction included in the Carbon Plan and assumed a minimum amount of annual UEE savings of 1% of eligible sales. The Panel continues that this load reduction was applied prior to evaluating any supply-side resources, in accordance with the first prong of the Companies' three-pronged planning approach: "shrink the challenge." Tr. vol. 13, 42-43. The testimony of Duke Energy Grid Edge Panel witnesses Huber and Duff shows that this UEE assumption will deliver an approximate 5% cumulative reduction in total retail load by 2030 over a seven-year period. Tr. vol. 30, Grid Edge Rebuttal Redirect Exhibit 1.

The Grid Edge Panel explains that several categories of energy efficiency savings are reflected in the forecast modeling, including naturally occurring energy efficiency that is driven by appliance or building codes and standards as well as efficiency improvements implemented by customers independent of UEE programs. The Grid Edge Panel then explains that the UEE forecast represents the incremental savings achieved each year, as well as the cumulative impacts of prior UEE savings resulting from measures with a multi-year life. Once the measure life of previously implemented measures expires, the associated energy savings are removed from the UEE forecast and become part of the cumulative embedded efficiency savings in the load forecast (*i.e.,* “roll off”). The total amount of energy savings from energy efficiency remains the same and continues to reduce total load but is accounted for in a different part of the forecast modeling inputs used in resource planning. The Grid Edge Panel explains that in order to accurately compare UEE savings levels in differing plans, the location of the “roll off” savings must be consistently applied for an accurate comparison. Tr. vol. 13, 45-46. The Grid Edge Panel also notes that another important consideration with respect to UEE savings is to understand that utility-sponsored programs are only credited with savings when they drive adoption of efficiency measures that exceed codes and standards at the time the measure is installed. As codes and standards evolve over time, the Grid Edge Panel states that the energy saving potential attributed to utility-sponsored programs is reduced because the energy savings are now represented as naturally occurring energy efficiency in the load forecast. *Id.* at 47-48.

The Grid Edge Panel provides further explanation as to the basis and reasonableness of the Companies’ 1% of eligible sales UEE savings as a reasonable assumption to meet the CO_2 reduction targets required by N.C.G.S. § 62-110.9. As a basis for their assumption, the Grid Edge Panel explains that the Companies considered the historical level of achievements, the forecast of UEE incorporated into the Companies’ most recently approved IRP, the performance targets built into the Companies’ recently modified EE/DSM Cost Recovery Mechanism (Mechanism), and the potential impact of some of the identified enablers included in the Carbon Plan, and determined that assumption of 1% of eligible load is appropriately aggressive yet achievable. Tr. vol. 13, 37-38. Specifically with respect to considering the IRP in setting its UEE savings assumption, the Grid Edge Panel explains that the Companies’ most recently approved IRPs included an amount of UEE that was based on a Market Potential Study, performed by a third-party expert. The Market Potential Study views energy efficiency investments through the lens of what is technically feasible, what makes economic sense, and what is likely achievable given market barriers, and ultimately recommended a 0.8% annual UEE savings over a shorter planning period than the Carbon Plan. In response to the CO_2 emissions reductions required by HB 951, the Companies then worked to identify several potential enablers to overcome economic and market barriers that, when considered along with new EE/DSM Programs, would potentially allow them to achieve more energy efficiency reduction than what was included in the IRP and determined that 1% annual UEE savings is a reasonable assumption for the first Carbon Plan. *Id.* at 38-39.

The Grid Edge Panel also explains that when developing the long-term forecast with a minimum of 1% UEE savings, the Companies identified several potential enablers that would be necessary to achieve the modeled long-term energy efficiency savings included in the Carbon Plan. While the Companies would request approval for these enablers through separate proceedings, the Grid Edge Panel states that it believes there is value in the Commission acknowledging and affirming in this proceeding that these identified enablers should be adopted in the appropriate forums. Tr. vol. 13, 56.

As detailed by the Grid Edge Panel, these enablers include (1) cost-effectiveness test input modifications to ensure that EE/DSM resources are appropriately valued in the context of other resources considered in the Carbon Plan, (2) moving to an "as found" baseline to increase savings associated with a customer's energy efficiency investment, (3) expanded low-income programs including expanding eligibility in these programs to 300% of the federal poverty guidelines, (4) on-tariff and other financing options to enable utility accounts to finance efficiency upgrades through a monthly bill charge to reduce upfront financial barriers, and (5) flexibility guidelines with respect to new customer programs. Tr. vol. 13, 56-58.

In further support of the 1% annual UEE savings assumption, the Grid Edge Panel states that the Companies' Mechanism, which the Commission approved in October 2020 in Docket Nos. E-2, Sub 931 and E-7, Sub 1032, and which went into effect January 2022, directly reflects the aggressive 1% energy efficiency target through its incentive and penalty structure. The Mechanism establishes an incentive to aggressively pursue savings from cost-effective EE and DSM programs because under the Mechanism, if DEC or DEP achieves annual energy savings of 1% of the prior year's system retail electricity sales, in any year during the four-year 2022-2025 period, that utility will receive an added incentive of $500,000 for that year. Conversely, if that utility fails to achieve annual energy savings of 0.5% of retail sales, net of sales associated with customers opting out of the Company's energy efficiency programs, it will reduce its energy efficiency revenue requirement by $500,000. The Grid Edge Panel summarizes that the Companies are essentially projecting to double the amount of what was an agreed upon performance floor year in and year out to help achieve the energy transition, yet the $500,000 bonus incentive tied to achievement of the 1% of total retail sales certainly will continue to motivate the Companies to try to exceed the level of energy efficiency incorporated in the Carbon Plan. Tr. vol. 13, 38-39.

The Companies also point out that, contrary to some intervenors' claim that the Companies should include efficiency levels based on load that is not currently eligible for EE/DSM programs, this UEE assumption is based only on the Companies' eligible load. The Grid Edge Panel further states that basing the energy efficiency impacts on the Companies' loads that are eligible to participate in energy efficiency programs is a reasonable methodology to forecast the amount of energy savings that can be achieved through the Companies' energy efficiency programs, and including load associated with customers that have opted out and cannot participate in the Companies' energy efficiency would likely significantly overstate the amount of energy efficiency savings included in the Carbon Plan from utility programs. Tr. vol. 13, 38.

Net Energy Metering (NEM)

As another example of a load modifier the Companies incorporated into the Carbon Plan modeling process, Appendix F to the Carbon Plan and the Modeling and Near-Term Actions Panel describe how the NEM forecast was derived. The Panel explains that the rooftop solar forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial, and industrial customer classes, with each capacity forecast being the product of a customer adoption forecast and an average capacity value. The adoption forecasts are developed using economic models of payback, which is a function of installed cost, regulatory incentives, regulatory statutes, and bill savings. Tr. vol. 7, 316-17. The Panel further explains that a relationship between payback and customer adoption is developed through regression modeling, with the resulting regression equations used to predict future customer adoptions based on projected payback curves. The Panel also notes that historical and projected technology costs are sourced from energy consulting firm Guidehouse, while projected incentives and bill savings are based on current regulatory policies as well as input from internal subject matter experts. Average system size (capacity) values are based on trends in historical adoption. The Panel further explains that the hourly production profiles are the equivalent of one 24-hour profile for each month derived from actual production data, where available, and solar PV modeling. The Panel states that the PV modeling is performed in the PVsyst model using 20+ years of historical irradiance data sourced from Solar Anywhere and Solcast and models are created for 13 irradiance locations across DEC's service area and nine irradiance locations across DEP's service area with the results for each jurisdiction combined on a weighted average basis to produce the final profiles. *Id.* at 317.

Electric Vehicles (EV)

Finally, the Modeling and Near-Term Actions Panel provides additional detail on another load modifier by describing how the Companies calculated their EV load forecast using the Vehicle Analytics and Simulation Tool (VAST). For purposes of the Carbon Plan, the EV forecast was developed in Fall 2021 using variable inputs from the middle of 2021. The Panel explains that VAST uses multiple variables (such as historical registration data, vehicle miles traveled, fuel cost projections, vehicle efficiency, etc.) as inputs to develop jurisdictional vehicle projections by duty (light, medium, and heavy). Then, the EV forecast is used as an input to develop the forecasted energy and loading demands that are provided to load forecasting. Tr. vol. 7, 320.

The Modeling and Near-Term Actions Panel notes that there are a few potential variables, however, that could impact the Companies' EV forecast. Examples of variables that may lead to higher adoption levels include increased consumer acceptance, automaker commitments, and strong public government support (policy and funding) while examples of variables that may lead to reduced adoption levels include the current global chip shortage, supply chain issues, cost of EVs for the public, and manufacturing limitations. The Panel explains that the EV forecast in the Carbon Plan considered these variables at the time the forecast was developed. The Panel states that the Companies will continue to evaluate the EV marketplace and will continue to update the forecast going forward and if actual EV adoption differs from the Companies' forecasts, such changes will be reflected in future Carbon Plan iterations. Tr. vol. 7, 320-21.

Public Staff Comments and Testimony

In its comments, the Public Staff concludes that after reviewing the Carbon Plan, it believes the Companies' 2022 peak demand and energy forecasts are reasonable for planning purposes. Moreover, with respect to the Companies' assumptions regarding NEM growth, the Public Staff states it has no issue with the assumptions used to develop the NEM forecast, including the Companies' estimated incremental NEM capacity growth of approximately 575 MW (system) for DEC and 307 MW (system) for DEP by calendar year 2035. With respect to the Companies' EV load forecast, the Public Staff states that it is reasonable for the purposes of developing the Carbon Plan while also urging the Companies to continue to study consumer EV charging behaviors, market trends, and to develop rates and programs to encourage managed charging behaviors. Public Staff July 15th Initial Comments at 49, 62-65.

With respect to the Company's 1% UEE savings assumption, the Public Staff questions whether the target is achievable, noting that "an increase in EE savings to 1% of both total and available sales would be substantial, particularly after 2030," and that achieving such savings would be a "formidable task." The Public Staff also notes that the 1% EE target deviates from the traditional approach of projecting EE utilized in previous IRPs, which has historically been based upon Market Potential Studies. The Public Staff also states that policy and legislative changes would be necessary to meeting this 1% annual UEE savings goal. Public Staff July 15th Initial Comments at 52-53; Tr. vol. 21, 169-72.

Intervenor Comments and Testimony

Generally, most intervenors do not appear to take issue with the Companies' process to develop the gross peak demand forecast, and instead challenge individual adjustments made to the gross peak demand forecast to arrive at the net peak demand modeled in the Carbon Plan (*i.e.,* UEE savings, and NEM and EV forecasts). The Modeling and Near-Term Actions Panel presents a high-level overview of the intervenors' load forecast in their testimony as reproduced below. Tr. vol. 7, 309-10.

Intervenor	UEE	NEM	EV	Net Peak Load
AGO	↑			
Appalachian Voices	↑		↑	
City of Asheville/Buncombe County				~

Intervenor	UEE	NEM	EV	Net Peak Load
CCEBA	~			
City of Charlotte	↑			
CIGFUR		↑		
NCSEA et al.	↑	↑		↓
CPSA	↑		↑	
EWG				↓
NCSEA/Synapse	↑	↑		↓
NCWARN				↓
Public Staff	↓	✓	✓	
Brad Rouse				↑
Tech Customers	↑			↓

Notes:

1) Public Staff believes Companies' process to develop load forecast is reasonable. No other intervenors had comments about the process.
2) No intervenor had significant comments about Critical Peak Pricing (CPP) or Peak Time Rates (PTR).
3) Key:
   - ✓ Intervenor agrees with Companies' assumption
   - ↑ Intervenor believes variable should be higher
   - ~ Intervenor's suggested change will have an unknown effect on variable
   - ↓ Intervenor believes variable should be lower

As shown in the above table, most intervenors disagree with the Public Staff and argue instead that the Companies' UEE assumption is unreasonable because it is too low. NCSEA, et al. and their consultant Synapse's modeling utilized EE assumptions of approximately 1.5% of *total* load. Tr. vol. 25, NCSEA, et al.'s Synapse Report, 24-25, 44. Tech Customers and their consultant, Gabel Associates, claim that a 7.7% reduction in the load forecast is achievable with EE alone. Tr. vol. 25, Tech Customers - Gabel Report, 12. The AGO similarly states that the Companies' EE assumptions are "arbitrary" and should be modeled as a selectable resource, while the City of Asheville/Buncombe County and City of Charlotte argue that EE targets based on the 1% of retail sales utilized by the Companies is below other states. AGO July 15th Initial Comments at 22, 32; City of Asheville and County of Buncombe July 15th Initial Comments at 5-6; City of Charlotte July 15th Initial Comments at 3, 12. Both NCSEA, et al. and Tech Customers rely in large part on a finding presented in the 2020 American Council for an Energy Efficient Economy (ACEEE) Report, "How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy Cost and Greenhouse Gas Impacts" (ACEEE Report). In addition to the ACEEE Report, the ACEEE also released a Scorecard in 2020, which the Tech

Customers and NCSEA et al. also cite to as evidence that the Companies can achieve more aggressive energy efficiency targets. Tr. vol. 25, Tech Customers - Gabel Report, at 41. Moreover, the AGO argues that the Companies did not properly account for roll-off in its UEE forecast and that the Companies should have modeled energy efficiency as a selectable resource. AGO July 15th Initial Comments at 22, 32.

Additionally, CPSA, EWG, NCSEA et al., Brad Rouse, and Tech Customers believe the Companies underestimated electrification in the load forecast. CPSA July 15th Initial Comments, Exhibit A at 11; EWG July 15th Initial Comments at 3; NCSEA, et al. July 15th Initial Comments at 28; Brad Rouse July 15th Initial Comments at 3, 13. The City of Asheville/Buncombe County state that load forecasts should be adjusted proactively to account for the impact of DSM programs and technological advances that reduce load as well as the impact of EVs and electrification that may increase it, resulting in and unknown impact to net peak demand. City of Asheville and County of Buncombe July 15th Initial Comments at 3.

Finally, NC WARN witness Powers argues that the Carbon Plan reduces the role of NEM solar relative to the 2020 IRP forecasts and NCSEA et al. argues that the Companies' EV forecast used in the Carbon Plan is below recent trends. Tr. vol. 22, 210; NCSEA et al. July 15th Initial Comments at 28.

Duke Rebuttal Testimony

In response to the Public Staff's concern that the Companies' annual UEE savings target of 1% is overly aggressive, the Grid Edge Panel first agrees that the assumption is aggressive and that it was described as such in the Carbon Plan. The Grid Edge Panel also notes, however, that it was important to include an increase in energy efficiency achievement in the Carbon Plan compared to its base case (*i.e.*, the amount of energy efficiency approved in the IRP) while also identifying enablers that could potentially advance the increased energy efficiency achievements. The Companies explain that identification of potential should help to ease the Public Staff's concerns, while also noting that the largest portion of the increase in the assumed efficiency occurs after 2030. The Grid Edge Panel explains that this ramping up of savings is important because it gives the Companies time to implement identified potential enablers to achieve the increase and allows the Companies to inform future Carbon Plan updates if potential enablers are not implemented, technology advances, or market conditions change. Tr. vol. 13, 53-54. Duke Energy witness Duff highlights this during the hearing, explaining that in the next five (2023-2027) years, the cumulative difference between the Public Staff's recommendation and the UEE savings assumption used in the Carbon Plan model is not even 2% different at 1.89%. Tr. vol. 30, 55-56; Tr. vol. 29, Grid Edge Panel Rebuttal Exhibit 1; Tr. vol. 30, Grid Edge Rebuttal Redirect Exhibit 1.

The Grid Edge Panel also responds to several intervenors' comments and reports that, contrary to the Public Staff, argue the Companies can obtain significantly higher load reductions through EE/DSM measures. The Companies first explain that the Tech Customers' Gabel Report assumes in its model EE/DSM savings of almost twice the already aggressive energy and capacity savings the Companies estimate by 2032, referring to the ACEEE Report and 2020 Scorecard to support its arguments. NCSEA, et al. similarly argues for an aggressive increase of 1.5% UEE of total retail sales to be included in the Carbon Plan model. Specifically with respect to the 2020 Scorecard, the Grid Edge Panel states that it fails to account for the fact that electric usage and electric rates vary widely in different states and these variables play a significant role in both the adoption and impact of EE programs. Tr. vol. 13, 48-50.

With respect to the ACEEE Report, the Grid Edge Panel notes that the Companies contributed to its preparation and the Tech Customers and NCSEA, et al. seem to have ignored several relevant factors from the ACEEE Report in making their recommendations. First, the Grid Edge Panel explains that the 11.1% UEE savings amount projected in the ACEEE Report is at the state level and includes actions beyond the Companies' control (*e.g.,* municipal and cooperative customers' actions). Tr. vol. 13, 49-50. The Grid Edge Panel also notes that the ACEEE Report assumes multiple legislative and policy changes occur that are not assured. The Grid Edge Panel states that another flaw in the Tech Customers' and NCSEA, et al.'s reliance on the projected energy savings level from the ACEEE Report is that the projected savings level is from a 2020 baseline, which would not reflect the continued market transformation of the lighting market to non-specialty LED lighting resulting from LEDs' increased accessibility and customer acceptance. The Grid Edge Panel finally notes that NCSEA, et al. and Tech Customers also fail to mention that the actual recommendation is an annual energy efficiency requirement of 10% cumulative electric energy savings from investor-owned utilities by 2030, below a baseline of each utility's total gross electric sales in 2020 with required annual savings ramping up to 1.2% of sales per year by 2032 continuing through 2040. This actual recommendation is far more in line with the Companies' projected energy efficiency savings in the Carbon Plan. *Id.* at 50.

In response to Commissioner McKissick's request made during the evidentiary hearing in this proceeding, however, the Companies identified potential enablers that would allow it to be more of a leader in energy efficiency and obtain annual energy savings over the next five years that were closer to 1.5% of eligible retail sales. The Companies provided a high-level list of potential enablers that could allow for the achievement of these aspirational levels over the next five years in Grid Edge Panel Rebuttal Exhibit 1 as informative to what measures the Companies believe would be necessary to meet a 1.5% of eligible retail sales target versus 1.0% of retail sales. Tr. vol. 14, 73-82; Tr. vol. 29, Grid Edge Panel Rebuttal Exhibit 1.

The Modeling and Near-Term Actions Panel also responds to contentions from some intervenors that the Companies' forecast for NEM is too conservative by first noting that NEM policy in the Carolinas is evolving and new NEM tariff and programs are awaiting approval or currently being developed. As the Panel explains, however, the Companies modeled future NEM adoption based on regulatory policies in place at the time the Carbon Plan was developed, consistent with the "snapshot in time" approach taken with the Carbon Plan as a whole. Tr. vol. 7, 317-18. The Panel states that while the Public Staff did not take issue with the Companies' assumptions used for the NEM forecast, NCSEA et al. thought the assumptions were below recent trends and NC WARN witness Powers argues that the Carbon Plan reduces the role of NEM solar relative to the most recent IRP forecasts. The Panel then explains that NCSEA et al.'s calculations supporting their arguments contain mathematical errors and, with these errors corrected, the Companies' projections of NEM adoption are in line with recent trends. *Id.* at 318-19. With respect to NC WARN witness Powers, the Grid Edge Panel similarly explains that the difference between the Carbon Plan forecast and the IRP forecast is due to the fact that the rooftop solar market is dynamic and changes in panel prices, historic adoption trends, average system size, etc. must be incorporated to make the forecasts as accurate as possible. Tr. vol. 29, 188. The Panel acknowledges that both future state and federal policy changes may change these trends, but until there is more certainty the Companies agree with the Public Staff that the point-in-time NEM forecast used in the Carbon Plan is appropriate for planning purposes. Tr. vol. 7, 319.

The Modeling and Near-Term Actions Panel then addresses some intervenors' critique of the Companies' EV forecast underestimating EV demand. The Panel first recognizes that there are numerous public EV forecasts and while the BNEF forecast CPSA refers to projects 30% EV sales in 2030, other forecasts from the same time period, such as IEA's "Global EV Outlook 2021", show 15% electric vehicle sales by 2030, which is comparable to Duke's forecast of 12.5%. Tr. vol. 7, 321. The Panel also explains that the impact of more than doubling the Companies' EV forecast by 2030 to match BNEF's forecast is approximately 430 MW of additional solar, which is less than 5% of total solar online by 2030 in the four Carbon Plan portfolios. The Panel points out that BNEF forecasts EV adoptions at the national level, and the Companies' EV forecast being approximately one-half of BNEF's at the start of the forecast period is largely attributable to EV adoption in California and other western states compared to EV adoption in the Carolinas. Finally, the Panel explains that the forecasts do not start to diverge until 2028, meaning the impact to the near-term action plan on this particular forecasting difference is negligible. *Id.* at 321-22.

The Modeling and Near-Term Actions Panel also refutes the AGO's recommendation that the Companies should have instead modeled energy efficiency as a selectable resource by explaining that modeling a resource that is dependent on customer preferences and participation using an economic optimization model is problematic. The Panel explains that the model in this situation would not account for customer adoption constraints and may result in unattainable levels of energy efficiency savings, which undermines the validity of the resource plan. The Panel adds that any overstatement of attainable energy efficiency savings results in an understatement of net load that must be served by supply-side resources and such understatement of load will lead to under build of new supply-side resources or premature retirement of existing resources. The Panel explains that both of these situations compromise system reliability. Tr. vol. 7, 316, 408. The Panel states that the Companies believe the current methodology of basing assumed UEE impacts on the Companies' load forecasts based on reasonable projections of customers that are eligible to participate is a reasonable and appropriate approach to forecasting the amount of UEE that can be achieved through the Companies' EE programs. *Id.* at 316.

The Grid Edge Panel also disagrees with the AGO's and Strategen's criticism regarding the Companies' methodology of including "roll off" of UEE in its load forecast relative to "naturally occurring" energy efficiency. First, the Grid Edge Panel notes that AGO Witness Burgess provides no formal analysis for his contention that the Companies' UEE roll-off forecast is inaccurate and his contention appears to be only based on the high-level observation that "Base" usage per customer (prior to factoring in UEE and electric vehicle adoption) is increasing in the near term before declining. The Panel then acknowledges that the "base" load forecast includes a moderate increase in residential usage per customer before starting to decline toward the end of the decade but explains that the AGO's criticisms are ultimately misplaced. The Panel explains that the AGO focuses on UEE usage per customer not declining for the entire forecast period as meaning that the Companies' methodology for translating UEE roll-off into naturally occurring energy efficiency in the load forecast is inaccurate. However, the AGO overlooks the fact that during the same time period, load impacts of EV adoption and beneficial electrification are included in the load forecast, which can more than mask the UEE roll-off being reflected in usage per customers, and one must look at the drivers to understand whether this is an accurate forecast or reflective of an underlying error related to UEE roll-off. Tr. vol. 29, 183-84. Moreover, the Grid Edge Panel states that considering that the forecast appropriately reflects the load growing due to adoption of internet of things devices and a portfolio of EE programs (with an average measure life of over eight years), a great deal of the EE roll-off from adoption of UEE programs will not occur until the latter half of the 2020s. *Id.* at 183. Finally, as pointed out by the Panel during the evidentiary hearing on its rebuttal testimony, the Companies' UEE roll-off is performed in a manner consistent with the Commission audited accounting of Energy Efficiency Credits (EECs) used to demonstrate compliance with the annual Renewable Energy Portfolio Standard (REPS). Tr. vol. 30, 47-49.

Ultimately, the Companies state that they stand behind the development of their load forecast and the projections of the UEE, NEM, and EV adjustments made to the load forecasts. The Modeling and Near-Term Actions Panel states that the assumptions made by the Companies are based upon reasonable projections unlike those made by intervenors who are outcome-based in their positions. Tr. vol. 7, 311.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission finds that the Companies have undertaken a reasonable and thorough approach to developing the load forecast in the Carbon Plan. No party challenges the Companies' general four step approach to develop the gross load forecast used in the Carbon Plan and the Commission finds such approach to be reasonable and appropriate for planning purposes. Several parties, however, raise several concerns regarding how the Companies' UEE assumption and EV and NEM forecasts that act as load modifiers.

With respect to the Companies' assumption of 1% of eligible load UEE savings floor used to reduce load, the Commission finds this assumption to be reasonable and appropriate to "shrink the challenge" consistent with the Companies' overall planning approach. The Commission acknowledges that a 1% annual UEE savings target is aggressive, but the Commission agrees with the Companies that an aggressive, yet achievable approach is necessary to match the aggressive CO_2 emissions reductions targets set forth in HB 951. The Commission finds that the Companies' 1% annual UEE savings of eligible load assumption strikes an appropriate balance between the Public Staff's recommendation that the lower, Market Potential Study assumption of 0.8%, as used in the Companies' 2020 IRP, be used and some intervenors' recommendation that a higher UEE savings be used to model the Carbon Plan. These intervening parties recommending higher energy efficiency modeling assumptions provide no programmatic detail behind their recommendations or explanation of how the proposed levels can be achieved over the course of the Carbon Plan. Similarly, the Commission is not persuaded by intervenors' reference to and reliance on the ACEEE Report and ACEEE Scorecard to support their argument that a higher UEE savings assumption should be used in the Carbon Plan. Instead, the Commission agrees with the Companies that the ACEEE Report and Scorecard may not properly account for the fact that electric usage and electric rates vary widely in different states, which impacts the adoption of UEE programs. Additionally, factors underlying certain conclusions in the Report and Scorecard, such as legislative and policy considerations, differ from those in North Carolina and are out of the Companies' control. Based on the foregoing, the Commission finds that overestimating UEE savings is imprudent and can lead to underbuilding resources necessary to reliably serve load.

The Commission also finds reasonable the Companies' identification of several enablers that will be necessary to continue achieving the assumed level of UEE each year, especially after 2030. The Commission acknowledges that these enablers, including the targeted modifications to the Companies' approved Mechanism to update the inputs used in determining the utility system value associated with energy efficiency and demand response programs, are critically important for the Companies to be able to sustain this high level of UEE savings on a year-over-year basis. The Commission expects that the Companies will petition the Commission as necessary to provide additional details and request approval of these enablers. The Commission also acknowledges the additional enablers referenced in the Grid Edge Rebuttal Exhibit 1 as a high-level summary of other potential enablers the Companies believe would be necessary should different, higher UEE savings assumptions be made in future Carbon Plans.

The Commission agrees that the NEM and EV forecasts that are included as load modifiers to the gross load forecast are appropriate for planning purposes. The Commission acknowledges that the NEM policy is in flux and reflecting currently approved NEM solar policies is a prudent assumption when developing the NEM forecast for the Carbon Plan. The Commission does not find merit in NC WARN's argument that changes in the NEM forecast between the 2020 IRP and the Carbon Plan filing reflect Duke Energy's commitment toward NEM adoption. Rather, the Commission acknowledges that the difference between the forecasts is due to changes in underlying forecast variables such as panel prices, system size, and historic adoptions that impact projections of future adoptions.

Similarly, the Commission acknowledges that the EV market is dynamic and rapidly evolving. In such a dynamic market, the Companies' forecasts reflect a snapshot in time that is consistent with modeling practices in the Carbon Plan. The Commission is not persuaded by forecasts presented by interveners that are more representative of trends outside of the Carolinas.

As such, the Commission finds that Duke Energy's EV forecasts are reasonable and reflect EV adoption trends that are specific to the Carolinas.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

The evidence in support of these findings of fact is found in the Companies' Proposed Carbon Plan, the testimonies of the Modeling and Near-Term Actions Panel, CPSA witness Hagerty, Public Staff witness Thomas, CCEBA witness DiFelice, AGO witness Burgess, and Tech Customers witness Borgatti.

Summary of the Evidence

The Carbon Plan describes two solar paired with storage configurations allowed to be economically selected in Carbon Plan modeling. These configurations consist of (1) a 75 MW solar facility paired with a 20 MW / 80 MWh battery storage asset and (2) a 75 MW solar facility paired with a 40 MW / 80 MWh battery storage asset. Carbon Plan, Ch. 2, 18-19; App'x E, 29-30. As shown in Table E-44 of the Carbon Plan, solar paired with storage is assumed to have the same generic transmission network upgrade costs as standalone solar. Carbon Plan, App'x E, 38-39.

Summary of Duke Energy Testimony

The Modeling and Near-Term Actions Panel describes that an additional solar paired with storage configuration was allowed to be selected in the Carbon Plan Supplemental Portfolios. Tr. vol. 7, 343. Additionally, the Panel explains that the Companies generally agree with intervenors that modeling additional solar paired with storage options is preferable, but further study is needed to assess how the ELCC of larger DC-coupled storage resources should be treated. *Id*. at 345.

The Modeling and Near-Term Actions Panel also explains that a fixed dispatch profile is used to model solar paired with storage in the Carbon Plan where the dispatch of the storage asset is based on nine premium peak, on-peak, and off-peak energy hours as defined in the Docket No. E-100, Sub 167 proceeding. This results in charging during off-peak hours and discharging during on-peak and premium hours throughout the year. While the Companies chose this approach for efficiency over endogenous dispatch through EnCompass in the Carbon Plan portfolios, Duke Energy did allow the model to optimize the storage component of solar paired with storage in the Supplemental Portfolios. The Companies found that model run time increased from 2-3 hours to 12-48+ hours when allowing the model to endogenously dispatch solar paired with storage assets. The Companies are evaluating options to reduce model run time when endogenously allowing EnCompass to dispatch the solar paired with storage assets. Tr. vol. 7, 344-45.

The Modeling and Near-Term Actions Panel identified that after allowing EnCompass to dispatch solar paired with storage assets, and after adding an additional solar paired with storage option, the amount of storage in the near term only increased from 1,600 MW to 1,800 MW in supplemental portfolios P5 and P5A. Tr. vol. 8, 48.

The Modeling and Near-Term Actions Panel explains that a significant portion of future procured solar will be paired with storage, but there is no benefit to pre-determining that all future solar must be paired with storage. The Panel explains that the amount of solar paired with storage may vary depending on the configurations of solar paired with storage that is bid into future procurements. Tr. vol. 27, 57.

Public Staff Testimony

Public Staff witness Thomas did not raise concerns with the limited configurations of solar paired with storage resources in its initial review of the Carbon Plan and acknowledges there are "infinite" configurations of solar paired with storage, so some approximations must be made. Nevertheless, witness Thomas finds the configurations proposed by CPSA and Tech Customers to be reasonable and notes that Duke Energy included one additional configuration incorporated into the Supplemental Portfolios. Tr. vol. 21, 63.

The Public Staff assumes that solar paired with storage resources will be procured through annual procurements where a variety of configurations will be submitted for evaluation. The Public Staff believes there will be sufficient time to incorporate common configurations and costs into the 2024 Carbon Plan proceeding if the Commission requires more than three configurations for modeling purposes. Witness Thomas recommends the Companies file preliminary 2023 Solar Procurement results in the 2024 Carbon Plan proceeding and explain how their solar paired with storage modeling is influenced by these results. Tr. vol. 21, 63-64.

The Public Staff states that the fixed dispatch profile used by Duke Energy to model solar paired with storage was not appropriate. The Public Staff contends that "this issue is addressed in SP5 and SP6 and results in significantly increased levels of solar paired with storage being selected by the model." Witness Thomas recommends the Companies model solar paired with storage to allow EnCompass to optimize the storage component and not use fixed dispatch profile. The Public Staff states that longer model run times are a "reasonable tradeoff" for more accurate solar paired with storage modeling. Tr. vol. 21, 65.

Public Staff Witness Thomas also testifies in response to CCEBA and CPSA that the current EnCompass algorithm assumes that a DC-coupled solar paired with storage resource can only charge from the solar array, and that an AC coupled resource can only charge from the grid. Witness Thomas suggests that it may be useful in future Carbon

Plans to model both AC-coupled and DC-coupled solar paired with storage configurations. The Public Staff believes that the 2023 Solar Procurement, which it expects will include solar paired with storage resources, will reveal what configurations are economical for developers, and the 2024 Carbon Plan Update should reflect this variety. Tr. vol. 21, 67.

Intervenor Comments and Testimony

CPSA Witness Hagerty criticizes Duke Energy's decision to initially model only two configurations of solar paired with storage and argues the Companies should model additional scenarios that include (1) 2-hour, 25% storage capacity as a share of solar capacity, and (2) 4-hour, 50% storage capacity as a share of solar capacity. Tr. vol. 25, 418-19. The AGO states the two initially modeled configurations "do not represent the full ranges of solar plus storage configurations that are available to the Companies, nor do they represent the configurations that are likely to maximize value into the future." AGO July 15th Initial Comments at 20. CCEBA witness DiFelice also argues that Duke Energy should not have excluded AC-coupled solar paired with storage as a possible configuration. Tr. vol. 26, 249-50.

CPSA Witness Hagerty states that the additional solar paired with storage configuration included in the Supplemental Portfolios only partially addresses CPSA's concerns because Duke Energy did not adjust its assumptions regarding capital costs or the benefits of the investment tax credit (ITC). Tr. vol. 25, 419.

CCEBA argues the IRA will accelerate deployment of energy storage in North Carolina because it allows solar paired with storage to receive a 30% ITC, and the assumptions Duke Energy used to model solar paired with storage are no longer valid because costs of those resources were too high during portfolio optimization. Tr. vol. 26, 248-49.

The AGO alleges that the Companies placed unreasonable constraints on solar paired with storage by modeling solar paired with storage resources with a fixed storage output profile instead of letting the model flexibly dispatch the storage component. AGO July 15th Initial Comments at 20; Tr. vol. 25, Strategen Report at 14; Tr. vol. 25, 259. The Tech Customers argue that a fixed dispatch profile could dramatically reduce the reliability benefits these resources provide. Tr. vol. 25, 62-63; Tr. vol. 25, Gabel Report at 9, 45.

CPSA and CCEBA suggest that Duke Energy's modeling unduly limited solar paired with storage because it did not allow charging from the grid. CPSA argues Duke Energy should not have assumed that DC-tied hybrid solar paired with storage facilities can charge only from the solar generating facilities. Tr. vol. 25, 418. CCEBA argues that the Companies failed to account for the fact that solar paired with storage utilizing bi-directional inverters can grid charge and any charging constraint should be lifted from the model. Tr. vol. 26, 246. Witness DiFelice asserts that the ability to grid charge should increase the ELCC of solar paired with storage resources making them more competitive against other technologies. *Id.* at 245-48.

CPSA witness Norris argues that all solar procured after 2022 be paired with storage until the storage requirements of the Carbon Plan portfolios are met. Tr. vol. 26, 76.

Discussion and Conclusions

The Commission is persuaded that the three solar paired with storage configurations used to model solar paired with storage in the Carbon Plan and Supplemental Portfolios are reasonable for planning purposes and the updates made to solar paired with storage in the supplemental portfolios did not substantially change the amount of storage Duke Energy proposes in its initial near-term action plan. There has been insufficient evidence to support the recommendation that all solar must include storage in the future, and the Commission concurs with Duke Energy that it is premature to prescriptively and preemptively dictate that outcome. The Commission can revisit this issue in the future if needed as more market information (including future bid pricing and configurations) is gathered through future procurements.

The Commission agrees with the Public Staff that the possible configurations are “infinite” and that procurement bids can inform the Companies’ modeling in the 2024 Carbon Plan Update. The Commission orders Duke Energy to use the results of the 2023 Solar Procurement to inform the 2024 Carbon Plan update modeling, as recommended by the Public Staff.

The Commission notes the significantly increased time necessary to allow Encompass to endogenously dispatch solar paired with storage, as highlighted by the Modeling and Near-Term Actions Panel. Given the number of model runs that must be completed to prepare and finalize the Carbon Plan, and the limited impact on the total amount of storage selected in supplemental portfolios P5 and P5A, the Commission is not persuaded that endogenous dispatch solar paired with storage modeling was necessary during this initial Carbon Plan but expects that Duke Energy will continue to work with EnCompass and to assess the capabilities to more fully integrate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is found in the Companies’ proposed Carbon Plan, the direct and rebuttal testimony of Duke Energy Modeling and Near-Term Actions Panel and witnesses Roberts and Farver (Transmission and Solar Procurement Panel), the testimony of Public Staff witness Thomas, AGO Witness Burgess, CPSA witnesses Watts and Norris, and the NCSEA, et. al. Synapse report.

Summary of the Evidence

The Carbon Plan Appendix E (Quantitative Analysis) identifies that the Carbon Plan modeling is designed to select “least cost” portfolios of supply-side resources that minimize the cost of the system, subject to meeting constraints such as CO_2 emissions reductions, capacity planning reserve margins and operating reserve requirements, as well as "when and how much" of a resource can be integrated to the portfolio. Carbon Plan, App'x E, 27. The Companies' modeling includes numerous constraints (as all models do) designed to reflect real world conditions and ensure the executability of the resulting portfolio. Specific to solar generation resources, the Carbon Plan includes a modeling constraint that limits the volume of new solar resources that can be selected by the model on an annual basis. This constraint is informed by the "real-world" limitations on the ability of Duke Energy (or any utility or transmission operator) to interconnect projects and is intended to reflect the volume of new solar resources the Companies forecast they can connect each year. Carbon Plan, App'x E, 27; App'x I, 4.

The Companies included two assumptions: a base case and a high case. The high case is used for Portfolio 1 (shown below as 70% by 2030) and the base case is used in Portfolios 2-4 (shown below as 70% by 2034), as shown in Table I-2[3] of the Carbon Plan:

Beginning of Year	2027	2028	2029	2030+
70% by 2034 with Wind or Nuclear	750	1,050	1,350	1,350
70% by 2030	750	1,050	1,800	1,800

The Companies begin forecasting solar interconnection limits in 2027 (that is, reflecting the amount of solar that can be interconnected and online at the beginning of 2027), given that this is the first year 2027), given that this is the first year the model can economically select new solar resources. The Carbon Plan explains that the solar interconnection base case scenario represents the capacity of solar that the Companies believe can be reasonably interconnected through 2030 as enabled through process improvements and certain transmission expansion plan upgrades. Carbon Plan, App'x I, 6; App'x P, 12-15. The high case scenario represents an aggressive case of increased solar interconnection, which requires additional transmission expansion planning studies and associated upgrades to enable the incremental 450 MW/year of solar beginning in 2029. Carbon Plan, App'x I, 6. The Carbon Plan provides a detailed analysis of the key factors and data points that informed the solar interconnection modeling constraint, including: (1) expected project size; (2) need for transmission upgrades; (3) increasingly complex interconnections; and (4) historic annual interconnection data. Carbon Plan, App'x I, 6-8. The Carbon Plan explains that since 2015, the Companies have averaged five transmission-connected solar projects each year, with a maximum of nine projects in 2017. Based partially on the historic maximum of nine solar transmission interconnections in a year and an assumption of an average solar facility size of 80 MW, the Companies targeted 750 MW to be connected in 2026, more than double the average capacity

[3] Table I-2: Maximum Solar (MW) Allowed to Connect Annually (by Jan. 1 of year shown). Carbon Plan, App'x I, 6.

connected in the last three years. Carbon Plan, App'x I, 6-8. The network upgrades required to enable solar growth can also take three to five (or more) years to construct.

Duke Energy Direct Testimony

The Modeling and Near-Term Actions Panel explains that in resource planning, modeling constraints are necessary to develop portfolios that can reasonably be expected to deliver desired outcomes and actually be executable in the real world. The Panel testifies that without appropriate constraints, model-selected resource portfolios may not maintain system reliability, may not achieve CO_2 emissions reduction targets, or may call for the addition of new resources faster than they can be procured, constructed, or interconnected in the real world. The Panel explains that it is therefore prudent to minimize the disconnect between model results and reality to avoid a disorderly transition or "unexecutable" expectations for transitioning of the Companies' fleet. Tr. vol. 7, 235.

Duke Energy witness Kalemba testifies that the Companies developed the solar interconnection assumptions based on engineering judgment, taking into account a variety of factors. Tr. vol. 7, 348. Witness Kalemba offers evidence as to the Companies' experience interconnecting solar over the past seven years. *Id.* at 353. Since 2015, the Companies have interconnected on average 520 MW per year of new solar facilities. *Id.* Over time, the Companies have seen the complexity of interconnection grow, which witness Kalemba explains increases the time period from when a facility may execute an Interconnection Agreement to when a facility becomes operational. *Id.* at 348-49. Currently, the Companies estimate that it takes between approximately 26 and 32 months for a solar facility to become commercially operational from the time that it executes an Interconnection Agreement, assuming the facility does not require network upgrades. *Id.* at 351.

Witness Kalemba also testifies that the volume of solar that has been interconnected to date results in reduced land availability to site projects without transmission constraints. Tr. vol. 7, 349-50. Figure 13 of the Modeling and Near-Term Actions Panel Direct Testimony illustrates the commonality between land that is primarily suitable for solar development and the areas that are identified as transmission constrained (also known as the Companies' "Red Zone" areas). *Id.* As to the transmission upgrades necessary to connect more solar facilities in the "Red Zones," witness Kalemba explains that the Companies' interconnection constraints assume transmission system upgrades in the Companies' "Red Zone" areas would materialize, thereby enabling increased annual solar interconnections in 2028 through 2030. *Id.* at 351-52. Witness Kalemba presents Modeling and Near-Term Actions Panel Direct Figure 15, which identifies the correlation between assumed transmission upgrades materializing between 2026 and 2028 and the increase in Duke Energy's increased ability to interconnect solar to Duke Energy's transmission system. As the Red Zone expansion plan transmission projects are completed, Duke Energy expects to increase the annual number of solar interconnections from eight in 2026 to 10 in 2027, 14 in 2028, and 15 in 2030. Witness Kalemba also points out that the Companies' finite transmission construction resources must also be allocated to interconnecting non-solar resources required under the Carbon

Plan as well as to perform other transmission system maintenance and upgrade construction during "shoulder" outage seasons to ensure reliability is not impacted. *Id.* at 352.

Witness Kalemba also testifies that the Companies expect to continue to see a shift from smaller, distribution-interconnected projects to larger, transmission-interconnected solar projects. Witness Kalemba testifies that while these larger projects can contribute to interconnection challenges, they also create efficiencies that are reflected in the Companies' interconnection forecast. Tr. vol. 7, 353.

Witness Kalemba further explains that the Carbon Plan calls for 11 GW to 15.3 GW of new generation to be added by 2030 and of this amount, only 50% to 60% is solar and solar paired with storage. He explains that there is a finite amount of interconnection resources available to connect this level of generation. Tr. vol. 7, 352.

Witness Kalemba explains that the Companies will update their projections of solar interconnection capabilities in the 2024 Carbon Plan update. The Companies' ability to interconnect new solar resources will be informed by the 2022 DISIS as well as ongoing transmission planning through the NCTPC. Tr. vol. 7, 365-66.

Public Staff Direct Testimony

Public Staff witness Thomas finds that the base solar interconnection limits used in P2, P3 and P4, as well as SP5 and SP6, to be reasonable for modeling purposes. Witness Thomas describes Public Staff's "serious concerns" about the Companies' ability to interconnect the amount of renewable generation that must be installed by 2030 to meet the interim CO_2 reduction target and testifies that the Public Staff is skeptical that high levels of annual solar interconnections are achievable in the short term. Tr. vol. 21, 41, 97. The Public Staff's testimony points to the fact that the 2022 DISIS interconnection process and upcoming 2023 DISIS should provide more specific information on the transmission needs to support the interconnection of new solar and that the potential interconnection rate will become more clear over time. *Id.* at 23. Witness Thomas notes the Public Staff's hope that interconnections will accelerate through this decade, and that such improvements can inform modeling for future Carbon Plan proceedings. *Id.* at 55. During the hearing, witness Thomas emphasized that the solar interconnection limit should not be considered in a vacuum and that solely considering how much solar can be interconnected is a bit myopic versus looking at the whole resource portfolio that needs to be interconnected and recognizing that interconnecting this volume of intermittent resources and dispatchable resources and energy storage simultaneously is an unprecedented challenge for the Companies transmission studies and transmission planners. *Id.* at 249-50.

Intervenor Direct Testimony

CPSA witnesses Watts and Norris criticize the Companies' interconnection constraints and recommend significantly higher interconnection limits, especially in the earlier years of the forecast. According to witness Norris, the Companies should assume that they can interconnect 1,500 MW in 2027[4] and 2028, and then utilize the "high case" assumption (1,800 MW) for 2029 and beyond. Tr. vol. 27, 31.

Witness Watts cites several reasons he believes interconnection constraints should be increased. For example, he argues that larger sized solar facilities will increase interconnection rates and that the RZEP projects will provide significant additional capacity to interconnect solar by the end of 2026. Tr. vol. 22, 278-79, 281. Witness Watts argues that CPSA's 1,800 MW interconnection limitation beginning in 2029 is reasonable based on the assumption that Duke Energy can interconnect 10-11 third-party owned PPA projects (assuming a size of 75-80 MW) and approximately 10 Duke Energy-owned projects (assuming a size of 100 MW) each year. CPSA witness Watts also argues that the Companies can use other tactics to improve interconnection, such as utilizing "shooflies" to reduce the outage requirements necessary to conduct necessary upgrades, implementing more lenient study requirements, and allowing for developers to self-build upgrades. Tr. vol. 22, 286.

Witness Watts also cites to other states as examples of utilities that have achieved higher interconnections each year than Duke Energy, including Texas (2,480 MW in 2020), California (1,650 MW in 2020), and Florida (1,640 MW in 2020). Tr. vol. 22, 286-87. In comparison to Duke Energy's historical interconnection rates, CPSA witness Norris argues that the Companies' solar interconnection limit assumes no improvements in interconnection over the past ten years, but also acknowledges that from 2019-2021, Duke Energy only interconnected approximately 300 MW of new solar each year. Tr. vol. 26, 34.

Witness Norris advocates for the Commission to resolve the question of the appropriate interconnection limit by setting aggressive solar procurement targets, beyond Duke Energy's anticipated volume of solar interconnections each year, to procure a significant volume of solar in the near-term and test the volume of projects that can be interconnected. Tr. vol. 26, 43.

AGO witness Burgess agrees that Duke Energy is grappling with real technical limitations on how much solar can be realistically interconnected each year, but he agrees with CPSA that modeled solar interconnection constraints should be increased. Tr. vol. 25, 251. In the short term, witness Burgess recommends the limit be set at the midpoint of Duke Energy's initial P1 portfolio and "High Solar Interconnection" sensitivity of the Supplemental Portfolios and advanced by one year. Tr. vol. 25, 250-51.

The Synapse Report performed on behalf of NCSEA, et. al. reflects increased solar additions beyond those of Duke Energy. Synapse capped incremental solar additions at 1,200 MW in 2025 before increasing to 1,800 MW in 2026 through 2028. In 2029 onward,

[4] The interconnection limits advocated for in Witness Norris's testimony actually begin with the year 2026, but because Witness Norris uses an "end of year" date and the Companies' utilize "beginning of year" dates, CPSA's "Year 2026" is equivalent to the Companies' "Year 2027."

Synapse increased annual solar deployments to 2,300 MW. Tr. vol. 25, Synapse Report, A-12.

CPSA witness Norris also advocates for an independent technical review committee to review interconnection rates similar to the one used to review the Companies' study supporting its Solar Integration Services Charge. Tr. vol. 26, 45-46. Witness Norris also supports a potential performance incentive mechanism to improve marginal interconnection efficiencies, but cautions the Commission from viewing a performance incentive mechanism as a "panacea" for reaching Duke Energy's interconnection potential. *Id*. Finally, witness Norris recommends that Duke Energy provide periodic reports on steps it has taken and plans to take to expedite the interconnection process, and on its interconnection performance. *Id.* at 76.

During the hearing, Tech Customers witness Borgatti complimented the Companies' transition to a cluster study process. He also highlighted the real-world challenges of significantly accelerating solar generator interconnections, which would require a 2.5x increase in annual interconnections from the highest annual level of solar interconnections achieved in the past and suggested that the more aggressive P1 assumption presents execution risk. Witness Borgatti also highlighted that generator interconnection challenges and delays are being experienced nationally, including in RTO regions like PJM and California ISO. Tr. vol. 25, 122-25.

Duke Energy Responsive Testimony

Duke Energy witness Kalemba testifies that intervenors generally accept that solar should not be modeled assuming an unlimited interconnection capability and that the question to be addressed is not whether a limitation or constraint on solar interconnections is appropriate, but what specific limitation represents the most reasonable forecast of the Companies' ability to interconnect solar in the future. Tr. vol. 7, 354.

In response to CPSA's assertions that the solar interconnection constraint increases costs for customers, witness Kalemba explains that including any constraint in a capacity expansion or system production cost model will increase costs when compared to an unconstrained solution. For example, relieving the constraints on natural gas availability or onshore wind timing would lead to a lower cost modeled solution. But Witness Kalemba points out that cost savings based on unrealistic and unexecutable assumptions are illusory. Tr. vol. 7, 359. Witness Kalemba also testifies that one of the primary risks of "front-loading" solar and paired battery storage procurement in the near-term would be losing out on technology maturation and development that will occur over time. Witness Kalemba also identifies that all parties except CPSA have suggested that the cost of solar resources is projected to continue to decline in the future. Tr. vol. 27, 62.

In response to CPSA witness Norris' assertions regarding the interconnection volumes of neighboring states, witness Kalemba states that comparing state level interconnection rates to a utility's rates of interconnection is not a valid comparison.

Further, Table 12 of the Modeling and Near-Term Actions Panel direct testimony presents a detailed assessment of peer utilities and finds that Duke Energy's interconnection assumptions are equal to, or more aggressive, than peer utilities. Tr. vol. 7, 361-65. Witness Kalemba also explains that given the significant volumes of solar that the Companies have interconnected to date, comparing the Companies' solar interconnection assumptions to other states that have only just begun installing solar is not a reasonable comparison. Witness Kalemba explains that the fact that North Carolina has interconnected a tremendous volume of solar over the past seven years is a primary reason why interconnecting significantly higher levels of solar in the future is challenging. Tr. vol. 27, 65-67.

On rebuttal, Duke Energy witness Roberts testifies that CPSA's contentions regarding the Companies' planning assumptions for future solar interconnections in the Carbon Plan are not informed by the specific considerations of the DEC and DEP systems and interconnection procedures. Witness Roberts provides additional detail and support for these constraints from a transmission perspective. Tr. vol. 28, 143-44.

Witness Roberts disagrees with CPSA witness Watts that the Companies should be able to interconnect 20-21 new solar generating facilities annually to their transmission systems. He notes that CPSA's assertion is based on the observation that Duke Energy interconnected approximately 750 MW of new solar in 2015 and 2017. He explains that ninety percent or greater of those projects were distribution level connections, which are significantly less complex because they do not require transmission outages to connect, and the interconnection facilities are significantly smaller than transmission interconnection facilities. He notes that the time to connect from signing the interconnection agreement to commercial operation was less than a year for a distribution level project versus 26-32 months currently for transmission level projects. He also points out that the ability to interconnect solar facilities to the Companies' systems without extensive transmission network upgrades (i.e., the "low hanging fruit") has occurred with the 4+ GW of solar already interconnected. Tr. vol. 28, 144-45.

Witness Roberts references Figure 15 in the Modeling and Near-Term Actions Panel Direct Testimony as showing that 14 to 15 interconnections can likely be achieved in the near term. From a transmission perspective, he states that this is a reasonable but aggressive target. Based on his detailed knowledge of the Companies' transmission system and extensive familiarity with the Red Zone constraints, he concludes that it would be very difficult, and possibly unachievable, to make 20 to 21 interconnections in a year from an outage and other transmission constraints viewpoint. He continues that, in his experience as past manager of the DEP transmission outage coordination group, one of the biggest constraints for the pace of solar interconnections looking to the future is that transmission line outages are needed to construct the interconnection facilities and transmission network upgrades needed to interconnect these resources. These outage considerations include at least five-week outages to construct the interconnection facilities alone, coordination of outages for constructing network upgrades and interconnection facilities, coordination and planning of additional transmission outages for NERC-related maintenance and other work, limitation of most outages to the spring and fall seasons due to the Carolinas peak demand in summer and winter seasons, weather uncertainty, and supply chain considerations. He emphasizes that all of these outages must be coordinated and planned such that reliability is maintained considering a contingency/forced outage of a transmission or generation asset. Tr. vol. 28, 144-46. Witness Roberts presents the example of Duke Energy's coordination of close to 1,100 outages during 2021, most of which occurred during the spring and fall. *Id.* at 193. He also clarifies in response to questions from CPSA counsel that the 14-15 annual interconnections shown by Modeling and Near-Term Actions Panel Direct Figure 15 occur starting in 2028, as enabled by the RZEP projects, and notes that the approximate midpoint of the range of MW additions indicated by CPSA Transmission Panel Rebuttal Cross Exhibit 1 is consistent with the 1350 MW of additions shown starting in 2028 in Modeling and Near-Term Actions Panel Direct Figure 15. *Id.* at 201.

Witness Roberts testifies further that proactively constructing the RZEP projects will help interconnect more solar generation. He explains that the RZEP projects are key to meeting interconnection targets and longer term will relieve constraints and enable new solar interconnections. He cautions that the Companies will need to continue to be confident that the planned number of interconnections can be executed in the timeframe required given the outage coordination hurdles he describes. Tr. vol. 28, 146-47.

Witness Roberts states that reliance on third-party construction as suggested by CPSA introduces significant reliability risk to the potential impact to day-to-day transmission operations. He clarifies that the Companies' OATT, based on FERC Order No. 845, therefore provides the option for interconnection customers to build interconnection facilities and stand-alone network upgrades, but not network upgrades that risk adverse reliability impacts. Tr. vol. 28, 148.

Witness Roberts concludes that Duke Energy has interconnected an extraordinary amount of solar within the DEC and DEP systems and continues to work to create efficiencies and pathways for interconnecting increasing amounts of solar for execution of the Carbon Plan. He notes that Duke Energy presented the process improvement initiative at the Duke Energy Carolinas Carbon Plan Technical Subgroup Virtual Meeting on February 18, 2022. He also notes that through continued interconnection process efficiency refinements as well as implementation of RZEP projects, the pace of solar interconnections should see an improving trend through 2030 and beyond. He emphasizes that this is a key area of focus for Duke Energy as it recognizes and plans an increasing pace of solar interconnections to the Companies' transmission system over the next decade to execute the Carbon Plan while ensuring reliability for customers. Tr. vol. 28, 150.

In response to intervenors' positions that higher solar interconnection volumes are appropriate, witness Kalemba also testifies that there are additional factors impacting the annual volume of solar additions, beyond merely interconnection. For example, under the Carbon Plan, the Companies are projected to nearly double the demand for solar generation in the Carolinas, at a time of heightened supply chain risk. He provides examples of delays that solar developers are experiencing who are attempting to interconnect to the Companies' systems today. He also notes that demand for solar is only increasing as other states and utilities set aggressive carbon reduction goals and developers are pursuing benefits under the IRA. Tr. vol. 7, 355-58.

Discussion and Conclusions

The testimony of the Public Staff, intervenors, and Duke Energy all agree that reflecting real-world solar interconnection limitations in the model is an important variable when developing the Carbon Plan. It is notable that the majority of parties agree that the question before the Commission is not whether a limitation on annual interconnections is appropriate, but rather, what specific limitation is appropriate.

The Commission recognizes that the Companies have historically connected an average of 500 MW per year over the past six years, with the highest rate at 750 MW (in 2017) and with recent years trending closer to 300 MW. This Commission has heard substantial testimony over the past decade regarding the Companies' interconnection processes and recognizes that the pace of solar interconnections in the Carolinas has made North Carolina a national leader in the amount of solar connected. The Commission further recognizes the Companies' efforts to expedite the interconnection process and commends Duke Energy on queue reform in the Carolinas as an important step that will assist in the energy transition and help to meet HB 951's goals. While the Commission recognizes the frustration from CPSA witness Norris and other industry participants that solar interconnections cannot be achieved at a more rapid pace, no evidence has been presented showing that the Companies are not making diligent efforts to interconnect new solar and other resources or that Companies' pace of interconnection is unreasonable when viewed in the aggregate and taking all relevant factors into consideration. In fact, the Companies offered evidence that they have been and continue to be among the national leaders regarding the amount of solar interconnections. The Commission also gives weight to the Companies' proactive actions in implementing queue reform and the transmission interconnection and construction process improvements initiative that has been communicated to stakeholders. Accordingly, the Commission declines to establish an independent technical review committee to review interconnection rates, as recommended by CPSA.

As to the appropriate modeling assumption for the annual solar interconnection limits, the Commission agrees with the Public Staff and the Companies that the Carbon Plan's base planning assumptions for annually interconnecting new solar resources are reasonable for planning purposes. The Commission is persuaded that the limits are not arbitrary, but instead that the Companies used appropriate engineering judgement and analysis, based on their unique role as the entity responsible for managing the transmission system and interconnecting new generation, to develop the modeling assumptions for annual solar additions in the Carbon Plan. The Commission gives substantial weight to Duke Energy's testimony that these assumptions reflect the real-world limitations of adding solar generation to the Companies' systems. The Commission gives substantial weight to Duke Energy witness Roberts' testimony that the ability to interconnect solar facilities to the Companies' systems without extensive transmission network upgrades (i.e., the "low hanging fruit") has occurred with the 4+ GW of solar already interconnected. The Commission understands that the majority of solar historically connected to the Duke Energy systems has been distribution-tied solar and agrees with witnesses Roberts and Kalemba that the majority of solar connected in the future will be transmission-tied solar that will be more complex to interconnect.

The Commission understands that forecasting future solar interconnections is uncertain given multiple factors including the current transmission congestion in the Carolinas. The Commission agrees with CPSA witness Norris as well as Duke Energy witness Kalemba that the timeline required to interconnect utility-scale generators will always entail some degree of uncertainty and that there are many factors impacting interconnection timelines that are outside of the Companies' control. The Commission also agrees with the testimony of the Public Staff encouraging a holistic view of the volume of new resources the Companies will be tasked with interconnecting in implementing the Carbon Plan. The Commission further agrees with witness Thomas that "…we need to look at the whole resource portfolio that we're trying to interconnect and realize that this is a challenge for Duke's transmission interconnection studies and Dukes [*sic*] transmission planners that I don't believe that they've ever faced before, in terms of interconnecting this volume of intermittent resources and dispatchable resource[s] and energy storage simultaneously." Tr. vol. 21, 249-50. And that, accordingly, the question of the volume of new solar resources that the Companies can interconnect needs to be "temper[ed] … with some dose of reality." *Id.*, 250.

Based upon all of the evidence in the record, the Commission finds and concludes that the Companies' solar interconnection assumptions are reasonable and that based on the volume of solar approved in the Near-Term Action Plan results in the continued aggressive pursuit of carbon-free resources to implement the objectives of HB 951. Further, as noted elsewhere in this Order, the Public Staff and the Companies are already recommending to exceed the volume of solar that is reasonably likely to be interconnected in 2026 (750 MW) as part of the 2022 solar procurement (targeting 1,200 MW and potentially up to 1,350 MW), and the Commission finds this assumption to be reasonably aggressive based on the evidence presented. Finally, the Commission recognizes that the Companies' experience implementing the 2022 DISIS, proactive construction of RZEP, if approved by the NCTPC, as well as other future proactive transmission planning developments will further inform these modeling assumptions in the future and directs the Companies to continue evaluating solar interconnection constraint assumptions in future Carbon Plans based upon the best information available at that time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is found in the Companies' proposed Carbon Plan, the testimony of the Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, NCSEA, et. al. witness Fitch, CPSA witness Hagerty, and the AGO witness Burgess, the CPSA July 15 Initial Comments, and the AGO July 15 Initial Comments.

Summary of the Evidence

Summary of Duke Energy Position

The Carbon Plan describes the onshore wind modeling assumptions that allow up to 1,200 MW and 600 MW cumulative additions of 30% capacity factor wind in DEP and DEC, respectively. Carbon Plan, App'x J, 13. The maximum assumed annual additions rate is 300 MW per year between DEP and DEC combined beginning in 2029 (on a beginning-of-year basis). Carbon Plan, Ch. 2, 22-23; Carbon Plan, App'x E, 36-37; Carbon Plan, App'x J, 13.

Duke Energy witness Snider testifies that modeling a 300 MW per year limit beginning in 2029 is reasonable given the current status of wind energy development in North Carolina. Tr. vol 11, 101-02. The costs for onshore wind are based on proprietary third-party engineering estimates specific to the Carolinas. Carbon Plan, Ch. 2, 22.

Appendix J states that identifying appropriate sites is a critical risk to the development of onshore wind. Carbon Plan, App'x J, 14. Appendix J explains that if enough generation is going to be sited in the Carolinas to meet the generation goal outlined in the Carbon Plan, current limitations such as the Ridge Laws may need to be reevaluated. The Carbon Plan further identifies community zoning/rezoning and community support as potential challenges to overcome in the development of wind in the Carolinas, which could be a significant challenge to onshore wind development, as it has been in other states. Any property under considerations for the development of a wind farm will likely require local county/town rezoning or conditional use permitting. The ability of wind developers to secure these permits is critical to achieving the desired onshore wind capacities described previously in the Carbon Plan. *Id*.

Onshore wind that is available for model selection in DEP is assumed to be located within the DEP service territory and includes an assumed Generic Transmission Network Upgrade Cost of $0.24/W.[5] Carbon Plan, App'x E, 38-39. Onshore wind that is available for model selection in DEC is assumed to be imported wind from regions such as PJM or the Midcontinent Independent System Operator (MISO) area using a PJM Border Charge rate of $67,625/MW-year, inflated at 5% per year. Carbon Plan, Ch. 2, 23; Carbon Plan, App'x E, 38-39.

The Modeling and Near-Term Actions Panel testify that onshore wind in DEP is selected in Portfolios P1-P4, as well as in the Supplemental Portfolios, as soon as it is available. Tr. vol. 7, 68. However, onshore wind imported into DEC is not selected until at least the mid to late 2030's. Carbon Plan, App'x E, 73-76.

Duke Energy Witness Roberts explains that wheeling power from MISO into the Carolinas would incur multiple transmission charges including the point-to-point rate from MISO, the point-to-point rate on PJM, and the network transmission upgrades that would probably be necessary on the Duke Energy system. Tr. vol. 28, 205-06. This is in addition

[5] The Generic Transmission Network Upgrade Cost is measured in 2022 dollars.

to the cost of the resource. *Id*. Moreover, witness Roberts explains that the Companies' system is not currently configured to import large quantities of onshore wind energy from PJM or MISO. *Id*. at 206. The Transmission and Solar Procurement Panel testifies that "Duke Energy is not shutting the door on the potential for acquiring Midwest onshore wind based on the results of our internal study of imports from PJM." *Id*. at 151. The Panel also testifies that "Duke Energy would plan to acquire any such off-system onshore wind energy facility selected by the Commission, consistent with the Ownership Requirements under HB 951 as well as the manner in which the Carbon Plan models this asset for DEC." *Id*. at 151-52.

The Transmission and Solar Procurement Panel testifies that the Companies have conducted a transmission planning analysis associated with increasing the import capability for off-system purchases, including by assessing past feasibility studies and affected system studies as well as the same study tools utilized by PJM to study a 1,500 MW transfer from PJM to DEP. The results of this study indicated the need to upgrade transmission facilities in both PJM and DEP with such upgrades requiring significant time and expense. It is estimated that significant system reinforcement projects are needed on both the PJM and DEP transmission systems to enable such import capacity with initial cost estimates starting at approximately $700 million. Tr. vol. 16, 104.

The Panel also responds to NCSEA, et al. and Tech Customers' assertions that Duke Energy should further analyze imports of Midwest Onshore Wind, explaining that Duke Energy views access to Midwest onshore wind generation to potentially be acquired by Duke Energy as not being economically feasible at this time. As discussed in Appendix P, Duke analyzed what transmission system upgrades would be needed to import capacity such as Midwest wind and in addition to the significant costs, the duration to complete the identified transmission projects was up to 84 months. To validate the results of this analysis, Duke Energy submitted a 1000 MW firm transmission service request (TSR) to the PJM queue and is awaiting results. The results of this TSR study will be considered in future iterations of the Carbon Plan. Tr. vol. 16, 104-05; Carbon Plan, App'x P, 22.

In response to cross-examination from the Public Staff regarding the increase in system upgrade costs to handle importing 2.5 GW from the Midwest as suggested by NCSEA et al., Duke Energy witness Roberts testified that the cost "would probably definitely escalate." Tr. vol. 28, 206-07.

Summary of Public Staff Testimony

Public Staff witness Thomas testifies that there is limited onshore wind development in NC to date and—using the Timbermill Wind facility as an example—the development of an onshore wind project could take a minimum of seven years to complete. Tr. vol. 21, 59-61. Witness Thomas's testimony adds 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. In addition, onshore wind imported from PJM or other neighboring areas would require firm point-to-point transmission service and would be subject to the appropriate boarder or wheeling charge.
>
> Absent convincing evidence that large quantities of onshore wind will be available to Duke earlier than 2029 or that more than 300 MW can be interconnected annually, the Public Staff finds Duke's assumptions with respect to onshore wind reasonable for the development of the Carbon Plan.

Id. at 60-61.

During the hearing, witness Thomas also corrected his testimony to confirm that the Carbon Plan modeling of imported wind energy resources in DEC were assumed to be utility owned resources. Tr. vol. 21, 78, 228; Tr. vol. 22, 316-17.

Summary of Intervenor Comments and Testimony

Several intervenors criticize Duke Energy's assumptions of onshore wind availability in the Carbon Plan. CPSA argues that the Carbon Plan likely overstates the potential for onshore wind development, exclusive of imports, noting the 2016-2018 legislative moratorium and the fact that no onshore wind projects are in the recently completed DISIS queue. CPSA July 15 Initial Comments at 45-46. CPSA also states that the development pipeline for new onshore wind farms and the timeline for such facilities in the Carolinas is "highly uncertain." Tr. vol. 25, 427.

AGO witness Burgess testifies that it is premature to presume both no more than 300 MW can be procured and that a 2029 in-service date is required prior to testing the market through a competitive solicitation. Tr. vol. 25, 254. He also argues that the Companies should explore the potential for non-firm or "energy only" type of transmission service for wind imports. *Id*. at 255. Furthermore, NCSEA witness Fitch testifies that the Synapse Report includes 2,500 MW of onshore wind from the Midwest and 900 MW "in-state" onshore wind by 2030. Tr. vol. 24, 178.

Modeling conducted by interveners relied on lower cost, publicly available onshore wind technology costs. Tr. vol. 7, 384-86. Both Synapse and Brattle relied on 2022 NREL ATB costs while Strategen relied on 2022 EIA AEO costs. Tr. vol. 24, 145 (Synapse), 422 (Brattle); AGO July 15th Initial Comments, Attachment 1, 23.

Discussion and Conclusions

The Commission finds that for planning purposes the Companies made reasonable and prudent modeling assumptions for onshore wind. The Companies' modeling assumptions, which include adding 300 MW of onshore wind starting in 2029, are proper due to the limited evidence of developer interest and community acceptance, both of which signal significant execution risk. Thus, the Commission also finds that the Companies' timing assumption—*i.e.*, first availability of new onshore wind at the beginning of 2029—are proper. The Commission agrees with the Companies that limitations such as zoning issues must be understood and overcome before the Companies can achieve the onshore wind capacities described in the Carbon Plan. The Commission finds that the third-party technology costs that are specific to developing wind in the Carolinas are reasonable for planning purposes.

The Commission finds that the costs of Duke Energy acquiring ownership of wind resources and wheeling energy from outside of the Carolinas—particularly from MISO and PJM—can include point-to-point rates in MISO and PJM, likely network transmission upgrades on the Duke Energy system, in addition to the cost of the resource located outside of the Carolinas. Additionally, imported wind from a Duke-owned wind resource is not selected until at least the mid-2030s in any portfolio, while "in-state" onshore wind is selected as soon as it is available in each portfolio. Therefore, the Commission is persuaded that when taking into account all costs and the modeling results, it is prudent to focus on advancing onshore wind development in the Carolinas while continuing to gather data on the costs to wheel in wind from outside of the Carolinas should the onshore wind market in the Carolinas not evolve.

Finally, the Commission does not find the alternative modeling assumptions and selection of imported onshore wind offered by NCSEA, et al. and the AGO to be reasonable for planning purposes, given the abovementioned execution risks. The Commission finds that neither party's comments or testimony justify the executability risks or costs associated with importing significant amounts of onshore wind energy from PJM or the Midwest. As the Companies correctly point out, importing onshore wind energy is not as simple as injecting it into the existing system. The imported energy would incur multiple transmission charges including the point-to-point rate from MISO and the point-to-point rate on PJM. Plus, the Companies' system will likely require significant network transmission upgrades to accommodate the imported energy. Given that the Companies' analysis yielded a need for $700+ million in system upgrade costs to import 1,000 MW of onshore wind—plus the possible conflict with the ownership requirements set forth by HB 951—the Commission does not agree with the NCSEA, et al. and the AGO regarding their determination that significant imported onshore wind should be included in a least cost Carbon Plan.

Based upon the foregoing, the Commission finds Duke Energy's modeling and assumptions regarding the cost and availability of onshore wind are reasonable for planning purposes.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-22

The evidence supporting these findings of fact are set forth in Duke Energy's proposed Carbon Plan, the testimony of Duke Energy's Modeling and Near-Term Actions Panel, the Public Staff July 15th Initial Comments, the testimony of Public Staff witness

Thomas, AGO witness Burgess, NCSEA et al. witness Fitch, and Tech Customers witnesses Borgatti and Kimbrough, and the entire record in this proceeding.

Summary of the Evidence

Natural Gas Assumptions in the Carbon Plan

Appendix M to Duke Energy's Carbon Plan explains that natural gas-fired generation is a proven and cost-effective dispatchable technology that has a long history of reliably serving DEC and DEP customers. Carbon Plan, App'x M, 1. In 2021, Duke Energy's natural gas fleet comprised one-third (33%) of the total Carolinas capacity and generated 28% of the overall Carolinas generation. *Id*. at 2. These natural gas resources consist of both CC and CT units. *Id.*

Appendix M further explains that natural gas will be a critical resource to ensure system reliability in the future, with a growing need for dispatchable resources to support the integration of large amounts of renewables. Carbon Plan, App'x M, 1, 4. Because intermittent resources like solar and wind cannot reliably meet customer demand each hour of each day of the year, high capacity factor dispatchable natural gas will be critical to maintaining system reliability as Duke Energy retires its existing coal fleet on an accelerated schedule. Carbon Plan, App'x M.

Looking forward to 2050, Appendix M explains that Duke Energy expects the eventual transition of natural gas units from providing baseload power as coal is retired to operating less frequently to provide system reliability and resilience with fewer hours of use and more aligned with complementing storage use. New CT/CC assets will be designed for high flexibility (e.g., ramping, turndown, cycling ability) needed with a high renewables presence and targeting transition to hydrogen blending with natural gas and, eventually 100% hydrogen use. Carbon Plan, App'x M, 6-7.

Chapter 2 and Appendix E of the Carbon Plan describe the natural gas CC and CT units, fuel supply assumptions and constraints assumed in modeling new natural gas units as selectable supply-side resources for the Carbon Plan. Appendix E explains that for planning purposes, Duke Energy assumed a 35-year asset life for new gas units with the first year of eligible selection for CTs in 2028 and CCs in 2029. Carbon Plan, App'x E, 31-32. For selectable CTs, Duke Energy uses a J-Class Frame CT with an SCR, with dual-fuel operations on natural gas and ultra-low sulfur diesel as the generic unit assumptions. According to Appendix E, this technology is a more efficient and flexible combustion technology than the F-Class Frame CTs that comprise the majority of Duke Energy's existing peaking CT technologies. The J-Class Frame CTs also are currently more hydrogen capable than the F-Class Frame CTs and compatible for conversion to 100% operation on hydrogen in the future. *Id*. at 30. With respect to CCs, Duke Energy used two configurations for the Carbon Plan: (1) a 2x1 J-Class CC with Duct Firing (CC-J) as the generic unit assumption; and (2) a 2x1 F-Class CC with dual fuel capabilities (CC-F), operating on both natural gas and ULSD in the alternate fuel supply sensitivity. *Id*. at 30-31.

Chapter 2 explains that all four Carbon Plan portfolios assumed a limited amount of firm transportation capacity to transport Appalachian gas supply to the Carolinas but were constrained to allow the model to select up to two new CC facilities or ~2,400 MW of new CC capacity. Carbon Plan, Ch. 2, 24. As Appendix N explains, however, additional firm gas transportation into the Carolinas is needed following cancellation of the Atlantic Coast Pipeline to support both Duke Energy's existing natural gas fleet, as well as the new natural gas resources selected by the Carbon Plan. Carbon Plan, App'x N, 7-8. In recognition of the risk that new Appalachian gas supply may not become available due to the current litigious environment for building new greenfield interstate pipeline capacity, Duke Energy performed a sensitivity analysis to assess its ability to meet carbon reduction targets using natural gas supply inputs that deviate from the base planning assumptions. The sensitivity analysis re-optimized the original four portfolios under the assumption that firm transportation for Appalachian gas cannot be secured. Carbon Plan, Ch. 3, 12. The lack of limited direct access to lower-cost gas from the Appalachia region impacts the commodity price of natural gas, the operations of units in the fleet, and the availability of incremental CC generation, but all other planning assumptions remained constant for the alternate portfolios. *Id*. Across all four alternate portfolios developed under the alternate gas supply assumption, the number and size of new CC units available for model selection was reduced from the two large units (2,400 MW total) available in the base analysis to a single smaller unit (800 MW) available in this sensitivity analysis. In all four of the alternate fuel portfolio sensitivity cases the model selected the single CC and added CTs, energy storage and, in some portfolios, additional solar resources to make up the energy and capacity lost from the second CC that was selected in P1-P4. *Id*.

The natural gas price forecast methodology used for the Carbon Plan utilized both short-term market-based price forecasts and longer-term fundamentals-based price forecasts, as well as a transition period from market-based pricing to fundamental based pricing. Carbon Plan, App'x E, 39. The Companies' natural gas price forecast relies upon five (5) years of natural gas market-based pricing, followed by three (3) years of transitioning from market-based pricing before fully utilizing fundamentals-based natural gas pricing forecast starting in 2031 for the remaining study period. Id. Given the variation in natural gas price forecasts among fundamentals providers, Duke Energy developed its fundamentals-based forecast by averaging four recent natural gas price forecasts: (1) EIA's Annual Energy Outlook Reference case (2021 AEO); (2) Wood Mackenzie North American Power Markets (Base Case) (2021); (3) EVA FuelCast (2021); and IHS Markit Long-Term Natural Gas Outlook (August 2021). *Id*. at 39-40. In addition to the alternate gas supply sensitivity analysis discussed above, Duke Energy performed a natural gas price portfolio sensitivity analysis on portfolios P4 and $P4_A$ to assess whether CC resource decisions are affected by the adoption of high price forecasts. Carbon Plan, Ch. 3, 13. Of the portfolios, P4 and $P4_A$ have the longest timeline to achieve the 70% interim target (by 2034) and represent the most diverse set of resources deployed to achieve that goal. The extended timeline provides the most flexibility for the model to avoid the selection of incremental CC capacity if that capacity is not economically justified. However, even under the high gas price case, new CC capacity was economically selected as part of the least-cost P4 and $P4_A$ portfolios that achieve both interim and long-term carbon reduction goals while maintaining or improving system reliability. *Id*.

Finally, Chapter 2 and Appendices E and N explain the Carbon Plan's assumptions regarding longer-term utilization of hydrogen fuel as an emerging zero-carbon or low-carbon emissions fuel that offers an alternative to fueling CC and CT units with natural gas. In particular, Chapter 2 states that while Duke Energy's existing CT and CC fleet was designed to operate by utilizing natural gas or fuel oil, hydrogen could potentially blend with or replace existing fossil fuels with some modifications to the combustion turbines and the development of a robust supply chain. Carbon Plan, App'x N, 7-8. As Chapter 2 explains, hydrogen capable simple-cycle CT capacity additions were modeled with sufficient ultra-low sulfur diesel back-up eliminating the need for interstate firm transportation natural gas capacity to ensure fuel security. Carbon Plan, Ch. 2, 24. Hydrogen blending is represented in the modeling with a starting point of 3% in 2035 and ramping up in several steps to 15% by 2041 and holding steady thereafter (both numbers representing hydrogen/natural gas volume ratio). This blend is applied to all gas assets existing or added before 2040. Any new peaking CT units built in the 2040s are as assumed to be designed 100% hydrogen fueled. By 2050, all existing CT and CC units continuing to operate on the system as well as all CTs and CCs added to the portfolios operate on hydrogen to achieve zero carbon emissions by the end of the planning horizon. Appendix O (Low-Carbon Fuels and Hydrogen) provides additional details on future hydrogen use considerations. *Id*. at 25.

Taking into account all of these inputs and constraints, Chapter 2 explains that all Carbon Plan base portfolios identify the need for 2,400 MW of CCs and 800 MW of CTs by 2035, with CCs are selected in 2029, the earliest these units are available for selection *Id*. at 12. New CCs and CTs are also selected in all fuel supply sensitivity alternate portfolios. As Appendix E explains, Duke Energy's modeling assumptions account for uncertainty in natural gas fuel supply and responsive planning to ensure reliable operation of the system. Carbon Plan, App'x E, 32. The Carbon Plan explains that resolution of current uncertainty regarding access to gas from the Appalachia region presents a future "pivot point," meaning the Companies will refine resource decisions over the near-term depending on the Companies' ability to access Appalachian gas supply. Carbon Plan, Ch. 3, 13.

Role of Natural Gas in Energy Transition

The Carbon Plan will involve the integration of significant amount of renewable energy resources, such as solar and wind, as Duke Energy transitions its fleet to a carbon neutral future. In Direct Testimony, Duke Energy's witnesses Holeman and Roberts (Reliability Panel) further underscore the importance of natural gas in supporting coal retirements. Witness Holeman explains that HB 951 includes a mandate that Duke Energy must maintain or improve upon the reliability of the existing grid during the electric grid transition. Tr. vol. 19, 129. Witnesses Holeman and Roberts explain that gas generating resources, due to their firm, dispatchable nature, are a necessary reliability "bridge" to achieving carbon neutrality while filling the resource adequacy needs created by the retirement of coal units. Tr. vol. 19, 164, 183. Witness Holeman further cites North American Electric Reliability Corporation (NERC) President and CEO James Robb for the proposition that:

> Natural gas is essential to a reliable transition . . . [O]n a daily basis in areas with significant solar generation, the mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap. Natural gas is best positioned to play that role. The criticality of natural gas as the 'fuel that keeps the lights on' will remain unless or until very large-scale battery deployments are feasible or an alternative flexible fuel such as hydrogen can be developed.

Tr. vol. 19, 138-39.[6] Mr. Roberts pointed to the significant role that the Companies' coal-fired generating fleet played during a recent extreme cold weather week in January 2018 to demonstrate the need for a diverse Carbon Plan portfolio to support an orderly energy transition that is not overly reliant on solar and batteries. Mr. Roberts explained that gas resources (CT and CC units and dual fuel conversions) are a necessary reliability "bridge" to achieving carbon neutrality to fill part of the resource adequacy needs created by the retirement of coal units. In all Plan portfolios, based on the aforementioned coal retirement and generation replacement concerns, additional gas generation capacity is a necessary complement to renewables and storage to provide dispatchable capacity and ensure energy adequacy during winter months when solar output is not well correlated to the Companies' early morning peak load shapes and overall energy demands can remain high for extended periods of time. Tr. vol. 19, 178-83.

Duke Energy's Supplemental Modeling

In response to Public Staff and intervenor recommendations to modify Carbon Plan assumptions and modeling techniques to test the robustness of the Carbon Plan portfolios, the Companies performed supplemental modeling that included natural gas supply input changes, among other modeling changes. As Duke Energy's Modeling and Near-Term Actions Panel explains, the supplemental modeling assumes no access to Appalachian gas supply as the base planning scenario and utilized the Public Staff's recommendation that allows Transco Zone 4 to supply all existing CC units as well as some limited additional procurement. Tr. vol. 7, 251. The assumed incremental Transco firm transportation is enough firm supply for two large, or three small, CC units. Tr. vol. 7, 251. In addition, the supplemental modeling excluded the selection of hydrogen fuel. Instead, the Public Staff and Duke Energy agreed to plan the system relying on up to 5% carbon offsets in 2050, as allowed under HB 951, rather than planning to zero CO_2 emissions in 2050. Tr. vol. 7, 251. The supplemental portfolios also allowed Duke Energy

[6] James R. Robb, North Am. Reliability Corp. Testimony Before United States Senate Committee on Energy and Nat. Resources, Full Committee Hrg On The Reliability, Resiliency, and Affordability of Electric Service (Mar. 11, 2021), *available at* https:www.energy.senate.gov/services/files/EB1D7E02-4DFF-A6A9-002341DA34CF.

to select between 1,200 MW advanced J-Class and smaller 800 MW F-Class CCs. Tr. vol. 7, Modeling and Near-Term Actions Panel Ex. 1, 7-8.

According to the Modeling and Near-Term Actions Panel, all Supplemental Modeling Portfolios continue to select two new advanced J-Class CCs by the year the interim target is achieved. Tr. vol. 7, Modeling and Near-Term Actions Panel Ex. 1, 23, 24. Both CCs and CTs are economically selected in each of the supplemental portfolios to support the variable energy and energy limited resources included in the Carbon Plan as well as to replace retiring coal and gas resources. Tr. vol. 7, Modeling and Near-Term Actions Panel Ex. 1, 24.

As the Modeling and Near-Term Actions Panel explains, Duke Energy continues to support using the Carbon Plan's limited Appalachian gas fuel supply assumption as the appropriate base assumption, including the potential "pivot" if limited Appalachian gas does not become available as anticipated. Tr. vol. 7, 254. Duke Energy believes this assumption is reasonable for planning purposes, reflects least cost and is in the best interest of customers. The Modeling and Near-Term Actions Panel explains that Duke Energy agreed to adopt the Public Staff's view for the limited purpose of developing the Supplemental Portfolios and validating Duke Energy's proposed near-term actions. Tr. vol. 7, 254.

Similarly, the Modeling and Near-Term Actions Panel explains that Duke Energy does not support the removal of hydrogen fuel from the development of Carbon Plan portfolios and understands that the intent of removing hydrogen as a potential fuel source in the supplemental portfolios was to further validate the selection of near-term CCs and CTs. Tr. vol. 7, 255-56. Duke Energy continues to believe the development of future hydrogen fuel sources is likely while also recognizing in the Carbon Plan that there is uncertainty around its development. Tr. vol. 7, 256. The Modeling and Near-Term Actions Panel believes hydrogen is highly likely to play a role in transforming the energy system over the next three decades. Accordingly, the Modeling and Near-Term Actions Panel views the removal of hydrogen completely from this analysis to be extraordinarily conservative. Tr. vol. 7, 256. This assumption change excluding hydrogen fuel can be considered a boundary condition to assess whether CC and CT resources would still be selected regardless of the degree to which hydrogen is utilized in the future. This fuel source and its ability to be used for power generation should continue to be viewed as an important factor in long-term reliability of the system and as critical to executing a least cost plan in achieving the 2050 goal. *Id.*

At the hearing, witness Snider testified in response to a question from Chair Mitchell that Duke Energy believes the Supplemental Portfolios support the near-term actions Duke Energy is proposing. Tr. vol. 27, 268. After reviewing the Supplemental Portfolios, witness Thomas states that the Public Staff supports the "No App 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. Tr. vol. 22, 47.

Natural Gas Supply Assumptions in Modeling

Public Staff Comments and Testimony

In both comments and testimony, the Public Staff raises a number of concerns regarding Duke Energy's natural gas supply inputs and assumptions. First, the Public Staff expresses concern that Duke Energy may have overstated the magnitude of the need for natural gas generation by utilizing what they view as "aggressive" assumptions about hydrogen and natural gas availability and prices. Comments of the Public Staff at 10; Tr. vol. 21, 73-74. Because of the continued uncertainty as to the completion of the Mountain Valley Pipeline (MVP) due to legal challenges, the Public Staff recommends that Appalachian Gas be disallowed at this time as a selectable fuel supply resource in the Companies' primary portfolios. Public Staff July 15th Initial Comments at 72-73.

Intervenor Comments and Testimony

Numerous other parties—including AGO, NCSEA et al., Tech Customers, CUCA, and CIGFUR—in their July 15 comments and subsequent testimony raised concerns regarding Duke Energy's future ability to access Appalachian gas fuel supply.

The AGO argues that Duke Energy's modeling relies on overly optimistic assumptions related to natural gas supply, suggesting that reliance on Appalachian natural gas introduces significant reliability risk for disruptions during peak load hours and severe cold weather events if the Companies are unable to secure new firm gas transportation service, which, the AGO argues, has been difficult to achieve in the Carolinas in recent years. AGO July 15th Initial Comments at 18-19; Tr. vol. 25, 267. The AGO argues that this risk applies to Duke Energy's existing fleet and that expanding its natural gas fleet will exacerbate the risk. Tr. vol. 25, 267. In addition, AGO witness Burgess suggests that it is not clear whether the costs of the additional pipeline capacity were correctly modeled by the Companies in its resource selection process and expresses concern that Duke Energy's analysis may have underestimated the fixed costs necessary to secure firm fuel transportation for new CC resources. Tr. vol. 25, 267-69. To address these "risks," witness Burgess and the AGO recommend that the Commission should consider Duke Energy's alternate fuel supply sensitivity as the primary scenario for each portfolio. Tr. vol. 25, 270; AGO July 15th Initial Comments at 19.

On behalf of NCSEA, et al., witness Fitch argues that Duke Energy's assumptions regarding the availability of Appalachian gas are "high risk." Tr. vol. 24, 158. Witness Fitch notes that Duke Energy may not have access to firm gas capacity to fuel its CCs if the pipeline necessary to supply Appalachian gas is not completed. Id. Tech Customers raise similar concerns that Duke Energy has insufficient firm transportation to support its existing natural gas fleet, let alone the new gas resources it proposes to procure. Tr. vol. 25, 59. Accordingly, Tech Customers witness Borgatti cautions against adding significantly more new CC and CT resources to the system and recommends that the Commission defer a decision to invest in new natural gas generation until risks can be thoroughly evaluated and managed. Tr. vol. 25, 59.

While both CUCA and CIGFUR strongly support the addition of new natural gas, CIGFUR notes some concern regarding reliability impacts in the event Duke Energy is unable to secure an adequate supply of natural gas or pipeline capacity or in the event construction of the MVP pipeline is not completed and placed into service. CIGFUR Comments at 19. CUCA likewise acknowledges that natural gas is a necessary bridge to a carbon-free future, but raises concern that Duke Energy's Carbon Plan does not propose proactive steps to obtain additional firm transportation of natural gas. CUCA Comments at 9-10. CUCA witness O'Donnell describes the current inadequate capacity supply on the Transco Interstate Natural Gas Pipeline at Transco Zone 5, where Duke Energy currently obtains its natural gas supply. Tr. vol. 25, 206. CUCA highlights that industrial users are now facing severe constraints in the availability of natural gas to support their business operations and opines that natural gas scarcity in the Southeast is poised to increase. CUCA July 15th Initial Comments at 9. CUCA Witness O'Donnell acknowledges that completion of the MVP pipeline may eliminate constraints on Transco Zone 5, but recommends that Duke Energy take additional steps to secure firm gas transportation. Tr. vol. 25, 207. Witness O'Donnell recommends the Commission should require Duke Energy to enter into discussions with Transco, obtain an approximate cost estimate for an expansion, and work that expansion cost into the Carbon Plan portfolios. *Id.* Person County also notes the highly constrained nature and recent extreme high prices for natural gas from Transco Zone 5, the only interstate natural gas pipeline that currently serves the state. Person County Comments at 18. Person County underscores that "North Carolina has a *very serious problem* in obtaining sufficient natural gas capacity to service its growing needs." *Id.* at 19 (emphasis in original). Person County urges the Commission to carefully consider the reality that North Carolina does not have adequate natural gas supplies, particularly during the winter months, due to supply and transportation constraints. *Id.* at 21. According to Person County, if natural gas fracking in North Carolina is not an acceptable solution, then approval of MVP and MVP Southgate is urgently needed to relieve the bottleneck in Transco Zone 5. *Id.* at 19-21.

Hydrogen Fuel Assumptions in Modeling

Public Staff Comments

The Public Staff expresses concern regarding the inclusion of hydrogen in the Carbon Plan model. In its Comments, the Public Staff notes that Duke Energy's assumptions regarding the availability of hydrogen fuel are based on achieving United States Department of Energy target electrolysis efficiencies and having sufficient excess renewable energy to produce the necessary quantities of hydrogen. Public Staff July 15th Initial Comments at 16. Accordingly, in the Public Staff's view, incorporating hydrogen fuel conversion assumptions for new natural gas CCs and CTs capacity represents a portfolio risk because if the production and blending of hydrogen does not materialize, meaning that meeting the carbon reduction goals will require substantial new generation to replace natural gas plants that would become stranded assets for which ratepayers would be responsible. *Id*. Accordingly, as Public Staff witness Thomas testifies, the Public Staff recommends that hydrogen should not be included in base case modeling at this time. Tr. vol. 21, 47; Comments of the Public Staff at 76. Nevertheless, the Public Staff acknowledged that hydrogen should be considered in an alternative portfolio analysis until

Duke Energy and the hydrogen industry resolve uncertainty around development risk, deliverability, and cost. Public Staff July 15th Initial Comments at 76.

Intervenor Comments and Testimony

On behalf of the AGO, witness Burgess raises two issues with Duke Energy's approach to modeling the adoption of clean hydrogen fuel. He suggests that (1) many of the cost assumptions used to model hydrogen resources are speculative; and (2) the feasibility of Duke Energy's plan is questionable. Tr. vol. 25, 271. With respect to the former, witness Burgess argues that because Duke Energy only performed PVRR calculations through 2050, the potentially significant future cost of hydrogen conversion of gas resources is largely absent simply due to the time horizon selected for the analysis. *Id.* With respect to the latter, witness Burgess notes that the availability of a robust hydrogen market by 2050 remains uncertain. Tr. vol. 25, 272. Accordingly, witness Burgess argues that new CC and CT units should be modeled assuming 20-year lifetimes, rather than the 35-year lifetimes that Duke Energy has assumed, at least until there is more clarity on the future of the hydrogen market. According to witness Burgess, it may also make sense to delay a decision on new CC and CT additions as long as possible in order to monitor the development of clean hydrogen technologies, gain further clarity on costs, and avoid stranded asset risks for consumers. Tr. vol. 25, 273.

For NCSEA et al., witness Fitch argues that it may not be technically feasible or cost-effective in the future to convert and operate combustion turbines on hydrogen. According to witness Fitch. Tr. vol. 24, 158. Witness Fitch notes that in the event technical issues prevent cost-effective turbine conversion or a sufficient supply of zero-carbon hydrogen is not available, existing and planned gas plants risk becoming obsolete, and the burden of paying off stranded gas assets will fall on either shareholders or Duke Energy's customers. Tr. vol. 24, 158-59.

Tech Customers similarly argue that hydrogen generation is not commercially viable and is, therefore, too speculative to be included in or funded through the carbon Plan. Tr. vol. 25, Tech Customers Gabel Report, 4.

Operable Life and Capital Costs for New Natural Gas Resources

Public Staff Comments and Testimony

Witness Thomas explains that the Public Staff finds Duke Energy's modeling based on a 35-year useful life for natural gas resources to be reasonable, and the Public Staff does not recommend any changes to either the capital costs or operable life assumptions in this proceeding. Tr. vol. 22, 81-82.

Intervenor Comments and Testimony

When analyzing Duke Energy's modeling on behalf of NCSEA, et al., Synapse proposed a number of revisions to Carbon Plan inputs and modeling assumptions, including increasing capital costs for new natural gas resources to align with the EIA's Annual Energy Outlook 2022. Tr. vol. 25, Carbon-Free by 2050 Report, 10. In addition, Synapse proposes to reduce the operational and book life of gas CCs and CTs from 35 years to 25 years for operational life and 20 years for the purposes of gas plant depreciation. *Id*. According to NCSEA et al. witness Fitch, this approach avoids stranded asset risk as carbon requirements decline toward zero by 2050. Tr. vol. 25, 160.

On behalf of the AGO, witness Burgess similarly takes issue with Duke Energy's decision to model a 35-year operable life on the grounds that any new CC or CT would necessarily not operate past HB 951's deadline to achieve carbon neutrality by 2050. Tr. vol. 25, 271. Witness Burgess notes that Duke Energy's Carbon Plan portfolios assume that natural gas plants will convert to hydrogen before 2050. However, given what witness Burgess views as uncertainty as to whether a robust hydrogen market will materialize in that timeframe, witness Burgess suggests that new natural gas plants should be assumed to have lifetimes that do not exceed 2050. Tr. vol. 25, 274. In other words, witness Burgess recommends that CC and CT additions contemplated as part of the near-term action plan, with in-service dates in or around 2029, should be modeled assuming 20-year lifetimes at least until there is more clarity on the future of the hydrogen market. Tr. vol. 25, 275. Tech Customers witness Kimbrough questions the reasonableness of Duke Energy's capital cost assumptions for new gas resources, suggesting they are out of line with a number of national industry publications that show higher costs for a single unit site. Tr. vol. 25, 79; *see also* Tr. vol. 25, Tech Customers Gabel Report, 8. According to witness Kimbrough, Duke Energy assumes that natural gas-fired CC and CT units will be approximately 27% less expensive than market benchmarks for comparable resources, while capital cost assumptions for solar and battery storage resources is approximately 12% to 59% more expensive than market benchmarks. According to witness Kimbrough, the combined impact of these purported cost disparities means that the model is more likely to select new gas resources over solar or battery storage resources. Tr. vol. 25, 249.

Natural Gas Price Assumptions

Public Staff Comments and Testimony

Public Staff witness Thomas confirms the Public Staff believes that the natural gas price forecasts used in the Carbon Plan are reasonable. Tr. vol. 22, 67-68. Witness Thomas finds that Duke Energy's methodology of using five years of forward market prices, followed by a three-year transition to an average of multiple fundamental forecasts is an improvement over the methodology used in past Integrated Resource Plans. Tr. vol. 22, 68. Acknowledging certain intervenors' concerns regarding the recent sharp increases in natural gas prices, witness Thomas notes that natural gas fuel consumption peaks around 2026 in all four portfolios and steadily declines through the remainder of the planning period, thereby reducing Duke Energy customers' exposure to volatile natural gas prices over time. Tr. vol. 22, 70-71.

Practically, witness Thomas also acknowledges that modeling for the Carbon Plan, as in IRP dockets, is a complex task and typically begins six to nine months in advance of any filing. Tr. vol. 22, 71. Fuel price forecasts are typically "locked in" at that time. Witness Thomas notes that the consequences of unanticipated changes in the market are tempered by procedural schedules that allow for frequent updates and a reliance on robust portfolios that cover a range of issues. Tr. vol. 22, 72. For example, the 2024 Carbon Plan update proceedings will utilize updated natural gas price forecasts. If future gas prices appear elevated at that time, that forecast will be reflected in the revised near-term action plan. *Id.*

In addition, Witness Thomas notes that more recent natural gas price forecasts continue to view gas prices declining between 2023 and 2029, well before natural gas plants are economically selected by the EnCompass model in the Carbon Plan. Tr. vol. 22, 72. Last, witness Thomas notes that Duke Energy must also obtain a CPCN for any new gas resources and the reasonableness of proposed natural gas plants will be evaluated in detail after the CPCN application is filed, which will include an analysis of the most recent gas price forecasts and market conditions. Tr. vol. 22, 73. For all of these reasons, witness Thomas explains, the Public Staff is not recommending any changes to Duke Energy's natural gas forecasting methodology nor recommending that the Commission to direct the Companies to update natural gas price forecasts. Tr. vol. 22, 67, 70.

Intervenor Comments and Testimony

On behalf of the AGO, witness Burgess expresses concern that Duke Energy's plan was developed before the recent and significant increase in natural gas prices driven in part by Russia's invasion of Ukraine and that current spot prices are significantly higher than the "worst case scenario" that the Companies modeled in its Carbon Plan. Tr. vol. 25, 264. Witness Burgess argues that there is uncertainty regarding when or if current prices will eventually subside and "return to normalcy." Tr. vol. 25, 264-65.

NCSEA et al., Tech Customers, CUCA, NC WARN, and Appalachian Voices similarly raise concerns that the Companies' natural gas price forecasts do not reflect the recent surge in natural gas prices. NCSEA et al. Initial Comments at 5-6; Tech Customers, Gabel Report at 29-30; CUCA Comments at 10-12; Appalachian Voices, PSE Health Report at 4-5.

Need for and Timing of New Natural Gas Generation in Carbon Plan

Multiple intervenors acknowledge the need for new natural gas resources. For example, CIGFUR witness Muller opines that renewable energy resources are variable resources, and the grid cannot operate without sufficient reliable, dispatchable back-up power. Tr. vol. 25, 363. Accordingly, witness Muller states that new natural gas will play a critical role as a bridge fuel to facilitate the energy transition in a way that does not compromise existing reliability. *Id.* Similarly, Person County recognizes the need for new natural gas generation and applauds Duke Energy for including natural gas generation in each of its four proposed portfolios. Person County Comments at 16. Expressing concern regarding the risk of blackouts and other service interruptions as Duke Energy retires the coal plants that are currently located in the county, Person County notes that natural gas is both a low-carbon emitting fuel source and provides highly reliable, dispatchable, on-demand electricity generation. Person County July 15th Initial Comments at 8-14, 16.

Noting that gas generating resources are in line with HB 951's directive to maintain or improve upon the adequacy and reliability of the existing grid, Person County urges the Commission to authorize Duke Energy to proceed with procuring sufficient natural gas-powered generation resources to replace the coal-fired power plants that will be retired under the Carbon Plan. *Id.* at 16.

Tech Customers, on the other hand, recommend that the Commission defer a decision to invest in new gas generation resources in this proceeding and eliminated new CCs as a selectable resource in their modeling. Tr. vol. 25, 57; Tr. vol. 25, Tech Customers Gabel Report. According to the Gabel Report, natural gas plants built in the early 2030s will survive well past 2050 and their cost-effectiveness is heavily reliant on Duke Energy's assumptions regarding green hydrogen. Tr. vol. 25, Tech Customers Gabel Report, 29. The Gabel Report also argues that new gas generation is not needed until at least 2029 and may not be necessary at all given that investment in evolving technologies like battery storage could satisfy the capacity need. Id. at 30. To avoid the construction of new gas units and the risk of stranded assets, the Gabel Report suggests that Duke Energy may be able to expand its contract capacity with existing North Carolina resources, including the Cleveland CT, Rowan CT, and Rowan CC, when those facilities' existing contracts with other purchasers expire. *Id.* at 30-31.

Duke Energy's Responsive Testimony

Duke Energy responds to the points and arguments made by the Public Staff and intervenors in their Initial Comments in both its Direct and Rebuttal testimony, respectively.

As a threshold matter, the Modeling and Near-Term Actions Panel's Direct Testimony explains that the recommendation made by AGO and NCSEA et al. to substantially reduce the operable life of new gas CC and CT units from 35 to 20 years, combined with artificially high-cost assumptions for CCs and CTs and artificially low cost assumptions for renewables and storage, is results oriented and effectively eliminates CCs and CTs from the portfolio in the near-term. Tr. vol. 7, 387. Tech Customers' modeling approach of completely eliminating new natural gas CCs as a selectable resources for purposes of developing a least cost plan is also not reasonable. *Id.* at 386.

In its Rebuttal testimony and Late-Filed Exhibit 1, the Modeling and Near-Term Actions Panel present additional preliminary modeling of the IRA to assess the potential impacts on resource selection in the Carbon Plan. Specifically, this modeling updates technology costs for CCs and CTs, solar, storage, and onshore wind to account for recent inflationary pressures. Tr. vol. 27, 73; Tr. vol. 30, Duke Energy Late-Filed Ex. 1, at 1-2. Duke Energy's IRA modeling analysis additionally incorporates an estimate of applicable tax incentives allowed under the IRA to test the robustness of Duke Energy's proposed near-term actions when accounting for some level of near-term inflationary impacts in resource pricing, and the cost reducing impacts of tax incentives included in the IRA. Tr. vol. 27, 73; Tr. vol. 30, Duke Energy Late-Filed Ex. 1. Under this analysis, the Modeling and Near-Term Actions Panel explains that the model continues to select CC and CT capacity by the end of 2030, generally supporting the Companies' near-term actions with respect to gas resources. Tr. vol. 27, 73. Duke Energy also performed the same analysis using its high gas price assumption to recognize near-term fuel price increases. Even in a high natural gas price scenario, with the inflationary costs of resources and responsive tax incentives, the Modeling and Near-Term Actions Panel explains that the model continues to select CC capacity in the near term. *Id.* at 74-75. The Modeling and Near-Term Actions Panel acknowledged that CT capacity may also still be economic in the high gas price sensitivity, but due to the time constraints, the Companies were not able to complete the additional modeling steps to verify the economic inclusion of battery storage compared to CTs. *Id.* at 74-75.

The Modeling and Near-Term Actions Panel's Rebuttal Testimony highlights that the IRA and Infrastructure Investment Jobs Act provide potential funding and significant incentives to promote near term development and scale up of the hydrogen economy. Tr. vol. 27, 76-77. As the Modeling and Near-Term Actions Panel explains, these new policy incentives for developing hydrogen fuel further increase the likelihood of the Companies' original planning assumption and reduces alleged stranded cost risk associated with the limited CC and CT capacity the Companies are recommending in their near-term actions as intervenors claim. Tr. vol. 27, 77. According to the Modeling and Near-Term Actions Panel, these policy provisions in support of clean hydrogen production further demonstrates that the assumed shortened book life recommended by Synapse on behalf of NCSEA, et al., Strategen on behalf of the AGO, and Gabel and Associates on behalf of Tech Customers are unreasonable and unnecessary. *Id*. at 78.

In its Rebuttal Testimony, the Modeling and Near-Term Actions Panel generally agrees with Public Staff witness Thomas and AGO witness Burgess that any future CPCN application for new gas should include an assessment of the IRA's impact on the Companies' Carbon Plan modeling to confirm new gas remains part of the least cost plan. Tr. vol. 27, 59. The Modeling and Near-Term Actions Panel explains that, as part of the CPCN process, Duke Energy will continue to evaluate the impact of changing resource technology costs, tax incentives, and commodity pricing with respect to the overall economics and need for the project, inclusive of project-specific cost estimates rather than generic cost estimates used in planning. *Id.* Duke Energy also plans to update its IRPs in the near future to assess changing market conditions, including updated commodity price forecasts, technology cost projections based on prevailing market conditions, and a more comprehensive analysis of the tax benefits attributable to the IRA. The CPCN application will provide detailed updates to project costs, commodity costs and many other project and site specific considerations while the 2023 IRP update will assess changing market conditions from a system perspective. Tr. vol. 27, 59-60.

The Modeling and Near-Term Actions Panel's Rebuttal Testimony additionally highlights that Duke Energy's planned coal unit retirements require replacement resources that can provide firm, dispatchable and equally reliable capacity like peaking CTs and baseload CCs. Without such replacement resources, Duke Energy cannot retire coal on an accelerated schedule. Tr. vol. 27, 80-81. Delaying selection of these resources could have significant impacts on Duke Energy's ability to accelerate retirement of coal resources and, accordingly, impede the Companies' achievement of HB 951's carbon emissions targets.

The Reliability Panel further underscores the importance of natural gas as a "bridge" to achieving carbon neutrality while maintaining the reliability of the system in its Rebuttal Testimony. The Panel explains that System Operators require resources like natural gas with the operational characteristics of coal—flexible and dispatchable operational reserves—that can persist through prolonged extreme weather events as Duke Energy retires its coal fleet. Until hydrogen, long-duration storage, and/or ZELFRs are available to replace at scale the dependability gas contributes to the system, additional natural gas will be needed to support the integration of more renewables and batteries and the retirement of coal. Tr. vol. 30, 106.

Additionally, the Modeling and Near-Term Actions Panel explains that Duke Energy may be able to avoid transmission investments as highlighted by AGO witness Burgess if it replaces coal with natural gas resources at retiring coal sites. Tr. vol. 27, 81. As witness Burgess notes, other potential savings accrued by re-using retirement sites include access to land, cooling water, and fuel infrastructure. Tr. vol. 27, 81.

The Modeling and Near-Term Actions Panel explains that there is a misconception among many of the intervenors that Duke Energy can proceed with all other elements of the Carbon Plan, but defer action on gas, and still meet emissions reductions targets along the least cost path. Tr. vol. 27, 79-80. To the contrary, the Modeling and Near-Term Actions Panel explains that flexible hydrogen-capable natural gas resources play an essential role in decreasing CO_2 emissions, while simultaneously providing reliable replacement capacity that enables the deployment of significant renewable resources. In the case of the new CCs, these resources emit approximately 60% less carbon per MWh compared to the coal they are replacing. Tr. vol. 27, 80. As the newest and most efficient resource on the system with access to the lowest cost gas on the system, new gas resources would offset higher carbon emissions resources over the life of the assets. As an example, the Modeling and Near-Term Actions Panel notes that delaying (or removing) a single gas CC in the plan and keeping an equivalent amount of coal online resulted in an increase of nearly 2 million tons of CO_2 on the system in the year 2030. Tr. vol. 27, 80.

In sum, the Modeling and Near-Term Actions Panel's Rebuttal Testimony posits that the limited hydrogen-capable CC and CT resources identified by Duke Energy in the near-term action plan are essential to achieving the emissions reduction target, while maintaining or improving reliability, and doing so along a least cost path. Tr. vol. 27, 81. Failing to have such flexible resources on the system as the Companies move forward with retiring 8,400 MW of coal unit capacity jeopardizes achieving the emissions reductions target, increases cost of operating the system, and increases risk of a disorderly transition. Accordingly, the Modeling and Near-Term Actions Panel recommends selection of these resources in this initial Carbon Plan as part of the near-term actions required to meet the HB 951 objectives. *Id*.

Hearing Testimony

During the hearing, both Duke Energy witness Snider and Public Staff witnesses Metz and Thomas supported the reasonableness of aspects of Duke Energy's modeling assumptions related to new natural gas resources. In response to questions from Tech

Customers, witness Snider explained that Duke Energy has a clear plan to secure firm fuel supply for natural gas plants, including a confidential contractual position related to the MVP pipeline as well as contingency plans for obtaining fuel supply from the Gulf Coast in the event the MVP pipeline is not completed. Tr. vol. 27, 189-90, 212-17.

In addition, witness Snider explained in response to a question from Chair Mitchell that intervenors' conservative arguments that there could be no hydrogen resource available in 20 years is highly unlikely. Tr. vol. 27, 269-70. Even in the event no hydrogen market materializes, however, witness Snider explained that Duke Energy has other options to ensure that new gas assets will not be stranded, including offsets and sequestration. In addition, if no other technology comes to fruition, HB 951 allows Duke Energy to continue running natural gas resources on a limited basis if needed to retain maintain reliability. Tr. vol. 10, 100; Tr. vol. 27, 271.

Similarly, Public Staff witness Thomas confirmed that the Public Staff believes Duke Energy's modeled CT and CC capital cost assumptions to be reasonable. Tr. vol. 21, 377. In response to questions from Tech Customers, witness Thomas stated that the Public Staff was not persuaded by the Gabel Report or witness Kimbrough that Duke Energy's capital cost assumptions for new natural resources are out of line with market benchmarks. While witness Thomas acknowledged that the publicly available sources cited in the Gabel Report and by witness Kimbrough were higher than Duke Energy's assumptions, he found Duke Energy's assumptions to be more reasonable for a number of reasons. First, witness Thomas noted that publicly available data does not always reflect fundamental differences in pricing based on the configuration and size of the resource. Tr. vol. 21, 380. In addition, he stated that based on his review, the Companies used reputable sources to prepare the CC and CT cost estimates and has "knowledge specific to the North Carolina market and to how Duke Energy would build these systems that I think is relevant to these proceedings." Tr. vol. 21, 380. Witness Metz also highlighted that the issue of CT capital costs had been extensively considered in recent avoided cost proceedings. Tr. vol. 21, 379.

Discussion and Conclusions

The modeling assumptions and the determination of need for new natural gas resources reflects one of the more significant resource planning decisions in this proceeding, as Duke Energy's near-term action plan includes 1,200 MW of new CCs and 800 MW of new CTs. Accordingly, based upon the foregoing and the entire record in this proceeding, the Commission makes the following conclusions:

As a threshold matter, the Commission gives substantial weight to the fact that Duke Energy's robust modeling across all portfolios, Supplemental Portfolios, and Duke Energy's preliminary additional IRA sensitivity analysis demonstrate need for new CCs as part of a least cost plan to continue the energy transition, retire coal resources, and meet HB 951 goals. Selection of new gas CC capacity in the Carbon Plan's initial high gas sensitivity, supplemental modeling analysis, as well as preliminary IRA modeling provide further support that limited new gas CC resources are needed and should be selected as part of least cost portfolio. Numerous modeling portfolios (including intervenor-sponsored modeling) also identified the need for new gas CTs by 2030 and the Commission also recognizes Duke Energy witness Roberts' testimony that generator replacement on site may avoid significant transmission upgrades at certain sites.

The Commission agrees with Duke Energy, Public Staff as well as other parties that there continues to be significant uncertainty around future interstate natural gas transportation to deliver gas into North Carolina. However, Duke Energy's Modeling and Near-Term Actions Panel has explained, in detail, a multi-faceted plan to obtain firm transportation of new natural gas to its system in a variety of contingencies, as identified in the Companies' Execution Plan and further detailed by Duke Energy witness Snider during the hearing. The Commission is persuaded that Duke Energy will be able to pivot to an alternate plan in the event the MVP pipeline is never completed or not completed timely.

The Commission also gives substantial weight to the Public Staff's testimony that Duke Energy's CC and CT capital cost assumptions and 35-year operational life assumptions are reasonable for planning purposes. While the Commission understands the position of the Public Staff and certain intervenors that there remains uncertainty in the development of a hydrogen market, the Commission does not believe it would be reasonable to significantly curtail the operable life of new natural gas resources based on that fact or to exclude hydrogen as a selectable resource at this time. As Duke Energy witnesses have advocated, the Commission understands that Duke Energy intends to "check and adjust" these assumptions as part of the 2024 Carbon Plan Update proceeding, and the Commission will reassess the reasonableness of those assumptions at that time.

The Commission likewise gives substantial weight to Duke Energy's testimony that limited new gas CC and CT resources identified by the Companies in the near-term action plan are essential to achieving the interim emissions reduction target, while maintaining or improving reliability, and doing so along a least cost path. In particular, the Commission is persuaded by the testimony of Duke Energy witnesses Holeman and Roberts that flexible and dispatchable new gas resources are needed on the system as Duke Energy moves forward with retiring 8,400 MW of coal unit capacity. Similarly persuasive was the Modeling and Near-Term Actions Panel's testimony that failing to develop new natural gas resources jeopardizes Duke Energy's ability to achieve HB 951's emissions reductions target, including witness Snider's testimony that new CC capacity resources are approximately 60% less carbon emitting per MWh compared to the coal they are replacing.

The Commission is also persuaded by Duke Energy's testimony that failure to develop new natural gas resources will increase cost of operating the system and increase the risk of a disorderly transition that curtails future longer-term development of the hydrogen economy and/or a carbon offset market that would provide a clear pathway for continued operation of new CC and CT resources beyond 2050 in a manner consistent with HB 951. In light of these considerations, the Commission finds that Duke Energy's assumptions regarding gas supply to be reasonable for planning purposes and that the overwhelming evidence supports selection of limited new gas CC and CT resources as part of Carbon Plan. Conversely, the Commission does not find it prudent for the Companies to pursue expansion of existing contract capacity with firm resources outside of Duke Energy's system. Consistent with the Commission's determination that N.C.G.S. § 62-110.9(2) requires the Companies to own new generation facilities or other resources selected by the Commission in the Carbon Plan, the Commission expects the Companies to evaluate the least cost approach to developing the limited new CC and CT units that are needed in the near-term. This should include assessing replacement generation options at the sites of retiring coal units on the DEC and DEP systems.

Therefore, as further discussed elsewhere in this Order, the Commission selects 800 MW of CTs and 1,200 MW of CC as part of the Carbon Plan. The Commission's foregoing determination supports further development of CC and CT resources as set forth in Duke Energy's Execution Plan including submission of a CPCN application. However, the Commission agrees with Duke Energy, the Public Staff, and AGO that the meaning of selecting a resource under HB 951 as part of the Carbon Plan must be considered flexibly. In this case, given both the uncertainty about interstate transportation as well as the very recent enactment of the IRA, it would not be appropriate to give the Commission's selection of 800 MW of CTs and 1,200 MW of CC dispositive weight in the future related CPCN proceedings. The Commission expects that any future CPCN application for a new gas resource submitted prior to the 2024 Carbon Plan update will include, in addition to the site-specific information required by law, a more detailed discussion of interstate gas transportation and modeling analysis to demonstrate that the specific resource selected continues to be part of the least cost path. However, the Commission's findings in this proceeding related to the value of and need for natural gas generation will be taken into account in any such future CPCN proceeding and provide strong evidence of public convenience and necessity.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 23

The evidence supporting this finding of fact is found in the testimonies of Duke Energy's Modeling and Near-Term Action Panel, NCSEA et al. witness Fitch, CPSA witness Hagerty, Tech Customers witness Borgatti, and AGO witness Burgess.

Summary of the Evidence

Background on Intervenors' Alternate Carbon Plan Analyses

The Commission's November 29, 2021, scheduling order established that Public Staff and intervenors may file plans or reports of their own, or may file evaluations of or comments on the Companies' proposed Carbon Plan by July 15, 2022. Numerous parties filed comments and NCSEA et al., CPSA, and Tech Customers filed alternate plans. The AGO and its consultant Strategen also filed a summary alternative modeling proposal on September 2, 2022, along with direct testimony. These alternate plans, consisting of a combined total of eleven portfolios, were informed to varying degrees by Duke Energy's Carbon Plan modeling inputs and assumptions and incorporated intervenor-supported changes to inputs and assumptions. NCSEA et al. and CPSA used their alternate plans to support specific recommended near-term actions, while Tech Customers and the AGO did not expressly formulate near-term action proposals. The Public Staff did not analyze any of the alternate modeling portfolios presented by intervenors and does not take a position on the reasonableness of these alternate portfolios.

Overviews of Alternate Carbon Plan Analyses Prepared by Intervenors

NCSEA et al.

NCSEA et al. consultant Synapse Energy Economics, Inc. (Synapse) prepared an alternate Carbon Plan analysis and report entitled Carbon Free by 2050: Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers (Synapse Report). The Synapse Report was sponsored by NCSEA et al. witness Fitch and consists of three portfolios developed using the EnCompass modeling toolset: a "Duke Resources" portfolio consisting of the resources selected in Duke's P1***A*** with costs re-calculated to reflect Synapse's cost assumptions, an "Optimized" portfolio that reflects Synapse's changes to both assumptions and analytical methods, and a "Regional Resources" portfolio that, in addition to the changes incorporated in the "Optimized" portfolio, allowed model selection of power purchase agreements (PPA) for onshore wind resources located in the Midwest and imported to the Carolinas. Each Synapse portfolio targets 70% CO_2 emissions reductions by 2030 from Duke Energy's 2005 baseline. Tr. vol. 25 SACE, et al. and NCSEA's Carbon-Free by 2050, Pathways to Achieving North Carolina's Power Sector Carbon Requirements at Least Cost to Ratepayers (Synapse Report), 1.

In developing its portfolios, Synapse changed several of Duke Energy's assumptions, using higher costs and shorter useful lives for new gas resources, higher operating and maintenance costs for existing coal units, lower costs for new renewables and battery energy storage resources, higher feasibility limits for the deployment of new renewables and battery energy storage, lower limits on deployment of new nuclear resources, and increased load reduction from EE and behind-the-meter (BTM) generation. In addition to the changes to the Companies' assumptions, Synapse also changed several modeling methods, forgoing validation of capacity expansion model-selected coal retirement dates and battery capacities, and relying on capacity expansion and production cost model results as the sole basis for assessing system reliability for the Synapse portfolios. Tr. vol. 25, Synapse Report 10-15.

CPSA

CPSA consultant The Brattle Group (Brattle) prepared an alternate Carbon Plan analysis (Brattle Analysis) consisting of five portfolios exploring different paces of CO_2 emissions reduction and different limitations on the pace of deployment of new solar resources. CSPA witness Hagerty sponsored the Brattle Analysis. CPSA based its recommended near-term actions on portfolios CPSA3 (70% CO_2 reduction by 2030) and CPSA5 (70% CO_2 reduction by 2032), both of which are based on an assumed feasible deployment rate for solar that is higher than the Companies' assumptions used in the Carbon Plan. Brattle also used higher cost assumptions than Duke Energy's for new gas resources as well as for new solar resources (although transmission cost assumptions for new solar were lower than those used in the proposed Carbon Plan), with costs for other resource types similar to the Companies'. Finally, Brattle assumed that new nuclear resources will not be available before 2036. Tr. vol. 25; CPSA June 15 Initial Comments Exhibit A, 16-34 (Brattle Report).

Brattle performed its analysis using the GridSim model, which resulted in substantial methodological differences from the Companies' Carbon Plan analysis developed using EnCompass. These differences included, but were not limited to, capacity expansion modeling limited to a few discreet years, production cost modeling limited to 49 non-consecutive days per year, and a study period that did not extend beyond 2035. Brattle did not perform additional analysis to confirm system reliability under any of the CPSA portfolios. Tr. vol. 25, 435-36.

Tech Customers

Tech Customers consultants Strategen and Gabel Associates prepared an alternate Carbon Plan analysis consisting of a version of Duke Energy's P1 with costs re-calculated to reflect Strategen/Gabel assumptions, and a "Preferred" portfolio developed using the EnCompass model and reflecting certain additional changes to Duke Energy's methods and assumptions. The "Preferred" portfolio targets 70% CO_2 reduction by 2030 from Duke Energy's 2005 baseline. Tech Customers July 15 Comments, Exhibit 1 , 50 (Gabel Report).

For the purposes of their analysis, Strategen and Gabel Associates made several significant changes to the Companies' Carbon Plan assumptions, including higher costs for new combustion turbine resources, higher feasible deployment rates for renewable and battery energy storage resources, assuming significant increases in the contributions from energy efficiency (EE) and behind-the-meter (BTM) generation to reduce forecasted load, and the assumption that the Companies will be able to execute contracts for additional capacity from existing third party-owned gas units. Strategen and Gabel Associates also made several significant changes to the Companies' modeling methods, such as precluding the model from selecting new combined cycle resources, forcing all coal units to retire by 2030, forgoing validation of capacity expansion model-selected battery capacities, and relying on capacity expansion and production cost model results as the sole basis for assessing system reliability for the "Preferred" portfolio. Tr. vol. 7, Modeling and Near-Term Actions Panel, Exhibit 8; Tr. vol. 25, Tech Customers – Gabel Report, at 23-57.

Tech Customers witness Dr. Roumpani presents additional modeling analysis in her direct testimony, introducing the "Adjusted Preferred" portfolio and several additional sensitivity analyses. In the "Adjusted Preferred" portfolio, the retirement of Belews Creek is delayed until the end of 2035. The "Adjusted Preferred" portfolio is otherwise identical to the Tech Customers' original "Preferred" portfolio. Witness Roumpani testified that delaying the Belews Creek retirement would resolve reliability concerns with the "Preferred" portfolio identified by the Companies in the direct testimony of the Modeling and Near-Term Actions Panel. Tr. vol. 25, 89-91. In the addition to the "Adjusted Preferred" portfolio, witness Roumpani also described sensitivity analyses evaluating (1) the cost of the “Preferred” portfolio under the Companies’ resource cost assumptions, (2) changes to the composition of the “Preferred” portfolio using less aggressive EE and BTM generation forecasts, and (3) changes to the composition of the “Preferred” portfolio assuming fewer contracts with existing gas-fired generating resources. *Id*. at 92-98. Notably, the Tech Customers’ witnesses did not present any analysis in which the constraint preventing model selection of new, efficient combined-cycle generation was lifted.

AGO

Unable to produce alternative modeling under the timelines of the other parties, AGO consultant Strategen included an alternate “SP-AGO” portfolio as Exhibit 2 to the direct testimony of AGO witness Burgess filed on September 2, 2022, providing the Companies and all parties with substantially less time to assess. The SP-AGO portfolio, developed using EnCompass, was based largely on the Companies’ Carbon Plan base planning assumptions, but with the notable changes of shorter useful lives for gas resources, higher assumed feasible deployment and interconnection rates for renewable and battery energy storage resources, the assumption that the Belews Creek station could be fired 100% on gas by 2028, and the assumption that energy from onshore wind farms in other regions should be imported to the Carolinas without securing firm transmission. Tr. vol. 25, 280-81. Similar to other intervenor analyses, Strategen opted to forgo validation of capacity expansion model-selected battery capacities, and to rely on capacity expansion and production cost model results as the sole basis for assessing system reliability for the SP-AGO portfolio. However, witness Burgess acknowledges that “It is essential that reliability be evaluated comprehensively, to ensure that any simplifications in models like EnCompass do not overlook any potential gaps.” *Id*. at 261.

The Companies’ Critiques of Intervenor Analyses

The Modeling and Near-Term Actions Panel, in its direct testimony, cites several significant concerns with intervenors’ alternate Carbon Plan analyses. These concerns relate to assumptions that depress the net load forecast (load after EE and BTM generation are accounted for), assumptions that unduly favor renewables and battery energy storage over other resource types, assumptions that are not aligned with real-world limitations on resource deployment, and modeling methods that fail to properly and thoroughly validate economic resource selection and system reliability for each portfolio. Furthermore, the Modeling and Near-Term Actions Panel expresses concern that near-term actions founded on these alternate analyses would unnecessarily add risk that implicate one or more of Carbon Plan objectives. Tr. vol. 7, 377, 396. The Panel argue that the Companies’ responsibility for safe and reliable execution of the Carbon Plan and operation of the electric system gives them a different perspective on planning than independent consultants for whom planning can become “a little bit academic in nature.” Tr. vol. 27, 276.

The Modeling and Near-Term Actions Panel elaborates on its concerns related to EE and BTM forecasts used by Synapse and Gabel/Strategen, explaining that higher forecasted contributions from these resources serve to lower the forecasted load that must be served by supply-side resources. If EE and BTM assumptions are not reasonable, which in the cases of Synapse and Gabel/Strategen the Companies contend that they are not, then "[o]verly optimistic net load forecasts could lead to under-investment in supply-side resources, putting system reliability at risk and potentially stalling progress in the energy transition, a potential consequence acknowledged by Synapse." Tr. vol. 7, 381. In addition to the concerns expressed by the Companies, Public Staff witness David Williamson notes that the Companies' own base EE forecast used in Carbon Plan modeling "…exceeds the achievable savings forecast by the MPS [market potential study]." Tr. vol. 21, 187. Witness Williamson goes on to say that "…Public Staff recommends that for future Carbon Plan proceedings, the Commission order that the Companies use the most recent MPS as the appropriate forecast assumption as the base case for modeling the impacts of UEE in the Carbon Plan." *Id*. at 189.

The Modeling and Near-Term Actions Panel explains its concerns related to assumptions that skew results in favor of renewables and storage, highlighting intervenors' changes to the Companies' assumptions that raise the cost of new CC and CT resources and, in the case of the Synapse analysis, simultaneously lower the cost of new renewables and battery energy storage. Tr. vol. 7, 384. The Panel points out that portfolios developed using cost forecasts that are not reasonable for planning purposes can result in the selection of resources that will not be the most economic for customers when the plan is executed. The Panel also explains that intervenors' assumption of a reduced useful life for new gas resources (or in the case of Tech Customers, completely removing gas CCs as a selectable resource) ignores the potential for the deployment of green hydrogen fuel, as well as the provision for carbon offsets in HB 951, and unnecessarily increases the cost of the resulting portfolios. Tr. vol. 27, 270-72.

In addition to the Companies' views on this issue, Public Staff witness Thomas opines that the Companies' resource cost assumptions are reasonable for planning purposes. Tr. vol. 21, 81.

The Modeling and Near-Term Actions Panel further explains that assuming rates of deployment for new resources that exceed real-world feasibility introduces unreasonable risk to successful Carbon Plan execution. In particular, the Panel expresses concern that all intervenor analyses are based on assumed rates of solar deployment that exceed what is realistically achievable, adding execution risk to an already challenging Carbon Plan. Tr. vol. 7, 383. The Panel also points out that the solar procurement process includes a mechanism by which volumes can be increased if bid prices are favorable, allowing customers to benefit in the event that more rapid solar deployment can be achieved while mitigating the cost risk associated with over-procuring in a high price environment. Tr. vol. 27, 58-60.

The Modeling and Near-Term Actions Panel also expresses concerns that the coal retirement dates used in the Synapse and Gabel/Strategen modeling are unsupported by unit-specific analyses confirming the feasibility and economics of these dates. Tr. vol. 7, 388. Similarly, the Panel notes that Strategen, on behalf of the AGO, assumed in its SP-AGO portfolio that Belews Creek would run 100% on gas by 2028, and expresses concern that this assumption "fails to consider real-world constraints on Transco Zone 5 gas supply" and reflects an inefficient use of the limited gas supply expected to be available in the Carolinas, relative to developing a new more efficient combined-cycle generator. Tr. vol. 27, 85, 159-62.

Finally, the Modeling and Near-Term Actions Panel expresses concerns about intervenors' analytical methodology, particularly the omission by all intervenors of critical steps necessary to ensure economic resource selection and system reliability. Tr. vol 27, 98-105, 112-13. The Panel explains that failing to perform the battery-CT Optimization step could result in inclusion of uneconomically high volumes of battery energy storage in the portfolio, increasing costs to customers. Tr. vol. 7, 390. The Panel further explains that, similarly, failing to perform more detailed reliability analysis than is possible in either EnCompass or GridSim unnecessarily risks failure to meet the requirement that system reliability must be maintained or improved. *Id*. at 390-95.

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission has determined that the Companies' Carbon Plan modeling assumptions and methods are reasonable for planning purposes. To the extent intervenors have modified those assumptions to support alternative modeling that arrives at differing conclusions, the Commission finds that the alternate analyses presented by intervenors are not more reasonable for planning purposes at this time. The Companies appreciate the perspective that these intervenors have brought to the process and their substantial commitment to be engaged in developing the Carbon Plan in this proceeding. In future Carbon Plan processes, to the extent such parties elect to continue to be involved, the Commission believes that the Companies should remain open to technical engagement with and feedback from such parties.

The Commission recognizes that the Companies' responsibility for successful Carbon Plan execution and safe and reliable system operations provides a unique perspective on planning for real-world conditions and limitations that may not be shared by other parties. Importantly, the Companies' assumptions and methods reflect a detailed understanding of the Companies' systems and resource costs and capabilities in the Carolinas, due consideration of potential risks to system reliability and the successful execution of an orderly energy transition, aspects of the Carbon Plan analysis that various intervenors' analyses did not fully consider. The Commission also finds it notable that the Public Staff did not analyze any of the alternate modeling portfolios presented by intervenors and does not take a position on the reasonableness of these alternate portfolios.

The Commission agrees with the Public Staff that the Companies' cost assumptions are reasonable for planning purposes and finds that intervenors' changes to those assumptions do not yield more reasonable results or present least cost plans that can be reliably executed to enable the Companies to continue to deliver highly reliable power to the citizens, business, and local government customers in North Carolina. The Commission recognizes the substantial uncertainty around future resource pricing created by inflation, supply chain challenges, and recently passed federal legislation, and expects that upcoming resource procurements and policy implementation will provide important data points that will be incorporated into future Carbon Plan updates. Substantial reliance on imports of off-system wind energy or banking on the Companies' ability to procure additional substantial dispatchable capacity from third-party owned generators that are needed for reliability but not available today is not prudent planning and is also inconsistent with HB 951's requirement that new generating facilities selected by the Commission to meet the Carbon Plan targets shall be owned and recovered on a cost of service basis, as addressed later in this Order.

The Commission recognizes that unit-specific costs and real-world replacement considerations and constraints are critical components of coal retirement analysis, and that these details cannot always be adequately captured in capacity expansion modeling. For these reasons, the Commission finds that intervenors' adjustments to the Companies' assumed coal retirement dates are not more reasonable for planning purposes than the Companies' assumptions.

As also addressed elsewhere in this Order, the Commission recognizes that the battery-CT Optimization step is appropriate to confirm the economic value of battery energy storage resources selected by the capacity expansion model and affirms that robust reliability validation analysis using tools suited to that purpose is critical to the development of a Carbon Plan to ensure the high levels of reliability required under HB 951. The Commission finds that plans developed through analysis that includes these steps are more reasonable for planning purposes than plans based on analysis that omits these steps.

The Commission finds that the Companies' assumptions for the pace at which new resources can be interconnected, including renewable energy and battery energy storage resources, reflect real-world conditions and are reasonable for planning purposes. The Commission further recognizes that plans based on more aggressive assumptions carry unnecessary execution risk.

In conclusion, the Commission has reviewed and considered the alternate modeling presented by other parties based on all evidence in the record and does not find those alternate analyses to be more reasonable for planning purpose than the Companies' Carbon Plan modeling and analysis.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence in support of this finding of fact is found in the Companies' proposed Carbon Plan, the testimonies of the Modeling and Near-Term Actions Panel, Duke Energy witness Bateman, Public Staff witness McLawhorn, CUCA witness O'Donnell, CIGFUR witness Muller, and the entire record in this Docket.

Summary of the Evidence

In the Carbon Plan, the Companies describe the calculation and purpose of the PVRR and bill impact metrics used to evaluate the relative costs of the Carbon Plan portfolios. Carbon Plan, App'x E, 81-84. Duke Energy witness Quinto further explains that "PVRR is a comparison metric only and is not useful for nor intended to be useful for evaluating the total cost of serving customers. Given its limited purpose as a comparison metric, it is not necessary to include costs common to all portfolios in the PVRR calculation." Tr. vol. 7, 289. According to witness Quinto the bill impact estimate, like PVRR, is a metric for comparing the cost of alternate Carbon Plan portfolios and was not developed for the purpose of estimating the future total cost of serving customers in the Carolinas. Tr. vol. 7, 289-90. Finally, witness Quinto points out that including costs that are common across portfolios would in fact obscure differences that do exist across portfolios making them appear less significant. Tr. vol. 7, 290.

Public Staff witness McLawhorn contends that PVRR and bill impacts calculations that include all costs, including those common across portfolios, are important to give customers an understanding of the true cost of the energy transition. Tr. vol. 23, 108-09. Similarly, CIGFUR witness Muller takes the position that the Commission and customers should be provided with PVRR and bill impact estimates that include all costs, "both related and unrelated to the Carbon Plan." Tr. vol. 25, 355. CUCA witness O'Donnell also takes this position and contends that the Companies have previously demonstrated the ability to develop long-term forecasts for all costs necessary to perform these calculations. Tr. vol. 25, 212.

Duke Energy witness Bateman addresses Public Staff and intervenor arguments in her rebuttal testimony. Witness Bateman explains that the Companies do not and are not able to prepare long-term forecasts for all costs. As witness Bateman explains, rate impacts were never intended to try to predict exactly what a customer's all-in rate will be in 10 or 15 years, but instead were meant to be a valuable tool for comparing alternative resource plans. Tr. vol. 28, 58. Witness Bateman continues:

> Even if the Companies were to try to produce [an all-in] forecast, it would inevitably be wrong due to the number of different factors that impact rates—interest rates, inflation, fuel costs, government regulations, amortization periods for deferred costs, etc., over many of which the Companies have no or limited control. For example, several witnesses suggest that we include storm securitization impacts. The Companies would have to try to predict the timing and magnitude of future storms, the cost of restoration, and timing of securitization in order to project a future rate impact from storm securitization. This is obviously impossible.

Tr. vol. 28, 59.

Witness Bateman goes on to explain that intervenors are incorrect in their implied assumption that the Companies can and do develop long-term grid investment plans, pointing out that the detailed plans the Companies do prepare and present to the Commission look out only three years. Witness Bateman reiterated these points during cross examination, and testified that she is not aware of any utility in the country that develops long-term, all-in cost forecasts. Tr. vol. 28, 68.

Discussion and Conclusions

The Commission finds that the PVRR and bill impact calculations provided by the Companies in the Carbon Plan analysis are reasonable for planning purposes and provides a helpful tool to compare the relative benefits of the different portfolios. The Commission recognizes that Companies do not possess all of the information that would be needed to even begin to calculate long-term, all-in rate forecasts and forcing the Companies to do so would require the Companies to make assumptions and guesses about future conditions and circumstances with little to no basis or foundation, resulting in forecasts that are of little to no value but that, if produced, might be relied on by customers in potentially harmful ways despite their substantial uncertainty. Furthermore, the Commission notes that this proceeding is focused on evaluating differences across planning portfolios in order to develop a Carbon Plan, and therefore costs that are common across portfolios and costs that are unrelated to the Carbon Plan are not necessarily relevant to this case.

SELECTING NEAR-TERM SUPPLY-SIDE DEVELOPMENT AND PROCUREMENT ACTIVITIES (Findings of Fact 25-33)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25-33

The evidence supporting these findings of fact is found in the Companies' proposed Carbon Plan, the direct testimony of Duke Energy witness Bowman and the direct and rebuttal testimonies of the Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, AGO witness Burgess, CPSA witnesses Norris and Hagerty, Tech Customers witness Borgatti, NCSEA et al. witness Fitch, CIGFUR witness Muller, NCEMC witness Fall, and the entire record in this proceeding.

Summary of the Evidence

The Companies present a proposed set of near-term supply-side resources as a central part of the Carbon Plan. In the case of those supply-side resources with potentially shorter or more defined lead times—solar, energy storage, natural gas, and onshore wind—the Carbon Plan explains that the Companies are requesting the Commission to "select" a defined amount of such resources pursuant to HB 951, and have proposed substantial near-term development and procurement activities consistent with such defined amounts. Commission selection of these new supply-side resources as part of the Carbon Plan provides the Companies direction to proceed with development and or procurement activities and the Commission will then have further opportunity to assess such projects through future CPCNs (where applicable), or through other regulatory processes as deemed necessary. Carbon Plan, Exec. Summary, 9; Ch. 4, 3-6.

Table 3 of the Carbon Plan Executive Summary presents the proposed near-term actions for supply-side resources that Duke Energy requests the Commission select in this proceeding. Carbon Plan, Exec. Summary, 23. The Carbon Plan explains that Duke Energy requests the Commission deem the following resources as being selected in this initial Carbon Plan for purposes of HB 951, Section 1.(2), in all cases subject to the obligation to obtain a CPCN (where applicable) and to keep the Commission apprised of material changes in assumed pricing or schedule:

- 3,100 MW of solar generation (including 750 MW requested to be procured through the 2022 Solar Procurement Program), of which a substantial portion is assumed to include paired storage;

- 1,600 MW of battery storage (1,000 MW stand-alone storage, 600 MW storage paired with solar);

- 600 MW of onshore wind;

- 800 MW of CTs; and

- 1,200 MW of CC.

The Carbon Plan's Execution Plan also explains that the accelerated timeframe to deliver new resources, along with the interdependencies between generation and transmission needed to achieve the target in-service dates presented in the Carbon Plan, underscores the importance of Commission approval and support for near-term Execution Plan activities in this initial Carbon Plan. The Carbon Plan also highlights that the dates and quantities in the portfolios should be considered directional and not exact. The specific resources (technology, design, capacity) to be developed and optimal in-service dates will be refined through the development and siting processes as Plan components are executed. As more information is gathered through execution, the Companies will keep the Commission apprised of material developments through future biennial Carbon Plan updates, as well as through resource-specific regulatory processes or approvals (e.g., a CPCN proceeding). Carbon Plan, Ch. 4, 3-5.

Duke Energy Direct Testimony

Duke Energy witness Bowman supports the Companies' request for Commission selection of supply-side resources and approval of the near-term development and procurement actions presented in the Carbon Plan. Witness Bowman explains that the Companies are committed to transitioning to a cleaner energy future and believe that the Commission's approval of a defined set of near-term actions that are generally consistent across all portfolios will support achievement of those goals while maintaining reliability and affordability and mitigating overall execution risks associated with over-reliance on any resource option. Tr. vol. 7, 43. The Companies' proposed near-term activities represent the "reasonable steps"[7] contemplated by HB 951 to decisively move forward in this next major phase of the energy transition and should be approved by the Commission. Tr. vol. 7, 41. Witness Bowman's Exhibit 3 presents the portfolio of supply-side resources included in Carbon Plan Executive Summary Table 3 proposed for development in the near term.

Witness Bowman also highlights that with more than 40 intervenors, 32 sets of comments, eight technical reports, and three alternative modeled plans raising a voluminous number of issues, it is necessary that the Commission focus on those decisions that must be made at this time, but also recognize the iterative nature of the biennial Carbon Plan process and that this proceeding does not require the resolution of every issue. Tr. vol. 7, 47. Approval of substantial near-term procurement and development actions that are generally consistent with all portfolios will both ensure that bold and aggressive actions occur in the next two years, while also positioning the Companies and the Commission to make more informed decisions in the 2024 Carbon Plan update. Tr. vol. 7, 48. Witness Bowman also explains that the Companies' Carbon Plan recognizes that the General Assembly specifically authorized the Commission to "retain discretion" as it pursues achieving the targeted reductions to ensure reliability is maintained and to accommodate certain new resource technologies. The Companies fully support this "check and adjust" strategy and note that the Public Staff and certain intervenors do not oppose the extensions to allow for a cost-effective addition of resources beyond 2030. Tr. vol. 7, 52-3.

The Modeling and Near-Term Actions Panel similarly testifies that the near-term execution actions for new supply-side resources are generally consistent with all portfolios and have been developed to enable the Commission to direct decisive and immediate action in the near-term, while retaining discretion to determine the optimal timing and least cost path to meeting HB 951's targets in future Carbon Plan update proceedings. Tr. vol. 7, 242. The Modeling and Near-Term Actions Panel explains that the initial Carbon Plan modeling identifies the need for a broad mix of zero-carbon resources, storage resources, and a limited amount of hydrogen-capable natural gas resources to maintain system reliability. Tr. vol. 7, 209-10. The Modeling and Near-Term Actions Panel also explains that the results of the supplemental portfolio modeling analysis presented in Exhibit 1 to the Panel's direct testimony continues to support their initial recommended amounts of supply-side resources in the near-term. Tr. vol. 7, 266-67. However, the Modeling and Near-Term Actions Panel also recommends that the target volume in the 2022 Solar Procurement be increased to recognize that 441 MW of HB 589 Competitive Procurement of Renewable Energy (CPRE) Program solar resources that were assumed to be procured and online by 2025 in advance of evaluating the need for additional solar to achieve the Carbon Plan targets in 2026 and beyond were not procured through tranche 3 of the CPRE Program. Adding the 441 CPRE Program Remainder MW to the 750 MW target procurement volume for 2022 results in a 1,200 MW 2022 Solar Procurement volume. Tr. vol. 7, 269.

[7] *See* N.C.G.S. § 62-110.9.

Public Staff Direct Testimony

Public Staff witness Thomas addresses the Companies' near-term procurement activities associated with an interim compliance date of 2032 and finds them generally reasonable. Tr. vol. 21, 34. Witness Thomas also recommends that the Commission approve a revised 2022 Solar Procurement goal of 1,200 MW, including a minimum procurement volume of 440 MW in DEC, equivalent to the CPRE shortfall. Tr. vol. 21, 36, 97 (corrected).[8] Witness Thomas testifies that the Public Staff's positions on near-term activities are significantly informed by the results of Supplemental Portfolio 5 and recommends the Commission approve SP5 compliant near-term procurement activities. Tr. vol. 21, 91. Witness Thomas presents a table showing that SP5 compliant procurement would require significantly more solar and solar paired with storage over the near-term by 2030 than proposed in the Companies' near-term action plan.

Table 3 – Resources	Requested Capacity (MW)	
	As-Filed	SP5 Compliant
Solar and S+S	3,100	4,250
Battery Storage (S+S)	600	1,225
Battery Storage (Standalone)	1,000	1,125
Onshore Wind	600	600
Natural Gas CTs	800	800
Natural Gas CCs	1,200	1,200

Witness Thomas also testifies that it was reasonable and appropriate for the Companies to model a delay in the interim compliance year beyond 2030. He explains that while meeting the interim compliance goal by 2030 should be a priority, it is also appropriate to model multiple portfolios with different interim compliance dates. This approach allows the Commission to evaluate the differing costs and generation resource mixes that would result and 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. Tr. vol. 21, 39-40. Witness Thomas states that the Public Staff is not recommending that the Commission preemptively authorize a delay in meeting the interim compliance goals, but also must 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. 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 Energy customers, witness Thomas recommends that the Commission should

[8] The Public Staff subsequently revised its position on the minimum allocated volume in comments filed on October 4, 2022, in Docket Nos. E-2, Sub 1159, E-2, Sub 1297, E-7, Sub 1156, and E-7, Sub 1268 recommending that the Commission direct at least 400 MW of the total solar capacity procured in the 2022 Solar Procurement, inclusive of CPRE designated projects and HB 951 projects, be located in DEC.

consider exercising the discretion afforded it by HB 951. According to witness Thomas, delaying until 2032 may allow the Commission to develop a Carbon Plan with lower costs and lower execution risk, as the more accelerated 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. Tr. vol. 21, 40-2.

Public Staff witness Thomas also explains that the Public Staff does not view approval of a near-term action plan as Commission approval of construction of generating plants or otherwise controlling in a CPCN proceeding. He suggests that approval or issuance of a near-term action plan provides clarification on what steps should be taken or are likely to be needed in the planning horizon. However, witness Thomas states that Duke Energy will still need to seek CPCN approval for its respective projects or other regulatory approval from local, state, or federal agencies as required. Witness Thomas also testifies that the Public Staff does not view the selection of resources by the Commission in the adoption of its Carbon Plan as authorizing the recovery of costs. Tr. vol. 21, 98.

Intervenor Testimony

AGO witness Burgess testifies that it is premature to approve all of the near-term actions Duke Energy has proposed. Tr. vol. 25, 295. Witness Burgess specifically expresses concerns with selecting the new gas CC and CT resources in the Carbon Plan. However, he testifies that the solar, storage, and wind procurements that Duke Energy has identified in its proposed near-term action plan should be pursued as part of a "no regrets" strategy and greater quantities of these resources may be warranted due to the IRA. Tr. vol. 25, 296.

Witness Burgess testifies that his alternative SP-AGO proposed portfolio aims for a 2030 compliance date, and thereby preserves the option to delay if there are unforeseen challenges. He comments that it should be no surprise that Duke Energy's Portfolio 4 might appear to be the "most achievable" but that is simply due to the fact that it has the most delayed compliance deadline (i.e., 2034 versus 2030). However, witness Burgess states that the Commission should not equate "most achievable" with "most preferred." AGO witness Burgess suggests that it may be better to aim high and miss the mark by a year or two, rather than aim low out of an overabundance of caution and fail to meet the statutory requirements. Tr. vol. 25, 323-24.

Tech Customers witness Borgatti testifies that the Tech Customers' strategy in terms of near-term actions prioritizes near-term investment in infrastructure necessary for any carbon plan, including each of the Companies' portfolios, while avoiding or delaying investments that may not be needed or are reliant on speculative or unproven technology. Tech Customers' preferred portfolio includes no standalone solar before 2030, but recommends one new combustion turbine, 1,200 MW of onshore wind in 2027-2028, 1,000 MW of solar paired with storage 25% 4-hr battery ratio in 2027-2028, 3,750 MW of solar paired with storage 50% 4-hr battery ratio in 2027-2029, 2,850 MW of standalone 4-hr battery in 2027-2029 and 50 MW of standalone 6-hr battery. Tr. vol. 25, 47. Witness Borgatti further explains that Gabel remains committed to its recommendation that the Commission should not select new gas generation in the near term and that it should wait—at least until the next Carbon Plan proceeding—to evaluate whether such resources are necessary to accomplish the least-cost, reliable pathway to achieve North Carolina's carbon goals. Tr. vol. 25, 50.

CPSA witness Norris specifically addresses near-term procurement of new solar resources based on modeling performed by CPSA witness Hagerty and recommends that the Commission direct near-term procurement of 4,800 MW of new solar for 2022-24: 1,500 MW in 2022, 1,500 MW in 2023, and 1,800 MW in 2024. Tr. vol. 26, 52. CPSA strongly recommends that its alternate portfolios CPSA3 and CPSA5, which are based on more aggressive solar interconnection assumptions, be included in the Carbon Plan for further consideration in the 2024 proceeding and to inform Duke Energy's near-term execution plan. In addition to selecting more solar than the Duke Energy portfolios, both CPSA3 and CPSA5 also select 600 MW of onshore wind as well as 2,400 MW of gas CCs as needed by 2030, which are consistent with Duke Energy's Carbon Plan portfolios. Tr. vol. 26, 47. Witness Norris criticizes Duke Energy's excessive conservatism about the rate of solar additions and testifies that the proposed near-term procurement targets are insufficient to achieve compliance with the 70% carbon emissions reduction mandate by 2030, even under the most solar-reliant portfolio in the Carbon Plan (PI). Tr. vol. 26, 28-29, 39. He argues that the Companies' near-term execution plan, as proposed does not in fact chart a course for achieving Duke Energy's PI—which is the only one that achieves 70% decarbonization by 2030 and alleges that Duke Energy's low levels of early solar procurement are also inconsistent with achieving 70% compliance in 2030. Tr. vol. 26, 49.

NCSEA et al. witness Fitch supports the Commission planning for a 2030 achievement date for 70 percent reduction requirement. He explains this approach maintains HB 951's default deadline for achievement of the 70 percent carbon reduction and allows for flexibility in later planning proceedings in the event that the Commission determines that a delay is warranted. Tr. vol. 24, 160. Witness Fitch's Table 6 presents recommendations to the Commission for short-term actions and resource selections through 2030 developed based upon Synapse's alternative modeling presented in the Synapse Carbon Free by 2050 Report. NCSEA et al.'s proposed actions for supply-side resources include beginning procurement of 4,000 MW of new solar 2022-2024 with target in-service dates of 2025-2028, begin procurement for 4,000 MW of stand-alone storage with target in-service dates of 2025-2028. Witness Fitch also recommends the Companies begin planning and/or development of 900 MW of onshore wind (in-state), 2,500 MW of onshore wind imported from the Midwest, and 800 MW of offshore wind to be placed into service by 2030. Tr. vol. 24, 177-78.

From a customer perspective, CIGFUR witness Muller testifies that a more measured pace of transition enables North Carolina to be flexible and in a position to adapt to new information or technology advancements or any number of other changed circumstances that could warrant altering the path forward in the future. Witness Muller similarly highlights, from an affordability perspective, taking a less accelerated pace of transition could also make the year-over-year rate impacts for ratepayers more manageable and ensuring that the least-cost plan is selected. Tr. vol. 25, 364. NCEMC Witness Fall also supports the Companies' proposed short-term action plan as reasonable, initial steps to lay the foundation for compliance with the carbon reduction goals in a reasonable manner that is consistent with least-cost principles while maintaining system reliability. Witness Fall agrees with Duke Energy witness Bowman that by taking short-term actions and continuing to update cost assumptions and monitor changing conditions over time, the Commission will be able to better chart the least-cost path to compliance with the best available information available at the time without locking into a more expensive or risky resource mix. Tr. vol. 23, 305-06.

Duke Energy Rebuttal Testimony

The Modeling and Near-Term Actions Panel's rebuttal testimony explains that the Companies' primary focus in the expedited rebuttal testimony phase was to assess whether any of the near-term actions supported by the Carbon Plan should be modified. The Panel reiterates that the Commission should focus its efforts on approving necessary near-term actions that chart a course for achieving HB 951's CO_2 emissions reductions targets in a manner that best achieves the core objectives of the law. The Commission and the Companies will then be able to "check and adjust" in future proceedings. Tr. vol. 27, 35. The Modeling and Near-Term Actions Panel focuses on both Commission selection of carbon free supply-side resources (solar, storage, and onshore wind) as well as the need for limited new natural gas CC and CT resources identified in the Carbon Plan.

Specific to selecting carbon-free solar (including solar paired with storage), battery energy storage, and onshore wind, the Modeling and Near-Term Actions Panel explains that there is substantial consensus amongst a number of parties that the volumes of these resources recommended by Duke Energy's near-term action plan are consistent with a "no regrets" strategy and should be selected by the Commission for procurement in the near-term. The Panel's Rebuttal Table 1[9] presents a comparison of alternative near-term action proposals between Duke Energy, Public Staff and intervenors. Tr. vol. 27, 41-42.

	Solar (including SPS)	BESS Paired w/ Solar	BESS Standalone	Onshore Wind	CT	CC
Supporting deployment by:[1]	YE 2028	YE 2028	YE 2029	YE 2029	YE 2029	YE 2029
Duke Energy Proposal (MW)	**3,100**	**600**	**1,000**	**600**	**800**	**1,200**

[9] The Commission has not replicated the Notes supporting Rebuttal Table 1, as presented in the Duke Energy Modeling and Near-Term Actions Panel's rebuttal testimony and replicated in Modeling and Near-Term Actions Panel Rebuttal Exhibit 1. *See* Tr. vol. 27, 41 for further detail.

Public Staff Proposal (MW)[2]	**2,630**	**820**	**1,130**	**600**	**800**	**1,200**
Alternative Proposals (MW)						
AGO[3]	3,100	600	1,000	600	0	0
Tech Customers[4]	3,450	1,600	2,900	1,200	400	0
CPSA[5]	4,800	1,650	*0*	*600*	*0 to 500*	*1,200*
NCSEA et al.[6]	4,000	0	4,000	600	0	0
Differences from Duke Energy Proposal						
Public Staff Proposal (MW)	**-470**	**+220**	**+130**	**0**	**0**	**0**
Alternative Proposals (MW)						
AGO	0	0	0	0	-800	-1,200
Tech Customers	+350	+1,000	+1,900	+600	-400	-1,200
CPSA	+1,700	+1,050	*-1,000*	*0*	*-800 to -300*	*0*
NCSEA et al.	+900	-600	+3,000	0	-800	-1,200

As shown in the Panel's Rebuttal Table 1, the Public Staff is generally aligned with Duke Energy on solar, battery energy storage, and onshore wind when assessed on an apples-to-apples basis, and the AGO supports the Companies' proposed near-term actions with respect to these resources as part of a "no regrets" approach. In contrast, CPSA, NCSEA et al., and Tech Customers all recommend significantly greater procurement of solar and battery energy storage in the near-term. However, Rebuttal Table 1 also shows that there are substantial inconsistencies between intervenors' specific recommendations for procurement of standalone energy storage and solar paired with storage as well as onshore wind between these other parties. Tr. vol. 27, 42.

The Modeling and Near-Term Actions Panel explains that the Companies are planning to procure significant solar paired with energy storage resources in future near-term procurements (2023-2024). While most of the 2,350 MW of solar resources procured in the near-term after 2022 will include storage, the volume of solar paired with storage needed will be based on the optimal configuration of the paired storage that can be procured at least cost and recognizing system needs. The Panel explains that for the remaining 2,350 MW of solar (inclusive of 600 MW of storage associated with solar paired with storage resources) to be procured, if all future solar paired with storage includes storage that is 25% of the solar nameplate capacity, then the Companies would need to procure 2,400 MW of solar paired with storage to reach the 600 MW paired storage target and thus no additional stand-alone solar would be required. If all future solar paired with storage includes storage that is 50% of the solar nameplate capacity, then the Companies would need to procure 1,200 MW of solar paired with storage to reach the 600 MW paired storage target. Tr. vol. 27, 57. The Panel also highlights that its proposed near-term actions do not include solar and storage procurement targets for 2025 that would be assumed to come online in 2029, as procurement that far in the future should be further informed by the outcomes of the earlier solar procurements and the 2024 Carbon Plan update. According to the Panel, this approach affords the Commission the time and flexibility to wait an additional two years to determine procurement targets for resources expected to come online in 2029 ahead of 2030. Tr. vol. 27, 67.

The Modeling and Near-Term Actions Panel also disputes CPSA witness Norris' testimony that approval of the Companies' proposed near-term actions would make 2030 compliance unachievable. The Panel explains that the Companies expect to procure 3,550 MW (inclusive of the 441 MW CPRE remainder), which leaves an additional 2,300 MW to be procured to reach P1 solar additions by 2029. Assuming a volume adjustment mechanism similar to the 2022 Solar Procurement is included in future procurements, then the Companies could procure solar volumes above in the near-term to remain on track to meet the P1 solar volume. The Panel also notes that there are numerous other considerations and aspects of an "all of the above" Carbon Plan that need to be considered to meet the carbon reduction targets and the pace of solar procurements must be viewed in the broader context of other resources and infrastructure needed in conjunction with the new solar resources to achieve the desired carbon reductions in an orderly fashion. Tr. vol. 27, 56-60. The Panel concludes that pre-emptively selecting the significantly higher volumes of solar and batteries recommended by CPSA and NCSEA et al. to be procured in the near-term would significantly increase execution risk and is not a reasonable step. Tr. vol. 27, 67.

The Panel also highlights that selecting limited amounts of new gas generation is recognized by a number of parties and is needed to provide system flexibility, support grid reliability, and to provide significant carbon reductions needed to achieve the interim 70% target called for in HB 951. Further delays in moving forward with a limited amount of hydrogen-capable natural gas resources will either present reliability challenges or delay achievement of the interim target and retirement of existing coal resources or both. Tr. vol. 27, 79.

In light of recent upward inflationary pressures on technology costs and the significance of the newly passed Inflation Reduction Act of 2022 (IRA), the Panel explains that Duke Energy performed preliminary modeling sensitivity analysis based on an initial review of the IRA to test the robustness of the Companies' proposed near-term actions. This IRA modeling sensitivity was filed as Duke Energy Modeling and Near-Term Actions Panel Late-Filed Exhibit 1 and continues to validate the near-term actions including supporting inclusion of limited new hydrogen-capable gas resources in the near-term action plan to drive down CO_2 emissions and maintain reliability over the planning horizon. The Panel also highlights that the IRA and Infrastructure Investment and Jobs Act's significant policy support for hydrogen infrastructure development undercut intervenors' stranded asset arguments. Tr. vol. 27, 70-8.

In conclusion, the Modeling and Near-Term Actions Panel explains that near-term actions to develop approximately 1,200 MW of CC and 800 MW of CTs have been consistently determined to be needed by Duke Energy's modeling, including Supplemental Portfolio 5 (no App gas) portfolio supported by Public Staff and now by the preliminary IRA sensitivity. Selecting these new hydrogen-capable natural gas resources is a key component of the decisive action needed to achieve a reliable least cost plan. *id*.

In response to recommendations that the Commission should delay selection of new gas resources, the Modeling and Near-Term Actions Panel explains that there also would be significant implications of delaying the selection of these resources until after the 2024 Carbon Plan update. According to the Panel, there is a misconception that the Companies can proceed with all other elements of the Carbon Plan but defer action on gas and still meet CO_2 emissions reductions targets along the least cost path. To the contrary, flexible hydrogen-capable natural gas resources play an essential role in decreasing CO_2 emissions, while simultaneously providing reliable replacement capacity that enables the deployment of significant renewable resources. Tr. vol. 27, 79-80.

Based on all of the modeling and analysis completed to support the Carbon Plan, the Panel testifies that Duke Energy continues to support Commission approval of all near-term actions in this initial Carbon Plan, including limited new natural gas resources, and commits to further evaluate the impact of changing resource capital costs, tax incentives, and commodity pricing with relation to the overall economics and need for a future gas project as part of a future CPCN proceeding. Tr. vol. 27, 38, 94.

Discussion and Conclusion

The General Assembly in enacting HB 951 established both the general requirement that the Commission develop a plan with the Companies that takes all reasonable steps to meet the State's CO_2 emission reductions targets, as well as the more specific requirement to "select[]" resources in that plan that are needed to achieve the targets. N.C.G.S. § 62-110.9(1)-(2). As discussed earlier in this Order, the Commission's responsibilities in developing the Carbon Plan create an expectation that Duke Energy will execute the development and procurement activities to bring online the resources selected by the Commission and to enable the orderly retirement and replacement of more carbon-intensive coal-fired generation. To that end, the Commission first identifies the resources selected in this initial Carbon Plan and then provides further guidance on how selecting resources in the Carbon Plan will inform future proceedings.

As discussed by Duke Energy witness Bowman and Public Staff witness Thomas, the Commission finds that Duke Energy's proposed Carbon Plan presents discrete and reasonable steps in the "near-term" period (2022-2024) towards achieving the interim 70% CO_2 emissions reductions target by 2030 as well as multiple pathways that appropriately allow the Commission to retain discretion to determine optimal timing and generation and resource mix to achieve compliance with HB 951's carbon reduction goals. At this time, the Commission is undertaking a decisive first step in executing the Carbon Plan by selecting the supply-side resources needed in the near-term that will progress the Companies' energy transition on the least cost path.

As discussed earlier in this Order, the Commission has discretion to extend the Interim Target Achievement Date to 2032, if determined necessary to achieve a more "optimal timing and generation and resource-mix." However, the Companies have not requested and the Commission need not determine whether to delay compliance with the interim 70% target beyond 2030 at this time. The near-term actions the Commission is selecting will support a range of portfolios and represent "reasonable steps," preserving the potential through decisive near-term actions to achieve the 70% Interim Target by 2030, while retaining discretion for the Commission to assess in the future the optimal path to achieve the 70% Interim Target. As more information becomes known, the Commission can check and adjust in 2024 and beyond.

Specific to selection of the near-term supply-side activities, the Commission finds that it is reasonable and prudent for DEC and DEP to undertake development and procurement activities for the supply-side resources presented in Carbon Plan Executive Summary Table 3 and Bowman Exhibit 3. As identified in the Modeling and Near-Term Action Panel's Rebuttal Table 1, the Commission finds that there is substantial alignment between the Companies and the Public Staff regarding the near-term resources to be selected. Further, there is substantial consensus amongst the parties that the Companies' proposed carbon free resources (solar, storage, and wind) for development in the near-term are "no regrets" and should be pursued at this time. The Commission also agrees with the Companies that its proposed near-term actions need not include solar and storage procurement targets planned for 2025 at this time, as procurement that far into the future should be further informed by the outcomes of the earlier solar procurements as well as the Companies update to the Carbon Plan to be filed in 2024. Recognizing that the Commission has determined the robust modeling presented by Duke Energy is reasonable for planning purposes and that the alternate modeling presented by other parties is not more reasonable and appropriate for purposes of this initial Carbon Plan, the Commission also does not find the alternative near-term action recommendations by other parties to be more reasonable or appropriate for selection at this time.

Specific to the development and procurement of new solar resources, the Commission herby selects 3,100 MW as part of the Carbon Plan for procurement in 2022-2024 (inclusive of the ongoing 2022 Solar Procurement). The Commission has already directed the Companies to target procuring 1,200 MW inclusive of the remaining unawarded CPRE Program MW in the Commission's Nov. 1, 2022, order in Docket Nos. E-2, Sub 1159, E-7, Sub 1156, E-2, Sub 1297 and E-7, Sub 1268. For 2023-2024, the Companies should target a minimum of 2,350 MW of solar and should determine the optimal timing and mix of new standalone solar and solar paired with storage. The Commission encourages the Companies to work with Public Staff and other stakeholders to consider mechanisms similar to the 2022 Solar Procurement volume adjustments mechanism during 2023-2024 to competitively procure additional solar at least cost and potentially up to the P1 target volume of 4,050 MW (3,300 in 2023-2024), particularly where there is new market information (from the 2022 Solar Procurement or otherwise) that suggests the ability to procure more cost-effective solar and more timely interconnect amounts of solar in amounts greater than the Companies currently project. The Commission also declines to mandate that all new solar must be paired with storage in future procurements. The Commission agrees with Duke Energy that the Companies should retain flexibility to procure solar paired with storage based on the optimal configuration of the paired storage that can be procured at least cost and recognizing system needs targeting 600 MW of storage during this period.

The Commission's expectation is that the vast majority of the 3,100 MW of solar to be procured in the near-term will be procured through a structured annual procurement (as is the case for the 2022 Solar Procurement). The Commission's selection of 3,100 MW of solar resources as part of the Carbon Plan combined with the structure and oversight to be provided in such procurement events will strongly inform the Commission's consideration of need in future related CPCN proceedings. More specifically, the Commission's selection of solar in this Carbon Plan combined with oversight to be provided to future procurement events provides dispositive evidence that any such solar project so procured is in the public convenience and necessity, absent a material change in fact or circumstance. The Commission does not believe that it is necessary or reasonable to require updated modeling or any new analysis of need for such CPCN proceedings.

Specific to the development and procurement of new standalone storage resources, the Commission herby selects 1,000 MW of stand-alone storage in the 2022-2024 timeframe targeting such projects being placed into service by 2029. Those stand-alone storage resources are selected as part of the Carbon Plan subject to the obligation to keep the Commission apprised of material changes in assumed pricing or schedule (with such updates to be made as necessary but potentially as part of future PBR applications).

Specific to the development and procurement of new onshore wind resources, the Commission herby selects 600 MW of onshore wind for development in the 2022-2024 timeframe targeting such projects being placed into service by 2029. The Commission further addresses development and procurement activities for onshore wind in the Execution Plan section of this Order.

Specific to selecting new natural gas generation, the Commission has addressed the Companies' modeling of natural gas resources elsewhere in this Order and will not fully readdress those findings and conclusions here. The Commission reiterates that each of the Companies' portfolios and supplemental portfolios identify the need for new natural gas CC resources in the near-term and new CC and CT resources by 2030 and the Commission gives substantial weight to the Public Staff's support for including new gas CC and CT capacity based on the supplemental modeling performed by the Companies. The Commission finds that limited new hydrogen-capable natural gas generation identified in the Companies' near-term action plan should be selected at this time. Therefore, the Commission selects 800 MW of CTs and 1,200 MW of CC as part of the Carbon Plan. The Commission also reiterates that the ultimate determination of whether to authorize construction of a new natural gas generating facility or any other new utility-owned generating selected in the Carbon Plan will be made in a future CPCN proceeding. As discussed elsewhere in this Order, the Commission expects that any future CPCN application for a new gas resource submitted prior to the 2024 Carbon Plan update will include, in addition to the site-specific information required by law, a more detailed discussion of interstate gas transportation and modeling analysis to demonstrate that the specific resource selected continues to be part of the least cost path. However, the Commission's findings in this proceeding related to the value of and need for natural gas generation will be taken into account in any such future CPCN proceeding and provide strong evidence of public convenience and necessity.

Turning to the issue of what Commission selection of a new supply-side resources in the Carbon Plan means under the Public Utilities Act, the Commission generally agrees with the Public Staff that inclusion of an in-state generating resource in a near-term action plan does not constitute preemptory Commission approval of construction and is not "controlling" in a future CPCN proceeding. As the Public Staff and a number of other parties have highlighted, HB 951 does not supplant or in any way eliminate the requirement for the Companies (or another person where proposing to construct a solar facility selected under the Carbon Plan, for example) to petition the Commission for a CPCN authorizing construction and for the Commission to assess the evidence presented in that proceeding to determine that the "public convenience and necessity requires, or will require, such construction." *See* G.S. § 62-110.1(a). However, Duke Energy has not suggested that to be the case. Instead, Duke Energy has highlighted the need for regulatory efficiency and suggests that the Commission should consider the intersection of resources selected in the Carbon Plan and the determination of need required in a CPCN.

As demonstrated above, the Commission agrees with Duke Energy that the Commission's obligation under the Carbon Plan to select resources should be exercised flexibly depending on the circumstances. This flexible approach is consistent with the Commission's approach to CPCNs in the PBR rulemaking process (Docket No. E-100, Sub 178) wherein the Commission declined to adopt a "one size fits all approach" and further recognized that a particular regulatory process should not be viewed in isolation but instead should be informed by relevant findings from other related proceedings, all with the goal of regulatory efficiency.

In the case of those resources that require a CPCN, the Commission will appropriately weigh selection in the Carbon Plan in a future CPCN proceeding. From a regulatory efficiency perspective, it is simply not feasible to expect that the Carbon Plan will be re-litigated in each and every CPCN process—the findings and conclusions in this Carbon Plan (or a future Carbon Plan update) should be given weight and, where there has been very little change in facts and circumstances, should be dispositive in a CPCN proceeding. The CPCN process will continue to provide a forum in which the Commission can review the site-specific plans for selected resources and ensure the more detailed projected construction cost is consistent with the cost assumed in the Carbon Plan modeling that supported the Commission's prior selection. However, as also demonstrated above in the case of natural gas resources, in some cases, due to the unique facts, it is appropriate for new modeling and analysis to be required as part of a CPCN proceeding.

In the case of those resources, that do not require a CPCN (e.g., standalone battery storage, offshore wind facilities located outside of North Carolina territorial waters, acquisition of existing out-of-state generation resources, and construction of new of out-of-state generating resources), it is appropriate for the Commission's selection of the resource in a Carbon Plan to provide firm and clear direction regarding the Companies' obligation to pursue development and procurement. In those cases, the Companies will nevertheless be obligated to keep the Commission apprised of any material changes in facts or circumstances, including where appropriate, providing such updates for the Commission's consideration in the context of future PBR proceedings.

In summary, the Commission finds that selection of a resource in a Carbon Plan does not obviate the need for a CPCN, when applicable, and reiterates that the Commission will assess material changes in circumstances in a future CPCN proceeding that call into question whether a resource remains part of a least cost plan; however, a party that disputes the resources selected by a Commission-approved Carbon Plan should not be allowed to have a second bite at the apple and seek modification of the Carbon Plan's selection of a resource through a CPCN without demonstrating that some material change in costs or circumstances supports such a finding. At a minimum, the selection of resources in the Carbon Plan creates a strong presumption that the resource is required for the public convenience and necessity and needed to meet the energy transition and carbon emission reductions Plan dictated by the General Assembly in HB 951, Section 1. This approach will promote regulatory efficiency, prevent inconsistent rulings on the same issues, and give the Carbon Plan process the weight it deserves.

APPROVAL OF NEAR-TERM INITIAL DEVELOPMENT ACTIONS TO SUPPORT FUTURE AVAILABILITY OF LONG LEAD-TIME RESOURCES (Bad Creek II, SMR, and Offshore Wind) (Findings of Fact Nos. 34-40)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-40

The evidence supporting this finding of fact is contained in the testimonies of the Duke Energy witnesses Repko, Immel, Nolan, and Pompee (Long Lead-Time Resources Panel); the testimonies of Public Staff witnesses Metz and Thomas; the direct testimony of AGO Witness Burgess; the testimonies of Avangrid witnesses Starrett and Gallagher; the testimony of NCSEA/Sierra Club witness Fitch; the testimony of Tech Customers witness Roumpani; the testimonies of Duke Energy Modeling and Near-Term Actions Panel witnesses Snider, McMurry, Quinto, and Kalemba; the testimony of Duke Energy Transmission and Solar Procurement witness Roberts; the testimony of Environmental Working Group witness Makhijani; the testimony of NC WARN witness Powers; and the testimony of CPSA witness Hagerty.

Summary of the Evidence

Duke Energy witness Repko testifies that the Companies' proposed Carbon Plan does not ask the Commission to select long lead-time resources as Carbon Plan resources right now. Tr. vol. 17, 78-79. Rather, the Companies request that the

Commission approve certain near-term development activities related to the development of the Bad Creek II pumped-storage hydro facility, the development of new nuclear generation sources, and the development of offshore wind generation sources. *Id*.; Carbon Plan Exec Summary, 24. The Companies explain that—if approved—the near-term development of these resources will allow the Companies to present "no regrets" resource generation options to the Commission, Tr. vol. 29, 116, thus ensuring that the Commission's resource selection process is based on real-world data (such as refined resource cost estimates and project timelines) gleaned from the proposed initial development activities. Tr. vol. 17, 78-79; Carbon Plan Exec. Summary, 24.[10] Witness Repko also testifies that the pursuit of the proposed near-term initial development activities will provide the Commission with the flexibility to select resources in a future Carbon Plan proceeding if any such resource is determined to be part of the least cost path to compliance. Tr. vol. 17, 128;[11] HB 951.

Duke Energy witness Repko testifies that all of the proposed long lead-time resources are carbon-free generation sources that are consistent with HB 951. Tr. vol. 17, 84-85. In addition to HB 951 compliance, Duke Energy witness Repko testifies that there are several reasons why it is appropriate to pursue the proposed near-term development activities for the Long Lead-Time Resources: *First*, both pumped storage and offshore wind are mature generation technologies that have been effectively used around the globe for decades and, in the case of pumped storage, in the Carolinas. *Id*.; *see also* Tr. vol. 25, 300-01 (supporting Bad Creek II because it is a mature technology). *Second*, obtaining an early site permit (ESP) for new nuclear technology is a "no regrets" decision because the ESP is an asset that retains value for customers for 20 years. Tr. vol. 29, 116; Tr. vol 17, 100 ("The ESP provides for NRC approval of the siting of one or more reactor technologies (i.e., bounded by the plant parameter envelope in the ESP) at a specific site for up to 20 years, with the option to renew for an additional 20 years."). *Lastly*—like the ESP—the Companies' initial development activities for Bad Creek II and offshore wind retain value for ratepayers because the completed permits that will be obtained through the proposed development activities provide the Companies with flexibility to develop the resources at a later date. Tr. vol. 29, 93; *see also* Tr. vol. 29, 115 ("Furthermore, these development activities have value for any future timeframe the resource is selected.").

Initial Development of Bad Creek II

Duke Energy witness Immel testifies that the Companies propose to expand the existing Bad Creek facility in Salem, South Carolina (Bad Creek I) to include another

[10] *See also* Tr. vol. 21, 124 (Public Staff witness Metz states that given the modeling results and the long development time for both SMRs and Bad Creek II, it is reasonable for Duke to perform further near-term evaluation to refine the timeline of commercial operation, identify risk factors, and determine more accurate cost estimates); Tr. vol. 23, 171 (stating that near term development actions are critical to advancing offshore wind); Tr. vol. 21, 255 ("I don't find it unreasonable that work will need to take place to set us up to potentially evaluate and refine cost estimates for new—either new nuclear or the Bad Creek II project.").
[11] *See also* Tr. vol. 27, 231, where Duke Energy witness Snider states, "we need to take a holistic view of what risks we're asking and have a broad all-of-the-above approach that puts those risks into real [resource] buckets and spreads them out."

pumped storage hydro facility. *See* Tr. vol. 17, 85, 87. Witness Immel testifies that the Companies have almost 50 years of experience operating pumped storage hydro facilities, as they currently operate the Bad Creek I and Jocassee Station facilities. *See Id*. at 88. The proposed facility—Bad Creek II—would include four new generating units that provide an additional 1,700 MW of capacity, thus bringing the facility's total capacity to over 3,330 MW. *Id.* at 87. By adding Bad Creek II, the Companies will be able to support their planned retirements of other generation assets and make more effective use of the existing reservoir. *Id.* at 87. The Companies state that their customers will benefit from the proposed Bad Creek II facility because it will allow for the integration of more renewable and low-carbon generation sources and allow the Companies to store excess generation during periods of low energy demand and produce generation quickly and nimbly when demand is high. *Id.* at 88.

Duke Energy witness Repko testifies that the Companies have requested that the Commission approve several near-term development activities for Bad Creek II. *Id*. at 81. Duke Energy witness Immel testifies that the primary near-term development activities for Bad Creek II include "(1) conduct[ing] a feasibility study; (2) develop[ing] an engineering, procurement and construction ("EPC") strategy; and (3) continu[ing] to develop the application to the Federal Energy Regulatory Commission ("FERC") to relicense the Bad Creek I facility to incorporate the Companies' operation of Bad Creek II." *Id*. A complete breakdown of all the proposed near-term development activities is detailed in the following chart:

Activity Description	2022	2023	2024	Total
Pre-Feasibility/Feasibility Study	5,000,000			**5,000,000**
Support Project Optimization and Functional Design (Support EPC Tender)	1,000,000	3,000,000	3,000,000	**7,000,000**
Execute Phase 2 Geotech Exploration	1,500,000			**1,500,000**
Phase 2 Geotech Exploration Field Support and Analysis	1,500,000			**1,500,000**
Major PH Equipment Solicitation Support Activities				
Support Bid Spec Prep	1,000,000			**1,000,000**
Support OEM Bid Evaluation and Contract Negotiation	200,000	300,000		**500,000**
OEM Hydraulic Design and Model Testing		1,500,000	1,500,000	**3,000,000**
EPC Solicitation Support Activities				
HDR Support Contract Strategy and Planning		200,000	200,000	**400,000**
HDR Prepares Tech Specs / Exhibits in Support of Duke's EPC Solicitation			3,000,000	**3,000,000**
Large Generator Interconnect Study	255,000			**255,000**
EPC Independent Estimate Review	150,000	300,000		**450,000**
Project Mgmt, Project Engineering, Implementation Mgmt	150,000	250,000	350,000	**750,000**
Contingency	500,000	1,500,000	2,000,000	**4,000,000**
Licensing	800,000	3,200,000	3,500,000	**7,500,000**
Total	**12,055,000**	**10,250,000**	**13,550,000**	**35,855,000**

Id. at 90.

Witness Immel testifies that Bad Creek I is now in its relicensing phase with FERC, and the Companies state that the proposed near-term development activities are necessary to preserve the option of expanding the facility through an integrated licensing procedure (ILP) with FERC. *Id*. at 88-89. Witness Repko testifies that the Companies proposed to the Commission to implement cost caps for the proposed development activities. Tr. vol. 29, 93-94. The Companies propose that the costs associated with incurring the near-term development activities for Bad Creek II shall not exceed $40 million.[12] Duke Energy Sept. 9th Pre-Hearing Comments at 47.

Company Witness Immel testifies that an ILP provides the most efficient and streamlined process for obtaining a license for the proposed Bad Creek II facility. Tr. vol. 17, 91. The ILP process is a preferred path because it increases the likelihood that FERC will grant the Companies a 50-year license that covers both Bad Creek I and II. *Id.* at 91. In the alternative, the Companies could proceed with an independent licensing process for Bad Creek I and then Bad Creek II, but this strategy would result in a duplicate licensing process because the licensing process for Bad Creek II would not start until after FERC had approved the relicense for Bad Creek I. *Id*. at 91. Thus, witness Immel testifies, the ILP process will save stakeholders approximately five years of development time, *id*.; in turn, this could result in construction of Bad Creek II beginning in 2027 to support an in-service date of 2033, if it was later selected as a Carbon Plan resource by the Commission. *Id*. at 90.

Duke Energy witness Immel also testifies that their modeling supports the construction of Bad Creek II. As stated by Duke Energy witness Immel,

> Bad Creek II is identified as necessary in every portfolio assessed by the Companies, and no intervenor has presented alternative modeling that identifies a compliance plan without Bad Creek II. As such, the Companies believe it is likely that Bad Creek II will be needed as they retire coal plants and execute on energy transition and the Carbon Plan. Therefore, it is reasonable for the Companies to continue to pursue development activities in order to develop more refined cost estimates for future consideration by the Commission and to preserve the potential for Bad Creek II to be developed on a timeline consistent with that assumed in the Companies' modeling.

Id. at 92. The results of the Intervenors' independent modeling are also consistent with the Companies' position. Tr. vol. 24, 177-78; Tr. vol. 25, 88, 95, and 97.

Generally, the Public Staff and intervenors testify that they support the near-term development actions for Bad Creek II. *See, e.g.*, Tr. vol. 21, 163 ("While the Public Staff is technology agnostic, the modeling results suggest that small modular reactors and the Bad Creek II expansion project are reasonable for further evaluation to refine cost estimates and identify risk factors."); Tr. vol. 25, 300-01 ("Pumped hydro is a mature technology with a well proven track record and is widely deployed across the U.S. Thus, from an execution risk standpoint, it may make sense to approve further development activities for this resource."). While initial comments from the Public Staff question whether it is realistic for the Companies to place Bad Creek II in service by 2033 (Public

[12] CIGFUR I and II witness Gorman has also taken the position that the Commission should limit the amount of costs associated with the Companies' near-term development activities. Tr. vol. 22, 32-33.

Staff July 15th Initial Comments at 87-88), witness Immel testifies that the Companies have confidence in their proposed timeline because they have already completed a pre-feasibility study and have started the feasibility study. Tr. vol. 17, 92-93. Duke Energy witness Snider testifies that intervenors that submitted alternative modeling assumed the availability of Bad Creek II. Tr. vol. 27, 38 ("Modeling and analysis supported by the Public Staff and other parties validates the Companies' modeling analysis showing the need for pumped storage hydro at Bad Creek II as well as the need for future SMRs.").

Initial Development of SMRs and Pursuit of ESP

Duke Energy witness Repko testifies that the Companies have requested that the Commission approve certain near-term development actions related to Small Modular Reactors (SMRs), including primarily development work need to pursue an ESP. Tr. vol. 17, 80. The Companies' modeling demonstrates that it will be necessary to utilize this new nuclear technology as a means for generating carbon free energy. *Id*. at 78-79. Duke Energy witness Nolan testifies that the Companies have a long history of successfully operating nuclear technology, as they operate 11 large light-water reactors at six sites across the Carolinas. *Id*. at 93. The Companies' fleet produces approximately 10,773 MW of capacity, which equates to over 50% of the electricity consumed by customers in the Carolinas. *Id*. at 93. Witness Nolan also testifies that in 2021, their nuclear fleet avoided 50 million tons of carbon dioxide emissions—this is the equivalent of keeping nearly 10 million cars off the road. *Id*. at 93.

Duke Energy witness Nolan testifies that SMRs are considered to be a "[n]ew nuclear reactor technology has evolved from nuclear plant designs that have run safely and reliably for many years." Tr. vol. 17, 96. Public Staff witness Metz testifies that the technology behind SMRs is not new, as these designs are a scaled-down version of the light-water reactors that the Companies operate. Tr. vol. 21, 131 ("At a very high level, SMRs are similar to existing nuclear reactors, but at a much smaller scale in terms of size, cost, and construction time due to their modular characteristics."). Duke Energy witness Nolan expounded on this point by testifying that:

> SMRs use water for cooling, just like all the commercial operating nuclear plants in the U.S. today. Therefore, it is a well-known and proven technology, with a more readily available supply chain. SMRs have a less challenging licensing path because their design is based on existing large light-water designs.

Tr. vol. 17, 97. Witness Nolan also testifies that there are currently four new nuclear technology reactor designs that are scheduled to be built on five different sites. *Id*. at 98-99.

Duke Energy witness Nolan testifies that new nuclear technology also includes Advanced Reactors (ARs). ARs are cooled differently than SMRs, as these reactors use "use liquid metal (*e.g*., sodium), molten salts (*e.g*., chlorides, fluorides), or hightemperature gas (*e.g.*, helium) for cooling." *Id*. at 97. ARs also use a higher-enriched fuel, which is currently not enriched in the United States. *Id*. at 97. While the Companies believe that SMRs have a less challenging licensing path than ARs because the design for SMRs is based on existing large light-water designs, the Companies state that the early site permit (ESP) they intend to pursue will be neutral to either technology. *Id.* at 97, 100.

The Environmental Working Group (EWG) witness Makhijani testifies that new nuclear technologies are no different than the alleged "failed nuclear renaissance" of the early 2000s. Tr. vol. 24, 101. In response, Duke Energy witness Nolan testifies that:

> SMRs and ARs are distinctly different than the large light-water-cooled nuclear plants (i.e., Generation III/III+) that were planned to be built during the early 2000s. The next generation SMRs and ARs have significant advantages over their historical counterparts. The modular design of these new reactors allows for more off-site construction and decreases production and construction timelines. *Designs have become smaller, meaning units require less capital investment and are more flexible, allowing for greater ability to match power output to system loads. In addition, the new generation of nuclear plants have significant safety enhancements.* Inherent safety features, such as passive shut down and self-cooling through natural circulation, mean that the system can turn off and cool itself with no operator intervention. *This enhanced safety makes the plants less complicated (i.e., fewer systems needed), enabling easier construction and operation.* The ability to build these next generation advanced nuclear plants much quicker and with less financial risk, while providing always-on baseload power generation, will help enable the Companies transition to net-zero carbon emissions.

Tr. vol. 29, 106-07 (emphasis added). Duke Energy witness Nolan testifies that while none of the new nuclear reactor designs have been approved, this should not delay the Companies' pursuit of near-term development activities. *Id*. at 107. He testifies:

> The focus at this time is to pursue siting for an SMR by developing an Early Site Permit ("ESP"). Obtaining an ESP allows the NRC to review and approve the environmental impacts and site safety analysis associated with nuclear deployment at a particular site before a technology needs to be selected or a decision to build has been made. *This allows time for the reactor technologies to develop, providing Duke Energy more time to make a better-informed decision on the best technology, or technologies, to pursue*. An ESP is approved for up to 20 years and can be renewed. Simply put,

> the ESP has value that is retained for a long period of time which allows time for the technologies to mature.

Id. at 107 (emphasis added).

The Companies' modeling has demonstrated the need for nuclear generation for meeting the carbon reduction goals set forth in HB 951.[13] Tr. vol. 17, 176. The Tech Customers' "Preferred Portfolio" also demonstrates the need for SMRs for meeting the carbon reduction goals set forth in HB 951. Tr. vol. 25, 47 (adding SMRs in the 2041-45 timeframe). The Modeling and Near-Term Actions Panel testifies that SMRs were economically selected to be in-service in mid-2032 for Portfolios 1, 3, 4, 5, and 6A; Portfolio 2 economically selected SMRs to be in-service in 2033. Tr. vol. 7, 248-50; Carbon Plan, App'x E, 34. Duke Energy witness Repko testifies that the Companies' near-term actions focus on SMRs, and include:

> (1) [B]egin work on an ESP for a to-be-determined site for one of the reactors; (2) perform a due diligence review to identify a nuclear technology for the SMRs that will ultimately be constructed; and (3) choose a company that will construct the new nuclear technology the Companies ultimately decide to have constructed.

Tr. vol. 17, 81. Duke Energy witness Nolan testifies to the following regarding the Companies' proposed work on an ESP:

> Given the rapid pace of development for both SMRs and ARs, the Companies believe it is prudent to move forward with site selection and an ESP, which is technology neutral, and then select a technology, either SMR or AR, at the appropriate development timeline. An ESP application provides the Companies an opportunity to obtain NRC approval of one or more sites for a new nuclear power plant, independent of a specific nuclear plant design or an application to build. The ESP provides for NRC approval of the siting of one or more reactor technologies (i.e., bounded by the plant parameter envelope in the ESP) at a specific site for up to 20 years, with the option to renew for an additional 20 years. Such a sequence will ensure the Companies are positioned to select the best, most cost-effective technology selection. The ESP results in a final agency position available for referencing in subsequent applications for either a construction permit or a combined construction and operating license ("COL").

[13] Tr. vol. 17, 176 (Q: "Duke anticipates that new nuclear will be an indispensable part of any of its portfolios, doesn't it, Mr. Nolan? A. (Chris Nolan) That is correct.").

Tr. vol. 17, 100. In rebuttal, witness Nolan testifies that, "[s]imply put, the ESP has value that is retained for a long period of time which allows time for the technologies to mature." Tr. vol. 29, 107.

The Companies have estimated the costs of those near-term development activities, which are summarized below:

Activity Description	2022	2023	2024	Total
Begin new nuclear Early Site Permit (ESP) development • Administrative and Financial Information • Site Safety Analysis Report (SSAR) • Plant Parameter Envelope • Environmental Report • Limited Work Authorization • Emergency Planning • Departures and Exemption Requests	5,000,000	25,000,000	25,000,000	**55,000,000**
Begin development activities for the first of two SMR units • Siting Assessment & Selection • Technology Assessment & Selection • Develop COL Application	3,500,000	3,500,000	10,000,000	**17,000,000**
Total	**8,500,000**	**28,500,000**	**35,000,000**	**72,000,000**

Id. at 102.

Duke Energy witness Repko testifies that the Companies propose to limit the costs associated with the new nuclear near-term development actions to $75 million.[14] Duke Energy Sept. 9th Pre-Hearing Comments at 47; Tr. vol. 29, 105. Several Intervenors question the validity of the Companies' cost estimates. For example, AGO witness Burgess, NC Warn witness Powers, and CPSA witness Hagerty testify that they have concerns regarding the costs associated with, as they describe, an "unproven" technology. Tr. vol. 25, 301-02; Tr. vol. 22, 198-201; Tr. vol. 25, 419-23.

Public Staff witness Thomas testifies that he found the Companies' assumptions regarding "non-commercialized technologies" to be reasonable. Tr. vol. 21, 76, 81. Public Staff witness Thomas further supports that position by testifying that:

[14] *Supra*, note 13.

> Duke's assumption that new nuclear resources will be available in the future is not unreasonable. It is impossible to know for certain at this time when new nuclear will first become available, or at what price; but the Public Staff believes that SMRs or advanced non-light water reactors will be an available resource at some point in the future. … *The need for additional nuclear capacity to meet growing electricity demand while reducing carbon emissions has been identified by the Intergovernmental Panel on Climate Change*, and utilities across the country are planning to incorporate SMRs in their future generation portfolios, with 19 utilities planning to add a combined 90 GW of SMRs to the nation's grid by 2050. *The Public Staff finds the assumptions used by Duke in its Proposed Carbon Plan to be reasonable for planning purposes and expects that these assumptions will be updated with new information in future Carbon Plan filings.*

Id. at 76-77 (emphasis added, internal citations omitted). Public Staff witness Thomas reiterated this point during cross-examination by CCEBA. He testifies:

> In general, we found that the assumptions that Duke used, particularly SMRs, reflect, to a certain extent, reasonable assumptions about the -- because I could tell you're going towards SMRs – the reasonable assumptions about the commercial availability of that technology based upon information known today. Will that maybe be wrong? Yes. But we'll revisit this in 2024. We may have more information on status of the industry by then. The NRC may take some actions, we may see -- if we see further delays, then in 2024 we may need to adjust that first availability date. If we see more progress than expected, we may pull it in. But that's the iterative nature of this update process.

Tr. vol. 21, 238-39.

Testimony from Public Staff witness Thomas demonstrated that other utilities plan to use SMRs to meet their Carbon Reduction goals. Tr. vol. 22, 329-30; Duke Energy Public Staff Panel 1 Cross Examination Exhibit 3.[15] Duke Energy witness Nolan testifies that the Companies plan to deploy SMRs by mid-2032. Tr. vol. 18, 50, 54. This strategy will allow "for the transition to ARs after they have demonstrated performance." Tr. vol.

[15] Duke Energy Public Staff Panel 1 Cross Examination Exhibit 3 at 2 ("Based on the status of SMR development, the [Dominion Energy Virginia] anticipates SMRs could be a feasible supply-side resource as soon as the early 2030s. The Company has thus included SMRs as a supply-side option starting in December 2032 in all Alternative Plans. Starting in 2034, the Company assumed that one 285 MW SMR could be built per year. For some light-water SMR designs that utilize current nuclear fuel technologies with an available supply chain, the commercial availability may be even sooner.").

17, 106. In sum, witness Nolan testifies that the Companies believe that their strategy for deploying SMRs and ARs, through pursuit of the development activities including an ESP, will allow the Companies "to meet the objectives of HB 951 in meeting the 70% reduction early, while allowing for the benefits of ARs to contribute to achieving net-zero by 2050." *Id.* at 106.

Initial Development of Offshore Wind

Duke Energy witness Repko testifies that the Companies have requested that the Commission approve certain near-term development actions related to offshore wind. Tr. vol. 17, 81-82. Duke Energy witness Pompee testifies that while the Companies have yet to develop an offshore wind facility, the deployment of the technology has a 25-year global track record. *Id.* at 110. The Companies state that the offshore wind market is growing, as there are over 30 GW of projects with leases in place to achieve state carbon reduction and economic policy goals. *Id.* at 110. The Companies propose to develop the Carolina Long Bay (CLB) wind energy area (WEA), which is one of three siting opportunities in the Carolinas (which includes CLB and the Kitty Hawk WEAs). *Id.* at 111-12. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Witness Pompee also testifies that the CLB and Kitty Hawk WEAs could produce approximately 4,800 MW of offshore wind energy. *Id.* Witness Pompee states that offshore wind offers numerous benefits, such as "carbon emissions reduction, fuel cost savings, and increased renewable resource diversity in regions with high penetration of solar energy." *Id.* at 112. In addition, the relatively high-capacity factors and lower intermittency compares favorably with other low carbon resources, and the WEAs distance from shore provides an opportunity to create larger and taller wind towers, thus resulting in site outputs that are measured in gigawatts. *Id.* at 112-13.

Witness Pompee testifies that "[o]nce a lease has been executed, it takes approximately 8 – 10 years from leasing a WEA to commercial operation." Tr. vol. 17, 113.[16] "Such a timeline could put Carolina Long Bay in operation between 2030 and 2032, as represented in the Carolinas Carbon Plan." *Id.* at 123; *see also* Tr. vol. 18, 98 ("But in reality, you can get to a construction and operations plan in three years. That's why we say we believe Carolina's Long Bay could be in operation by the end of year 2030."). Witness Pompee pointed to the two critical steps in the development of a WEA include conducting a site assessment plan (SAP) and developing a construction and operations plan (COP) for filing at BOEM. Tr. vol. 17, 114-15. Witness Pompee testifies that

[16] Witnesses for Avangrid Renewables, LLC (Avangrid) and Public Staff witness Metz all testify that the development of a WEA typically takes up to ten years. Tr. vol. 17, 114; Tr. vol. 23, 176; Tr. vol. 21, 221.

development of a SAP should be completed within 12 months of acquiring a lease, subject to extension by BOEM, and can take 6-12 months for approval by BOEM; development of a COP can take as few as three years and no more than five years once the SAP is approved by BOEM. *Id.* at 118-19.

The Companies and Avangrid both support the need to develop offshore wind, as Mr. Pompee testifies that the Companies' modeling economically selected 800 MW of offshore wind energy in 2029 for both Portfolios 1 and 2. *Id*. at 123-24. Avangrid witness Starrett testifies "that at least 1.3 GW of offshore wind can … serve as a cornerstone to meeting the 70% reduction target required by HB 951 by 2030, with more offshore wind capacity available to follow thereafter." Tr. vol. 23, 165. But testimony from the Companies and Avangrid reveal differing views of the benefits of the various Carolinas WEAs. Avangrid purchased the lease for the Kitty Hawk WEA (*id*. at 177) and the Companies' unregulated affiliate, DERW, purchased the lease for one of the CLB WEAs. Tr. vol. 29, 95. Avangrid witness Starrett testifies that—using publicly available data—the Kitty Hawk WEA provides a superior net capacity factor of 46% versus the 36% NCF for the CLB WEA. Tr. vol. 23, 181-82. Duke Energy witness Pompee testifies that the Companies disagree with Avangrid's calculated NCF for the CLB WEA. As witness Pompee testifies, "[d]etermining the NCF of any lease area requires detailed site assessment planning and, at this time, the Companies do not believe that any party has performed the requisite analysis to definitively establish an NCF of 36% for the Carolina Long Bay WEA." Tr. vol. 29, 114. Witness Pompee concludes that the NCF for the CLB WEA owned by DERW is not known without further study, the kind that will occur if the development activities are pursued. *Id*. at 114.

Witness Pompee also testifies that the Kitty Hawk WEA would require longer undersea cable than Avangrid claims. Tr. vol. 29, 111-13. The shortest route for undersea cable for the Kitty Hawk WEA would have to traverse the Pamlico Sound, an environmentally sensitive area. *Id*. at 113. Crossing the Pamlico Sound "introduces significant uncertainty due to challenges that could be encountered from a permitting, timing, and cost perspective, and it is likely that BOEM will require an assessment of multiple alternatives to a cable route through Pamlico Sound to reduce potential impacts." *Id*. at 113. Witness Pompee testifies that the less challenging undersea cable route for the Kitty Hawk WEA would require roughly 100 miles of additional cabling.[17] Tr. vol. 18, 105 (transcript error; Pompee answering). This longer route would add approximately $350 million to the cost of developing the Kitty Hawk WEA which could offset the lower NCF from the CLB WEA owned by DERW. *Id.* at 105.

Testimony from Avangrid Witness Starrett revealed that the ability to advance development of the Kitty Hawk WEA for the benefit of the Companies' customers is uncertain. Tr. vol. 23, 211-12; 217, 219. First, Avangrid witness Starrett admitted that the current iteration of the COP for Kitty Hawk North WEA places its interconnection point at Virginia Beach, Virginia, and amending the COP to change that interconnection point to

[17] *See also* Tr. vol. 29, 111 ("The Companies disagree with Avangrid's analysis that the export route differential is only 25 km. Our analysis of transmission routing indicates an estimate of a longer cable by about 170 km.").

a point in North Carolina could add approximately 18 months to the site's development timeline. *Id*. Second, Avangrid Witness Starrett also admitted that while the COP for Kitty Hawk South WEA lists North Carolina counties as possible interconnection points, they could easily amend the COP to list Virginia counties as interconnection points through PJM. Tr. vol. 23, 216-17. Third, the permitting for Kitty Hawk South WEA is not as far along as Avangrid claims. *Compare id*. at 178; *with* Duke Energy Avangrid Direct Cross Examination Exhibits 1 and 2. Fourth, Public Staff witness Thomas testifies that development of the Kitty Hawk parcels is not as straightforward because "there is no guarantee that the more advanced Kitty Hawk offshore wind resource can be secured by Duke, as electric public utilities in Virginia also have stringent carbon reduction goals under the Virginia Clean Economy Act." Tr. vol. 21, 62. Finally, Avangrid witness Starrett insists that procurement of the resource through a Power Purchase Agreement (PPA) meets the utility ownership requirements of HB 951. Tr. vol. 23, 173. As was explained in detail in Duke Energy's Sept. 9th Pre-Hearing Comments at 23-36 and in its Post-Hearing Brief, the Companies do not believe that a PPA arrangement for offshore wind is consistent with HB 951.

Public Staff witness Metz testifies that the Public Staff does not agree with the Companies or Avangrid regarding the need to begin near-term development activities for offshore wind at this time. Tr. vol. 21, 221. This recommendation is based on SP5 and SP6 not selecting offshore wind until the 2040s. Witness Metz, therefore, recommends that the Companies re-evaluate the need for offshore wind in the 2024 Carbon Plan. *Id.* at 221-22. Public Staff witness Metz recommends that the Commission deny the Companies' request to begin near-term resource development activities for offshore wind. *Id*. at 221.

Duke Energy witness Repko testifies that if the Commission were to adopt the Public Staff's position, it "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. Duke Energy witness Repko further elaborates on this point:

> The Companies do not believe this is a prudent approach, as it is inconsistent with the "all of the above" strategy addressed at length in the Companies' Carbon Plan. As I stated in my direct testimony, the Companies believe that it is likely that offshore wind will be needed to meet the ambitious carbon reduction goals of HB 951, and, therefore, it is prudent and reasonable to engage in development activities in the near-term to pursue initial development and permitting requirements and refine cost estimates. Avangrid . . . and the AGO are aligned with the direction that the Companies should pursue development activities to further offshore wind and retain the ability to meet the 70% Interim Target.

Id. at 96-97. Witness Repko concludes that offshore wind—like Bad Creek II and SMRs—is needed to create and retain options through "no regrets" options to ensure that it is available on a timeline necessary to achieve the 70% Interim Target. *Id*. at 98. Witness Repko's point is bolstered by the Companies' Modeling and Near-Term Actions Panel testimony. There, Company witness Snider testifies that he recognized Public Staff Witness Metz's observation that offshore wind in SP5 is not economically selected until the 2040s. Tr. vol. 27, 38-39. But the Panel counters that "the supplemental portfolios could support the acceleration of offshore wind to provide resource diversity and mitigate technology cost and timing risk while increasing executability of the portfolio." *Id*. at 97. Expanding on this point, the panel states:

> Offshore wind continues to increase overall executability of achieving interim reduction targets, as pointed out by the Public Staff in their initial comments due to the inclusion of diverse portfolio of resources utilized to achieve the interim emission reductions target. Contrary to the witness Metz' position on behalf of the Public Staff, the Companies believe initial development activities associated with offshore wind present a prudent approach to investigating the necessary step to develop a least cost energy transition and achieving the HB 951 emissions reductions targets. *Without progressing early development activities for offshore wind in the near-term, meeting the interim emissions reduction targets by 2030 would be exceedingly challenging and further jeopardizes ensuring timely achievement of the interim emissions reduction targets.*

Id. at 97-98 (emphasis added). Witness Pompee testifies he did not know what development work would occur over the next two years if the Companies did not acquire the lease from DERW. Tr. vol. 18, 114-15. To that point, Mr. Pompee testifies to the following:

> If we wait two years to come back, and in 2024 the decision is that we need to get offshore wind by 2030, we will have lost two years, and then that opportunity is gone. If we decide we want offshore wind by 2032 in some of the portfolios, then we would have lost two years and would have to incur additional risk to try to do a ten-year project in eight years because we had not been expeditious with the prior two years.

Tr. vol. 18, 110. Further elaborating on this point, witness Pompee testifies:

> So Duke Energy Renewables Wind, in this hypothetical situation, is five years to submit a COP. I agree. One year SAP is pretty straight. Up to five years to submit a COP. *What we were saying was that, if the Commission would like to have the option for offshore wind in the 2030s, in the early 2030s, that there is no obligation for Duke Energy Renewables Wind*

> *to accelerate the timeline and get a COP in three years, right*? The requirement is five….and you can do five. And you can have your progress reports and be within the law and still get five years to do a COP.
>
> Now, aside from that, we've seen Dominion, for example, they got their lease in 2013, didn't file a COP until 2020. They worked with BOEM based on their particular situation to get an extension. Now, I don't know what Duke Energy Renewables Wind is doing, *but the five years to get a COP would put us, I believe, behind where we would need to be if we want to get offshore wind in the 2030s*.

Tr. vol. 29, 133-34 (emphasis added).

At the hearing, Duke Energy witness Repko testified to the following regarding the need for a regulated entity to develop offshore wind:

> Q. Wouldn't it be less risky to shift to Duke Wind -- or some other third party, sorry, not just Duke Wind -- these offshore wind development projects? Less risky for the ratepayers?
>
> A. Again, you know, our view is that to maintain offshore wind is [sic] *an option on a time frame of discretion of the Commission* that they commence now.

Tr. vol. 18, 82 (emphasis added). Witness Repko then added that "the value of offshore wind earlier for the regulated utilities is for earliest possibility to be selected by the Commission as a resource, and then again as an option for risk management," *id*. at 84-85, and that "the solution that we have is for the lease to go to a regulated -- to the regulated Companies." Tr. vol 29, 134.

Duke Energy witness Repko testifies that the Companies proposed near-term development actions for offshore wind include: (1) securing a lease for the CLB WEA from its affiliate, DERW; (2) initiating permitting activities, which will include developing and submitting a SAP, developing a COP, and initiating an interconnection study process; and (3) obtaining approval of a SAP from the Bureau of Ocean Energy Management (BOEM). Tr. vol. 17, 81-82. The following chart represents the estimated cost of the proposed near-term development activities:

Activity Description	2022	2023	2024	Total
Lease	$155,000,000	$200,000	$200,000	**$155,400,000**
Development Expenses	$2,000,000	$20,000,000	$40,000,000	**$62,000,000**
Transmission from landing site to point of injection	$5,000,000	$10,000,000	$85,000,000	**$100,000,000**
Construction	$0	$0	$0	**$0**
Total:	$162,000,000	$30,200,000	$125,200,000	**$317,400,000**

Id. at 119.

The Companies again propose to limit expenditures for these near-term development activities. In this case, the Companies propose a cap of $325 million. Tr. vol. 29, 105.[18]

While Public Staff is generally opposed to the Companies' proposed near-term development activities for offshore wind, Avangrid specifically objects to the Companies' development of the CLB WEA. In addition to its abovementioned analysis regarding the NCF for the WEA, Avangrid argues that it fails to see how securing a lease from DERW "adds value for or protects ratepayers." Tr. vol. 23, 171.

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

The Companies cite the following four primary benefits for proceeding with near-term development activities by procuring the CLB lease: First, the Companies—unlike an unregulated developer—must procure the lease at the lower of cost or market price, which ensures that it would acquire the lease for $155 million. Tr. vol. 29, 103. Second, acquiring the CLB lease provides certainty of timing because the Companies know that DERW will sell the lease and the transfer will only be subject to a straightforward affiliate agreement application before the Commission. *Id.* Third, the Companies' proposed path clearly meets HB 951's ownership requirements. And fourth, the proposed path does not foreclose other options, rather it ensures that the Companies will have at least one offshore wind project available for consideration in the 2024 Carbon Plan update. *Id.*

Avangrid's Request for an Independent Third-Party Study

Avangrid witness Gallagher testifies that Avangrid recommends that the Commission procure an independent third-party to calculate the levelized cost of energy (LCOE), present value rate of return (PVRR) or similar metrics, technical and permitting viability, schedule, size, and overall plan, along with any other Commission-determined metrics. Tr. vol. 23, 183. She testifies that such a study should "solicit information from developers in a manner that ensures confidentiality and accountability." *Id.* She also states that Avangrid would participate in such a study. *Id.* at 191.

Duke Energy witness Repko testifies that it is unnecessary to hire an independent third-party consultant to run a third-party study. Tr. vol. 29, 101. Witness Pompee testifies that the Companies proposed development activities will include detailed analyses of the CLB WEA. *Id*. at 114. Witness Repko also testifies that the Companies solution is to procure a lease that would be held by a *regulated* entity, thus ensuring that a WEA would be developed with full transparency, oversight, and progress relative to the requested development activities and timelines. *Id*. at 134. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Point of Interconnection and Need to Commence Work on Transmission Infrastructure to Advance Offshore Wind

Appendix P (Transmission Planning and Grid Transformation) addresses the transmission required to support offshore wind as contemplated in the Carbon Plan portfolios. Appendix P states that completing this required transmission will be challenging from a timing and scheduling standpoint as new right-of-way and major construction will be required. It continues that the transmission needed to interconnect offshore wind to the DEP system was recently evaluated through a 2020 NCTPC planning study, which the Companies used along with their own analysis to inform their strategy around installing offshore wind under the Carbon Plan. In addition, based on that study and Duke Energy's own analysis, the Companies determined that the New Bern 230 kV Substation would be the most appropriate point of interconnection (POI) for both the Kitty Hawk and Carolina Long Bay parcels due to having higher MW capability at relatively lower cost. Carbon Plan, App'x P, 16-17.

Appendix P also presents the results of additional internal analysis of the full transmission cost of injecting offshore wind into a New Bern POI. The estimates, which reflect the cost of radial transmission interconnection facilities to the New Bern POI and network upgrades from New Bern to the Wake 500 kV substation, are $1.3 billion to $2.39 billion for injection of 800 MW to 1.6 GW, respectively. It notes that screening studies indicate that 800 MW can be injected at New Bern without adding major new network lines, but with some significant upgrades to the existing system in the area. To inject 1,600 MW or more at New Bern, it is likely that new 500 kV network lines would need to be constructed. The Companies explain that the schedule associated with siting, permitting, and constructing this transmission will depend on public engagement, routing, scoping, and acquisition of new right-of-way, and that delays in these dependencies are key risks in meeting any timeline for offshore wind energy imports. In addition, such interconnection will require the submission of a generator interconnection request and study in the annual DISIS Cluster Study process. Carbon Plan, App'x P, 17-18.

Duke Energy Transmission and Solar Procurement Panel witness Roberts discusses the results of the NCTPC and Duke Energy studies in greater detail. Witness Roberts notes that for an official specification of the requirements for interconnection facilities and identified transmission network upgrades for reliably injecting a given level of offshore wind energy into the DEP system in accordance with the FERC approved process in the OATT, official generator interconnection studies must be conducted. He considers the 2020 NCTPC Offshore Wind Study results to nonetheless be informative with respect to identifying a reliable, cost-effective point of interconnection for injecting offshore wind energy into the DEP transmission system. Tr. vol. 16, 99-101.

Witness Roberts explains the basis for the Companies' identification of New Bern Substation as the preferred point of interconnection to inject offshore wind into the DEP transmission system. He states that the 2020 NCTPC Offshore Wind Study screened 32 potential injection sites and that based on the injection capability and cost results of that screening analysis, further analyzed the feasibility and costs of injecting up to 5,000 MW of offshore wind power at up to the three most promising sites based on those criteria in eastern DEP: New Bern 230 kV Substation; Greenville 230 kV Substation (selected for high initial MW screening levels, though with higher cost per watt); and Sutton North 230 kV switching station (relatively low cost per watt but only up to 2,500 MW). The analysis evaluated the MW breakpoints at which transmission upgrades would be needed. He reports that as reflected in the 2020 NCTPC Offshore Wind Study Report, New Bern 230 kV Substation is the most feasible and economic POI for injecting 800 MW to 1,600 MW of offshore wind, with capability to inject even more. He notes that, as shown by the 2020 NCTPC Offshore Wind Study Report, the Greenville substation would only be able to accommodate an 1,106 MW injection at a cost of $0.38/W, and that the Havelock substation could only accommodate an 859 MW injection, although at a lower cost of $0.02/W. The New Bern POI was more cost effective, able to accommodate 1,449 MW at $0.12/W and 3,252 MW at $0.36/W. Witness Roberts adds that in addition to the NCTPC study, Duke Energy performed a cost analysis to determine the most cost-effective transmission path including the POI for importing up to 1,600 MW of offshore wind into the DEP system. This cost analysis, which included both offshore and onshore transmission costs (network transmission and interconnection facilities), revealed that the New Bern POI was approximately $700 million less compared with other potential POIs. He notes that the New Bern POI also allows the Companies to utilize existing right-of-way for the network transmission and will reduce risk and cost for an offshore wind project. Additionally, New Bern 230 kV substation benefits from already having five 230 kV lines, two of which head in the direction of the DEP Raleigh load center. Tr. vol. 16, 101-103; Carbon Plan, App'x P, 17.

Avangrid's comments and testimony suggest the Greenville and Havelock substations as potential POIs and claim that 1.3 GW of offshore wind can be delivered without the 500 kV grid expansion considered in the Carbon Plan. Avangrid July 15th Initial Comments at 13; Tr. vol. 23, 170.

In response, witness Roberts testifies that upon being studied in an annual official DISIS Cluster Study, the Greenville and Havelock potential POIs would most likely be shown to require extensive network upgrades to transfer offshore wind reliably into the DEP system. Additionally, extensive upgrades would most likely be required to transfer offshore wind energy to the corridor for a new 500 kV line needed in order to inject 1,600 MW of offshore wind reliably into the DEP system to transfer to load centers. This is particularly true given the approximate 2,600 MW of generation located nearby at DEP's Brunswick Nuclear Station and Sutton Plant and nearby solar facilities. He notes that the Havelock substation has three 230 kV lines connecting it to the system with one 230 kV line essentially going to a peninsula (Morehead City), and the Greenville substation has three 230 kV lines connecting it to the DEP system and one 230 kV line connecting to PJM's system. The New Bern substation has five 230 kV lines connecting it to the system and is thus much more reliable for injecting appreciable offshore wind. He also notes that a submerged cable connecting an offshore wind resource to a Greenville 230 POI would need to traverse the shallow, environmentally sensitive Albemarle Sound, and that Greenville is notorious for Tar River flooding with past hurricane events. Tr. vol. 16, 103-04; Tr. vol. 28, 138-140. With regard to the need for a 500 kV expansion, he clarifies that based on preliminary transmission planning screening analysis and as addressed in Appendix P, Duke Energy assumes in the Carbon Plan that an 800 MW offshore wind resource does not include any 500 kV expansion. However, at 1,600 MW and above, the Companies' modeling assumes a 500 kV expansion is needed to reliably transfer offshore wind energy into the DEP system. Tr. vol. 28, 138; Carbon Plan, App'x P, 18.

Cost Recovery Request

In their Sept. 9th Pre-Hearing Comments, the Companies state that the Verified Petition for Approval of Carbon Plan (Petition) requested that the Commission make a number of determinations to provide Duke Energy reasonable assurance that reasonable and prudently incurred project development costs associated with the Long Lead-Time Resources identified in Table 3 of the Carbon Plan Executive Summary, if approved by the Commission, would be recoverable. Specifically, the Companies asked the Commission to determine that:

(i) Engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;

(ii) To the extent not already authorized under applicable accounting rules, that the Companies are authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies then authorized, net-of-tax, weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and

(iii) That in the event the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 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.[19]

[19] Petition at 89.

Duke Energy Sept. 9th Pre-Hearing Comments at 36-37.

The Companies Pre-Hearing Comments assert that they are not in this proceeding seeking authorization to defer initial development costs in a regulatory asset account under the Commission's two-pronged test because the proposed costs generally qualify for balance sheet accounting under "FERC Account 183, Preliminary Survey and Investigation Charges." *Id*. at 38; *see also* 18 C.F.R. § 367.1830. Rather, the Companies argue that they are seeking assurances from the Commission that: (1) engaging in initial project development activities, in advance of receiving any required CPCN, for these significant long lead-time resources is a reasonable and prudent step in executing the Carbon Plan to enable potential future selection of Bad Creek II, new nuclear and offshore wind on the timeline required to meet HB 951 goals; (2) to the extent the Commission later finds the individual costs incurred to be reasonable and prudent, they will be recoverable in rates; and (3) that such reasonable opportunity for recovery will be available to the Companies should the resource not ultimately be selected by the Commission and development activities abandoned in the future. *Id*. at 38. The Companies assert that the Commission's grant of this request is within its authority and consistent with its past practice and is "reasonable and necessary to ensure that the Companies can prudently invest in the initial development activities necessary to ensure these significant longer lead-time zero-carbon emitting resources are available on the timelines contemplated in the proposed Carbon Plan portfolios." *Id*.

The Public Staff and several Intervenors object to the Companies' request, and argue that (1) it would be inappropriate for the Commission to make any determination at this time regarding the reasonableness or prudence of the costs associated with project development activities or otherwise pre-determine that such costs shall be recoverable in rates;[20] and (2) it is premature for the Commission to authorize deferral accounting for costs incurred to develop long lead-time resources as the Companies have not shown that such costs meet the Commission's two-pronged test for authorizing deferral of extraordinary costs outside of a rate case.[21]

[20] Public Staff July 15th Initial Comments at 155-59 ("The Public Staff does not recommend that the Commission approve [project development] actions for ratemaking or other purposes prior to the time that the same or similar actions would normally be approved under existing statutory authority or Commission practices."); NCSEA, *et al.* July 15th Initial Comments at 20-21, 35 ("The Commission need not . . . approve of any costs related to project development activities in order to develop a Carbon Plan[.]"); Tech Customers July 15th Initial Comments at 2, 15-18 ("There is no statutory basis for the preordained recovery of these costs."); CIGFUR July 15th Initial Comments at 35 ("Any determination at this time regarding whether DEC and/or DEP acted reasonably and prudently in developing, constructing, and placing into service new electric generating facilities at some future date would be premature."); Walmart July 15th Initial Comments at 5-10 ("Allowing cost recovery of costs for projects that may never go into service is contrary to typical FERC accounting rules; CUCA July 15th Initial Comments at 5-6 ("N.C. Gen. Stat. § 62-110.7 addresses special accounting treatment/recovery for nuclear-generation projects only, not for offshore wind and pumped-storage development costs; nor does the statute allow for a return on costs for cancelled projects.").

[21] Public Staff July 15th Initial Comments at 155-159 ("It is premature at this time to authorize any deferrals related to the Carbon Plan."); Tech Customers July 15th Initial Comments at 2, 15-18 (arguing that Duke

Duke Energy witness Repko testifies that these initial efforts are beneficial because they "preserve the potential to be able to use one or more of these resources to meet the 70% interim carbon emissions reduction target . . . of the Carbon Plan." Tr. vol. 29, 93. Moreover, the initial development work for the long lead-time resources will be "no regrets" actions because they retain value for future use. *Id*. at 93, 98. Witness Repko testifies that the Companies believe it is reasonable to cap the amount of money that the Companies may spend for the proposed near term development activities through 2024. *Id*. at 104; *see also* Tr. vol. 18, 23 ("The Company supports caps for all the three resources for long lead items."). The Companies propose the following caps:

Long Lead-Time Resource	Proposed Development Cost Cap (2022-2024)
Offshore Wind	$325 million[10]
Nuclear	$75 million[11]
Bad Creek II	$40 million

Tr. vol. 29, 105. Witness Repko testifies that the Companies must obtain Commission approval for any spending beyond the proposed cap, and that they are committed to providing the Commission with biannual updates that includes a summary of all major development activities—including costs incurred—and milestones. *Id*. at 104-05.

Discussion and Conclusions

The Commission finds that it is reasonable and prudent for the Companies to pursue near-term development activities for the three long lead-time resources because they are reasonable and prudent activities that retain value and all three resources will likely be needed for HB 951 compliance either for the 70% Interim Target or 2050 compliance. The Commission intends to further consider in future Carbon Plan proceedings whether any of the three Long Lead-Time Resources should be selected based, in part, on the more refined cost estimates to be prepared through these development activities. But without these near-term actions, it is unlikely that any of the three resources will be available on a timeline that would enable consideration of deployment to meet the interim target. The following sections provide specific discussion and conclusions for each resource, Avangrid's request for creating a third-party comparison process, and cost recovery for each resource.

Bad Creek II

The expansion of the Bad Creek I facility will be an integral resource for generating carbon-free energy and ensuring that the Companies remain on schedule to retire certain generation sources. Thus, the Companies have requested that the Commission approve

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Energy could not show that costs are "extraordinary," unanticipated, or unplanned because the Companies had already voluntarily adopted its own carbon-reduction goals."); NCSEA, *et al.* July 15th Comments at 21, 35; CIGFUR July 15th Initial Comments at 22-24, 27; CUCA July 15th Initial Comments at 5-6.

the decision to incur costs related to certain near-term development activities for the proposed Bad Creek II facility. The Commission recognizes that the parties appear to agree that constructing Bad Creek II is necessary to meet the carbon reduction goals set forth in HB 951 and is consistent with prudent utility planning.

The Commission agrees with Public Staff and the Companies that it is reasonable and prudent for Duke Energy Carolinas to engage in near-term (through EOY 2024) development activities for Bad Creek II. The Commission recognizes the importance of this resource for meeting the goals set forth in HB 951 and, thus, directs the Companies to continue the ILP process with FERC. In doing so, the Companies should ensure that the in-process feasibility study is completed and that they develop an EPC strategy that provides the Companies with an opportunity to meet the projected 2033 in-service date. The Commission finds that proceeding in this manner—when combined with the Companies' extensive experience in developing and operating pumped storage hydro facilities—alleviates the Public Staff's concern that it is unrealistic to place Bad Creek II in-service by 2033.

SMRs

The Companies testified that SMRs are an integral generation source for meeting the carbon reduction goals required by HB 951. Thus, the Companies have requested that the Commission approve the decision to incur costs related to the near-term development of SMRs, including specifically through the pursuit of an ESP for a single site. The Companies state that these costs would be incurred through 2024. The Commission recognizes that the position of several Intervenors on SMRs—and new nuclear technology generally—differs from that of the Companies and the Public Staff. Nevertheless, the Commission finds that it is reasonable and prudent for the Companies to pursue the aforementioned development activities as doing so will ensure that SMRs remain an available resource option for the Companies' customers. SMRs are identified as being needed in all of the Companies' modeling analysis, with the exact first date of need shifting slightly between each of the portfolios. Modeling and analysis supported by the Public Staff and other parties validates the need for SMRs. Duke Energy has a long track record of exemplary nuclear operations, and nuclear generation has long been a stable and low-priced source of carbon priced energy in the state. Nuclear is also unique in that it is the only currently viable carbon free 24/7 generation source. Finally, the Commission also takes note of the fact that the General Assembly expressly identified nuclear generation as a possible tool for the Carbon Plan, including for meeting the interim target, and this development work will preserve that potential.

To ensure that SMRs remain a resource option in a future Carbon Plan proceeding, the Companies have requested that the Commission approve the decision to begin work on an ESP, perform a due diligence review to identify a nuclear design technology for its SMRs, and determine whether DEC or DEP will construct the Companies' new nuclear technologies. The Commission agrees with the Companies and the Public Staff that such near-term development activities are necessary and finds that it is reasonable and prudent for the Companies to pursue the aforementioned near-term development activities.

The Commission takes seriously the implications of any future decision to select nuclear generation as part of the Carbon Plan and authorize construction and will be closely monitoring developments across the country (including regulatory developments at the NRC) and throughout the world regarding the deployment of new nuclear, including SMRs. The Commission expects that Duke Energy will stay closely informed regarding all such developments, as well as seek to avail itself of any available federal funding or support opportunities that may become available in the coming years (with Commission approval where necessary).

Offshore Wind

The Companies testified that they must begin near-term development activities for offshore wind because doing so is a necessary step to meeting HB 951's carbon-reduction goals. Offshore wind is identified in the short-term to achieve the 70% Interim Target in three out of the six initial and supplemental portfolios and in the long-term in five out of six portfolios. Therefore, the Companies' proposed offshore wind development activities are prudent and reasonable and a no-regrets strategy. The Public Staff offers several reasons why the near-term development activities should be delayed until 2024.[22] Similarly, Avangrid presents an analysis why the Companies should consider the Kitty Hawk WEA. But the Commission is not persuaded by either position. Thus, the Commission finds that it is reasonable and prudent for DEP to engage in the proposed near-term (through 2024) development activities for offshore wind. The Commission therefore authorizes DEP to acquire DERW's lease for the CLB WEA, with such transfer occurring after compliance with the requirements in N.C.G.S. § 62-153. The Commission also directs DEP to develop, submit, and obtain approval of a SAP from BOEM; begin development of a COP; and initiate an interconnection study process. With regard to the transmission planning and interconnection study process, the Commission also finds that the New Bern Substation is the most reasonable POI in terms of cost-effectiveness and feasibility, and that the Companies should commence initial development work on the tie-line from landing to New Bern POI (the cost of which was identified in the Companies' estimate of the initial development work for OSW).

The Commission's conclusion in this respect is also informed by HB 951's ownership requirements and the Commission's related conclusions related to Findings of Fact Nos. 55-59. Because HB 951 contains an unambiguous requirement that "[a]ny new generation facilities . . . selected by the Commission" as part of the Carbon Plan must be

[22] During live testimony, the Public Staff asked Duke Energy witnesses Repko and Pompee several questions about the BOEM's ability to cancel a WEA lease for an untimely filing of either a SAP or COP. *See, e.g.*, Tr. vol. 29, 133-34. The Commission finds that the responses from witnesses Repko and Pompee are consistent with BOEM's regulations that extensions can be granted by BOEM in lieu of lease cancellation. *See* 30 C.F.R. § 585.415 *et seq.*; *see also* 30 C.F.R. § 585.416(c) ("If you do not timely submit a SAP, COP, or GAP, as required, you may request a suspension to extend the preliminary or site assessment term of your lease or grant that includes a revised schedule for submission of a SAP, COP, or GAP, as appropriate.").

"owned and recovered on a cost of service basis by the applicable electric public utility" with the exception of solar, the Commission finds the Companies' plan for offshore wind in the near-term to be the most prudent and reasonable path consistent with the law.

In so ordering, the Commission also takes note of the fact that the General Assembly expressly identified wind generation as a possible tool for the Carbon Plan, including for meeting the interim target, and this initial development work will preserve that potential. The Commission takes seriously the implications of any future decision to select offshore wind generation as part of the Carbon Plan and authorize construction and will be closely monitoring developments across the country (but particularly on the east coast) and throughout the world regarding the deployment of new offshore wind. The Commission expects that Duke Energy will stay closely informed regarding all such developments, as well as seek to avail itself of any available federal funding or support opportunities that may become available in the coming years (with Commission approval where necessary).

Avangrid's Request for an Independent Third-Party Study

Avangrid witness Gallagher recommends that the Commission procure an independent third-party to analyze the offshore WEAs. The Companies counter that such a study is unnecessary.

The Commission rejects Avangrid's request to initiate a third-party WEA comparison process based on the information provided publicly as well as in confidential session because it is unlikely to yield a better WEA for DEP to pursue to develop offshore wind, at this time, and introduces uncertainty regarding whether and on what timeline any WEA will be available to meet the 70% Interim Target. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

As the Public Staff noted, there is no guarantee that the Avangrid lease would be available to serve North Carolina because Avangrid is not regulated by Commission, it is not required that it interconnect into DEP's service territory and could easily seek an offtaker in Virginia, and Avangrid seeks a PPA arrangement that does not comply with HB 951. The Commission does not believe it would be prudent to spend the next several years studying offshore wind alternatives because it will delay any offshore wind project and would be unlikely to lead to a lower cost resource than the CLB lease held by DERW. Lastly, the Companies recommended path of acquiring the CLB lease from DERW ensures that development of the WEA will be pursued with full transparency and Commission oversight at a lease price that can be secured at cost that is in line with the market price.

Cost Recovery

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

That the Commission has the authority to grant this requested relief is made clear by the Commission's March 20, 2007, decision in the Lee Nuclear proceeding in Docket No. E-7, Sub 819, which decision was issued prior to the enactment of N.C.G.S. § 62-110.7. While the General Assembly specifically codified this authority as it relates to nuclear facilities, such statute did not limit the Commission's pre-existing authority to grant the requested relief.

Cost Recovery for SMRs:

With respect to SMRs, N.C.G.S. § 62-110.7 provides a clear mechanism for approval and recovery of new nuclear project development costs. Under the statute, a utility may make a request pursuant to N.C.G.S. 62-110.7 "*at any time* prior to the filing of an application for a certificate to construct a potential nuclear electric generating facility[.]" *See* N.C.G.S. § 62-110.7(b) (emphasis added). The Companies' plan for developing new nuclear is set out in detail both in the Carbon Plan's Execution Plan, Appendix L (Nuclear) and the Companies' direct and rebuttal testimonies. In fact, the level of detailed support presented in the Companies' Carbon Plan and testimony regarding its planned new nuclear development activities exceeds that which the Commission found appropriate for granting relief in its Order issuing Declaratory Ruling in the Lee Nuclear proceeding.[23] *Compare* Carbon Plan Execution Plan, Appendix L (Nuclear); *with* Lee Application.

The Commission finds that the Companies' testimony combined with the level of detail contained in the Carbon Plan, match the level of specificity required under N.C.G.S § 110.7. Thus, the Commission finds that N.C.G.S. § 62-110.7 provides clear authority to grant approval of and cost recovery assurances for new nuclear project development costs, and the Commission finds that it is reasonable and prudent to approve the decision to incur the costs and to allow the Companies to recover those costs. The Commission does not believe that it is necessary, nor consistent with administrative efficiency, to require a separate proceeding to consider these issues. The Commission has before it

[23] In the Matter of Application of Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment, Order issuing Declaratory Ruling, Docket No. E-7, Sub 819 (Mar. 20, 2007) (Declaratory Ruling Order); *id*. at Application for Authority to Recover Nuclear Generation Development Expenses, Docket No. E-7, Sub 819 (filed Sept. 20, 2006) (Lee Application).

all of the information necessary to grant the requested relief and N.C.G.S. § 62-110.7 does not mandate that the utility's "request" be filed in a separate docket.

The Commission agrees with the Companies regarding their proposed cap on development costs and finds that it is reasonable and prudent for the Companies to expend up to $75 million to complete the near-term development activities. The Commission also finds that the Companies' near-term development work related to SMRs is in furtherance of executing the Carbon Plan and that the Companies may seek recovery of the proposed near-term development costs in a future rate case if they later seek to abandon the development of new nuclear technologies. The Commission also adopts the Companies' proposed biennial reporting requirements.

Cost Recovery for Bad Creek II and Offshore Wind:

As discussed above, the Commission has previously determined that it has the authority to grant the requested relief. Specifically, in the Lee Nuclear proceeding, the Commission preapproved development costs prior to the enactment of N.C.G.S. § 62-110.7. Put differently, the Commission affirmatively found that it had legal authority to grant the requested assurances of future recovery of pre-CPCN development costs before the enactment of N.C.G.S. § 62-110.7. The Commission continues to believe it has the authority for Bad Creek II and offshore wind even though N.C.G.S. § 62-110.7 was ultimately enacted for nuclear development costs.

The Commission's Declaratory Ruling Order considered the public policy implications related to Duke Energy's requested assurances. The Commission held that the identified pre-CPCN development work was "generally consistent with the promotion of adequate, reliable, and economical utility service to the citizens of North Carolina and the policies expressed in G.S. 62-2" and that it is "in the public interest for the Commission to issue a declaratory ruling which gives Duke a general assurance that its activities in assessing the development of the proposed Lee Nuclear Station . . . are appropriate activities." Declaratory Ruling Order at 22. Expounding on that concept, the Commission more specifically held that "it is in the public interest for all potential resource options . . . to be adequately considered to ensure that the most economical resources are *available to meet customers' needs* on a timely basis." *Id*. (emphasis added).

The Commission recognizes that certain intervenors object to the Companies' request on legal grounds. The Commission does not find their objections persuasive. The Commission finds that enactment of N.C.G.S. § 62-110.7 does not constrict the Commission's general regulatory authority. Rather, the statute serves as needed policy direction given industry dynamics that existed at the time of enactment. The Commission also finds that the General Assembly's decision to not to use HB 951 to enlarge the scope of N.C.G.S. § 62-110.7 does not change the fact that the Commission previously assumed the ability to grant the Companies' requested relief without an express statute.[24]

The Commission applies its rationale from the Declaratory Ruling Order to the Companies' request as it relates to Bad Creek II and offshore wind. The Commission recognizes that the Companies—like Duke Power more than a decade ago—are seeking general assurances for the preconstruction development costs of Bad Creek II and offshore wind, both of which are significant long lead-time carbon-free resources. This request also includes a request for the Commission to find that the Companies reasonably and prudently incurred costs in furtherance of executing the Carbon Plan and, thus, can be recovered if development is abandoned. By applying its rationale from the Declaratory Ruling Order, the Commission finds that it is reasonable to provide the Companies with "general assurances" that the development activities are "appropriate activities," and it is in the "public interest" for the development of Bad Creek II and offshore wind "to be adequately considered to ensure that the most economical resources are available to meet customers' needs on a timely basis."

HB 951 also provides the Commission with additional authority to grant the relief requested. Through the text of HB 951, the General Assembly directed the Commission to take "all reasonable steps" to achieve the least cost path towards carbon neutrality by the year 2050. A straightforward reading of this mandate counsels in favor of pursuing multiple pathways to potentially meet those new legislatively mandated planning goals, including the pursuit of development activities for Bad Creek II and offshore wind.[25] The Commission finds that the pursuit of the development of these resources is especially important at this early stage of Carbon Plan implementation, as doing so will ensure that those resources remain available for customers on the timeline needed to meet HB 951's carbon reduction targets. Assurances regarding cost recovery—whether or not the resource is ultimately determined to be needed and selected by the Commission as part of the least cost path—is critical to ensure the Companies can pursue the needed development steps. Simply put, the Commission has clear legal authority to grant the Companies' requested relief and grant assurances regarding the potential for recovery of

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

[25] The Commission recognizes that DEBS pursuit of pre-CLB lease auction negotiations with Avangrid demonstrates the Companies' commitment to investigating multiple pathways to developing offshore wind. The Commission also recognizes that if those negotiations would have been successful, the structure of the proposed agreement—*i.e.*, the year option period—would have provided the Companies with the opportunity to understand the Commission's direction in this docket on offshore wind before committing to purchasing Avangrid's lease.

pre-CPCN expenses to ensure the Companies' customers retain access to the long lead-time resources identified in the Execution Plan.

Accordingly, the Commission finds that it is reasonable to provide the Companies with general assurances that the proposed development activities for Bad Creek II and offshore wind are appropriate activities, regardless of whether the resource is ultimately completed. The Commission also finds that it is in the public interest for Bad Creek II and offshore wind to be adequately considered to ensure that the most economical resources are available to meet customers' need on a timely basis. *See* general policy statements in N.C.G.S. § 62-2.

The Commission agrees with the Companies that $40 million is a reasonable cap for the expenses that will be incurred to complete the near-term development activities associated with Bad Creek II. Thus, the Commission directs the Companies to expend no more than $40 million to complete the near-term development activities associated with the proposed Bad Creek II facility. The Commission also finds that the Companies may seek recovery of project development costs in a future rate case if they later seek to abandon the development of Bad Creek II. The Commission also adopts the Companies' proposed biennial reporting requirements.

The Commission agrees with the Companies that $325 million is a reasonable cap for the expenses that will be incurred to complete the near-term development activities associated with the development of offshore wind as a generating source. Thus, the Commission orders that DEP shall expend no more than $325 million to complete the proposed near-term development activities for offshore wind. The Commission also finds that the Companies may seek recovery of the proposed near-term development costs in a future rate case if they later seek to abandon the development of the proposed offshore wind project. The Commission also adopts the Companies' proposed biennial reporting requirements.

<u>NEAR-TERM ACTIONS FOR EXISTING SUPPLY-SIDE RESOURCES (Findings of Fact Nos. 41-43)</u>

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41-43

The evidence supporting these findings of fact is found in Duke Energy's Verified Petition; the Companies' proposed Carbon Plan; the testimonies of the Duke Energy Modeling and Near-Term Actions Panel, Long Lead-Time Resources Panel, and Reliability Panel; the Public Staff July 15th Initial Comments; testimony of Public Staff witness Dustin Metz, CIGFUR witness Muller, and AGO witness Burgess; and the entire record in this proceeding.

Summary of the Evidence

Duke Energy Comments and Testimony

Duke Energy's Petition requests that the Commission approve the Companies' proposed actions with respect to existing supply-side resources, including through expanding flexibility of the existing gas fleet and continued disciplined pursuit of subsequent license renewal (SLR) for the Companies' existing nuclear fleet. Petition, at 10-11, 16.

The Modeling and Near-Term Actions Panel testifies that achieving increased flexibility of the existing gas fleet and pursuing SLRs are critical to successfully achieving the carbon emissions reductions targets established by HB 951. Tr. vol. 7, 325-26. Appendix Q to Duke Energy's Carbon Plan explains that in coordination with energy storage, operating the CC fleet in a more flexible manner to meet the ramping and cycling demands of portfolios with significantly increased amounts of intermittent resources will be necessary to maintain system reliability in all portfolios to achieve HB 951's CO_2 emissions targets. Carbon Plan, App'x Q, 10. Appendix Q further explains that the DEC and DEP CC fleets have been historically designed and operated specifically for baseload operations and have faced a limited need to cycle given the flexibility of the remaining generators. *Id*. The Modeling and Near-Term Actions Panel testifies, however, that for some of the Carbon Plan portfolios to meet HB 951's carbon reduction targets, the majority of the CC fleet will require daily cycling for certain periods of the year in order for the system to receive injections of zero-carbon energy. Tr. vol. 7, 367-368. This operational approach will be new to the Companies' fleet and is likely to require changes to operations and maintenance practices as well as investments and upgrades to increase unit flexibility. Carbon Plan, App'x Q, 10. The Modeling and Near-Term Action Panel testifies that the Companies will need combustion turbines (CT) and CC generators to preserve reliability. The Panel explains that the Companies must ensure that the grid is reliable at all times, and doing so will require dispatchable and flexible resources, such as CCs and CTs. The Companies will need CCs and CTs to complement the variability in output of renewables and provide a backstop in the event that the renewable resources are unavailable. As energy storage resources continue to grow and additional forms of energy storage become available, the Companies could continue to offset the utilization of natural gas resources in flexible, dispatchable peaking resources to maintain reliability. However, the use of energy storage resources – regardless of form – will require rigorous analysis to ensure reliability can be preserved in such cases. Tr. vol. 7, 224.

The Carbon Plan states that in the future CTs and CCs will run fewer hours while simultaneously providing increasingly important system flexibility and reliability services required to meet customers' needs into the future and under all weather conditions. Carbon Plan, Ch. 3, 5. The Modeling and Near-Term Actions Panel testifies that "[g]as generation resources are also needed to work in tandem with storage to provide the increasing level of dispatchable operational reserves necessary to match the growing variability and uncertainty that accompany a grid more reliant on weather-dependent renewables." Tr. vol. 7, 368.

The Reliability Panel testifies that "[t]o maintain the grid, System Operators require adequate flexible and dispatchable operational reserves that can *persist* through prolonged extreme weather events." Tr. vol. 30, 106 (emphasis in original). This change in mission is particularly important as remaining coal units are retired and the system becomes increasingly dependent on intermittent renewable resources and limited-duration storage technologies. Carbon Plan, Ch. 3, 5; *see also* Tr. vol. 7, 302 ("As the Companies reduce dependence on dispatchable fossil fuels and increase dependence on intermittent resources, prudent utility planning and HB 951 requires that this transition be planned and executed in a manner that does not impact reliability to customers."). The Reliability Panel testifies that natural gas is "a bridge to integrate more renewables and batteries until hydrogen and long-duration storage and ZELFRs[26] are available and can replace at scale what gas contributes to the system." Tr. vol. 30, 106.[27] The Modeling and Near-Term Actions Panel testifies that expanding the flexibility of the Companies' existing gas fleet "will allow the Companies to maintain system reliability and quality of service while integrating intermittent resources, such as wind and solar, that may not match customer demand." Tr. vol. 7, 325.[28] The Reliability Panel notes that the Companies must have a plan for a significant increase in battery storage and balancing resources (e.g., hydrogen, ZELFRs) *at scale* while retiring significant amounts of baseload generation before the role of natural gas is reduced. This means that the Companies must maintain enough dependable, flexible, dispatchable resources to maintain or improve upon reliability while they retire over 8,000 MW of high-capacity coal over roughly the next decade *and* place into service substantially more than 8,000 MW of variable energy renewables and energy-limited batteries. Tr. vol. 30, 107.

The Reliability Panel testifies that NERC strongly acknowledges that flexible gas is the tool that provides operational flexibility and energy sufficiency as the Companies transform the grid, and cites NERC President and CEO James Robb's comments to the United States Senate Committee on Energy and Natural Resources in March 2021 that the mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap. *See* Tr. vol. 19, 138-39.

Chapter 3 of Duke Energy's Carbon Plan explains that in addition to significantly expanding renewable capacity, all portfolios also continue to rely heavily on nuclear energy as well as other baseload and dispatchable resources to provide capacity and to ensure power supply reliability for customers. Carbon Plan, Ch. 3, 5. Further, over 60% of the Companies' energy mix by 2050 is obtained from nuclear resources in all portfolios. *Id*.

Appendix L to Duke Energy's Carbon Plan describes the Companies' intent to pursue SLRs for the 11 existing nuclear generation units in the Carolinas. Carbon Plan, App'x L, 3. The current operating licenses will begin to expire in the 2030s and renewing

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[26] ZELFRs is an acronym for zero-emitting load following resources.
[27] CIGFUR witness Muller testifies that "Charlotte Pipe and many other CIGFUR member companies support natural gas and believe it will play a critical role as a bridge fuel to facilitate the energy transition in a way that does not compromise existing reliability." Tr. vol 25, 363.
[28] The Public Staff supports this position. Public Staff July 15th Initial Comments at 159-160.

the operating licenses for another 20 years will ensure a source of reliable, zero-carbon, cost-competitive power for the Companies' customers through 2050 and beyond. The Carbon Plan explains that continued investment in maintaining and operating zero-carbon assets like the Companies' current fleet of nuclear plants into the midcentury will result in a great benefit to customers and the communities they serve. Moreover, extending the operation of these existing facilities through SLR renewals is a critical base assumption in all the Carolinas Carbon Plan portfolios. *Id*.; Tr. vol. 17, 95. If the Companies do not pursue the SLRs they would need to replace almost 11,000-megawatt electric ("MWe") of existing baseload zero-carbon generation from 2030 through 2046. Carbon Plan, App'x L, 3. The Modeling and Near-Term Actions Panel testifies that the Public Staff supports continued pursuit of the SLR. Tr. vol 7, 326; *see also* Public Staff July 15th Initial Comments at 159-60 ("Pursuing SLRs will allow Duke to continue providing a large amount of carbon-free energy from its existing nuclear fleet.").

Chapter 4 of the Carbon Plan discusses the Companies' overall proposed Carbon Plan Execution Plan. There, the Companies identify near-term (2022-2024) actions that are planned to expand flexibility of the existing gas fleet and to extend the life of the existing nuclear fleet with SLRs. Carbon Plan, Ch. 4, 4; *see also* Tr. vol. 7, 325-26. Chapter 4 of the Carbon Plan also states that it has a combined total gas-fired generation fleet of 11,991 MW. Carbon Plan, Ch. 4, 10. To increase the flexibility of the existing gas-fired fleet, the Companies will need to equip a number of its CC/CT stations to support more flexible operational capabilities, such as lower load operations, increased ramp rates, and the ability to cycle more often to respond to increased variability in the output of renewable resources. *Id*. In the near and intermediate term, the Companies will plan and implement gas unit control upgrades and equipment changes and seek regulatory approvals for operational and air permit changes. *Id*. at 4.

Chapter 4 of the Carbon Plan also explains that the 20-year SLRs for the 11 existing nuclear generation units (10,773 MW) require federal regulatory approval to maintain operation. Carbon Plan, Ch. 4, 10. Duke Energy witness Nolan testifies that the current operating licenses will begin to expire in the 2030, Tr. vol. 17, 95, and the regulatory approval process may take up to 4 years per SLR application. Carbon Plan, Ch. 4, 10. The Carbon Plan explains that the Nuclear Regulatory Commission has accepted the Companies' first SLR application for review in mid-2021 and is currently in the process requesting additional information to support its review. The Companies plan to develop and submit an SLR application for each nuclear station approximately every three years, with the remaining submittals tentatively planned for 2024, 2027, 2030, 2033 and 2036. In addition to extending the operating licenses at each site, the Companies continue to optimize the use of power uprates when cost-effective. Several of the nuclear facilities (*e.g*., Harris, Robinson and Brunswick) have already been uprated extensively while the Companies are in the early evaluation stages for the remaining facilities (e.g., Oconee, McGuire and Catawba). If implemented, these power uprate modifications would provide additional zero-carbon capacity and energy to Duke Energy's customers in the Carolinas. Carbon Plan, Ch. 4, 11.

Public Staff Comments and Testimony

The Public Staff July 15, 2022 Initial Comments address the Companies' plan to expand the flexibility of the existing gas fleet:

> Expanding flexibility of the existing gas fleet will allow Duke to maintain system reliability and quality of service while integrating intermittent resources such as wind and solar that may not match customer demand. Pursuing SLRs will allow Duke to continue providing a large amount of carbon-free energy from its existing nuclear fleet. *The Public Staff believes the Companies should take appropriate actions to implement the Carbon Plan approved by the Commission*, to the extent that such actions are prudent and reasonable.

Public Staff July 15th Initial Comments at 159-60 (emphasis added).

Public Staff witness Metz provides testimony that further elaborates on the Public Staff's comments:

> If flexible expansion projects prove to be least cost for compliance with Section 110.9 and improve or maintain system operability requirements, it is reasonable for Duke to pursue the projects as needed. Future Carbon Plans will likely further evaluate ramping and start/stop constraints, given the changes in the generation portfolio and load shapes, and will also identify discrete flexibility requirements. Therefore, the capital investments required to increase the flexibility of Duke's existing fleet of natural gas resources should demonstrate through cost-benefit analyses that the additional benefits of flexibility justify the costs, and that system flexibility cannot be achieved through alternative means.

Tr. vol. 21, 132-33.

Public Staff witness Metz testifies that he does not oppose the Companies' pursuit of SLRs for its existing nuclear fleet because the existing nuclear fleet can serve as a foundational component of complying with Section 110.9. *Id*. at 133. Witness Metz also testifies that "[i]n addition, the costs of the existing nuclear fleet are already reflected in customer rates." *Id*. Witness Metz testified that he is not advocating for blind pursuit of the Companies' SLRs and the continued operation of the existing nuclear plants, but rather the SLR process should identify the actions necessary to continue safe and reliable plant operations and carefully weigh the costs against the benefits and potential alternative solutions. *Id*. at 134. Witness Metz testifies that Duke Energy must demonstrate that the SLR costs incurred are reasonable and prudent before it can recover those costs from ratepayers, and that in future Carbon Plans the Companies should clearly lay out its schedule for pursuing SLRs for each existing nuclear plant along with a contingency plan should any nuclear plant not acquire its SLR in time to continue operations. *Id*.

Intervenor Comments and Testimony

CIGFUR Witness Muller testifies that Charlotte Pipe strongly supports Duke Energy's efforts to relicense its existing nuclear fleet, which will be necessary to serve base load and that without the Companies' nuclear fleet it would be impossible to implement a Carbon Plan from a reliability, cost, and executability perspective. Tr. vol. 25, 363.

AGO Witness Burgess also testifies in support of extending the life of the Companies' nuclear plants. *Id*. at 303 ("Similarly, extending the life of existing nuclear plants will significantly minimize the challenge of meeting the Carbon Plan's requirements.").

The Environmental Working Group's (EWG) witness Makhijani testifies that two of the EWG's four proposed portfolios retain existing nuclear resources. Tr. vol. 24, 109.

Discussion and Conclusions

The Commission finds and concludes that it is reasonable and prudent for the Companies to pursue these near-term actions for existing supply-side resources. The Commission finds that the Companies must maintain their existing gas units and nuclear generating sources because they are integral for Duke Energy to maintain system reliability and quality of service while integrating intermittent resources. The Companies pursuit of these actions will ensure that system reliability is maintained or improved upon as coal units are retired. Accordingly, the Commission finds that the Companies' proposed actions reflect the appropriate steps necessary to achieve the least cost energy transition path for the Companies' systems under HB 951. The Commission also directs the Companies to update the Commission on the Companies' progress regarding existing supply side resources in their 2024 Carbon Plan update.

The Commission finds that it is reasonable and prudent for the Companies to increase flexibility of the existing gas fleet—including gas unit control upgrades and equipment changes—and seek regulatory approvals for operational and air permit changes. The mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap, thus the Commission finds that flexible gas generation sources will provide the Companies with operational flexibility and energy sufficiency as they transform the grid. Accordingly, the Commission directs the Companies to pursue upgrades to its gas unit controls, the necessary changes to gas generating equipment, the necessary regulatory approvals, and any other reasonable and prudent actions necessary to increase the flexibility of the Companies' gas fleet.

The Commission also finds that it is reasonable and prudent for the Companies to continue to develop and submit 20-year SLRs for the 11 existing nuclear facilities. These facilities provide nearly 11 GW of carbon-free capacity and the Commission finds that the Companies' pursuit of the SLRs is critical to the Companies achieving the carbon emissions reduction targets established by HB 951. The Commission takes note that the Public Staff and several intervenors support the Companies' pursuit of SLRs for the existing nuclear fleet and no party has identified an alternative compliance path that does not rely on the continued operation of the existing nuclear fleet, as doing so will allow Duke to continue to provide a large amount of carbon-free energy from its existing nuclear fleet.

PLANNING FOR COAL RETIREMENTS (Findings of Fact Nos. 44-45)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 44-45

The evidence supporting these findings of fact is found in Duke Energy's proposed Carbon Plan, the direct and rebuttal testimony of the Duke Energy Modeling and Near-Term Actions Panel and the Transmission and Solar Procurement Panel, the testimony of the Public Staff, NCSEA, and the AGO, the initial comments of the Public Staff, CIGFUR, Tech Customers, and Person County, and the entire record in this proceeding.

Summary of the Evidence

Determining Economic Retirement of Coal Generating Capacity

Carbon Plan Appendix E (Quantitative Analysis) provides detailed discussion of the analytical tools and process used in performing the coal retirement analysis. Appendix E describes how the Companies conducted a detailed multiple step process to determine the most economic and appropriate unit retirement schedule for the DEC and DEP coal fleets factoring in both coal retirement economic analysis as well as real world considerations for required replacement generation and transmission needed to facilitate coal retirements. The Companies leveraged the EnCompass software's capacity expansion model to evaluate the benefits to the system and costs to maintain these resources compared to other replacement resources to meet energy and capacity needs of the system including meeting CO_2 emissions reduction targets. Appendix E explains that through this multiple step process, the Companies were able to establish accurate projections of cost to operate these resources, evaluate economic optimization of resources in the capacity expansion model, and reach a final determination of the retirements based on real-world factors that provide time to ensure reliability is maintained on the transmission system as units are retired and to optimize the retirements for an orderly transition of the fleet. Tr. vol. 7, 326-27; Carbon Plan, App'x E, 44-50.

Specifically, the Companies first ran the capacity expansion model to project the anticipated utilization of the coal units through their depreciable lives, with the exception of the remaining operating coal units at Allen Station, which are anticipated to be retired by the end of 2023, and Belews Creek, whose latest retirement date was accelerated to the end of 2035, to address growing regulatory risk of continued operation of coal capacity and long-term fuel security for these assets. Carbon Plan, App'x E, 45-46.

Next the Companies took the projected utilization of these assets and determined the cost to maintain and reliably operate these units over these initial fixed retirement dates. The costs to operate each unit may change based on planning criteria such as need and availability of other resources, targeted year of CO_2 emissions reductions, and overall operation including fuel usage, natural gas co-firing, starts, and time since previous major maintenance cycle. In the 2020 IRP the Companies previously evaluated coal retirement agnostic to the remaining net book value (NBV) of these units. Because HB 951 provides for securitizing remaining NBV of accelerated retirements of subcritical coal units, the Companies explain that this benefit was factored into the cost estimate used to decide the economic retirement date within the capacity expansion modeling. Carbon Plan, App'x E, 44-46.

The Companies then used these costs to maintain the coal units in the capacity expansion model to identify economic acceleration of the retirement of the coal unit to as early as the end of the year 2025. This process allowed for the EnCompass model to co-optimize coal retirements along with the economic replacement resources needed to meet energy, capacity, and CO_2 emissions targets. With the transmission projected to be completed in 2023 to enable the retirement of Allen, and Cliffside 6 capable of operating exclusively on natural gas, these units were not evaluated for further acceleration of retirement. The economic evaluation of coal retirements was performed for each portfolio. Carbon Plan, App'x E, 47-48.

Appendix E explains that the retirement dates selected by the endogenous analysis are limited to a single and static view of costs to operate and maintain the coal units over the course of their entire depreciable (or adjusted) lives, and therefore, should be treated as representative and directional in nature due to these limitations. Relying exclusively on results from the capacity expansion model is not best practice for resource planning for selecting resource additions nor retirements. Appendix E explains that to more accurately reflect the complex interdependencies of resource additions and retirements, the coal retirement analysis resulting from the capacity expansion model's optimization must be evaluated to determine optimal retirement dates for each unit that reflect real-world operating constraints and as a holistic approach to transitioning the fleet with least cost principles considered. Tr. vol. 7, 326-27; Carbon Plan, App'x E, 48-49.

To optimize unit retirement dates based upon planned availability of new capacity additions while also ensuring the Companies can meet the statutory requirement to maintain or improve upon the adequacy and reliability of the system when accounting for retirement of these resources, Appendix E describes minor adjustments to the coal retirement dates for certain units to allow for more orderly and executable retirement schedules. Table E-47 presents the final results of the Companies' coal retirement analysis. As indicated in Table E-47, a range of retirement dates are presented for Roxboro units 3-4 depending on the portfolio, with retirement of those units effective beginning of year 2028 in P1, 2032 in P2, and 2034 in P3 and P4. Carbon Plan, App'x E, 48-49.

The Companies further discuss in Appendix N (Fuel Supply) that continued operation of the DEC and DEP coal fleets presents increasing risk over time. Carbon Plan, App'x N, 1-2. As explained in Appendix E, these risks must be balanced with minimizing cost and ensuring reliability and the actual retirement dates for the Companies' coal units may change from those projected in this analysis based on the Companies' abilities to procure and bring online adequate and reliably equivalent resources. Carbon Plan, App'x E, 49.

Based on this analysis, Chapter 4 of the Carbon Plan (Execution Plan) addresses the Companies' plans for coal unit retirements and transmission analysis to assess reliability needs and options for construction of additional transmission system upgrades to enable coal unit retirements. The Companies' proposed Execution Plan presented in Chapter 4 lays out transmission, regulatory, operational, and environmental near-term and intermediate-term actions regarding the retirement of the remaining units at Allen Station, Cliffside 5, Marshall, Mayo, and Roxboro stations. Carbon Plan, Ch. 4, 9-10 (Table 4-2). The Companies present further detail on the necessary near-term actions on the transmission system based on the Carbon Plan analysis including plans to evaluate transmission upgrades and replacement generation requirements to enable the coal retirement. Specifically, Table 4-13 indicates that among the near-term actions the Companies plan to take in 2023-2024 are (1) determining feasibility for upgrading the McGuire-Marshall 230 kV lines by end of year 2028 and studying replacement generation located at a brownfield site, (2) conducting transmission planning to evaluate transmission upgrades and replacement generation requirements to enable retirements by end of year 2035, and (3) conducting transmission planning to evaluate transmission upgrades and replacement generation requirements to enable retirements of Roxboro and Mayo Stations by their earliest planned dates, and to evaluate the transmission upgrades needed to site replacement generation for these stations in the DEC service area. Carbon Plan, Ch. 4, 26-27.

Adjustment to Endogenously Identified Coal Retirement Dates

Public Staff and Intervenor Comments and Testimony

Overall, the Public Staff acknowledges that extended lives of coal units do not directly conflict with achieving a least cost transition of the fleet and achieving the targeted CO_2 emissions reductions while playing a crucial role in system reliability. Public Staff witness Metz explains that the coal generation assets that are not retired before 2030 can be used as capacity resources (e.g., Cliffside Unit 6, Belews Creek, and possibly Roxboro Units 3 and 4, pending their firm fuel availability) to meet reserve margin requirements while not being dispatched for daily system needs. Witness Metz testifies that these units would also be used to account for system anomalies such as loss of another generator during a system peak or unanticipated demand increases resulting from hotter or colder weather than planned. Tr. vol. 21, 112-14.

Witness Metz further explains that while maintaining the operation of any generating resource beyond its economic life is not preferrable, there are operational and reliability implications that must be considered and managed as part of any coal exit strategy. He recognizes 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 (both upgrades and greenfield facilities), coal inventory and fuel supply, and maintaining system reserves to account for system abnormalities that occur outside of a model (e.g., colder than expected weather, delays in replacement resources coming online, transmission scheduling considerations, etc.). He testifies that given the transition of the electric system, coupled with technological innovations and aging existing assets, physical and operational limitations must be taken into account in planning for coal unit retirements. Tr. vol. 21, 116-17.

Witness Metz supports the Companies' proposed near-term actions to evaluate the impacts of plant retirements and new generation additions on the transmission system as presented in the Execution Plan. He notes that this evaluation performed by the North Carolina Transmission Planning Collaborative (NCTPC) should aid in identifying potential least-cost options for new generation and transmission build-out. Tr. vol. 21, 118.

Finally, witness Metz cautions against a definitive schedule for the retirement of the Companies' coal units and suggests that the Commission's primary focus should be on maintaining operational flexibility and reliability at a reasonable cost. He states that the Commission should not order an overly prescriptive, inflexible, retirement schedule for the entire coal generation fleet given these multiple factors. Witness Metz suggests that Duke Energy should continue to update the Commission and stakeholders, on an ongoing basis, of any changes to the current retirement schedule in an annual filing or at minimum in each biennial Carbon Plan update proceeding. Tr. vol. 21, 116-17.

Tech Customers also acknowledge that actual retirement decisions must consider factors outside those available in the model. Tr. vol. 25, Gabel Report, 27-28. While the Gabel Report's alternate Carbon Plan modeling accelerates the retirement of the Companies' coal fleet to before 2030, it also describes its analysis as a "modeling exercise to illustrate hypothetical results that may be possible." Tr. vol. 25, Gabel Report, 28.

Person County expresses desire that replacement resources be located at the retiring coal unit sites to minimize cost to customers. Person County Initial Comments, 9. Person County also advocates for maintaining the Mayo and Roxboro units for as long as possible to support the HB 951 goals of maintaining adequacy and reliability of the existing grid and offers that it is prudent planning to extend the operational lives of Roxboro and Mayo past the retirement dates identified in the Carbon Plan but used only for emergency purposes. *Id*. at 12-13.

AGO witness Burgess takes issue with the Companies' optimization of retirement dates after being informed by the capacity expansion retirement evaluation. Witness Burgess states that earlier retirement of coal generation at Marshall, Mayo, and Belews Creek may be economic and feasible. He finds Duke Energy's rationale for delaying these retirements to be insufficient and recommends accelerating procurement of new resources to replace what he views as increasingly uneconomic coal unit operations. He suggests the use of battery storage to potentially avoid transmission upgrades and allow for earlier coal unit retirement. Tr. vol. 25, 285-86. He also advocates for utilizing retired coal sites to limit transmission impacts and expedite replacement resources. Tr. vol. 25, 296.

NCSEA et al. witness Fitch suggests that the adjustments to the endogenously identified coal retirements dates lack analytical justification and would result in additional costs to ratepayers. Witness Fitch asserts that the adjustments were not necessary to maintain reliability of the system and that the Companies should have accepted the EnCompass optimization results as the most cost-effective retirement dates. He contends that the dates selected by the model are the most optimal co-optimization of mix of resources. He argues that the reasoning provided in the Carbon Plan and by Duke Energy witness Roberts' direct testimony rely too heavily on high level assumptions rather than detailed requirements and timelines. He presents Synapse's scenarios for coal unit retirement and recommends the Commission make all efforts to implement the most economic coal retirement dates. Tr. vol. 24, 171-77.

Duke Energy Responsive Testimony

The Modeling and Near-Term Actions Panel explains that the Companies recognized when developing the Carbon Plan that any adjustments to model identified retirements would necessitate explanation. The Companies, therefore, proactively presented substantial detail supporting the limited adjustments to the initially identified coal retirement dates in Appendix E of the Carbon Plan. For example, the Carbon Plan states while the Companies' capacity expansion and production cost models are sophisticated tools, capacity expansion modeling, in general, is not an exact indication of the optimal selection of resources nor, in this case, the optimal timing to retire a unit. The Companies explain that the capacity expansion model's inadequate ability to determine optimal timing of retirements due to the simplifications used in the model, and the inability to adjust on-going costs for different retirement dates, make the evaluation useful as a general guide only. Additionally, the Companies state several factors that could influence optimal timing of retirements, including timing with new resources, transmission constraints, and the ability to leverage sites for future development. The Companies note that as supported by the Public Staff and acknowledged by Gabel Associates on behalf of Tech Customers, some factors do not lend themselves to perfect integration into the model and as such, it is appropriate for Duke Energy to consider these factors in determining the optimal timing of such decisions, such as coal retirements. Tr. vol. 7, 326-28.

The Modeling and Near-Term Actions Panel also highlights the scale of the Companies' coal capacity reduction plans in the Carolinas, explaining that, including the coal-to-gas conversion of Cliffside Unit 6, Duke Energy is planning to retire and/or replace 9,274 MW of coal capacity. Compared to the Companies' southeastern peer utilities, Modeling and Near-Term Actions Panel Direct Figure 11 shows that Duke Energy is reducing more coal capacity than any other utility surveyed and the Companies' plans are almost double Georgia Power and about five to six times higher than Dominion Energy South Carolina, FP&L, and Virginia Electric and Power Company. Tr. vol. 7, 335-36.

In response to NCSEA et al. witness Fitch, the Modeling and Near-Term Actions Panel testifies that the Companies reviewed the analysis used as a basis for Witness Fitch's assertions and concluded that Synapse's analysis is seriously flawed and should be disregarded by the Commission. The Panel explains that the cost Synapse calculated does not account for net capacity changes on the system, that is the replacement resources, essentially only factoring in one side of the ledger. Furthermore, the cost estimates are based on a generalized industry study that does not specifically apply to the Companies' coal units in question, whereas the Companies' decades of experience operating these units serves as a more appropriate estimate when evaluating the cost for continued reliable operation of these units. Tr. vol. 7, 333-34.

The Panel explains further that Carbon Plan Appendix E proactively describes the adjustments made to economically identified retirement dates for Marshall 1 and 2 and Roxboro 3 and 4, as examples, pointing to transmission projects to enable the retirements or optimal timing of new resource availability. The Panel provides additional context related to the Companies' need to delay retirements of these assets in the modeling. The Panel states that optimally timing the coal retirements to recognize the necessary transmission timelines is an appropriate consideration. In doing so, this further allows for the selection from a wider array of resources in meeting the near-term and long-term needs of the system. The timelines additionally allow for the Companies to take advantage of continued cost declines for declining cost resources, such as batteries, if they are selected as a part of the collective optimal replacement resources. Tr. vol. 7, 327-28; Carbon Plan, App'x E, 48.

The Panel continues that to retire Marshall 1 and 2 requires the completion of the McGuire – Marshall 230 kV transmission project to retire the units without replacement resources on site. The Companies explain that the earlier deployment of batteries as a potential replacement resource at the site is not a feasible solution. The replacement resources contemplated by the adjustment to the Marshall retirement dates must be dispatchable resources capable of longer run times to satisfy grid reliability requirements; energy limited batteries that need charging do not allow for avoidance of the transmission project to enable these coal retirements. Tr. vol. 7, 328-29.

Similarly, the Modeling and Near-Term Actions Panel explains, accelerated retirement of Mayo as identified by the capacity expansion model, without replacement with dispatchable resources capable of longer run times, requires several potential transmission projects that push the feasible retirement date of Mayo to later in this decade at the earliest. Tr. vol. 7, 329-30.

Duke Energy witness Roberts testifies as part of the Transmission and Solar Procurement Panel that the Companies must ensure that any transmission projects required to accommodate coal retirements are in place prior to the planned retirement dates. He echoes Appendix P in his testimony that, based on the planned retirement dates for the Companies' coal units, varying levels of transmission planning analysis and considerations have occurred based on different scenarios for generation replacement. He explains that several of these scenarios reveal the dependence of replacing the retiring generation on-site connected to the same electrical point of interconnection. He notes that this is a major consideration with respect to the timing for which the generation retirement can occur if long-term transmission upgrades can be avoided and was a major driver in the Companies' request for FERC approval to incorporate a Generation Replacement process into the LGIP. He updates that FERC's approval of this process, which was obtained on September 6, 2022, will be critical to efficient, timely, and cost-effective replacement of retired coal-fired generation with new generation interconnected at the same switchyard. Tr. vol. 16, 94-96; Carbon Plan, App'x P, 15-16.

As part of the Transmission and Solar Procurement Panel, witness Roberts states that when evaluating coal retirements, the Companies not only need to consider the resource adequacy of the replacement resources, but also need to plan for grid impacts such as voltage support, changing power flows, and the need for associated transmission upgrades and/or greenfield transmission infrastructure, should replacement generation not be located at the coal retirement site. He counters that Synapse fails to recognize real-world execution and operations risks and relies too heavily on accepting the modeling results as a foolproof, reliable portfolio with no need for scrutinizing the results for execution risks or operational reliability risks. He notes the Appendix P discussion of several retirement scenarios in which potentially significant transmission upgrades would need to occur if the replacement generation is not located at the site of the retiring coal generation. For example, if any Marshall coal units are retired and not replaced with new generation on-site, significant transmission projects will be needed (i.e., upgrade McGuire to Marshall 230 kV lines) and in service by December 2028. The retirement of Roxboro or Mayo will also cause the need for additional transmission projects if the generation is not replaced sufficiently onsite, and coincident with the retirements, many of which would be greenfield transmission projects and not able to be completed to enable a 2030 retirement date. He concludes that neither Synapse nor Gabel meaningfully engages with these challenges as they simply assume that Duke Energy can replace all retiring coal generation onsite. Tr. vol. 16, 97-100; Tr. vol. 28, 141-42.

Finally, as part of the Reliability Panel, witness Roberts presents the critical role that coal and dispatchable resources played during the extended winter peak event of 2018. Tr. vol. 19, 178-79. He describes how system operations must consider solar and wind facility performance to maintain reliability in extended cold weather periods, and how the planned retirement of the coal fleet impacts system operations reliability risks. Tr. vol. 19, 179-83. He testifies that coal unit retirements will need to be carefully planned to maintain resource adequacy and reliability of the system during the transition away from coal. Noting the actual customer demand and irradiance experience during January 2018, he concludes that it would be impossible for him to agree with Synapse or Gabel that their portfolios could provide energy adequacy for reliably serving similar long duration winter events, as they over-rely on the weather-dependent resources of solar and wind. He adds that the Synapse and Gabel proposed portfolios retire coal early without effectively providing replacement generation or resources that can achieve high-capacity factors for extended periods when needed as demonstrated by Duke Energy's coal fleet in January 2018. Tr. vol. 19, 182, 197-99.

Conversion of Coal Units to Natural Gas

Public Staff and Intervenor Comments and Testimony

As an alternative to accelerating coal retirement and perhaps necessitating the deployment of replacement resources, in their initial comments the Public Staff recommends modeling Belews Creek as operating exclusively on natural gas post 2035 until the end of 2037, the end of the station's projected depreciable life. Public Staff July 15th Initial Comments, 21, 117-19.

AGO Witness Burgess also suggests increasing the natural gas co-firing at the Belews Station in lieu of accelerated retirement. AGO witness Burgess explains that in his alternate modeling, he modeled the conversion of Belews Creek to operate exclusively on natural gas starting in 2028. He states that due to the complexities of modeling the Belews Creek gas conversion, this resource was assumed as an input the 2028 timeframe rather than being a result of the model's resource selection process. While acknowledging that ideally this should be supported by model, he suggests that this is a reasonable approximation of the optimal outcome due to the considerably favorable economics of this conversion over a new gas plant addition. Tr. vol. 24, 281-83, 288.

In their initial comments, CIGFUR contends that Duke Energy failed to adequately consider as a potentially more cost-effective alternative solution to reducing CO_2 emissions retrofitting existing coal plants to burn natural gas as a means of extending the life of the assets. CIGFUR July 15th Initial Comments, 19-20.

Duke Energy Responsive Testimony

The Companies agree with witness Burgess that it is preferable to utilize retiring coal facility sites for replacement generation, where possible, as such replacement resources may be able to avoid transmission investments and achieve other transition savings. Tr. vol. 27, 81. At the hearing, the Modeling and Near-Term Actions Panel testified that to the extent that existing coal or other brownfield sites can be used for the optimal development of such resources, that would facilitate more expedited replacement resources to replace retiring coal capacity, and this will continue to be pursued by the Companies. Tr. vol. 8, 63.

With respect to the further utilization of coal units operating exclusively on natural gas for longer periods of time, the Companies respond that they evaluated the high-level business case of expanding natural gas co-firing beyond the current 50% at Belews Creek and Marshall, and while the expansions were potentially feasible (subject to detailed engineering studies to confirm), the evaluation did not indicate favorable economics. Tr. vol. 7, 332; Tr. vol. 27, 85; Confidential Tr. vol. 27, 154-55, 159-60.

Discussion and Conclusions

Based on the foregoing evidence, the Commission finds the Companies' coal retirement analysis and modeling reasonable for planning purposes. The coal retirement schedule presented in Duke Energy's proposed Carbon Plan enables substantial CO_2 reductions that contribute to meeting targets under least-cost portfolios while providing for an orderly transition away from coal. The Companies employed a detailed multi-step modeling and analysis process to appropriately estimate the cost of continued operation and leveraged the results of the endogenous coal retirement analysis to inform and guide a coal retirement schedule that recognizes real-world operating constraints. The Commission recognizes the magnitude of the challenge the Companies are undertaking over the next decade, including the significant fleet transition required to retire 8,400 MW of coal-fired units that are operating today and to replace over 9,200 MW of coal capacity when the Cliffside Unit 6 coal-to-gas conversion is taken into account. The Commission appreciates the AGO's focus on ensuring that the Companies are reasonably considering all feasible options, such as converting Belews Creek Station to operate 100% on natural gas, to ensure this transition occurs on a least-cost path. Based on the record presented, the Commission finds that the Companies are taking reasonable steps in this regard.

The Commission agrees with the Public Staff that planning for retirement of the Companies' remaining coal fleet should continue to focus on maintaining operational flexibility and reliability at a reasonable cost. Retirements generally requires replacement resources to maintain the resource adequacy of the system. Providing an overly prescriptive approach to coal unit retirements based solely on expansion planning model outputs is not prudent, and the Commission agrees with Public Staff witness Metz and Duke Energy witness Roberts that accelerating coal unit retirements without enabling transmission or necessary replacement resources may endanger the reliability of the grid. The Companies' approach of an orderly transition provides for time to evaluate transmission system needs, identify replacement resources, and pursue a holistic approach to an orderly transition of the fleet.

Duke Energy's proposed Execution Plan identifies that the Companies are planning both to retire coal units in the near term in DEC (Table 4-2) as well as to conduct planning transmission studies and other assessments needed to ensure reliable retirement/replacement generation options are in-service in advance of other unit retirements for both utilities (Table 4-13). The Commission finds Duke Energy's planned schedule for coal retirement presented in the proposed Carbon Plan (Appendix E, Table E-47) is reasonable for planning purposes. The Commission also supports the Companies' approach to conduct studies to quantify the impacts to the transmission system based on the retirement of coal capacity as part of the Execution Plan in the near term.

Finally, the Commission agrees with the Public Staff that it is appropriate for the Companies to keep the Commission and stakeholders apprised of both the timing of scheduled coal unit retirements in the near-term as well as to update the Commission on planned analysis to inform future retirements. As addressed elsewhere in this Order, the

Commission directs Duke Energy to provide an update on Execution Plan activities as part of the 2023 IRP update for informational purposes. The Commission expects that the Companies will again present a comprehensive analysis of the planned coal unit retirement schedule in the 2024 Carbon Plan update proceeding to enable the Commission to check and adjust the Carbon Plan, as needed, to ensure the Companies remain on the least-cost path and to ensure a continued reliable and orderly energy transition.

GRID EDGE AND CUSTOMER PROGRAMS (Finding of Fact No. 46)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 46

This evidence in support of this finding of fact is found in the Companies' Carbon Plan and Appendix G to the Carbon Plan, the comments of the Public Staff, the testimony and exhibits of the Grid Edge Panel, Public Staff witness Williamson, AGO witness Burgess, Appalachian Voices witness McIlmoil, and the entire record in this proceeding.

Summary of the Evidence

Duke Energy's Carbon Plan and Direct Testimony

The Grid Edge Panel explains that the Carbon Plan prioritizes the role of grid edge and customer programs to be part of achieving the carbon reduction goals, while offsetting more carbon-intensive resources on the system today through additions of renewables and advanced technologies in the future, all while maintaining or improving on the reliability of the system. The Grid Edge Panel notes that this is evidenced by the fact that the first step of the Companies' multi-pronged approach is to "shrink the challenge." The Grid Edge Panel defines "grid edge" as technologies, programs, and investments that advance a decentralized, distributed, and two-way grid, with the "edge" referring to the edge of the electricity grid where the Companies' electricity reaches customers' homes and businesses. The Grid Edge Panel continues that grid edge programs include certain rate designs, voltage control efforts, and other customer programs, such as energy efficiency and DSM programs, as well as renewable energy programs and electric transportation programs. The Panel emphasizes that given that now more than ever, customers may more directly manage and impact their use of electricity, it is important to provide customers with a variety of options to manage their electric use - both reduce monthly bills and to provide value to the electric grid that delivers long term savings to all customers. Tr. vol. 13, 31, 34.

The Grid Edge Panel then explains that when the Companies determined that a 1% of eligible load of UEE savings was an aggressive but reasonable assumption to "shrink the challenge," the Companies also identified several enablers that would be necessary to continue to meet this UEE savings target on a long-term, annual basis. The Grid Edge Panel notes that several enablers identified in the Carbon Plan Appendix G should be approved in separate dockets from the DSM/EE Mechanism. Because of the complexity, scope, and goals of energy transition, however, the Grid Edge Panel explained that there is value in the Commission acknowledging and affirming in its Order in this proceeding that these identified enablers should be adopted in the appropriate forums so that the Companies' work on this path can begin. The enablers identified by the Grid Edge Panel include: (1) updating the inputs underlying the determination of the utility system benefits, (2) moving to an "as-found" baseline, (3) expanding the pool of low-income customers; (4) approval of the Companies' proposed tariff on-bill programs, and (5) the adoption of new flexibility and rapid prototyping guidelines to ensure regulatory approval of new DSM/EE pilots and rate designs in a timely manner. Tr. vol. 13, 32-33.

Because of its significance to achieving the 1% of eligible retail load energy savings goal, the Grid Edge Panel first discusses potential modifications to the Cost-Effectiveness Test Inputs as an enabler. These proposed modifications would ensure that EE/DSM resources are appropriately valued in the context of other resources considered in the Carbon Plan. After the Commission issues its Carbon Plan, the Companies intend to develop a formal proposal to modify their approved Mechanism and share it with the Collaborative and other interested stakeholders prior to filing it for approval with the Commission. By making these necessary modifications, the Grid Edge Panel states that the Companies may be able to increase incentive levels and participation while maintaining cost effectiveness in existing programs. The Companies could also potentially add new programs and measures that would not have been cost effective with the prior inputs. The Grid Edge Panel further explains that the modifications will detail the source and methodology to be used for periodic updates of inputs that will be based on specific costs associated with the selected marginal carbon-free and storage resources in the approved Carbon Plan added to the system energy and capacity, inclusive of transmission and other required infrastructure. Finally, the Grid Edge Panel notes that although the Public Staff asserts that *any* changes would require a thorough review of the Mechanism and Commission approval, the proposed enabler appears to be otherwise well-received as both NCSEA, et al., and the AGO Strategen Report support these proposed updates to more accurately reflect the utility system value of savings from EE/DSM Programs. Tr. vol. 13, 58-60.

Another enabler identified by the Grid Edge Panel is use of an "as found" baseline, which would increase savings associated with customers' energy efficiency investment. The Grid Edge Panel explains that this would increase the potential incentive amount that the Companies can provide to a customer, which will motivate customers to replace operational, but nonetheless energy inefficient, equipment. The Grid Edge Panel states that it is appropriate, when considering energy savings in the context of carbon reduction, to recognize that the amount of carbon being reduced is associated with the old usage from old equipment compared to the new usage from the new equipment, and an "as found" baseline would accomplish this. The Grid Edge Panel further explains that the recognition of "as found" baselines for certain energy efficiency measures is appropriate because the early replacement of inefficient equipment creates savings compared to the equipment being replaced, not the efficiency standard in place at the time of replacement. Tr. vol. 13, 60-62.

The Grid Edge Panel next explains that with respect to the expanded low-income programs enabler, the Companies intend to seek Commission approval for additional pilots and programs targeting income qualified customers, as well as the adoption of other recommendations of the Low-Income Affordability Collaborative (LIAC) and the LIAC Report filed on August 12, 2022, in Docket Nos. E-2, Subs 1193 and 1219; E-7, Subs 1187, 1213, 1214; G-5, Sub 632 and 634; and G-9, Subs 781 and 786. The Grid Edge Panel specifically points out that the Companies identified the potential expansion of the definition of income qualified to include customers with income up to 300% of the federal poverty guideline as an enabler to expand the pool of eligible customers that may participate in low-income energy efficiency programs. The Grid Edge Panel acknowledges that in many cases programs targeting low-income customers are not cost effective, but the Companies plan to fully vet any new programs or modifications to existing programs with the Collaborative before filing for Commission approval. The Grid Edge Panel also notes that, in general, the Companies have recognized considerable benefit in regularly working with the stakeholders through the Collaborative for well over a decade, and they plan to continue doing so in developing and refining other certain enablers. Tr. vol. 13, 56-57.

Next, the Grid Edge Panel states that the Companies will seek Commission approval of cost recovery associated with the proposed tariffed on-bill programs that will enable utility accounts to effectively leverage EE program incentives and finance efficiency upgrades in the form of a charge on the monthly bill. The Grid Edge Panel explains that this will greatly reduce the upfront financial barriers to energy efficiency investments. Tr. vol. 13, 57.

Finally, the fifth enabler the Grid Edge Panel identified is additional flexibility and rapid prototyping guidelines to be adopted by the Commission. The Grid Edge Panel explains that other states have expedited implementation processes for customer programs, and the Companies believe similar guidelines in North Carolina can help enable timely implementation of energy transition and the Carbon Plan. The Grid Edge Panel notes that the current "Flexibility Guidelines" the Commission has approved as part of the Companies' Mechanisms is an example of such a guideline, and that a similar expedited approval process for new customer pilots would better allow the Companies to innovate, shrink the challenge, and timely implement the Carbon Plan. The Grid Edge Panel states that the Companies will consider this issue further and may file a formal proposal with the Commission after it issues its Carbon Plan. Tr. vol. 13, 33, 74.

In addition to the identified enablers, the Grid Edge Panel also describes the Companies' current efforts with respect to net metering reform, innovative rate designs, and new customer programs related to energy efficiency and DSM. First, the Grid Edge Panel describes the Companies' current efforts to reform net metering and to tie time-of-use schedules to rooftop solar. The Grid Edge Panel explains that this effort was in direct response to HB 951's requirement to "revise net metering rates" and as a result the Companies have filed proposed reforms (called the "NEM tariffs") to its net metering program in Docket No. E-100, Sub 180 (Solar Choice). The Grid Edge Panel summarizes Solar Choice as utilizing more sophisticated rate design features, including a Time-of-Use design, to send more targeted price signals to customers, incentivizing rooftop solar developers to design systems that maximize the value to the electric system. Another program currently pending approval is the Smart $aver Solar programs tin Docket Nos. E-2, Sub 1287 and E-7, Sub 1261. The Grid Edge Panel explains that this proposed program offers incentives to customers who not only install rooftop solar panels, but also agree to long- term participation in a winter smart thermostat demand response program. The Grid Edge Panel also states that by bundling rooftop solar with a demand response tool, customers choosing to participate in net metering would offer a more complete resource that provides valuable utility system benefits. Finally, the Grid Edge Panel notes that these pending programs have received support from a wide variety of parties, including NCSEA and the Southern Environmental Law Center on behalf of Vote Solar. Tr. vol. 13, 65-66.

Regarding rate design reform, the Grid Edge Panel explains that the Companies engaged a third-party facilitator to support a broad stakeholder process covering both DEC and DEP rate designs over the course of 12 months, concluding in March 2022. The Grid Edge Panel describes the collaborative process as including participation from more than 50 organizations including commercial and industrial customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy companies, and legal/consulting companies to cover a comprehensive number of topics. The Grid Edge Panel explains that this stakeholder engagement resulted in the Companies crafting an informed vision and direction for future pricing and rate design options in the form of a Roadmap, which the Companies filed with the Commission in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219 on March 31, 2022. Tr. vol. 13, 67.

The Grid Edge Panel also provides examples of specific program concepts that the Companies have discussed with stakeholders. First, the Panel describes a new, improved large customer program, which expands and adds new features to the current Green Source Advantage (GSA) program. The Grid Edge Panel explains that this new GSA Choice program offering would allow up to 100% energy matching, which is not available today, and would allow customers to work with either a third party or the Companies on their renewable energy needs. Moreover, whether a customer selected the third party or utility-owned option, there would be an optional feature to partner in energy storage technology where the Companies would use the battery for peak capacity needs and allow the customer to better time-align their renewable energy with their actual energy use profile through participation in storage technology investments. The Grid Edge Panel describes the second program as “Clean Energy Impact” which would be for residential and business customers beginning their sustainability journey and who want to support the advancement of renewables by purchasing locally generated RECs from Company-owned renewable resources without a long-term commitment and would allow customers to select flexible increments. The third and final specific customer program described by the Grid Edge Panel is the Clean Energy Connection Program, which is a subscription solar program for all customer types to support renewable energy in North Carolina. Tr. vol. 13, 69-71.

Public Staff Comments and Testimony

The Public Staff responded to the Companies' position with respect to some of the identified enablers. First, regarding the Companies' proposal to update the inputs used in determining utility system benefits, Public Staff witness Williamson stated that the Public Staff does not agree with the Companies' proposal to update the inputs. Witness Williamson stated that the Companies have not proposed a preferred portfolio and the Commission has not yet approved a Carbon Plan that would use these assumptions. Thus, the Public Staff is unable to assess the reasonableness of using specific inputs within a particular portfolio as the foundation for determining the avoided cost benefits associated with utility energy efficiency. The Public Staff further testified that any modification to individual components should take place in the context of a full, formal review of the Mechanism. Tr. vol. 21, 192-93. Second, and similarly, the Public Staff states that consideration for utilizing an "as found" baseline should occur in the DSM/EE Mechanism proceeding. Public Staff witness Williamson also contends that the "as-found" baseline should not apply to measures that have baseline efficiency standards. Tr. vol. 21, 195-97. Finally, and distinct from issues raised regarding the Companies' identified enablers, the Public Staff recommends that the Commission distinguish energy savings used for EE/DSM cost recovery purposes from those used for Carbon Plan compliance. Tr. vol. 21, 197-99.

Intervenors Comments and Testimony

The AGO's Strategen Report also raised issues with the identified "as found" enabler, arguing that such an approach will not actually increase the efficiency of measures being installed. AGO Witness Burgess also states that commercial and industrial customers would opt-in to the Companies' EE/DSM programs if those programs offered were more attractive. AGO Strategen Report, 44-45.

Appalachian Voices witness McIlmoil claims that the Companies' programs targeting low-income customers are underfunded. Witness McIlmoil also argues that funding and participation shortfalls in existing energy efficiency programs must be addressed before consideration of any proposal to expand the eligibility for low-income programs. Tr. vol. 24, 43-44.

CIGFUR witness Gorman asserts that the Companies failed to consider non-residential flexible load and criticizes the Companies for allegedly not including any new renewable programs for industrial customers. Tr. vol. 22, 43.

Duke Energy's Responsive Testimony

In their rebuttal testimony, the Grid Edge Panel responds to concerns from the Public Staff that the Mechanism would need to be re-opened to implement some of the identified enablers. The Grid Edge Panel agrees that any updates to the inputs utilized for justifying demand-side utility programs must be part of a Commission-approved modification to the Mechanism; however, all of the Mechanism's terms and conditions, which were approved two years ago after months of negotiation and comment among numerous parties, do not need to be reopened, reconsidered, or modified. The Grid Edge Panel instead states that the Commission can approve targeted, required modifications to the Mechanism to facilitate a more expedited process than the unnecessary complexity of reopening the entire Mechanism. The Mechanism includes other, unrelated provisions and is formally reviewed by the parties and the Commission approximately every four years. The Grid Edge Panel highlights the precedent for targeted modifications to an approved Mechanism from the past year, when the Companies worked with the Public Staff on developing specific language modifying the Mechanism to include application of the Reserve Margin Adjustment Factor in the determination of the avoided capacity values associated with energy efficiency savings. The Companies proposed the specific, agreed-upon modifying language for review in their respective annual DSM/EE rider filings, without requiring any additional changes to the Mechanism. Tr. vol. 29, 176-77.

The Grid Edge Panel also responds to the Public Staff's argument that consideration for utilizing "as found" as a baseline should occur in a proceeding reopening the Mechanism. The Grid Edge Panel notes that it is not seeking blanket approval of "as found" baselines for use for all energy efficiency or demand-side management programs, without exception. Instead, the Companies propose that they will vet the proposal with the Collaborative and file for Commission approval for any programs or measures added to existing programs that include an "as found" baseline for determining savings. The Grid Edge Panel states that they do not believe modifications to the Mechanism are necessary if the Commission may approve programs or measures utilizing "as found" savings when the programs or measures are submitted for approval. The Grid Edge Panel argues that the existing Mechanism has the necessary protections to protect customers built in, as the Mechanism caps the return on cost that the Companies may earn through their Portfolio Performance Incentive. The Grid Edge Panel also responds to the Public Staff's argument that an "as found" baseline methodology is inappropriate for any energy efficiency measure with an identified baseline efficiency. The Grid Edge Panel states that Witness Williamson's overly broad recommendation fails to recognize the requisite link between "as-found" savings and energy efficiency programs that promote early replacement of measures. The Grid Edge Panel explains that the Companies' Mechanism neither prescribes nor prohibits the use of an "as-found" baseline, but rather requires that the energy savings are Evaluated, Measured and Verified (EM&V) by an independent third-party using industry-accepted practices. Well-known industry accepted methods and practices recognize "as-found" savings associated with early replacements based on program designs that motivate customers to replace operating inefficient equipment with higher efficiency equipment prior to the end of life of the old equipment. The Grid Edge Panel specifically cites the TRM/Mid-Atlantic Technical Reference Manual as an example of a documented process for recommending and quantifying "as found" savings. Tr. vol. 29, 177-79.

The Grid Edge Panel also states that Public Staff witness Williamson understates the extent to which the Companies' existing, accepted EM&V results appropriately recognize "as-found" impacts. The Grid Edge Panel explains that while EM&V for measures without an efficiency baseline recognize "as-found" savings, so do other accepted EM&V results for measures with efficiency baselines that utilize a consumption analysis. As an example, the Grid Edge Panel describes how DEC's Income Qualified Weatherization program assesses the impact of Tier Two measures, which include both HVAC and insulation, through a consumption analysis by comparing consumption of the treated participant group being evaluated against the consumption of a comparison group. Consequently, the Grid Edge Panel states, the "as-found" methodology recognizes the actual system benefits that are being realized from the energy savings associated with the customer's participation in the program. Tr. vol. 29, 178-79.

The Grid Edge Panel also addresses the Public Staff's recommendation that the Commission distinguish energy savings used for EE/DSM cost recovery purposes from those used for Carbon Plan compliance. The Grid Edge Panel states that isolating these items appears arbitrary. The Grid Edge Panel explains that if reduced carbon emissions associated with energy savings derived from utility EE programs is a value or utility system benefit (reducing the need for supply side investments needed to reduce carbon emissions), not recognizing the energy savings benefit in the cost effectiveness justification for offering EE programs under the Mechanism is a problematic disconnect. For example, if the Companies design a program to achieve energy savings associated with customer's early replacement of an energy *inefficient* appliance and, accordingly, develop a higher incentive level based on the cost effectiveness resulting from recognition of "as-found" savings, the Companies should be able to recognize the higher incentive cost associated with utilizing the "as-found" methodology. Recognizing the higher incentive cost, while ignoring the higher energy savings and the associated system benefit, will yield a program that is not cost effective and should not be offered under the Mechanism. The Mechanism has a demonstrated record of accomplishment of effectively motivating the Companies to develop and offer customers EE and demand response programs that will deliver as much energy and capacity savings as cost-effectively possible. The high level of EE program performance that the Companies have achieved through the Mechanism has been enabled by the Mechanism's alignment of cost effectiveness test results and the utility Portfolio Performance Incentives (PPI). The PPI appropriately reflects the recognized utility system benefits and costs associated with the energy savings achieved by the programs. If the Commission were to adopt the Public Staff's recommendation and sever this alignment, the goal of achieving as much cost-effective energy efficiency savings as possible will be significantly eroded. As this Commission has previously recognized, Senate Bill 3 provided that the utilities should be compensated for their DSM/EE efforts and allowed awarding of incentives, including rewards based upon shared savings and avoided costs achieved by DSM/EE measures. Tr. vol. 29, 179-80.

The Grid Edge Panel also explains that Strategen's claim that utilizing an "as-found" approach will not actually increase efficiency of measures being installed seems to be uninformed as "as found" baselines are utilized by many different utilities associated with early replacement measures. The Grid Edge Panel states that if a utility incentive effectively motivates a customer to make the large capital investment necessary to replace an aging but repairable inefficient piece of equipment, then more energy savings are occurring than if the customer were to repair and continue using the inefficient equipment. Tr. vol. 29, 182-83.

The Grid Edge Panel then responds to AGO witness Burgess' comments that more commercial and industrial customers would opt-in to DSM/EE programs if those offered were more attractive, by first pointing out that witness Burgess does not provide a basis for his contention that the Companies' programs are not attractive or describing in what ways they are lacking. The Panel highlights the Companies' long history of working with stakeholders in the DSM/EE Collaborative to ensure that the Companies' portfolios of non-residential programs are both attractive and comprehensive and that the Companies' portfolios offer customer prescriptive incentives associated with over 440 unique energy efficiency measures, as well as two approaches to a custom non-residential program. The first approach, the Grid Edge Panel explains, in the Performance Incentive Program is designed to cover less certain customer performance-based projects, like retro-commission and energy management system installations. The second approach, the Custom Incentives offered under the Energy Efficient Products and Assessment Program, is designed to allow customers to receive incentives for specific complex efficiency projects where the savings are based on equipment and process efficiencies. The Grid Edge Panel also notes that witness Burgess fails to acknowledge that the Companies have made a number of changes to make opting in more attractive, such as developing separate EE and DSM Rider components to allow customers to opt into only paying for the portion of the non-residential programs that they participate in. Tr. vol. 29, 181-82. Similarly, the Grid Edge Panel also responds to CIGFUR witness Gorman's critique that the Companies are not proposing new customer renewable programs by first noting that CIGFUR has been involved in extensive stakeholder efforts to develop such programs. Additionally, the Companies state that in the near future they will also be filing for Commission approval of a "GSA bridge" programs of 250 MW in response to CIGFUR's recommendation in this proceeding. Tr. vol. 29, 186-87.[29]

The Grid Edge Panel then addresses claims from Appalachian Voices witness McIlmoil that the Companies' programs targeting low-income customers are underfunded by explaining that the projected budgets and fundings levels included in the Companies' annual EE/DSM rider filings for these programs are in no way intended to be, nor do they act as, a cap on annual funding for the programs. The Grid Edge Panel also disagrees with witness McIlmoil that funding and participation shortfalls in existing EE programs must be addressed before consideration of any proposal to expand the eligibility for low-income EE programs. The Grid Edge Panel explains that the Companies' proposed enabler expanding the definition of low-income to 300% of the federal poverty guideline was in no way envisioned to shift funding from the existing income eligible participants, but rather it was identified as a way to recognize that a larger pool of eligible customers would, if approved by the Commission in future program filings, allow for more customer participation and more energy efficiency savings. Tr. vol. 29, 184-85.

Finally, the Grid Edge Panel responds to CIGFUR witness Gorman's assertion that the Companies failed to consider non-residential flexible load by pointing out that the Companies in fact included several hundred megawatts of price-responsive loads in the Companies' Carbon Plan, consistent with the Comprehensive Rate Design Study

[29] The Companies filed GSA Bridge programs for approval in Docket Nos. E-7, Sub 1277 and E-2, Sub 1306 on September 27, 2022.

Roadmap filed with the Commission in March 2022. Additionally, the Companies engaged CIGFUR members on multiple occasions to discuss demand response program options, including programs similar to the Southern California Edison program referenced by CIGFUR. The Companies plan to propose expansions to both demand response and dynamic pricing rates that will create load responsiveness supportive of both customer cost management and the Carbon Plan. Tr. vol. 29, 186.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission finds that the enablers proposed by the Companies are necessary to aid the Companies in achieving the 1% of eligible retail sales target, which the Commission has previously determined was reasonable. These enablers include: (1) updating the inputs underlying the determination of the utility system benefits, (2) approving programs that promote early replacement and retrofits and recognize an "as-found" baseline, (3) expanding the pool of low-income customers; (4) approval of the Companies' proposed tariff on-bill programs; and (5) the adoption of new flexibility and rapid prototyping guidelines to ensure regulatory approval of new DSM/EE pilots and rate designs in a timely manner.

As to the first identified enabler, updating the inputs underlying the determination of utility system benefits, the Commission agrees with the Companies that this change will be an important and necessary step to appropriately incentivizing and justifying future DSM/EE program offerings as cost effective consistent with the Carbon Plan as approved at this time. The Public Staff argued that it did not support the proposal to update the inputs to the underlying determination of the utility system benefits at this time because, in part, there is not an approved Carbon Plan. While that was the case when the Public Staff filed its testimony, the Commission now has approved a Carbon Plan to base the updates to the inputs on in this Order. The Public Staff indicated that it could not assess the reasonableness of using specific inputs within a particular portfolio until a Carbon Plan is adopted by the Commission. The Commission finds this is a valid concern that can be addressed by allowing the Public Staff and other parties the opportunity to vet the proposal now that there is an approved near-term action plan through the EE/DSM Collaborative.

Thus, the Commission directs the Companies to expeditiously develop a formal proposal targeted to update the inputs to the cost effectiveness tests that are based on specific costs associated with the marginal carbon-free and storage resources selected in this Order added to the system energy and capacity, inclusive of transmission and other required infrastructure. After receiving stakeholder input from the DSM/EE Collaborative, the Companies shall file this targeted update to the Mechanism to modify the cost effectiveness test to be able to be utilized in the Companies' annual EE/DSM rider filings.

The Commission also finds value in acknowledging at this time the necessity of the other identified enablers in achieving the 1% annual energy savings goal. The Commission recognizes that, after working with stakeholders, the Companies have now filed for approval of a Tariffed On Bill program, one of the identified enablers. The tariff-on-bill programs are designed to lower the higher upfront costs of installation of energy efficient appliances for residential customers. At this time, the Commission has not yet completed its review of the proposals. Nonetheless, the Commission acknowledges that removing barriers to participation in EE and DSM programs (as the Tariffed On Bill program seeks to do) is an important component of the Companies' energy transition and implementation of the Carbon Plan.

The Commission also recognizes that using an "as found" baseline for both the Tariffed On Bill program and other EE and DSM programs on a case-by-case basis is appropriate. The Commission has previously approved "as found" savings without reopening the Mechanism for additional review and revisions; thus, it agrees with the Companies that reopening of the Mechanism is not necessary to utilize "as found" baselines in future programs as appropriate. The Commission agrees that the Companies may work through the DSM/EE Collaborative, as necessary, to bring EE and DSM programs, measures, and modifications to same using "as found" savings to the Commission for approval.

As noted, the Commission agrees that barriers to increasing participation in cost-effective DSM/EE programs should be removed when possible. The Commission further agrees that there is value in expanding the number of customers that are eligible to participate in DSM/EE programs that are specifically targeted to low-income customers. These programs, while frequently not cost-effective, nonetheless produce energy savings. Currently, eligibility for low-income DSM/EE programs is generally set at 200% of the Federal Poverty Guidelines (FPG). The Commission acknowledges that the LIAC Report did not recommend that the eligibility level for low-income programs be raised to 300% of FPG. The Commission does not intend to draw any conclusions in this docket that may be seen as negating any part of the LIAC Report or any future comments or discussions in the LIAC dockets. Nevertheless, the Commission directs the Companies to discuss ways to raise the number of low-income customers that may be eligible to participate in DSM/EE programs and to report on those discussions in their annual DSM/EE rider proceedings.

The Commission also agrees that review and potential revision of how customer pilot programs – DSM, EE, or otherwise – are filed and approved is warranted as a result of the goals of HB 951. To that end, the Commission directs the Companies to propose new flexibility and rapid prototyping guidelines to ensure regulatory approval of new DSM/EE pilots and rate designs in a manner to maximize benefits and learnings.

Finally, the Commission notes that acknowledging these enablers and directing a path forward for future consideration of them does not guarantee their approval. The Companies themselves acknowledge that many of these enablers are generally subject to review and input by the Collaborative before filing for approval at the Commission in future dockets. But acknowledgement of these enablers as the requested provides the Companies with the necessary road map to follow as they try to "shrink the challenge" with their customer programs. As the Grid Edge Panel testified, this "road map" is necessary to move them forward to the 2024 Carbon Plan update, where their goals and enablers are subject to a check and, if necessary, adjustment. Therefore, the Commission finds and concludes the Companies' proposed customer programs and enablers, which still remain subject to all necessary approvals in other, future dockets, are reasonable for purposes of shrinking the challenge at this time.

TRANSMISSION DEVELOPMENT ACTIVITIES (Findings of Fact Nos. 47-48)

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

The evidence supporting these findings of fact is found in Appendix P to the Carbon Plan, the direct and rebuttal testimony of the Transmission and Solar Procurement Panel, the testimony of Public Staff witness Metz, NCEMC witness Ragsdale, CPSA witness Norris, NCSEA witness Caspary, CCEBA/MAREC witness Gonatas, AGO witness Burgess, and the entire record in this proceeding.

Summary of the Evidence

Transmission Planning and the NCTPC

Appendix P and Duke Energy Direct Testimony

As explained by Duke Energy witness Roberts' direct testimony, transmission planning was a key area of focus in the 2020 IRP proceeding (Docket No. E-100, Sub 165). Issued subsequent to the enactment of HB 951, the Commission's November 19, 2021, final order on the Companies' 2020 IRPs highlighted the increasing focus on transmission planning and the transmission network upgrades required to retire existing coal facilities and integrate portfolios of new supply-side resources needed to achieve a least-cost energy transition as mandated by HB 951. In that order, the Commission directed the Companies to analyze the anticipated or likely grid impacts associated with alternative resource portfolios modeled in the IRPs and to continue to refine transmission network upgrade cost estimates for incremental resources to take into account the most recent system impact study results. The Commission also directed the Companies to assess the critical transmission network upgrades required to enable interconnection of incremental resources identified in resource plans and build on recent transmission planning studies completed by the North Carolina Transmission Planning Collaborative (NCTPC). Tr. vol. 16, 59-60.[30] Witness Roberts recounts that in response to these Commission directives and recognizing transmission planning's critical role in enabling the system-wide energy transition planned within the Carbon Plan, Duke Energy provided significant detail on transmission planning and grid transformation considerations in Appendix P (Transmission System Planning and Grid Transformation) to the Carbon Plan. Tr. vol. 16, 59-60.

[30] *In the Matter of 2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans*, Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning, Docket No. E-100, Sub 165 (Nov. 19, 2021).

As referenced by witness Roberts, Appendix P to the Carbon Plan describes DEC's and DEP's existing transmission systems and the current local and regional transmission planning processes that the Companies use to ensure system adequacy and reliability and meet public policy requirements. Carbon Plan, App'x P at 2-4. Appendix P explains the organization and local transmission planning process of the NCTPC and the Southeastern Regional Transmission Planning (SERTP) regional planning process, as well as other regional transmission planning working groups in which the Companies participate. *Id.* at 8-10.

Appendix P explains that executing the Carbon Plan will require a transformation of the DEC and DEP transmission system in both the near- and long-term to interconnect the unprecedented amount of new supply-side resources that will be needed to retire significant amounts of coal-fired generation and achieve the carbon emission reduction targets established by HB 951. It states that to meet this challenge while maintaining or improving the existing grid's adequacy and reliability, the Companies will utilize the new annual Definitive Interconnection System Impact Study (DISIS) Cluster Study process and work through the FERC jurisdictional transmission planning process to build out the grid over time. Carbon Plan, App'x P at 1. Appendix P also discusses the transmission requirements and associated cost estimates related to the Companies' initial four proposed Carbon Plan portfolios.[31] It also introduces the "red zone" constraints on the DEC and DEP transmission system and explains that prior serial-queued resource interconnection requests and recent Transitional Cluster Study requests point to common transmission constraints in this high solar viability area in need of resolution to enable reliable interconnection to the DEC and DEP systems. *Id*. at 1-2, 12-15. Appendix P also identifies that a more proactive approach to transmission planning and expansion is needed to meet the Carbon Plan objectives and outlines the Companies' plans for proposing the red zone transmission expansion plan (RZEP) projects listed in Table P-3 to the NCTPC. *Id*. at 1-2, 13-15.

Witness Roberts' direct testimony expands on the key points established by Appendix P. He testifies that HB 951 establishes new public policy goals requiring new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the Companies' joint Open Access Transmission Tariff (OATT). He explains that the Companies are requesting the Commission to direct Duke Energy to continue to study future transmission needs to reliably implement the Carbon Plan primarily through the NCTPC. Tr. vol. 16, 53.

Witness Roberts also testifies that the Companies' local and regional transmission system planning processes are designed to ensure open, coordinated, and transparent planning of the transmission system under FERC requirements and to establish a process for ensuring the continued adequacy and reliability of the transmission system, to provide for generator interconnections, and to meet the NERC reliability requirements. He states that the robust transmission planning processes that Duke Energy engages in today have developed over time based upon a series of significant FERC orders including Order Nos.

[31] The Companies updated the transmission cost adder with the Modeling and Near-Term Actions Panel Direct Testimony, which was used to develop the two supplemental portfolios. Tr. vol. 7, 258-259.

890 and 1000 that form the regulatory framework for local, regional, and inter-regional transmission planning. Tr. vol. 16, 54-55; *see also* Carbon Plan, App'x P at 4-10.

Witness Roberts continues that, as reflected in Attachment N-1, Part I of the OATT, the NCTPC local planning process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads in the Companies' North Carolina and South Carolina service areas. He states that, based on a base reliability study and resource supply analysis, the NCTPC annually develops a single, coordinated local transmission plan (Local Transmission Plan) that appropriately balances costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources to meet the needs of Load Serving Entities as well as Transmission Customers under the OATT. He notes that this local transmission planning process also enables solutions to public policy requirements to be considered for adoption into the Local Transmission Plan. Tr. vol. 16, 55-56; *see also* Carbon Plan, App'x P at 8-10.

Witness Roberts explains further that DEC and DEP participate in the NCTPC local transmission planning process as members of the Oversight/Steering Committee (OSC) and Planning Working Group (PWG) together with Electricities of North Carolina (Electricities) and NCEMC, and through that process annually develop a Local Transmission Plan for their systems. Consistent with the terms of Attachment N-1, the OSC and PWG engage with the Transmission Advisory Group (TAG), composed of interested stakeholders, to solicit input and recommendations to incorporate into the Local Transmission Plan. TAG participants have the opportunity to propose alternative transmission, generation, and/or demand response solutions to address reliability, economic, and/or public policy transmission needs. Tr. vol. 16, 56-57; *see also* Carbon Plan, App'x P at 8-9.

Witness Roberts testifies that transmission planning is integrally linked to planning for and reliably interconnecting new generating facilities. He states that generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures (LGIP and SGIP) contained in the OATT and the North Carolina and South Carolina state generator interconnection procedures applicable to qualifying facilities selling their output to DEC or DEP under the Public Utility Regulatory Policies Act of 1978 (PURPA). Through queue reform, he states that the Companies have successfully transitioned to administering the DISIS, a first-ready, first-served Cluster Study process to study the transmission and distribution system impacts of all FERC and state jurisdictional interconnection customers. Tr. vol. 16, 57-58; *see also* Carbon Plan, App'x P at 10-11.

Witness Roberts continues that transmission planning must be integrated with resource planning to meet the HB 951 targets, consistent with the Commission's and FERC's respective authorities. Tr. vol. 16, 59. He explains that misalignment of these planning processes could lead to insufficient transmission development on a timely basis, and that the lack of transmission infrastructure to reliably support coal retirements and integrate significant amounts of new generation would put Carbon Plan and energy transition execution at risk. Tr. vol. 16, 61-62.

Turning to the specifics of the Carbon Plan, witness Roberts notes that an additional 4.5 GW to 5.4 GW of additional solar will need to be interconnected to the DEC and DEP systems by January 1, 2030, to meet the interim HB 951 carbon reduction targets. He notes that the current timeline for a generator requesting interconnection to the DEC or DEP system and reaching commercial operations can be several years, including approximately two and a quarter years from interconnection request to interconnection agreement, and several more years after that point for a project to come online. Tr. vol. 16, 62-63, Figure 1.

Witness Roberts explains that the history of solar generator interconnection requests in DEC and DEP shows that solar facilities continue to request interconnection in the red zones, despite the Companies' published guidance that locating solar in the red zones will require significant network upgrades, and to then withdraw from the interconnection queue when the cost allocation for transmission network upgrades necessary to enable interconnection of their resource is realized. He notes that the high solar viability region is characterized by land lease rates, land availability, lack of significant forestation, and lack of population density. He states that this piecemeal approach to transmission planning and generator interconnection presents a significant challenge to Carbon Plan and energy transition execution, and the RZEP projects will unlock these high solar viability areas where numerous generator interconnection studies have shown that solar resources desire to interconnect. Tr. vol. 16, 66-67, 159; App'x P at 12-15. Witness Roberts concludes that DEC and DEP must work within the NCTPC framework to evolve from a reactive mode that primarily relies on the generator interconnection process to integrate new generation to a more proactive, forward-looking view that anticipates the transmission projects that will be needed to meet future generation needs. Tr. vol. 16, 63-66. He reports that DEC and DEP have been engaged during 2022 through the NCTPC to introduce the RZEP projects for inclusion in a Local Transmission Plan as 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. Tr. vol. 16, 66.

Witness Roberts agrees with comments by the Public Staff and other parties that the NCTPC planning process should evolve to meet the need to execute the Carbon Plan. He states that the Companies will work with other NCTPC OSC members and stakeholders to consider changes to the local transmission planning processes to improve coordination with Carbon Plan execution and ensure timely and robust review of transmission projects necessary to meet anticipated generation needs. He also suggests that the NCTPC local planning processes can evolve and improve by incorporating deliverability studies that more closely align with the scope of current generator interconnection studies. Additionally, after the increased interest in TAG participation seen with the RZEP projects, he notes that the Companies foresee the need for clarifications to the process and procedures for obtaining TAG feedback. Tr. vol. 16, 85, 139.

Witness Roberts testifies that the Companies will consider the Public Staff recommendation to extend long-term transmission planning to 20 years but notes that doing so would introduce challenges. Numerous study inputs such as resource types, sizes, and locations, climate and its impact on resource output, availability, customer demand, and model topology would all experience more changes and decreased certainty over a 20-year period. Moving to a 20-year transmission plan would need to be combined with scenario-based planning change cases for any decision-making to be meaningful on a 20-year time horizon. For this change to be successful, in addition to DEC and DEP's adoption of a longer-term planning process, the local, regional, and interregional transmission planning processes would also need to adopt a 20-year transmission planning process. Finally, any such changes to transmission planning processes will require FERC-approved tariff changes. He notes that while it is focused on long-term, scenario planning for regional transmission planning processes, FERC's on-going Transmission Planning NOPR proceeding[32] may provide useful insights on how to incorporate more scenario-planning into the NCTPC local transmission processes. Tr. vol. 16, 85-86.

In response to the CPSA comments' recommendation that the Commission initiate a proceeding to establish a proactive, long-term transmission planning process, witness Roberts agrees that the local transmission planning process can be evolved and improved and states the Companies' support for the NCTPC initiating a review to evaluate changes to the local transmission process and to consider changes to Attachment N-1 of the OATT that could be filed with FERC. He suggests that a stakeholder process would be helpful to gather feedback on improvements to the local transmission planning process. Tr. vol. 16, 86-87.

Witness Roberts also explains that the Commission does not need to require the Companies to consider grid enhancing technologies (GETs) as part of the transmission planning process, because they have and will continue to investigate the potential benefits from integrating existing and emerging technological solutions to provide reliable and affordable service to customers. For example, he notes that Duke Energy installed Remedial Action Schemes and load swap-overs, series and switchable reactors, and phase shifters. He concludes that Duke Energy continues to evaluate these technologies, but intends to be prudent in GETs application, noting that application of some GETs could increase the probability of placing the system in unanalyzed conditions in real time and complicate operators' ability to maintain situational awareness. Tr. vol. 16, 89-90.

Public Staff Direct Testimony

Public Staff witness Metz testifies that mitigating execution risk to achieve Section 110.9 compliance requires proactive transmission planning and proactive upgrades. He supports the Commission's acknowledgement of the public policy goals for North Carolina as part of its 2022 Carbon Plan. Tr. vol. 21, 149-50.

Witness Metz acknowledges that the significant transition that the Companies' generation fleet is undergoing cannot be considered in isolation from the impact on the

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[32] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).

transmission system. He testifies that the Public Staff supports the general concept of proactive transmission planning and upgrades and acknowledges that it is warranted to meet the goals of the Carbon Plan. He also notes that appropriate cost allocation must be evaluated prior to implementation and requested that any proactive transmission projects be excluded from the multiyear rate plan (MYRP) until the issues in its Initial Comments are resolved. Tr. vol. 21, 139-40.

Other Intervenor Direct Testimony

No party disagreed with the Companies' request that the Commission conclude that 951 establishes new public policy goals that inform the need for new proactive transmission planning. Tr. vol. 28, 123-24.

NCSEA witness Caspary describes the benefits of proactive planning as contrasted with traditional reactive planning, including cost savings through economies of scale and the potential for building larger connections to high-value resource areas. Tr. vol. 22, 228-32. Witness Caspary also advocates for multi-value transmission planning, which he states would likely show the RZEP projects to be even more valuable. He also recommends the use of a 20-30-year transmission planning horizon. *Id.* at 232-36. Additionally, he suggests that the Commission engage in collaborative planning processes and encourage Duke to provide leadership to expand the scope of SERTP and NCTPC planning processes to address future uncertainties and inform decision making. Tr. vol. 22, 237-41. He also advocates for the Companies to actively consider the multi-value benefits of GETs and advanced transmission technologies in their planning. *Id*. at 241-44. Finally, witness Caspary espouses the benefits of improved regional and interregional integration and suggests that Duke Energy should improve coordination of its system planning and operations with neighboring utilities. He suggests that the Commission require the Companies to synchronize development of the Carbon Plan with transmission planning processes and make changes in the next Plan to those existing processes to expand the planning horizon and scope. *Id*. at 244-49.

CPSA Witness Norris conveys support for proactive transmission planning and upgrades to the transmission system. Witness Norris testifies that a long-term, comprehensive proactive approach to the development of transmission resources is more cost-effective than reactive generator-driven transmission improvement and provides a wide range of material benefits to the system and customers. Tr. vol. 26, 25. He recommends initiation of a proceeding including a technical conference with the goal of establishing a proactive, long-term transmission planning process. *Id*. at 76.

CCEBA/MAREC witness Gonatas advocates for long-term scenario planning and consideration of scenarios enabled by different transmission buildouts, including multi-value project assessments that balance transmission's multiple benefits against costs. Witness Gonatas also recommends that the NCTPC structure change to incorporate more stakeholder participation and additional consideration of advanced grid technologies. Tr. vol. 22, 122-23, 135-41. He suggests more frequent TAG meetings and merging the TAG with the OSC. *Id*. at 147-49.

AGO witness Burgess advocates for the Companies' consideration of a 20-year transmission plan and does not oppose the RZEP projects. Tr. vol. 25, 304.

Duke Energy Rebuttal Testimony

On rebuttal, witness Roberts reiterates that the reactive nature of relying on commitments in generator interconnection agreements before beginning construction of transmission network upgrades to enable new generator interconnections will not support the pace or volume of interconnecting resources necessary to implement the Carbon Plan. He states that a proactive transmission planning approach, that is scenario based and coordinates transmission network upgrades, greenfield transmission expansion, and explores alternatives is necessary to meet the requirements of the Carbon Plan in the specified timeframes and in a cost-effective manner. Tr. vol. 28, 124.

Witness Roberts commits that Duke Energy will continue to engage with the FERC NOPR proceeding and will implement FERC Orders on changes to transmission planning processes in its OATT. He states that Duke Energy will also engage with NCTPC OSC members in reviewing and improving NCTPC Local Transmission Planning processes to include the necessary proactive planning process steps for cost-effective transmission planning for the transmission systems within DEC and DEP. In addition, he states that DEC and DEP will continue to participate in regional planning through the SERTP process that will comply with the results of the FERC Transmission Planning NOPR. Tr. vol. 28, 125.

Need for RZEP Projects For Execution of the Carbon Plan

Duke Energy Direct Testimony

Duke Energy witness Roberts explains that in March 2022, the Companies introduced the RZEP projects to the NCTPC OSC 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. 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, and the NCTPC distributed a draft of the 2021 Mid-year Update Report to the TAG for review prior to the June TAG meeting. The draft 2021 Mid-Year Update Report proposed adding the RZEP projects to the Local Transmission Plan. Tr. vol. 16, 67-68.

In its June 10, 2022, 2022 Solar Procurement Order, the Commission directed Duke Energy not to include RZEP projects in the 2022 DISIS baseline, concluding that doing so would be premature based on its finding that "no party has presented competent evidence that the RZEP projects are necessary to achieve the Carbon Plan." The Commission encouraged Duke Energy and any intervenor supporting the RZEP "to provide substantial evidence supporting the necessity of the RZEP projects to achieve the goals of the Carbon Plan in that proceeding." Tr. vol. 28, 134.[33] In its Issues Report filed in this proceeding on July 22, 2022, Duke agreed to perform supplemental planning analysis for the Public Staff to address the need for RZEP projects. Tr. vol. 21, 140.

Witness Roberts testified that on June 27, 2022, the Companies presented the 2021 Plan Mid-Year Update Report to the TAG, including information on the RZEP projects as needed to enable solar interconnections to integrate significant amounts of generation and for executing the Carbon Plan. At that time, the plan 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. To provide sufficient time to construct the RZEP projects necessary to integrate 4.5 GW to 5.4 GW of incremental solar generation between 2026 and 2030, witness Roberts declares that 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. He reports that, based on feedback and additional input received from TAG stakeholders and the Commission's directive in the 2022 Solar Procurement Order, the NCTPC OSC communicated that the RZEP projects would be removed from consideration to be included in the 2021 Plan Mid-Year Update Report. Tr. vol. 16, 68-69.

Witness Roberts states that the Companies continue to support proactive development of the RZEP projects through the NCTPC. He also states the Companies' recognition 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. Through subsequent engagement with Public Staff in response to the Commission directive in the 2022 Solar Procurement dockets, he explains that DEC and DEP agreed to perform supplemental planning studies based on agreed-upon planning assumptions to further evaluate the need for the RZEP. He testifies that the supplemental planning studies reinforce the need for the majority of the RZEP projects, and that the Companies plan to reintroduce the RZEP projects into the NCTPC process as necessary to integrate anticipated future generation and execute the Carbon Plan, 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. Tr. vol. 16, 69-70.

Witness Roberts explains that the Companies view the RZEP projects as a prudent and necessary first step to interconnect to the DEC and DEP systems the volume of solar needed to execute the Carbon Plan. Tr. vol. 16, 70-71. He states that the Companies have provided the substantial evidence required by the 2022 Solar Procurement Order. Specifically, Exhibits 1 and 2 to the Transmission Panel's direct testimony present additional mapping of past generator interconnection studies with the RZEP projects, which reflects the number of past generator interconnection and interdependency grouping studies completed between 2017 and 2021 identifying each RZEP transmission

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[33] In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2.(c), Order Approving Request for Proposals and Pro Forma Power Purchase Agreement Subject to Amendments at 7, Docket Nos. E2, Sub 1297, E-7, Sub 1268 (Jun. 10, 2022) ("2022 Solar Procurement Order").

network upgrade project as necessary for interconnecting solar facilities being studied. He notes that while several of the studies identifying the need for the RZEP projects were conducted under the old serial queue study process, several of these same projects were also identified in the recent Transitional Cluster Study results. Tr. vol. 16, 72.

Duke Energy witness Farver adds that the volume and location of solar projects in the 2022 DISIS support the Companies' view that the RZEP projects are needed to interconnect new generating resources, as a significant volume of 2022 DISIS solar facilities are requesting interconnection in the red zones. Tr. vol. 16, 79-80, Figure 2. Witness Farver also describes the overlap between the location of the RZEP projects and areas of high solar viability, primarily in the red zones. Tr. vol. 16, 80, Figure 3. At the hearing, witnesses Roberts emphasized that the dark green areas in Figure 3 are attractive to solar because they lack, for example, significant forestation, population density, or state or federal parks. Tr. vol. 16, 167; Tr. vol. 19, 61-62.

In addition, witness Farver testifies that the market response in the 2022 Solar Procurement further demonstrates the continued market interest in developing projects in the red zone. She explains that of the approximately 4,900 MW of proposals received, over 70% of the MW are located in known red-zone areas. She notes that these known congested areas were shared with market participants ahead of the 2022 Solar Procurement, and all three CPRE RFPs, and yet this information does not seem to drive project development to non-congested areas in any significant way. She presents in Figure 4 the locations of the proposals in the 2022 Solar Procurement overlaid with the known "red zones." Tr. vol. 16, 81-82.

As additional support, witness Roberts describes the supplemental cluster-like studies of recent solar generator interconnection requests that the Companies conducted to provide additional evidence of the need for the RZEP projects. Specifically, he explains that these studies evaluated the most recent generator interconnection requests for 5.4 GW, which aligns with the level of solar identified by the Carbon Plan Portfolio as needed to meet a 70% Interim Target by 2030. He states 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. 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. He notes that the supplemental study scope and criteria were discussed and agreed upon with the Public Staff in advance of performing the study. Tr. vol. 16, 72-74.

Witness Roberts presents the results of the DEC and DEP supplemental planning studies described at Exhibits 3 and 4 to the direct testimony. For DEC, he explains that the study results support all four RZEP projects identified in DEC as being needed to enable 981 MW of solar projects to be interconnected in the red zones. Tr. vol. 16, 74. For DEP, he explains that the study results support 11 RZEP projects identified in DEP as needed to enable 2,778 MW of solar projects to be interconnected in the red zones. He notes that 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. Tr. vol. 16, 74-75. Witness Roberts also notes that the supplemental studies identified additional network upgrades as necessary to interconnect 5.4 GW or more of solar inside and outside the red zones. Tr. vol. 16, 75-76.

Witness Roberts concludes that the supplemental studies demonstrate that NCTPC approval of the majority of these projects as part of its 2022 Local Transmission Plan is necessary to execute the Carbon Plan and achieve the public policy objectives in HB 951. He also concludes that if the RZEP projects are not approved as part of the NCTPC's Local Transmission Plan, Carbon Plan execution is at risk. Tr. vol. 16, 76.

Witness Roberts also presents the Companies' quantification of the RZEP projects' reliability benefits through cost-benefit analyses. He explains that transmission utilizes two primary value models to quantify Reliability benefits based off investment types. Capacity & Customer Planning investment types utilize a value model that calculates reliability benefits based off observed overload/voltage criteria for the investment and measures the societal impact of an outage to customers utilizing Interruption Cost Estimate or "ICE" Calculator data based off the probability of failure. Conversely, Asset replacement investment types utilize a value model that calculates reliability benefits based off asset deterioration curves for the investment and measures the societal impact of an outage utilizing ICE data based off the probability of failure. He continues that as shown in DEP's Technical Conference CBA materials presented on July 15, 2022, in Docket No. E-2, Sub 1300, the RZEP projects were initially evaluated utilizing the planning value model to quantify reliability benefits of the investment. Since the RZEP rebuild projects involve replacing aging conductors and structures with new, more reliable equipment and new higher capacity conductors generally have lower impedance that reduces transmission losses, Duke Energy also evaluated the RZEP projects utilizing the asset replacement value model to quantify reliability benefits of replacing aging infrastructure. While the value models for these projects is different than the methodology used previously, he states that this evaluation provides a better representation of the benefits being achieved for these investments due to the large aging asset base that is being replaced. He states that the results for the CBA using the asset replacement value model show the four DEC RZEP projects identified in the DEC supplemental study with scores ranging from 5.1 to 22.5 with an average score of 14.6, and the eleven DEP RZEP projects identified in the DEP supplemental study with scores ranging from 10.5 to 21.4 with an average score of 15.5. He explains that these scores do not ascribe any value to compliance with the HB 951 carbon reduction targets or any other carbon reduction value. Using the asset replacement value model, the combined cost-benefit ratio for the 15 RZEP projects identified by the DEC and DEP supplemental studies is 15.1. Tr. vol. 16, 78.

Witness Roberts also identifies a number of additional benefits from the RZEP projects. First, the increase in transmission capability will help to enable solar located in the red zones to charge stand-alone battery storage that is located closer to load centers. In addition, the RZEP projects will replace aging, less resilient equipment with new, more resilient equipment such as replacing wood poles with steel poles. Tr. vol. 16, 71. Finally, he notes non-reliability, cost related benefits of the RZEP projects, citing as an example approximately $140 million of benefits that could be realized by the RZEP enabling three large projects in the 2022 DISIS cluster to be constructed, in lieu of smaller sites outside of the red zones. Tr. vol. 16, 78-79.

Witness Roberts also discusses how the RZEP projects address the risk factors associated with future proactive transmission planning identified by the Public Staff: insufficient time to build large-scale transmission upgrades to allow economically selected generation; and wasted proactive transmission assets. First, he notes the Companies' agreement that proactive transmission planning and associated construction of identified necessary projects is critical to meeting energy transition and Carbon Plan objectives in a timely manner. Second, he does not view future underutilization of the RZEP projects as a material concern because of the historic demonstration of a significant amount of solar that would site and rely on the upgrades. He notes that the Companies' transmission planners do consider and apply engineering judgement when a network upgrade is identified as necessary to provide assurance that the current transmission network upgrade will not need additional upgrades in the foreseeable future. He commits that Duke Energy will continue to engage with Public Staff and other stakeholders through the iterative NCTPC local transmission planning process to ensure that these risks are appropriately considered and prudently managed. Tr. vol. 16, 82-84.

Witness Roberts concludes that the Commission should acknowledge that the RZEP projects are needed to execute the Carbon Plan based on the need for and benefits from implementing the RZEP projects. He states that the Commission's acknowledgement of the need for the RZEP projects to interconnect new solar generation and to meet the objectives of the Carbon Plan will provide strong evidence to the NCTPC that approval of the RZEP projects in the 2022 Local Transmission Plan is a reasonable and prudent step. Tr. vol. 16, 84. In the alternative, he asks that based on the results of the Supplemental Studies, the Commission acknowledge the need for the 15 RZEP projects identified in those studies. Tr. vol. 16, 84.

At the hearing, witness Roberts emphasized that it will be extremely challenging for Duke Energy to implement the amount of solar needed for the Carbon Plan without the RZEP projects. Tr. vol. 16, 187. He also clarified that merging the DEC and DEP balancing authorities, while offering many benefits as discussed by the CUO panel, would not alleviate the need for the RZEP projects. Tr. vol. 17, 39; Tr. vol. 19, 52-54. He noted that the Companies' support for the RZEP projects was part of the need to evaluate transmission planning in a holistic manner. Tr. vol. 17, 39. He and witness Farver testified that the approach taken by the supplemental studies of looking back at previous generator interconnection studies was appropriate to have the specific data needed to conduct the studies. Tr. vol. 19, 38-39. They also clarified that the RZEP projects' cost was reflected in the transmission cost adder used to model the Carbon Plan, and that the model still selected the near-term solar additions with those costs included. Tr. vol. 19, 45-46. They confirmed that the RZEP projects are required for the Companies to interconnect the large quantities of solar generation identified in previous IRPs and the Carbon Plan modeling, and that even with the RZEP upgrade costs included, solar is still a large part of a least-cost Carbon Plan portfolio. Tr. vol. 19, 54-55. Witness Roberts concluded that the RZEP projects will facilitate larger projects with economies of scale and will increase the likelihood of these solar projects moving forward to interconnection agreement. Tr. vol. 19, 66.

Public Staff Direct Testimony

Public Staff witness Metz testifies to the Public Staff's support for the concept of proactive upgrades and least-regrets planning to ensure timely compliance with Section 110.9. Tr. vol. 21, 148. Witness Metz states that he generally believes the supplemental studies support the need for the RZEP projects at this time, subject to certain exceptions and caveats. Tr. vol. 21, 40. He also states that the supplemental study is a valid effort to refine the study process to determine potential proactive upgrades. Tr. vol. 21, 38. He offers that he has no reason to doubt the integrity of the study. Tr. vol. 21, 143.

Witness Metz continues that overall, the Companies used realistic assumptions, which addressed the Public Staff's concerns around speculative generation of solar facilities and changing land availability and went further to isolate solar facilities that were extraneous and required substantial line upgrades that mostly benefited one interconnection request. He notes that the amount of solar MWs studied was the same amount identified in the proposed Carbon Plan, and the study attempted to maintain the solar allocations used in the Carbon Plan. He caveats the Public Staff's support that the study was based on historic queue information, while future generation may have different technical characteristics or points of interconnection, and it 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. He nonetheless concludes that the results of this evaluation in combination with the current DISIS project locations continue to support constructing upgrades that are likely or common to multiple solar projects, and 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. Tr. vol. 21, 142-44.

Regarding DEC, witness Metz testifies that three out of the four proposed transmission 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. He asserts that Project #4, the Clinton 100 kV lines, had many fewer generator facilities necessary to support the upgrade, and that based on the information known to date, he would not recommend DEC build this project 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. He notes his understanding that this potential 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. He also opines that the incremental solar capacity that is dependent on Projects #1 thru #3 or Project #4 is unclear. He asks that the Companies address in rebuttal whether exclusion of Project #4 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 Projects #1 thru #3. He also asks that the Companies explain why Project #4 is needed based on more than just historic interconnection requests, such as the 2022 DISIS results and if there is any potential if further development of solar plus storage would mitigate the need for Project #4. Tr. vol. 21, 145-46.

With regard to DEP, witness Metz states that four out of the proposed transmission projects would facilitate the interconnection of over 50% of the studied solar facilities and nine out of the proposed transmission projects would facilitate the interconnection of solar facilities. He states that this finding suggests a stronger relationship between common upgrades than just the TCS results indicated, highlighting the continued interest of developers to locate in these areas of DEP's system. He references and agrees with the Companies' recommendation to delay three of DEP's transmission projects (Projects #9, #11, and #12) because they did not show a strong dependance in the transmission study. Further, he recommends that Projects #7 and #14 be removed from the RZEP at this time. He asserts that Projects #7 and #14 have approximately 25% of all common upgrades affecting the proposed transmission projects in the study (24% and 26%, respectively); that Project #14 appears relatively small in scope compared to the other transmission upgrades; and that removal of Projects #7 and #14 is separate from the results of a power-flow analysis (or equivalent) or project estimated completion timeline. He asks that the Companies address in rebuttal whether exclusion of Projects #7 and #14 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 and explain how Project #7 is needed based on more than just historic interconnection requests. Tr. vol. 21, 146-47.

Witness Metz continues that interconnection requests are likely to increase in the red zone after Duke Energy completes proactive upgrades of the transmission system. He notes that this increase could create congestion again, and to the extent possible, recommends that the Companies evaluate future proactive upgrades to reflect anticipated interconnections over at least a ten-year horizon and potentially a 20-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. Tr. vol. 21, 149.

Finally, witness Metz asks that the Companies confirm his understanding of the NCTPC process to determining proactive upgrades following the issuance of the Commission's 2022 Carbon Plan. He also recommends that, if the Commission acknowledges the need for proactive transmission upgrades in its Carbon Plan, the Commission also require Duke Energy 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. Tr. vol. 21, 150.

Witness Metz also recommends that the Commission require and approve a cost allocation or cost sharing mechanism for DEC and DEP to share the cost of the proactive upgrades. The flow of power from DEP-located generation to serve DEC load is a concern of the Public Staff. 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. Tr. vol. 21, 150-51.

Intervenor Direct Testimony

CPSA witness Norris testifies that "Duke has amply demonstrated that the RZEP upgrades are needed to achieve compliance with HB 951 and that ratepayers would be well served by the completion of those upgrades as soon as possible." Tr. vol. 26, 25. Witness Norris explains that the additional analysis provided in the supplemental studies further demonstrates that these projects represent a "no-regrets" set of upgrades that will be required to cost-effectively achieve HB 951's carbon reduction targets. He notes that the supplemental study is consistent with CPSA members' experience in developing solar projects in the Carolinas. *Id*. at 63-64. He also notes that although the RZEP will facilitate the addition of a significant amount of additional generation, it is likely that additional upgrades will eventually be needed to fully achieve the goals of HB 951. *Id*. at 64.

CCEBA/MAREC witness Gonatas acknowledges that solar interconnections have been significantly constrained in the red zone and states that a build out into the red zone is urgently required to further solar development. Tr. vol. 22, 122, 136-38.

NCSEA witness Caspary testifies that the RZEP projects are necessary to achieve the 2030 interim targets, but also asserted that planning for additional projects to the RZEP projects would also likely be needed. Witness Caspary acknowledges the efficiency of planning resources and transmission at the same time and agrees with the Companies that the risk that the RZEP projects will be underutilized is low. Tr. vol. 22, 13-15.

NCEMC witness Ragsdale agrees that the supplemental study identifies the common constraints identified in multiple interconnection requests for renewable generation that the RZEP projects would help mitigate. Witness Ragsdale also emphasizes that the expedited timeline for RZEP should not result in the RZEP projects being prioritized over other transmission projects needed for reliability and maintaining service quality for retail and wholesale customers. Tr. vol. 26, 204-05.

Duke Energy Rebuttal Testimony

In rebuttal, witness Roberts testifies that the RZEP projects are a key example of the Companies' commitment to proactive planning. He explains that Duke Energy considers the RZEP projects to be a necessary and appropriate first step in this direction as these projects have multiple value propositions, including replacing aging infrastructure, resiliency improvements, lower impedance, thus lower transmission losses, in addition to facilitating improvement in the pace and volume of interconnection of incremental resources. Tr. vol. 28, 126. He also states that the projects are a key component to reliable and successful execution of the Carbon Plan, explaining that the RZEP projects will allow for more interconnections of solar facilities in the Red Zone, in which to date the significant network transmission upgrades required to interconnection new generation have created insurmountable cost hurdles for developers of one or two projects being asked to bear the upfront burden of that cost. Tr. vol. 28, 126.

In response to the Public Staff, witness Roberts notes that the three lines contested by the Public Staff are located within the high solar viability red zone areas. Tr. vol. 28, 129-30. He argues that the prior generator interconnection studies and supplemental studies demonstrate that the Clinton 100 kV lines and Erwin-Fayetteville 115 kV line are needed in order to integrate 100s of MW of generation in the red zone and that they provide a clear causal relationship between the incremental addition of generation in this region and the need for these projects. Tr. vol. 28, 130.

Specifically, witness Roberts explains that as shown by Exhibit 1 to the panel's direct testimony, the RZEP mapping of prior generator interconnection studies reflects the Clinton 100 kV Black/White lines in DEC's red zone have over 428 MW of solar facilities mapped to needing this network upgrade, and that as shown by Exhibit 3, the DEC supplemental study reflects the Clinton 100 kV B/W lines had the DFax threshold and/or the line Loading Impact threshold exceeded for approximately 740 MW of solar facilities considered in the study. He also explains that as shown by Exhibit 2 to the panel's direct testimony, the DEP RZEP mapping of prior generator interconnection studies reflects the Erwin – Fayetteville 115 kV line in DEP's red zone has over 734 MW of solar facilities mapped to needing this network upgrade in the Transitional Cluster Study alone, and that as shown by Exhibit 4, the DEP supplemental study reflects the Erwin – Fayetteville 115 kV line had the DFax threshold and/or the line Loading Impact threshold exceeded for approximately 625 MW of solar facilities considered in the study. He states that while Duke Energy agrees that Project #14—the Camden–Camden Dupont 115 kV line upgrade—may be able to be postponed at this time, the Companies will pay close attention to this upgrade being needed in the near-term if identified in the 2022 DISIS Phase 1 Study. Tr. vol. 28, 131-132. He presents an updated list of RZEP projects that the Companies are requesting the Commission acknowledge as needed in the initial Carbon Plan at Transmission and Solar Procurement Rebuttal Exhibit 3. Tr. vol. 28, 135.

Witness Roberts explains further that, as noted in the February 2022 DEC Transitional Cluster Study report, the upgrade of sections of the Clinton 100 kV B/W lines is estimated to take 48 months. He notes that if smaller generators are able to interconnect with sections of the Clinton 100 kV B/W lines prior to constructing the RZEP upgrades, additional cost could be incurred through the need for temporary line construction not contemplated in the current project scope. The DEP Transitional Cluster Study Report also reflects that it would take 54 months to upgrade the Erwin – Fayetteville 115 kV line. Even though DEP plans to accelerate this schedule, if delayed and outages need to be scheduled beyond 2026 that would be competing for the same outage window needed for implementing the upgrade to the Erwin-Fayetteville 115 kV line, this delay in the upgrade schedule could delay interconnecting generators dependent on this RZEP upgrade. Witness Roberts concludes that the Clinton 100 kV B/W lines and the Erwin – Fayetteville 115 kV line should therefore remain in the list of RZEP projects for which the

Companies are requesting Commission acknowledgement that they are necessary for executing Carbon Plan portfolios at this time. Tr. vol. 28, 132-33.

Witness Roberts clarifies that the next steps in the NCTPC process for incorporating the RZEP projects are to: 1) present the updated status of the RZEP projects to the TAG stakeholders and receive feedback/input on the projects, and 2) seek approval from the NCTPC to include the RZEP projects in the 2022 Local Transmission Plan. He states that the Commission's acknowledgement that the proposed RZEP projects are needed to interconnect new solar generating facilities and necessary for execution of the Carbon Plan would bolster the position that the RZEP projects need to be included in the 2022 NCTPC Local Transmission Plan. Tr. vol. 28, 133. He also clarifies that Duke Energy continues to believe that all of the originally identified RZEP projects are necessary to interconnect the volumes of solar needed to meet HB 951 targets and progress the system-wide Carolinas energy transition, though their current request is for acknowledgement of the 14 projects listed in Rebuttal Exhibit 3. Tr. vol. 28, 135. He also states that regardless of the outcome of the Commission's acknowledgement of the RZEP projects being necessary, the Companies will 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. Tr. vol. 28, 136.

Finally, witness Roberts agrees with NCEMC regarding not prioritizing RZEP projects over other transmission projects needed for reliability and maintaining service quality for retail and wholesale customers, and states that the Companies will continue to engage with affected systems in the context of generator interconnections as contemplated in the OATT. Tr. vol. 28, 127.

Witness Roberts concludes that, in response to the Commission's 2022 Solar Procurement Order, the Companies conducted supplemental studies to provide substantial evidence of the necessity of the RZEP projects to achieve the goals of the Carbon Plan, the results of which were included in the Panel's direct testimony. Given the Commission's directives in the 2022 Solar Procurement Order, he states that the Companies are therefore seeking Commission acknowledgement that there is substantial evidence demonstrating the need for the 14 RZEP projects listed at Rebuttal Exhibit 3 for implementation of Carbon Plan portfolios. Tr. vol. 28, 134.

At the hearing, witness Roberts confirmed that even if it did not have the history of generator interconnection requests seeking to interconnect in the Red Zone, Duke Energy would choose to site the solar generation it needs to execute the Carbon Plan in the Red Zone for the reasons discussed above. Tr. vol. 29, 54-55.

Discussion and Conclusions

As evidenced by Appendix P and the testimony provided in this proceeding, transmission planning, and the RZEP projects specifically, are key factors that will impact the Companies' ability to reliably and successfully interconnect new generation resources, execute a Carbon Plan, and accomplish an orderly energy transition. The Commission agrees with the Companies that HB 951 and the energy transition more generally will require the development of new generation and other resources, and that these new resources will necessarily inform the Companies' transmission planning going forward. As referenced by Duke Energy witness Roberts, HB 951 specifically contemplates that the Carbon Plan consider transmission (and distribution) to achieve the least cost path to compliance with the carbon reduction goals. N.C.G.S. § 62-110.9(1). Considering the significant amount of new solar generation that the Companies must connect in order to meet the HB 951 interim and long-term targets, as well as the other near term actions of adding new generation and coal retirements that the Carbon Plan and energy transition more generally entail, the Commission agrees with Duke that an effective transmission planning process is necessary for system adequacy and reliability as the Companies navigate the pathway toward retiring coal generation and meeting Carbon Plan objectives. The Commission also agrees with Duke Energy's view of the transmission planning process as a key enabler of achieving the goals of the Carbon Plan and successfully navigating the energy transition.

The Companies Should Continue to Study Future Transmission Needs Through the NCTPC

Based on the evidence presented and the entire record in this proceeding, the Commission finds and concludes that it is reasonable for the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the NCTPC as well as SERTP and other transmission planning forums identified in Appendix P and discussed by witness Roberts.

As detailed by Appendix P and the Companies' testimony, and discussed extensively during the hearing, the NCTPC is the entity through which the Companies conduct local transmission planning in compliance with FERC requirements. Attachment N-1 to the Companies' Joint OATT provides a detailed process by which DEC and DEP together with Electricities and NCEMC conduct local transmission planning through the NCTPC with stakeholder input provided by the TAG. Duke Energy and other utilities conduct regional transmission planning through the FERC-approved SERTP process.

There is general recognition among the parties of the need to shift from the traditional reactive transmission planning that has historically been conducted through the NCTPC toward more proactive, scenario-based transmission planning. The benefits of proactive transmission planning as opposed to traditional reactive planning are well documented in the record. A number of intervenors offered suggestions for how the Companies and NCTPC can evolve toward a more proactive, multi-value scenario planning approach as well as other ways to improve upon the NCTPC local transmission planning process. The Companies agree that changes are needed, and support transitioning to more proactive, scenario-based transmission planning. DEC and DEP have stated their plan to continue to pursue that transition going forward, while noting that any such changes will need to be implemented consistent with the requirement to obtain FERC approval where needed.

The Commission declines to initiate any additional Commission proceedings regarding transmission planning or require the Companies to implement any specific changes to their transmission planning processes. The Companies have acknowledged that the NCTPC process needs to evolve and agree that evolution should be toward more proactive and scenario-based planning. As the Companies stated, it would be useful for the NCTPC to initiate a review of its processes as it has done previously. Additionally, there may be improvements to be considered based on the ongoing FERC NOPR that could apply to local transmission planning. Duke Energy and the other members of the NCTPC can pursue such review and any resulting changes consistent with NCTPC process and FERC requirements, and do not need a Commission directive to do so.[34] The Companies should continue to address their transmission planning and grid transformation efforts, including the scope and results of any review of NCTPC processes, in future Carbon Plan updates.

With regard to GETs and advanced transmission technologies, the Companies' testimony demonstrates that they already do consider such technologies in the course of transmission planning and no requirement is needed for them to do so. The Commission finds that the Companies should continue to consider these technologies in conducting transmission planning and report on such consideration in future Carbon Plan updates.

While we decline to establish any transmission planning specific proceedings or require specific changes to Duke Energy's transmission planning process, the Commission concludes that it is appropriate and reasonable to direct the Companies to continue to study future transmission needs to meet Carbon Plan objectives through the NCTPC. We note witness Roberts' testimony that Duke Energy will continue to engage with the FERC NOPR proceeding and implement FERC Orders on changes to transmission planning processes in its OATT, as well as engage with NCTPC OSC members in reviewing and improving NCTPC Local Transmission Planning processes to include the necessary proactive planning process steps for cost-effective transmission planning for the transmission systems within DEC and DEP. Based on the evidence presented, the Commission concludes that the NCTPC provides an appropriate forum in which the Companies can work to shift to the more proactive transmission planning that all parties agree is needed.

As evidenced by the Companies' pursuit of the RZEP projects, the NCTPC also provides an appropriate forum for Duke Energy to continue to work to align transmission

[34] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 107 (2011) (acknowledging "longstanding state authority over certain matters relevant to transmission planning and expansion, such as matters relevant to siting, permitting, and construction"); Order No. 1000-A, 138 FERC ¶ 61,132 at PP 186-190 (2012) (reiterating that nothing in these orders "is intended to preempt or otherwise conflict with state authority over siting, permitting, and construction of transmission facilities or over integrated resource planning and similar processes" and clarifying that "Order No. 1000's transmission planning reforms are concerned with process but are not intended to dictate substantive outcomes such as what transmission facilities will be built and where").

planning and resource planning, which multiple parties agree is needed going forward to execute the Carbon Plan. We are persuaded by the Companies' testimony that the reactive nature of relying on commitments in generator interconnection agreements before beginning construction of transmission network upgrades to enable new generator interconnections will not support the pace or volume of interconnecting resources necessary to implement the Carbon Plan. The Commission sees the value of a proactive, scenario-based transmission planning approach as necessary to meet the requirements of the Carbon Plan in a cost-effective manner, and concludes that the FERC-approved NCTPC, as well as SERTP regional processes, continue to offer the forum for the Companies to evolve their transmission planning in this manner.

With regard to arguments about cost allocation and inclusion of the RZEP projects in the MYRP, aside from noting the potential for some of these projects to be included in a MYRP, we conclude that such issues are beyond scope of the Carbon Plan and this proceeding, and the Commission will address those issues, if raised, in other dockets as appropriate.

Need for the RZEP Projects

In the 2022 Solar Procurement Order, the Commission found that including the RZEP projects in the 2022 DISIS baseline would be premature due to the lack of competent evidence that the RZEP projects were necessary to achieve the Carbon Plan and encouraged the Companies and other parties supporting the RZEP projects to provide that evidence in this proceeding. To address this directive, the Companies presented the DEC and DEP supplemental studies of the RZEP projects with their direct testimony. Based on the supplemental studies and after reviewing the Public Staff's testimony, the Companies included 14 RZEP projects in Exhibit 3 to the Transmission and Solar Procurement Panel's rebuttal testimony for which they request the Commission's acknowledgement as needed for purposes of executing the Carbon Plan. Based on the totality of the evidence presented and as discussed further below, the Commission concludes and acknowledges that these 14 projects are needed in order to execute the Carbon Plan.

There is widespread agreement among the parties regarding the existence of the red zone, the high solar viability region of DEC's and DEP's service areas in which solar generation developers continue to locate projects despite the known challenges. CPSA witness Norris confirmed that the supplemental study is consistent with CPSA members' experience in developing solar projects in the Carolinas.

There is also widespread agreement among many parties that the near-term action of developing and constructing the RZEP projects is a critical path step to executing the Carbon Plan. Witness Roberts and others, including witnesses Metz, Norris, and Caspary also acknowledge that while the RZEP projects are a necessary first step, they are only the first step, and that more transmission upgrades like them will likely be needed as the Companies proceed toward the 2050 carbon reduction target. The Companies' continued study of future transmission needs through the NCTPC as directed herein will allow for increased understanding of the need for future RZEP projects or other needed transmission projects going forward, and the Companies should update the Commission on any additional needed transmission projects in its Carbon Plan updates.

The Commission concludes that the supplemental studies provide the substantial and competent evidence that we found lacking earlier this year to support the need for the RZEP projects to execute the Carbon Plan. Specifically, the supplemental studies show that the RZEP projects will enable the interconnection of 3,600 MW of solar generation. No party contested the Companies' general method for conducting the supplemental studies. The Public Staff caveated its support and identified limitations to the studies, which were conducted within a matter of a few weeks, but did not identify any errors or other reasons to question the integrity of the studies. Taken together with the additional considerations of the history of the RZEP projects' need as identified in generator interconnection studies and the Transitional Cluster Study, the mapping of interconnection requests to the red zone, the cost-benefit analyses, and the reliability and other secondary benefits as presented in Duke Energy's direct testimony, and the time required to interconnect solar generation as demonstrated by recent history, and the testimony of the Companies' witnesses that even a combination of the DEC and DEP balancing authorities will not eliminate the need, the Commission is persuaded that these projects are generally needed in order to execute the Carbon Plan.

While the Public Staff overall is supportive of Commission acknowledgement of the RZEP, there remains limited disagreement with the Companies with regard to the need for two of the RZEP projects, the Clinton 100 kV B/W lines and the Erwin-Fayetteville 115 kV line. The Public Staff questions the need for the Clinton 100 kV lines in DEC (project #4), and the Erwin-Fayetteville 115 kV and Camden-Camden Dupont lines in DEC (projects #7 and #14). The Companies agreed in rebuttal testimony that the Camden-Camden Dupont line can be postponed but continued to support the other projects as needed.

Based on the evidence presented, the Commission agrees with the Companies that the Clinton and Erwin-Fayetteville lines should be pursued at this time through the NCTPC, and the Commission acknowledges that these lines are needed to interconnect significant new solar generation and to reliably and successfully execute the Carbon Plan. In reaching this conclusion, the Commission is persuaded by the concrete justifications for the need for these projects presented by the Companies. These include that both projects are located within the high solar viability red zone areas.

With regard to the DEC Clinton lines specifically, we are also persuaded due to (1) the RZEP mapping of prior generator interconnection studies reflecting that the Clinton 100 kV Black/White lines have over 428 MW of solar facilities mapped to needing this network upgrade, (2) the DEC supplemental study reflects the Clinton 100 kV B/W lines had the DFax threshold and/or the line Loading Impact threshold exceeded for approximately 740 MW of solar facilities considered in the study, (3) the February 2022 DEC Transitional Cluster Study report shows that the upgrade of sections of the Clinton 100 kV B/W lines is estimated to take 48 months, and (4) if smaller generators are able to interconnect with sections of the Clinton 100 kV B/W lines prior to constructing the RZEP upgrades, additional cost could be incurred through the need for temporary line construction not contemplated in the current project scope.

With regard to the DEP Erwin-Fayetteville 115 kV line, we are persuaded due to (1) RZEP mapping of prior generator interconnection studies reflects the Erwin – Fayetteville 115 kV line has over 734 MW of solar facilities mapped to needing this network upgrade in the Transitional Cluster Study alone, (2) the DEP supplemental study reflects the Erwin–Fayetteville 115 kV line had the DFax threshold and/or the line Loading Impact threshold exceeded for approximately 625 MW of solar facilities considered in the study, (3) the DEP Transitional Cluster Study Report shows that it would take 54 months to upgrade this line, and (4) even though DEP plans to accelerate this schedule, if delayed and outages need to be scheduled beyond 2026 that would be competing for the same outage window needed for implementing the upgrade to this line, this delay in the upgrade schedule could delay interconnecting generators dependent on this RZEP upgrade.

The Commission notes in reaching this conclusion that the Companies originally proposed 18 RZEP projects and removed three projects from its "alternative" request for acknowledgement with their direct testimony based on the supplemental studies. The Companies then agreed with the Public Staff's recommendation to remove the Camden–Camden Dupont 115 kV line upgrade (project #14) from the list of projects sought for acknowledgement, while noting that they will pay close attention to this upgrade being needed in the near-term if identified in the 2022 DISIS Phase 1 Study. The Companies therefore demonstrated reasonableness in their willingness to reevaluate the need for these projects, lending further support to the remaining projects that the Companies have determined truly need to be pursued at this time.

These reasons are in addition to the Commission's overall recognition that the RZEP projects have grown to be significant and long-existing areas of constraint in high solar viability areas of the Companies' transmission systems, that the Companies must interconnect up to 5.4 GW solar. We are also persuaded by the Companies' testimony that the RZEP projects' cost was reflected in the transmission cost adder used to model the Carbon Plan, and that the model still selected the near-term solar additions with those costs included. Additionally, we find persuasive Duke Energy's testimony that including the RZEP projects in the DISIS baseline and constructing the projects will allow the Companies to meet the obligation to interconnect the new solar generation needed to comply with HB 951 at least cost.

Based on the evidence presented regarding the cost-benefit analyses of the RZEP projects, and testimony provided by the Companies regarding the improved reliability, resiliency, and lower impedance that will result from the projects, the Commission also concludes that the RZEP projects will provide system benefits for Duke Energy. In making these conclusions, the Commission gives substantial weight to witness Roberts' testimony on this subject, due to his expertise with the complex considerations involved with transmission planning on the Companies' system, which was not questioned in this proceeding.

The Commission finds value in the Public Staff's suggestion that the Companies provide updates on the status and cost of the RZEP projects as they progress. However, several of the projects have been included in DEP's proposed multi-year rate plan (MYRP) in Docket No. E-2, Sub 1300. To the extent therefore that any RZEP projects are approved as part of the DEP MYRP, the Companies may file the most recent construction status report required by Rule R1-17B(h)(2) for those projects, in this docket on a semi-annual basis, and for any projects not approved as part of the DEP (or DEC) MYRP, file information in a similar format to the construction status report at the same time.

Based on the foregoing, the Commission concludes that the Companies have met the directive of the 2022 Solar Procurement Order and presented substantial and competent evidence that the 14 RZEP projects listed at Transmission and Solar Procurement Panel Rebuttal Exhibit 3 are needed to reliably and successfully execute the Carbon Plan, and we acknowledge that these 14 projects, including the Clinton 100 kV B/W lines and the Erwin–Fayetteville 115 kV line, are needed. The Commission also concludes that the RZEP projects will provide system benefits such as reliability, resiliency, and lower transmission losses as discussed herein.

PLANNING FOR CONSOLIDATED CAROLINAS UTILITIES OPERATIONS AND POTENTIAL MERGER OF DEC AND DEP (Findings of Fact Nos. 49-52)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-52

The evidence supporting these findings of fact are set forth in Duke Energy's proposed Carbon Plan, the testimony of Duke Energy' Consolidated Carolinas Utilities Operations Panel and Modeling and Near-Term Actions Panel, the Rebuttal Testimony of Duke Energy witness Bateman, the testimony of Public Staff witnesses Thomas and McLawhorn, the testimony of AGO witness Burgess, the testimony of CIGFUR witnesses Muller and Gorman, and the entire record in this proceeding.

Summary of the Evidence

Rate Differences and Merger

Duke Energy Testimony

Appendix R to Duke Energy's proposed Carbon Plan explains that DEC and DEP currently operate as separate NERC registered Balancing Authorities (BA), Transmission Operations (TOP), and Transmission Service Providers (TSP) and plan as separate NERC registered Transmission Planners. Carbon Plan, App'x R, 1. As registered BAs, the Companies separately integrate unit commitment plans ahead of time, maintain generation-load-interchange-balance within each Balancing Authority Area and contribute to interconnection frequency in real time. DEC has one Balancing Authority Area, and DEP has two Balancing Authority Areas. As registered TOPs, the Companies are responsible for the real-time operating reliability of the transmission assets in their separate TOP Areas. The Duke Energy TOPs have the authority to take certain actions to ensure that they operate reliably. As registered TSPs, Duke Energy administers the

FERC-approved open access transmission tariff (OATT) for the separate Duke Energy transmission zones and provides transmission service to transmission customers under applicable transmission service agreements. *Id*. In response to a question from Chair Mitchell, witness Peeler explained that the Carbon Plan was developed and modeled assuming consolidation of these system operations. Tr. vol. 16, 25; *see also* Carbon Plan, App'x E, 8.

On behalf of the Carolina Utilities Operations Panel, witness Peeler explains that Duke Energy is proposing to consolidate system operations—including the BA, TOP, and TSP operating functions—through a merger of DEC and DEP. Tr. vol. 15, 24. Witness Peeler explains that consolidated operations provide a number of customer benefits, including lowering reserve requirements, improving dispatch efficiencies, reducing CO_2 emissions, and allowing more solar generation to serve Duke Energy's customers. *Id.* According to witness Peeler, combining into a single balancing authority to manage load and resources produces savings annually for customers, helps accommodate expanded levels of variable renewable energy resources, substantially reduces forced solar curtailment, and eliminates several hundred annual CT starts that increase fleet maintenance costs. Tr. vol. 15, 24; Carbon Plan, App'x R, 2. Witness Peeler explains that each of these improvements provide annual direct benefits to customers in the form of lower fuel costs and reduced CO_2 emission. Tr. vol. 15, 24. Accordingly, the Modeling and Near-Term Actions Panel confirms that the Carbon Plan assumes consolidated system operations in its modeling. Tr. vol. 7, 292; Carbon Plan, App'x E, 8.

Witness Peeler explains that Duke Energy believes a merger of DEP and DEC is the best long-term path to achieve the benefits of consolidated operations for a number of reasons, including addressing rate differences between DEC and DEP over time, helping to moderate rate impacts by spreading new investments over a larger customer base, reducing complexity, and achieving regulatory efficiency. Tr. vol. 15, 25.

Importantly, witness Bateman explains that a merger is the most straightforward and direct way to address rate differences between DEC and DEP. Tr. vol. 15, 29. According to witness Bateman, if stakeholders and regulators can agree on an approach that is equitable to all jurisdictions, customer classes and the Companies, and a merger receives the necessary approvals, there are various approaches to preventing further rate divergence and addressing historical differences between DEP and DEC. Tr. vol. 15, 30. The Companies could adopt the approach taken Florida Power & Light, conduct cost of service studies for both the standalone and merged entities, and propose a rider that would move the rates from the standalone cost of service study for each utilities' customers to the combined one over a five-year period. Tr. vol. 15, 30. In the alternative, Duke Energy could create a combined cost of service study with one rate base and combined accounting records but maintain the separate legacy rate schedules. In each rate case, the combined utility could apply the new rate increase for each customer class to the legacy rate schedules within the class and then also make further adjustments to move the rate schedules closer together over time. This approach leaves more flexibility to consider other factors in each rate case rather than committing to a fixed five-year schedule and is consistent with how the Companies currently address rate schedules that vary from the cost of service within a rate class. This is similar to the approach that DEC took after the merger with Nantahala Power & Light Company. Tr. vol. 15, 31.

Witness Bateman notes that these two options address base rates, but Duke Energy will also have to propose how to combine the riders, the most impactful of which will be the fuel riders. As witness Bateman explains, the jurisdictional shifts in cost would happen right away, but the Commission would have discretion on how quickly to merge the DEC and DEP rates within the retail jurisdiction. Tr. vol. 15, 22.

In addition to merging the rates, witness Bateman notes that there are numerous complexities that will need to be worked through before the rate schedules can be fully merged. For example, DEC currently offers voltage differentiated rates for commercial and industrial customers while DEP does not. DEC's fuel rates are differentiated between commercial and industrial, not by rate schedule. DEP fuel rates follow the rate schedules and are not different between commercial and industrial. These are just a few examples. Tr. vol. 15, 22.

Duke Energy is also evaluating alternatives to achieve equitable allocation of Carbon Plan costs in the event merger cannot be achieved. Tr. vol. 15, 32-33. For example, witness Bateman explains that the Companies are evaluating whether DEC could own solar generation in DEP's service territory and whether DEP and DEC could jointly own offshore wind generation. *Id.* at 33-34.

Witness Bateman explains that Duke Energy is also looking at the allocation of transmission investments. Even without a merger of DEC and DEP, CSO would require a combination of the balancing authorities and a combined OATT rate for wholesale customers. The Companies could take a similar approach in retail rates and combine the transmission costs for DEP and DEC and then allocate them back to the separate utilities based on a transmission allocation method. Tr. vol. 15, 34-35.

Public Staff and Intervenor Testimony

Public Staff witness McLawhorn testifies that, on average, DEP's customers pay rates that are substantially higher than those of DEC's customers even though the rates of both utilities have been found to be just and reasonable. Tr. vol. 23, 91-92. Witness McLawhorn acknowledges that some amount of rate difference is expected given that DEC and DEP are separate utilities, each possessing a unique service territory, customer base, and generation, transmission, and distribution assets. Tr. vo. 23, 92. However, witness McLawhorn expresses concern that such rate differential have grown significantly since the 2012 merger. *Id.* Witness McLawhorn notes that there are many issues that could have contributed to this growing disparity over time, but points to the impact of the significantly greater amount of solar generation developed in DEP's service territory, along with associated transmission and distribution system upgrades, as a likely significant driver of the current disparity. Tr. vol. 23, 93.

Witness McLawhorn notes that Section 110.9 presents a state-wide mandate to achieve a 70% reduction in carbon dioxide emissions from 2005 levels by 2030 and carbon neutrality, including through the development of additional significant amounts of solar and other renewable generation. According to witness McLawhorn, DEP's service territory will continue to be the likely location for much, if not all, of the solar, solar plus storage, and onshore wind resource development, and any offshore wind generation will require significant transmission development and upgrades on DEP's system. Tr. vol. 23, 96. Witness McLawhorn expresses concern that DEP's retail customers will absorb a disproportionate share of the costs to achieve statewide compliance with the Carbon Plan without action to address the growing rate differences. Witness McLawhorn further notes that it may become increasingly difficult to recruit new economic development into DEP's service territory, and the higher electricity costs will likely drive out existing business. Tr. vol. 23, 97.

To address these concerns, witness McLawhorn states that "the most efficient way to achieve a least cost Carbon Plan is through a full merger of DEC and DEP." Tr. vol. 23, 91 Witness McLawhorn states that the Public Staff recommends that the Commission order the utilities to begin implementing plans to merge DEC and DEP into a single utility as soon as reasonably practicable. Tr. vol. 23, 102. In addition, the Public Staff recommends that the Commission instruct Duke Energy to take immediate steps to allocate all Carbon Plan costs proportionately between DEC and DEP to ensure that DEP customers to not disproportionately bear costs incurred to achieve system-wide carbon reductions. Finally, the Public Staff recommends that the Commission require the Companies to work with the Public Staff and other interested intervenors to develop a plan for this allocation. Tr. vol. 23, 102. At the hearing, witness McLawhorn stated that the merger timeline presented by the Companies appeared reasonable. Tr. vol. 23, 145.

On behalf of the AGO, witness Burgess states that he is supportive of the proposal to consolidate balancing authorities for a variety of reasons, including that it will aid in the integration of variable resources, improve operational efficiency and reduce related operating costs, and enhance reliability. Tr. vol. 25, 303. NCEMC witness Fall similarly states that NCEMC is supportive of the proposed consolidation of DEC and DEP system operations. Tr. vol. 23, 308. Witness Fall notes that consolidation of system operations presents a broad range of customer benefits, including operational efficiencies and cost savings benefiting transmission customers. Witness Fall further acknowledges that a merger of DEC and DEP presents even greater overall potential benefits to Duke's retail and wholesale customers. Tr. vol. 23, 308. Further, witness Fall states that the merger timeline presented by Duke Energy witness Bateman appears reasonable. Ultimately, witness Fall states that NCEMC recommends that the Commission issue a procedural order to establish stakeholder engagement and reporting timelines consistent with the schedule proposed by Duke Energy. Tr. vol. 23, 308-09.

Duke Energy Rebuttal Testimony

In her Rebuttal Testimony, witness Bateman reiterates that one of the primary reasons for the current and historic rate differences between DEC and DEP is fuel costs. Tr. vol. 28, 54. DEC has a higher percentage of low fuel cost nuclear generation than DEP has. In addition, due to its geographic location, DEP has higher fuel transportation costs than DEC does. These fuel differentials have led to DEP having higher avoided cost rates than DEC, which has contributed to DEP's higher volume and cost of PURPA contracts, and to a higher DSM/EE rate. Tr. vol. 28, 54. Witness Bateman agrees with Public Staff witness McLawhorn that these types of differences can be expected based on unique characteristics of each utility. Witness Bateman additionally notes that while DEP's rates are higher than DEC's, they are still below the national average. Tr. vol. 28, 54. In response to a question from Commissioner Clodfelter, witness Bateman explained that the existing rate difference is not the result of something that Duke Energy has done wrong or that Duke Energy should have been working to remediate since the time of the merger. Tr. vol. 28, 100. Instead, as Public Staff witness McLawhorn acknowledges, the disparity is the result of a variety of regulatory requirements with which DEP was required to comply, such as the purchase of solar PPAs under PURPA. Tr. Vo. 28, 100-01. In response to questions from Chair Mitchell at the hearing, witness Bateman stated that the Companies have sought to make DEC's and DEP's rates as low as possible, not more even. According to witness Bateman, one utility subsidizing the other would violate the Companies' Regulatory Conditions Code of Conduct. In other words, the Companies do not charge DEC customers more to make the rates more even. Tr. vol. 28, 111. Witness Bateman agreed with witness McLawhorn that because HB 951 is a statewide policy, the cost of complying should be spread more even across DEC and DEP. Tr. Vo. 28, 102. Witness Bateman explained that four of the six Carbon Plan portfolios reduce the rate difference in 2026, and the other two increase the rate difference by just 8 cents per MWh and 55 cents per MWh, respectively. Tr. vol. 28, 102.

Looking to the future, witness Bateman stated that Duke Energy agrees with witness McLawhorn that merger is the most straightforward way to address rate differences. Nevertheless, witness Bateman explains that the Companies do not believe an interim cost allocation is necessary given the timing of the Carbon Plan investments and the timing of the merger. Tr. vol. 28, 56. Witness Bateman explains that the projected impact of Carbon Plan investments on current rate differences prior to the targeted merger date of the end of 2026 is "minimal to non-existent." Tr. vol. 28, 56. Given that, Duke Energy believes that attention and resources should be devoted toward pursuing the potential merger rather than pursuing a stop-gap method for cost allocation that is not needed at this time. *Id*.

Continued Dual-State System Operations and Planning

Duke Energy Testimony

Chapter 1 of the Carbon Plan explains that the Companies operate two dual-state electricity systems serving North Carolina and South Carolina. In other words, North Carolina customers are served, in part, by South Carolina-sited generation, and South Carolina customers are served, in part, by North Carolina-sited generation. Carbon Plan, Ch. 1, 1. Witness Peeler explains that Duke Energy has successfully operated its dual-state systems for more than a century and customers from both states have benefitted from the scale and diversity of the dual-state system. Tr. vol. 14, 34. As witness Peeler explains, this effective model leverages efficiencies, scale, and geographic characteristics to provide reliable and increasingly clean energy to customers at affordable rates. Resources have been selected to meet combined needs and have been located in the most economic locations. Witness Peeler notes that dual-state planning has allowed the Companies to take advantage of the geographic diversity of the two states for investment in the nation's second largest nuclear fleet and in significant flexible resources, such as pumped storage. *Id.*

According to witness Peeler, it is not feasible to separate existing assets by state boundary as assets located in each state do not match the state-specific needs, but rather serve the collective requirements of both states. Tr. vol. 15, 35. Further, the Companies' transmission and distribution lines cross the border between North Carolina and South Carolina, and electrons flow both ways. Continuing to plan and operate the dual-state systems allows for the most economic dispatch of existing assets and the most efficient planning for future investments. The dual-state system provides both scale and flexibility to operate reliability and economically with increasing amounts of variable generation resources over the coming decades. Tr. vol. 15, 35.

Finally, witness Peeler explains that moving away from the dual-state system developed over the last century would be extremely complex and that operating with a single stack economic dispatch model and joint commitment is the most efficient for all customers. Tr. vol. 15, 36-37.

In response to Chair Mitchell's questions at the hearing, witnesses Bateman and Peeler stated they were hopeful about the future of dual-state planning and operations in North and South Carolina and that the Companies have successfully navigated through jurisdictional issues in the past and are actively engaged in doing so now. Tr. vol. 16, 32.

Public Staff and Intervenor Testimony

CIGFUR's witnesses each express concern regarding the potential for additional costs to North Carolina customers in the event that the Public Service Commission of South Carolina (PSCSC) rejects the carbon Plan or otherwise disallows cost recovery of costs to comply with HB 951. Tr. vol. 25, 355; Tr. vol. 22, 22. Witness Muller states that CIGFUR believes that Duke Energy's North Carolina customers should be held harmless for the South Carolina jurisdictional allocable portion of the Carbon Plan implementation and compliance costs. Tr. vol. 25, 355. In addition, witness Muller advocates for some modification of the carbon plan in the near-term (until 2024) as a hedge against the substantial regulatory risk that the PSCSC rejects the Carbon Plan. *Id.*

On behalf of the Public Staff, witness Thomas states that the Public Staff does not believe Duke Energy should perform additional modeling to address the risk that the PSCSC does not approve some or all of the Carbon Plan. According to witness Thomas, the Public Staff is concerned that the PSCSC could potentially disallow recovery of these costs, but believes it is premature at this time to model the impact on system operations and portfolio costs. Tr. vol. 25, 57. Witness Thomas also noted that it may be practically difficult to model this impact on the system. Tr. vol. 21, 57.

Duke Energy Rebuttal Testimony

In her Rebuttal Testimony, witness Bateman reiterates that the Companies believe that the focus of this proceeding should be on the near-term resource development and procurement activities and, as stated in the Carbon Plan, such near-term resources are no-regrets resources. Tr. vol. 28, 60. At the hearing, witness Bateman stated that she remains optimistic of the potential for continued dual-state operations and planning and noted that Duke Energy is working on developing a framework that can maintain the dual-state system, which the Companies believe to be a benefit to customers, in the event the PSCSC does not adopt the Carbon Plan portfolios. Tr. vol. 28, 85. According to Witness Bateman, all Portfolios add at least 7,000 MW of solar and North Carolina accounts for 80% of the combined DEC and DEP load meaning that the additional solar and solar plus storage to be procured prior to the next Carbon Plan Update will be needed for North Carolina customers regardless of any decision by the PSCSC. Tr. vol. 28, 60.

In addition, Duke Energy will submit its next comprehensive IRP in South Carolina in 2023 informed by the Carbon Plan to pursue continued dual-state planning. Carbon Plan, Ch. 4, 41; Tr. vol. 7, 233. This, along with other regulatory proceedings, will provide more clarity regarding the options available to facilitate continuation of the dual-state system while allowing for differences in state policy. Tr. vol. 28, 61.

If full continued state planning alignment is not achieved, witness Bateman testified in response to Commissioner Clodfelter's question that Duke Energy is in the early stages of identifying potential alternatives that preserve dual-state operations while allowing each state to bear costs and receive benefits associated with new resource decisions. Such an alternative might include an arrangement referred to as "opt-in/opt-out" pursuant to which the costs and benefits of new resources added to the system would be allocated between the states based each state's respective decisions. Tr. vol. 16, 19; Tr. vol. 28, 61.

Discussion and Conclusions

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

The Commission finds that it is appropriate for the Companies to pursue merger of DEC and DEP according to the timeline set forth in the panel testimony of Witnesses Peeler and Bateman. All parties appear to support merger, and the record shows potential planning, operational and cost benefits to customers. The merger is the most straightforward approach to resolving retail rate differences between DEC and DEP and should result in even greater operational efficiencies. The Companies are hereby directed to the keep the Commission apprised of any material developments or material changes in such schedule.

With respect to the Public Staff's recommendation to address existing and future rate differences (and related cost allocation issues), the Commission appreciates Public Staff's focus on ensuring future Carbon Plan costs are fairly allocated across all customer classes, but does not believe it is necessary for the Companies to implement stop-gap cost allocation approaches for Carbon Plan-related investments pre-merger given the minimal impacts in the short-term prior to the targeted merger date. However, in the event that it becomes clear a merger is not able to be achieved the Commission directs the Companies to work with the Public Staff to develop alternative cost allocation approaches for Carbon Plan costs.

The Commission is also persuaded of the ongoing and future benefits of dual-state planning and operations. As the Commission previously noted in its February 1, 2021, order in Docket Nos. E-2, Sub 1283 and E-7, Sub 1259, "[t]he DEP and DEC systems, each of which operates as a single integrated system across both North Carolina and South Carolina, for many generations have provided reliable, efficient, and affordable electricity to the residents of both states." The Commission continues to believe that a path forward that involves continuation of dual-state planning and operation is in the best interest of customers. While the Commission acknowledges that South Carolina is not bound by North Carolina law, the Commission believes that the continued energy transition reflected in this Carbon Plan is consistent with prudent and reasonable planning practices and will provide benefits to customers over the short and long-term. The Commission also finds persuasive the testimony of witnesses Bateman and Peeler that Duke Energy has successfully navigated jurisdictional issues in the past and is actively engaged in doing so now. The Commission will continue to monitor developments in South Carolina and assess in future Carbon Plan proceedings whether and to what extent modifications to the Carbon Plan are needed based on the regulatory and policy decisions of South Carolina. The Commission is also optimistic that continued alignment between the states can be achieved, particularly in light of impacts of the IRA, changing regulatory environment, and other market factors that support the energy transition. Finally, the Commission is persuaded that the near-term plan approved in this Carbon Plan are "no-regrets" actions regardless of the ultimate outcome in terms of dual-state planning alignment.

ENSURING SYSTEM RELIABILITY (Findings of Fact Nos. 53-54)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 53-54

The evidence supporting these findings of fact is set forth in Duke Energy's proposed Carbon Plan, the testimony of Duke Energy's Reliability Panel and Modeling and Near-Term Actions Panel, the testimony of Public Staff witnesses Thomas and Metz, AGO witness Burgess, NCSEA et al. witness Fitch, CIGFUR witness Muller, CIGFUR witness Gorman, CPSA witness Hagerty, NC WARN witness Powers, and NCEMC witness Fall, the initial comments of the Public Staff, CUCA, NC WARN, and NCEMC, and the entire record in this proceeding.

Summary of the Evidence

Reliability Assumptions in the Carbon Plan

The Carbon Plan identifies that reliability is one of the Companies' core objectives, along with CO_2 emissions reductions, affordability, and executability. Carbon Plan, Ch. 2, 2. Chapter 2 to the Companies' proposed Carbon Plan explains that HB 951 establishes that any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid and the Commission may adjust the interim target to achieve 70% Interim Target by 2030 in the event it is necessary to maintain the adequacy and reliability of the existing grid. Carbon Plan, Ch. 2, 2; App'x Q, 1; App'x E, 5. Appendix Q explains that this core statutory objective recognizes the Companies' public service obligation to plan and operate their generating fleets and transmission and distribution systems to provide reliable power system operations to their customers 24 hours per day, 7 days per week, 52 weeks per year in accordance with federally mandated NERC Reliability Standards. Carbon Plan, App'x Q, 1.

The Carbon Plan is Reasonably Modeled to Maintain or Improve Reliability

The Carbon Plan describes a structured modeling process—the Carbon Plan Analytical Process Flow—which the Companies used to develop and analyze portfolio options that first and foremost maintain strong power system reliability while simultaneously meeting carbon reduction targets in the most economic manner for customers. Carbon Plan, Ch. 2, 1, 3. The Carbon Plan Analytical Process Flow includes reliability analyses at each of the first four stages: Inputs, Portfolio Development, Production Cost, and Reliability Validation. Carbon Plan, Ch. 2, 3; Carbon Plan, App'x E, 3.

The Carbon Plan inputs stage includes multiple reliability inputs, including planning reserve margin, ELCC values for renewable and energy storage resources, and operational reserve requirements. Carbon Plan, Ch. 2, 6-7. The Carbon Plan defines resource adequacy as "having sufficient resources available to reliably serve electric demand especially during extreme conditions" and explains that the planning reserve margin target is used in the planning process to ensure resource adequacy. Carbon Plan, App'x E, 9. The Carbon Plan uses a 17% winter planning reserve margin to achieve a "one-day-in-10-year" industry standard Loss of Load Expectation (0.1 LOLE), or one firm load shed event every 10 years due to a shortage of generating capacity, as an acceptable level of physical reliability as determined by the 2020 Resource Adequacy Study conducted by Astrapé Consulting. Carbon Plan, Ch. 2, 6; Carbon Plan, App'x E, 9-10. The Carbon Plan uses a 2022 ELCC study developed in collaboration with Astrapé Consulting using the SERVM state-of-the-art reliability and hourly production cost simulation tool to estimate the reliability capacity value attributable to variable solar and wind (seasonal contribution) and energy-limited storage resources. Carbon Plan, Ch. 2, 6; Carbon Plan, App'x E, 10-16. Finally, the Carbon Plan uses a planning and reliability tool developed by the Electric Power Research Institute (EPRI) to calculate hourly operational reserves requirements to ensure that the Companies will have sufficient flexible resources available to mitigate the risk of load and renewable output uncertainty. Carbon Plan, Ch. 2, 6-7.

The Portfolio Development stage of the Carbon Plan Analytical Process Flow includes simplified capacity expansion screening modeling in Encompass with average representation of hourly system demand to determine optimal resource portfolios that meet reliability standards, CO_2 emissions reductions targets, and least cost planning requirements. Carbon Plan, Ch. 2, 25-26; App'x E, 4. The Carbon Plan uses the output of the capacity expansion model to develop operational reserve requirements in the EPRI tool to ensure adequate flexible resources to mitigate load and variable resource uncertainty; the capacity expansion is then reoptimized with the operational reserve requirements. Carbon Plan, Ch. 2, 6-7, 26. Within this Portfolio Development capacity expansion stage, the Carbon Plan describes how coal retirement analysis is integrated into the resource portfolios, and that final coal unit retirement dates are established based on the ability to execute replacement resources and transmission upgrades necessary to ensure or improve reliability to allow for orderly and executable retirement schedules. Carbon Plan, Ch. 2, 26; App'x E, 48.

The Carbon Plan describes how this capacity expansion, due to its computational and data simplifications, must be further modeled in more detail in the production cost stage to validate and adjust resources across cost, reliability, and CO_2 emissions reductions targets. Carbon Plan, Ch. 2, 25; App'x E, 4. The Carbon Plan used the portfolio output from the preliminary identification of resources in the capacity expansion model and ran them through the detailed Encompass production cost model that reflected more detailed hourly dispatch versus an "average" representation in capacity expansion, thus developing refined resource outcomes based on more realistic hourly loads. Carbon Plan, Ch. 2, 26; App'x E, 59. The Carbon Plan explains that the battery-CT optimization step then considered hourly loads for each hour of the year to arrive at a portfolio that balanced carbon reduction targets while minimizing costs, and had the added benefit of enhanced system reliability by replacing shorter-duration batteries with CTs with longer duration capabilities to meet system needs 24 hours a day, every day of the year without limitation. Carbon Plan, App'x E, 59. In the final Encompass production cost model, each of the portfolios were run through the production cost model through 2050, to ensure operations of the system within the detailed, hourly simulation, meet CO_2 and energy requirements and identified resource insufficiencies to meet the zero CO_2 emissions constraint and energy requirements to meet reliability in 2050. Carbon Plan, App'x E, 61.

In the reliability validation stage of the Portfolio Verification process, the portfolios were checked using the SERVM tool to provide reasonable assurance that the final Carbon Plan portfolios perform at levels of reliability equivalent to or better than the current system configuration based on satisfying the LOLE resource adequacy metric in 2030 and 2035. Carbon Plan, App'x E, 62. This reliability validation step provides assurance, taking into account existing levels of market support from being an interconnected system, that all Carbon Plan portfolios could meet LOLE reliability thresholds required to maintain or improve upon reliability, in addition to providing results for reliability metrics of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) reliability metrics. Carbon Plan, App'x E, 62-64.

The Carbon Plan explains that while LOLE thresholds are important, they do not consider the duration or magnitude of reliability events which, with portfolios relying on higher levels of variable energy and energy limited resources, may result in energy adequacy issues. Carbon Plan, App'x E, 65. The Carbon Plan uses an example analysis of Portfolio 3 shifts in LOLE, LOLH, and EUE from 2030 to 2035 to describe indicators of potential energy adequacy issues and discusses the industry's recognition that more granular analysis and sophisticated reliability metrics will be needed in the future to fully evaluate portfolios with high adoption of variable energy and energy storage resources. Carbon Plan, App'x E, 65-67; App'x Q, 15-16.

The Carbon Plan explains that all portfolios were verified for adequate projected planning reserves. Carbon Plan, App'x E, 67-68. In this explanation, the Carbon Plan discusses how levels of non-dispatchable renewables, storage, and dispatchable resources in combination with CO_2 emission reduction targets and seasonal factors impact the projected levels of summer and winter planning reserves. Id. at 67-72. With significant levels of solar additions for DEC and DEP, the difference in winter versus summer reserve margins can be significant. *Id*. at 69. The Carbon Plan explains that as firm capacity decreases and reliance on variable energy and energy limited storage for maintaining a reliable system increases, the ability to satisfy the reserve margin threshold will be dependent on accurate estimates of firm capacity contributions of variable energy and energy limited storage resources at peak. *Id*. at 70.

Taken as a whole, the Carbon Plan designed reliability input parameters, structured modeling processes, verification steps, and additional analysis for proposed portfolio development to maintain or improve reliability, particularly as portfolios rely on higher levels of intermittent resources and storage to achieve HB 951 CO_2 emissions reductions.

Ensuring Ongoing System Reliability during Energy Transition

Appendix Q explains that the power system transformation contemplated by the Carbon Plan portfolios raises many new challenges for managing the grid as increasing levels of renewable generation will fundamentally change patterns of net load demand and increased uncertainty. Carbon Plan, App'x Q, 17. While traditional planning metrics of adequate day-to-day operating reserves and long-term planning reserves required to meet customer demands during cold winter morning and hot summer afternoons are necessary, the change in resource mix due the energy transition creates new challenges. Carbon Plan, Ch. 3, 17; App'x Q, 1.

The Carbon Plan demonstrates the Companies' recognition that maintaining current standards of reliability will require new, flexible solutions, models and metrics; and as the grid rapidly changes, a continuous process of operational learning and adjusting will be needed to keep pace with the energy transition. Carbon Plan, App'x Q, 17.

The Carbon Plan identifies the following six reliability risks and mitigating solutions of the energy transition that will create new challenges for managing the grid. Carbon Plan, App'x Q, 1-2.

1. Resource and energy adequacy from renewables and storage: Seasonal and daily variability of renewables and batteries coupled with the potential for extended periods of low output during weather events drives a need for resource diversity and dispatchable resources, such as gas and ZELFRs, to ensure resource and energy adequacy. *Id.* at 2-3.
2. Additional firm gas generation and transportation: New hydrogen-capable gas is needed to achieve as the "fuel to keep the lights on" to achieve 70% CO_2 emissions reductions as more intermittent resources are integrated and of coal retires. These new resources also contribute to carbon neutrality by operating in a net-zero power system using carbon-free hydrogen fuel. *Id.* at 4-5.
3. Coal generator reliability during the transition: Coal generation is currently critically important to system reliability, therefore adequate new dispatchable resources must already be available for the system to remain reliable once those units are no longer in service. Additionally, these units must be adequately maintained with sufficient coal supply and inventory management strategies for the duration that coal remains in service. *Id.* at 5-6.
4. Zero Emitting Load Following Resources (ZELFRs) to reach net-zero: As incremental reliability provided by new variable renewables and storage decrease at very high penetrations, new carbon-free technologies that have "dispatchability and flexibility characteristics that are fundamental to power system reliability" will be needed to reliably achieve net-zero carbon. *Id.* at 6.
5. Flexible generation needs for integrating renewables: As more renewables place new stresses on the power system through net load demand (time, shape, magnitude), intra-hour volatility, forecast error, balancing issues, or frequency deviations across interconnections, having adequate and reliable flexible resources for all types of reserves will be essential to maintain grid reliability. *Id.* at 8-15.
6. Future system resilience to withstand extreme events: Considerations for managing through and recovering from extended and extreme weather events (e.g, multi-day polar vortex, hurricane) or other events (e.g., cyber disruptions) with a significantly different resource mix should inform the design and operation of the grid during the energy transition. *Id.* at 16-17.

The Carbon Plan explains that the Companies must plan on meeting capacity and energy adequacy needs to maintain reliability during the energy transition without over-reliance on imports from neighboring systems, which are also rapidly decarbonizing their systems and may experience concurrent periods of limited resources thus lowering available assistance when needed the most (e.g., during winter months). Carbon Plan, App'x Q, 3-4; App'x E, 62-63. The Carbon Plan identifies additional risks associated with reliance on off-system capacity purchases such as delays in resource availability due to siting, permitting or construction between the systems, the potential of curtailing delivery by the neighboring system, and impacts to system stability. Carbon Plan, App'x R, 23.

Duke Energy Direct Testimony

The Direct Testimony of Duke Energy's Reliability Panel provides a System Operator's perspective of the Carbon Plan's reliability analysis and HB 951's requirement to maintain or improve upon reliability as the Carbon Plan is executed. Tr. vol. 19, 114-15. Specifically, witness Holeman explains that the Companies are uniquely obligated to the Commission and customers to provide secure and reliable electric service and to meet NERC Reliability Standards to ensure the stability of Bulk Electric System every minute of the day in all operating conditions. Witness Holeman explains that NERC, with consensus across the broader industry, has identified the energy transition as a significant reliability risk, as energy transitions are taking place across the country and real-world operational experience accrues. For the Companies' System Operators, this means the Carbon Plan must ensure a robust and diverse generation adequacy and reliability toolbox to deal with expected and unexpected operational conditions. As over 8,400 MW of coal units retire by end of 2035, witness Holeman explains that replacement resources must have operational capabilities to meet NERC Reliability Standards. According to witness Holeman, the Companies appropriately analyzed the reliability of proposed Carbon Plan portfolios, including additional reliability validations that considered varying load and weather conditions more reflective of actual operational conditions. From a System Operator's point of view, witness Holeman explains there are real-world implications that must be factored in when maintaining grid adequacy and reliability during this energy transition, and certain intervenors did not sufficiently consider those reliability obligations or risks in alternate plans and recommendations. *Id.* at 116-19.

Witness Holeman agrees that the Companies' proposed Carbon Plan portfolios were intentionally planned for reliability and compliance with mandatory NERC Reliability Standards to ensure power supply adequacy and grid reliability during the energy transition, stating the "Carbon Plan takes unprecedented steps to analyze and plan for integrating solar and other clean energy technologies to achieve the interim 70% CO_2 emissions reductions target as well as the long-term carbon neutrality target set by HB 951." *Id.* at 20. Witness Holeman further reinforces the core obligation to maintain reliability set out by HB 951 by stating that "[e]nsuring ongoing system reliability and compliance with mandatory NERC Reliability Standards in the face of this challenging transition is non-negotiable for the Companies and for customers." *Id.* at 121. Witnesses Holeman and Roberts reiterate that the Companies will enhance reliability analyses and metrics, in line with updated industry practices and NERC Reliability Standards, as the Carbon Plan and energy transition evolves. Tr. vol. 19, 168-69.

Witness Roberts describes the importance of the additional reliability validation step taken during modeling that reflect Modeling team collaboration with System Planning and Operations functions to ensure the validation reflects realistic weather, demand, and outage operational patterns. *Id.* at 172. Witnesses Holeman and Roberts agree that the Carbon Plan is "laser-focused" on reliability through modeling, reliability validation, and reliability risk assessment, and that the reliability risks identified in the Carbon Plan are appropriately addressed. *Id.* at 139, 167-68.

The Reliability Panel discusses the criticality of resource planning resulting in an orderly, planned transition of the system, and that the Companies "must strive to reduce risks, not heighten risks, for their customers and communities as their resource mix transitions through the Carbon Plan to achieve vital CO_2 emissions reductions targets" as intended by HB 951 to maintain or improve upon the reliability of the grid. *Id.* at 129-30, 140. The Reliability Panel further notes that NERC has identified the risks of energy transition as "merit[ing] the highest attention and mitigation efforts from regulators and grid operators", specifically citing resource adequacy during extreme weather events, appropriate sequencing of resource transitions (retirements and replacements) and having adequate flexible and dispatchable resources. *Id.* at 131, 133-34.

Witness Holeman provides numerous industry examples of decarbonization studies, existing issues with pacing of retirements and replacements, and real-world operational events that illuminate the practical issues of maintaining reliability during an energy transition. *Id.* at 145-56. Based on learnings from the industry, witness Holeman explains that an orderly transition prioritizes robust resource diversity to have as many tools as possible available in the System Operators' toolbox to respond to changing operational conditions and adequate firm, flexible resources to provide operational reserve margins and operational flexibility to respond to capacity and energy needs across all operating horizons, weather, and operating conditions. *Id.* at 157-61. During the hearing witness Holeman testified that the Carbon Plan is an "all of the above" strategy and "in order for us to comply with the mandate on adequacy and reliability in House Bill 951, we're gonna have to make sure that toolbox for our operators stays deep and diverse." *Id.* at 209, 214. Witness Roberts also testifies how consolidating DEC and DEP system operations as proposed in the Carbon Plan Appendix R (Consolidated System Operations) is an essential step to efficiently facilitate reliability benefits during the energy transition. *Id.* at 185-86.

Based on Duke Energy's system operational experience and trends across the industry, Duke Energy's Reliability Panel underscores the need for a carefully planned transition to retire over 8,400 MW of coal by 2035, with assurance that there is timely replacement with a robust mix of resources with operational capabilities that coal provides—particularly in constrained periods and prolonged weather events. *Id.* at 134, 154-55, 161, 182; Tr. vol. 30, 105-06. In response to CIGFUR questions on coal retirements, witness Holeman punctuated this concept: "Replace before you retire. So I believe I'm confident after 38 years in this industry in the operations area that if we keep that order right, we'll be able to deliver what's mandated in House Bill 951." Tr. vol. 19, 208. The Companies agree with Public Staff witness Metz, as he was discussing coal retirement schedules, that "[n]ot all system operational factors can be captured within a model", and that the Companies should leverage operational experience to continue to inform an orderly energy transition. Tr. vol. 21, 117; Tr. vol. 19, 119. During the hearing in response to Commissioner Clodfelter's line of questioning on the importance of ensuring replacement resources prior to coal retirements, witness Holeman clarified that ensuring replacement resource are in place prior to retirement were applicable to all coal units, not just super-critical units as referenced in Appendix Q of the Carbon Plan. Tr. vol. 20, 94-96.

Witnesses Holeman and Roberts explain that gas generating resources, due to their firm, dispatchable nature, are a necessary reliability "bridge" to achieving carbon neutrality while filling the resource adequacy needs created by the retirement of substantial amounts of coal that today contributes in a substantial way to resource adequacy. Tr. vol. 19, 160, 183-84; Tr. vol. 30, 106-07. The Reliability Panel highlights NERC's assertion for the ongoing need for dispatchable gas to mitigate potential capacity and energy shortfalls due to a changing resource mix: "[u]ntil storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain a necessary balancing resource to provide increasing flexibility needs,"[35] including NERC CEO's perspective of natural gas being "the fuel that keeps the lights on" by providing scaled operational margin.[36] Tr. vol. 19, 138-39; Tr. vol. 30, 106-07. Witnesses Holeman and Roberts deem essential adequate firm, flexible, dispatchable gas resources "for the Carolinas to anchor much of this needed margin at scale throughout this grid transformation" both for energy adequacy in short-term time horizons and to persistently provide resource adequacy through prolonged seasonal and extreme events. Tr. vol. 19, 160, 183-84; Tr. vol. 30, 106. During the hearing in response to a question from Chair Mitchell on the role of natural gas to manage reliability during the energy transition, the Public Staff witnesses Metz and Thomas both concurred that in Duke Energy's proposed Carbon Plan gas resources appear to be "serving a transitional bridge" and "important in maintaining system reliability" in the absence of ZELFRs – generation resources that are firm, dispatchable and carbon-free. Tr. vol. 19, 45-46.

Intervenor Comments and Testimony

In general, intervenors did not address reliability issues in the same level of depth and detail as the Companies' witnesses. AGO witness Burgess testifies that it is essential that reliability be evaluated comprehensively to ensure that any simplifications in models like EnCompass do not overlook any potential gaps. Tr. vol. 25, 261. Witness Burgess agrees that a step similar to Duke Energy's final reliability adjustment may be necessary but also cautions that this step can be difficult to assess. Tr. vol. 25, 261. Witness Burgess argues that reliance on natural gas introduces significant risk, in the event of severe cold weather events like Winter Storm Uri in Texas. *Id.* at 266-68.

CIGFUR witness Muller opines that renewable energy resources are variable resources, and the grid cannot operate without sufficient reliable, dispatchable back-up

[35] North American Electric Reliability Corp, 2022 State of Reliability Report at 26.
[36] James R. Robb, North Am. Elec. Reliability Corp., Testimony Before United States Senate Committee on Energy and Natural Resources, Full Committee Hearing On The Reliability, Resiliency, And Affordability of Electric Service, at 9, 10.

power. *Id.* at 363. Witness Muller testifies that Charlotte Pipe and many other CIGFUR member companies support natural gas and believe it will play a critical role as a bridge fuel to facilitate the energy transition in a way that does not compromise existing reliability. *Id.* at 363. Witness Gorman argues that the Carbon Plan fails to maintain or improve upon reliability due to an over-reliance on unproven technologies such as ZELFRs. Tr. vol. 22, 44-45.

CPSA witness Hagerty testifies that Duke relied on market conditions in California to explain ramp rate issues, and it is unclear how this event is applicable to Duke's system and must run their own analysis specific to the Carolinas. Tr. vol. 25, 453. Witness Hagerty testifies that the addition of renewable energy resources into the power system will change the operation of the system and the dispatch of non-renewable generation resources. *Id.* at 453. The daily generation profile of solar resources is predictable and results in the need for a significant increase in resources as the sun goes down and demand increases. *Id.* at 453. According to witness Hagerty, Duke Energy will need to have flexible resources on its system, including storage and natural gas-fired CCs and CTs, that can ramp up during these hours to serve the daily peak demand hours. *Id.*

CUCA notes that the Commission should diligently ensure that transition to renewable, intermittent resources does not undermine the reliability of North Carolina's electric grid and recommends that Duke Energy should backstop intermittent renewable resources with the availability of dispatchable resources. CUCA July 15th Initial Comments at 14.

NCSEA, et al. witness Fitch notes that the Companies' 2020 IRPs did not include a Reliability Validation step and states that the Companies' use of SERVM in developing the Carbon Plan lacks analytical justification and recommends that the Commission reject this change. Tr. vol. 24, 141-44. Witness Fitch also testifies that reliability is maintained in the Synapse scenarios even with the accelerated retirement dates of some units compared to Duke resources since the Synapse scenarios meet reserve margin requirements every month and meet 100 percent load in all hours in the production cost modeling. *Id.* at 176.

NCEMC agrees that forming a single balancing authority will improve reliability and that generation resource diversity provides flexibility and mitigates implementation risk that could result from overreliance on any one technology to meet reliability and resilience requirements during the energy transition. NCEMC July 15th Initial Comments at 16. NCEMC witness Fall testifies that he agrees with Duke's concerns that reduced resource diversity will impact Duke's ability to rely on market assistance for reliability purposes and that continuing to evaluate changes in neighboring system resource portfolios and load profiles will be important considerations going forward to support those assumptions regarding resource availability. Tr. vol. 23, 307.

NC WARN et al. recommends that the Companies should be ordered to assume that they will meet winter peak demand with non-firm imports in calculating the planning reserve margin. NC WARN, et al. July 15th Initial Comments at 6.

Public Staff Comments and Testimony

Public Staff highlights the importance of system reliability in developing the Carbon Plan and finds that the metrics the Companies used to validate portfolio reliability are reasonable. Public Staff July 15th Initial Comments at 33.

Public Staff witness Metz testifies that he does not have any concerns with Duke Energy's use of a reserve margin in development of the Carbon Plan and states that the Resource Adequacy Study Duke filed in Docket No. E-100, Sub 165 explains the reserve margin, the need for a reserve margin, and how the reserve margin can potentially change over time or be influenced by external factors. Public Staff witness Thomas testifies that the Public Staff has reviewed the results of Duke's ELCC studies for solar and storage and found them to be reasonable for planning purposes. Tr. vol. 21, 78. Witness Thomas also testifies that the reliability validation step appears reasonable and is consistent with HB 951's mandate to maintain or improve upon the reliability of the grid. *Id.* at 52. Witness Metz further testifies that the supplemental portfolios maintain adequate reliability based on results from Duke's Reliability Validation step. *Id.* at 159.

Witness Metz testifies that he disagrees with NC WARN and Charlotte Mecklenburg NAACP Witness Powers' request that the Companies be ordered to assume they can rely on non-firm imports for meeting winter peak demand. *Id.* at 155. Witness Metz explains that solely relying on non-firm energy during the winter peaks would be imprudent and potentially dangerous. *Id.* Witness Metz explains that it would not be prudent to assume that a loss of generation during a contingency event could be fully mitigated in every occurrence with non-firm resources and that non-firm power is just what the name implies; it is not firm, and it may or may not be available when it is needed. Tr. vol. 21, 155. Witness Metz also disputes witness Powers conclusion that Duke's planning reserve margin is excessive. Tr. vol. 21, 156-58.

Duke Energy's Rebuttal Testimony

In its rebuttal testimony, the Reliability Panel agrees with Public Staff witness Metz's statement that "[n]ot all system operational factors can be captured within a model." Tr. vol. 30, 103. The Panel explains that while modeling a planning reserve margin establishes a reliability baseline and is an important component to long-term resource plan adequacy, the Companies' reliability validation step is critical to ensuring each portfolio maintains and improves upon the reliability of the grid because it checks the portfolios against weather, demand, and outage parameters that better reflect what occurs in the Companies' operating areas, providing confidence that the portfolios can perform in real world conditions. *Id. at* 94. In this way, the Panel explains, the reliability validation step serves as a final check to ensure that the Carbon Plan portfolios' resulting resource mixes meet LOLE thresholds under varying weather and outage parameters that System Operators must address in real time. *Id. at* 95.

The Reliability Panel further explains that the reliability validation step was not used to develop the Companies' 2020 IRP portfolios because the industry-wide effort to revise reliability metrics in light of a changing resource mix that integrates high levels of solar and other intermittent renewables just beginning at that time. According to the Panel, the Companies began working to develop enhanced planning methods to further validate grid adequacy and reliability in 2021, around the time NERC commenced efforts to revise its Reliability Standards. *Id.* at 100.

In response to CPSA witness Hagerty's argument that modeling a 25% reserve margin, as Brattle did in developing its alternative portfolio, addresses any need for additional resources beyond the Companies' 17% planning reserve, the Reliability Panel explains that simply increasing the reserve margin does not test a portfolio against varying weather and outage parameters that reflect real world operational conditions in the Carolinas. *Id.* at 101.

The Reliability Panel also reiterates the importance of natural gas in achieving an orderly energy transition. The Panel explains that the Companies will retire over 8,000 MW of high capacity coal over the next decade while also placing into service thousands more megawatts of variable energy renewables and energy-limited batteries. To maintain the grid during this transition, System Operators require adequate, flexible, dispatchable operational reserves that can persist through prolonged extreme weather events. This includes additional gas as a bridge to integrate more renewables until hydrogen, long-duration storage, and ZELFRs are available and can replace at scale what gas contributes to the system. *Id.* at 106-07.

The Panel describes from an operations perspective that batteries paired with solar are not a replacement for gas resources as certain intervenors assert, nor can batteries alone ensure reliable operations during the energy transition. *Id.* at 108-10. The Reliability Panel explains how storage will be critically important for the energy transition, however they are not generators but rather energy takers that are energy-limited. *Id*. The witnesses further testify that batteries cannot displace the sheer scale and flexible, on-demand nature of 12,000 MW of existing CCs and CTs 3 (winter rating), nor 9,000 MW of existing coal units. *Id*. As an example, the Reliability Panel notes that the Belews Creek coal station provided approximately 34 GWh of firm dispatchable energy on January 24, 2022. This is more than three times the energy storage capability of every battery installed in the United States as of 2021. *Id.* at 107-08.

The Reliability Panel disagrees with AGO witness Burgess that natural gas introduces significant risk during cold weather events like what Texas experienced with Winter Storm Uri. *Id.* at 111-112. The Panel explains that there is a history of weatherization practices and preparedness in the Carolinas compared with Texas, and the Companies operational performance during 2015 and 2018 cold weather events in the Carolinas demonstrated activities undertaken by the Companies to apply continued operational improvements. *Id.*

In response to CPSA witness Hagerty's argument that ramp issues presented were not applicable to the Carolinas, witness Roberts provides analytical support specific to the Companies' systems (different than California) that demonstrates how ramp rates will grow as renewables amounts grow, and ramp issues can amplify in specific operational conditions. *Id.* at 112-15.

The Reliability Panel discusses in depth the operational realities and compounding risks System Operators face when relying on off-system imports for reliability and adequacy, which serves to respond to NC WARN and Charlotte Mecklenburg NAACP Witness Powers' request that the Companies be ordered to assume they can rely on non-firm imports for meeting winter peak demand. Tr. vol. 19, 186-90; Tr. vol. 30, 115-18. The Reliability panel agrees with Public Staff witness Metz that "solely relying on non-firm energy during the winter peaks would be imprudent and potentially dangerous" if adequate imports do not materialize due to neighboring system issues or curtailment. Tr. vol. 19, 186-90; Tr. vol. 30, 115-18.

Discussion and Conclusions

As a threshold matter, the Commission notes that HB 951 places emphasis on ensuring system reliability is maintained or improved while the electric grid transforms to meet the carbon reduction requirements of the law. Specifically, N.C.G.S. § 62-110.9(3) expressly provides that the Commission, in developing the Carbon Plan *must* "[e]nsure any generation and resources changes maintain or improve upon the adequacy and reliability of the existing grid." And HB 951 further provides for timeline extension wherever "necessary to maintain the adequacy and reliability of the existing grid." After reviewing the evidence, the Commission finds that each of the portfolios in Duke Energy's proposed Carbon Plan meet the statutory mandate to maintain or improve upon the reliability of Duke Energy's system.

The Commission is persuaded by the significant testimony of the Reliability Panel that the Companies, in developing the proposed Carbon Plan, appropriately focused on maintaining adequacy and reliability of the grid. The Companies designed prudent and reasonable inputs, modeling approaches, and verification steps to ensure reliability of proposed Carbon Plan portfolios, including by collaborating with system operations functions to ensure that each portfolio performs well in real-world situations. Additionally, the Companies developed evaluation criteria across Carbon Plan objectives to understand the risks and tradeoffs across portfolios, which included reliability and operational flexibility. Finally, the Companies integrated operational and industry learnings to identify reliability risks and mitigating solutions related to the energy transition, as major resource changes create new challenges in grid operations. The Carbon Plan demonstrated the Companies' recognition that the energy transition is a journey of ongoing operational learning and adjustment, and that maintaining existing reliability levels will require the potential for new future modeling approaches and metrics to keep pace with the energy transition.

The Reliability Panel provides substantial and meaningful industry information and practical first-hand experience operating Duke Energy's systems in real world situations to illustrate reliability challenges and the importance of meeting NERC Reliability Standards through this energy transition. The Commission gives substantial weight to this testimony as industry learnings and operational experience will be critical going forward to successfully transition the system to both the 70% Interim Target and ultimately to achieve Carbon Neutrality while maintaining or improving upon the adequacy and reliability of the existing grid.

The Commission finds that the input parameters, structured modeling processes and verification steps that serve to validate the reliability of proposed Carbon Plan portfolios were reasonable and necessary for purposes of meeting reliability core objectives and HB 951 requirements to maintain and improve upon the adequacy and reliability of the grid. In developing future Carbon Plan updates, Duke Energy should continue to utilize modeling that best ensures that future generation and resource changes presented in future Carbon Plan updates maintain or improve upon the adequacy and reliability of the existing grid.

The Commission agrees with Duke Energy witness Holeman that ensuring ongoing system reliability and compliance with mandatory NERC Reliability Standards in the face of an energy transition is a requirement of HB 951 and non-negotiable for the continued vitality of communities and customers, and for the Companies, considering their unique role as DEC and DEP System Operators obligated to provide reliable and secure electric service at all times of day, every day, in all operational and weather conditions.

PURSUING OVERALL EXECUTION PLAN IN NEAR-TERM (Findings of Fact Nos. 55-59)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 55-59

The evidence supporting these findings of fact is found in the Companies' proposed Carbon Plan, the direct testimony of Duke Energy witness Bowman, the direct and rebuttal testimonies of the Modeling and Near-Term Actions Panel, the testimony of Public Staff witnesses Metz and Thomas, AGO witness Burgess, CCEBA witness DiFelice, NCSEA, et al. witness Fitch, and the entire record in this proceeding.

Summary of the Evidence

The Companies' Carbon Plan presents a first-of-its-kind "Execution Plan" detailing the actions and enablers that Duke Energy has identified as necessary to achieve the CO_2 emissions reductions and energy transition targets identified in the Carbon Plan, along with potential challenges. The Execution Plan represents an evolution from the short-term action plan framework presented in past IRPs, and is designed to provide the Commission and stakeholders a more detailed overview of the Companies' near-term, all-of-the-above, energy transition strategy for executing the Carbon Plan, as well as intermediate- and longer-term strategies to meet the 70% Interim Target and to achieve carbon neutrality by 2050. Carbon Plan, Ch. 4, 1-2.

The Execution Plan presents execution actions and procurement strategies by resource type (supply-side resources, grid resources, and demand-side resources) across three horizons: *near-term actions* required in the 2022-2024 time frame; *intermediate-term actions* that the Companies are planning to achieve the initial 70% Interim Target under the Carbon Plan; and *long-term planning* beyond the intermediate term focused on strategies, considerations, and signposts that the Companies are actively monitoring and plan to explore over time to help ensure the Carbon Plan achieves the least-cost path to 2050 carbon neutrality. This approach allows the Companies to obtain Commission authorization to proceed with implementing near-term activities while monitoring risks and signposts across all planning horizons. The Execution Plan explains that monitoring intermediate- and longer-term risks and signposts will provide key information that will be used to check and adjust plans during future biennial updates of the Carbon Plan. Carbon Plan, Ch. 4, 2, 36-40.

The Execution Plan describes how implementation of the Carbon Plan will include a range of procurement methods, including utility self-development, asset acquisitions, and for solar and solar paired with storage, solicitations for controllable purchase power agreements. Asset acquisitions can be accomplished through procurements or bilateral negotiations and are generally utilized when there is flexibility as to where the assets are located and the market for development is more mature. Specific types of acquisitions for new assets include asset transfers, asset transfers plus EPC services, Build-Own-Transfers, and acquisition of operating assets. Foundational to the procurement activities identified in the Carbon Plan is the need to preserve customer value by pursuing least cost across each procurement action the Companies undertake. In all cases, the information gained through the procurement process will be used to inform and refine future Carbon Plan analysis and filings and will provide the Commission and the Companies with opportunities to adjust the pace and volumes of procurement activities in response to changing market conditions relative to planning assumptions at any given point in time. Carbon Plan, Ch. 4, 12-13.

The Execution Plan then presents more detailed near-term and intermediate-term execution planning actions across a number of key areas of the Carbon Plan.

Table 4-2 (Coal Retirements), Table 4-3 (Expanding Flexibility of the Existing Gas Fleet), Table 4-4 (Extending the Life of Existing Nuclear Fleet with Subsequent License Renewal) present the Companies' near-term and intermediate term execution strategy for existing supply-side resources. Carbon Plan, Ch. 4, 9-11.

The Execution Plan also presents actions that the Companies intend to commence immediately in the near term and to continue over the intermediate term relating to the development and procurement of new supply-side resources. Specific to transitioning with new dispatchable hydrogen capable natural gas resources assets, the Execution Plan identifies that an aggressive development timeline designed to enable the Companies to achieve commercial operation of two CTs by the end of 2027 and the first CC unit by the end of 2028 is required to enable coal retirements on the schedules contemplate in the Carbon Plan. The Companies execution plan for new natural gas assets is presented in Table 4-5 (Natural Gas Assets). The Execution Plan highlights the Companies' plans to self-develop the initial new CT and CC gas assets and to locate these assets on the

Companies' existing sites, explaining that these initial CT/CC assets would be brownfield additions at existing power stations that can utilize the Companies' existing transmission, infrastructure, workforce, while greenfield sites would take longer to develop. Finally, the Execution Plan explains that the Companies are only commencing development activities at this time and will return to the Commission at a later date for a CPCN. Carbon Plan, Ch. 4, 13-15.

The Execution Plan also presents development and procurement plans for all other near-term supply side resources proposed to be selected by the Commission as well as initial development plans for longer lead time development activities. Table 4-6 (Solar), Table 4-8 (Onshore Wind), and Table 4-11 (Energy Storage) address the Companies' execution planning for carbon-free resources requested to be selected in this initial Carbon Plan. Table 4-7 (New Nuclear), Table 4-9 (Offshore Wind), Table 4-10 (Pumped Storage Hydro) presents the near-term and intermediate term actions for long-lead time resources. The Companies also present near-term and intermediate-term plans and activities to advance the understanding and development of hydrogen production, storage, transportation, and generation (Table 4-12 Hydrogen). Carbon Plan, Ch. 4, 16-24.

The Execution Plan also provides significant detail on the Companies near-term plans for transmission system planning and grid transformation required to execute the Carbon Plan. Executing the Carbon Plan will require a transformation of the Companies' transmission system to achieve CO_2 emission reduction targets while ensuring adequate and reliable service is maintained. The Execution Plan specifically highlights transmission planning activities will be needed to enable coal unit retirements, to proactively develop the Red Zone transmission projects subject to obtaining NCTPC approval, and beginning to plan offshore wind-enabling transmission projects. Table 4-13 (Transmission Planning and Grid Transformation) provides additional detail on these near-term and intermediate term activities that Duke Energy is planning to transform the transmission system and to continue planning for coal unit retirements. Carbon Plan, Chapter 4, 25-27. One activity identified for 2022 was to obtain FERC authorization to establish generation replacement queue process. The Transmission and Solar Procurement Panel identified that that Companies obtained FERC authorization of a generator replacement queue process on September 6, 2022. Tr. vol. 28, 141-42.

The Execution Plan also presents Table 4-15 describing the Companies' plans for near-term actions necessary to support a detailed evaluation of consolidated system benefits, stakeholder outreach, and development of North Carolina, South Carolina and FERC regulatory filings as part of the initial consolidated system operations strategy. Carbon Plan, Ch. 4, 27-29. As addressed by Duke Energy witness Nelson Peeler, the Companies are now planning to pursue merger of DEC and DEP on the timeline identified in Carolinas Utilities Operations Panel Direct Exhibit 1 with a target complete date in 2026. Tr. vol. 15, 27.

Finally, the Execution Plan presents Table 4-16 describing the Companies planned near-term actions and execution plans for grid edge and customer programs. Carbon Plan, Ch. 4, 29-35.

Development and Procurement Activities

Public Staff Testimony

Public Staff witness Thomas testifies that solar, wind, and battery storage will be needed in great quantities over the next ten to 15 years, and Duke Energy should procure these resources via competitive procurements. However, he suggests that 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. Witness Thomas further explains that Public Staff is generally supportive of using competitive procurement principles for the procurement of all generation resources identified by the Carbon Plan. However, the carbon reduction goals in Section 62-110.9 may have changed whether an all-source procurement is appropriate, regardless of how the RFP is designed. Public Staff witness Thomas also highlighted that the ongoing 2022 Solar Procurement and the anticipated 2023 procurement for solar and solar paired with storage resources will help further define how competitive procurements are implemented in the Carolinas and presumably will result in innovative evaluation methods and contract structures in order to move beyond a solar-only procurement. Tr. vol. 21, 80.

Public Staff witness Metz testifies regarding near-term development actions related to long lead time resources including (1) development of pumped storage hydro upgrades to the Bad Creek facility (Bad Creek II); (2) offshore wind; and (3) new nuclear, in particular small modular reactors (SMRs). He explains that all three of these resources have substantially long lead times and will require near-term actions to be commercially operational in time for Section 110.9 compliance, should the Commission decide that these resources should be a part of the Commission's Carbon Plan. Witness Metz is supportive of the Commission authorizing near-term development activities for Bad Creek II and SMRs but recommends that the Commission deny Duke's request to begin near-term resource development activities for offshore wind. Tr. vol. 21, 122-27.

Intervenor Testimony

AGO witness Burgess recommends that the Commission should direct Duke Energy to conduct a near-term solicitation for onshore wind to test market readiness with a target in-service date in the 2026-2027 timeframe. This solicitation should allow for wind imports with non-firm transmission. Both the wind and solar procurements should seek to maximize competition through third party providers. Witness Burgess explains that it is premature to presume both that no more than 300 MW can be procured and that a 2029 in-service date is required prior to testing the market through a true competitive solicitation. According to witness Burgess, while it is true that significant wind resource development has not yet occurred in the Carolinas, such development has occurred already in PJM and there continues to be a substantial amount of wind projects in development there. Tr. vol. 25, 239, 254-55.

CCEBA witness DiFelice argues that larger and faster near-term procurement of standalone and solar paired with storage is needed to integrate more solar generation in the near term. He suggests that all future solar procurements should consider only solar paired with storage resources, excluding solar only resources. He also asserts that standalone resources would best be procured through competitive procurements, which will allow build-own-transfer bidder participation and, he contends, ensure that such procurement occurs at least cost. Tr. vol. 26, 253-254. He claims that a competitive procurement will allow for more rapid deployment of storage and for selection of the lowest cost/highest value projects. Tr. vol. 26, 242.

Duke Rebuttal Testimony

Duke Energy witness Farver discusses the Companies' extensive experience with administering solar procurements gained through the CPRE Program and the 2022 Solar Procurement that have delivered benefits to customers. Based on that work, she states that there is a strong foundation of established practices and structure on which to build in the future. She notes that in her current role, she was responsible for designing and implementing the 2022 Solar Procurement and routinely engages with market participants to hear their perspectives on how to continue to evolve the Companies' solar procurement processes. Looking forward, she states that the Companies are proposing substantial near-term procurements of solar and solar paired with storage in procurement events to be conducted in 2023 and 2024 (in addition to the ongoing 2022 Solar Procurement). Tr. vol. 28, 154-55.

Witness Farver explains how the most substantial hurdle for the procurement of solar paired with storage will be the development of new contractual structures for solar paired with storage. While the PPAs for solar-only projects are well developed based on prior procurements, it will be necessary to develop substantially new contract forms to facilitate the purchase of output from third-party owned solar facilities that are paired with storage that meets the HB 951 requirement to be dispatched, operated, and controlled "in the same manner as the utility's own generating resources." She explains how critically important these contracts are in terms of the Companies' ability to operate the facilities, the need to design contract terms and pricing to enable Duke Energy to maximize the benefits of solar plus storage facilities over the full contract term at a price that is fair to customers and protects them from overpayment, and to provide adequate risk adjusted revenue to the project owner to enable them to attract capital to finance the projects. She notes that the Companies plan to commence stakeholder engagement with respect to this contract development in the fourth quarter of 2022 in advance of the 2023 procurement. Tr. vol. 28, 155-57.

With regard to standalone storage, witness Farver testifies that this resource should not be procured in the same manner as solar and solar paired with storage. She explains that the Companies regularly use competitive sourcing opportunities for standalone storage projects, which ensures low costs for customers through market competition. Tr. vol. 28, 158-160. She also responds that allowing third party developers to participate in standalone storage will not increase the speed at which batteries can come online because the storage facilities remain subject to the same interconnection cluster processes and timelines, and she contrasts such projects with the majority of solar generation, which usually already has site control. Tr. vol. 28, 160-61.

Witness Farver discusses the advantages to the Companies' self-development of standalone storage, including the ability to utilize existing grid assets and land, and the ability to set and meet safety standards. She states that with regard to an open build-own-transfer procurement process for standalone storage, the Companies support all available avenues to keep customer costs low, and would be open to further exploring options for a future build-own transfer RFP for standalone storage. In such a scenario, the RFP would be subject to Duke Energy-directed siting based on system needs, benefits, timing, and other requirements. The technical requirements for a standalone storage acquisition RFP would be very specific, including approved vendors and equipment, design standards, safety requirements, capacity and energy content, and appropriate use case-driven capabilities. The Companies continue to believe that a build-own-transfer model may not be appropriate or feasible in all scenarios but the Companies would, in every case, utilize competitive sourcing processes for the benefit of customers. Tr. vol. 28, 161-63.

Ownership of Resources Selected in Carbon Plan

Duke Energy's Modeling and Near-Term Actions Panel addresses how the Carbon Plan modeling complies with the ownership requirements set forth in HB 951. The Panel explains that the Execution Plan presents the Companies' general procurement approach and explains that implementation of the Carbon Plan will comply with the ownership requirements set forth in HB 951, including the specified allocation of ownership of solar and solar paired with storage. According to the Panel, the General Assembly in enacting HB 951 prescribed that any new generation facilities or other resources selected by the Commission in order to achieve the CO_2 emissions reduction goals for electric public utilities must be owned and recovered on a cost of service basis by the applicable electric public utility, except in the case of energy efficiency measures and demand-side management, for which existing law applies, and in the case of solar generation, which is to be allocated according to the percentages specified in the law. Tr. vol. 7, 243-44. Duke Energy reiterates in its Pre-Hearing Comments filed on September 9, 2022, its position that N.C.G.S. § 62-110.9(2) mandates specific ownership requirements of new generation facilities or other resources selected by the Commission as part of the Carbon Plan. Duke Energy Sept. 9th Pre-Hearing Comments at 19-30. This position was further explained in the Companies' Post-Hearing Brief.

In its Pre-Hearing Comments, the Public Staff opines that the language in Section 62-110.9(2) is clear and unambiguous and states that "the legislature made clear that new generation facilities or other resources selected by the Commission to achieve the goals of Section 110.9 must be owned and recovered on a cost of service basis by the utility" except as provided in N.C.G.S. § 62-110.9(2)(a)-(b). Public Staff Sept. 9th Pre-

Hearing Comments at 7. According to the Public Staff, by specifically prescribing the method of ownership in N.C.G.S. § 62-110.9(2), the legislature necessarily excluded any other type of ownership. *Id.* Addressing the role of purchased power in achieving carbon reduction goals, the Public Staff acknowledges that purchased power can be considered a resource and that non-utility ownership arrangements such as purchased power agreements could facilitate lower-cost and lower-risk resource procurement than the construction of utility-owned assets. *Id.* Nevertheless, the Public Staff states that the ownership requirement must be read in tandem with the requirement for recovery on a cost-of-service basis, which contemplates inclusion of the asset in rate base along with a rate of return. *Id.* at 11. Conversely, the Public Staff explains that purchased power has always been recovered as a pass-through in accordance with N.C.G.S. § 62-133.2 or as an "operations and maintenance" line item in base revenues without a return component. *Id.* Finally, Public Staff witness Thomas testified during the hearing that the Public Staff and the Commission should be cautious of Duke Energy acquiring or developing off-system resources to ensure they are properly acquired. Tr. vol. 22, 316-17.

CPSA likewise acknowledges that the plain language of N.C.G.S. § 62-110.9(2) prohibits the Commission from approving a Carbon Plan that relies on new non-utility-owned generating resources, other than solar and solar paired with storage, in order to meet the decarbonization mandates of the statute. CPSA Pre-Hearing Comments at 6-7.

The AGO argues that N.C.G.S. § 62-110.9 should be read to allow purchases from third party-owned generation because the statutory phrase "other resources" is broad enough to include wholesale third-party purchases. AGO Sept. 9th Pre-Hearing Comments at 11. According to the AGO, energy is owned by the utility once it is purchased from a third party and may be recovered on a cost of service basis, thus complying with the statutory language. *Id.* at 10-11. The AGO states that this interpretation conforms with historic planning practices, which have long recognized the prudency of utilizing third-party purchases. *Id.* at 12. In addition, the AGO argues that North Carolina's statutes governing integrated resource planning and certificates for public necessity and convenience require the Commission to consider alternatives to a utility proposal for construction of generation such as purchased power when it reviews petitions for construction of new generating facilities. For these reasons, the AGO recommends that the Commission find that N.C.G.S. § 62-110.9(2) does not prohibit the purchase of wholesale power and evaluate wholesale purchases alongside other resources for the purposes of developing the Carbon Plan. *Id*. at 13.

With respect to least cost planning, AGO witness Burgess argues that wind and solar procurements should seek to maximize competition through third party providers, suggesting that is typical for PPA projects procured through a competitive bidding process to be lower in cost than utility-owned generation. He testifies that to the extent the Commission has the flexibility to authorize or even require PPAs for a share of solar resource greater than 45%, this could produce substantial cost savings to Duke customers. Witness Burgess also argues the same is true for all other resources that could be procured as PPAs through a competitive process, including wind, battery storage, and even natural gas. Tr. vol. 25, 296, 299.

NCSEA, et al. argue that the second sentence of N.C.G.S. § 62-110.9(2) regarding utility ownership is at odds with the first sentence's mandate to comply with current law and practice with respect to the least cost planning for generation. NCSEA et al. Sept. 9th Pre-Hearing Comments at 9. According to NCSEA, et al., purchases of energy and capacity from independent power producers can and do play an important role in least-cost planning. *Id.* at 10. NCSEA et al. argues that to the extent the two sentences are in conflict, the Commission should resolve the resulting ambiguity in favor of adhering to the least-cost mix of generation to fulfill the carbon plan requirements, which can include non-utility owned resources. *Id.* In addition, NCSEA, et al. witness Fitch argues that his Regional Resources scenario allows the model to select onshore wind PPAs from the MISO region, transferred to Duke's territory through PJM. Witness Fitch recommends the Commission consider both firm and non-firm power purchase agreements of zero-carbon wind power from outside the Carolinas in developing the Carbon Plan and directing further modeling. Tr. vol. 24, 150, 152.

Tech Customers argue that the plain language of N.C.G.S. § 62-110.9(2) authorizes purchased power to be used as a component of the Commission's Carbon Plan. Tech Customers Sept. 9th Pre-Hearing Comments at 4. According to Tech Customers, power purchased by Duke Energy from third parties is a "resource" that is "owned" by the respective company that has purchased it, thus meeting the ownership requirements of the statute. *Id.* at 5-6. Tech Customers additionally note that the Carbon Plan relies of administration of the JDA, which facilitates the sale of power generated by one affiliate to the other, and that Duke Energy's portfolios include existing PPAs and purchased wind power from other jurisdictions. *Id.* at 8-9.

In its Pre-Hearing Comments, Avangrid Renewables argues that N.C.G.S. § 62-110.9(2)'s ownership requirements are ambiguous. Avangrid Renewables Sept. 9th Pre-Hearing Comments at 9. Specifically with respect to onshore wind, Avangrid Renewables argues that traditional cost recovery mechanisms in North Carolina have not had to deal with resources sited in non-state territory like the offshore wind that will likely be located in federal waters. *Id.* at 10. According to Avangrid Renewables, requiring Duke ownership of offshore wind facilities sited in federal waters would not result in a least cost path of compliance, particularly if that ownership is further limited to Duke's preferred Carolina Long Bay lease area that is currently owned by a Duke Energy affiliate. *Id.* at 13. Avangrid Renewables witnesses Michael Starrett and Becky Gallagher also address ownership requirements and testify that Avangrid Renewables 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. Avangrid would also consider entering into service contracts for development, construction, and/or operations and maintenance of the asset. Tr. vol. 23, 173.

While CCEBA does not dispute that "[t]aken at face value," N.C.G.S. § 62-110.9(2) "arguably" prevents the selection in a Carbon Plan of any non-solar resource that is not 100% owned by Duke Energy, CCEBA argues that it would be poor public policy and inconsistent with the mandates of HB 951 and Executive Order No. 218 regarding development of offshore wind resources to regard the ownership provisions of N.C.G.S.

§ 110.9(2) as an impenetrable barrier to development of offshore wind resources in North Carolina. CCEBA Sept. 9th Pre-Hearing Comments at 4-5. In addition, CCEBA argues that Section 62-110.9(2) does not prevent the development and ownership of offshore wind resources by parties other than Duke Energy. According to CCEBA, such a restriction on the rights of parties in federal waters outside of the territorial jurisdiction of North Carolina would be of dubious Constitutionality. *Id.* at 5-6.

Kingfisher also argues that the Commission should conclude that third-party ownership of resources is lawful and is critical to complying with the statute's mandate that the Companies engage in least cost planning and maintain or improve upon the adequacy of the existing grid. Kingfisher Sept. 9th Pre-Hearing Comments at 2-7. Kingfisher further recommends that the Commission direct Duke Energy to implement a competitive procurement process as part of its near-term actions. *Id.* at 8.

These and other parties also address legal issues related to the application of HB 951's ownership requirements in comments filed on September 9, 2022.

Discussion and Conclusions

Executability of the Carbon Plan is a core objective identified by Duke Energy and its importance to the Companies is reflected in the detailed first-of-its-kind Execution Plan framework presented in Carbon Plan Chapter 4. The Commission is tasked with developing the Carbon Plan with Duke Energy — who, ultimately, must execute the Plan under the Commission's oversight — and the Commission appreciates the thoughtful approach presented in the Execution Plan. The Execution Plan evolves from past IRP short-term action plans provided under Rule R8-60 to give the Commission substantially more information on the Companies' near-term, all-of-the-above, energy transition strategy for executing the Carbon Plan, as well as intermediate- and longer-term strategies to plan for and to meet the interim CO_2 emissions reductions target and to achieve carbon neutrality by 2050. No other party to the proceeding presented anything remotely comparable in breadth and detail to the Companies' Execution Plan and the Commission places substantial weight on the Companies' focus on executability in this proceeding. The Commission finds and concludes that the Execution Plan is reasonable and further finds that the Companies should pursue the near-term actions presented therein as further discussed below and informed by other parts of this Order.

While Section 62-110.9(1) provides that the Carbon Plan shall be reviewed every two years, the Commission finds there would be significant value to an annual update to the Carbon Plan execution planning activities and, therefore, directs the Companies to provide an update on Execution Plan activities and progress as part of the Companies' 2023 IRP update filing. This Execution Plan update will be reviewed by the Public Staff and accepted by the Commission for informational purposes and is not intended to require stakeholder input or result in Commission-directed adjustments to the Companies' ongoing development and procurement activities. Consistent with Section 62-110.9(1), the Commission will review and adjust the Carbon Plan again in 2024.

The Commission does, however, expect that the Companies shall utilize competitive procurement structures to deliver value for customers, as recommended by the Public Staff and discussed by the Companies. To the extent the Companies pursue self-development or bilateral negotiations to procure resources selected in the Carbon Plan, the Commission expects the Companies to demonstrate in a future CPCN proceeding how such efforts resulted in costs that were consistent with the least-cost requirements of HB 951.

As stated in the Execution Plan and discussed by Duke Energy witness Farver, the Companies have a successful track record of engaging with market participants and other stakeholders to support development of competitive solicitations for new solar resources and are also open to pursuing new competitive procurement contract structures and procurement options for both utility-owned and third-party owned controllable solar paired with storage resources as well as build-own-transfer of standalone storage assets to be owned and operated by the Companies. The Commission supports development of innovative new controllable solar paired with storage contract structures that will enable Duke Energy to maximize the benefits of solar paired with storage facilities over the full contract term at a price that is fair to customers and protects them from overpayment and, maximizes the Companies' ability to operate the facilities in the same manner as utility-owned facilities. The Commission also supports the Companies exploring opportunities for a future build-own transfer RFP for standalone storage in those cases where such approach provides benefits for customers. Accordingly, Duke Energy should evolve its execution plan for solar paired with storage to prioritize stakeholder engagement in the near-term and to develop potential contract structures and procurement frameworks for future procurements for solar paired with storage. Recognizing that Duke Energy will ultimately own the standalone storage resource as well as the critical importance of siting standalone storage on the system where it is of greatest value for customers, the Commission agrees with witness Farver that, when an RFP is utilized, such RFP would be subject to Duke Energy-directed technical requirements and siting based on system needs, benefits, timing, and other requirements.

Onshore wind energy is another area that the Commission expects the Companies to begin development and procurement activities as set forth in Table 4-8 in order to assess the viability of developing onshore wind energy in the Carolinas between now and 2024. As addressed elsewhere in this Order, the Commission has selected 600 MW of new onshore wind under the Carbon Plan to be developed and placed in service by (year end) 2029. It is reasonable and appropriate for Duke Energy to begin engaging with wind energy industry stakeholders to assess whether and when the market will support development and/or procurement of such resources in the Carolinas or whether the Companies should further explore procuring wind energy under development in other States or regions. The Commission recognizes arguments by AGO witness Burgess and NCSEA, et al. witness Fitch that the Commission should require Duke Energy to broadly procure non-firm wind energy from PJM or MISO to promote lower costs for customers. However, as discussed below, such resources, if selected, would need to be owned by Duke Energy and recovered on a cost-of-service basis. In this initial Carbon Plan, Duke Energy has not presented procuring non-firm wind energy for delivery into the Companies' balancing authority areas as part of its Execution Plan and it has also not been demonstrated to be part of a least cost resource plan that ensures the adequacy and reliability of the grid is maintained or improved. The Commission also notes the Public Staff's caution regarding such an approach. To the extent Duke Energy determines that it would be least cost to develop and/or procure ownership of onshore wind energy resources the energy from which would be imported into the Carolinas as part of the Carbon Plan, the Companies should support that proposal in detail in the 2024 Carbon Plan update.

The Commission will also address the controverted ownership requirements issue for new generation and other resources selected in the Carbon Plan in order to provide Duke Energy regulatory certainty and to inform its Execution Plan activities as the Companies commence executing the Carbon Plan. The Commission finds that a straightforward reading of the plain language of Section 62-110.9(2) mandates that resources selected in the Carbon Plan must be owned by Duke Energy except that Duke Energy may own only 55% of the total MW of new solar and solar paired with storage resources selected in the Plan. Specifically, N.C.G.S. § 62-110.9(2) provides that

> Any new generation facilities or other resources selected by the Commission in order to achieve the authorized reduction goals for electric public utilities shall be owned and recovered on a cost of service basis by the applicable electric public utility except that:
>
> . . .
>
> b. To the extent that new solar generation is selected by the Commission, in adherence with least cost requirements, the solar generation selected shall be subject to the following: (i) forty-five percent (45%) of the total megawatts alternating current (MW AC) of any solar energy facilities established pursuant to this section shall be supplied through the execution of power purchase agreements with third parties pursuant to which the electric public utility purchases solar energy, capacity, and environmental and renewable attributes from solar energy facilities owned and operated by third parties that are 80 MW AC or less that commit to allow the procuring electric public utility rights to dispatch, operate, and control the solicited solar energy facilities in the same manner as the utility's own generating resources and (ii) fifty-five percent (55%) of the total MW AC of any solar energy facilities established pursuant to this section shall be supplied from solar energy facilities that are utility-built or purchased by the utility from third parties and owned

> and operated and recovered on a cost of service basis by the soliciting electric public utility. These ownership requirements shall be applicable to solar energy facilities (i) paired with energy storage and (ii) procured in connection with any voluntary customer program.

The Commission does not find ambiguity in the language used or the legislative intent expressed by the General Assembly. The Commission's role is to effectuate the purpose of the General Assembly in enacting HB 951. *High Rock Lake Partners, LLC v. N. Carolina Dep't of Transp.*, 366 N.C. 315, 322, 735 S.E.2d 300, 305 (2012); *see also State ex rel. Utilities Comm'n v. Thurston Motor Lines*, 240 N.C. 166, 168, 81 S.E.2d 404, 406 (1954) ("The Utilities Commission is a creature of the Legislature. It may exercise only such authority as is vested in it by statute."). To accomplish this objective, the Commission must first look to the plain language of the legislation. *See State v. Hooper*, 358 N.C. 122, 125, 591 S.E.2d 514, 516 (2004). The Commission is "without power to interpolate, or superimpose, provisions and limitations not contained" in "clear and unambiguous" legislative enactments. *State v. Jackson*, 353 N.C. 495, 501, 546 S.E.2d 570, 574 (2001) (quoting *In re Banks*, 295 N.C. 236, 239, 244 S.E.2d 386, 388-89 (1978)).

There could be no clearer manifestation of the General Assembly's intent to require utility ownership than actually using the words "shall be owned . . . by the applicable electric public utility." N.C.G.S. § 62-110.9(2). We need not look elsewhere for the General Assembly's intent on this subject. The Commission, therefore, concludes as a matter of law that any new generating facilities or other resources selected in the Carbon Plan must be owned by the Companies, except that 45% of any new solar that is selected must be owned by third parties.

The Public Staff and most other parties recognize or do not challenge the General Assembly's unambiguously stated intent in this regard. However, several intervenors urge the Commission to ignore the General Assembly's plain language, and instead adopt an interpretation of Section 62-110.9(2) that would broadly authorize third-party ownership of all new generating facilities, not just 45% of new solar and solar paired with storage resources. These intervenors argue, in large part, that the ownership requirements are ambiguous because the first sentence of Section 62-110.9(2) requires the Commission to "comply with current law and practice with respect to the least cost planning, pursuant to G.S. 62-2(a)(3a)," and least cost planning has traditionally required consideration of third-party energy suppliers. *See, e.g.*, Tech Customers Sept. 9th Pre-Hearing Comments at 4 ("There is nothing in the Statute that overrides the obligation of the Commission and the Companies to follow usual practices for least cost planning, including the explicit analysis of purchased power."); NCSEA Sept. 9th Pre-Hearing Comments at 10 ("To the extent that the two sentences are in conflict, the Commission should resolve the resulting ambiguity in accordance with the declaration of policy, which requires adhering to the least-cost mix of generation and demand-side resources to fulfill the carbon plan requirements, which can include non-utility owned resources."). They further argue that least cost planning is inconsistent with a strict application of HB 951's utility ownership requirement. Thus, they argue that the General Assembly actually intended to authorize consideration of third-party ownership for *all* new Facilities.

The Commission declines to adopt an interpretation of Section 62-110.9(2) that not just ignores, but contradicts, the General Assembly's plain language. The statute's specific language stating that any new Facilities "shall be owned . . . by the applicable electric public utility" cannot reasonably be interpreted to mean the exact opposite — *i.e.*, that third parties may own new generating facilities selected in the Carbon Plan. The Commission has "no power to add to or subtract from the language of the statute." *Ferguson v. Riddle*, 233 N.C. 54, 57, 62 S.E.2d 525, 528 (1950). "[A] statute must be considered as a whole and construed, if possible, so that none of its provisions shall be rendered useless or redundant." *R.J. Reynolds Tobacco Co. v. N.C. Dep't of Envtl. and Natural Res.*, 148 N.C. App. 610, 616, 560 S.E.2d 163, 168 (2002) (quoting *Porsh Builders, Inc. v. City of Winston–Salem*, 302 N.C. 550, 556, 276 S.E.2d 443, 447 (1981) (internal quotations and citations omitted)). Furthermore, "[i]t is presumed that the legislature intended each portion to be given full effect and did not intend any provision to be mere surplusage." *Id*. at 616, 560 S.E.2d at 168. Intervenors' interpretation would require the Commission to either ignore the entire second sentence of Section 62-110.9(2) or add language that broadly authorizes third-party ownership that the General Assembly deliberately did not include. Neither construction is permissible under North Carolina law. In fact, taken to its extreme, these intervenors' interpretation could actually be used to negate even the CO_2 emissions reduction targets contained in HB 951. In contrast, the Companies' interpretation presents a more logical, straightforward and common sense reading of Section 62-110.9(2) that allows all of the provisions to read in harmony, incorporating and balancing all of the requirements in a manner that gives full effect to clear and unambiguous statutory directives and ensuring that no provision is rendered useless or surplusage.

The AGO and other parties, including Tech Customers and Avangrid Renewables, additionally argue that third party ownership is appropriate under Section 62-110.9(2) because, according to those parties, energy is owned by the utility once it is purchased from a third party and is therefore an "other resource" that may be recovered on a cost of service basis. This interpretation has no basis in the text of the statute. Section 62-110.9(2) states that "[a]ny new generation facilities or other resources selected by the Commission . . . shall be owned and recovered on a cost of service basis by the applicable electric public utility." The AGO's interpretation contradicts the plain reading of the statute. The General Assembly imposed a straightforward directive that "new generation resources" should be owned by the utility, but the AGO's baseless interpretative expansion of the phrase "other resources" would essentially fully negate the unambiguous directive of utility ownership of generation resources. It strains credulity to suggest that the General Assembly would direct utility ownership of "generation resources" and then completely eviscerate the requirement in the very next phrase (since all third-party owned generators produce electricity that can be sold to the Companies, the AGO's interpretation would simply incoherently negate the clear ownership generation ownership requirement). Instead, the more natural reading is that "other resources" was simply intended to refer to resources that are not technically generation resources, such as standalone storage and make clear the utility ownership requirement also extends to such non-generation resources. Moreover, as the Public Staff points out, the ownership requirement must be read in tandem with the requirement for recovery on a cost of service basis, which contemplates inclusion of the asset in rate base along with a rate of return. Purchased power has always been recovered as a pass-through in accordance with N.C.G.S. § 62-133.2 or as an operations and maintenance line items in base revenues without a return component. The Commission agrees with the Public Staff that this difference in cost recovery treatment between utility-owned assets and purchased power further demonstrates why the AGO's reading of Section 62-110.9(2) is wrong on its face.

Tech Customers also argue that the Companies' reliance on the JDA and existing resources that are not utility-owned is inconsistent with the Companies' interpretation of the statute. With respect to reliance on the JDA, however, the Companies' commitment to pursuing merger of the utilities renders the issue moot. In any event, Section 62-110.9(2) does not prohibit reliance on *existing* resources that are not utility-owned, and the Commission therefore rejects Tech Customers' argument. Neither the JDA nor existing resources are "new generation facilities or other resource[]…[being] selected by the Commission" as part of the Carbon Plan and therefore the assumed continuation of such arrangements has no bearing on this issue (and moreover would not alter the clear language of the statute). The Commission is likewise not persuaded by the arguments of Avangrid Renewables and CCEBA that prohibiting third party ownership of offshore wind located in federal waters would not result in a least cost path of compliance. While both Avangrid and CCEBA make several policy-based arguments regarding purported advantages to third party development of offshore wind, the General Assembly is responsible for setting state policy in legislation after comprehensively weighing competing interests. With respect to new generation facilities and "other resources," the General Assembly's mandate is clear: third party ownership is permitted only for solar and solar paired with storage resources. If offshore wind is not part of the least cost path to compliance with the carbon reduction targets under the parameters established in Section 110.9(2), then Duke Energy's Carbon Plan modeling would not have selected them.

Finally, the Commission declines to adopt Kingfisher's recommended reframing of HB 951 as authorizing the Commission to select only some resources that will be needed to achieve the CO_2 emissions reductions goals mandated by HB 951 while mandating procurement from third parties. Kingfisher Sept. 9th Pre-Hearing Comments at 3-4 ("grant[ing] the Commission discretion to not select resources or to select only those resources that are required to be utility-owned . . . [while] [t]the remainder of the resources that are needed to achieve the carbon reduction goals should be subject to an evaluation through a competitive procurement"). Contrary to Kingfisher's suggestion, the General Assembly in enacting N.C.G.S. § 62-110.9 designed a comprehensive framework under which the Commission's Carbon Plan necessarily must select the full portfolio of new generation facilities or other resources to achieve the authorized reduction goals mandated by HB 951. In other words, the Commission anticipates that the Companies will be moving forward with development and procurement activities and then filing CPCN petitions, as applicable, for all resources specifically "selected" in this or future Carbon

Plan proceedings. Simply put, the Commission's actions in this Order are designed "to achieve the authorized reduction goals" under N.C.G.S. § 110.9(1) and the Commission would not meet its delegated authority and responsibility under HB 951 by only selecting some resources for a partial Carbon Plan.

The Commission is also persuaded that, in addition to the clear legal guidance provided by the General Assembly, there are strong policy arguments in favor of utility ownership. Given the magnitude of the system transition and the central role that Duke Energy plays in both accomplishing the transition and maintaining reliability, it is reasonable for the General Assembly to conclude that the utility should have a substantial ownership interest in the new Facilities required. The reasonableness of this policy decision is only highlighted when one considers that many of the new facilities are simply replacing retiring coal-fired generating facilities that Duke Energy previously owned, managed, operated and relied upon to provide reliable electric service to the citizens of North Carolina for decades. Requiring utility ownership through Commission-supervised least-cost planning also embodies the regulatory compact between Duke Energy and the State. The General Assembly has recognized that rates, services and operations of public utilities are affected with the public interest and has declared it to be the "policy of the State of North Carolina . . . to promote the inherent advantage of regulated public utilities." Doing so allows for the "availability of an adequate and reliable supply of electric power . . . to the people, economy and government of North Carolina[.]" N.C.G.S. 62-2(a). It is not surprising that the General Assembly would turn to traditional cost-of-service regulation principles when enacting such transformative energy legislation. The utility ownership mandate reflects the General Assembly's conclusion that investing in, developing, and executing the significant generation resource transition and power system transformation required to execute the Carbon Plan is best accomplished through Duke Energy's vertically-integrated operations under the comprehensive and constructive regulatory oversight of the Commission and PSCSC.

Putting aside the clear legal conclusion required by HB 951, the Commission also notes that while numerous parties have summarily asserted that third-party resources are more cost-effective than utility-owned generation, no party has provided any detailed analysis to support such argument. Once again, putting aside the legal requirements, there is no clear evidence to suggest that third-party ownership will be more cost-effective than utility ownership. Moreover, the Commission's understanding is that recent changes in tax law imposed under the IRA will even further improve the economics of utility-owned resources.

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

In summary, the Commission finds that HB 951 establishes a comprehensive plan for achieving carbon emission reductions in North Carolina and directs the Commission to develop a Carbon Plan with Duke Energy, including stakeholder input, where Duke Energy will plan for and retire its significant utility-owned carbon-emitting coal-fired generation (approximately 8,400 MW) and invest in other new generation that, over time, achieves carbon neutrality. Duke Energy must execute this energy transition under the oversight of the Commission and consistent with the framework established by the General Assembly, which requires the Commission to ensure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid. N.C.G.S. § 110.9(3). As Duke Energy begins to execute this initial Carbon Plan, the Commission finds that the Companies should plan for and execute the Carbon Plan in a least cost manner but also consistent with the General Assembly's clearly-expressed intent that "[a]ny new generation facilities or other resources selected by the Commission in order to achieve the authorized reduction goals for electric public utilities shall be owned and recovered on a cost of service basis" with the exception of solar and solar paired with storage resources, of which Duke Energy is to own 55%.

FERC-JURISDICTIONAL POWER CONTRACT RECOMMENDATIONS (Finding of Fact No. 60)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 60

The evidence supporting this finding of fact is found in the Initial Comments of the Electricities of North Carolina, Inc. (Electricities), North Carolina Eastern Municipal Power Agency (NCEMPA), and North Carolina Municipal Power Agency Number 1 (NCMPA1 and, together with Electricities and NCEMPA, Power Agencies), the testimony of NCEMC, the Pre-Hearing Comments of the Companies, and the entire record in this proceeding.

Summary of the Evidence

The Power Agencies contend that the Carbon Plan cannot comply with HB 951's least cost mandate without taking full advantage of as much load side management as its wholesale customers can possibly provide. The Power Agencies claim that the Companies' current plan "effectively ignores the potential for demand reduction associated with as much as 30% of DEP's load" and recommends that the Commission direct the Companies to take full advantage of as much load side management as wholesale customers can possibly provide. Power Agencies July 15th Initial Comments at 4-5.

NCEMC witness Ragsdale states that coordination between NCEMC's Distribution Operator (DO) and Duke Energy will continue to be important. Witness Ragsdale requests that the Commission order Duke Energy to continue coordinating with NCEMC in the ISOP process and as part of future updates to the Carbon Plan. Tr. vol. 26, 207-10.

The Companies respond that the Power Agencies' request asks the Commission to extend the Carbon Plan proceeding well beyond its statutorily prescribed purpose. The Companies explain that, as the North Carolina Court of Appeals has recognized, "exclusive jurisdiction over interstate wholesale electric power transactions is conferred upon [the Federal Energy Regulatory Commission]."[37] The Companies note that Duke Energy's wholesale requirements contracts with multiple entities in the Carolinas are on file with FERC and subject to its jurisdiction, including as they relate to how the wholesale customers' demand side management or energy efficiency programs interact with wholesale charges. Accordingly, the Companies conclude, the issue raised by the Power Agencies is not properly before the Commission in this proceeding. Duke Energy Sept. 9th Pre-Hearing Comments at 63.

Discussion and Conclusions

Based on the foregoing, the Commission declines to require the Companies to take particular actions with respect to coordination with wholesale customers on load side management. As the Companies point out, Duke Energy's wholesale requirements contracts are on file with FERC and subject to its jurisdiction, including as they relate to how the wholesale customers' demand side management or energy efficiency programs interact with wholesale charges. Issuing such directives would inappropriately expand the scope of this proceeding and such issues can be addressed before FERC. While recognizing that such issues are FERC jurisdictional, the Commission does find it reasonable and appropriate to encourage the Companies to continue to look for opportunities to engage with wholesale customers on distribution system coordination and cost effective programs to enable CO_2 reductions.

<u>PROCEDURAL MATTERS FOR FUTURE CARBON PLANS (Findings of Fact Nos. 61-62)</u>

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 61-62

The evidence supporting these findings of fact is found in the Initial Scheduling Order, the Petition, the July 15th Initial Comments of the Public Staff, CCEBA, and

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

NCSEA, and the Sept. 9th Pre-Hearing Comments of the Companies, the Public Staff, CCEBA, NCSEA, CIGFUR, Tech Customers, and the AGO.

Summary of the Evidence

Schedule for Carbon Plan Updates

Initial Scheduling Order – Petition – Initial Comments

In the Initial Scheduling Order, the Commission recognized the significant overlap between the analyses required to prepare a proposed Carbon Plan under HB 951 and development of the Companies' biennial IRP and indicated an intent to "sync, eventually, the Carbon Plan proceedings with the IRP proceedings."[38] The Commission therefore delayed DEC's and DEP's next biennial IRP filings required by Commission Rule R8-60(h)(1) to September 2023.[39]

In their Verified Petition for Approval of Carbon Plan, the Companies request that the Commission hold the Companies' next biennial IRPs in abeyance to 2024 to align with the next Carbon Plan proceeding as contemplated under HB 951, thereby achieving the Commission's goal of syncing the biennial IRP and Carbon Plan proceedings. This approach also recognizes the fact that the Companies' initial Carbon Plan reflects a planning document that is at least as comprehensive as a biennial IRP filing. Duke Energy Petition at 14-15.

The Carbon Plan Execution Plan also explains that filing the Companies' next comprehensive IRP/Carbon Plan update in 2024 would recognize the important role of the Public Service Commission of South Carolina, as the Companies necessarily must be able to execute on a single systemwide resource planning pathway. Deferring the next comprehensive IRP/Carbon Plan Update to 2024 would allow the Companies to more fully focus in 2023 on developing and presenting comprehensive IRPs to the Public Service Commission of South Carolina, as required by S.C. Code Ann. § 58-37-40. Recognizing the benefits to customers of dual-state systems planning, the Companies strongly believe that regulatory clarity and resource planning alignment between the two jurisdictions will be critically important to obtaining these benefits for customers moving forward. Carbon Plan, Ch. 4, 40-41.

No party opposed the Companies' proposal. The Public Staff supported the Companies' proposal and recommended that the Companies should file an IRP update pursuant to Commission Rule R8-60(h)(2) and (j) in 2023. Public Staff July 15 Initial Comments at 24. CCEBA and NCSEA et al. also supported the proposal. CCEBA July 15th Initial Comments at 58; NCSEA, et al. July 15th Initial Comments at 32.

[38] Initial Scheduling Order at 1.
[39] *Id*.

Pre-Hearing Comments

In their Pre-Hearing Comments, the Companies agree with the Public Staff's recommendation and state their plan to file IRP updates for the DEC and DEP systems in 2023. The Companies represent that the 2023 update will further serve the purpose of apprising the Commission on the status of the near-term execution plan as well as longer-term development activities. Duke Energy Sept. 9th Pre-Hearing Comments at 56-57.

The Public Staff reiterates its support for delaying the next full Carbon Plan proceeding until 2024, noting that in September 2023 the Carbon Plan will only have been in place for nine months, and that this approach will allow more time for a full review of any necessary revisions to Rule R8-60. The Public Staff requests a timeline that allows for discovery, filing of testimony and comments as appropriate, an evidentiary hearing, public hearings, and stakeholder engagement, and sufficient time for the Public Staff and intervenors to review and work with the data and inputs used by the Companies in their modeling. Public Staff Sept. 9th Pre-Hearing Comments at 1-2.

CIGFUR supports the Companies' request that the first biennial Carbon Plan review proceeding be delayed until 2024, subject to the clarification that the 2024 proceeding comprise a full review of the Carbon Plan and not merely an update to the Plan that results from this initial proceeding. CIGFUR Sept. 9th Pre-Hearing Comments at 2-3.

NCSEA et al. recommends that, given the passage of the IRA since July 15, to the extent that the 2022 Carbon Plan's short-term action plan does not take IRA policies into account, there should 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. While recognizing that the expedited statutory timeline imposed on this first carbon plan proceeding caused the Companies' timeline for developing its proposed plan to overlap with the stakeholder process, NCSEA, et al. suggests that the next carbon plan update proceeding should begin with a stakeholder process, including Commission-established deadlines for iterative and collaborative sharing of EnCompass modeling inputs as all parties work to develop plan updates. NCSEA, et al. Sept. 9th Pre-Hearing Comments at 1-4.

The AGO also suggests that the Commission should allow for reflection of the IRA in the Carbon Plan before syncing up the Carbon Plan and IRP proceedings. AGO Sept. 9th Pre-Hearing Comments at 4-5.

Tech Customers recognize the time constraints under which all parties were operating in this first Carbon Plan proceeding. For future Carbon Plan update proceedings, Tech Customers recommend that the Commission establish a date certain for Duke Energy to provide a functioning and validated model database to intervenors, perhaps in conjunction with Public Staff confirmation that the provided model functions and reproduces the results indicated by the Companies, with the time period for intervenors to develop comments not starting until Public Staff confirmation that a working model is available to intervenors. Tech Customers also suggest other requirements associated with the Companies' provision of the model database that would formalize certain of their preferences with regard to the modeling. Tech Customers Sept. 9th Pre-Hearing Comments at 18-19.

Rulemaking Revisions to R8-60

Initial Scheduling Order – Petition – Initial Comments

In the Initial Scheduling Order, the Commission also indicated that it "will initiate, by separate order . . . a rulemaking proceeding to revise Commission Rule R8-60 to reflect the approach of syncing the Carbon Plan with the IRP proceedings."[40]

In their Petition, the Companies request that the Commission direct Duke Energy and Public Staff to, by January 31, 2023, develop and propose for comment revisions to Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan in order to ensure that the necessary revisions to R8-60 can be developed and implemented in advance of the proposed 2024 joint Carbon Plan / IRP proceeding. Petition at 15.

In its initial comments, the Public Staff generally agrees with the Companies' proposal but recommends that the deadline for filing proposed revised rules should be extended to April 28, 2023. Public Staff July 15 Initial Comments at 163. CCEBA also supports the proposal as long as full opportunity is provided for stakeholder and intervenor participation, comment, and feedback. CCEBA July 15th Initial Comments at 58.

NCSEA, et al. objects to the Companies' request, claiming that the timeline the Companies originally proposed would require development of the proposed rule contemporaneous with the Commission's consideration of the Carbon Plan, and that it would be inappropriate for Duke Energy and the Public Staff to develop changes to Rule R8-60 without the input of other stakeholders. NCSEA, et al. July 15th Initial Comments at 33-34. NCSEA et al. acknowledges, however, that the relief the Companies request is consistent with the Commission's stated intent to initiate a rulemaking proceeding to revise Commission Rule 8-60. NCSEA, et al. July 15th Initial Comments at 32-33.

Pre-Hearing Comments

The Companies reiterate their request, and do not oppose the Public Staff's proposal to extend the deadline for proposed rule changes, noting that the extended deadline will allow more time for all parties to engage and develop draft rules. Duke Energy Sept. 9th Pre-Hearing Comments at 59.

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[40] Initial Scheduling Order at 1-2.

The Public Staff reiterates its support for the April 28, 2023, deadline. Additionally, the Public Staff recommends that the Commission direct the Companies and the Public Staff to work together to develop proposed rule revisions, 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. Public Staff recommends that interested parties should also have the opportunity to submit comments on the proposed revisions, as well as alternative proposals. Public Staff Sept. 9th Pre-Hearing Comments at 3.

CIGFUR does not object to the Companies request, and specifically supports the Public Staff's proposed deadline of April 28, 2023. CIGFUR Sept. 9th Pre-Hearing Comments at 3-4.

NCSEA, et al. states that all parties should be afforded more time to develop draft rules. It asserts 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 et al. contends that a broader array of stakeholders than those who have the resources to formally intervene in the docket should be engaged prior to the Commission revising its IRP rules and that important, diverse perspectives will be lost if only the Companies and the Public Staff are involved in proposing initial revisions to Rule R8-60. NCSEA Sept. 9th Pre-Hearing Comments at 4-5.

CCEBA acknowledges the need for reform to Rule R8-60 to accommodate the Carbon Plan and its future revisions and urges that any such revision process be conducted with full involvement of stakeholders and the public. CCEBA Sept. 9th Pre-Hearing Comments at 1.

The AGO objects to the originally proposed January 31, 2023, deadline for proposed revisions to Rule R8-60, asserting that any schedule for modifying Commission rules should permit sufficient time for input, but does not address the modified April 28, 2023, deadline discussed in the Public Staff's Initial comments. The AGO also states that all interested parties should be encouraged to participate as in other rulemaking dockets. AGO Sept. 9th Pre-Hearing Comments at 5-6.

Discussion and Conclusions

Based on the foregoing, in light of the agreement between the Companies and the Public Staff, and in the absence of opposition from any other party, the Commission concludes that it is reasonable and appropriate to direct the Companies to file IRP updates in 2023 and to then file integrated Carbon Plan updates and comprehensive IRPs in 2024. This approach will sync the Carbon Plan and IRP proceedings as contemplated in the Initial Scheduling Order and recognizes the fact that the Companies' initial Carbon Plan reflects a planning document that is at least as comprehensive as a biennial IRP filing. The Commission agrees with the Companies that filing IRP updates in 2023 will further serve the purpose of apprising the Commission on the status of development and procurement of near-term supply side resources as well as progress on initial development activities for longer lead time resources, as approved in this Order. The Commission is also directing the Companies to provide an informational update on the Carbon Plan execution plan with the 2023 IRP filing.

We also agree with the Public Staff that this approach accounts for the relatively short duration of time that the Carbon Plan approved in this order will have been in effect and will allow more time for a full review of any necessary revisions to Rule R8-60. Based on the normal timing for IRP updates of September 1 as provided in Rule R8-60(h)(2), we conclude that the Companies should file this update by September 1, 2023. We clarify that the nature of the 2023 IRP updates will be as the Public Staff suggests, to update the Carbon Plan as contemplated by Rule R8-60(h)(2) and (j) and the Commission intends to follow the more streamlined review process for IRP updates established by Rule R8-60(l). The Commission expects the next biennial IRP/Carbon Plan filing in 2024 will comprise a comprehensive update to the Carbon Plan and integrating a “full” IRP based on the Commission’s then-modified rules.

The Commission agrees that it will be important for the 2024 Carbon Plan proceeding to ensure that interested parties have sufficient opportunity to participate in stakeholder activities underlying the development of Duke Energy’s updated proposed Carbon Plan, just as they have done in this case. While the Commission anticipates the 2023 IRP update and limited informational update on the Carbon Plan to be streamlined and informational in nature, the 2024 Carbon Plan proceeding will afford all parties full opportunities for participation similar to this proceeding. Consistent with N.C.G.S. § 62-110.9(1) directive requiring the Commission to develop the 2022 Carbon Plan with Duke Energy and “including stakeholder input” the Commission finds it reasonable and appropriate for Duke Energy to again engage with interested stakeholders in advance of the 2024 Carbon Plan update. While the Commission will not prescribe a specific schedule or detailed expectations at this time, commencing such engagement at least three months in advance of the 2024 Carbon Plan filing generally aligns with the period for stakeholder engagement that occurred in advance of this 2022 initial Carbon Plan and it is the Commission’s hope and expectation this timeline will allow sufficient time for engagement as well as developing potential consensus in advance of the 2024 Carbon Plan updated filing.

The Commission is also cognizant that the Companies operate a dual-state system and that Duke Energy must file comprehensive IRPs with the Public Service Commission of South Carolina on August 15, 2023 that are currently scheduled for hearing in March 2024 with a decision to be issued in June 2024.[41] In addition to aligning the 2024 integrated Carbon Plan/IRP with the September 1 filing date traditionally used for IRPs in

[41] The Commission takes judicial notice pursuant to N.C.G.S. § 62-65(b) of the Public Service Commission of South Carolina’s Directive Order Approving Adoption of Schedules as Proposed for Calendar Years 2023, 2024, and 2025 and Allowing Modifications as Necessary, Order No. 2022-594, P.S.C.S.C. Docket Nos. 2005-83-A, 2022-162-E, 2023-15-E, 2023-16-E, 2023-17-E (Sept. 1, 2022). Pursuant to S.C. Code Ann. § 58-37-40(C)(1), the Public Service Commission must issue a final order approving, modifying or denying the Companies’ IRPs within 300 days of filing or by June 10, 2024.

North Carolina, directing the 2024 North Carolina Carbon Plan/IRP to be filed on September 1, 2024, will allow the Companies time to receive a ruling from the Public Service Commission of South Carolina on the Companies' comprehensive IRPs in advance of filing the 2024 North Carolina Carbon Plan/IRP. In addition, the Commission anticipates that a September 1 filing date will allow the 2024 North Carolina Carbon Plan/IRP analysis to be based on 2024-vintage modeling inputs and to better reflect up-to-date market conditions and procurement experience.

The Commission also finds it reasonable and appropriate to direct the Companies and the Public Staff to develop and propose for comment by April 28, 2023, revisions to Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan. The Commission concludes that extending the originally proposed deadline from January 31, 2023, to April 28, 2023, provides the Companies and the Public Staff, as well as other parties who may wish to do so, sufficient time subsequent to the conclusion of this proceeding to contemplate and develop proposed rules. At the time that draft rules are proposed by Duke Energy and the Public Staff (either jointly or separately), the Commission will issue a procedural order that will provide all interested parties an opportunity to comment on the proposed rules, consistent with Commission practice in other rulemaking proceedings. The Commission declines to order Duke Energy and the Public Staff to establish a formal stakeholder process in advance of April 28, 2023, as recommended by NCSEA, et al., but encourages the Companies and Public Staff to informally engage with stakeholders in order to potentially reduce issues in dispute.

Based on the record in this proceeding, specifically including the comments and recommendations of Duke Energy and the Public Staff, as well as the Commission's cognizance of the South Carolina comprehensive IRP proceeding to occur in late 2023 through early 2024, the Commission provides the following general guidance regarding future planning for IRP and Carbon Plan rulemaking and updates in 2023 and 2024.

Date	Action
December 31, 2022	Commission issues Final Carbon Plan Order
April 28, 2023	Proposed Carbon Plan/IRP and related rule revision filed by Duke Energy and Public Staff
September 1, 2023	Duke Energy to file IRP update and informational Carbon Plan update on Execution Plan
December 31, 2023	Commission issues updated Carbon Plan/IRP and related rule revision
June 2024 – August 2024	Engagement with Stakeholders in advance of 2024 comprehensive Carbon Plan/IRP update
September 1, 2024	Duke Energy to file comprehensive Carbon Plan/IRP update

At the appropriate time, the Commission will provide further direction, including deadlines and procedural milestones, in procedural scheduling orders initiating these proceedings.

IT IS, THEREFORE, ORDERED as follows:

Commission-Developed Carbon Plan

1. Based on the entire record in this proceeding, the Commission has developed and hereby approves a Carbon Plan for North Carolina, as set forth in this Order and as required by Section 62-110.9(1). The Commission shall monitor the Companies' progress in the near-term, including through the various Carbon Plan-related filings and proceedings that will occur in 2023 (including the 2023 IRP update and Execution Plan informational update discussed above) and provide further direction on an as-needed basis and then shall conduct a review of the Carbon Plan in the initial Carbon Plan update proceeding occurring in 2024, at which time the Carbon Plan shall be modified as may be deemed necessary;

Modeling

2. That the Companies' Carbon Plan modeling including supplemental modeling presented in Duke Energy Near-Term Actions Panel Direct Exhibit 1 is reasonable for planning purposes and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning;

3. That the Companies' Carbon Plan modeling and "all of the above" resource planning approach recommending deployment of both supply-side and demand-side resources to achieve HB 951's goals align with and are supported by current law and practice with respect to the least cost planning for generation, pursuant to G.S. 62-2(a)(3a), in achieving the authorized carbon reduction goals and determining generation and resource mix for the future;

Near-Term Supply-Side Development and Procurement Activities

4. That Duke Energy's proposed Carbon Plan presents initial reasonable steps towards achieving the interim 70% CO_2 emissions reduction target by 2030 and appropriately retains discretion for the Commission to determine optimal timing and generation and resource mix to achieve compliance with HB 951's carbon reduction goals;

5. That the Companies shall undertake development and procurement activities to develop the supply-side resources identified in the Near-Term Action Plan presented in Carbon Plan Executive Summary Table 3 and Bowman Direct Exhibit 3 and selected by the Commission in this Order;

6. That the Commission selects 3,100 MW of solar resources as part of the Carbon Plan subject to the obligation to obtain a CPCN and the further guidance provided in this Order regarding the Commission's expectations regarding the contents of such CPCN applications. Subject to the further direction in this Order, the

Companies shall undertake development and procurement activities for 3,100 MW of solar generation in the 2022-2024 timeframe targeting such projects being placed into service by 2028;

7. That as directed in the Commission's Nov. 1, 2022, order in Docket Nos. E-2, Sub 1159, E-7, Sub 1156, E-2, Sub 1297 and E-7, Sub 1268, the Companies' 2022 Solar Procurement Program shall procure approximately 1,200 MW of new standalone solar resources including a minimum of 750 MW of new HB 951 standalone solar and the 441 CPRE Program remainder MW. The Companies shall target procuring a minimum of 400 MW of new solar resources in DEC and 400 MW in DEP as part of an overall least cost portfolio of new solar resources. The Companies shall target a minimum of 2,350 MW of solar in 2023-2024 and determine the optimal timing and mix of new standalone solar and solar paired with storage. The Companies shall consider volume adjustments or other mechanisms similar to the 2022 Solar Procurement during this period to competitively procure additional solar at least cost;

8. That the Commission selects 600 MW of storage paired with the new solar resources as part of the Carbon Plan to be procured in the 2023-2024 timeframe. The Companies shall undertake development and procurement activities for 600 MW of storage paired with the solar, targeting such projects being placed into service by 2028;

9. That the Commission selects 1,000 MW of stand-alone storage as part of the Carbon Plan to be developed in the 2022-2024 timeframe. The Companies shall undertake development and procurement activities for 1,000 MW of stand-alone storage, targeting such projects being placed into service by 2029;

10. That the Commission selects 600 MW of onshore wind as part of the Carbon Plan to be developed in the 2022-2024 timeframe. The Companies shall undertake development and procurement activities for 600 MW of onshore wind, targeting such projects being placed into service by 2029. Onshore wind resources are selected as part of the Carbon Plan subject to the obligation to obtain a CPCN and the further guidance provided in this Order regarding the Commission's expectations regarding the contents of such CPCN applications;

11. That the Commission selects 800 MW of CTs as part of the Carbon Plan to be developed in the 2022-2024 timeframe. The Companies shall undertake development and procurement activities for 800 MW of CTs, targeting such projects being placed into service by 2029. CT resources are selected as part of the Carbon Plan subject to the obligation to obtain a CPCN and the further guidance provided in this order regarding the Commission's expectations regarding the contents of such CPCN applications;

12. That the Commission selects 1,200 MW of CC units as part of the Carbon Plan to be developed in the 2022-2024 timeframe. The Companies shall undertake

development and procurement activities for 1,200 MW of CCs targeting such projects being placed into service by 2029. CC resources are selected as part of the Carbon Plan subject to the obligation to obtain a CPCN and the further guidance provided in this order regarding the Commission's expectations regarding the contents of such CPCN applications;

Long-Lead Time

13. That the Companies' plans to pursue initial development activities to support the future availability of offshore wind, SMRs, and new pumped storage hydro at Bad Creek to ensure that these resources are available options for the Companies' customers on the timelines identified in the portfolios to be selected in future Carbon Plan updates are approved;

14. That near-term development activities for a new pumped storage hydro facility at Bad Creek shall include, but are not limited to: completing the in-process feasibility study; developing an engineering, procurement, and construction strategy that provides the Companies with an opportunity to meet an in-service date of 2033; and continuing to develop the Companies' integrated licensing procedure with the FERC;

15. That the near-term development activities for SMRs shall include, but are not limited to: developing an ESP for a single site; performing a due diligence review to identify a nuclear design technology for the Companies' SMRs; and determining a preferred potential site;

16. That the near-term development activities for offshore wind shall include, but are not limited to: DEP acquiring the DERW WEA for the Carolina Long Bay Wind Energy Area; developing, submitting, and obtaining an approval of a Site Assessment Plan from the Bureau of Ocean Energy Management (BOEM); and beginning the development of a Construction and Operation Plan from BOEM;

17. That project development costs for the initial development activities necessary to support the future availability of offshore wind, SMRs, and a new pumped storage hydro facility at Bad Creek are hereby authorized, however, the Companies shall expend no more than:

    (i) $75 million to develop SMRs;
    (ii) $40 million to develop a new pumped storage hydro facility at Bad Creek; and
    (iii) $325 million to develop offshore wind (including development work on the onshore tie-line), which includes the $155 million cost to procure the DERW WEA;

18. That the Companies' near-term development activities for offshore wind shall focus on the DERW WEA and that it is not necessary for Duke Energy to conduct or obtain an independent third-party study of wind energy areas at this time; however, nothing would prohibit the Companies from continuing to review the offshore wind

opportunities off the coast of North Carolina to consider future projects for presentation to the Commission for consideration, as appropriate;

19. That the Companies shall file biannual reports with the Commission that detail the progress of the development activities and costs incurred in pursuing such activities for the new pumped storage hydro facility at Bad Creek, SMRs, and offshore wind and adherence to the approved cost caps;

20. That the approved initial development activities for Bad Creek II, SMRs, and offshore wind are reasonable and prudent steps directed by the Commission in executing the Carbon Plan to enable potential selection of these generating facilities in the future and to maintain the potential for one or more of the resources to be used in reaching the 70% Interim Target;

21. That in the event any of the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 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;

22. That specific to development of SMRs, the Commission finds that this authorization of initial development costs constitutes approval under N.C.G.S. § 62-110.7(b);

Existing Supply-side resources

23. That the Companies' proposed Execution Plan actions with respect to existing supply-side resources, including through expanding flexibility of the existing gas fleet and continued disciplined pursuit of subsequent license renewals for the Companies' existing nuclear fleet, are approved as part of the Carbon Plan;

Coal Retirements

24. That Duke Energy's planned schedule for coal retirements presented in the proposed Carbon Plan (Appendix E, Table E-47) is reasonable for planning purposes;

25. That the Companies shall continue to analyze planned retirement dates for the Companies' coal units, including the transmission impact analysis presented in Execution Plan Table 4-13 and provide an updated coal retirements planning analysis to the Commission with their 2024 Carbon Plan update;

Grid Edge

26. The Companies shall expeditiously develop a formal proposal targeted to update the inputs to the cost effectiveness tests in the DSM/EE cost recovery Mechanism that are based on specific costs associated with the marginal carbon-free and

storage resources selected in this Order added to the system energy and capacity, inclusive of transmission and other required infrastructure, and receive stakeholder input on such proposal from the DSM/EE Collaborative. After receiving input from the DSM/EE Collaborative, the Companies shall file this targeted update to the Mechanism to modify the cost effectiveness test to be able to be utilized in the Companies' annual EE/DSM rider filings;

27. The Companies shall work through the DSM/EE Collaborative, as necessary, to bring EE and DSM programs, measures, and modifications to the Collaborative using "as found" savings to the Commission for approval;

28. The Companies shall consider ways to raise the number of low-income customers that may be eligible to participate in DSM/EE programs and to report on those discussions in their annual DSM/EE rider proceedings;

29. The Companies shall propose new flexibility and rapid prototyping guidelines to ensure regulatory approval of new DSM/EE pilots and rate designs in a manner to maximize benefits and learnings and shall file this proposal in a new docket within 90 days of this Order;

Transmission

30. That HB 951 establishes new public policy goals requiring new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the Open Access Transmission Tariff and the Companies shall continue to study future transmission needs to reliably implement the Carbon Plan through the North Carolina Transmission Planning Collaborative (NCTPC);

31. That the Red Zone Transmission Expansion Plan projects identified in Transmission and Solar Procurement Panel Rebuttal Exhibit 3 are necessary transmission upgrades to achieve the objectives of the Carbon Plan and the Companies shall pursue approval of these projects through the NCTPC;

Carbon Tracking Methodology & Accounting Requirements

32. That the Companies' methodologies outlined in Appendix A (Carbon Baseline and Accounting) for tracking compliance with HB 951's CO_2 emissions reductions targets are approved;

33. That the CO_2 emissions reductions requirements in HB 951 apply to CO_2 "emitted in the State" but that for purposes of this proceeding, the Commission accepts the Companies' approach to modeling compliance that assumes that any new CO_2 emitting resources would be sited in North Carolina and will revisit this issue, if needed, in the future;

Ensuring System Reliability

34. That the generation and resource changes selected by the Commission in this initial Carbon Plan are supported by the Companies' Carbon Plan modeling and reliability validation analysis and meet N.C.G.S. § 62-110.9(3)'s requirement for the Commission to ensure that the adequacy and reliability of the existing grid is maintained or improved;

35. That the Companies should continue to utilize modeling in future Carbon Plan updates that best ensures that future generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid and shall update such modeling where needed to best ensure that reliability is maintained or improved;

Procedural

36. That the first biennial Carbon Plan update proceeding shall be held in 2024, that the Companies' next biennial IRPs will be held in abeyance to 2024 to align with the Carbon Plan update, and that the Companies shall file their 2024 Carbon Plan update and IRP on or before September 1, 2024;

37. That, in the interim, the Companies shall file an IRP update with the Commission on or before September 1, 2023, pursuant to Rule R8-60(h)(2) and (j);

38. That the Companies shall provide an informational update on the Carbon Plan Execution Plan for review by the Commission and the Public Staff with the 2023 IRP update; and

39. That the Companies and Public Staff shall develop and propose for comment by April 30, 2023, revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of December, 2022.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston, Chief Clerk

CERTIFICATE OF SERVICE

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

This the 24th day of October, 2022.

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