PLACE: Dobbs Building, Raleigh, North Carolina

DATE: September 23, 2022

DOCKET NO.: E-100, Sub 179

TIME IN SESSION: 9:30 A.M. TO 12:46 P.M.

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and

Duke Energy Carolinas, LLC,

2022 Biennial Integrated Resource Plans

and Carbon Plan

VOLUME 22

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC, AND
DUKE ENERGY PROGRESS, LLC:
Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq.
Nicholas A. Dantonio, Esq.
McGuireWoods, LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq.
McGuireWoods, LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-39116

A P P E A R A N C E S Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Taylor M. Jones, Esq.
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY:

Gudrun Thompson, Esq.
David L. Neal, Esq.
Nicholas Jimenez, Esq.
Southern Environmental Law Center
601 W. Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

A P P E A R A N C E S Cont'd.:

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:

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

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:

Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

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

A P P E A R A N C E S Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION (CPSA):
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

Carolina Leary, Esq.
1250 I Street Northwest, Suite 1000
Washington, DC 20005

FOR WALMART INC.:
Carrie H. Grundmann, Esq., Member
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:
Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

A P P E A R A N C E S Cont'd.:

FOR APPALACHIAN VOICES:

Catherine Cralle Jones, Esq.

Andrea C. Bonvecchio, Esq.

Law Office of F. Bryan Brice, Jr.

127 W. 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, Esq.

ECB Holdings LLC

1624 Nandina Comers Alley

Charlotte, North Carolina 28205

FOR NC WARN and

FOR CHARLOTTE-MECKLENBURG NAACP:

Matthew D. Quinn, Esq.

Lewis & Roberts, PLLC

3700 Glenwood Avenue, Suite 410

Raleigh, North Carolina 27612

A P P E A R A N C E S Cont'd.:

FOR BROAD RIVER ENERGY, LLC:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

FOR KINGFISHER ENERGY HOLDINGS, LLC, and
FOR PERSON COUNTY, NORTH CAROLINA:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

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

FOR NORTH CAROLINA ELECTRIC MEMBERSHIP
CORPORATION:
Tim Dodge, Esq., Regulatory Counsel
3400 Sumner Boulevard
Raleigh, North Carolina 27616

A P P E A R A N C E S Cont'd.:

FOR THE CITY OF ASHEVILLE and COUNTY OF BUNCOMBE:

Jannice Ashley, Esq., Senior City Assistant Attorney
City Attorney's Office
70 Court Plaza
Asheville, North Carolina 28801

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

FOR MAREC ACTION:

Bruce Burcat, Esq., Executive Director
MAREC Action
Post Office Box 385
Camden, Delaware 19934

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

A P P E A R A N C E S Cont'd.:

FOR TOTALENERGIES RENEWABLES USA, LLC, and
FOR CLEAN ENERGY BUYERS ASSOCIATION:
Joseph W. Eason, Esq.
Nelson, Mullins, Riley & Scarborough LLP
4140 Parklake Avenue, Suite 200
Raleigh, North Carolina 27612

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

FOR PORK COUNCIL:
Kurt J. Olson, Esq.
Law Offices of Kurt J. Olson
P.O. Box 10031
Raleigh, North Carolina 27605

FOR COUNCIL OF CHURCHES:
James P. Longest, Jr., Esq.
Duke University School of Law
Box 90360
Durham, North Carolina 27708

A P P E A R A N C E S Cont'd.:

FOR AVANGRID RENEWABLES, LLC:
Benjamin Smith, Esq.
Todd S. Roessler, Esq.
Joseph S. Dowdy, Esq.
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, THE STATE, AND ITS CITIZENS:
Margaret Force, Esq., Special Deputy Attorney General
Tirrill Moore, Esq., Assistant Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC:

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

TABLE OF CONTENTS

EXAMINATIONS

PAGE

MICHAEL GORMAN – PREFILED TESTIMONY AND SUMMARY........17

BRAD ROUSE – PREFILED TESTIMONY AND SUMMARY............56

DINOS GONATAS – PREFILED TESTIMONY AND SUMMARY........118

WILLIAM POWERS – PREFILED TESTIMONY AND SUMMARY.......154

JAY CASPARY – PREFILED TESTIMONY AND SUMMARY..........223

PANEL - DUSTIN METZ, JEFF THOMAS, DAVID WILLIAMSON

Continued Cross Examination by Mr. Schauer............254

Cross Examination by Ms. Grundmann....................274

Cross Examination by Mr. Breitschwerdt................288

Cross Examination by Ms. Link.........................318

Redirect Examination by Mr. Josey.....................353

Redirect Examination by Ms. Luhr......................355

Examination by Commissioner Clodfelter................364

Examination by Commissioner Duffley...................376

Examination by Commissioner Hughes....................378

E X H I B I T S

IDENTIFIED/ADMITTED

Exhibit MPG-1..................................--/16

Exhibit MPG-2..................................--/16

CCEBA/MAREC Gonatas Exhibit 1................--/117

CCEBA/MAREC Gonatas Exhibit 2................--/117

Powers Exhibit 1.............................--/153

Tech Customers Public Staff Panel 1
Cross Examination Exhibit 1.................266/---

Duke Energy Public Staff Panel 1
Cross Examination Exhibit 1.................304/---

Duke Energy Public Staff Panel 1
Cross Examination Exhibit 2.................315/---

Duke Energy Public Staff Panel 1 Direct
Cross Examination Exhibit 3.................328/---

Duke Energy Public Staff Panel 1 Direct
Cross Examination Exhibit 4.................342/---

P R O C E E D I N G S

CHAIR MITCHELL: All right. Good morning. Let's go on the record, please. Before we return to cross examination of Public Staff panel, we will -- I will entertain motions from parties regarding testimony of witnesses that have been waived for cross examination purposes.

MS. CRESS: Good morning, Chair Mitchell. Christina Cress for CIGFUR. The parties have indicated that they do not have any cross examination for CIGFUR witness Michael P. Gorman. And as such, CIGFUR II and III would move that the Commission excuse him from appearing at the hearing and that his direct testimony filed in Docket Number E-100, Sub 179 on September 2nd, 2022, consisting of 31 pages of testimony, one appendix totaling four pages, and two exhibits titled Exhibit MPG-1 and MPG-2 totaling 27 pages, as well as his three-page witness summary filed in Docket Number E-100, Sub 179A on September 19th, 2022 be moved into evidence and entered into the record at the appropriate time.

CHAIR MITCHELL: Okay. Hearing no objection to your motion, Ms. Cress, I will allow it. The witness' testimony will be copied into the record at the appropriate time, as will his testimony summary, and his exhibits will be accepted into evidence, and he may be excused from the hearing.

MS. CRESS: Thank you, Chair Mitchell.

(Whereupon, the prefiled direct testimony of Michael Gorman, Appendix A, and summary were copied into the record as if given orally from the stand.)

(Exhibits MPG-1 and MPG-2 were admitted into evidence.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	**DIRECT TESTIMONY**
	)	**AND EXHIBITS OF**
Duke Energy Progress, LLC, and Duke	)	**MICHAEL P. GORMAN**
Energy Carolinas, LLC, 2022 Biennial	)	**ON BEHALF OF**
Integrated Resource Plans and Carbon Plan	)	**CIGFUR II & III**
	)	

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

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

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

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

Q: IN SETTING THE HEARING CONCERNING THE COMPANIES' CARBON PLAN, DID THE COMMISSION OUTLINE SPECIFIC ISSUES FOR EXPERT WITNESSES TO ADDRESS IN THIS PROCEEDING?

A: Yes. In its July 29, 2022 order issued in this docket, the Commission outlined specific topics and sub-issues based on the Issues Report Duke filed after consultation with other parties. In its July 29, 2022 order, the Commission directed expert witnesses to organize their pre-filed direct testimony in accordance with these issues lists. As a result, the remaining portion of my testimony addresses specific Commission-identified topics and sub-issues, which are identified in accordance with the topical categories set forth in the Commission's July 29, 2022 Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines ("Order").

Q: DID DUKE OFFER POLICY OBJECTIVES IN THE DEVELOPMENT OF ITS CARBON PLAN?

A: This response corresponds to Ordering Paragraphs 1.a.i., 1.b., 1.i., and 1.j. of the Commission's Order.

Yes. Duke has offered a proposed Carbon Plan ("Plan") that outlines its next major step in an ongoing energy transition. Duke maintains that its Plan to transition to net-zero carbon emissions:

1. Reflects a diverse portfolio of technologies with lower carbon intensity;
2. Continues to support system reliability at or better than current levels;
3. Permits the Companies access to capital at reasonable costs for the benefit of their customers; and

4. Continues to target affordable and competitive utility rates for their customers.

The Companies opine that the foundation of their Plan is based on decades of reasonable and prudent utility planning practices that have been jointly overseen by the North Carolina Utilities Commission ("NCUC" or "Commission") and the Public Service Commission of South Carolina ("PSCSC"). They maintain that Duke's dual-state approach to least-cost resource planning has benefitted customers in the two Duke Carolinas jurisdictions and supported the provision of reliable and affordable electric service.

Duke maintains that its combined carbon dioxide ("CO_2") emissions between DEC and DEP are already lower than the national average among all privately held and investor-owned utilities. Duke plans to continue this modernization of its Carolinas systems by further reducing CO_2 emissions based on what Duke contends will be prudent, orderly, and cost-effective infrastructure planning and investments.

Based on its Carbon Plan proposal in this case, Duke has proposed four portfolios which are designed to achieve an interim 70% carbon reduction goal projected to be achieved in years ranging from 2030 up through 2034. A summary of the four plans is outlined on Exhibit MPG-1. A critical component of all four plans is the anticipated early retirement of North Carolina located coal-fired generation capacity: 4,900 MW planned to be retired by 2030 and increasing to 6,300 MW retired by 2034.

Q: DO YOU BELIEVE THE POLICY GOALS SET OUT BY DUKE CONCERNING THE DEVELOPMENT OF A CARBON REDUCTION PLAN ARE REASONABLE AND PRUDENT?

A: This response corresponds to Ordering Paragraph 1.j. of the Commission's Order.

Generally, for the reasons outlined below, I find the Companies' proposed Plan fails to meet many of the objectives set forth in House Bill 951 ("HB 951") as well as some of the Companies' own policy objectives, by failing to propose a Plan that:

1. Would facilitate joint implementation by the NCUC and PSCSC in an orderly and controlled manner, with reliability being assessed on the system in terms of both adequate capacity to maintain system resources during constrained peak period conditions and ensuring an ability to support reliability, particularly in light of the "new risk of energy adequacy," which Duke states will impair reliability due to limited dispatchable generation resources if not planned for and managed effectively.[1]
2. Requires dispatchable resources that do not emit carbon which will be fundamental to the power system reliability, including load-following capabilities as well as adequate resources for constrained period deliveries. The Company acknowledges limited known technology available to operate under the zero-emission load-following resource ("ZELFR") criteria, even though new technologies and new sources were considered in modeling the various resource portfolio options supporting the carbon reduction goals.
3. Will rely on proven technology.
4. Ensures the financial integrity and credit standing of the utility, but at least-cost and competitive tariff rates.

These limitations in Duke's Plan support a careful, systematic, and slow progression toward transitioning to carbon-free generating resources in a manner that meets the multi-prong objectives of carbon emissions reductions, maintaining or improving system reliability, and maintaining competitive and least-cost electric service rates.

[1]Duke's Proposed Carbon Plan, Appendix Q at 2.

Q: PLEASE COMMENT ON ISSUES FALLING UNDER SECTION 1.a., "MODELING—METHODOLOGY, ASSUMPTIONS AND OTHER MODELING ISSUES" INCLUDED IN THE COMMISSION'S ORDER.

A: My responses to each of the topics and sub-issues set forth in the Commission's Order follow:

Alternative Modeling Needed – North Carolina Ratepayers Should be Held Harmless if South Carolina Jurisdictional Allocable Carbon Plan Costs Are Disallowed by the PSCSC

Duke's proposed Carbon Plan fails to address cost recovery and likewise fails to produce a systematic plan that ensures least-cost, competitive rates in North Carolina. This limitation is due to, among other things:

1. Uncertainties with respect to multi-jurisdictional cost recovery, more specifically related to joint jurisdictional resource planning.
2. Use of emerging zero carbon technology and fuel sources which may hold promise but are not currently known to be viable resource options.
3. Political and economic limitations on expanding natural gas pipeline delivery systems, which are critical in relying on planned new gas-fired generation to be available during constrained peak period conditions.

Duke has acknowledged that the Companies' Integrated Resource Plan is based on its dual system serving jurisdictional operations in both North Carolina and South Carolina. Under current ratemaking protocols, this dual system allocates the cost of common infrastructure (transmission and production) across both jurisdictions using a load share methodology. Specifically, production and bulk transmission costs are allocated across jurisdictions using a coincident peak methodology. The load share allocation of this common infrastructure investment methodology emulates the load included in a resource plan, which is ostensibly used to determine the amount and most economic structure of infrastructure investments needed to provide reliable service in the two jurisdictions combined.

The jurisdictional allocation of costs to each jurisdiction for their load share benefits of the dual infrastructure for production and transmission ensures that all customers are allocated a fair and reasonable share of the total system common infrastructure costs based on the load demands they placed on the system. This jurisdictional allocation methodology is a critical element in ensuring that customers' rates in North Carolina are responsible for no more than a fair allocation of dual system common costs of production and transmission infrastructure. Moreover, this jurisdictional cost allocation methodology is a critical element in ensuring that Duke's North Carolina rates remain competitive, low-cost rates that support Duke's financial integrity and ability to continue supplying high quality and reliable service.

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

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

<u>Design of Curtailable or Interruptible Rates</u>

Duke's proposed Carbon Plan assumes increased energy efficiency and demand-side management program participation from Duke's customers. However, to maximize the amount of viable customer participation in such programs, the outline and design of curtailment rates and interruptible rates, and the associated benefits to customers of participating in these programs, need to be carefully considered. CIGFUR appreciates the continued dialogue with the Companies regarding the potential design of a new demand response program, but CIGFUR maintains that without an emergency demand response program similar to that offered by Southern California Edison through its Base Interruptible Program ("BIP") and corresponding Emergency Load Reduction Program ("ELRP"), flexible industrial load will continue to be an under-leveraged demand-side resource.

Power Quality Issues Not Adequately Modeled – Metrics Required to Ensure Carbon Plan is Maintaining or Improving Reliability of Existing Grid

The energy transition is changing Duke's system for both planning purposes and operational purposes. If the Carbon Plan transition is not carefully implemented, significant deficiencies can impact Duke's ability to provide high quality and reliable power. Indeed, Duke recognizes the need for evolving planning and operating procedures, as well as the need to carefully and critically manage the movement toward the carbon emissions reductions goals. Specifically, Duke witnesses John Holeman and Roberts state, in pertinent part that:

> Resource adequacy has traditionally been assumed through verifying capacity with appropriate planning reserves to serve peak demand in the long-term resource planning. However, recent industry events have highlighted that the changing resource mix performing in real- world situations can result in energy inadequacy.[2]

They go on to explain that the North American Electric Reliability Corporation ("NERC") has noted concerns about the changing planning and operational protocols for electric utilities who transition to low carbon resources and away from dispatchable coal and dispatchable nuclear generating facilities.

The witnesses outline NERC's concern about providing adequate frequency support in the Eastern Interconnection which in turn impairs the potential for maintaining demand and resource balancing within the Balancing Authority Areas.[3] They state that a Balancing Authority must purposefully plan and dispatch its generating fleet in order to ensure compliance with NERC BAL Standards and thus, cannot rely on unscheduled power flow from neighboring Balancing Authorities to satisfy the

[2]Direct Testimony of Duke witnesses Holeman and Roberts, at 23-24.

[3]*Id*. at 6.

obligation to maintain operating reliability. They state that these Balancing Authority Standards are important Reliability Standards because they regulate a Balancing Authority's real-time performance with respect to maintaining proper reserves to balance resources and demand and to provide for proper frequency regulation, energy adequacy, or operating reliability. Failure to meet the NERC Reliability Standards could result in system emergencies and reliability failure such as unscheduled power flows, automatic firm load shedding, or in the worst case, cascading outages across the Interconnection.[4] Just as importantly, however, these frequency variations and energy inadequacies can result in frequency variations and voltage sags which render sophisticated electronic and digital equipment in businesses and homes at risk of unreliable operation.

The witnesses state that maintaining reliability and operational resilience is outlined in Appendix Q to their proposed Carbon Plan. Key components for evaluating reliability risks and mitigating solutions include the following:

1. Resource and energy adequacy from renewables and storage;
2. Additional firm gas generation and transportation;
3. Coal generator reliability during the transition;
4. Zero emitting load-following resources to reach net zero;
5. Flexible generation needs for integrating renewables; and
6. Future system resilience to withstand extreme weather events.

---

[4] *Id*. at 17.

However, each of the six items above illustrates why the Companies' Carbon Plan is, at best, at risk of failing to maintain or improve system reliability. Specifically, weaknesses in the Plan include:

a. Relying on unproven ZELFR and other zero carbon fuel to operate dispatchable generation to follow load for the purpose of ensuring energy adequacy and sufficient frequency control, to preserve customers' ability to operate sophisticated electronic equipment without interruption or damage to equipment.

b. Need for additional firm pipeline delivery capacity, which Duke acknowledges is currently not available, and is experiencing significant political and economic opposition to expanding delivery capacity into North Carolina. Without this firm delivery capacity, new gas-fired generation resources may not be available to operate during constrained peak demand periods.

c. The Companies' ability to produce dispatchable generation to operate along with intermittent resources, to preserve system resilience and to withstand extreme weather events is not captured well in the Companies' Plan.

<u>Compliance in 2032 or 2034 is Reasonable for Planning Purposes and Consistent with Least-Cost Planning Principles</u>

HB 951 delegates broad discretion to the Commission in developing and implementing the Carbon Plan in accordance with certain parameters, including that the Plan must comply with least-cost principles and must maintain or improve the reliability of the electric grid. The time frames for compliance are goals, not mandates. Moreover, the legislation delegates to the Commission the flexibility to extend the 2030 compliance target until 2032 for any reason, and then to delay it further—until 2034 or potentially even beyond—"in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility, or in the event necessary to maintain the adequacy and reliability of the existing grid."[5] The Commission has been empowered with this discretion because the Legislature saw fit to delegate it; the Commission should use it in order to ensure that the least-cost and reliability mandates are satisfied.

Carbon Baseline and Accounting Methodologies

The Carbon Baseline is the Companies' emission level at a specific point in time, 2005. DEC and DEP must demonstrate a reduction to their carbon emissions from this Carbon Baseline in accordance with the requirements set forth in House Bill 951. The Commission does have discretion to ensure that the plan is developed and implemented in accordance with North Carolina law, and House Bill 951 specifically provides for Commission flexibility with respect to extending compliance time frames by two years for any reason, or indefinitely thereafter if off-shore wind or new nuclear is selected as a Carbon Plan generation resource, or if the reliability of the existing grid would be compromised.[6]

In establishing these carbon reduction infrastructure investments, the design targets should consider a balance between achieving carbon emissions reduction targets when weighed against competing objectives, including least-cost planning, maintaining

---

[5] G.S. 62-110.9(4).

[6] *See id.*

or improving the reliability of the existing grid through investments in proven resources with demonstrated operating performance and which can provide high-quality power at competitive rates.

Duke is already ahead of the curve when it comes to its carbon emissions reductions baseline compared to the national average. In reducing carbon emissions, system benefits should be considered. However, CIGFUR encourages maximum flexibility in adopting an initial and subsequent iterations of a Carbon Plan. More specifically, a flexible Carbon Plan should be adopted that allows for Duke, the Commission, and other stakeholders to continuously evaluate, assess, and respond to new technology operational risk, needed infrastructure logistical constraints and risks, acceptable construction and development risks, least-cost planning, and reliability (i.e., both peak and operating) concerns.

Minimizing carbon emissions is the objective, but so too is designing a structured and systematic Plan that lowers emissions, while still maintaining service reliability, power quality, and competitive utility rates based on the least-cost set of investments necessary to comply with House Bill 951.

Accounting Requirements for Emissions From New Out-of-State Resources

As a threshold matter, the carbon emissions reduction targets set forth in House Bill 951 apply only to emissions "emitted in the State[.]"[7] House Bill 951 further clarifies this threshold criterion in its definition of "carbon neutrality" when it reiterates that it applies to carbon emissions emitted in North Carolina.[8] As a result, emissions

[7] HB 951, Part I, Section 1 (S.L. 2021-165) (N.C.G.A.).

[8] *See id.*

that occur outside North Carolina should not count against achievement of the interim target or carbon neutrality by 2050.

Emissions Leakages Associated with Price-Induced Demand Erosion

A reduction in carbon emissions caused by reductions in sales should be reflected in the Plan as the Companies work toward the stated carbon reduction goals. "Shrinking the problem" via energy efficiency and demand-side management are important and economic options available to reduce carbon emissions. Existing empirical research tends to show evidence of a causal relationship between high electricity prices and premature deindustrialization. "[W]e find that higher electricity prices are associated with industry share turning downward at lower peaks and at lower levels of GDP per capita. Moreover, the downtrend tends to be steeper the higher are electricity prices."[9]

Q: PLEASE COMMENT ON SECTION 1.b., "COAL UNIT RETIREMENT SCHEDULE; SECURITIZATION" INCLUDED IN THE COMMISSION ORDER.

A: Duke's outline of resource portfolios does not include the costs associated with early retirement of coal units. To the extent the early retirement of coal units results in significant amounts of abandoned plant costs that DEC and/or DEP may have a right to recover from customers, the cost of the early retirement should be reflected in the economic projections in the Plan. The timing of coal plant retirements, and the timing of replacement resources that are needed to maintain system reliability (both planning

[9] Majah-Leah V. Ravago, Arlan Zandro I. Brucal, James Roumasset, Jan Carlo Punongbayan, "The Role of Electricity Prices in Structural Transformation: Evidence from the Philippines," at 20, University of Hawai'i at Manoa Department of Economics Working Paper Series (February 2019), a complete copy of which is attached hereto as Exhibit MPG-2.

reserves and operating quality) must be reasonably reflected in the Plan, and the resulting Present Value of Revenue Requirement ("PVRR") costs of the Plan can then reasonably reflect all costs to implement the Plan.

Importantly, if the Plan ignores significant background infrastructure costs and coal plant retirement costs, the full cost of the Plan cannot be known. Without knowing the full cost of the Plan, the Commission cannot determine whether or not plans need to be modified in order to maintain affordability for all customer rate classes as an important planning criteria in achieving the carbon emissions reductions goals. Specifically, timing of coal unit retirements, timing of installation and new gas-fired or alternative fuel dispatchable generating resources, and the time period it takes new demand-side management and curtailment tariff rate programs to gain acceptance and modify load consumptions are all dependent on a clear understanding of what the cost of each of the plans will be. Duke's representation that certain costs are common to all plans assumes no flexibility in these embedded common costs in terms of timing of occurrence, level of occurrence, or other means of modifying plans to accomplish the multi-prong objective of carbon reductions, maintaining or improving system reliability (both planning reserves and operating flexibility), and maintaining affordable rates for all classes of Duke's North Carolina customers.

Duke's proposed Carbon Plan simply ignores the likely cost to customers of coal retirements and understates rate impacts necessary to support the investments outlined in the Plan. Stated more directly, early retirements are an integral part of the Plan to reduce carbon emissions, and the retirement costs should be reflected in the cost estimates for the various Carbon Plan portfolio options.

Use of special financing mechanisms for reducing ratepayer costs for early coal plant retirements can also have economic benefits by supporting the Companies' financial integrity during the combined early retirement and development of replacement resources, as well as possibly helping to offset costs to ratepayers for the cost of such early retirement. For example, securitization bonds may be useful for reducing costs to customers for recovery of abandoned coal plant early retirement costs, and the securitization bond proceeds will enhance utility cash flows and support financial integrity during the development of low carbon replacement resources. Not only can this securitization pathway provide economic benefits for the benefit and protection of ratepayers, but it is required by House Bill 951.[10]

Reviewing potential ratemaking treatment of abandoned plant costs, use of special financing mechanisms such as securitization bonds, and the resulting impact on the utilities' financial integrity during development of replacement resources is necessary in order to both assess the cost of each of the various portfolio options to customers, and to assess the need, if any, for utility financial support during the development of new low- or zero- carbon resources and infrastructure transition.

This is particularly true for new resources with longer development times between the time the utility incurs costs to develop the resources and the time the resource is placed in-service and the cost recovered in the utility's tariff rates. Careful planning from the customer standpoint and the utility's financial standpoint is necessary to assess the benefits of each of the portfolios from a rate and financial integrity standpoint, and this analysis will ultimately improve planning.

[10] Part III, Section 5, HB 951 (S.L. 2021-165) (N.C.G.A.).

Q: PLEASE COMMENT ON SECTION 1.c., "NEAR-TERM PROCUREMENT ACTIVITY—SOLAR, SOLAR+STORAGE, STANDALONE STORAGE, ONSHORE WIND, NATURAL GAS GENERATION" INCLUDED IN THE COMMISSION ORDER.

A: There are several critical aspects of the Companies' Plan which diminish its ability to identify the least-cost resource portfolio over the planning period. These deficiencies relate to certain infrastructure necessary to reliably operate new generating facilities, uncertainty with respect to subsequent license renewals ("SLRs") for Duke's existing nuclear fleet, and the expected remaining operating lives of new pipeline infrastructure, and thoughtful consideration of use of carbon emission offsets to manage the selection of unproven resources while remaining in compliance with carbon reduction goals.

<u>Duke's Proposal Fails to Provide Sufficient Guardrails, Spending Caps, and Other Parameters Around its Proposed Near-Term Supply-Side Activities.</u>

Duke has essentially developed a lower-carbon Integrated Resource Plan which includes its best estimate of what the projected cost of the infrastructure investments will be, and the expected operating performance of those resources. However, many of these resources are unproven, or the infrastructure needed to operate the new resource as a resource capacity is at best highly uncertain. Further, the actual installed cost of these resources is also a best estimate which could vary significantly based on resource demands as the plan moves forward. These installed cost uncertainties and this need for resource capacity infrastructure expansion is problematic at this time. As a result, the Commission should require Duke to establish budgetary limits (i.e. not-to-exceed spending caps) that can act as pivot points as Duke moves forward with Carbon Plan implementation to continue to assess market factors, resource viability and adequacy, and technological improvements to resources and/or zero carbon fuel in a manner that addresses least-cost, high quality, reliable, and affordable rates to all classes of Duke's retail customers.

Duke's proposed Carbon Plan fails to ensure that Duke is bearing some of the risk in the event these investments do not result in assets that eventually become used and useful in the provision of electric service to ratepayers.

The ability to move forward with uncertain infrastructure investments, uncertain zero carbon fuels, and uncertain ZELFRs should be done carefully and systematically during initial development and implementation of the Carbon Plan. Competing objectives include competitive and affordable rates across customer classes, service quality, reliability, and the continued viability of the North Carolina economy.

To ensure risk of all the uncertain elements of Duke's proposed Carbon Plan are managed efficiently and economically, Duke should bear the risk that it has failed to fully consider certain elements or variables within the multi-pronged analysis of the Plan.

Third-Party Owned Generation Should Be Considered if Available and Least-Cost.

Duke's proposed Carbon Plan is based entirely on the premise that only utility-owned investments in production and necessary transmission expansion may be made, and only by the utility. However, to the extent a merchant provider of transmission upgrades and/or production resources can develop resources at a much lower cost than Duke and sell that resource capacity to Duke under a supply contract, then those resources should be considered by Duke in selecting the best and least-cost resource available.

All utilities including Duke have a natural economic interest to select investments funded by the utility and included in rate base. These types of investments grow the utility and enhance shareholder value by growing rate base, which in turn increase utilities' earnings and dividend-paying ability. While financial integrity and strong credit standing are important for enabling efficient and economic investments in prudent utility infrastructure, that balance also requires selection of investments that produce the least possible costs borne by ratepayers while also achieving these financial protections for the utility. To the extent merchant development of production or transmission resources are lower cost than a utility's infrastructure developments, then the merchant developer should be considered and included in the resource plan. This same logic applies to the possibility of pursuing competitive procurement for the purpose of executing least-cost purchased power agreements ("PPAs") with the independent power producers ("IPPs") who submit the lowest bid in terms of total project cost or PPA cost that would then be recovered from ratepayers.

As a means of further protecting customers, the Commission can establish financial and technical qualifications for production and transmission investments supplied by merchant providers that will best assure such merchant providers are financially and technologically capable of developing the infrastructure to meet the needs of Duke's dual system planning criteria.

<u>Reasonableness and prudency for purposes of future cost recovery should be deferred for decision in a future rate case.</u>

Customer protections for paying rates which are just and reasonable while maintaining the utility's financial integrity and credit standing will be a critical aspect of implementing the Carbon Plan. Under traditional cost-of-service ratemaking principles, customers' rates reflect the cost of infrastructure that is currently in-service, and used and useful in providing service. Only under extraordinary circumstances should customers be asked to pay costs associated with infrastructure assets that have not yet been declared in commercial operation or in-service operation. Moreover, ratepayers should only be asked to pay such costs under extraordinary financial circumstances that justify this intergenerational constraint on customer rate protections.

The Commission should make it clear that establishment of just and reasonable rates will be a priority throughout the development and implementation of the Carbon Plan, and ratepayer support for long-term asset development will only be considered under the existence of extraordinary financial circumstances which prove that such departure from precedent is necessary and in the public interest to support the utilities' financial integrity and credit standing. In such extraordinary circumstances, customers should receive a *quid pro quo* deal by paying higher rates during construction to support the utility, but paying lower rates after the construction period is completed, and assets are placed in-service, and used and useful in the provision of electric service to customers.

New Combined Cycle Natural Gas Facilities' Need for New Firm Pipeline Delivery Capacity

All four preferred resource portfolios included in the Plan assume 2,400 MW of new natural gas-fired generation combined cycle ("CC") units will be placed in-service by 2030. However, the Companies acknowledge that developing new gas delivery pipeline infrastructure is a plan execution risk.

Recognizing the significant risks to developing new interstate natural gas pipeline delivery capacity, the Company stated:

> **Execution and Risk Management**
>
> Pipelines: New gas interstate pipelines have been increasingly challenged through every permit approval required. The ability to bring additional gas supply to the Carolinas via pipelines is important to the success of the Companies' clean energy transition.[11]

The Companies note the uncertainty of new natural gas pipeline capacity to fuel existing and/or new natural gas-fired generation in the discussion of their intention to convert to hydrogen fuel over time:

> Currently, the Companies' natural gas generation stations rely on interstate pipeline firm transportation or on-site coal and diesel dual-fuel capability for fuel security; however, the Companies' combined cycle fleet is currently deficient of interstate pipeline firm transportation capacity due to the cancellation of Atlantic Coast Pipeline ("ACP"). Looking ahead, current and future gas turbines could transition to hydrogen or other low- or zero-carbon fuels. Although promising, hydrogen still requires additional production and generation technology development to be widely utilized as a utility fuel. As discussed in Appendix O (Low-Carbon Fuels and Hydrogen), the Companies will continue to closely follow hydrogen technology in preparation for its potential future use as a substitute for natural gas. Regardless of the future utilization of natural gas, renewable gas or hydrogen as the fuel, there is still a need for additional pipeline capacity in the Carolinas.[12]

The Company's Plan has significant risk about the increased use of combined cycle natural gas units because the Company's ability to secure adequate and reliable firm delivery capacity is a significant execution risk of the Plan.

Regarding firm pipeline delivery capacity, the Companies will not have firm capacity rights that can be expected to operate during system peaks and therefore cannot reliably be expected to contribute toward a reliable source of power from the Companies' system.

---

[11] Duke's Proposed Carbon Plan, Appendix M.

[12] *Id.* at Appendix N.

SLRs – Existing Nuclear Resources

The Companies make several projections for increasing the operating lives of its nuclear facilities. However, in order to continue to operate the Companies' nuclear generation fleet, they will need SLRs approved by the Nuclear Regulatory Commission ("NRC").

The Companies' nuclear fleet and the existing NRC operating licenses are shown below in Table 1.

TABLE 1

Existing Nuclear Generating Units Operating License Renewal

Line	Utility (1)	Unit & Plant Name (2)	Capacity (MW) Winter (3)	Capacity (MW) Summer (4)	Location (5)	Original Operating License Expiration (6)	Date of Approval (7)	Extended Operating Expiration (8)
1	DEC	Catawba Unit 1	1,199	1,160	York, SC	12/6/2024	12/5/2003	12/5/2043
2	DEC	Catawba Unit 2	1,180	1,150	York, SC	2/24/2026	12/5/2003	12/5/2043
3	DEC	McGuire Unit 1	1,199	1,158	Huntersville, NC	6/12/2021	12/5/2003	3/3/2041
4	DEC	McGuire Unit 2	1,187	1,158	Huntersville, NC	3/3/2023	12/5/2003	3/3/2043
5	DEC	Oconee Unit 1	865	847	Seneca, SC	2/6/2013	5/23/2000	2/6/2033
6	DEC	Oconee Unit 2	872	848	Seneca, SC	10/6/2013	5/23/2000	10/6/2033
7	DEC	Oconee Unit 3	881	859	Seneca, SC	7/19/2014	5/23/2000	7/19/2034
8	DEP	Robinson 2	793	759	Hartsville, SC	7/31/2010	4/19/2004	7/31/2030
9	DEP	Brunswick 2	953	932	Southport, NC	12/27/2014	6/26/2006	12/27/2034
10	DEP	Brunswick 1	975	938	Southport, NC	9/8/2016	6/26/2006	9/8/2036
11	DEP	Harris 1	1,009	964	New Hill, NC	10/24/2026	12/17/2008	10/24/2046
12	Total		11,113	10,773				

Sources:
Appendix D, Table D-9 and Table D-14.

As outlined in Table 1 above, total capacity of the nuclear fleet to meet Duke's demands is around 11,100 MW. These are non-carbon emitting resources. None of these plants have current operating licenses that extend beyond 2046, the time period preceding the target carbon emission limit of 2050. More significantly, a significant amount of this capacity may no longer be available to Duke if a nuclear operating license fails to be extended. Specifically, in 2030, Robinson 2 (793 MW) may no longer be available. By 2035, approximately 5,400 MW of nuclear operating license may expire and would not be available without a license extension. However, and importantly, the Companies' four preferred portfolios do not anticipate the retirement of nuclear generation. Hence, the cost of SLRs—which was omitted from Duke's proposed Carbon Plan—must be included in the Plan and is likely a significant and material cost.

As outlined in Table 2 above, Duke Carolinas will have 11 facilities to seek relicensing for, and a total winter operating capacity of around 11,113 MW. Until shown otherwise, we should assume the cost of these SLRs is material, and should therefore be analyzed and considered in the Plan.

Q: PLEASE COMMENT ON SECTION 1.d., "NEAR-TERM DEVELOPMENT ACTIVITY—PRUDENCE OF DEVELOPMENT WORK AND NEED FOR LONG-LEAD TIME RESOURCES (BAD CREEK II, SMALL MODULAR REACTORS, OFFSHORE WIND)" INCLUDED IN THE COMMISSION ORDER.

A: Utilities are typically provided adequate engineering services, finance services and treasury services to execute any integrated resource planning process, and to stay current on new technologies. To the extent the overhead cost for this resource planning is already included in their tariff rate revenue (treasury, regulatory and engineering), then the utility should charge against current revenues, and deferrals are not justified.

Concerning investments in new and unproven technology, the Commission should clearly find that this function should be performed by unregulated major equipment manufacturing companies, and not utilities. To the extent new, innovative resources hold promise, major equipment manufacturers should be the ones making these technology investments, not regulated utility companies. To the extent Duke's corporate enterprises choose to take on this technology research and development and/or innovation function, they should do so through an unregulated affiliate with clear ring-fence separation and financial protections from its regulated utility companies generally, but DEC and DEP specifically.

From a financial integrity standpoint, the utilities' ability to support significant capital investments for transmission infrastructure needed to deliver low- or zero-carbon emitting generation resources requires a complete review of the investment development, duration of development, and impact on the utilities' access to capital and other financial considerations. To the extent the utilities' financial integrity and cash flow strength is adequate during the initial development stage, then customers should not be asked to pay any costs associated with assets under development unless and until they are placed in-service and used and useful in providing service.

The Commission may also consider financial tests to determine whether or not it is in the public interest to ask customers to provide financial protection to the utilities during the development of long lead time assets. For example, developing new nuclear generating stations can result in construction projects with almost a ten-year development period. In these instances, Public Utilities Commissions (PUCs) have considered providing financial support to the utility in the form of current return on construction work in progress, or other measures to enhance the utility's cash flows and financial strength during construction. But these should only be approved to the extent there is clear ratepayer support and public interest benefits by asking customers to pay a return on a long lead time asset development, where the asset is not providing any benefits to customers and the asset is simply not used and useful for ratemaking purposes.

Moreover, under all four portfolios of the Companies' current Plan, it will be in a major construction period but the utilities may benefit from the recovery of abandoned plant costs on an accelerated basis at the outset of the Carbon Plan. Providing accelerated recovery of early retirement cost of coal plants, particularly if DEC and DEP are refinanced using securitization bonds, will provide an immediate injection of cash to the utilities that may support any potentially weakened financial positions of the utilities as they move into major construction programs.

But importantly, customers' ratemaking protections must be preserved. Assets that are under development are not normally included in cost of service and should not be, absent extraordinary circumstances like extreme financial conditions.

The Commission should find that no extraordinary ratepayer support for major construction activities will be done absent extraordinary circumstances. Prior to asking for customers to pay a portion of development costs or construction period carrying charges, the Commission should instruct the utilities to outline plans that can be executed through traditional financial integrity constraints, without the need for extraordinary customer support, to appropriately balance the utilities' financial soundness against the competing consumer protection interest of ensuring that just and reasonable rates are maintained.

Q: PLEASE COMMENT ON SECTION 1.e., "WORK ON EXISTING RESOURCES (NATURAL GAS AND SLR)" INCLUDED IN THE COMMISSION ORDER.

A: I have already outlined concerns with the utilities' ability to actually increase firm natural gas pipeline delivery capacity to fuel new combined cycle natural gas facilities. The Companies' own evidence suggests they face significant economic and political opposition to the development of new natural gas delivery capacity.

But significantly, to the extent new capacity is put in-service, the Companies' proposed Carbon Plan of converting natural gas-fueled facilities to hydrogen fuel facilities in the near term creates another economic restriction on the development of new firm natural gas pipeline capacity. A pipeline utility company would only be willing to invest in a new pipeline capacity to the extent it has a viable and stable marketplace for the pipeline capacity. If Duke's plan is to have temporary use of the pipeline capacity, only to later switch the fuel from natural gas to hydrogen, the viability of the new pipeline capacity may be placed in jeopardy. This may require an accelerated recovery of the firm pipeline capacity costs, or the refusal of a pipeline company to make the pipeline capacity upgrade in the first place.

SLRs are also a significant concern and likely will be a material cost which at present is not factored into Duke's projected Carbon Plan costs or rate impacts. Duke has not provided sufficient data or analysis to estimate a cost of upgrades to its existing facilities in order to receive approval from the NRC for SLRs.

Q: PLEASE COMMENT ON SECTION 1.f., "TRANSMISSION PLANNING, PROACTIVE TRANSMISSION, AND RZEP" INCLUDED IN THE COMMISSION ORDER.

A: Transmission planning is a key aspect of the Integrated Resource Plan. However, transmission planning should be done hand in hand with production resource planning.

Transmission investments can be used to mitigate costs of production resources, or conversely, location and size of production resources can be used to mitigate the need for increasing transmission infrastructure investments. The two should be combined together, and the resulting production and transmission plan should result in least-cost resource options available to the utility to ensure the utility's ability to be a competitive least-cost provider of electric service.

Q: PLEASE COMMENT ON SECTION 1.g., "RATE DISPARITY / MERGER / STATE ALIGNMENT" INCLUDED IN THE COMMISSION ORDER.

A: DEP and DEC have operated across two jurisdictions for decades. The two utilities are currently operated on a joint dispatch basis, and in all other respects are operated as a single system. As such, dual-system integrated resource planning pursued by the utilities should continue to be approved by the regulatory commissions in both North Carolina and South Carolina, and a commitment by both Commissions for the continued cost-sharing of joint resources is needed to accurately estimate the Carbon Plan's costs and rate impacts to North Carolina customers.

To ensure the best and lowest risk estimate of the potential impact on customers, the following agreements between jurisdictions should be sought:

1. Approval on integrated resource plans transitioning to zero carbon.
2. Agreement among jurisdictions on maintaining common production and transmission cost allocations necessary to maintain system reliability, both with respect to planning reserves and adequate operating flexibility.
3. Agreement on continuation of existing inter-jurisdictional cost allocation methods for rate-setting purposes.
4. Commitment from both jurisdictions on agreement of above to ensure the financial integrity and ability of the Companies to continue to make necessary infrastructure investments to maintain reliable and high-quality electric service, at competitive and affordable electric rates.

Q: PLEASE COMMENT ON SECTION 1.h., "EE/DSM ISSUES/GRID EDGE" INCLUDED IN THE COMMISSION ORDER.

A: CIGFUR is in strong agreement with the notion that conservation and demand-side management should be an important part of the carbon reduction plan. To realize the maximum benefits of energy efficiency and demand-side management requires a clear economic signal produced through tariff rate mechanisms to encourage customers to modify consumption, invest in new energy assets, or take operating procedures that will change load shape, shifting load from high-cost constrained periods to low-cost non-constrained periods, or to reduce consumption overall.

Designing interruptible and curtailment rates with interruptible credits that are aligned with the avoided costs of supply-side resources will create economic incentive for customers to pursue economic demand-side management and energy efficiency programs and actions. Duke's proposal fails to sufficiently leverage flexible load of certain non-residential customers through demand response and demand-side management programs. Duke's proposal further fails to sufficiently leverage non-residential customers' interest in participating in new customer renewable energy programs.

Q: PLEASE COMMENT ON SECTION 1.i., "COST" INCLUDED IN THE COMMISSION ORDER.

A: As previously testified, Duke's proposal fails to provide an "all-in" total cost and projected rate impact for all planned spending both related and unrelated to the Carbon Plan. By excluding the all-in costs, the Commission cannot accurately gauge the affordability of each of the respective Carbon Plan portfolios on customers in North

Carolina, and cannot determine whether or not refining the Plan to improve affordability is possible, consistent with the goals, or necessary to reflect uncertainty in the implementation of the Carbon Plan, such as ensuring technology evolves in a reliable and prudent manner, for both physical assets and zero carbon related fuel options.

Q: PLEASE COMMENT ON SECTION 1.j., "RELIABILITY" INCLUDED IN THE COMMISSION ORDER.

A: Reliability is a concept that should ensure infrastructure that has the peak day demand resources to meet firm demand of the customers in a reliable and predictable manner. But reliability should also require the status quo of power quality, for example, voltage stability, phase or wave stability, and "energy adequacy." Power quality will ensure that customers are able to operate sensitive digital and electronic equipment and machinery in a safe, reliable, uninterrupted manner. The benefits of reliable service and minimizing unintended interruptions are critically important to customers that can avoid costs associated with unplanned outages, momentary interruptions in service, or electronic equipment failure due to power quality factors. Similarly, many customers that are highly dependent on power quality may experience outages and/or equipment failure even without a total power outage in the event of voltage or phase/wave intolerances. The Company's Plan outlines a need for capacity needed to maintain service on peak days but provides little to no assessments of the need to manage "operating" power quality: voltage stability, phasing/wave stability, energy adequacy, and other factors that impact power quality.

The need for power quality is particularly relevant to the North Carolina jurisdiction because this jurisdiction is where all 4,900 MW to 6,300 MW of coal-fired capacity that is expected to be retired under the four proposed Carbon Plan portfolios is located. The locations of the Companies' retiring coal-fired units are shown below in Table 2.

TABLE 2

Coal Unit Retirements

Line	Unit (1)	State (2)	Utility (3)	Winter Capacity (MW) (4)	Effective Year (Jan 1) (5)
1	Allen 1	North Carolina	DEC	167	2024
2	Allen 5	North Carolina	DEC	259	2024
3	Cliffside 5	North Carolina	DEC	546	2026
4	Marshall 1	North Carolina	DEC	380	2029
5	Marshall 2	North Carolina	DEC	380	2029
6	Mayo 1	North Carolina	DEP	713	2029
7	Roxboro 1	North Carolina	DEP	380	2029
8	Roxboro 2	North Carolina	DEP	673	2029
9	Roxboro 3	North Carolina	DEP	698	2028-2034
10	Roxboro 4	North Carolina	DEP	711	2028-2034
11	Marshall 3	North Carolina	DEC	658	2033
12	Marshall 4	North Carolina	DEC	660	2033
13	Belews Creek 1	North Carolina	DEC	1,110	2036
14	Belews Creek 2	North Carolina	DEC	1,110	2036

Sources:
Chapter 3, Table 3-1, and Appendix C.

As shown above, all of Duke's coal-fired capacity that is planned to be retired will be in the North Carolina jurisdiction. For this reason, North Carolina is particularly at risk for the Companies' continued ability to operate facilities within load/control areas in a manner that ensures adequate stability of voltage, phase/wave tolerance, and other power quality factors.

Q: PLEASE COMMENT ON SECTION 1.k., "EXECUTION RISKS" INCLUDED IN THE COMMISSION ORDER.

A: In general, the execution risks of each proposed portfolio should be taken into consideration when deciding whether extending the time frames for compliance with the carbon emissions reduction goals Execution risks are largely outlined in other parts of this testimony, but are summarized here:

1. The Companies plans to develop 2,400 MW of combined cycle natural gas generation by 2030. The Companies acknowledge that there is significant political and public opposition to installing the needed pipeline firm capacity necessary to operate these CC facilities as firm capacity. Without firm adequate natural gas pipeline capacity, the new CC capacity that will be replacing coal-fired resource capacity may render the system reliability unclear and uncertain at the very least. Hence, the Plan's assumption that the new combined cycle gas capacity will be available to meet system peak demands is an assumption that is at significant risk due to environmental, public and regulatory limitations to develop needed new pipeline capacity.

2. If pipeline capacity can be installed to serve the new combined cycle units, to support their ability to provide service during peak periods, the cost of that capacity should be carefully reviewed. Specifically, the Companies' Plan anticipates installing natural gas facilities and then converting them to hydrogen fueled generation during the Plan. After this conversion, the natural gas pipeline capacity previously used to operate the natural gas facilities will no longer be used by the Companies. As such, the revenue stream to the pipeline company could be impaired, which could be a significant economic factor in a pipeline utility's willingness to make capital investments to expand pipeline capacity in the Carolinas. One potential remedy to that would be allow for accelerated recovery of new pipeline capacity investment costs, which will have a material impact on the economics of the various portfolios for new gas generation.

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

4. The Companies' SLR assuming nuclear stations' lives will be extended is not based on detailed review of the individual nuclear stations needed to accomplish the objectives of the Carbon Plan. Further, the NRC likely will require significant retrofits of the existing nuclear stations in order to grant

an SLR, and this material cost has not been included by Duke Carolinas in their Carbon Plan. As such, a major source of carbon-free generation, the nuclear stations, has not been accurately modeled by the Companies, resulting in an inaccurate estimate of the economics of each of the four Carbon Plans.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

Qualifications of Michael P. Gorman

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q: PLEASE STATE YOUR OCCUPATION.

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

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Detroit, Michigan; Louisville, Kentucky and Phoenix, Arizona.

Q: HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A: Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q: PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A: I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

Summary of Direct Testimony of Michael P. Gorman
On behalf of Carolina Industrial Group for Fair Utility Rates II and III
Docket No. E-100, Sub 179

My name is Michael P. Gorman, and I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic, and regulatory consultants.

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

A summary of my position and recommendations included in my direct testimony follows:

First, I provide an outline is provided of the policy goals Duke attempts to achieve through their presented Carbon Plan (Plan), including a necessary balance between carbon dioxide emissions reductions and the concerns of reliability, affordability, and executability. I provide extensive testimony regarding cost risks, reliability risks, and execution risks. In addition, I highlight several specific concerns, including (1) the inadequate consideration Duke gave to the possibility that the Public Service Commission of South Carolina (PSCSC) may disallow costs to implement the Carbon Plan; (2) the lack of zero-emission load-following resources (ZELFR) currently available at scale; (3) Duke's reliance on unproven technologies; and (4) Duke's failure to provide that the Carbon Plan as proposed is the least-cost pathway to achieving the carbon dioxide emissions reductions goals set forth in House Bill 951.

Second, I highlight the shortcomings of Duke's modeling and methodology. I recommend that alternative modeling is needed to account for the regulatory risk posed by jurisdictional cost allocation issues. More specifically, alternative modeling is needed in the event the PSCSC fails to approve its share of costs to implement the Plan. Further, Duke didn't adequately model new energy efficiency or demand-side management programs within their models, including but not limited to Duke's failure to include a new emergency demand response program like that offered by Southern California Edison. Next, I address how power quality metrics were also excluded from modeling that the Companies performed as well as the Companies' reliability analysis and recommend that power quality metrics are necessary to ensure that the Carbon Plan is maintaining or improving reliability of the existing grid as required by HB 951. In addition, I discuss how the Companies failed to analyze or otherwise model emissions leakages associated with price-induced demand erosion.

Next, I note that compliance in 2032 or 2034 is reasonable for planning purposes and consistent with least-cost planning principles.

Fourth, I show how Duke's proposed Plan doesn't adequately consider the costs associated with early retirement of coal plants. I also discuss securitization and the importance of utilizing securitization for the benefit and protection of ratepayers pursuant to HB 951. This area of my testimony shines a light on how Duke omitted certain costs common to all portfolios from consideration when calculating bill impacts.

Fifth, I evaluate the near-term procurement plan laid out by the Companies. Here, I testify that Duke's proposal fails to provide sufficient guardrails, spending caps, and other parameters around its proposed near-term supply-side activities. I also note that Duke's proposed Plan fails to ensure that Duke is bearing some of the risk in the event these investments do not result in assets that eventually become used and useful in the provision of electric service to ratepayers. Next, I encourage the Commission to consider third-party owned generation if available and least-cost. Further, I encourage the Commission to defer to a future rate case decisions pertaining to reasonableness and prudency for purposes of future cost recovery.

Sixth, I supply analysis on how the Companies treat existing resources within the Plan, including natural gas and SLRs. More specifically, I note the cause for concern posed by the possibility of the Companies not getting SLRs approved for one or more of their existing nuclear generation facilities. With respect to natural gas, I show how more firm delivery capacity is needed for natural gas to ensure that new natural gas plants provide maximum reliability benefits to the system.

Seventh, I testify regarding Duke's proposed near-term development activity. I speak to the fact that many of the resources championed within the Plan are mostly unproven or are technologies that are new to the Carolinas. This is troubling whenever, as the Plan is currently presented, Duke would bear little to none of the risk involved in relying on such new and/or unproven resources; instead, ratepayers would largely bear this risk, at least as currently proposed. I offer several recommendations to alleviate this risk and to attempt to provide a least-cost path forward that maintains reliability and complies with traditional cost-of-service ratemaking principles.

Eighth, I look at the transmission planning that Duke provides within the Plan and I point out that for an adequate assessment of Duke's proposed transmission upgrades to be undertaken, then those upgrades should be considered at the same time as production resource planning occurs.

Ninth, I discuss the potential regulatory issues that face the Companies, the Commission, and the Companies' customers if Duke pursues a potential future merger between DEP and DEC and highlight some policy goals that should be considered if a merger is to occur.

Finally, I discuss CIGFUR's perspectives on the EE/DSM issues and the Companies' proposed Grid Edge programs.

This concludes my summary.

CHAIR MITCHELL: All right. Mr. Rouse?

MR. ROUSE: Yes, Chair Mitchell. The parties have indicated that they do not have any cross examination for me, Brad Rouse, my witness. As such, I would move that the Commission excuse me from appearing at the hearing for purposes of taking the witness stand and that my direct testimony consisting of 57 pages, filed in Docket E-100, Sub 179 on September 2nd, 2022, as well as my witness summary consisting of three pages filed in Docket E-100, Sub 179A on September 20th, be moved into evidence in the record and entered into the record at the appropriate time.

CHAIR MITCHELL: All right. Hearing no objection to your motion Mr. Rouse, it will be allowed. Your testimony will be copied into the record as if given orally from the stand. It will be copied into the record at the appropriate time, and your exhibits will be received into evidence, and you are excused from the -- from participating as a witness in the hearing.

(Whereupon, the prefiled direct testimony of Brad Rouse and witness summary were copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA

UTILITIES COMMISSION

RALEIGH

DOCKET NO. E-100, SUB 179

North Carolina Utilities Commission

In the Matter of:	)	
Duke Energy Progress, LLC, and	)	DIRECT
Duke Energy Carolinas, LLC, 2022	)	TESTIMONY
Biennial Integrated Resource Plan	)	OF BRAD ROUSE
And Carbon Plan	)	

TABLE OF CONTENTS

I. BRAD ROUSE BACKGROUND AND QUALIFICATIONS 3

II. OVERVIEW ……………………………………….……..…....9

III. MODELING- METHODOLOGY, ASSUMPTIONS, AND OTHER MODELING ISSUES …………………………......11

IV. NEAR TERM PROCUREMENT ACTIVITY — SOLAR, SOLAR PLUS STORAGE, STANDALONE STORAGE, ONSHORE WIND, NATURAL GAS GENERATION ……..32

V. EE / DSM ISSUES / GRID EDGE ………………………….….33

VI. COST ……………………………………………………....38

VII. RELIABILITY ……………………………………………….39

VIII. SUMMARY ………………………………………………….55

I. BRAD ROUSE BACKGROUND AND QUALIFICATIONS

Q. MR. ROUSE, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT OCCUPATION.

A. My full name is Harold Bradley Rouse. I go by the name of Brad Rouse. My address is 3 Stegall Lane, Asheville, NC 28805. I work as an energy policy consultant and spend most of my time writing and volunteering in efforts to further the ongoing energy transition. I recently published a book on the energy transition, and I am currently spending time promoting and speaking about the book.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I am a native of North Carolina, growing up in Farmville and Kinston. I attended high school at Woodberry Forest School in Orange, Virginia, received a bachelor's degree in economics from Yale University and a master's in business administration from the University of North Carolina at Chapel Hill.

Q PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. For the first 21 years of my career I worked as a consultant and developer of resource planning systems developer for utility companies. After receiving my MBA from UNC, I worked as a consultant for Data Resources, Inc. (DRI) in Lexington, Massachusetts. My role there was to work with utility companies in the Southeast to apply economic methods and data to planning departments, particularly in utility demand and load forecasting. These assignments included working with the Southern Company and Carolina Power & Light (CP&L) (predecessor of Duke Energy Progress). I led the development of CP&L's first economics and end-use based load forecasting system, working with CP&L's load forecasting team in Raleigh. As a side note, the load forecasting approach employed by Duke Progress and Duke Carolinas in the Carbon Plan bears a lot of similarities to the system that we developed (many years ago) for CP&L. At DRI I rose to the level of Manager – Utility Industry Practice.

Q. **WHAT WAS THE NEXT STAGE OF YOUR WORK WITH ELECTRIC UTILITIES?**

A. After 5 years at DRI I joined Energy Management Associates, Inc. (EMA) in Atlanta GA. EMA was well known for its detailed production simulation system PROMOD III which was becoming widely used for detailed production cost and reliability assessment in the industry. I took on responsibility for developing a new product line focused on the ideas of "integrated" and "scenario" planning. Utility managements and regulators back in those days were very frustrated with the slow turn-around speed for developing alternative modeled visions of the future, and we set out to try to solve that problem.

Our response was PROSCREEN II, an integrated system that included modules for production costing, load forecast adjustment, capital expenditure analysis, rate class pricing, and financial simulation. We were very successful with over 120 industry clients. PROSCREEN II was a breakthrough in the industry and many utilities adopted it as their preferred analytical took for a new approach to planning that was taking hold – Integrated Resource Planning (IRP). As I said before, I led the development of these tools and became deeply involved in their inner workings and in their applications. I would often work alongside EMA's consulting division to use our systems in rate cases and in IRP proceedings.

We were always working to further enhance the capabilities of PROSCREEN II and had the great opportunity to spend time working extensively with one of our clients – Duke Power (predecessor of Duke Energy Carolinas) – on an extension of the system to do capacity planning optimization – called PROVIEW. One of our top client contributors (intellectual and financial) was Bruce Anderson, Manager of System Planning at Duke Power. Many of his ideas made it into the system and I would like to thank my friends at Duke for their efforts. PROVIEW was so successful that it became a product line on its own. Over time, PROVIEW and PROSCREEN II became widely accepted, including being used for planning by the predecessor companies of all of Duke Energy's electric utility operating companies.

I left EMA in 1997. Since then, the software division has gone through a number of mergers and spinoffs, but the software products are still in use today. In fact, Duke used PROVIEW up until last year for Integrated Resource Planning. I consider EnCompass, the software system used by Duke and one of the intervenors in this case, to be an improved version of PROVIEW. Several of the principals of Anchor Software, the developer of EnCompass, worked in the division of EMA that I headed. When I left EMA, I held the title of Senior Vice President.

Q. **WHAT HAVE YOU BEEN DOING SINCE YOU LEFT EMA?**

A. I wanted to do something very different from utility consulting for a while and after leaving EMA I became a financial advisor, first working for Smith Barney and later as an independent. I developed a successful practice helping individuals manage their money and develop financial plans, so in that sense I have been in planning the whole time. I receive the Certified Financial Planner designation.

As a financial advisor, I continued to avidly follow developments in energy policy. I became quite concerned about climate change and about the seeming inability of those who were supposed to do something about climate, particularly our elected representatives, to do something about it. So, in 2013

I decided I had to step forward and see what I could do. I sold my advisory practice so I could get involved full-time on climate issues. My efforts have included lobbying Congress and local and state governments, writing articles for the online publication "CleanTechnica", taking personal actions to reduce my carbon footprint, teaching a course about climate change, and making public presentations. In 2016 I became involved with local efforts here in Asheville to move our local community toward cleaner energy, including chairing the "Peaker Committee" of the Energy Innovation Task Force, which was a collaboration between the City of Asheville, Buncombe County, and Duke Energy. I continue to volunteer with the task force's successor, the Blue Horizons Project Community Council, and serve on their strategic planning and technology committees.

In 2016 I co-founded a non-profit in Asheville – Energy Savers Network – which has provided basic weatherization and energy efficiency services to almost 1000 families. I did a lot of the hands-on work myself and continue to volunteer time doing weatherization and energy efficiency related repairs in low-income homes. I have firsthand, intimate, knowledge of the opportunity to help our low-income neighbors as part of the energy transition. Some of the funding for this nonprofit has come from our collaboration with Duke Energy, by the way.

In 2022 I published my first book – *Climate Warrior: Climate Activism and Our Energy Future*. Much of my research for that book involves understanding the energy transition that is needed to solve climate change and several chapters are directly relate to the key issues in this proceeding, including chapters on the energy system by 2050, the near-term energy goals for 2030, energy efficiency, federal policy needs, electrification, carbon border adjustments, renewable energy intermittency, and intermittency solutions.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. Yes. I testified before the Commission in Docket E-2 Sub 1089 in 2016. This was the application for a CPCN for the combined cycle gas unit that replaced the Asheville Coal Plant.

II. OVERVIEW

Q. **MR. ROUSE, WHAT IS THE BASIS OF YOUR TESTIMONY**

A. I've reviewed Duke's Carbon Plan, the testimony that they presented on August 19, 2022, and many of the filings from intervenors. My testimony is based on this review. I did not do any of my own modeling and did not sign a Confidentiality Agreement with Duke, so I was not able to review the modeling inputs and outputs at their most detailed level. So, my conclusions are based on what I can see in the filed testimony, my experience in long range planning and systems, and my understanding of other work that has been done in the energy transition.

Q. **WHAT ARE YOUR HIGH-LEVEL CONCLUSIONS**.

A. Duke has presented four alternative portfolios based on an optimization analysis. Intervenors have shown that with a change in assumptions, a far lower cost option is available. Duke disputes the assumptions and argues that the alternative plans are not executable, too risky, and threaten the reliability of the power supply. Meanwhile, new legislation, the Inflation Reduction Act has come into law.

The four portfolios presented are not substantially different from one another, and they do not represent the broadest range of options available, especially given the academic studies that show that high levels of renewable energy penetration are possible and low cost. While I agree that these plans are "reasonable" as Duke requests the Commission to affirm, I do not agree that the plans are "sufficient" for planning. The evidence from the academic studies and other conclusions from my analysis suggests **one of the alternative plans from intervenors, or something similar, should be accepted as an alternate pathway for continued analysis as part of the Carbon Plan process and that the near-term actions required by this alternate plan should be approved by the Commission.**

I also examine the criticisms of one of the intervenor portfolios —the "Synapse Portfolio" — presented by Duke. The Synapse Portfolio allows us to examine the fundamental choice before this Commission – **whether Duke should pursue a strategy to meet the carbon goals which relies heavily on new gas and nuclear or whether they should pursue a strategy which relies mostly on solar, wind, and storage**. While those criticisms contain merit in some cases, they do not disqualify the alternative from consideration. My examination of these criticisms covers modeling issues, near term procurement, the level of ambition in energy efficiency and distributed energy programs recommended, cost, and reliability.

My high-level conclusion is that the Carbon Plan needs to continue to evolve and should consider this key comparison of this fundamental choice. Additionally, I conclude that the new Inflation Reduction Act's passage renders the conclusions of Duke and intervenors outdated and the comparison of these two fundamental choices should be updated before irrevocable decisions are made. In the meantime, near term actions should be taken that preserve the opportunity of **both** choices.

III - MODELING - METHODOLOGY, ASSUMPTIONS AND OTHER MODELING ISSUES

Q. **MR ROUSE, DUKE REQUESTS THAT THE COMMISSION SHOULD FIND THAT THEIR PROCESSES AND INPUTS ARE "REASONABLE". ARE THEIR PROCESSES AND INPUTS REASONABLE?**

A. Duke's direct testimony of Snider, McMurry, Quinto, and Kalemba requests that the Commission find that the Carbon Plan was developed based upon

> "…reasonable inputs, assumptions, and methods at the snapshot in time in which the plan was developed and further find the associated results are reasonable for planning purposes for energy transition and supports Commission approval of the near-term actions."[1]

I can see that a Commission finding that the Carbon Plan is "reasonable" is substantially warranted. But what is "reasonable"? To me that word means that there is a good chance that the assumptions, methods, processes and results are plausibly based on "reason". Duke has gone a good job of laying out their reasoning, of utilizing advanced methods in the modeling, of documenting plausible assumptions, and of countering criticisms with logical responses.

But is being reasonable enough? Is just being based on reason what the Commission should hope for in a case where we are trying to effect a fundamental

[11] DIRECT TESTIMONY OF GLEN SNIDER, BOBBY McMURRY, MICHAEL QUINTO AND MATT KALEMBA (SNIDER, et al), page 9

change to one of the foundations of our economy (the energy system) that has a current structure (use of fossil fuels) which threatens the foundations of civilization from climate change? We must do better than just "be reasonable". Additional questions must be asked, including: are the assumptions, methods, processes, and results "sufficient" for the task at hand? When subjected to scrutiny and to the vagaries of change, will they provide the best results? And even if the answers to those questions are "yes", we must also ask "can they be improved and made better" as we repeat these processes over the years. Asking if the Carbon Plan is reasonable is missing the point. And the answer to the questions of "is it sufficient?" and "is it the best we can do?" is no. The answer to "can it be improved?" is yes.

The Commission should find that the Duke Carbon Plan is reasonable, but that reasonableness does not go far enough, and that the plan is insufficient, does not produce results at this time that can be fully relied on, and must be improved upon.

Q. **WHY DO YOU CONCLUDE THAT DUKE'S CARBON PLAN IS INSUFFICIENT? PLEASE WALK US THROUGH YOUR THOUGHT PROCESS.**

A. First, I would like to reiterate that I find Duke's process to be reasonable, as far as it goes. I very much support their framing of the process where the Commission is requested to consider near term actions to support multiple possible portfolios, or, in other words, to support "optionality" going forward. I also support Duke's decision to use the EnCompass modeling system to chart a least cost "optimal" trajectory given the assumptions provided. Because EnCompass relies on a reserve margin construct to reach a conclusion, I conclude that the calculation of Electric Load Carrying Capacity (ELCC) for different capacity options is a necessary first step to using EnCompass. I also believe that it is necessary to run portfolios selected by EnCompass through a more detailed hour-by-hour simulation to determine the reliability of the selected portfolios and that adjustments need to be made to ensure that any plan results in an electric system that is sufficiently reliable. This final step is necessary because the use of a reserve margin target combined with the uncertainty of the ELCC calculation itself introduces inaccuracies into the EnCompass optimization results.

While these three steps are reasonable, they do not go far enough. Duke recognizes that, to a limited degree, because they present four different options for the Commission's approval. Of these four scenarios, only Portfolio-1 was the "optimal" plan because it is the only one that meets the 70% carbon reduction by 2030 constraint. The model could not have chosen Plans 2-4 because they do not satisfy this constraint. Possibly plans 2-4 were selected by relaxing the 70% constraint to 2032 or 2034.

Other than the timeframe for meeting the 70% constraint, these plans are mostly the same. They share many common characteristics. They all retire coal units relatively quickly and bring on new gas combined cycle (CC) and gas combustion turbines (CT). They all extend the life of the current nuclear fleet beyond 2050. They all have the same underlying load forecast and assumptions about the efficacy of energy efficiency (EE) programs and distributed energy resources (DER) such as rooftop solar. They all have the proposed changes to the Bad Creek pumped hydro station and they all select a modest amount of battery storage. They all have substantial solar and modest amounts of wind in the near term combined with a predominant reliance on nuclear in the mid to long term. From a long-term perspective, these portfolios 1-4 are all pretty much the same and produce much the same results in terms of present value of revenue requirements (PVRR). This structuring guides the reader to focus on a comparison of the four scenarios and not on the bigger picture.

Duke's structuring ignores the elephant in the room. This elephant is the great body of academic studies and intervenor scenarios, in this case, that suggest a much larger share of renewables, approaching 100% in some cases, is a low-cost solution to our energy system. The future represented in these studies is starkly different from Portfolios 1-4 in the current version of the carbon plan.

Q. **WHAT ARE THESE OTHER STUDIES SAYING?**

A. Although utilities around the world are adding renewable energy at a record pace, few of them are approaching levels of renewables penetration that demonstrate conclusively the feasibility of high levels of renewables. And the ones that are adding a lot of renewables are in a learning mode right now as the testimony of Roberts and Holeman document.[2] Numerous academic studies, however, conclude that high levels of renewables, as high as 100%, can power the grid reliably.[3]

[2] DIRECT TESTIMONY OF HOLEMAN AND ROBERTS, August 19, 2022

[3] For more examples of these academic studies see COMMENTS OF BRAD ROUSE, ANALYSIS OF DUKE CARBON PLAN, filed in this docket 7/12/2022

The studies that I am most familiar with were performed by a team led by Dr. Mark Z Jacobson, Director of the Atmosphere / Energy Program at Stanford University. Jacobson's team used an hourly multiyear production simulation of the state of North Carolina using public data and determined that a mix of solar, wind, and batteries could reliably meet the demand for a 2050 NC energy system at each hour without outages without using any fossil fuel or nuclear. The demand for energy in his forecast included the expansion of the electric system to assume electrification of all energy uses including 100% of transportation, 100% of energy, and 100% of residential and commercial heating.[4]

The electric demands used in Jacobson's analysis is much higher than what Duke is projecting now, but the startling result was that overall spending on energy for consumers would be ½ of what that spending would be in the business-as-usual case before considering any climate or health benefits of less pollution. While Jacobson's work covers the state of North Carolina, which is not the same as the DEP and DEC service territory, it's a reasonable approximation. The combined DEP and DEC territory has about 20% more energy demand than the state of North Carolina. I provided more detail on the comparison of this scenario to that of Duke's Portfolio-1 in my earlier comments to the Commission.[5]

[4] Jacobson, Mark Z., "Zero Air Pollution and Zero Carbon From All Energy Without Blackouts at Low Cost in North Carolina", Stanford University, December 7, 2021, https://web.stanford.edu/group/efmh/jacobson/Articles/I/WWS-USA.html (accessed 9/1/2022). See also, Jacobson, Mark Z., (2021) *Clean Renewable Energy and Storage for Everything*, Cambridge University Press

[5] COMMENTS OF BRAD ROUSE

Q. **HOW DO INTERVENOR STUDIES IN THIS CASE ADD TO THE BODY OF EVIDENCE?**

A. Three intervenors provided alternative modeling scenarios. All three of these add to the body of evidence. I will focus on one of these, the two scenarios in the "Carbon Free by 2050: Pathways to Achieving North Carolina's Power Sector Carbon Requirements at Least Cost to Ratepayers" report prepared for North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club. The report, dated July 20, 2022, was authored by a team from Synapse Energy Economics Inc. In the remainder of my testimony I will refer to the plan portfolios developed in this report as "The Synapse Portfolio(s)".

I think the Synapse Portfolios are of greatest interest and add most to the body of evidence because they used the EnCompass modeling system seeded with the same dataset that was used by Duke in Portfolios 1-4. The most substantive input changes made by Synapse to produce the difference in results and remarkable reduction in costs are as follows:

- Increase ambition (and results) by Duke to implement energy efficiency (EE) and distributed energy resources (DER)
- Greater ability of Duke to interconnect solar in the near and longer term
- Sourcing of capital cost and fuel cost estimates from other available sources than the ones used by Duke

- The above changes were reflected in the Synapse portfolio referred to as the "Optimized Scenario". An additional scenario, referred to as the "Regional Resources Scenario" also assumed the ability of Duke to add 2,500 MW of wind energy from the Midwest delivered along a firm transmission pathway through the PJM interconnection.

Note that from here forward I will compare the Synapse Portfolios to Duke Portfolio-1 because, as mentioned before, Duke Portfolio-1 is substantially the same compared to the Portfolios 2-4, but it is the only one that meets the 70% carbon reduction target.

The Synapse Portfolio has many common elements with Duke Portfolio-1 such as the license extension of Duke's nuclear fleet, the expansion of the Bad Creek pumped hydro capacity, and the underlying energy forecast assumption as a starting point. However, the Synapse Portfolios rely on more renewable energy and energy efficiency programs and add a greater amount of battery storage. Synapse's "Regional Resources" portfolio makes wind energy available from the Midwest. The Synapse Portfolios are a very different scenario of the future, and they calculate that the cost to Duke ratepayers will be as much as 20%, or $25 Billion, less expensive than the Duke Portfolio – 1. That is a remarkable difference.

Q **DOES THIS $25 BILLION IN SAVINGS LEAD YOU TO RECOMMEND THAT THE COMMISSION CHOOSE THE SYNAPSE PORTFOLIO AS THE CARBON PLAN?**

A. No, it doesn't. The Synapse Portfolio is a visioning of a very different future for Duke's electric system, and it should inform the Commission's thinking. Plus, the analysis of the Synapse Portfolio as well as Duke's Portfolio-1 are already out of date due to the provisions of the Inflation Reduction Act recently passed by President Biden. Also, Duke has stated concerns related to that plan which would need to be resolved before fully adopting it.

While I don't propose the Synapse Portfolio as **the** Carbon Plan for now, **I do ask the Commission to find that the Synapse Portfolio is "reasonable" and that it or a similar plan should be added as an additional portfolio to be carried by the planning process. Furthermore, the near-term actions requested by Duke as needed to preserve the "optionality" of portfolios should include the steps that would be required now to enable Duke to follow the Synapse Portfolio's proposed resource strategy going forward.**

Q. **ARE YOU PROPOSING THAT THE CARBON PLAN INCORPORATE MULTIPLE, SUBSTANTIALLY DIFFERENT PORTFOLIOS? PLEASE ELABORATE.**

A. Yes. Duke also believes in presenting a plan with multiple scenarios, because that is what they presented in the Carbon Plan. This is a good planning practice because it stretches the mind of the decision makers. It helps them to better understand the issues involved and provides room for the judgment of the Commission. If this were a simple engineering problem then Duke could simply run EnCompass, which is, after all, supposed to generate the "optimal" resource plan, and the Commission could just accept the result. Feed the inputs in, let the optimization engine do its thing, and go with the results.

But developing the Carbon Plan is much more than a simple engineering problem, and even if it were, there are too many possible strategies and too many unknowns and uncertainties to just simply rely on any one software tool. Instead, tools like EnCompass are designed to develop one or more plausible futures and present that information to the decision makers, who must use their strategic vision to decide what to do, i.e., what near-term actions to take. And if there is a downside to using a tool like EnCompass, it is that using it can lead to complacency on the part of planners who would rather have the comfort of an analysis tool that simply gave them the answer. And the Synapse exercise, where a few assumptions were changed and you get $25 Billion in savings with a somewhat different plan, is the perfect exercise to illustrate what overreliance on one tool and a single set of input assumptions could lead to.

Q. **WHAT IS YOUR SOLUTION TO THIS PROBLEM?**

A. I think Duke was on the right track with the presentation of multiple portfolios. The solution is to use a process often called “scenario” planning, used by utility Southern California Edison back in the 1980’s, as described in “Scenario Planning at Southern

California Edison"[6], and at Royal Dutch Shell back then and currently [7]. This process requires significantly different scenarios to be presented to inform and stimulate discussion. To some degree this discussion has been already begun by the comparison of the Duke Portfolios with the Synapse Portfolios. This is a good thing and will lead to a better decision. In the words of consulting firm Deloitte and Touche Principal Consultant Geoff Tuff,

> "We no longer live in a world that's impacted primarily by linear change with reasonably predictable outcomes; today's organizations are operating amid great uncertainty and exponential change. So, as we think about the Future of Energy, we have to do a better job planning and allocating capital in the face of that uncertainty. One way to do this is to get out of the business of trying to predict the future and acknowledge that we don't know precisely how it's going to play out. The only way we can act in the near term is to plan for multiple, equally plausible versions of the future. That's why scenarios should be an essential element in every energy company's—in fact, every company's—strategic planning process"[8]

Just to reiterate, Duke is on the right track with the multiple portfolios, it's just that Duke's portfolios are too similar to each other to be useful. **For that reason, I ask the Commission to incorporate the Synapse Portfolio as an alternative view of**

---

[6] Fred Mobasheri, Lowell H. Orren, Fereidoon P. Sioshansi, (1989) Scenario Planning at Southern California Edison. Interfaces 19(5):31-44.

https://doi.org/10.1287/inte.19.5.31

[7] "The Energy Planning Scenarios", Royal Dutch Shell website, https://www.shell.com/energy-and-innovation/the-energy-future/scenarios/the-energy-transformation-scenarios.html#iframe=L3dlYmFwcHMvU2NlbmFyaW9zX2xvbmdfaG9yaXpvbnMv

[8] https://www2.deloitte.com/us/en/pages/consulting/articles/scenario-planning-future-energy-sector.html (accessed 8/27/2022)

the future into the 2022 Carbon Plan and ask Duke to incorporate such a substantially different scenario in future versions of the plan.

Q. **DO YOU THINK OTHER SCENARIOS SHOULD BE INCLUDED IN ADDITION TO THE SYNAPSE PORTFOLIO?**

A. Yes. As mentioned in my earlier comments to the Commission[9], I believe that Duke should consider the implementation of the full energy transition required to meet the goal of the full decarbonization of energy use economy wide, not just electricity. Most of that transition will involve full electrification of transportation, buildings, and industry. In my book *Climate Warrior: Climate Activism and Our Energy Future*, I go through the numbers and conclude that the electric sector in 2050 for the US as a whole will be approximately 2.5 times what it was in 2019.[10] Similarly, Jacobson's analysis of the NC electric system concluded that such a future would involve electricity consumption that is approximately double what it was in 2018.[11] Note that Jacobson and my forecasts already include aggressive energy efficiency improvements above and beyond background improvements in energy efficiency embedded in the baseline forecast. I would envision four scenarios with an alternate energy demand forecast – the current a portfolio like the one selected by Synapse (no gas and relying mostly on renewables) and one like the current Duke Portfolio-1

[9] Brad Rouse Comments, 7/12/2022

[10] Rouse, Brad, (2022) "*Climate Warrior: Climate Activism and Our Energy Future*", (Wisdom House Books), pages 75-87

[11] Jacobson footnote

approach (near term gas, moderate renewables, and heavy reliance on nuclear long-term) combined with the higher load forecasts. This would result in four plans:

- Duke Portfolio-1 approach, base load forecast
- Duke Portfolio-1 approach, full decarbonization load forecast
- Synapse like portfolio – base load forecast
- Synapse like portfolio – full decarbonization load forecast.

Obviously, such additional scenarios cannot be completed for the 2022 Carbon Plan end of year deadline, but the Commission should ask Duke to provide this broader set of scenarios as part of its update in 2024, and before the Commission approves any new gas capacity.

Q. **DUKE'S TESTIMONY IMPLIES THAT THE SYNAPSE PORTFOLIO IS NOT REASONABLE. PLEASE RESPOND.**

A. I disagree. I think that the Synapse Portfolio is reasonable, but in many ways that is beside the point. This additional portfolio should be considered exactly because it is so different from the Duke plan that it illustrates the question that so animates the debate in this case – **"do we need a plan that relies on gas and nuclear or can we go with a plan that is mostly dominated by wind, solar, and storage?"** This process needs to ask that question every year and make comparisons of what the latest data show as we move forward in time.

What I like about the Synapse analysis is that it used the same EnCompass system that Duke used and the assumptions and data inputs that they used were almost identical. As Duke rightly points out, these assumptions reflect a point in time view of the world. Indeed, both scenarios are already quite out of date after President Biden signed the Inflation Reduction Act into law. Neither the Duke Portfolio – 1 nor the Synapse Portfolios represent a good "point in time" view of the world as it stands today.

The Synapse Portfolio analysis makes a few input changes that I view to be quite reasonable for scenario planning purposes. On the other hand, Duke rightly criticizes the omission of a final detailed reliability evaluation as a final step. Fortunately, Duke ran the Synapse portfolio through that detailed reliability evaluation, so we have the benefit of that analysis. Overall, I would rate the Synapse Portfoio as just as reasonable as Duke Portfolio – 1. The Synapse Portfolio represents a plausible alternative set of circumstances that results in a radically different future for Duke's power system and a significant $25 Billion benefit for Duke ratepayers.

That level of ratepayer benefit is worth Duke's full consideration as an alternative. Duke, and the Commission, should seek to do everything they can to achieve that benefit for their ratepayers, even if they have some strong arguments for why they think it is a hard thing to do. At a minimum, Duke's near-term actions should be augmented to preserve and develop the option presented in the Synapse Portfolio.

Q. **PLEASE REVIEW DUKE'S CRITICISMS OF THE SYNAPSE PORTFOLIO**

A. The two Synapse Portfolio scenarios are quite different from Duke's. The main difference in their result is their conclusion that the optimal plan has no new gas, far greater ambition than Duke on EE and DER reductions in load, little or no additional nuclear power, and far greater reliance on renewables and storage. As mentioned above, they also show a far lower cost to the rate payers. Duke's testimony on August 19, from several of the authors, but particularly that of Snider et al, spends a significant amount of ink criticizing this plan, either directly or indirectly. Here are Duke's primary areas of criticism from my reading:

- Level of technical objectivity.
- Executability of the proposed plan.
- Cost estimates for capital costs.
- Reliability of the proposed system.

Another way to phrase these criticisms is that Duke is saying that the Synapse Portfolios were based on a process that lacked objectivity, the portfolios can't be executed, they won't be as inexpensive for ratepayers as Synapse claims, and they will result in untenable risk of power not being available to serve customers when needed.

Q. **WHAT ARE YOUR THOUGHTS ON THE CRITICISM THAT THE SYNAPSE PORTFOLIO LACKS TECHNICAL OBJECTIVITY?**

A. Duke defines technical objectivity in the testimony of Snider et al.[12] My general reaction to this line of reasoning is twofold. First, I appreciate the need to be objective, but the focus on this issue seems to me to be based on trying to "get the right answer" from an engineering perspective when the vast uncertainty and dramatic change in this whole environment makes a pure engineering solution impossible. In my view, the strictest level of technical objectivity is not required if the goal is to present an alternative that represents a plausible future for scenario planning purposes. Duke accuses Synapse of favoring renewables and energy efficiency and choosing inputs that would favor these preferred solutions. Nevertheless, I find nothing particularly unreasonable in Synapse Portfolio inputs and they appear to be based on a plausible analysis of the situation.

Are they the "right" inputs? Undoubtedly not, nor are Duke's, because the passage of the Inflation Reduction Act plus the inevitable march of time has changed the validity of all inputs already. The Synapse Portfolio's assumptions are reasonable, however, and none of them are made up out of thin air. I find that they are useful for developing an alternative perspective for the Commission's review, and they, like all projections, should be taken with a "grain of salt". Indeed, if someone asked me "what key inputs do I need to change, without just making things up, to save the ratepayers $25 Billion, I would say: Go for it so we can look to what might try to do to get a better result for the ratepayers".

[12] DIRECT TESTIMONY OF SNIDER, McMURRY, QUINTO, AND KALEMBA, Duke Energy, p 184

My second reaction to Snider et al is that I don't find a number of their arguments compelling. First, Snider et al argue that the modeling inputs for the Synapse Portfolio "create material risks that the core Carbon Plan objectives will not be achieved."[13] Of course, this is not true because it is only if the Commission and Duke act to pursue these options at the exclusion of the others, and their assumptions are wrong, that this will be the case. Putting this scenario out there and holding it in mind as a possible future, possibly to be pursued, does nothing to put the objectives of the Carbon Plan at risk.

Snider et al discuss the Synapse Portfolio assumption of greater Duke ambition to interconnect more solar[14]. Duke is saying "we can't move that fast". Synapse is saying "we need and want to move faster". I think Duke should spend the resources to see if they can move faster. I'm not an expert in transmission or interconnection, but **I hope that the Commission will try to create the incentives and resources to get Duke to move faster. I applaud the initiatives for transmission reform that will enable a faster rate of interconnection.**

I disagree, however, with Snider et al when they say that this need for faster interconnection is "unsupported by any analysis demonstrating a need for this pace".[15] The overall Synapse Portfolios, with $25 billion in savings, of which this faster interconnection is a part, is all the analysis I need to support the need for a faster pace. But, of course, the deepening climate crisis, the resulting need for even

[13] Snider et al, page 185
[14] Snider et al, page 190
[15] Snider et al, page 191

faster decarbonization, and the risk of much higher underlying load growth, all support the need for faster interconnection.

I do find Snider et al to be persuasive in their criticism of the capital cost for gas CT and CC [16] related to the multiple units issue. However, I disagree that the shortened life assumptions used in the Synapse Portfolio for CC and CT units should be seen as a problem. Duke's modeling itself shows very little use of these units once they are running on hydrogen in the 2040-2050 timeframe. Furthermore, it's hard for me to see how a 25-year useful life would have a negative impact or penalize the modeling when that puts the lifetime outside of the modeling time frame. And the book recovery over 20 years would seem to better match the usefulness of the asset with the cost recovery period. If anything, Duke's use of a 35-year recovery period for these plants might indicate that Duke itself has a bit of "lack of technical objectivity".

Finally, I do not agree with Duke's assertion that Synapse's higher rate of ambition to pursue energy efficiency and distributed energy resources is an example of lack of technical objectivity.[17] I believe that Duke and the Commission should continue to up their ambition on EE and DER programs and devote the resources necessary to make that happen. It should be part of the Carbon Plan to do that. **Such increased resourcing should be part of the near-term action plan.** The new Inflation Reduction Act provides substantial new incentives for both EE and DER and Duke should up its ambition based on that new information alone. However, as I

[16] Snider et al, page 193
[17] Snider et al, page 186-189

say above, the load forecast that is the starting point for subtracting the impact of EE and DER may be understated due to the need for electrification of all end-uses to meet our economy wide carbon goals. This will necessitate a much higher load forecast, which I recommend that Duke incorporate into additional scenarios for "economy wide decarbonization". If something like this transition were to occur, that will mean increased pressure on supply side resources and present increased need for greater ambition for EE and DERs.

Q. WHAT ABOUT DUKE'S CRITICISMS REGARDING CAPITAL COSTS, EXECUTION RISKS AND RELIABILITY?

A. Some of these criticisms are discussed in my answer to the previous question, but there is also criticism of the assumption regarding the availability of 2,500 MW of Midwest wind energy that was chosen in the Synapse Portfolio modeling in the "regional resources" scenario. This option alone reduces utility revenue (customer bills) through 2050 by $5.4 billion dollars, over 4%. This is a highly attractive economic resource that would be a very useful additional to the mix available for Duke ratepayers. Plus, the Inflation Reduction Act recently signed by President Biden reinstates the wind tax benefits that were scheduled to go away when this modeling was done and adds new funding to support transmission upgrades that might be needed. This Midwest wind energy resource, plus 900 MW of instate onshore wind and 800 MW offshore wind brings in enough wind capacity to retire many of the coal units and have sufficient capacity without the additional natural gas units.

The testimony on transmission by Roberts and Farver addresses the idea of 2,500 MW of wind resource being imported from the Midwest, noting that the resource has been studied by Duke and found that the cost of the transmission upgrades in PJM and to connect from PJM to DEP rendered that resource "not economically feasible at this time". [18] Duke did note that they had submitted a request for firm transmission for 1000 MW of Midwest wind and would consider that resource in future Carbon Plans. None of the studies of this large Midwest wind energy import incorporated the reductions in wind cost due to the Inflation Reduction Act or the funds available for transmission system upgrades in the Act. Certainly, the choice of natural gas CC and CT in the Duke Carbon Plan versus this resource in the Synapse portfolios needs significant investigation as it directly bears on near term decisions that are needed to make the 2030 70% reduction goal.

Q. **PLEASE GIVE US YOUR PERSPECTIVE ON DUKE'S CONCERNS ABOUT RELIABILITY IN THE SYNAPSE MODELING?**

A. Duke also criticizes Synapse because they did not subject their final portfolio to the analysis that Duke uses to check the robustness of the EnCompass solution in a more detailed hour by hour simulation. This final step hour by hour simulation uses 41 years of historical weather data so that the modeling exercise can understand the full breadth of possible combinations of hourly weather conditions to assess the

[18] DIRECT TESTIMONY OF DEWEY S. ROBERTS II AND MAURA FARVER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC, page 59

interaction of energy demand and the supply of intermittent solar and wind resources. I agree with Duke that this is a necessary step and I applaud their testing of the Synapse portfolio on their own. These results are reported in the testimony of Snider et al. [19] Figure 18 shows that the Synapse portfolio passes this reliability test for 2030 but fails it for 2035. Duke then asserts that this shortfall would require more CTs or the equivalent storage resources. I agree that this is a necessary step and the revenue requirements for the Synapse portfolio should be adjusted to account for the additional capacity. However, it may be that just adding additional gas CTs to the system is not the least cost answer and that one of the other ways of resolving reliability issues is less cost.

I think it will be worthy to consider how well the last 41 years of weather will represent the next 30 years in a warming climate. One would think, weather extremes excepted, that the summers and winters will be getting warmer over that period. With an expected winter peaking utility system, we might not have the reliability problems in the winter that that historical data would suggest. Additionally, we will need to look carefully at the wind and solar profiles used in the modeling, since a widely dispersed set of wind and solar resources will provide greater stability due to the diverse weather conditions over a large geographic area than the much more limited historical record on solar and wind profiles would provide.

Q. **DO YOU HAVE ANY FINAL THOUGHTS ON DUKE'S CRITIQUE OF THE SYNAPSE MODELING?**

[19] Snider et al, page 202.

A. To reiterate, I do not know which of the Synapse Portfolio or the Duke Portfolio -1 is the better. But I do think they are both excellent illustrations of the alternative pathways that are available. The difference between the two points to a key near term fork in the road:

- go bigger on renewable energy now or
- invest in gas fired power plants that will have a limited useful life.

Then there is a longer-term fork in the road we will face, which is to invest in far more solar, wind, and storage or to invest in nuclear power. And we will also need to consider the possibility of much faster load growth to support economy wide decarbonization. These uncertainties suggest that we keep our minds open and not try so hard to find the absolute best portfolio for the next 28 years, and instead seek to understand the key points of decision and major opportunities ahead.

III. NEAR TERM PROCUREMENT ACTIVITY - SOLAR, SOLAR PLUS STORAGE, STANDALONE STORAGE, ONSHORE WIND, NATURAL GAS GENERATION

Q. MR. ROUSE, DO YOU HAVE RECOMMENDATIONS FOR NEAR TERM PROCUREMENT ACTIVITY

A. Yes. generally, I support the company's proposed near-term actions. I also support the near-term actions proposed in pages 4 and 5 of Synapse's "Carbon Free by 2050" report, other than I would not change the DER targets or the EE targets at this time (first two items of recommendations in that report) but ask Duke to develop and implement a plan for higher levels of ambition for these programs especially considering the new Inflation Reduction Act provisions.

I also support the Commission ordering Duke to do a plan update for 2023 due to the changes in the utility landscape and to extend the modeling at that time to include a scenario that contemplates no gas and no additional nuclear, similar to Synapse's "Carbon Free by 2050" report. With respect to any CPCN for gas CC and CT units I would ask the Commission to approve any such CPCN only if updated scenarios are available that include a full alternative which does not include the CC and CT units, and only after modeling is done that incorporates the provisions of the Inflation Reduction Act.

IV. EE / DSM ISSUES / GRID EDGE –

Q. EARLIER IN YOUR TESTIMONY YOU ARGUED THAT DUKE SHOULD "UP ITS AMBITION" ON GRID EDGE ACTIVITIES INCLUDING EE, DSM, AND DISTRIBUTED ENERGY (DER). PLEASE ELABORATE.

A. Based on my personal experience and on my ongoing research, I believe that there are many opportunities to achieve greater results than those projected by Duke. Achieving these results will take additional funding and probably staff resources to achieve a greater level of impact. Whether or not these initiatives are enough to meet or exceed the projections proposed by Synapse (2% reduction in total energy use by 2035, 5% by 2050), is not the point.[20] Investment to achieve these results is likely to be cost effective, especially given recent changes.

The Inflation Reduction Act (IRA) recently signed by President Biden includes major new incentives for EE for low-income and upper-income customers alike. The new law allows for a great increase in funding for whole home retrofits for low-income people, that would be on top of the funding already available and the funding that Duke is proposing. With the new federal funding, Duke could reorient the funding for its low-income effort to facilitate enhanced uptake of the programs. Duke would be well advised to aggressively work with other stakeholders and government to secure funding for our region by acting in the very near term. For

[20] "Carbon Free by 2050", page 3

middle and upper-income ratepayers, the new law allows for a greatly expanded annual tax credit to be available as opposed to a smaller lifetime credit.

The IRA is also a game-changer for the growth in net metering customers. The investment tax credit for solar is restated to 30% and is made refundable in some circumstances. Non-profits are now eligible to take the investment tax credit immediately. That means that a charitably minded person or company can take a tax deduction for a donation to install solar and the non-profit will receive the tax credit, which together could amount to more than a 50% contribution from the federal government.

The benefits of EE and DER go far beyond the value that they provide in reducing utility revenue requirements. They are a way of producing energy or reducing demand that provide less stress on the existing transmission system than other resources. They potentially provide local resilience if DER investments are paired with battery back-ups or local micro- or mini-grids, lessening the costs to some communities of the loss of power from grid outages. They produce local jobs in many communities versus fossil fuel or major utility scale investments which often are out of state. They produce streams of income (or reduced cost) that benefit local areas, and EE and DER programs that are targeted to low-income reduce the impact of income inequality and so bring attendant justice benefits. These benefits justify additional resources or incentives or financing support to make them happen.

Duke does not need to "go it alone" to realize these benefits. Individuals, cities, counties, non-profits, and corporations want to participate in transforming our energy economy to address climate change. The comments of the City of Asheville and Buncombe County are indicative of this desire:

> "We have a history of partnering with Duke Energy on energy programs that benefit our residents, businesses, and local government operations. We look forward to and are committed to working with Duke Energy and the NCUC to enable the solutions outlined in this letter that we believe will accelerate a more affordable, clean, equitable, resilient, and reliable energy system. Through continued partnership, we can demonstrate to both North Carolinians and the nation what collaborative clean energy leadership looks like."[21]

Similarly, the City of Charlotte, in its comments indicates a willingness to further partner with Duke in accelerating EE and DER,

> "The City and other NC local governments are important and willing partners to design, develop, and deliver EE/DSM programs to our respective residents and businesses in multiple ways, including by increasing the uptake and success of utility programs through local networks and targeted outreach, as well as through improving utilization rates of low-income weatherization programming."[22]

The public comments received, as part of this docket, includes a letter from 12 North Carolina cities. This letter adds to the evidence that there is an underutilized and vast local interest in working with Duke to achieve the goals of the carbon plan. This letter, signed by the leaders of the cities of Boone, Greensboro, Chapel Hill,

[21] CITY OF ASHEVILLE AND COUNTY OF BUNCOMBE INITIAL COMMENTS ON CARBON PLAN, July 14, 2022, page 14
[22] CITY OF CHARLOTTE INITIAL COMMENTS ON CARBON PLAN, July 15, 2022, page 4

Hillsborough, Matthews, Durham, and Raleigh along with Chatham County represent more than "1.3 million North Carolina residents".[23] They add:

> "We suggest that Duke consider new or enhanced customer engagement strategies, including increased collaboration with local governments. The undersigned believe local governments can be important partners to design, develop, and deliver EE and DSM programs to North Carolina residents and businesses in multiple ways, such as improving local ordinances, increasing the uptake and success of utility programs through local networks and targeted outreach, and supporting low-income weatherization."[24]

I have personal experience that suggests that there is great underutilized potential in opportunities for Duke to collaborate.[25] In 2016 I co-founded an effort in Buncombe County to mobilize volunteers to help fight climate change and help low-income members of our community to save energy. This program is known as Energy Savers Network and to date has helped almost 1000 low-income residents save on their energy costs.[26]

We perform first tier energy upgrades which consist of a home visit, energy assessment, and installation of basic energy saving measures such as weather sealing, LED lighting, water saving fixtures, water heater and pipe wraps, new furnace filters, minor home repairs, etc. We do what can be done by a small team (one professional staff and 2-4 volunteers) in a three-to-six-hour visit, and often schedule follow-on minor home repairs or more extensive energy upgrades. This is not a whole home upgrade with insulation and major appliance replacement, but it can lead to one

[23] COMMENTS OF NORTH CAROLINA LOCAL GOVERNMENTS ON DUKE ENERGY'S PROPOSED CARBON PLAN, August 23,2022 letter to the North Carolina Utilities Commission page 2.
[24] Ibid, page 6
[25] For more information see *Climate Warrior,* Brad Rouse, Chapter 16, "Helping God's Creation by Helping His People", and Chapter 17, "A Network of Energy Savers".
[26] See www.energysaversnetwork.org for more information

through our referrals. Nevertheless, we have been able to work with on measurement and verification and have determined that these efforts alone reduce energy demand for our low-income clients by around 15% per year.

Energy Savers Network has been fortunate to receive some funding from Duke Progress to supplement our funding from City of Asheville, Buncombe County, foundations and private donors and the contributions from our volunteers. We are hopeful for a continuation and expansion of Duke's support in the future. Through this experience I have come to understand that there is tremendous untapped opportunity in scaling up our efforts to help low-income clients. This will require funding, volunteer engagement, and local leadership. If expansion of such a community mobilization in Buncombe County and elsewhere were to be a part of the Duke Carbon Plan, I believe it could help Duke achieve greater ambition in their energy efficiency efforts than what is forecast.

In summary, the Commission should order that Duke expand its EE and DER efforts between now and 2030 so that some of the benefits and impacts of these programs could have a more meaningful impact in the near term. The near-term question facing the Commission is whether there is a plan which can avoid the expansion of natural gas CC and CT resources in the next 10 years as Duke pursues the other longer-term aspects of the plan. Greater ambition in EE and DER, especially low-income, has strong support. Even greater community mobilization including opportunities for volunteer actions could play a major role in making this effort a success.

V. COST

Q. **DUKES CARBON PLAN SHOWS THE COST TO RESIDENTIAL RATEPAYER FOR 2030 AND 2035 FOR ITS PORTFOLIOS. PLEASE COMMENT ON THIS PORTRAYAL OF COST.**

A. At best, it's just not a helpful portrayal of portfolio results, at worst it is misleading, and certainly there is an opportunity for improvement. What I am referring to is the estimate of the additional cost for each portfolio for a residential customer using 1000 kwh versus today shown in the Carolina's Carbon Plan Executive Summary and then in Chapter 3.[27] For instance, the Portfolio-1 bill impact for DEP in 2030 is $35. At first glance, with a current bill around $120 for a typical customer, this would represent almost a 30% increase. What is not shown is the amount of that increase in constant dollars, so the reader could judge his own rate impact. Is it more than inflation or less? What was the overall inflation rate assumed? The value of this output in current dollars should be shown.

In addition, Duke's plan incorporates assisting customers in obtaining EE improvements. It would be more helpful to show the impact on customer bills after e EE improvements. The customer cares about bills, not rates per se. Overstating the rate impact of any of these portfolios is not in the interest of the eventual success of the carbon plan. **The Commission should require Duke to provide better information on customer rate impacts in future Carbon Plans.**

[27] "Carolina's Carbon Plan", Executive Summary, Table 1, Page 16

VI. RELIABILITY

Q. **YOU MENTIONED EARLIER THAT ONE OF DUKE'S CRITICISMS OF THE SYNAPSE PORTFOLIOS WAS BASED ON IT NOT BEING RELIABLE. PLEASE PROVIDE MORE DETAIL ON THIS AND RELATED ISSUES.**

A. Yes, I wanted to return to this topic because it is fundamental to the question of whether Duke can take advantage of the lower cost from wind and solar ($25 Billion cost savings in Synapse portfolios) or must their near-term plan require natural gas and their long-term plan require nuclear. This issue is discussed in the modeling section by Snider et al and then again in the testimonies on reliability by Roberts and Holeman and on transmission by Roberts and Farver. As I mentioned earlier, the Carbon Plan modeling process concluded that the Synapse portfolios needed additional capacity to support reliability by 2035, so technically Synapse indicated that we could get to the early 2030's without adding new gas. I don't see in that testimony what the reliability modeling results would be for the Synapse portfolio by 2050, and I will be interested in seeing that in the future.

Holeman's testimony on reliability lays out the need for detailed assessment of reliability and asserts that none of the intervenors, including Synapse, performed a proper reliability assessment of the system that they proposed:

> "none of the proposed alternative plans or corresponding comments filed by intervenors present any focused analysis of the Companies' obligations to

> comply with mandatory NERC Reliability Standards today as well as under future resource planning scenarios."[28]

Holeman outlines the obligations of Duke under NERC and to its customers for "resource assurance" or the obligation to plan for resources being available to meet demand under all circumstances. Then he says,

> "a resource plan like the Carbon Plan that is not objectively developed and is unduly biased towards resources for which resource assurance is subject to the sun shining or the wind blowing and does not plan for dependable and dispatchable generation to meet all reasonably-foreseeable contingencies is counter to resource assurance. As I describe in more detail later in my testimony, even coupled with storage, if the sun is not shining for consecutive days due to dense cloud cover or precipitation, this real- world operating condition in the Carolinas could result in little energy production from these resources to store."

Holeman describes some examples of where this problem of the "sun not shining or the wind not blowing" and then discusses NERC's conclusion that natural gas is critical "as the fuel that keeps the lights on" until or unless very "large scale battery deployments are feasible or an alternative flexible fuel such as hydrogen can be developed."[29]

I found this testimony to be quite interesting and illuminating and certainly provides strong evidence for the need to be vigilant about resource assurance going forward. Any plan to bring high levels of renewable energy into the Duke grid must

[28] DIRECT TESTIMONY OF HOLEMAN AND ROBERTS, page 10
[29] Ibid, page 28

satisfy the concerns expressed in this testimony and also in Appendix Q of the Carbon Plan.

Q. **EARLIER IN YOUR TESTIMONY YOU MENTIONED ACADEMIC STUDIES THAT SHOW THAT LARGE GRIDS ARE COMPOSED OF CLOSE 100% RENEWABLE ENERGY. HOW DO YOU SQUARE THOSE STUDIES WITH THE ABOVE TESTIMONY?**

A. That's an excellent question. Jacobson, for example, constructs a model of the NC power system that shows that the hour-by-hour demand for electricity can be solved reliably by a blend of just wind, solar, hydro, flexible demand, hydrogen and storage. Jacobson's modeling uses three years of historical weather data, which is less than the 41 years of weather data that Duke's final modeling stage uses to stress the system, but it still represents a far more detailed treatment of the issues brought forth in Holeman's testimony than in the EnCompass model. But if you look at Jacobson's modeling and compare it to Duke's you can see that Jacobson employs quite a robust set of methods to ensure reliability.

Part of the problem in comparing Duke's experience with Jacobson's approach stems from their separate starting points. Jacobson goes to the drawing board and designs the system from scratch and concludes we can do such a system with renewable energy and batteries. Duke, on the other hand, is trying to manage the transition of the system from one that uses a lot of traditional resources to one that uses zero carbon resources, so it is an inherently harder problem. Duke must reliably satisfy demand for a whole series of different system states, ending in one that is zero carbon, whereas Jacobson can just design a zero-carbon system from scratch. What Duke is doing is much harder. But because Duke's modeling challenge is more difficult, they try to simplify and end up not using some of the tools that may be available. I do think that we can all learn about "how to get there" from a detailed blueprint of the "end state" of a fossil fuel and nuclear free system, even if we accept that nuclear will be part of our the system in 2050 or beyond.

Q. **HOW WOULD YOU COMPARE THE INTERMITTENCY SOLUTIONS THAT JACOBSON'S MODELING USES TO THE ONES THAT DUKE USES IN THE CARBON PLAN? AND COULD JACOBSON'S SOLUTIONS PROVIDE INSIGHT THAT COULD GUIDE THE TRANSITION OF DUKE'S SYSTEM?**

A. Yes, I believe our efforts here could be greatly aided by this comparison.

Let's start with what Duke is trying to do compared with what Jacobson is able to do with a "from scratch" system. As Duke integrates renewables, it must deal with two related issues: reliability and intermittency. I would define reliability of a power resource as the likelihood that it is working when called upon. I would define intermittency as the variability in the supply of "fuel" for that resource based on factors that are outside of the control of the utility such as hour by hour wind speed or solar insolation (is the sun shining or the wind blowing?) when power is needed.

Utilities have always had to deal with reliability issues. The proper treatment of forced outages of traditional generators was a main selling point of the systems we developed at EMA. The fact is that generators can fail at any time. Indeed, multiple generators can fail at the same time, and it is theoretically possible that all generators on a system could all fail simultaneously. And this is actually a very big problem for "island" systems with one or a small number of generators. Fortunately, such an occurrence is of very low probability in a large utility like Duke's NC system. Nevertheless, both in operations and modeling, this possibility of a forced outage is of great concern. The more diverse a utility system, with more operating units, the less of a problem this is because the proportional impact of outage of a large generator is less. Add to that the gradual introduction of intermittent resources and the problem gets a harder. I can sympathize with utility operations departments because the problem is challenging enough without the extra complexity.

The pure renewable energy system doesn't need to deal with reliability issues much because renewables typically come in such small unit sizes (one solar panel or a 10kw home system or a 10 MW wind turbine versus a 500 MW gas unit, for example). You can assume that any reliability problems are "lost in the noise". Models that rely completely on renewables can assume away the randomness of forced outage. All the 100% renewable system needs to do is deal with intermittency, which is nevertheless a much bigger problem when intermittency characterizes 100% of the resources.

Q. **HOW DO 100% RENEWABLE SYSTEMS SOLVE THE INTERMITTENCY PROBLEM?**

A. The system that Jacobson developed to model NC and other approaches draw from a wide array of options to do solve intermittency. Below are the main such solutions and how much are they employed by the Duke and Synapse portfolios.

- **Diversity of resource**. The combination of wind and solar get us a long way there. Wind tends to blow at night and sun shines only in the day, but their patterns are offsetting. Combinations of wind and solar are better than either alone. Plus, wind tends to be dominant in the winter when there is less sunlight.

  Jacobson's solution for NC has about the same amount of energy being produced from solar as from wind. The wind resource shows a little more offshore than onshore. Duke's Portfolio-1, on the other hand, shows vastly more solar than wind in 2030 and in 2050. The Synapse "optimized" scenario shows more wind and solar than Duke, but it is still heavily weighted toward solar. The Synapse Portfolio "regional resources scenario" shows more wind added to the mix, but it is still heavier on solar than wind. If either the Synapse Portfolio or the Duke Portfolio -1 were to need to respond to a higher load forecast or deal with less nuclear, they would need to move to much more wind in the mix.

- **Diversity of geographic location.** Wind in one region and wind in another will have very different patterns of availability. The same with sunlight. A

Midwest resource will have a different wind profile than an onshore Eastern NC wind resource or an offshore wind resource. Solar over a wide area of NC will have offsetting periods of sun and clouds and Western NC sun sets later and rises earlier than NC sun. The key in such a system is more robust and reliable transmission to take advantage of the diversity. The sun may not always be shining here but it is always shining somewhere. I understand that the wind and solar profiles used by both Duke and Synapse are the same, so the greater dispersion of wind and solar (more Midwest wind, more distributed solar) is not reflected in the modeling.

- **Short term storage.** We can store solar during the day and use it at night. A full renewables system will need a lot of it. Jacobson's modeling has approximately 120 GW of 4-hour batteries versus approximately 30 GW for Synapse and about 20 GW for Duke. The more renewables you employ the more storage you need.
- **Long term storage.** We won't cycle it as often as we do short term storage, but it will be available for major seasonal differences such as Duke's projected winter peak in the Carbon Plan. Duke's Bad Creek Hydro has many characteristics of long-term because the amount of energy behind the dam is high relative to the capacity.
- **Overbuilding.** Once the need for regularly cycled (day/night) storage is filled, one lower cost intermittency solution will be to be to build more wind and solar than we would need if we had infinite storage. It is likely to be more economical to build more renewables than we need in summer so that

we have enough in the winter versus building enough storage in summer to save it for the winter. During the summer we will likely have more energy than we can store so the incremental cost of using it will be zero. This can then lead, potentially, to a low-cost resource that can do beneficial things, like create green hydrogen. In the modeling, the amount of overbuilding can be measured by the volume of curtailments. From what I can see the models in this case, all assumed a zero value for curtailed energy, but if it is available to produce hydrogen, then it will presumably have value which conceivably could be included in the modeling.[30] . In Jacobson's modeling, curtailed energy equals almost 50% of required demand, so that this is an order of magnitude higher than the curtailed amounts in the Duke Portfolio-1 or Synapse Portfolio modeling.

- **Green hydrogen.** If a large amount of electricity is available at low or zero (from overbuilding above) cost, then the production of hydrogen through electrolysis can be part of the solution. Of course, hydrogen has many uses in industrial processes and fertilizer production, so the first goal of green hydrogen will be to replace the current fossil fuels used to produce hydrogen. But after that, enough hydrogen could be available to serve as a fuel source for fuel cells or turbines that can produce electricity when needed to improve reliability and meet shortfalls from a grid with a high level of intermittent resources. This option is relied upon quite heavily by Duke and Synapse to

[30] Jacobson, Mark Z et al, Zero Air Pollution and Zero Carbon From All Energy Without Blackouts at Low Cost in North Carolina, December 7, 2021

the order of 4% or so of total energy supply in 2050, although neither specifies where the hydrogen will come from or what the cost will be. Jacobson explicitly incorporates hydrogen, which makes up about 6% of total grid energy in his NC 100% renewable energy simulation. Unlike Duke and Synapse, Jacobson develops an explicit hydrogen model and includes the production of electricity for hydrogen (which uses some of the curtailed energy from solar and wind) and the cost and efficiency loss of electrolysis.

- **Flexible loads (demand response).** Jacobson makes extensive use of flexible loads in his modeling, which require a degree of control over what the customer is doing. Flexible loads include EV charging, water heating (preheating), home heating and cooling, and industrial loads that agree to be available for interruption for the right price. Flexible industrial loads (interruptible loads) could have a very high amount of capacity. In a recent ERCOT energy emergency, over 1000 MW of load was shed from industrial customers.[31] From what I can see, Duke and Synapse both see flexible loads as an input and not part of the reliability modeling part of the process.
- **Distributed energy resources (DERs).** As battery costs decline and the fear of climate or other shocks increase, there will be increased demand for micro-grids which can spring to life to provide power from battery backup systems for businesses, government facilities and homes in the case of power outages. When not in a power outage situation, these batteries and generators can be

[31] https://www.utilitydive.com/news/texas-expands-industrial-demand-response-program-as-grid-goes-to-the-brink/627358/ (accessed 8/30/2022)

used by the utility to supplement grid reliability if the right incentives are in place. None of the modelers have explicitly accounted for this opportunity.

- **Energy efficiency programs ramped up and targeted at the intermittency problem.** I agree with Duke's testimony, from various witnesses, that the greatest reliability problems will come in the winter and that some problems may result not just from hourly capacity shortfalls but from prolonged energy shortfalls. One solution to this problem is to provide much heavier focus and incentives on energy efficiency programs that reduce demand in winter. Additional incentives and promotion of cold weather air source heat pumps, geothermal heat pumps, ending resistance heat use in low-income homes, insulation, and weather sealing are just a few of the possible steps to take to reduce this problem.

In summary, there is a lot going on in this space and there is a tremendous array of possibilities for managing renewable grids that are emerging. As Holeman's testimony points out, utility system operators are in an intense "learning mode". They are learning from each other and through that learning are understanding the stakes involved and how to reconfigure their systems during the transition. Researchers and entrepreneurs around the world are also driving the cost of intermittency solutions down.

There are many solutions to the intermittency problem that will work in concert to provide a reliable electric system. Neither the Duke nor the Synapse modeling make nearly the amount of use of these solutions as does Jacobson, especially when it comes to overbuilding, battery storage, resource and geographic diversity, and flexible loads. This would indicate to me that there are more available tools that could be used to resolve the intermittency problem if NC wishes to add more intermittent options to the system and rely less on gas and nuclear.

The challenge of ensuring reliability of a grid that employs substantial intermittent resources will be a critical and challenging issue as we move forward. **However, I conclude that there are enough current and emerging solutions that Duke and the Commission should continue to thoroughly explore scenarios that allow us to take advantage of the lower cost energy from wind and solar.**

Q. **ARE THERE OPPORTUNITIES TO PRESERVE RELIABILITY DURING THE TRANSITION THAT WOULD ADD TO THIS LIST OF SOLUTIONS?**

A. Yes, it's fine to look how we might design a system in 2040 or 2050 that uses far more renewable energy, but we also need to manage the transition while we are adding solar and wind, retiring coal, and moving to that 70% carbon reduction by 2050. Indeed, Duke's analysis of the Synapse Portfolio showed that there was a reliability gap in 2035 that needed to be plugged with additional gas CTs. Any of the above solutions – batteries, flexible loads, overbuilding wind and solar could be used instead of adding a new CT.

Another option that might be worthy of consideration would be to slow down the retirement of the coal units. My bringing this up is based on several factors. First, coal's contribution to carbon emissions is based on how much coal is burned, not on whether the unit has been retired or not. One of the coal units could be kept on standby and readied for service to respond to a period of prolonged outages from other units or from extreme weather events. This would help with the fear of prolonged periods of time when the "wind doesn't blow, and the sun doesn't shine." It's most likely that these extreme situations would occur mostly in the winter. Of course, the cost of keeping these units ready to go with say a week's warning needs to be balanced with the costs of keeping the units on reserve.

This option was not able to be considered in the Synapse Portfolio development of the coal retirement schedule because the reliability shortfall in 2035 that Duke discovered was only identified after the EnCompass modeling was complete and in the production costing and reliability phase of the modeling.

The idea of not retiring the coal brings up the risk that a polar vortex or similar event might cause Duke to violate the carbon restriction in a year through the use of coal. That indeed could happen, and perhaps the Commission should consider what should be done in that circumstance. Indeed, extreme variance from the forecast, or indeed from the loss of availability of a nuclear unit, could cause Duke to exceed the limits in any year, with or without keeping coal as a backup. Duke could prepare for this by having a "reliable reduction in carbon" as well as a reliable supply of electricity. Such reliability might require planning to exceed the carbon reductions under "normal" conditions to be more likely to at least meet the carbon reductions under abnormal conditions. Food for thought.

Q. **IS IT ACTUALLY POSSIBLE TO RUN A 100% RENEWABLE GRID AS MODELED BY JACOBSON? SOME OF DUKE'S**

TESTIMONY SEEMS TO INDICATE THAT SOME TRADITIONAL GENERATING ASSETS USING FOSSIL FUELS, OR AT LEAST HYDROGEN, IS NECESSARY FOR RELIABILITY PURPOSES.

A. I think a 100% renewable grid is possible, or will be, by having sufficient overbuilding and battery storage and other solutions. It is true that you can't increase the output of solar and wind beyond what those resources are producing at any one moment in time. However, you can reduce their use through curtailment or increase the load through storage charging or flexible loads such as pre-heating water such that the generation matches the demand. Then, when the load exceeds the renewable resources, you draw upon storage or reduce flexible loads to make up the difference. So, when you are just talking about matching energy to load and when you have overbuilt the renewables and added enough storage and other of the above intermittency solutions you should be able to reliably meet the load to satisfy reliability constraints.

Duke, as I understand it, is referring to a slightly different problem, in Robert's testimony when he states,

> "What is needed are resources that do not emit carbon and have the dispatchability and flexibility characteristics that are fundamental to power system reliability (e.g., load-following capabilities). This new technology need is referenced throughout the Carbon Plan as a general need for zero emissions load following resources ("ZELFRs")"[32].

[32] DIRECT TESTIMONY OF HOLEMAN AND ROBERTS, page 55

ZELFRs are needed to ensure that grid frequency is maintained and unexpected spikes in supply or demand are appropriately responded to. In the 100% renewable electricity scenario those resources would be supplied by batteries or hydrogen generators designed to be able to do that. And as Duke's testimony rightly points out, such capabilities are only now under development so Duke and its peers cannot point to examples where they have been widely deployed yet. But progress is continuing at a rapid pace, and I draw your attention to a recent headline from South Australia announcing "Tesla big battery begins providing inertia grid services at scale in world first in Australia"[33] The article goes on to say:

> "Known as virtual synchronous machines or grid forming inverters, this technology gives batteries the capacity to help stabilize the grid by providing inertia. Along with frequency control services, inertia is necessary for operating a stable grid and is especially important after major disturbances. Until now, inertia services have only been provided by gas or coal-fired generators and their rapid retirement is causing inertia shortfalls or grid instability."

This paragraph both confirms Duke's concerns but also points to a developing solution. And this solution isn't in a lab, it is working in an actual utility grid situation, and augers rapid progress in the energy transition.

Circling back to the question at hand, I agree with Duke's assertion that these capabilities will be necessary before the grid can no longer use fossil fuels, but I can see that that day is on the way and that this concern will not keep us from reaching 100% renewable electricity, if that is what we want to do.

---

[33] Peacock, Bella, PV Magazine, July 27, 2022, https://www.pv-magazine.com/2022/07/27/tesla-big-battery-begins-providing-inertia-grid-services-at-scale-in-world-first-in-australia/ (accessed 9/1/2022)

Q. **SO, DOES THIS MEAN THAT DUKE'S CARBON PLAN SHOULD AIM FOR A 100% RENEWABLE ELECTRIC GRID, WITH NO NUCLEAR OR FOSSIL FUEL?**

A. **No, it doesn't mean that. The 100% carbon neutral by 2050 objective is fine and the existing nuclear is likely to be cost effective to keep around. What it does mean is that the Commission should keep the idea in mind that a grid that builds no new nuclear and no new fossil fuels represents a future that we can explicitly consider as a co-equal path with the more fossil fuel and nuclear expansion in all four Carbon Plan portfolios.** And it means that the concerns of Duke about reliability, especially during the transition, are valid but may be fleeting. In my estimation, the learning going on now in the industry and the developments of technology like the recent demonstration in Australia demonstrate that the reliability concerns will be solved so that we can achieve the promise of lower power cost from renewable energy.

Q. **HOW MIGHT DUKE PROVIDE A "CO-EQUAL PLAN" THAT DID NOT RELY ON NEW NATURAL GAS OR NEW NUCLEAR.**

A. From a modeling perspective, the first thing they should do is incorporate the impact of the Inflation Reduction Act and other developments into the models. Then they could just take the Synapse Portfolio and go from there. Alternately they could re-run EnCompass and not allow selection of new gas (other than hydrogen fuel cells or CTs) or new nuclear. This would create an all-new renewables and storage portfolio. Plus, they would need to add modeling avenues for the intermittency solutions that I mentioned such as adding longer duration storage, overbuilding, flexible loads, delaying the coal retirements, and focusing EE programs on winter demand. I don't know how well EnCompass handles some of these items so they might need to be handled in the post-EnCompass step or with additional refinement of the models.

Beyond the modeling, Duke should identify the near- and medium-term actions required for this scenario. Until one or the other paths are clearly identified, or perhaps some sort of blend, the Carbon Plan should pursue near-term actions that would preserve the option of going in either direction.

VII. SUMMARY

Q. **PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY**

A. I am happy to provide my perspective on this extremely important issue before the Commission. The issues before the Commission are of great importance to answer the question "How will the electric sector achieve the goals of 70% reduction in carbon emissions by 2030 and 100% by 2050." Duke Energy has responded with a reasoned, comprehensive plan for achieving that goal. Intervenors have brought forth some criticisms of Duke's plan and some reasoned alternative plans that purport to lower cost and provide a better plan to achieve the goals we all share. At the same time economic events and Federal legislation have changed the landscape such that the assumptions underlying these plans are no longer a good representation of the situation.

The main debate regarding the carbon plan boils down to one question: **"Do we set a course now for a future with a heavy reliance on natural gas in the near term and nuclear in the long term, or do we set a course for a future which doesn't rely on gas in the near term and relies much more on renewable energy in the long-term".** Much of the Duke's testimony seems to be arguing that the intervenor suggested plan can't be executed, it's not cheaper due to errant assumptions, or will lead to problems (grid reliability). I have reviewed those assertions above, and I don't find them to be compelling, but they bring up issues that require future analysis.

The good news is that Duke is not asking for approval of major investments today to build new gas plants or to build new nuclear plants. They are asking for approval for near-term actions that set the stage for implementing that pathway a little later, and they are asking the Commission to bless the process that they have used to come up with the plan.

Q. **PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR ACTIONS THE COMMISSION AND DUKE SHOULD.**

A. First, as to the initial "carbon plan" that the commission is tasked with developing, the Commission should not "accept" the Duke Carbon Plan as filed as "The Plan". The Commission, or public staff, should develop its own plan as "The Plan". The Plan would explicitly state that we don't know which of the two basic directions we want to go in, or whether it should be a blend. Duke's Portfolio – 1 could be the representative example of one of these directions, and the Duke Carbon Plan document (with all appendices) could be attached to The Plan or simply referred to. The Synapse Portfolio, represented in the "Carbon Free by 2050" report could be that plan chosen as representative of the other direction that we might want to go, and similarly included as an attachment to The Plan or referred to.

The Commission would order Duke to develop similar alternatives in future filings that represent the broader range of options as suggested here. This would mean that the modeling Duke does using EnCompass is merely used to credibly develop alternative paths, as opposed to trying to get "the answer". Duke's Carbon Plan process would be seen as an example of "Scenario Planning". The Commission could ask for various scenarios to be explicitly explored, and the next iteration should fully develop an understanding of the impact of federal legislative changes and of the longer-term implications on Duke's plan of a full economic decarbonization scenario and the attendant higher electric demand. No decisions to build new gas or nuclear capacity should be made at least until the modeling considers the multiple scenarios and the impact of recent Federal legislation.

As far as near-term actions, I believe the Commission should approve "all of the above". The Commission should approve Duke's requests for near-term actions it should also approve the requests made by Synapse in the "Carbon Free by 2050" report to speed up solar interconnection, embrace more ambition in EE and DSM programs, and seek to obtain access to low-cost Midwest wind energy.

Q. **MR ROUSE, DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

STATE OF NORTH CAROLINA

UTILITIES COMMISSION

RALEIGH

DOCKET NO. E-100, SUB 179

North Carolina Utilities Commission

In the Matter of:	)	
Duke Energy Progress, LLC, and	)	WITNESS SUMMARY
Duke Energy Carolinas, LLC, 2022	)	OF BRAD ROUSE
Duke Carbon Plan	)	

The purpose of my testimony is to present the results of my investigation into Duke Energy Carolinas, LLC's (DEC) and Duke Energy Progress, LLC's (DEP) (collectively, Duke) proposed Carbon Plan.

1. The key unresolved near-term issue is whether to commit to building new gas fired capacity by 2030. Duke is saying that the Commission does not have to make such a decision until they file a CPCN (2023?). However, Duke has not developed a scenario showing an alternative without new gas capacity and not seeking near term actions that keep such an alternative available. The Commission should approve a scenario in the Carbon Plan that does not include any, or as much, natural gas in this time frame for comparison to Duke's plans and should require that Duke examine and present such an alternative as part of the 2024 Carbon Plan or any CPCN application that proceeds the 2024 Carbon Plan.

2 The increase in gas costs and the recent passage of the Inflation Reduction Act (IRA) have dramatically changed the landscape for achievement of the Carbon Plan goals. These changes should be fully considered in the 2024 Carbon Plan and any CPCN that precedes it.

3. Duke's four portfolios (later expanded to six) are too similar and don't illustrate the more fundamental choices. These choices are better illustrated by comparing any of Duke's Portfolios with other intervenor modeling, and by the public studies on the future electric system showing that adding a much more substantial mix of renewable energy, energy efficiency, demand side management, and storage are lower cost and less risky.

4. Duke's modeling of the reliability risks stemming from the intermittency of renewable resources did not evaluate the full range of solutions to intermittency including overbuilding renewable energy, active demand side management, flexible loads and others.

5. In keeping with the general approach of "Scenario Planning", the Commission's plan should adopt scenarios that represent at least two substantively different pathways. The 2022 Carbon Plan should also adopt a near-term plan of actions that support the potential of going in either of these two directions and of continuing to develop and study both alternatives.

7. Neither Duke nor intervenors have developed sensitivities to investigate the possibility that NC might reach economy wide net zero by 2050, understanding that this would likely require even more climate legislations. This future would likely involve complete electrification of the energy system and much higher load forecasts The Commission should order future Carbon Plans to include such sensitivities.

8. I review Duke's criticisms of one intervenor portfolios as an illustration and conclude that the process and underlying assumptions of this intervenor analysis is

reasonable for development of an alternative scenario illustrating a portfolio without new gas capacity.

9. There is significant interest among local governments and community groups in working with Duke to speed the energy transition, but a strategy of doing this seems to be, at best, underemphasized in Duke's Carbon Plan. Opportunities for collaboration should receive more emphasis as an explicit strategy of the Carbon Plan, especially as it relates to possible increased near-term ambition for energy efficiency and distributed energy resources and to leveraging the new opportunities under IRA for customers to decrease their energy use, especially as regards to low-income customers.

9. The presentation of cost to ratepayers and affordability in Duke's Carbon Plan is flawed and should be improved to include consistent projections of average rates for all scenarios.

This completes my summary.

MR. BURNS: Madam Chair, on behalf of CCEBA we would take waiver from all parties who had stated that they had cross questions for Dr. Dinos Gonatas, CCEBA witness, and all those parties including Duke have waived that cross. I understand that there are also no Commissioner questions planned for Dr. Gonatas, so we therefore move and seek permission to excuse Dr. Gonatas from his appearance and to submit his revised testimony, as filed on September 16th, 2022, and the accompanying two exhibits into evidence. His summary will also be submitted into evidence. I expect to be able file that, along with Dr. DiFelice's, this weekend, and ask to be admitted at the proper time.

CHAIR MITCHELL: All right, Mr. Burns. Having heard no objection to your testimony, the witness' revised testimony filed on September 16th --

MR. BURNS: Yes, ma'am.

CHAIR MITCHELL: -- will be copied into the record as if given orally from the stand at the appropriate time, as will his testimony summary and exhibits accepted into evidence, and he's excused from participating as a witness in the hearing.

MR. BURNS: Thank you very much.

(Whereupon, the revised prefiled direct testimony of Dinos Gonatas and summary were copied into the record as if given orally from the stand.)

(Whereupon, CCEBA/MAREC Gonatas Exhibits 1 and 2 were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET No. E-100, Sub 179

In the Matter of:	)
	)
Duke Energy Progress, LLC, and Duke	)
Duke Energy Carolinas, LLC,	)
2022 Biennial Integrated Resource Plan	)
And Carbon Plan	)

REVISED DIRECT TESTIMONY AND EXHIBITS OF

DINOS GONATAS

ON BEHALF OF

CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION

And

MAREC ACTION

September 16, 2022

I. Introduction

Q. Please state your name, position and business address.

A. My name is Constantine (Dinos) Gonatas, and I am Principal at CPG Advisors, a consultant in the Boston area, with business address at 260 Old Marlboro Rd, Concord MA 01742.

Q. Please describe your work.

A. I consult in grid and regulatory analysis, especially on issues concerning grid integration with renewables and smart grid

Q. Please describe your experience and education.

A. I have worked in the energy industry for over 20 years. My education includes a PhD in physics from the University of Chicago, followed by post-doctoral work in Electrical Engineering at the University of Illinois. I developed new hydrogen generation technology at ExxonMobil Research & Engineering Company, followed by work on valuing natural gas trading products at Tenneco Energy, then part of the Tennessee Gas Pipeline Company. In subsequent roles as a finance manager at Enron Corp I developed models for power markets, supervised resource planning modeling, valued transactions for acquisitions of integrated electric utilities and supported asset development, including merchant transmission lines. Recent work includes consulting for the US Department of Defense to model grid reliability, technology development for solar + storage systems, techno-economic assessment of hydrogen generation technologies, smart inverters for PV systems, regulatory and economic analyses for wind power expansions. Publications include articles on carbon mitigation for *Public Utilities Fortnightly* and on power markets for the *Electricity Journal.*

Q. On whose behalf are you testifying in this docket?

A. I am testifying on behalf of the Carolinas Clean Energy Business Association ("CCEBA") and MAREC Action.

Q. Have you testified before this Commission in any other docket?

A. No.

Q. Have you testified in other energy-related proceedings?

A. I have been part of an expert witness team submitting amicus briefs opposing FERC at the Federal Appeals Court for the DC Circuit and at the Supreme Court.

Q. Which issue identified by the Commission in its July 29, 2022 Order Scheduling Expert Witness Hearing does your testimony address?

A. I believe this testimony is best considered under Topic 1(f) "Transmission Planning, Proactive Transmission, and RZEP."

Q. How is your testimony structured?

A. In this testimony I will provide an overview of the need for an improved transmission planning process in North Carolina, then focus on some individual elements: (1) I discuss the need for inter-regional and intra-regional transmission capacity to support the reliability and flexibility of current operations and expected integration of renewables s (2) I will highlight how restrictions on renewables expansion hinge on transmission constraints at existing coal plants and advocate for increased transparency; (3) I recommend multiple transmission planning scenarios long-term in addition to the single transmission build-out Duke proposes, highlighting the Multi-Value project framework suggested by FERC and MISO; (4) I suggest transmission planning process reforms that would increase the responsiveness of North Carolina's transmission planning process to stakeholders. These include modifications to Duke's Open Access Transmission Tariff (OATT), attachment N-1, to allow such improvements as restructuring the North Carolina Transmission Planning Collaborative (NCTPC), the stakeholder Transmission Advisory Group (TAG) and the Oversight/ Steering Committee (OSC) to be more inclusive and responsive to stakeholders.

II. Overview

Q. Can you give an overview of your assessment of the Duke Carbon Plan and the role of transmission planning?

A. While the Duke Carbon Plan is a significant undertaking by Duke Energy to present its approach to decarbonizing Duke Energy's generation portfolio through eventual integration of new renewable resources, have reviewed the comments filed by CCEBA and other parties and agree that, while notable, there is substantial room for improvement. On behalf of the CCEBA and MAREC Action, I comment on transmission aspects of Duke's plan together with its 8/19/22 direct testimony (particularly attachment 6 by witnesses Roberts and Farver), taking into account observations by various Intervenors (Tech Customers/ Gabel, Clean Power Supplier's Association/ Brattle Group, and the NC Sustainable Energy Association/ Synapse).

Although I focus primarily on transmission, that topic cannot be considered completely separately from generation because an optimal plan co-optimizes transmission with renewables distant from load centers. As discussed in the proposed Carbon Plan, solar interconnection requests have been significantly constrained in a "Red Zone" across the southern mid-section of the State south of Raleigh-Durham/ east of Charlotte and extending into South Carolina (*see* Carbon Plan Figure P-1). Although there is not a big variation in solar insolation across the State, I understand that this area is more favorable to development because of the relative feasibility of obtaining sizeable land parcels due to topography, available parcel size and contiguity, land prices, and population density compared to other parts of the Carolinas. Offshore wind is located in blocs in the Carolina Long Bay off Cape Fear and off Kitty Hawk. On-shore wind is distantly located in MISO and parts of PJM (Indiana/ Illinois/WV), with only one project currently within the borders of North Carolina. Onshore thus poses a particular transmission challenge requiring wheeling through PJM.

Transmission is a critical ingredient enabling new renewable resources. However, it is a costly and long lead-time item, especially if new right of way is required, with Duke stating lead times ranging from 4.5 to 7 years (in the Red Zone for example). Therefore, long-term scenario planning is essential. In its recent NOPR, FERC has proposed a 20-year planning horizon and multiple scenarios to accommodate evolving needs and public policy requirements such as North Carolina's carbon law, HB 951. However, Duke documents basically a single scenario, looking only to 2030 (8 years ahead), back-filling the end years of its plan with new nuclear plants and converting gas generation to hydrogen fuel-thus obviating the need for longer-term transmission planning. While this could be an upside scenario if these prime movers evolve from their current technologically immature status, it appears prudent to consider scenarios enabled by different transmission build-outs. In order to facilitate development of resources in the next few years, some significant improvements must be undertaken early, but adoption of planning process reforms will significantly improve prospects for the middle to long term.

Q. Is there a useful framework for assessing transmission planning scenarios?

A. Both FERC and regional transmission operators like MISO and PJM advocate "multi-value project" assessments that balance transmission's multiple benefits versus its costs. FERC delineates 12 benefits to value[1] while MISO considers 6 buckets of benefits.[2] Opting for simplicity here, we can consolidate MISO's categories: (1) value of congestion relief/ fuel savings; (2) Avoided capital cost of local resources and other transmission upgrades (that otherwise would be done anyway); (3) Resource adequacy savings & reduced occurrence of load shedding; (4) Decarbonization benefits.

Q. How are transmission constraints obstacles in adding more renewables than Duke considers?

A. A primary driver in Duke's choices for generation portfolios in its scenarios are the transmission restrictions it claims exist and cannot be effectively remediated. Specifically, it claims that the Marshall, Belews Creek, Roxboro and Mayo coal

---

[1] FERC NOPR Docket RM-11-17 pp. 159-160, Table I, "Long Term Regional Transmission Benefits"
[2] MISO MTEP21 Addendum, Long Range Transmission Planning Tranche 1 – Executive Summary, https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf. (Attached as Exhibit 1). *See* Figure 2, p. 3: "LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)"

plants are "reliability must-run" status due in part to transmission constraints (*see* Carbon Plan, Appx. P, at 15-16). Prolonging the retirement of these coal units in part limits new solar additions in the planning period to 5.4GW by 2030 (in Portfolio 1), even though an unconstrained economic model would likely add considerably more solar energy, as detailed in the comments of the Clean Power Suppliers Association.

Q. Is Duke Energy transparent about the transmission constraints requiring coal generation to stay on-line for longer, and replacing coal plants with speculative technologies?

A. No. Duke does not appear enthusiastic about remediating the transmission constraints, choosing instead to add generation, including potential nuclear or hydrogen-powered turbine generation at the location of the current coal plants, in order to avoid additional network upgrades. Even if its assertion is true that transmission additions to allow coal retirements at sites such as Belews Creek could take up to 10 years, it is prudent to consider a transmission scenario with those needed improvements built-in. Inexplicably, Duke's plan does not consider such a scenario. It is self-defeating to state the transmission constraints will take too long to fix, then not create long term planning scenarios where they are fixed so that even by the 2030's when they could have been fixed, the critical constraints persist.

This situation suggests a need for transmission planning reform where stakeholders could have timely influence on system build-outs. Duke acknowledges the need for reform in its 8/19/22 direct testimony by Roberts and

Farver at pp. 41-42 , stating "the Company is supportive of the North Carolina Transmission Planning Collaborative (NCTPC) initiating a review to evaluate changes to the local transmission process and consider changes to Attachment N-1 of the joint Open Access Transmission Tariff [OATT] that could be filed with FERC." Rather than relying solely on the existing NCTPC structure to accomplish these evaluations and changes, I propose changes to the current structure itself, which awkwardly puts stakeholders to the side, consulting them quarterly only and having only indirect influence on the main committees - composed solely of transmission owners.

<u>Transmission Capabilities and Regional / Inter-regional Transfers</u>

Q. Is a role for inter-regional planning in North Carolina being considered adequately in the Carbon Plan?

A. FERC Order 1000 mandates inter-regional planning. Duke's Carbon Plan and direct testimony state that PJM's import tariff ($67.625/kw-yr) makes imports from PJM prohibitively expensive combined with Duke's estimated $700M cost for required upgrades to enable a 1000MW transfer (Carbon Plan, Appendix P. pp. 22-23; Duke direct testimony by Roberts and Farver at pp. 59-62). Here, Duke cites modeling with the Power-GEM/ PJM Generator deliverability tools. It would be helpful for Duke to clarify, as they should be a critical part of NCTPC, considering Duke's statements indicate FERC-mandated planning with neighboring regions is a desolate task indeed. This is unfortunate considering the value other grid operators have found in "seams" interconnecting adjacent systems. MISO even has a subcommittee specifically investigating seams, with a recent report.[3]

Q. Would incorporating inter-regional connections into long term planning undermine the case for more immediate transmission improvements such as the Red Zone and development of local resources?

A. Not in my opinion, no. By discussing these issues, I do not intend to contradict CCEBA's positions on the importance of those near and medium-term improvements, which can assist in the development of solar, storage and off-shore wind resources.

Q. Have you looked for such studies on inter-regional connections on the NCTPC's website?

A. Yes. The only available study I have located on inter-regional connections on the NCTPC website is an analysis from 2015 ("MISO-NCTPC-PJM Joint Study of NC Impact of PJM 2016/2017 Base Capacity Auction") modeling unscheduled flows into Duke from PJM from adding new PJM capacity resources external to PJM (e.g. in MISO). It is puzzling there has been no other analyses on inter-regional flows within the NCTPC process.

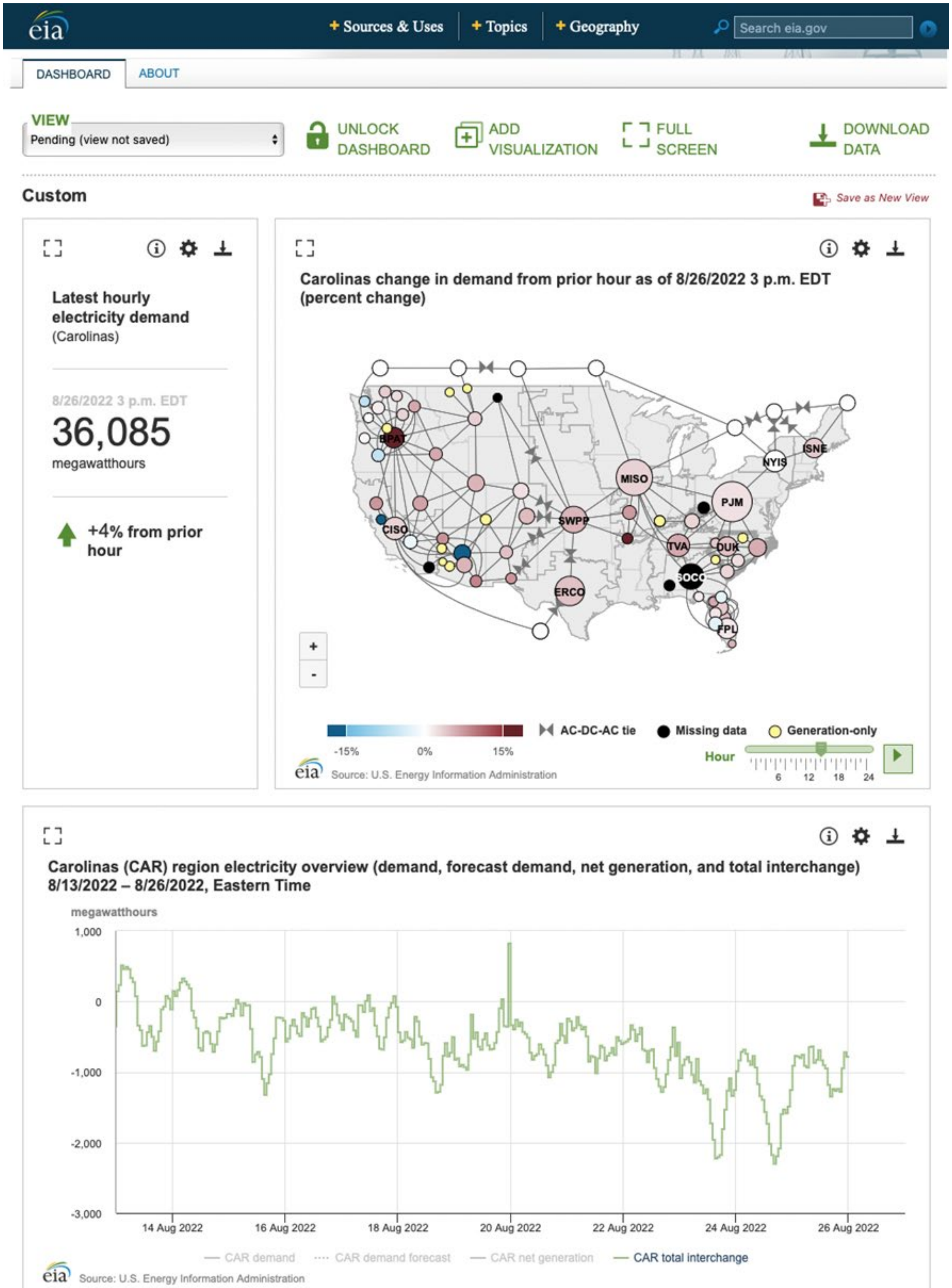
For further information on inter-regional flows, we obtained public data from EIA into the Carolinas region (below). This chart shows a regional topology where the Carolinas have been selected for quantitative measures. The line chart in the bottom panel plots net MW of power interchanged to the regions connecting to

[3] https://cdn.misoenergy.org/JTIQ%20Report623262.pdf

the Carolinas. These show transfers greater than 2000MW. Thus, sizeable transfers do occur, although by no means do we claim that transfers 1000-1500MW beyond this level could be achieved without investment.

The EIA Chart is on the following page:[4]

[4] https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overiew/regional/REG-CAR


eia
Sources & Uses
Topics
Geography
Search eia.gov
DASHBOARD
ABOUT
VIEW
Pending (view not saved)
UNLOCK DASHBOARD
ADD VISUALIZATION
FULL SCREEN
DOWNLOAD DATA
Custom
Save as New View
Latest hourly electricity demand
(Carolinas)
8/26/2022 3 p.m. EDT
36,085
megawatthours
+4% from prior hour
Carolinas change in demand from prior hour as of 8/26/2022 3 p.m. EDT (percent change)
BPAT
CISO
MISO
SWPP
ERCO
PJM
NYIS
ISNE
TVA
DUK
SOCO
FPL
AC-DC-AC tie
Missing data
Generation-only
-15%
0%
15%
Hour
6
12
18
24
Source: U.S. Energy Information Administration
Carolinas (CAR) region electricity overview (demand, forecast demand, net generation, and total interchange) 8/13/2022 – 8/26/2022, Eastern Time
megawatthours
1,000
0
-1,000
-2,000
-3,000
14 Aug 2022
16 Aug 2022
18 Aug 2022
20 Aug 2022
22 Aug 2022
24 Aug 2022
26 Aug 2022
CAR demand
CAR demand forecast
CAR net generation
CAR total interchange
Source: U.S. Energy Information Administration

Q. What are examples of benefits of inter-regional transfers?

A. Inter-regional transfers between two systems can benefit both systems by smoothing out differences in generation resources and load between them by increasing diversity. Particularly for systems with increasing levels of renewable generation, enhanced transmission "leverages the geospatial diversity of the variable resources to smooth output ramping.[5]" Longer term, increased transmission connections enables the integration of renewable resources in both systems.[6]

Q. Are there other areas in which considering inter-regional planning would benefit transmission planning for the Carbon Plan?

A. Yes. Besides the benefits of inter-regional flows for economical dispatch and support in case of contingencies, it would be helpful to coordinate with Dominion Energy's offshore wind project, where they have requested an 800MW interconnection at the Birdneck and other substations in Virginia Beach, adjacent to the Kitty Hawk lease area. While Duke discusses offshore wind plans for North Carolina with interconnections recommended at the New Bern substation, joint planning could result in infrastructure optimized for both projects and economies of scale.

---

[5] Brian Parsons, NREL "Renewable Energy Futures" conference presentation, (January 9, 2012), https://cleanenergygrid.org/wp-content/uploads/2013/01/Brian-Parsons.pdf at p. 17.

[6] Aaron Bloom, et al., *Eastern Renewable Grid Integration Study* (August 2016), National Renewable Energy Laboratory, NREL/TP-6A20-64472-ES, at p. xii, https://www.nrel.gov/docs/fy16osti/64472-ES.pdf (stating that increased connections enables "PV in SERC and FRCC [to have] a large impact on regional flows… due to the cheaper power coming from SERC.")

Q. What recommendations can you make to address inter-regional connections?

A. At pages 63-64 of their direct testimony, Duke Energy witnesses Farver and Roberts, refer to the 2011 SPP blackout and 2020 CAISO load shed events as problematic events that call into question the need for imports and joint planning. I recommend a diligent set of interconnection studies examining costs and benefits to optimize existing facilities and assess expansion potential not only to PJM but to the Southern Company- as part of a routine and public planning process. Clearly some interconnections have already been assessed, considering Duke's Sensitivity Analysis (Carbon Plan Appendix E - Quantitative Analysis, p. 63, Table E-56) shows far lower Loss of Load Expectation operating Duke as an interconnected system rather than islanded:

Study	LOLE Value [Event-Days / Year]
Islanded	0.235
Interconnected	0.082

Q. In your review of the Carbon Plan, did you consider how Duke's coal retirement schedule is affected by transmission?

A. Yes. In its Carbon Plan Appendix P and 8/19/22 direct testimony by Roberts and Farver, at p. 53, Duke asserts coal plants must operate into the 2030's or new generation must be sited at coal plant locations because of transmission constraints:

> If any Marshall [RMR] coal units are retired and not replaced with new generation on-site, then significant transmission projects will be needed (i.e., upgrade McGuire to Marshall 230 kV lines) and in service by December 2028… Belews Creek units will continue to operate into the 2030s and DEC plans to evaluate transmission upgrades to enable retirements as the planned retirement date approaches. However, preliminary analysis does suggest that

> transmission upgrades will be required to retire the 2,220 MW of capacity at Belews Creek if not replaced with new generation on-site and coincident with the retirements.

With respect to retiring Roxboro and Mayo coal generation by 2030, Duke contends:

> ***Currently, there is no available import capability from DEC to DEP.*** Thus, if the Roxboro/Mayo replacement generation is located in DEC and requires import into DEP, then additional, more costly and time-consuming upgrades would be required. Conceptual transmission projects that would likely be needed would be a Durham-Parkwood Tie 500 kV interconnection, a Bynum 500/230 kV Switching Station interconnection along with associated line upgrades, and potentially a Roxboro Plant-Sadler Tie 230 kV.[7] (emphasis added)

Responding to the Synapse comments on retiring coal plants in its testimony, Duke states (8/19/22 direct testimony of Roberts and Farver, p. 54)

> Synapse does not meaningfully engage with these challenges and merely states that "the extent that local transmission or generation resources are needed to retire these units, Duke Energy could identify and accelerate development of these resources, including using transparent, all-source procurement for replacement generation resources, to meet economical retirement dates."

Q. Has Duke enabled transmission planning to overcome the constraints it asserts exist at coal plant locations?

A. No. Determining the needed transmission upgrades is a specialized engineering analysis including load flow studies, system stability and short-circuit analysis testing different transmission line additions or other equipment upgrades to identify which combination of new lines and equipment enhances available transmission capacity economically. These studies require confidential technical

[7] Duke Carbon Plan, Appendix P p. 16.

data on the transmission network, proprietary software and weeks if not months of third-party engineering consulting time. A transparent planning process would provide stakeholders timely and detailed advice on alternatives in response to stakeholder input as opposed to a stand-off like this. If there is a need to obtain rights of way as part of a needed transmission build-out, this should be a contingency in regional planning driving action ahead of time. These scenarios must be studied as opposed to relying on Duke's sole proposed solution to simply install new generation plants at current coal plant sites.

Q. How could stakeholders determine independently if it is possible to overcome critical transmission constraints over a long-term period?

A. The lack of detailed technical information available to stakeholders strengthens CPSA's suggestion that the Commission "Direct Duke to commission a third party, assisted by an independent technical advisory committee, to study the achievability of higher interconnection rates in Duke's territory, and advise the Company and the Commission on measures that can be taken to expedite interconnections…" (CPSA Comments at 6.) This recommendation is opposed in Duke's 8/19/22 direct testimony, in which witnesses Roberts and Farver (p. 42) state that the "CPSA recommendation appears premised on the assumption that Duke has failed… but Duke is among national leaders in solar generation." It is in no way suggesting incompetence or anything less than the highest ethics among Duke's staff to point out that Duke management has a fiduciary duty to their shareholders that may not always be aligned with public/ stakeholder interests. Thus, the planning process for Duke's FERC-jurisdictional and open-access infrastructure should provide technical information to all stakeholders within a timely process sufficient for them to shape infrastructure of the future.

Q. What are Duke's must-run constraints for coal plants and prospective coal plant retirements?

A. As coal plant retirements drive both transmission needs and renewable generation scenarios, I summarize their retirement plans by reference to Table 3-1 of the Carbon Plan, also addressed in Duke's direct testimony, 8/19/22 by Roberts and Farver, p. 50):

Table 1: Carbon Plan Portfolio Coal Retirements

Table 3-1: Coal Unit Retirements (effective by January 1 of year shown)

Unit	Utility	Winter Capacity [MW]	Effective Year (Jan 1)
Allen 1[2]	DEC	167	2024
Allen 5[2]	DEC	259	2024
Belews Creek 1	DEC	1,110	2036
Belews Creek 2	DEC	1,110	2036
Cliffside 5	DEC	546	2026
Marshall 1	DEC	380	2029
Marshall 2	DEC	380	2029
Marshall 3	DEC	658	2033
Marshall 4	DEC	660	2033
Mayo 1	DEP	713	2029
Roxboro 1	DEP	380	2029
Roxboro 2	DEP	673	2029
Roxboro 3	DEP	698	2028-2034[3]
Roxboro 4	DEP	711	2028-2034[3]

[1]Cliffside 6 is assumed to cease coal operations by the beginning of 2036 and was not included in the Carbon Plan's Coal Retirement Analysis because the unit is capable of operating 100% on natural gas

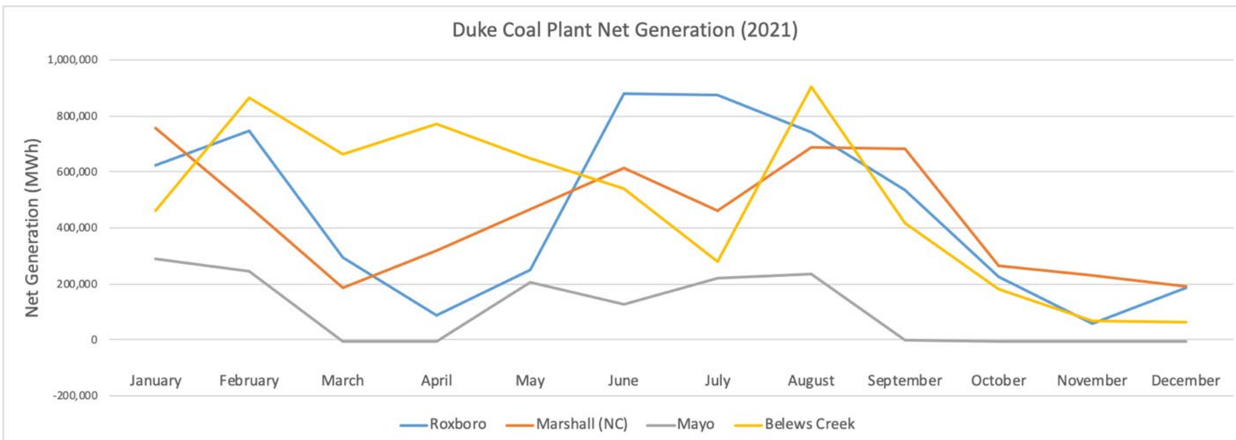
[2]Allen 1 and 5 retirements are planned by 2024 and were not re-optimized in the Carbon Plan's Coal Retirement Analysis

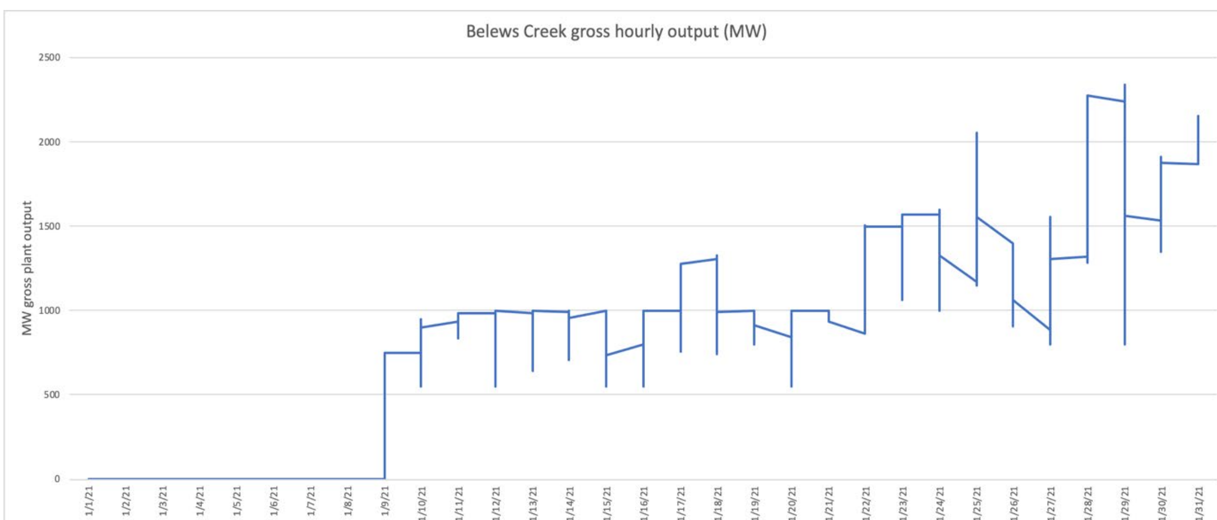
[3]Retirement year for Roxboro Units 3 and 4 vary by portfolio, with retirement of those units effective 2028 in P1, 2032 in P2, and 2034 in P3 and P4

Q. Does Duke operate its coal plants in a way consistent with their claim that they are must-run?

A. To understand the must-run plant conditions in more detail we show 2021 monthly outputs for Duke's must-run coal plants and hourly detail for the Belews Creek plant for January 2021, obtained from the Energy Information

Administration (EIA)[8] and the EPA [9] (Figures below.) Compiled into charts, these data show that must-run coal plant output is highly variable – Mayo output is zero for long stretches of 2021. Even a mid-output month like January 2021 for Belews Creek contains many hours where output is either zero or operating far below the plant maximum 2.2GW.





[8] https://www.eia.gov/electricity/data/eia923

[9] https://campd.epa.gov/data/custom-data-download

This suggests for some of the must-run coal plants, there are operating conditions that permit the plants to be turned down considerably, if not completely, suggesting the transmission constraints at these plants are not as rigid as Duke asserts. This emphasizes the need for an open planning process developing solutions for transmission constraints. Separately, it would be helpful to understand Duke's extended operation of these plants far below their maximum outputs – as they are inefficient at part-load, potentially incurring above market fuel costs for ratepayers.

Q. Are intra-regional transfer limits a problem and what could they impact?

A. Duke's current transmission transfer limitations, particularly between DEC and DEP are worrisome, and indicate a clear need for immediate transmission analyses to survey the deficiencies in Duke's system and planning for improvements that would provide needed upgrades even in the absence of the need to integrate more renewable energy. Transmission scenarios for renewable energy should quantify the value of benefits from a build-out not just for integrating low-cost renewable generation, but for improving operations during contingencies, lowering operating reserves, severe weather management, or additional economic operation beyond that afforded by renewable generation.

Q. Could advanced grid technologies be part of a solution?

A. FERC Order 881 requires ambient-adjusted line ratings, AD-22-5 is considering requiring dynamic line ratings and FERC RM-21-17 is considering requiring grid-enhancing technologies. In their 8/19/22 direct testimony (pp. 44-45), witnesses Roberts and Farver states that Duke it should not be *required* to consider advanced grid-enhancing technologies because it already is considering them and has chosen to use some, but not others. With respect to advanced conductors, Duke states it is not currently using them due to "recent installation concerns" (*Id.*) but that "Duke Energy is always investigating and, where it makes engineering and economic sense, applying technological solutions to the benefit of an efficient, reliable power system." (*Id.*)

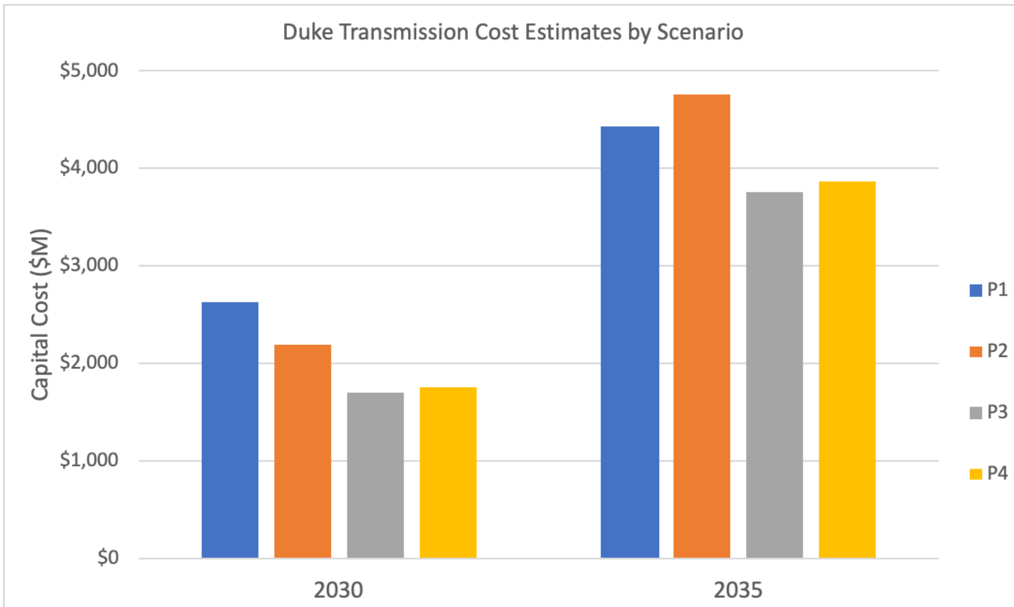
Thus, Duke dismisses any meaningful ratepayer/ stakeholder oversight that could be brought to bear on advanced practices and technologies, notwithstanding their potential status as required by FERC. While these technologies might well not be mature enough for implementation, it would be helpful to track their business cases as technology matures and compare to experiences where they've been implemented successfully. Communication with stakeholders could be on a regular and collaborative basis as opposed to the once/quarter advisory committee in the NCTPC process or ad-hoc through regulatory interrogatories.

<u>Scenario Planning</u>

Q. Does Duke engage in scenario planning for transmission in its Carbon Plan?

A. In its notice of rulemaking (NOPR RM 21-17) FERC proposes requiring multiple (4) long-term planning scenarios, instituting processes already in place at MISO and SPP among other regions. Duke's Carbon Plan has 4 *resource* scenarios- a base case (P1) showing compliance with 70% carbon reduction by 2030 together with three alternative cases (P2-P4). For transmission and interconnection, these scenarios all include a build-out to the "Red Zone" which will be required to further solar development (below) and separately, connecting the New Bern substation to offshore wind.

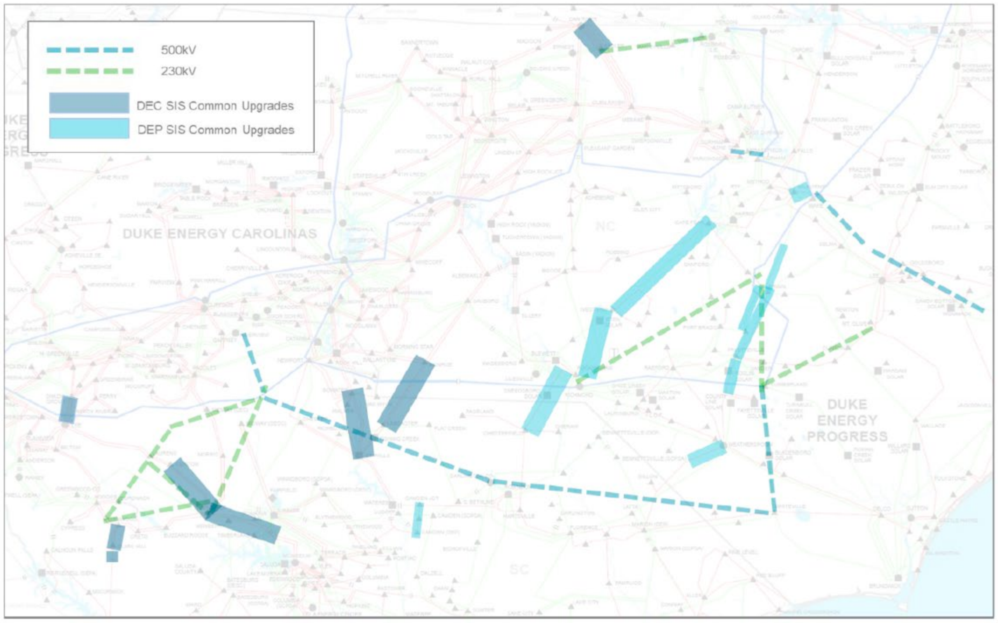
What is unclear is how the underlying resource scenarios relate to different transmission planning scenarios. In its Carbon Plan, Duke provides cost estimates: for its scenarios, however it is unclear what transmission needs differentiate them:



While scenario P1 appears more costly by 2030 than the other scenarios, that is primarily because that is the only scenario that complies with the 70% carbon reduction by 2030. As a result, it is likely just building out earlier what may be contained in the other scenarios by 2035. It is unclear what differentiates costs for the 2035 scenarios. From the Carbon Plan itself, it is unclear how the transmission scenarios for P1-P4 relate to Figure P-3 “Long Term Transmission Planning –

Example" from Appendix P of Duke's Carbon Plan. Greater transparency and clarity here is essential.

Figure P-3: Long-term Transmission Expansion Planning - Example



Q. What transmission scenarios would you suggest should be considered?

A. Scenarios should encompass a *broad* range of potential futures. Here, Duke has helpfully provided some guidance on transmission needs given the urgency of building out the Red Zone and preparing for off-shore wind, but additional components to scenarios could be:

- Considering the transmission needed to retire coal plants earlier than the 2030's as in the Brattle (CPSA) alternative carbon plan portfolios;
- Considering economics of scenarios with higher levels of renewables to balance out potential risk of higher fuel prices long-term;

- Increased interconnection within the Carolinas and to Southern Company to leverage hydroelectric resources more effectively as load-following for variable generation.

In particular, Duke's long-term scenarios rely considerably on technologies with a low technology readiness level (hydrogen for gas turbines, and small modular nuclear reactors), and thus appear more suited to upside cases rather than base cases. These should therefore not be the *only* or even primary scenarios considered. The scenarios need to be considered in an open process where stakeholders have an equal voice as the utility. Stakeholders need equal access to planning information on a more frequent basis than the quarterly updates afforded in the current NCTPC framework.

Multi-value Project Framework

Q. What is a multi-value project framework, and how would it quantify transmission benefits?

A. FERC (in RM-21-17), MISO[10] & PJM have set forth a multi-value project methodology that assesses economic benefits for transmission projects. ACORE has a report, , comparing these approaches.[11] FERC outlines 12 possible benefits. This is a large number and MISO simplifies this to 6: congestion/fuel savings,

[10] **Exhibit 2** - MISO *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 – Executive Summary*, https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf.

[11] Rob Gramlich, *Enabling Low Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis*, (August 9, 2022), https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf. Attached as **Exhibit 2.**

avoided capital costs for local resources (whose upgrades are obviated with a more integrated plan), other avoided transmission investment, resource adequacy savings, avoided risk of load shedding and decarbonization benefits. MISO's analysis for its MTEP21 expansion is summarized in the below chart[12]:

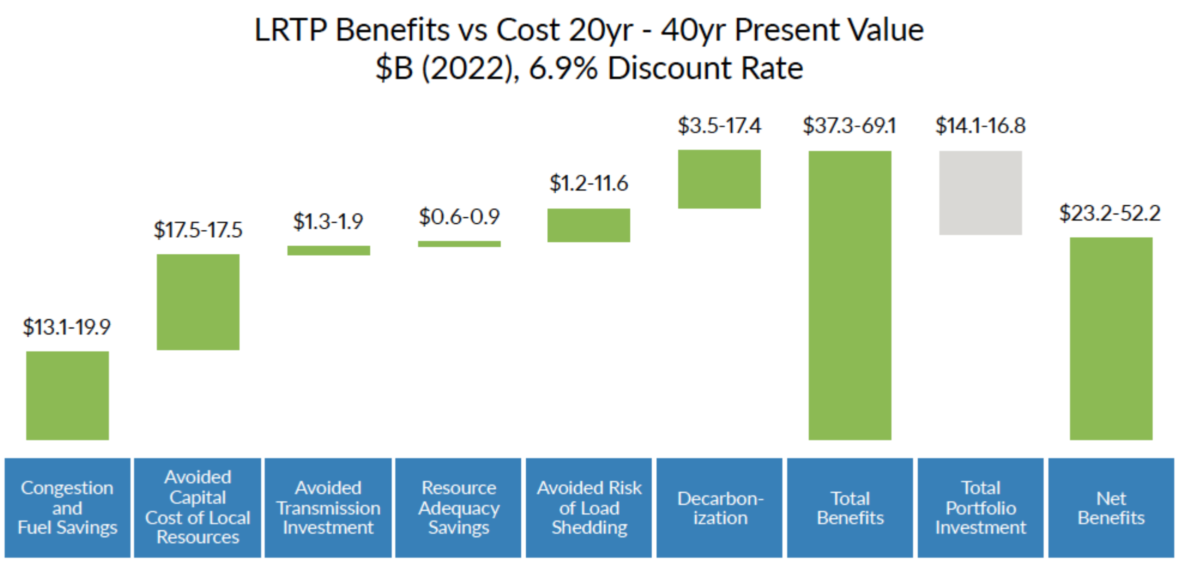


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

In its report, MISO estimates the benefit/cost ratio for its expansion as between 2.6 and 3.8. It would be helpful if a similar, systematic process could quantify the costs & benefits of Duke's proposed expansions, allowing the selection of the optimal scenario. It would also be helpful if Duke could adopt this planning framework as it is becoming an emerging industry standard.

Q. Did you apply this framework to the Duke Carbon Plan?

[12] **Exhibit 2**, Fig. 2, p. 3.

A. To a limited extent, yes, although of course much more information is needed to adequately assess each.

Congestion Benefits:

Q. How could Duke capture congestion benefits/ fuel cost reductions?

A. Duke presents its transmission scenarios in Appendix P to the Carbon Plan. These are fairly similar among their 2035 cases; for generation their bottom result is typically summarized as total PV of revenue requirements, with sensitivity cases for high and low gas prices. Considering the joint co-optimization of both generation and transmission additions, it is unclear what the fuel savings due to reduced transmission congestion might be for various scenarios. However, if Duke had developed significantly differing transmission buildouts, then the deltas in congestion among them would point to fuel savings attributable to the scenarios. Deltas in congestion compared to the existing network would be helpful.

Transmission synergies:

Q. Does Duke capture transmission cost reductions from synergies?

A. Inferring cost savings attributed to a build-out's overlap with local transmission needs is difficult. In the 8/19/22 direct testimony of witnesses Roberts and Farver (transmission, section 6) Duke provides extensive data on large-scale transmission upgrade costs to accommodate Red Zone requests. In the attachments they provide a list of transmission and local distribution upgrades with computed costs and benefits. The average benefit/ cost ratio exceeds 15. They further cite the recent Duke/NCUC technical conference of July 2022[13]. Here, programs in numerous categories were presented, covering system intelligence, transformer & breaker upgrades, hardening & resiliency, hazard tree removal, infrastructure integrity for both transmission and distribution functions – laudable grid modernization and safety projects. Spreadsheets itemizing costs and benefits were also included, together with significant benefit/ cost ratios. It could be helpful to integrate transmission planning and improvements into the Duke Carbon Plan build-out and attribute potential synergies/ savings to the build-out. If there are any transmission costs that could be saved by executing the Red Zone build-out or the offshore wind connection to New Bern, that analysis would be of interest, but it is not presented.

Resource Adequacy and Loss of Load Expectation Savings:

Q. How could Duke capture transmission benefits due to improvements on resource adequacy and loss of load?

A. With respect to any possibility of resource adequacy savings and decreased cost of lost load attributed to new transmission in MISO's analysis framework, attachments I & II of the Duke Carbon Plan present a 2024 resource adequacy analysis performed by Astrapé consulting (from 2020). The assessment was performed for Duke Energy Carolinas and Duke Energy Progress respectively and separately (although considering the joint case as well), it's puzzling the emphasis

[13] NCUC docket E-2 sub 1300 technical conference

would be on separate intra-company operations for reliability. Again, with Duke's emphasis on operating as an effective island with limited import/export capacity, this misses the engineering theorem that optimizing a system as a whole obtains better results than optimizing its sub-systems separately. While Figure 18 of Duke's 8/19/22 direct testimony part 7, by Snider, McMurry, Quinto and Kalemba on page 202 illustrates Loss of Load Expectation for the P1-P4 portfolios and other cases to show an alleged lack of reliability for the Gabel/Strategen resource portfolio, it is unclear what the full context is, what the cost savings are for reliability under different scenarios and so on. The Carbon Plan is an opportunity to revisit resource adequacy under new assumptions and translate load shedding risks into economic benefits of the proposed transmission scenarios. That planning should be undertaken.

Carbon Benefits:

Q. How could Duke capture carbon benefits in its plan?

A. With respect to the carbon benefits component in MISO's multi-value framework, these are suggested by Synapse Consulting's analysis in a sensitivity case, calculated per ton of carbon emissions reduced. Synapse uses a range of $10-$50 per ton. A $50/ton carbon cost is supported by the White House Interagency Working Group.[14] If Duke had presented significantly differing transmission scenarios, then carbon reduction deltas could be attributed to the different

[14] Technical Support Document: Social Cost of Carbon, Methane and Nitrous Oxide Interim Estimates under Executive Order 13990 p. 5 Table ES-2 https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

transmission build-out scenarios. A comparison to a Business-as-Usual case would also be helpful. This is unfortunately absent from Duke's presentation.

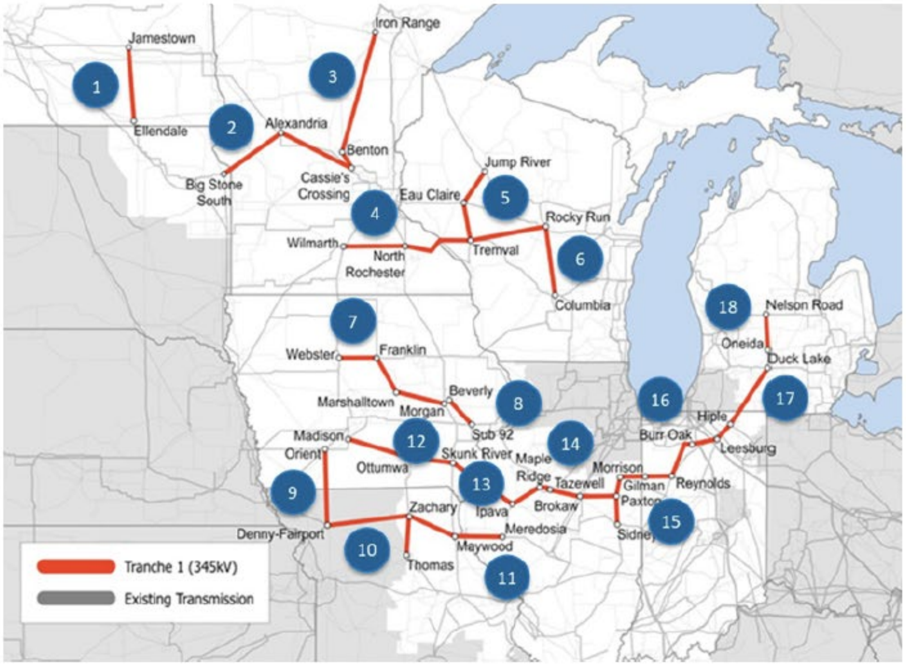
Process & Communications Recommendations

Q. How could Duke enhance transparency in its process?

A. Here it is helpful to compare Duke's figure P-3 (above) from its Carbon Plan to MISO's MTEP21 expansion (below).

In its MTEP21 expansion plan, MISO presents a single map showing each line, voltage level, point of interconnection and cost while necessarily leaving out background detail that might compromise Confidential Energy Infrastructure Information (CEII). Duke's figure P-3 from its presentation is harder to figure out. It is difficult to see where proposed lines interconnect, although it appears to be Red Zone coverage. It is also unclear what the SIS common upgrades represent. Although the text refers back to the system impact study in the queue (available on Duke's OASIS), it is cumbersome to go through the numerous queue filings and piece together numerous impact studies, some of which have been withdrawn.

MISO MTEP21 Upgrades:[15]



ID	DESCRIPTION	EXPECTED ISD	EST COST ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689
5	Tremval – Eau Claire – Jump River	6/1/2028	$505
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755
8	Beverly – Sub 92	12/31/2028	$231
9	Orient – Denny – Fairport	6/1/2030	$390
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769
11	Maywood – Meredosia	6/1/2028	$301
12	Madison – Ottumwa – Skunk River	6/1/2029	$673
13	Skunk River – Ipava	12/31/2029	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572
15	Sidney – Paxton East – Gilman South – Morrison Ditch	6/1/2029	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261
17	Hiple – Duck Lake	6/1/2030	$696
18	Oneida – Nelson Rd.	12/29/2029	$403
	TOTAL PROJECT PORTFOLIO COST		$10,324

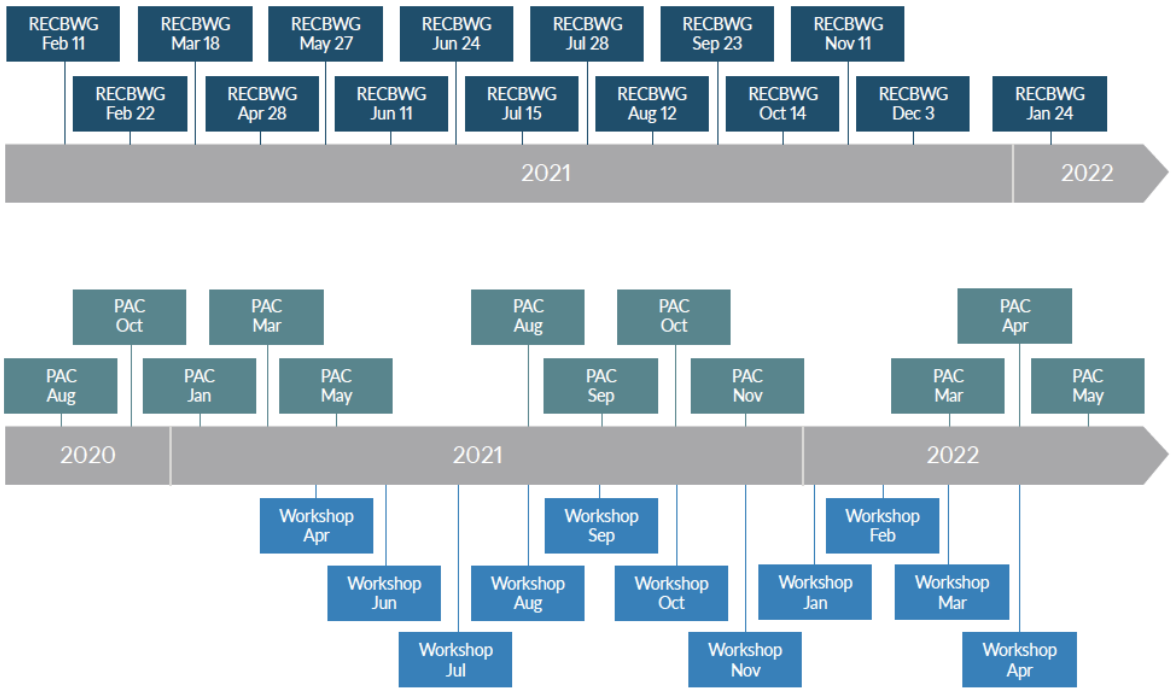
[15] **Exhibit 2**, Fig. 1, p. 2.

In the confidential map for the proposed offshore wind interconnection Duke simply shows the existing network as opposed to an overlay with proposed new lines. Although we can infer these from the text, why not provide a visual aid considering the extensive work Duke performed to communicate the Carbon Plan? Finally, it would have been helpful to have a global view of the base transmission plan corresponding to scenario P1. Duke states Figure P-3 represents $7B of greenfield expansion to "move beyond 2030 toward carbon-neutral CO2 emissions," but a highlighted list as MISO shows would aid transparency, identifying each project and cost together with line-miles (MISO discloses it would cost $10.3B for "over 2,000 line miles").

Q. What substantive changes do you recommend for enhancing stakeholder participation in the transmission planning process?

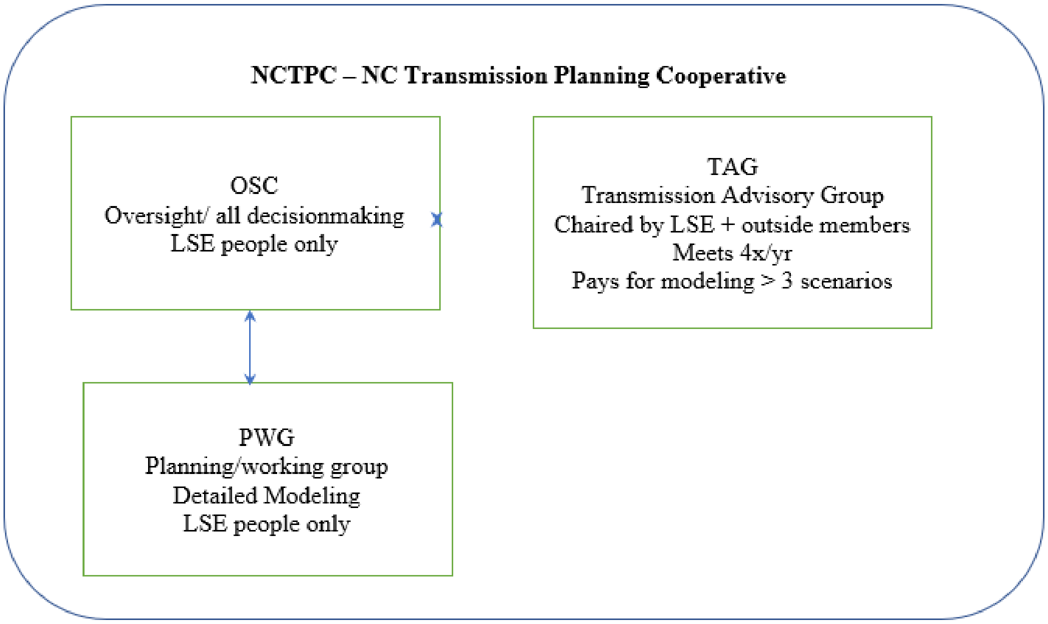
A. Considering that transmission constraints at coal plant sites are a primary driver of new generation scenarios, a process giving stakeholders an early heads-up about these constraints in time to participate in meaningful remediation is essential, together with timely disclosure of technical data sufficient to inform 3rd-party engineering consultants. Otherwise, stakeholders are held captive. The Carbon Plan references $7 Billion of new transmission post-2030, about 70% of the scale of the MISO MTEP21 plan. Such a plan deserves comparable transparency to that of MISO.

As opposed to quarterly meetings with the Transmission Advisory Group (TAG) as part of the NCTPC process, MISO has more regular stakeholder meetings whose schedule is depicted below, showing the participation of the public through the Planning and Advisory Committee (PAC) and Regional Expansion Cost and Benefits Working Group (RECBWG):[16]



By contrast the NCTPC's structure shunts stakeholders to a peripheral role within the Transmission Advisory Group that is so limited, if they request more than three studies per year, individual stakeholders must pay the costs themselves. The real driver is the Oversight/ Steering Committee, managing the analytical activities of the Planning/ Working Group – and both groups are composed solely of Transmission Owners:

[16] **Exhibit 2**, Fig. 6, p. 8.



One option, for discussion purposes, would be to merge the TAG with the OSC so that transmission planning would be directly accountable to all stakeholders. This would, of course, require discussion and planning in its own right. Nevertheless, a typical regional transmission organization invites stakeholder participation, with dedicated voting rights for non-utility generators, project developers, transmission owners, municipal utilities, public consumer advocates, end-use customers, environmental groups and regulators. Since regulators have a statutory role reviewing Duke's proposals it would save time if regulators participated in the formation of those plans as opposed to receiving them when they are already baked and harder to change.

I would urge the Commission to consider necessary revisions to Duke's open access transmission tariff, charged with revising its attachment N-1, detailing the planning process consistent with the above recommendations giving stakeholders full participation.

Q. Does this conclude your testimony?

A. Yes.

Summary of direct testimony of Dinos Gonatas on behalf of CCEBA

The purpose of my testimony is to discuss and opine on certain issues related to transmission planning and implementation in Duke's territories in North Carolina. Duke presented its Carbon Plan, supported by its direct testimony and rebuttal comments in support of its strategy. Elements provoking controversy comprised Duke's limitation of new solar capacity to 5.4GW within the "Red Zone" favorable to solar developers and its continued operation of coal plants with their subsequent replacement by gas plants and emerging nuclear technologies, due to transmission constraints at those existing coal sites.

With respect to Red Zone transmission upgrades, I support Duke's initiative to upgrade facilities as a top priority, however I am concerned the limited upgrades detailed in Exhibits 3 & 4 of the Roberts & Farver testimony, while necessary, are not sufficient to fully enable even 5.4GW of solar interconnections. Duke details a list of upgrades that, primarily, are on 115kV lines. Only three upgrades involve re-conductoring 230kV lines and no new lines are included.

Duke has not disclosed evidence supporting the "must run" status for its coal plants and the need for their continued operation/ replacement with gas. In fact, operational data shows these plants are turned down considerably from peak thermal efficiency much of the year and there are weeks when the plants do not run. Without a good understanding of their operating conditions, it's impossible to verify Duke's contention these plants must continue to operate into the 2030's.

Duke further precludes meaningful interconnections with PJM and elsewhere, pointing only to a high interconnection tariff with PJM. There is no discussion of ties to the Southern Company. Yet, hydroelectric resources within the Carolinas and elsewhere could be key balancing resources vs solar and offshore wind. Duke has not considered cooperation with Dominion Energy, whose offshore wind projects off the North Carolina coast suggests a good opportunity for savings through joint transmission planning.

The largest weakness in Duke's presentation is the lack of transparency of transmission information. There are shortcomings within the NC transmission planning process that Duke itself recognizes and a lack of accountability to stakeholders. The current process holds stakeholders other than transmission owners at arms-length – making it difficult for them to obtain real time information on scenario development and planning, to ask questions, or to pose alternative scenarios to those modelers executing the actual planning. The key committees in the process as-is contain no stakeholders other than the transmission owners. If a more open model were adopted, similar to other regions where all stakeholders are treated equally instead of deferring to the incumbent utility on all matters, it would be possible to consider alternative ideas at an early stage when implementation could still be feasible. While the utility has a monopoly on electric service, it does not have a monopoly on the best ideas! A transparent system responsible to stakeholders could be beneficial to all, including transmission owners.

MR. QUINN: Good morning, Chair Mitchell. This is Matthew Quinn with NC WARN and Charlotte-Mecklenburg NAACP. We sponsored witness William E. Powers in this matter. On September 2nd of this year we filed and served the prefiled direct testimony of Mr. Powers in this docket. It consisted of 61 pages and one exhibit. There were no confidential information in either.

All parties to this matter have waived cross examination of Mr. Powers, therefore, we would ask that Mr. Powers' in-person attendance at this proceeding be excused. We would ask that Mr. Powers' direct testimony be copied into the record at the appropriate place and time as if he had read it from the stand.

And finally, we would ask that Exhibit 1 to Mr. Powers' testimony be admitted into evidence.

We've not prepared a summary. I see now that people -- that witnesses who are excused can offer summaries. We'd like the opportunity to do so, and I will, with the Chair's permission, file such a summary.

CHAIR MITCHELL: All right. Good morning, Mr. Quinn. Having heard no objection to your motion, I'll allow it. The witness' testimony will be copied into the record as if given orally from the stand, will be copied into the record at the appropriate time, as will the testimony summary to be filed. Exhibits to that testimony or exhibit to that testimony will be accepted into evidence, and your witness is excused from participating in this expert witness hearing.

MR. QUINN: Thank you, Chair Mitchell.

(Whereupon, the prefiled direct testimony of William Powers and summary were copied into the record as if given orally from the stand.)

(Whereupon, Powers Exhibit 1 was admitted into evidence.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	**DIRECT TESTIMONY OF**
Duke Energy Progress, LLC and	)	**WILLIAM E. POWERS FOR**
Duke Energy Carolinas, LLC, 2022	)	**NC WARN AND CHARLOTTE**
Biennial Integrated Resource Plan	)	**MECKLENBURG NAACP**
and Carbon Plan	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William E. Powers, P.E. My business address is Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, CA 92116.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. My employer is Powers Engineering. I am the founder and principal of the company.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am a consulting and environmental engineer with 40 years of experience in the fields of power plant operations and environmental engineering. I have worked on the permitting of numerous combined cycle, peaking gas turbine, micro-turbine, and engine cogeneration plants, and am involved in siting of distributed solar photovoltaic (PV) and battery storage projects. I have been an expert witness is high voltage transmission application proceedings in California, Missouri, and Wisconsin, and have evaluated the impact of rooftop solar and battery storage on electric distribution systems for multiple clients. Furthermore, I have offered reports or testimony in numerous utility resource planning proceedings throughout the country, including in the State of North Carolina.

I began my career converting Navy and Marine Corps shore installation projects from oil firing to domestic waste, including wood waste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo in the 1970's.

I authored "Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego" (2020), "(San Francisco) Bay Area Smart Energy 2020" (2012), and "North Carolina Clean Path 2025" (2017), and I have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources.

I have a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from UNC – Chapel Hill, and I am a registered professional engineer in California and Missouri.

Q. HAVE YOU EVER TESTIFIED BEFORE THE N.C. UTILITIES COMMISSION (THE "COMMISSION") OR ANY OTHER REGULATORY BODIES IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified on behalf of NC WARN in Docket No. E-7, SUB 1214, Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Services in North Carolina, as well as Docket No. E-2, SUB 1219, Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina. Further, I testified on behalf of NC WARN in Docket No. EMP-92, SUB 0, Application of NTE Carolinas II, LLC for a Certificate of Public Convenience and Necessity to Construct a Natural Gas-Fueled Electric Generation Facility in Rockingham County, North Carolina. I have also offered affidavit testimony and reports to this Commission in numerous prior dockets, such as Docket No. E-2, SUB 1089 and Docket No. E-100, SUB 180. Further, I have offered testimony before other utilities commissions across the country, such as the commissions in California, Missouri, and Wisconsin.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is: 1) to address deficiencies in the proposed Carbon Plan filed in the present docket by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"), and 2) to outline why the Commission should adopt an alternative Carbon Plan similar to that prepared by Synapse Energy Economics on behalf of NCSEA *et al.*

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The Commission instructed the parties to this proceeding to address specific Carbon Plan topic areas in its Order of July 29, 2022. This testimony will address the following topic areas from among those listed in the Commission's Order:

I. Modeling—Methodology, Assumptions, and Other Modeling Issues
II. Near-Term Procurement and Development Activity
III. Near-Term Development Activity—Small Modular Reactors
IV. Transmission Planning, Proactive Transmission and RZEP
V. EE/DSM Issues / Grid Edge
VI. Reliability

I. CARBON PLAN MODELING

A. Demand Growth Forecast

Q. DO YOU AGREE WITH THE COMPANIES' DEMAND GROWTH FORECAST?

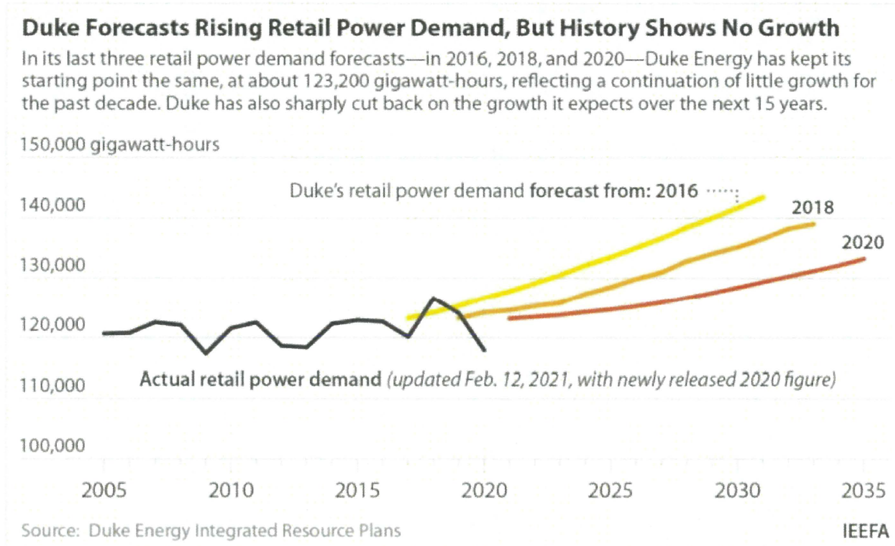
A. In my opinion, the Companies' load growth forecast is flawed and unrealistic. In their "Modeling Panel" direct testimony, the Companies list the four steps they use in developing their demand growth forecasts.[1] These four steps do not include a reality check that would compare the forecast outputs to historic actual annual energy and peak demand trends. As a result, the Companies' proposed Carbon Plan load forecasts show relentless growth, with no mention of the actual load growth trend, with accelerating growth after 2035.[2]

Q. DO THE ACTUAL LOAD GROWTH RATES EXPERIENCED BY THE COMPANIES SUPPORT THE LOAD GROWTH PROJECTIONS IN THE CARBON PLAN?

A. No. The Companies have consistently overestimated demand growth in their respective service territories. In Figure 1 below, I provide a chart prepared by Dennis Wamsted, an Energy Analyst with the Institute for Energy Economics and Financial Analysis, which illustrates the Companies' consistent historical overestimation of load growth:

[1] The Companies' Modeling Testimony, p. 115.
[2] The Companies' Carbon Plan, Appendix E, Figure E-17: Load Sensitivity Analysis - Total System Load Comparison [GWh], p. 97.

Figure 1. Comparison of Duke Energy actual demand growth to forecast demand growth[3]



Q. DESCRIBE SOME OF THE FLAWS IN THE COMPANIES' LOAD GROWTH ANALYSIS SPECIFIC TO DEC.

A. Actual DEC retail sales growth from 2016 through 2021, the most recent five-year period shown in the Carbon Plan, averaged 0.0 percent.[4] Instead, the Companies analyze the period 2012 to 2021 to assert a sales growth rate forecast for DEC of 0.8 percent.[5] 2012 was a relatively low retail sales year, as can be seen in Figure 1 above. Using 2012 as the base year gives the impression of significant demand growth over time, when review of the

---

[3] D. Wamsted - Institute for Energy Economics and Financial Analysis, *Key Shortcomings in Duke's North Carolina IRPs: An Issue-by-Issue Analysis: Part 2*, February 2021: http://ieefa.org/wp-content/uploads/2021/02/Key-Shortcomings-in-Duke-North-Carolina-IRPs_Part-2_February-2021.pdf.
[4] The Companies' Carbon Plan, App. F, p. 16. Table F-14: Electricity Sales (GWh) – DEC.
[5] The Companies' Carbon Plan, App. F, p. 15. "Historical Retail Sales growth over the presented period was 0.9% and 0.8% respectively for DEC and DEP."; p. 19. "Projected Retail sales growth is 0.8% and 0.4% for DEC and DEP."

record going back to 2007 shows no growth. The DEC retail sales growth rate forecast used in the proposed Carbon Plan is not supported by actual historical DEC retail demand.

DEC is projecting in its base-case resource forecast that its annual retail sales will increase by 0.7 percent per year and will rise by an estimated 6,974 GWh by 2035.[6] This is equivalent to the output of two new 500 MW CC plants. Two 500 MW CC plants running at capacity factors of 75 percent would generate about this amount of electricity on an annual basis.[7] The justification for this new capacity would be eliminated with an accurate DEC demand forecast.

Q. DESCRIBE SOME OF THE FLAWS IN THE COMPANIES' LOAD GROWTH ANALYSIS SPECIFIC TO DEP.

A. The Carbon Plan retail sales data shows that actual DEP retail sales declined from 2016 through 2021, the most recent five-year period, at a rate of -0.7 percent.[8] The Companies analyze the period 2012 to 2021 to assert a sales growth rate forecast for DEP of 0.4 percent.[9] As reflected in Figure 1 above, 2012 was a relatively low retail sales year. Using 2012 as the base year gives the inaccurate impression of demand growth over time. In fact, DEP demand is declining.

---

[6] The Companies' Carbon Plan, App. F, p. 20, Table F-16: Forecasted Energy Sales by Class – DEC.

[7] 1,000 MX x 8,760 hr/yr x 0.75 = 6,570,000 MWh/yr.

[8] The Companies' Carbon Plan, App. F, p. 17. Table F-15: Electricity Sales (GWh) – DEP.

[9] The Companies' Carbon Plan, App. F, p. 15. "Historical Retail Sales growth over the presented period was 0.9% and 0.8% respectively for DEC and DEP."; p. 19. "Projected Retail sales growth is 0.8% and 0.4% for DEC and DEP."

Nonetheless, DEP is projecting in its base-case demand growth forecast that its annual retail sales will increase by 0.4 percent per year, rising by an estimated 1,455 GWh by 2035.[10] This projection is simply not supported by the evidence.

Q. WHAT IS THE SIGNIFICANCE OF THE COMPANIES' OVERSTATED LOAD GROWTH PROJECTION?

A. The combined 2035 forecast increase in annual retail sales between DEC and DEP above 2023 demand is 8,429 GWh. This is equivalent to the output of about 1,300 MW of CC capacity running at a capacity factor of about 75 percent.[11] This new capacity would not be justifiable with an accurate demand forecast.

The Companies attribute significant load growth, both annual energy and peak load, to the increase over time of electric vehicles ("EVs").[12] Such load growth is not inevitable. Accelerated growth of net energy metering ("NEM") solar would offset increased energy demand due to EV charging. The Companies recognize this scenario in the Carbon Plan, identifying it as the "high NEM sensitivity" case.[13] Minimizing or eliminating the EV charging contribution to peak load could also be

---

[10] The Companies' Carbon Plan, App. F, p. 21. Table F-17: Forecasted Energy Sales by Class – DEP.
[11] 1,300 MW x 8,760 hr/yr x 0.75 = 8,541,000 MWh/yr (8,541 GWh/yr)
[12] The Companies' Carbon Plan, App. F, pp. 12-15.
[13] The Companies' Carbon Plan, App. E, p. 17. "Base Net Energy Metering ("NEM") growth reflects currently approved net metering rate designs in the Carolinas as of January 1, 2022. The high NEM sensitivity, which is used in the low load forecast, envisions future program offerings that would drive additional NEM growth in the Carolinas . . ."

achieved by structuring the EV tariff to include very high rates during on-peak hours (for example).

The last fifteen years of data on the Companies' annual retail sales (*see* Figure 1 above) and winter peak demand trends[14] provide no basis for projecting any annual energy demand or peak load growth going forward. Much of the CT and nuclear build-out proposed by the Companies in the 2035 to 2050 timeframe is designed to meet load growth that is highly unlikely to materialize.

Q. THE COMPANIES ALLUDE TO GROWTH IN EV ADOPTION AND ELECTRIFICATION AS POTENTIAL DRIVERS OF FUTURE LOAD GROWTH. DO YOU AGREE?[15]

A. Not necessarily. Many of the Companies' customers are already all-electric.[16] As they install more efficient electrical devices over time, customer electric demand may decline. The August 2022 Inflation Reduction Act directs major funding at incentives for high efficiency electrical appliances.[17] EV owners often pair rooftop solar with EV

[14] The Companies' Carbon Plan, App. F, pp. 18-19 (System Peaks).
[15] The Companies' Modeling Testimony, pp. 15 & 55.
[16] The Companies' Response to the Public Staff's Data Request No. 1-2 in NCUC Docket No. E-100 SUB 180 (*see* Tab 4 ("DEC Unit Costs"), lines 11-13). This spreadsheet cannot be filed as an exhibit because it must be provided in native Excel format. This Excel spreadsheet will be provided to any party or Commission staff upon request.
[17] Kiplinger Tax Letter, *Save More on Green Home Improvements Under the Inflation Reduction Act*, August 19, 2022: https://www.kiplinger.com/taxes/605069/inflation-reduction-act-tax-credits-energy-efficient-home-improvements.

ownership.[18] If this pattern continues, much of the electric load increase imposed by EVs will be supplied behind-the-meter and will not result in load growth for the Companies. In short, substantial additional study would be required before any conclusion could be reliably made that growth in EV adoption will materially drive future load growth. At this moment, the Companies' conclusion is purely speculative.

Q. WHAT LOAD GROWTH FORECAST DO YOU RECOMMEND THE COMPANIES USE IN THE CARBON PLAN?

A. The Companies should assume recent actual annual energy and peak demand rates are the best indicator of future trends. The Companies have a substantial degree of control over future growth rates. For example, a favorable NEM tariff will lead to a higher percentage of EV owners also having rooftop solar, to address the EV load and any additional home loads due to electrification.

Q. DID OTHER PARTIES ADOPT A SIMILAR PERSPECTIVE?

A. Yes. The City of Asheville/Buncombe County cautioned that the Commission should not simply assume that higher EV adoption rates and building electrification will necessarily result in an increase in grid power demand. The City of Asheville/Buncombe County stated, "Load forecasts should be adjusted to proactively and accurately account for the impact of demand side management DSM programs and technological advances that

[18] Solar Builder, *Electric vehicles will drive solar installations — and these key home upgrades*, March 14, 2022: https://solarbuildermag.com/featured/electric-vehicles-will-drive-solar-installations-and-these-key-home-upgrades/.

reduce load as well as increased load that may result from transportation and building electrification."[19]

B. Modeling Inputs and Assumptions Regarding Reliability

Q. DO YOU HAVE CRITICISMS REGARDING THE COMPANIES' MODELING INPUTS AND ASSUMPTIONS ON THE ISSUE OF RELIABILITY?

A. Yes, I have several criticisms regarding the Companies' modeling inputs and assumptions on the reliability issue. In fact, the Companies' modeling errors related to the reliability issue directly led the Companies to propose an unnecessary and prolonged reliance upon coal-fired generation.

Because these reliability issues involve the Companies' modeling, I will address these issues under the present "Modeling" topic. Subsequently, I will address other reliability issues under a separate "Reliability" topic appearing separately below.

Q. DO YOU AGREE WITH THE COMPANIES THAT A 17% WINTER PLANNING RESERVE MARGIN CREATES SIGNIFICANT RISK OF OVER-RELIANCE ON NON-FIRM MARKET PURCHASES?

A. No. In the last two winters the Companies have left many thousands of MW of coal capacity and combustion turbine ("CT") capacity idle at the winter peak, and dispatched no DSM resources, and imported relatively little non-firm power from neighboring balancing authorities. In their prefiled direct

[19] City of Asheville/Buncombe County Comments, p. 3.

testimony, the Companies present the high-capacity factors of their coal units during a week-long January 2018 cold snap to imply this one week is representative of the critical role the coal units play during winter peak load events generally.[20] The Companies also assert that their CTs play this same vital role.[21]

Actual operating data for the Companies' coal and CT fleets during the winter of 2020/2021 and 2021/2022 tell a different story. There is a large excess of coal capacity and CT capacity that goes unused, with little reliance on non-firm imports (excluding inter-Companies transactions) from neighboring balancing authorities. Below, Table 1 summarizes the circumstances of the highest winter peak hour in 2020/2021 and the highest winter peak hour in 2021/2022 for the Companies. Table 2 (below) summarizes the quantity of coal unit capacity, CT capacity, and DSM that was not utilized to meet the winter peak hours summarized in Table 1. Also below, Table 3 lists the relatively small amount of non-firm imports relied on by the Companies to meet the winter peak demand for the winter peak hours summarized in Table 1.

[20] The Companies' Reliability Testimony, Table 1: Coal Generation Capacity Factors for January 2-8, 2018, p. 68.
[21] The Companies' Transmission Testimony, pp. 73-74.

Table 1. Summary of Conditions During the Companies' Highest Coincident Winter Peak Hours, Winter 2020/2021 and Winter 2021/2022

Date, hour	Demand, MW	Winter peak hour demand ranking	DSM dispatched, MW
February 4, 2021, hour ending 8 am:			
DEC	15,583	1st highest, 2020/2021	0
DEP	11,815	2nd highest, 2020/2021	0
January 27, 2022, hour ending 8 am:			
DEC	16,282	1st highest, 2021/2022	0
DEP	12,746	6th highest, 2021/2022	0

DEP 1st highest actual winter peak demand hour in winter 2020/2021 was 11,984 MW on January 29, 2021 in the hour ending at 8 am. DEP 1st highest actual winter peak demand hour in winter 2021/2022 was 13,148 MW on January 23, 2022 in the hour ending at 8 am. *See* Companies' Response to the Public Staff's Data Request Nos. 4-1, 4-2 & 26-2.

Table 2. Coal, CT, and DSM Capacity Not Used During Companies' Highest Coincident Winter Peak Hours, Winter 2020/2021 and Winter 2021/2022

Date, hour	Coal used/ idle, MW	CT used/ idle, MW	DSM used/ idle, MW	Coal, CT, DSM idle, MW
Total Companies' coal winter capacity = 9,294 MW; CT capacity = 6,147 MW.				
Feb. 4, 2021, 8 am	5,773/3,521	2,711/3,436	0/700	7,657
Jan. 27, 2022, 8 am	6,187/3,107	2,699/3,448	0/700	7,255

Note: Total Companies' coal winter capacity = 9,294 MW; CT winter capacity = 6,147 MW. See 2022 Carbon Plan, Appendix D, Table D-1 (p. 2) and Table D-2 (p. 5). Companies' DSM capacity = 700 MW. See 2022 Carbon Plan, Appendix G, Table G-12 (p. 27).

Q: THE COMPANIES STATE THAT THEY RELY ON NON-FIRM IMPORTS TO OFFSET 6.5 PERCENT OF THE 23.5 PERCENT RESERVE MARGIN WHICH THEY WOULD NEED TO OPERATE DURING "ISLAND" MODE TO REDUCE THE RESERVE

MARGIN TO 17 PERCENT.[22,23] DID THAT HAPPEN AT THE WINTER PEAKS IN 2020/2021 AND 2021/2022?

A. No. The Companies relied on substantially less non-firm imports (excluding inter-Companies exchanges) at the 2020/2021 and 2021/2022 winter peaks. Slightly more than 1,000 MW of non-firm imports were relied on by the Companies to meet the 2020/2021 and 2021/2022 coincident winter peaks, as shown in Table 3 below.

Table 3. Non-Firm Imports Relied On By Companies' During Highest Winter Peak Hours, Winter 2020/2021 and Winter 2021/2022

Date, hour	DEC total imports, MW	DEC imports w/o imports from DEP, MW	DEP total imports, MW	DEP imports w/o imports from DEC, MW	Companies coincident peak demand, MW	Non-Companies imports, % of coincident peak demand
02/4/21, 8 am	1,433	1,031	0	0	27,398	3.8
1/27/22, 8 am	1,636	1,151	0	0	29,028	4.0

Source of imports data: Duke Energy DR response NC WARN DR 3-3.

Q. WHAT WOULD THE QUANTITY OF NON-FIRM IMPORTS HAVE BEEN IF THE COMPANIES HAD REACHED THE "6.5 PERCENT OF TOTAL RESERVE MARGIN" TARGET FOR NON-FIRM IMPORTS?

[22] The Companies' Modeling Testimony, p. 108.

[23] *See* the Companies' 2020 IRPs filed in NCUC Docket No. E-100 SUB 165. DEC's 2020 IRP, p. 72: "The Base Case reflects a 6.5% decrease in reserve margin compared to the Island Case (from 22.5% to 16.0%). Thus, approximately 29% (6.5/22.5 = 29%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market." DEP's 2020 IRP, p. 74: "The Base Case reflects a 6.25% decrease in reserve margin compared to the Island Case (from 25.5% to 19.25%). Thus, approximately one quarter (6.25/25.5 = 25%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market."

A. Using the actual winter peaks as the point of reference, the amount of non-firm imports relied on to meet the 2020/2021 coincident winter peak, if they equaled 6.5 percent of the reserve margin, would have been 2,199 MW.[24] The amount of non-firm imports relied on to meet the 2021/2022 coincident winter peak, if they equaled 6.5 percent of the reserve margin, would have been 2,330 MW.[25]

Q. IS THIS QUANTITY OF NON-FIRM IMPORTS USED TO MEET THE WINTER PEAK CONSISTENT WITH THE COMPANIES' CALCULATIONS?

A. Yes. The Companies' witness Farver states "Reiterating what the Companies communicated to the Commission in the 2020 IRP Technical Conference, the Companies' Resource Adequacy study accounts for nearly 2,000 MW of non-firm assistance from neighboring systems during peak demand periods."[26]

Q. SO THE COMPANIES WERE SHORT, RELATIVE TO THEIR NON-FIRM IMPORTS TARGET, BY ABOUT 1,000 MW AT THE 2020/2021 AND 2021/2022 WINTER PEAKS?

A. Yes. 1,031 MW of non-firm imports were utilized by the Companies to meet the 2020/2021 winter peak, not 2,199 MW. 1,151 MW of non-firm imports were utilized to meet the 2021/2022 winter peak, not 2,330 MW. In each case, the Companies collectively underutilized non-firm imports. Had the

---

[24] (27,398 MW x 1.235) x 0.065 = 2,199 MW.
[25] (29,028 MW x 1.235) x 0.065 = 2,330 MW.
[26] The Companies' Transmission Testimony, p. 61.

non-firm imports target been met, the Companies could have idled more than 1,000 MW of additional Companies-owned generation that would have been substituted with non-firm imports. For example, more than 1,000 MW of the Companies' coal capacity that was online to meet the winter peak could have been idled.

Q. **DID THE FAILURE TO REACH THE NON-FIRM IMPORTS TARGET COMPROMISE THE COMPANIES' RESERVE MARGIN DURING THE COMPANIES' 2020/2021 AND 2021/2022 WINTER PEAKS?**

A. No. Below, Table 4 summarizes the Companies' dispatched and unused coal, CT, and DSM capacity at the 2020/2021 and 2021/2022 winter peaks. Over 7,000 MW of this capacity was not utilized to meet the 2020/2021 and 2021/2022 winter peaks.

Table 4. Coal, CT, and DSM Capacity Not Used During Companies' Highest Winter Peak Hours, Winter 2020/2021 and Winter 2021/2022

Date, hour	Coal used/ idle, MW	CT used/ idle, MW	DSM used/ idle, MW	Coal, CT, DSM idle, MW
Feb. 4, 2021, 8 am	5,773/3,521	2,711/3,436	0/700	7,657
Jan. 27, 2022, 8 am	6,187/3,107	2,699/3,448	0/700	7,255

Table 5 (below) summarizes the actual equivalent planning reserve margins at the 2020/2021 and 2021/2022 coincident winter peaks, considering only 1) actual non-firm imports and 2) unused coal, CT, and DSM capacity to calculate the reserve margin.[27] Table 5 clearly demonstrates that the Companies' actual reserve margins during the 2020/2021 and 2021/2022 winter peaks were ample.

Table 5. Calculated Actual Winter Peak Equivalent Planning Reserve Margins ("PRMs") for DEC and DEP in the Winters of 2020/2021 and 2021/2022

Winter peak year	Coincident winter peak, MW	Unused coal, CT, and DSM, MW	Reserve margin at actual peak, %
2020/2021	27,398	7,657	27.9
2021/2022	29,028	7,255	25.0

Q. ARE THE COMPANIES' ACTUAL 2020/2021 AND 2021/2022 COINCIDENT WINTER PEAK LOADS SHOWN IN TABLE 5 REPRESENTATIVE OF "TYPICAL YEAR" COINCIDENT WINTER PEAK LOADS FOR THE COMPANIES?

A. Yes, especially the 29,028 MW coincident winter peak in the winter of 2021/2022. The last 10-year average, 5-year average, and 2-year average winter peak actual demand for DEC and DEP are shown in Table 6. These are non-coincident actual winter peak values for each utility.[28] The 2021/2022 DEC actual winter peak demand of 16,282 MW falls between the most recent 5-year and 2-year DEC averages, while the 2020/2021 DEC actual winter peak demand of 15,583 MW was incrementally below the most recent 2-year average of 15,933 MW.

[27] The Companies' idle combined-cycle, nuclear, hydro, or pumped storage capacity during the 2020/2021 and 2021/2022 winter peak hours are unknown by NC WARN *et al.*

[28] Coincident peak values are generally lower, as the Companies rarely experience individual peaks in the same hour.

Table 6. 10-Year, 5-Year, And 2-Year Average Noncoincident Actual DEC and DEP Winter Peak Demand[29]

Utility	10-year average	5-year average	2-year average
DEC	17.048	16,791	15,933
DEP	13,779	13,388	12,566

The 2021/2022 DEP actual winter peak demand of 13,148 MW falls between the most recent 5-year and 2-year DEP averages, while the 2020/2021 DEP actual winter peak demand of 11,894 MW was incrementally below the most recent 2-year average of 12,566 MW.

The planning reserve margin ("PRM") used by the Companies is supposed to be based on the 1-in-2 year peak forecast,[30] or "average year" forecast, and that peak forecast is supposed to be based on actual historic data. The 2021/2022 DEC and DEP actual winter peak loads of 16,282 MW and 13,148 MW, respectively, are representative of actual 1-in-2 year coincident winter peak loads. The 2020/2021 DEC and DEP actual winter peak loads of 15,583 MW and 11,894 MW, respectively, are incrementally below the actual 1-in-2 year winter peak loads.

For the 2020/2021 coincident winter peak, the Companies could have met their 17 percent PRM target with 3,000 MW less reserve

[29] For actual winter peaks in years 2013-2021, see the Companies' Carbon Plan, App. F, p. 18, Tables F-8 and F-9 ("Actual"). For 2022, see Table 1 to the present testimony (above),
[30] North American Electric Reliability Corporation (NERC), *M-1 Reserve Margin*: https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx (accessed on August 28, 2022): "Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in planning horizon . . . Generally, the projected demand is based on a 50/50 forecast."

capacity.[31] If the Companies had met the peak demand non-firm imports target, adding about 1,000 MW to their supply, the 17 percent PRM target could have been met with 4,000 MW less reserve capacity.

That reduction in reserve capacity need could be the permanent closure of 4,000 MW of coal capacity. There was 5,773 MW of the Companies' coal capacity online at the 2020/2021 winter peak. The Companies could have maintained the 17 percent target PRM with the target non-firm imports level and 1,773 MW of coal capacity. The Companies can generate up to 2,618 MW of output from the dual-fuel coal units firing natural gas only.[32] The Companies could have readily met a 1,773 MW demand with their dual-fuel coal units on natural gas only.

For the 2021/2022 coincident winter peak, the Companies could have met their 17 percent PRM target with 2,300 MW less reserve capacity.[33] If the Companies had met the peak demand non-firm imports target, adding more than 1,000 MW to its supply, the 17 percent PRM target could have been met with 3,300 MW less reserve capacity.

---

[31] (27,398 MW + 7,657 MW) – (27,398 MW x 1.17) = 2,999.3 MW.

[32] The Companies' Carbon Plan, App. E, Table E-46, p. E-47. "Cliffside 5 and Marshall 1 and 2 are capable of co-firing on natural gas at 40% capacity. However, these units are only able to do so when the other units at these sites are not fully utilizing their natural gas capability." Total dual-fuel coal unit simultaneous output on natural gas: Belews Creek 1: 1,110 x 0.50 = 555 MW; Belews Creek 2: 1,110 x 0.50 = 555 MW; Cliffside 6: 849 MW x 1.00 = 849 MW; Marshall 3 = 658 MW x 0.50 = 329 MW; Marshall 4 = 660 MW x 0.50 = 330 MW. Total simultaneous natural gas-only output from dual-fuel coal units = 2,618 MW. Total non-simultaneous dual-fuel unit natural gas capacity is 3,150 MW (The Companies' Carbon Plan, Introduction, p. 2).

[33] (29,028 MW + 7,255 MW) – (29,028 MW x 1.17) = 2,300.2 MW.

In the case of the 2021/2022 winter peak, that reduction in reserve capacity need could be the permanent closure of 3,300 MW of coal capacity. There was 6,187 MW of the Companies' coal capacity online at the 2021/2022 winter peak. The Companies could have maintained the 17 percent target PRM with the target non-firm imports level and 2,887 MW of coal capacity.[34] As noted, the Companies can generate up to 2,618 MW of output from the dual-fuel coal units firing natural gas only. The Companies could largely meet a 2,887 MW demand with their dual-fuel coal units firing natural gas only.

Q. ARE THE COAL-ONLY UNITS IN THE COMPANIES' COAL PLANT INVENTORY EXPENSIVE TO OPERATE AND POTENTIALLY UNRELIABLE?

A. Yes. DEP has two coal-only plants, Mayo (one unit, 713 MW) and Roxboro (four units, 2,462 MW).[35] Mayo is nearly 40 years old and very costly to operate at $90/MWh.[36] Roxboro has a production cost of $54/MWh.[37] The average age of the Roxboro units is 50 years.[38] Roxboro is a prime example, due to the age of the coal units there, of the Companies' statement in their proposed Carbon Plan that "The Companies' remaining coal facilities are nearing the end of their technical and economic life and becoming riskier to

[34] 6,187 MW -3,300 MW = 2,887 MW.
[35] The Companies' Carbon Plan, App. D, p. 2, Table D-1.
[36] DEP's 2020 FERC Form 1, April 15, 2021, p. 403. Mayo, line 35, expenses per net KWh = $0.0897 ($89.70/MWh).
[37] Ibid, p. 402.1 (Roxboro, $0.0538/kWh).
[38] Ibid.

operate; thus, retirement is increasingly inevitable."[39] All DEC coal units, except for Allen Units 1 and 5 which are projected to be retired in early 2024,[40] are dual-fuel and can operate at partial load or full load on natural gas.

Q. BASED ON HOW THE COMPANIES MET THE 2020/2021 AND 2021/2022 ACTUAL COINCIDENT WINTER PEAKS, CAN THE COMPANIES MEET WINTER PEAK DEMAND WITHOUT FIRING COAL?

A. Yes. The Companies have sufficient excess capacity in their supply portfolios, and sufficient underutilized non-firm imports supply, to immediately eliminate coal-only units from their portfolios. The remaining dual-fuel coal units have a combined simultaneous output capacity on natural gas of 2,618 MW. This is a sufficient capacity contribution to assure the Companies can meet the "typical year" winter peak demand with a 17 percent reserve margin.

Q: THE COMPANIES EXPRESS DOUBT ABOUT THE AVAILABILITY OF NON-FIRM IMPORTS IN THE FUTURE. DO THE WINTER RESERVE MARGINS IN NEIGHBORING BALANCING AUTHORITIES CITED IN THE COMPANIES' DIRECT TESTIMONY SUPPORT THIS CLAIM?

---

[39] The Companies' Carbon Plan, Introduction, p. 4.
[40] Ibid, App. E, p. 45. "Additionally, the remaining Allen units, units 1 and 5, were modeled to be retired by the beginning of 2024, consistent with transmission project under construction in DEC to enable the retirement of these units."

A. No. The Companies go to considerable lengths to document the more conservative winter planning reserve margins being applied by neighboring balancing authorities to make the case that the Companies' winter 17 percent PRM is reasonable.[41] All neighboring balancing authorities listed by the Companies, with the exception of Virginia Electric Power Company, have winter PRMs of 20 percent or greater. The Companies have provided no evidence that neighboring balancing authorities will be less able in the future to provide non-firm imports than they are now.

C. Modeling Assumptions Regarding Capital Costs

Q. HAVE THE COMPANIES MADE CRITICAL ERRORS IN THEIR CAPITAL COST ASSUMPTIONS FOR CTs AND CCs?

A. Yes. The lack of any publicly-available CT and CC $/kilowatt ("$/kW") capital cost information in the Carbon Plan is a major flaw from the standpoint of assessing the validity of the portfolios without signing a non-disclosure agreement ("NDA").

In the Companies' earlier iteration of a climate action plan, the 2020 Climate Report, the Companies publicly identified capital cost assumptions of $650/kW for CCs and $550/kW for CTs.[42] The inclusion of specific capital cost estimates for the CTs and CCs allowed other parties to

[41] The Companies' Modeling Testimony, Table 7, p. 107.
[42] The Companies' 2020 Climate Report, p. 24: Combustion Turbines – $550/kilowatt (kW) (represents multi-unit site); Combined Cycle – $650/kW (represents 2x1 advanced class).

corroborate the accuracy of those estimates through comparisons to recent CC and CT projects built by the Companies.

The Companies have actual recent experience building both CC and CT projects. The capital costs of these CC and CT projects are known. These are the CC and CT capital costs that should be used in the Carbon Plan modeling and not hypothetical, generic values which are revealed only to parties willing to sign an NDA.

The actual capital cost of the 560 MW Asheville combined cycle plant, which came online in 2020, was $817 million.[43] This is equivalent to a unit CC cost of about $1,460/kW,[44] over double the Companies' assumed CC cost of $650/kW in the 2020 Climate Report. The same National Renewable Energy Laboratory ("NREL") database that the Companies reference as the basis for their solar and battery storage costs in their proposed Carbon Plan identifies a generic mid-range capital cost for CC plants of $1,044/kW in 2021, declining only slightly to $977/kW in 2035.[45] Presumably the Companies did not use this same NREL 2021 Annual Technology Baseline ("ATB") moderate scenario data for the CC capital

[43] Duke Energy News Center, *Duke Energy Progress customers receiving 560 megawatts of cleaner energy from new natural gas power plant in North Carolina*, July 22, 2020: https://news.duke-energy.com/releases/duke-energy-progress-customers-receiving-560-megawatts-of-cleaner-energy-from-new-natural-gas-power-plant-in-north-carolina.
[44] $817,000,000 ÷ 560,000 kW = $1,459/kW.
[45] NREL, Electricity Annual Technology Baseline (ATB) 2021, "Fossil Energy Technologies" tab, Natural Gas FE CT Ave CF, webpage accessed July 2, 2022. https://atb.nrel.gov/electricity/2021/fossil_energy_technologies.

cost, as they did for solar and battery storage, because the value was inconveniently high.

The capital cost of the 402 MW Lincoln CT, the most recent example of a CT built and owned by the Companies, is not public information and was filed with the Commission under seal.[46] For this reason, I assume the CC cost multiplier of the Asheville CC plant, which is more than double the generic CC cost assumption used by the Companies in the 2020 Climate Report, also applies to new CTs. This is equivalent to a unit CT cost of approximately $1,250/kW,[47] compared to the Companies' assumed CT cost of $550/kW in the 2020 Climate Report. Also, the NREL ATB database referenced by the Companies identifies a generic mid-range capital cost for CTs of $919/kW in 2021, declining to $823/kW in 2035.[48]

The Companies rely on the NREL ATB database for capital cost values for some generation sources, but opt to develop distinct proprietary values for the CCs and CTs in the Carbon Plan. This choice by the Companies implies that they found the NREL ATB CC and CT capital costs to be too high to support the CC and CT capacity the Companies desired in the Carbon Plan portfolios.

---

[46] *See* NCUC Docket No. E-7 SUB 1134.

[47] Adjusted combustion turbine unit cost: ($1,460/kW ÷ $650/kW) x $550/kW = $1,235/kW.

[48] NREL, Electricity Annual Technology Baseline (ATB) 2021, "Fossil Energy Technologies" tab, Natural Gas FE CT Ave CF, webpage accessed July 2, 2022. https://atb.nrel.gov/electricity/2021/fossil_energy_technologies.

Q. WHAT CAPITAL COST ASSUMPTIONS SHOULD THE COMPANIES USE FOR THE CTs AND CCs IN THEIR PROPOSED CARBON PLAN PORTFOLIOS?

A. The Commission should direct the Companies to use the final capital cost of the Lincoln 402 MW CT and the Asheville 560 MW CC as the base case 2022 capital cost assumptions for CTs and CCs in the Carbon Plan portfolio modeling.

Q. DO COMPETING UTILITIES IDENTIFY SOLAR PLUS STORAGE ("SPS") AS SUPERIOR TO OTHER GENERATION OPTIONS FOR COST REASONS, INCLUDING GAS-FIRED GENERATION?

A. Yes. Other investor-owned utilities operating in the markets of the Companies' sister operating companies view solar plus battery storage as a superior alternative to CTs for cost reasons alone. For instance, NextEra Energy, parent company of Florida Power & Light ("FPL"),[49] states that "batteries are now more economic than gas-fired peakers (CTs), even at today's natural gas prices."[50] FPL is the largest investor-owned utility in Florida.[51] NextEra Energy also forecasts the production cost of solar plus battery storage is less than the production cost of an existing CT.[52]

---

[49] Companies owned by NextEra Energy: https://www.nexteraenergy.com/company/subsidiaries.html.

[50] GreenTech Media, *NextEra looks to spend $1B on energy storage in 2021*, April 22, 2020.

[51] EIA, *Florida Electricity Profile 2020* (*see* Table 3, "Top five retailers of electricity, with end use sectors"): https://www.eia.gov/electricity/state/florida/.

[52] NextEra Energy, Investor Conference 2022, PowerPoint, June 14, 2022, p. 26: https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/news-and-

FPL is far larger than Duke Energy Florida, with 114,000 GWh of retail sales in 2020 compared to 39,000 GWh for Duke Energy Florida.[53] By way of comparison, the combined DEC and DEP retail sales in North Carolina were 92,000 GWh in 2020.[54]

NextEra Energy included its forecast of late 2020s production costs for selected generation technologies in its June 2022 Investor Conference 2022 presentation.[55] These production costs are summarized in Table 7 below.

Table 7. NextEra Energy Late 2020s Production Costs For Selected Generation Technologies

Generation technology	Production cost, $/MWh
Solar with 4-hour battery storage*	30 - 37
Existing natural gas-fired	35 - 47
Existing nuclear	34 - 49
Existing coal-fired	43 - 74
New natural gas CC	56 - 69

*) Assumes a 4-hour battery to achieve roughly equivalent reliability during peak hours for comparison with dispatchable generation sources.

The relative cost relationships shown in Table 7 hold true for the Companies' units as well. For example, the CT power plant with the lowest

events/events-and-presentations/2022/06-14-2022/June%202022%20Investor%20Presentation_Website_vF.pdf.

53 EIA, *Florida Electricity Profile 2020* (*see* Table 3, "Top five retailers of electricity, with end use sectors"): https://www.eia.gov/electricity/state/florida/. 2020 FPL retail sales = 113,663,998 MWh; 2020 Duke Energy Florida retail sales = 39,230,213 MWh.

54 EIA, *North Carolina Electricity Profile 2020* (*see* Table 3: "Top five retailers of electricity, with end use sectors"): https://www.eia.gov/electricity/state/northcarolina/. 2020 DEC retail sales = 55,703,047 MWh; 2020 DEP retail sales = 36,297,536 MWh. Total 2020 DEC + DEP = 92,000,583 MWh.

55 NextEra Energy, Investor Conference 2022, PowerPoint, June 14, 2022, p. 26: https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/news-and-events/events-and-presentations/2022/06-14-2022/June%202022%20Investor%20Presentation_Website_vF.pdf.

production cost among the Companies' CTs is the 978 MW Rockingham plant, with a production cost of $42 per MWh in 2019.[56] This contrasts with the production cost of DEP's coal-only Roxboro and Mayo plants, which range from $54/MWh to $90/MWh.[57] There are CTs in the Companies' fleet that operate at lower cost than DEP's remaining coal units and are a lower-cost power production option to those coal-only units.

D. Counter Carbon Plan

Q. DID OTHER INTERVENORS TO THE PRESENT DOCKET PROPOSE CARBON PLANS WHICH ARE PREFERABLE TO THE COMPANIES' PROPOSED CARBON PLAN?

A. Yes. For instance, the portfolio prepared by Synapse Energy Economics ("Synapse") for NCSEA *et al.* is far superior to the Carbon Plan proposed by the Companies, and I would support adoption of the Synapse proposal. However, the portfolio developed by Synapse does not include any details on the nature of the utility-scale solar development included in the scope of the portfolio. The Commission should also direct that the utility-scale solar component of the Synapse portfolio prioritize the Distributed Generation SPS described in NC WARN *et al.*'s July 15, 2022 comments filed with the Commission in this proceeding. The Distributed Generation SPS prioritizes solar projects less than 5 MW installed at the distribution grid level in or

[56] DEC's 2019 FERC Form 1, April 14, 2020, p. 403.3 (Rockingham), line 35, $0.043/kWh ($42/MWh).
[57] DEP's 2020 FERC Form 1, April 15, 2021, p. 402.1 (Roxboro, $0.0538/kWh) and p. 403 (Mayo, $0.0897/kWh).

near demand centers (Charlotte, Raleigh-Durham, Greensboro/Winston-Salem), to avoid the delay and cost of the major transmission build-out that would be necessary if much of the new solar capacity is located in the rural transmission "red zones" preferred by the Companies.

II. NEAR-TERM PROCUREMENT ACTIVITY

A. Errors in the Companies' Analysis of Solar Paired with Storage

Q. DID THE COMPANIES MAKE ERRORS RELATED TO THEIR ANALYSIS OF THE LIKELY PERFORMANCE OF SOLAR PAIRED WITH STORAGE ("SPS")?

A. Yes. The Companies include a minimal amount of battery storage in the Carbon Plan in the near term, in part due to "outcome driven" assumptions by the Companies. As discussed in more detail below, the Companies committed the following errors: (a) the Companies undersized the battery storage component of SPS, and (b) the Companies failed to assume for modeling purposes that the storage component of SPS can be charged from either the associated solar array or the grid. These errors constitute serious flaws in the Companies' proposed Carbon Plan portfolios. As a result, the Carbon Plan target of 350 MW of cumulative operational battery storage by the end of 2027 is very limited in light of the actual U.S. battery storage deployment rate of 3,500 MW per year in 2021.[58,59]

Q. DO THE COMPANIES CURRENTLY LAG BEHIND THEIR PEERS IN IMPLEMENTING BATTERY STORAGE?

A. Yes. The Companies' claim in their 2020 IRPs that the electric utility industry has little meaningful experience with batteries is unsupported.[60] However, utility-scale battery storage has been deployed at scale in the U.S. since 2016.[61] Yet in their proposed Carbon Plan, the Companies imply that utility-scale battery storage is still transitioning to full commercial status, and therefore, the Companies propose to add only 350 MW of new battery storage by 2027.[62] The Companies' said assumption is unwarranted.

A specific concern expressed by the Companies in their 2020 Climate Report is the ability of the battery storage industry to manufacture the 15,000 MW of additional four-, six- and eight-hour battery storage by 2030 that the Companies say they would need to avoid adding new gas-fired capacity.[63] The Companies have only 13 MW of operational battery storage

---

[58] The Companies' Carbon Plan, Appendix E, p. 26. ". . . the Carbon Plan assumes the deployment of approximately 350 MW of nameplate capacity (approximately 110 MW in DEC and 240 MW in DEP) with various storage capacity durations through 2027."
[59] Wood Mackenzie, *US battery storage deployment doubles in a single year*, March 24, 2022: https://www.woodmac.com/news/opinion/us-battery-storage-deployment-doubles-in-a-single-year/.
[60] NCUC E-100 SUB 165, DEC's 2020 IRP, p. 23. "The lack of meaningful industry experience with battery storage resources at this scale presents significant operational considerations that would need to be resolved prior to deployment at such a large scale."
[61] Renewable Energy World, *A Brief History of Utility-Scale Energy Storage*, September 19, 2017: https://www.renewableenergyworld.com/storage/a-brief-history-of-utility-scale-energy-storage/#gref.
[62] The Companies' Carbon Plan, App. E, p. 26.
[63] The Companies' 2020 Climate Report, p. 2.

as of May 2022.[64] In contrast, leading balancing authorities have thousands of MW of battery storage online.

The Companies' concern about the ability of SPS to completely displace new gas capacity is misplaced. The Companies are far behind their peers in adopting battery storage. The California Independent System Operator ("CAISO"), which includes three major investor-owned utilities, had about 2,500 MW of operational 4-hour battery storage at the end of 2021 and anticipates having 12,000 MW of battery storage by 2025.[65,66] The California Public Utilities Commission has ordered procurement of 1,000 MW of 8-hour battery storage to complement the 4-hour battery storage fleet.[67] CAISO has an all-time summer peak load of about 50,000 MW, compared to the Companies' combined summer peak record of 34,079 MW.[68,69]

---

[64] The Companies' Carbon Plan, App. K, p. 2, Table K-1: Energy Storage Systems Located in the Carolinas.

[65] CAISO, *Another side of the battery story*, December 8, 2021: http://www.caiso.com/about/Pages/Blog/Posts/Another-side-of-the-battery-storage-story.aspx.

[66] CAISO, *Storage: An intersection between reliability today and climate goals of tomorrow*, September 14, 2021: http://www.caiso.com/about/Pages/Blog/Posts/Storage-An-intersection-between-reliability-today-and-climate-goals-of-tomorrow.aspx.

[67] Ibid. "As penetration of storage grows, managing the system will require that storage resources be of longer duration or that significantly more four-hour resources are built. In fact, the California Public Utilities Commission has already ordered the procurement of 1,000 MW of 8-hour (long duration) storage."

[68] CAISO, *California ISO Peak Load History 1998 through 2021*: https://www.caiso.com/documents/californiaisopeakloadhistory.pdf. All-time peak = 50,270 MW (2006).

[69] By way of comparison, the Companies' combined summer peak record is 34,079 MW. *See* Duke Energy News Center, *Duke Energy Carolinas Customers Set Summertime Record for Electricity Use*, June 15, 2022: https://news.duke-energy.com/releases/duke-energy-carolinas-customers-set-summertime-record-for-electricity-use-6873667.

Grid battery storage capacity is rapidly expanding in the U.S., as shown in Figure 2 below. Battery storage deployments are expected to reach 7,500 MW per year in 2025, of which about 80 percent is grid battery storage. Below, Figure 3 shows that battery storage deployments in 2021 met the 2021 projection in Figure 2 on the pathway to 7,500 MW per year of overall battery storage additions in 2025. The Companies' battery storage installation target through 2027 is 350 MW, about 1 percent of the projected US installed capacity through 2025 shown in Figure 2.[70]

A 2030 target of 15,000 MW of new battery storage would not require a leap in battery production capability. Other utilities are approaching this target much more quickly than 2030. As noted, California investor-owned utilities are projected to have 12,000 MW of grid-tied battery storage online by 2025. The Companies are unlikely to encounter battery storage supply issues if they opt to pursue deployment of 15,000 MW of battery storage by 2030 to avoid the addition of new CC and CT capacity.

[70] The cumulative US installed battery storage capacity through 2025 shown in Figure 2 is approx. 30,000 MW.

Figure 2. U.S. battery storage additions to reach 7,500 MW annually in 2025[71]

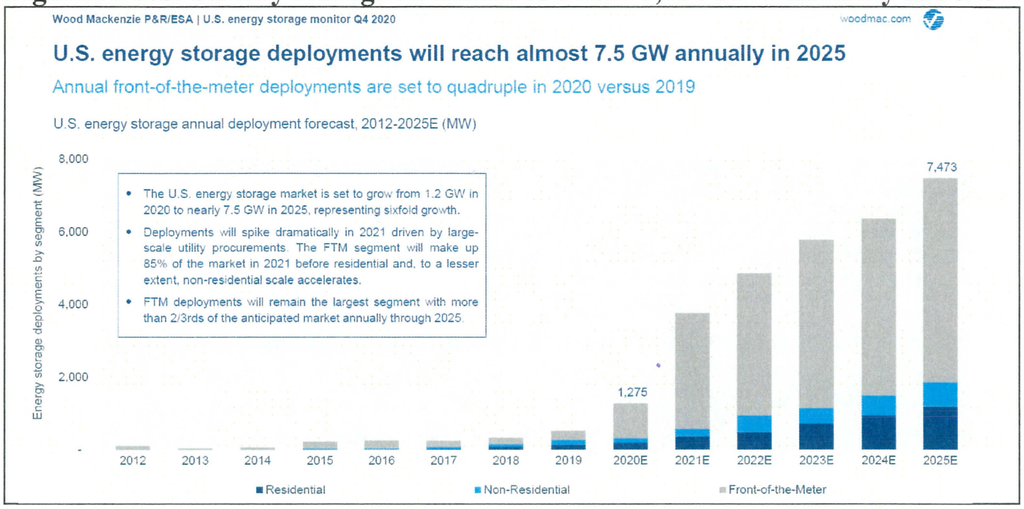
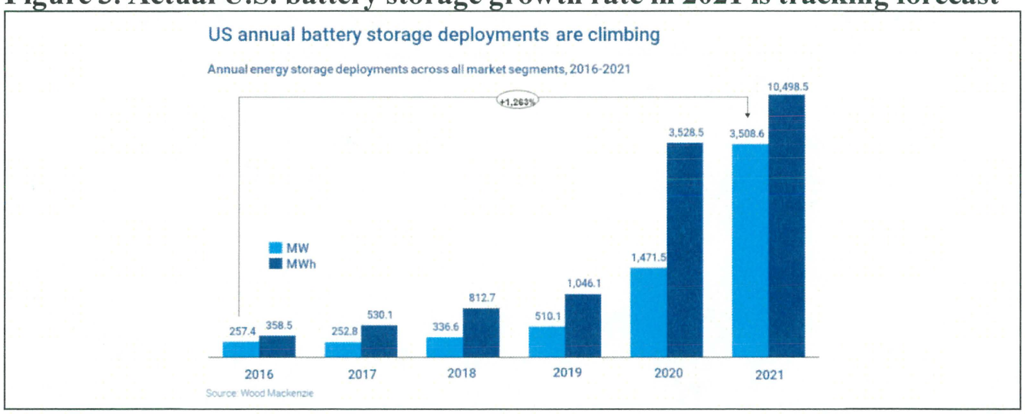


Figure 3. Actual U.S. battery storage growth rate in 2021 is tracking forecast[72]



In light of the above context, it is important to note that the lack of sufficient battery storage in the portfolios is a primary reason that the Companies fill the gap with new CC and CT capacity.

---

[71] Bloomberg Green, *This Is the Dawning of the Age of the Battery*, December 17, 2020: https://www.bloomberg.com/news/articles/2020-12-17/this-is-the-dawning-of-the-age-of-the-battery.

[72] Wood Mackenzie, *US battery storage deployment doubles in a single year*, March 24, 2022: https://www.woodmac.com/news/opinion/us-battery-storage-deployment-doubles-in-a-single-year/. "Overall, 2021 was a record year for grid-scale battery storage deployments with 2.9 GW/9.2 GWh in total, despite over 2 GW being pushed into 2022 and 2023."

Q. DID THE COMPANIES MAKE ANY DEFINITIONAL ERRORS WHICH HAD THE EFFECT OF REDUCING THE COMPANIES' PROPOSED RELIANCE UPON SPS?

A. Yes. The Companies used a misleading definition of solar plus 4-hour battery storage in the Carbon Plan. The generally accepted industry definition of the number of hours of battery storage relative to the nameplate capacity of the solar array is the number of hours of storage at the capacity rating of that solar array. In other words, if the solar array is rated at 75 MW, then four hours of battery storage is 75 MW x 4 hours = 300 megawatt-hours (MWh).

The Companies do not use this definition. The base case SPS system modeled by the Companies is a 75 MW solar array coupled to 20 MW of battery storage with four hours of storage at 20 MW.[73] This results in the equivalent of about one hour of storage at 75 MW, not four hours of storage at the capacity rating of the solar array. The Companies have added an additional SPS configuration at the request of Public Staff, 75 MW solar with 40 MW/160 MWh storage (50% 4-hour storage).[74] However, this additional configuration, while an improvement on the two SPS configurations in the Carbon Plan, is one-half the storage necessary for the SPS to achieve equivalency to a CT.

[73] The Companies' Carbon Plan, App. K, p. 7. "For SPS in the Carbon Plan, the Companies originally intended to only model a 4-hour battery that was sized at 25% of the solar facility, but based on this feedback, the Companies included a 2-hour storage option that was paired with solar, sized at 50% of the solar capacity."
[74] The Companies' Modeling Testimony, p. 151.

Q. **DID THE COMPANIES ACKNOWLEDGE IN THEIR DIRECT TESTIMONY THEIR ERROR IN FAILING TO MODEL THE SPS BATTERIES AS CAPABLE OF BEING RECHARGED WITH GRID POWER TO MAXIMIZE THE RELIABILITY OF THE BATTERIES TO MEET THE WINTER PEAK?**

A. Yes. In their prefiled direct testimony, the Companies state: "The Companies acknowledge that hybrid SPS assets are being designed with bidirectional inverters to enable charging the storage asset with both DC solar energy and grid energy."[75] However, the Companies go on to say that the Encompass model is not yet equipped to model this reality, and will not be until later this year.[76]

Q. **IS THIS A CREDIBLE BASIS FOR NOT ACCORDING THE SPS BATTERIES THE HIGH LEVEL OF RELIABILITY THEY ACTUALLY WILL HAVE AT THE WINTER PEAK?**

A. No. The portfolio modeling performed by the Companies must reflect that the SPS batteries can be charged with grid power to assure battery reliability at the winter peak.

Q. **DESPITE THE COMPANIES' ACKNOWLEDGMENT, ISN'T THE COMPANIES' TESTIMONY STILL FULL OF CLAIMS THAT THE SPS BATTERY STORAGE IS OF LIMITED USEFULNESS TO MEET THE WINTER PEAK BECAUSE THE SPS BATTERIES**

---

[75] The Companies' Modeling Testimony, p. 154.
[76] Ibid.

MAY NOT GET FULLY CHARGED BY SOLAR UNDER INCLEMENT WINTER PEAK CONDITIONS?

A. Yes. Again and again, despite the Companies' acknowledgment that the SPS batteries can charge from the grid if collocated solar power is not available, the testimony contains a drumbeat of assertions to the contrary.

Q. CAN YOU PROVIDE A FEW EXAMPLES?

A. Yes. Examples from the Companies' Modeling testimony and Reliability testimony are provided in Table 8 below.

Table 8. Statements in Companies' Testimony Asserting Limited SPS Battery Reliability

Modeling Testimony, page	Companies' Statement
137	In short, energy limited batteries that need to be charged do not allow for the avoidance of the transmission project to enable these coal retirements.
153	It is likely that if the SPS asset with a larger storage component can only charge from solar there will be times that the storage component will not be fully charged at the time of peak demand and therefore its contribution to meeting peak demand will be diminished.
154	The SPS system was not allowed to be charged from the grid. The only source of charging for the SPS system was the full DC solar energy output of the solar resource that the storage asset was coupled with.
Reliability Testimony, page	
69	However, if the SPS system experienced just one-two cloudy days earlier in that week, there would not be enough energy to charge the batteries to make it through the remainder of the week to supply the equivalent amount of energy as was produced from the Roxboro Plant
70	If the Companies are dependent on renewable energy resources to serve customer demand and to charge battery storage (on cold, snowy, cloudy winter days), energy adequacy becomes a big operational concern.

70	On the low capacity factor days, Duke Energy would not receive enough energy from solar to refill the pumped storage basins, let alone charge four-hour batteries.
73	. . . 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 . . .
74	Not only is solar not well correlated to the Companies' winter load shape, as mentioned previously, winter is the time where solar capacity factors can vary drastically as shown in Figure 10. This day-to-day change would make it difficult, if not impossible, to reliably depend on significant solar energy to store for peaking capacity needed to ensure reliability during an extended cold weather period.

Q. HOW SHOULD THE COMMISSION MOVE FORWARD IN SELECTING A PREFERRED CARBON PLAN PORTFOLIO IF THE COMPANIES' MODELED PORTFOLIOS CONTAIN SUCH SERIOUS FLAWS?

A. The Commission should reject the portfolios advanced by the Companies and select instead an alternative advanced by another party to the proceeding.

Q. WHAT ALTERNATIVE PORTFOLIO WOULD YOU RECOMMEND THE COMMISSION ADOPT?

A. As described more fully above, the Synapse portfolio should be adopted with additional specificity on the development of the SPS component of the portfolio. The solar component of the Synapse portfolio should prioritize utility-scale solar less than 5 MW interconnected at the distribution grid level and located in or near major North Carolina demand centers.

Q. WHAT IS THE SOURCE OF THE "SMALLER SCALE UTILITY SPS INTERCONNECTED AT THE DISTRIBUTION LEVEL CLOSE TO LOAD" ALTERNATIVE THAT YOU PROPOSE?

A. This approach was proposed in NC WARN *et al.*'s July 15, 2022 comments to the Commission in this proceeding as the "Distributed Generation Counter Proposal."

Q. PLEASE PROVIDE MORE DETAIL ON THE SPS ASPECTS OF NC WARN *ET AL.*'S SAID PROPOSAL.

A. Wholesale urban SPS installations would be built on commercial and industrial rooftops, parking lots, available urban parcels with 1 MW+ solar potential, and brownfield sites. Battery storage, with a minimum of 4 hours of storage at the capacity of the paired solar array, would be collocated with all new solar to assure the dispatchability of the solar resource and provide maximum resilience.

The solar potential in North Carolina on commercial rooftops, commercial parking lots, undeveloped large urban parcels, and brownfield (contaminated land) sites is about 67,000 MW (105,000 GWh per year).[77] This is two-and-a-half times the 25,000 MW of new solar capacity that would be needed – by itself with no additional renewable resources – to meet the 2050 carbon-free target in the Carbon Plan.[78] Of the 105,000 MW

---

[77] B. Powers – Powers Engineering, *North Carolina Clean Path 2025*, August 2017, p. 57: https://www.ncwarn.org/wp-content/uploads/NC-CLEAN-PATH-2025-FINAL-8-9-17.pdf.

[78] 1 MWac of installed fixed solar capacity in NC produces about 1,500 MWh per year of solar energy. There is approximately 8,000 MW of existing solar capacity in North

total, about 18,600 MW (~30,000 GWh per year) is rooftop and commercial parking lot PV potential. Open parcels with at least 1 MW solar capacity potential and without restrictive uses in urbanized areas of North Carolina can provide up to 43,000 MW (68,000 GWh per year) of solar capacity. There is also approximately 5,000 MW (8,000 GWh per year) of additional PV that could be developed on contaminated land, known as brownfield sites, in North Carolina. The quantity and distribution of these solar resources are shown in Table 9 below.

Table 9. Estimate of North Carolina Local Solar and Brownfield PV Potential

Unit	Residential rooftop	Commercial/ industrial rooftop	Commercial parking lot	Undeveloped urban > 1 MW parcels	Brown-fields	Total
MW	19,400	9,300	9,300	43,000	5,000	86,000
GWh/yr	30,600	14,700	14,700	68,000	8,000	136,000

Q. DO THE COMPANIES ACKNOWLEDGE THE POTENTIAL TO BUILD SOLAR PROJECTS OUTSIDE OF THE "RED ZONE" AS A WAY TO ACCELERATE SOLAR/SPS DEPLOYMENTS?

A. Yes. The Companies state: "Also, in order to connect the amount of solar intervenors such as CPSA or CCEBA suggest should be modeled, developers would need to locate solar outside of transmission constrained

---

Carolina, producing about 12,000,000 MWh per year. Therefore, sufficient new solar capacity to generate 38,000,000 MWh per year must be added. 38,000,000 MWh/yr ÷ 1,500 MWh/MW = ~25,000 MW.

areas that may be more costly than locations that could be connected once RZEP are completed."[79]

B. The Companies' Proposed Conversion from Natural Gas to "Green Hydrogen"

Q. DO YOU HAVE CONCERNS ABOUT THE COMPANIES' PROPOSED CONVERSION OF NATURAL GAS TO "GREEN HYDROGEN"?

A. Yes. The Companies' proposal is highly speculative and not supported by the evidence.

Q. PLEASE DESCRIBE YOUR CONCERNS REGARDING THE SOURCES CITED BY THE COMPANIES IN FAVOR OF THIS PROPOSED TRANSMISSION TO GREEN HYDROGEN.[80]

A. For example, the Companies relied on a 19-page green hydrogen (H_2) promotional brochure prepared by the Department of Energy's ("DOE") Office of Energy Efficiency and Renewable Energy ("EERE"). That said promotional brochure contains exceptionally low aspirational cost projections for green H_2 production, as support for the future viability of gas turbines operating on 100 percent green H_2. The Companies' extensive reliance upon this short promotional brochure for such a significant planning issue is unrealistic.

[79] The Companies' Modeling Testimony, p. 168.
[80] Ibid, p. 179.

Q. DO THE COMPANIES SIMPLY ASSUME A CONVERSION TO 100 PERCENT GREEN HYDROGEN WILL HAPPEN BY 2050, DESPITE THE UNCERTAINTIES?

A. Yes. The Companies propose a tremendous build-out of CC and CT capacity on the presumption that all gas-fired generation will convert to 100 percent H_2 fuel by 2050, while at the same time acknowledging that the conversion to H_2 may not happen. The Companies, while acknowledging "significant uncertainties" in the future supply of H_2, simply assume that H_2 will be available at scale in 2050 to operate all CCs and CTs on 100 percent H_2. On that basis, the Companies propose to add 800 MW to 2,400 MW of CCs and 6,400 MW to 10,900 MW of CTs to achieve carbon neutrality by 2050.[81]

The Carbon Plan asserts that all CTs and CCs will burn 100 percent H_2 by 2050, if uncertainties around H_2 supply are resolved by then. There is no assessment of what happens with the CTs and CCs if those uncertainties are not resolved by 2050. The issue of stranded costs associated with new gas-fired generation, and who will be responsible for those stranded costs, is not addressed by the Companies in the Carbon Plan or testimony supporting the Carbon Plan.

There also is no accounting in the Carbon Plan for the potentially high capital cost of converting a CC or CT power plant designed to burn

[81] The Companies' Carbon Plan, Chapter 1, p. 31.

natural gas to burn 100 percent H_2. The Companies simply assume that green H_2 will be "readily accessible" in 2050.[82] All elements of the Companies' existing CC and CT power plants that will operate beyond 2050 will likely require major modification to enable use of 100 percent H_2 fuel.[83,84] These elements include: fuel piping component materials, pipe sizes, sensors and safety systems, and gas turbine components exposed to H_2 combustion exhaust gases.[85] There is no indication that the Companies have considered the additional cost of converting the CC and CT power plants to burn 100 percent H_2, or the potentially high fuel cost of green H_2 that will be required.

Q. DO GAS TURBINE MANUFACTURERS ANTICIPATE A WHOLESALE CONVERSION OF GAS TURBINES TO 100 PERCENT GREEN HYDROGEN BY 2050?

A. No. Gas turbine manufacturers envision gas turbines firing 100 percent H_2 as operating infrequently, and then only in regions with high power costs.

---

[82] Ibid, p. 31.

[83] The Companies' Carbon Plan, App. E, p. 23. "A limited number of natural gas resources currently on the system are expected to continue operating in 2050 and beyond. These include the WS Lee CC, the Asheville CCs, Sutton CTs 4 and 5, and Lincoln CT 17. For these combustion units that are planned to remain on the system in 2050, the Carbon Plan assumes these units are converted to hydrogen-fired units near the end of the planning horizon. In the Carbon Plan modeling, these units operate exclusively on hydrogen to comply with the 2050 carbon neutrality target."

[84] Siemens, *Hydrogen power with Siemens gas turbines*, 2020, p. 16: https://www.infrastructureasia. org/-/media/Articles-for-ASIA-Panel/Siemens-Energy---Hydrogen-Power-with-Siemens-Gas-Turbines.pdf?la=en&hash= 1B91FADA342293EFB56CDBE312083FE1B64DA111.

[85] Ibid.

For instance, Siemens, a major European gas turbine manufacturer and the provider of the Companies' 402 MW Lincoln 17 CT, states:[86]

> As significantly, today, running electrolysis to produce 50 MW for one hour at a CCGT running at 50% efficiency could require 175 MW of renewable power and 3,400 kilograms (more than 14,000 gallons) of hydrogen, he said. "So, the affordability part of the equation could be an issue," which is why hydrogen power could prove more economical as short-term (three or four hours a day) renewable support in places such as Europe, he added.

Even this niche for gas turbines burning 100 percent H_2 is undercut by the gas turbine industry's recognition that battery storage is already the preferred technology to fill this shorter-duration power supply role:

> Asked how the technology will compete against advancements in battery storage, Browning (Mitsubishi Hitachi Power Systems) said, "We think lithium-ion batteries will probably be the right choice if you want to store electricity for shorter periods of time." The economics of hydrogen "are going to work no matter how long you store it," he noted.

Utility-scale solar plus lithium-ion battery storage is already a more cost-effective alternative to a CT burning natural gas according to the power industry itself.[87] Utility-scale long-duration lithium-ion battery storage systems are being installed now. There will be no obvious power generation "gap" for gas turbines firing H_2 blends or 100 percent H_2, operating only a few hours a day, to fill in the future.

---

86 Power Magazine, *High-Volume Hydrogen Gas Turbines Take Shape*, September 2019: https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/.

87 GreenTech Media, *NextEra looks to spend $1B on energy storage in 2021*, April 22, 2020: https://www.greentechmedia.com/articles/read/nextera-energy-to-spend-1b-on-energy-storage-projects-in-2021.

C. The Companies' Natural Gas Price Projections

Q. DO YOU HAVE CONCERNS ABOUT THE COMPANIES' NATURAL GAS PRICE PROJECTIONS?

A. Yes. As described below, the Companies' natural gas price projections fail to adequately recognize the volatility in the natural gas market and are unrealistically optimistic.

Q. DID THE COMPANIES MAKE ANY ATTEMPT TO CROSS-CHECK OR ADJUST THEIR LOW AND CONSISTENT NATURAL GAS PRICE FORECAST WITH VOLATILE NATURAL GAS PRICES OF THE LAST 10-15 YEARS?

A. No. The Companies' testimony on this issue suffers the same weakness as their demand forecast testimony. There was no look-back to assess how accurate the natural gas price forecasts have been relative to the actual natural gas prices.

Q. HAS HIGH VOLATILITY BEEN A DEFINING FEATURE OF ACTUAL NATURAL GAS PRICES OVER THE LAST 15-20 YEARS?

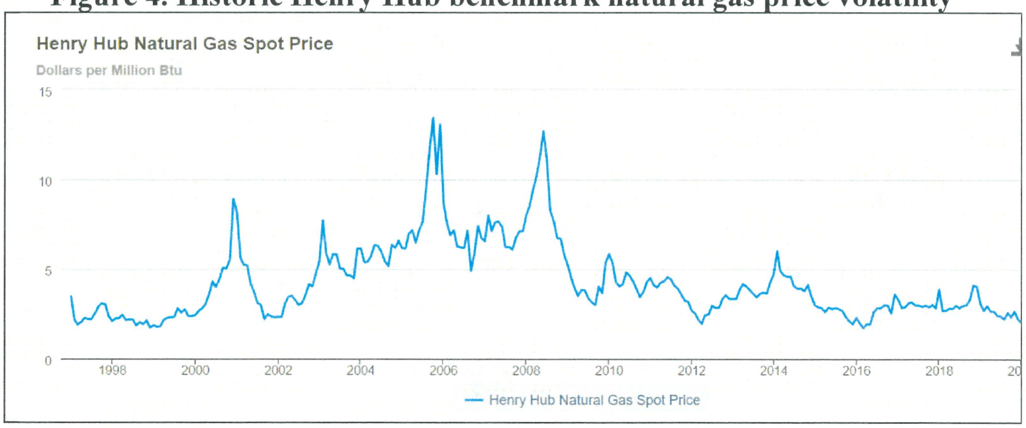
A. Yes. The Carbon Plan acknowledges significant natural gas price risk, though only in the context of potentially insufficient firm natural gas pipeline capacity to supply the proposed new gas-fired capacity. The

Companies address this risk in a sensitivity analysis by displacing CC capacity with battery storage and CTs.[88]

Q. HOW VOLATILE HAVE NATURAL GAS PRICES BEEN OVER THE LAST 15-20 YEARS?

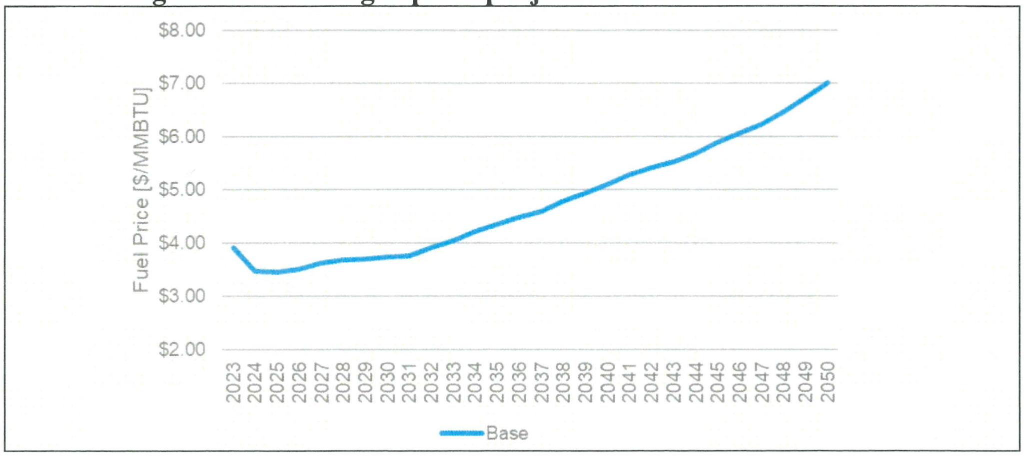
A. Actual natural gas prices have been quite volatile. Natural gas price volatility has been an inherent feature of the natural gas market, as shown in Figure 4 below. Natural gas prices have been especially volatile in 2022, with the May 2022 Henry Hub price over $8 per million Btu. Western Europe has become a high-demand, priority delivery point for U.S. natural gas in the form of LNG as a result of the Ukraine war, driving increases in U.S. natural gas prices. Yet the Companies' proposed Carbon Plan assumes a low base price for natural gas, under $4/MMBtu through 2032 rising to $5/MMBtu in 2040, as shown in Figure 5 below.

Figure 4. Historic Henry Hub benchmark natural gas price volatility[89]



[88] Methane is not mentioned in the Companies' proposed Carbon Plan. Methane is a much stronger greenhouse gas than CO_2. However, there is no mention in the proposed Carbon Plan of upstream methane emissions from the production of natural gas and the impact of those methane emissions on climate.
[89] EIA, Natural Gas, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm (accessed July 3, 2022).

Figure 5. Natural gas price projection in the Carbon Plan[90]



Q. DOES SOLAR POWER EXHIBIT PRICE VOLATILITY OVER TIME?

A. No. There is no price volatility over time in the price (free) or availability of solar power.

III. NEAR-TERM DEVELOPMENT ACTIVITY—SMALL MODULAR REACTORS

Q. DO YOU HAVE CONCERNS ABOUT THE COMPANIES' PROPOSED RELIANCE UPON SMALL MODULAR REACTORS?

A. Yes. Small modular reactors ("SMRs") are an unproven option without any history of success in the power industry, and in addition, SMRs are not economically viable.

Q. PLEASE DESCRIBE HOW THE COMPANIES HAVE FAILED TO PROVE THAT SMRs ARE ECONOMICALLY VIABLE IN PRACTICE?

---

[90] The Companies' Carbon Plan, App. E, p. 40, Figure E-6: Base Henry Hub Natural Gas Price Forecast [$/MMBtu].

A. The Companies include SMRs in all four Carbon Plan portfolios, despite the present lack of a commercially viable SMR. Bringing reliable and cost-effective SMRs into the marketplace remains highly speculative and high-risk, in spite of numerous SMR developers putting in years of effort. The challenges include unproven and challenging designs, cost viability and economies-of-scale, lack of full regulatory or investor approval, radioactive waste, safety and security, and competition from cheaper, safer alternatives. Any combination of these uncertainties remaining unresolved would make construction of SMRs unlikely.

Q. ARE THERE ANY PROMINENT EXAMPLES WHICH ILLUSTRATE YOUR POINT THAT SMRs ARE BOTH IMPRACTICAL AND NOT ECONOMICALLY VIABLE?

A. Yes. This situation is reminiscent of the decade-plus effort by Duke Energy and other United States utilities to design, license and construct the Westinghouse AP1000 reactor as part of the last "nuclear renaissance" beginning in 2005.[91] The effort ended in cancellation of all but one of the more than a dozen twin-reactor AP1000 projects that reached some stage of planning, licensing or construction. Billions of dollars in stranded costs were passed along to ratepayers, primarily across the Southeast. Duke Energy cancelled the last of its three failed projects in 2017.

[91] The Guardian, *Reviving nuclear power debates is a distraction. We need to use less energy*, November 7, 2013: https://www.theguardian.com/commentisfree/2013/nov/08/reviving-nuclear-power-debates-is-a-distraction-we-need-to-use-less-energy.

The manufacturer Westinghouse and utilities such as Duke Energy had claimed that the "Advanced Passive (AP) 1000" reactor would avoid the large cost overruns and mid-stream cancellations of the first generation of US nuclear power plant construction projects. That promise was largely based on plans for off-site construction of various modules that could then be pieced together at each proposed site. The AP1000 plan was not successful. In fact, the sole US AP1000 project still underway, Plant Vogtle Units 3 and 4 in Georgia, is years behind schedule with a cost of over $30 billion.[92] The same promise of off-site, modular construction used with the AP1000 is central to the promotion of SMRs.

NuScale, considered the leading US developer of SMR technology, is years behind schedule. Cost estimates for its SMR are speculative, as no units have yet been built or operated.[93]

NuScale reached agreement with Utah Associated Municipal Power Systems (UAMPS) in 2017 to build twelve 50 MW modules that would come online in 2024.[94] Later, the plan changed to six 77 MW modules

---

[92] GPB News, *Georgia nuclear plant's cost now forecast to top $30 billion*, May 9, 2022: https://www.gpb.org/news/2022/05/09/georgia-nuclear-plants-cost-now-forecast-top-30-billion.

[93] IFEEA, *NuScale's Small Modular Reactor - Risks of Rising Costs, Likely Delays, and Increasing Competition Cast Doubt on Long-Running Development Effort*, February 2022, pp. 6-9: https://ieefa.org/wp-content/uploads/2022/02/NuScales-Small-Modular-Reactor_February-2022.pdf.

[94] Utility Dive, *NuScale makes public debut but requires 'a lot of financing' to launch small nuclear reactor in 2029*, June 1, 2022: https://www.utilitydive.com/news/nuscale-makes-public-debut-but-requires-a-lot-of-financing-to-launch-smal/624568/.

projected to come online in 2029.[95] The currently projected NuScale production cost could be more than twice the cost of utility-scale solar and wind power generation.[96]

Investor reaction to NuScale's progress has been mixed. Despite going public in May 2022, NuScale still "needs substantial financing to stay afloat for the next several years" until its UAMPS project comes online.[97,98] Officials say current cash projections would carry the company until 2024. NuScale's problematic financial state would indicate a 2029 operational date for its SMR is highly problematic.

Q. DO YOU HAVE OTHER CONCERNS ABOUT SMRs?

A. Yes. Radioactive waste is also a weakness of SMRs. A May 2022 research study found that, if ever built, SMRs will produce far more, not less, radioactive waste per MW generated than the typical US nuclear reactor.[99] SMRs would add to the intractable challenge the US has faced throughout the nuclear power era: namely, how to safely manage spent fuel and other waste streams for generations to come.

---

[95] Utility Dive, *Newly public small modular reactor developer NuScale reports increased losses, big cash infusion*, June 8, 2022: https://www.utilitydive.com/news/newly-public-small-modular-reactor-developer-nuscale-reports-increased-loss/625102/.
[96] IEEFA, *supra* n.93.
[97] Utility Dive, *supra* n.94.
[98] Utility Dive, *supra* n.95.
[99] Stanford News, *Stanford-led research finds small modular reactors will exacerbate challenges of highly radioactive nuclear waste*, May 30, 2022: https://news.stanford.edu/2022/05/30/small-modular-reactors-produce-high-levels-nuclear-waste/.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE AUTHORIZATION OF DEVELOPMENT FUNDING FOR SMRs?

A. It would be imprudent for the Commission to authorize any development funding for SMRs.

IV. TRANSMISSION PLANNING, PROACTIVE TRANSMISSION AND RZEP[100]

Q. THE COMPANIES CLAIM THAT BUILDING LARGE-SCALE SOLAR IN THE "RED ZONE" WOULD BE THE LEAST-COST SOLAR ENERGY ALTERNATIVE. DO YOU AGREE?

A. No. The Public Staff expressed concern, regarding the Companies' 2022 Solar Procurement Proposal, that the uncertain cost of transmission upgrades necessary to interconnect large volumes of (utility-scale) solar may not result in least-cost compliance with HB 951's carbon reduction goals.[101] These transmission upgrade costs reflect project developer preference to locate these projects in transmission-limited rural areas where land costs are low.[102] The Companies' testimony implies this is sufficient reason, solar developer preference, for the proposed extremely extensive Red Zone Expansion Plan

[100] Red Zone Transmission Expansion Plan ("RZEP").
[101] NCUC, 2022 Solar Procurement Proposal, Docket No. E-2, Sub 1297 & Docket No. E-7, Sub 1268, Initial Comments of the Public Staff, March 28, 2022, p. 4.
[102] Ibid, p. 7: "Stakeholders from the solar industry have emphasized the need to site solar capacity in DEP's southeastern service territory due to available land and lower land costs to solar developers. However, DEP's southeastern territory has significant transmission congestion because of the large amount of solar generation currently located in this area. The large quantities of new solar capacity in the interconnection queue in that area are already resulting in larger transmission upgrade costs compared to DEC. If solar capacity and the necessary transmission upgrades are built in DEP's territory to meet DEC's carbon reduction goals, current cost allocation methodologies could cause the costs to be largely recovered from DEP customers."

("RZEP"),[103] However, it is the ratepayer, not the solar developers, that will pay for the backbone transmission system upgrades necessary to develop the Red Zones.

Reliance on wholesale rooftop and parking lot SPS in the Carbon Plan would largely eliminate transmission upgrades that would otherwise be necessary to interconnect utility-scale solar proposed in areas of the state with inadequate transmission capacity.

Q. ARE THERE FAR LESS TRANSMISSION COST IMPACTS WITH SMALLER (< 5 MW) ARRAYS CONNECTED AT THE DISTRIBUTION LEVEL?

A. Yes. The Companies' proposed Carbon Plan is correct in pointing out that the historic pattern in the Carolinas of building smaller 5 MW utility-scale solar arrays, interconnected at the distribution level, has allowed the incorporation of over 4,000 MW of solar capacity with little utility upgrade expense. The Companies state:[104]

> Of the 4,350 MW of solar connected today, over 95% of installed solar projects are smaller, distribution-tied projects
> . . .

One of the key barriers to adding resources, particularly solar, to the system is increasing transmission network upgrades required to interconnect new

---

[103] The Companies' Transmission Testimony, p. 36. "The bid window for 2022 Solar Procurement recently closed on July 22, 2022. Of the more than 5,000 MW of proposals received, over 70% of the MW are located in known red-zone areas. These known congested areas have been 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."
[104] The Companies' Carbon Plan, App. I, p. 1.

resources. The one justification used by the Companies for shifting to large, transmission-dependent utility-scale solar arrays is the improved efficiency of the solar production. The Companies note that the existing, distribution grid-connected projects have efficiencies in the range of 23 percent, while the larger proposed arrays would use bifacial panels and single-axis tracking to improve efficiency to 28 percent.[105]

There is no acknowledgement in the Companies' proposed Carbon Plan that smaller projects can also use bifacial panels and single-axis tracking in the future, negating the implied advantage of larger, transmission-connected solar projects. There is also no comment on the fact that the higher cost of bifacial solar panels largely offsets the increased solar production.[106] Finally, solar project economies-of-scale are not addressed in the Carbon Plan. A distribution grid-connected 5 MW solar array with bifacial solar panels and single-axis tracking in the same location would have the same 28 percent efficiency as the Companies assert for the 75 MW solar arrays modeled in the Carbon Plan. The major cost advantage of interconnection at the distribution level is the avoidance of substantial transmission upgrade costs.

The economies-of-scale are largely realized for solar projects at relatively small size. Figure 6 (below) was developed by NREL and is a

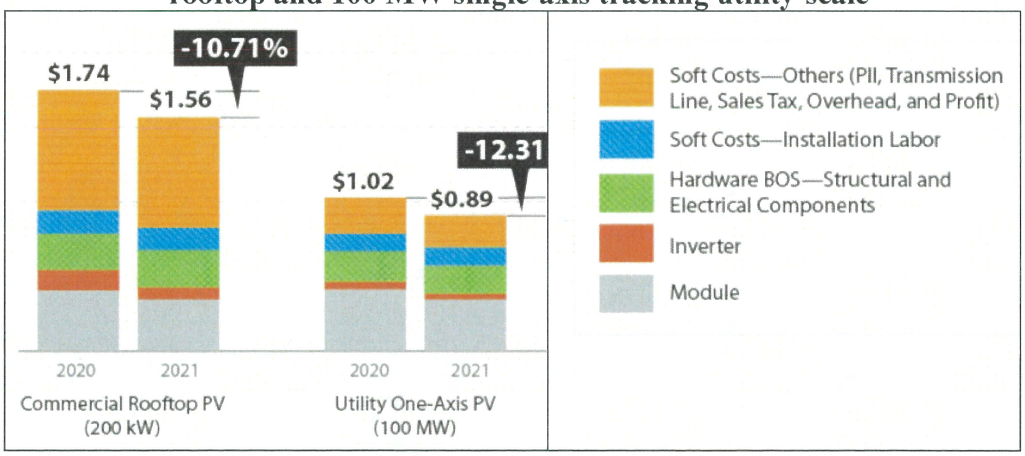
---

[105] Ibid, p. 2.

[106] Reuters, *U.S. Solar tariffs bolster growing dominance of bifacial panels*, March 16, 2022: https://www.reutersevents.com/renewables/solar-pv/us-solar-tariffs-bolster-growing-dominance-bifacial-panels.

comparison of the cost elements of a 200 kW commercial rooftop solar array and a 100 MW single-axis tracking solar array.[107] There is essentially no difference in the $/watt cost of the hardware and installation labor between the two projects. The cost difference is in the level of effort (soft costs – orange) required by solar installation firms to secure individual commercial rooftop projects compared to a single 100 MW utility-scale project. However, the Companies have the capability to aggregate hundreds of rooftops and substantially reduce the soft costs associated with wholesale urban projects.

Figure 6. NREL comparison of solar cost elements, 200 kW commercial rooftop and 100 MW single-axis tracking utility-scale



Q. IS THERE SUFFICIENT DISTRIBUTION LEVEL WHOLESALE SOLAR POTENTIAL IN OR NEAR DEMAND CENTERS TO PRIORITIZE THIS SOLAR RESOURCE?

[107] NREL, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2021*, November 4, 2021: https://www.nrel.gov/news/program/2021/new-reports-from-nrel-document-continuing-pv-and-pv-plus-storage-cost-declines.html.

A. Yes. The Companies have tremendous, and largely untapped, commercial/industrial building wholesale rooftop and parking lot solar potential and urban undeveloped land potential available for the development of wholesale SPS projects. North Carolina has a solar rooftop and parking lot solar potential of 38,000 MW.[108] The state has an undeveloped urban land wholesale SPS potential of 43,000 MW.[109] There is ample solar potential to meet the Carbon Plan reduction targets with projects that tie into the local distribution grid and predominantly serve local demand.

There are no transmission constraints to the wholesale urban SPS installation rate. The Companies have imposed a 750 MW per year solar expansion restriction due to transmission constraints.[110] The Companies project they can increase the solar interconnection pace to 1,800 MW per year by 2030 in Portfolio 1.[111] Prioritizing wholesale urban SPS would eliminate transmission constraints on the solar build-out toward carbon-free power.

One U.S. investor-owned utility has built a large-scale aggregated warehouse rooftop project selling wholesale power over the distribution grid. In March 2008, Southern California Edison ("SCE") proposed to build 250 MW of solar on warehouse rooftops in urban Southern California. The

---

[108] B. Powers – Powers Engineering, *NC Clean Path 2025*, Table 25, p. 57: https://www.ncwarn.org/wp-content/uploads/NC-CLEAN-PATH-2025-FINAL-8-9-17.pdf.
[109] Ibid.
[110] The Companies' Carbon Plan, Chp. 2, p. 19. Table 2-10: Maximum Solar [MW] Allowed to Connect Annually.
[111] Ibid, p. 17.

project involved aggregating a large number of 1 MW to 2 MW rooftop projects. The California Public Utilities Commission ultimately approved a larger 500 MW SCE warehouse rooftop solar project in June 2009, stating:[112]

> Unlike other generation resources, these (large-scale rooftop solar) projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts.

The CEO of SCE at the time, John Bryson, was an advocate for the warehouse rooftop solar project, explaining how it benefitted the SCE grid:[113]

> "These new solar stations, which we will be installing at a rate of one megawatt a week, will provide a new source of clean energy, directly in the fast-growing regions where we need it most," said Bryson.

Multi-year delays in solar deployments, huge transmission build-out expenditures, and increasing community resistance to large-scale solar development in rural areas can be avoided by prioritizing smaller-scale utility solar projects on the distribution grid in and near demand centers.

Q. DO THE COMPANIES ACKNOWLEDGE COMMUNITY RESISTANCE TO LARGE-SCALE SOLAR DEVELOPMENT IN THE RED ZONES?

---

[112] CPUC press release, *CPUC Approves Edison Solar Roof Program* (June 18, 2009): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/NEWS_RELEASE/102580.PDF.

[113] Edison International News Release, *Southern California Edison Launches Nation's Largest Solar Panel Installation*, March 27, 2008: https://newsroom.edison.com/releases/southern-california-edison-launches-nations-largest-solar-panel-installation.

A. Yes. The Companies acknowledge growing rural community resistance to solar projects, referencing other parties in stating "In ten years, 1,800 MW/year of solar would cover approximately 225 square miles of land . . . "[Local opposition to development] is increasingly one of the top barriers . . ."[114]

Q. DOES THE CARBON PLAN CONSIDER ANY ALTERNATIVE SOLAR DEVELOPMENT OPTIONS TO AVOID THE TRANSMISSION CONGESTION, TRANSMISSION COST, AND COMMUNITY RESISTANCE IN RED ZONES?

A. No. This failure constitutes an error in the Companies' proposed Carbon Plan.

V. EE/DSM ISSUES / GRID EDGE

Q. IS THE COMPANIES' STATED COMMITMENT IN THE CARBON PLAN TO PRIORITIZE "SHRINKING THE CHALLENGE" REFLECTED IN THE PROJECTED ROOFTOP SOLAR (NEM) INSTALLATION RATE?

A. No. In their proposed Carbon Plan, the Companies claim to use a three-pronged approach, focusing first on "grid edge" strategies, including NEM solar, to reduce energy requirements and load profiles. The Carbon Plan underscores that:[115] Grid edge programs are identified as the first priority in the Carbon Plan. Grid edge programs include energy efficiency (EE),

[114] The Companies' Modeling Testimony, pp. 166-167.
[115] The Companies' Carbon Plan, Executive Summary, p. 9.

demand-side management (DSM), customer self-generation (NEM solar), voltage management and other distributed energy resources (DER).[116] The Carbon Plan forecasts 15 percent growth rate for NEM solar through 2030.[117] However, the Companies have proposed modifications to the NEM tariff that will reduce the economic benefit of NEM by 30 percent or more to address an alleged (by the Companies) cost shift from NEM residential customers to non-NEM residential customers.[118]

The Companies' growth projection for NEM has substantially declined between the 2020 DEC and DEP IRPs and the Carbon Plan. There were 169 MW of NEM solar online in the Companies' territories in North Carolina at the end of 2021.[119] The Companies projected in the 2020 IRPs that 745 MW would be online in North Carolina by 2035.[120] This is a NEM solar increase in North Carolina of 576 MW between the end of 2021 and 2035.

The Companies' proposed Carbon Plan projects a NEM addition rate of 26.5 MW per year in North Carolina,[121] the equivalent of an

---

[116] The Companies' Carbon Plan, App. G, p. 1.
[117] The Companies' Carbon Plan, Chp. 2, p. 12.
[118] NCUC Docket No. E-100 SUB 180, Joint Initial Comments of NC WARN *et al.*, March 29, 2022.
[119] The Companies' total NEM solar capacity at the end of 2021, per EIA (https://www.eia.gov/electricity/data/eia861m/#netmeter): DEC NC = 90.6 MW; DEP NC = 78.5 MW. Total NEM solar = 169.1 MW.
[120] NCUC Docket No. E-100 SUB 165, DEC's 2020 IRP, p. 230, Table C-4.
[121] The Companies' total NEM solar capacity at the end of 2021, per EIA (https://www.eia.gov/electricity/data/eia861m/#netmeter): DEC NC = 90.6 MW; DEC SC = 92.3 MW; DEP NC = 78.5 MW; DEP SC = 19.8 MW. NC NEM solar = 169.1 MW; Total NEM solar = 281.2 MW. The Companies' Carbon Plan, App. G, p. 18, Table G-7: current NEM production = 493,343 MWh/yr. Table G-8: new NEM production by 2030 = 697,707 MWh/yr. Therefore, total new NEM by 2030 (in MW) = 281.2 MW x (697,707

additional 371 MW by 2035.[122] The Carbon Plan reduces the role of NEM solar dramatically, relative to the 2020 IRP forecasts, despite identifying NEM solar as a first priority in reducing carbon emissions. The NEM solar additions forecast in the 2020 IRPs were made in the context of the Companies modifying the NEM tariff to reduce bill savings.[123] That process is underway in the Commission's Docket No. E-100 SUB 180. No new rationale is put forth in the Companies' proposed Carbon Plan to justify the substantial decline in new NEM solar capacity in North Carolina between the Companies' 2020 IRP(s) forecast and the Carbon Plan forecast.

Q. DOES THE CARBON PLAN NEM INSTALLATION RATE ANTICIPATE THE TEN-YEAR EXTENSION OF THE SOLAR TAX CREDIT IN THE AUGUST 2022 INFLATION REDUCTION ACT (IRA)?

A. No. The White House projects that North Carolina will add an additional 170,000 rooftop systems,[124] and South Carolina will add an additional 220,000 rooftop systems,[125] as a result of the 10-year extension of the solar

MWh/yr ÷ 493,343 MWh/yr) = 397.7 MW. New NC NEM by 2030 = (169.1 MW/281.2 MW) x 397.7 MW = 239 MW. Annual NC NEM additions, 2022-2030 (9 years) = 239 MW/9 years = 26.5 MW per year.

[122] The Companies' Carbon Plan NEM forecast is through 2030. The Carbon Plan forecast is extrapolated to 2035 to calculate expected additional NC NEM solar capacity in 2035. 26.5 MW per year x 14 years (2022-2035) = 371 MW.

[123] NCUC Docket No. E-100 SUB 165, DEC's 2020 IRP, p. 228: "For this IRP, DEC assumes that NEM tariffs will evolve to more closely align with the cost to serve rooftop solar customers, such that bill savings would gradually decrease over time."

[124] North Carolina: https://www.whitehouse.gov/wp-content/uploads/2022/08/North-Carolina.pdf.

[125] South Carolina: https://www.whitehouse.gov/wp-content/uploads/2022/08/South-Carolina.pdf.

tax credit in the IRA. These rooftop solar additions have not been factored into the Companies' NEM solar forecasts or their load growth projections.

VI. RELIABILITY

Q. DO THE COMPANIES MISSTATE THE CAUSES OF THE CAISO BLACKOUTS IN AUGUST 2020 TO SUPPORT A POSITION THAT OVER-RELIANCE ON IMPORTS CAN COMPROMISE RELIABILITY?

A. Yes. In the Companies' prefiled direct testimony, Mr. Holeman states that ". . . over-reliance on imports was a causal factor for the (August 2020 CAISO blackout) events."[126] I was an expert witness in the California Public Utilities Commission proceeding that examined the causes for the August 14-15, 2020 blackouts, and my testimony in the proceeding is attached hereto as **Exhibit 1**.[127] Over-reliance on imports was not a significant factor in the CAISO August 14-15, 2020 blackouts. Market mismanagement by the CAISO was the overwhelmingly primary cause, which allowed the exporting of 3,500 MW of California generation to neighboring states when that supply was needed in California. The second and substantially less significant cause was the high forced outage rate of

---

[126] The Companies' Reliability Testimony, p. 79.

[127] **Exhibit 1**, California Public Utilities Commission, Rulemaking R.20-11-003 (Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021), Prepared Opening Testimony of Bill Powers, P.E., On Behalf of the Protect Our Communities Foundation, January 11, 2021.

aging coastal steam boiler units that remain operational specifically to provide capacity during summer heat waves.

Q. IS MR. HOLEMAN CORRECT WHEN HE ASSERTS ALL IMPORTS INTO THE CAISO BALANCING AUTHORITY ARE FIRM IMPORTS?

A. No. The Root Cause Analysis that Mr. Holeman references states that "The imports category includes both non-resource-specific resources as well as resource-specific imports like those from Hoover Dam and Palo Verde Nuclear Generating Station."[128] CAISO imports consist of a mix of firm and non-firm imports.

Q. DOES MR. HOLEMAN ACKNOWLEDGE THE CAISO BLACKOUTS' PRIMARY CAUSE, SUPPLY MISMANAGEMENT BY CAISO, IN HIS TESTIMONY?

A. No. He notes that "The 2020 California firm load shed event . . . multiple factors including . . . and (CAISO) market functions that compounded the existing supply challenges."[129] The "market functions" issue was the cause of the blackouts. According to CAISO, a computer programming error allowed exports from California to be allowed when the supply was needed in California to meet demand.[130] 3,500 MW was being exported from

[128] CAISO *et al.*, *Root Cause Analysis (RCA) – Mid-August 2020 Extreme Heat Wave*, January 13, 2021, p. 48: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.
[129] The Companies' Reliability Testimony, pp. 38-39.
[130] CAISO *et al.*, *Root Cause Analysis (RCA) – Mid-August 2020 Extreme Heat Wave*, January 13, 2021, p. 5: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

California at the time the rolling blackouts were initiated on both days.[131] To put this in perspective, 3,500 MW is approximately the entire capacity of the Companies' combined cycle fleet added in the last ten years.[132] This was not a simple "market function" executed by the CAISO – it was a major CAISO error that resulted in two avoidable rolling blackouts at a time when supply was adequate to meet demand but some of that in-state supply was erroneously exported out-of-state.

Q. WAS THE SAME ENTITY RESPONSIBLE FOR THE AUGUST 2020 BLACKOUTS, CAISO, ALSO THE LEAD INVESTIGATOR ON THE ROOT CAUSE ANALYSIS OF THE BLACKOUTS?

A. Yes. There was no neutral, independent investigation of the root causes of the blackouts. The bias toward deflecting responsibility for the blackouts to the weather is reflected in the title of CAISO's root cause analysis – "Root Cause Analysis – Mid-August 2020 Extreme Heat Wave." It was hot in California in August 2020. However, the peak load on August 14, 2020 was approximately the forecast 1-in-2 peak summer load. The rolling blackout was initiated after the peak had been reached and demand was in decline. The loads were substantially lower on August 15, 2020. Again the rolling blackouts were initiated after the peak load had occurred and the load was in decline.[133]

---

[131] Ibid, Figure B.36: Total Day-Ahead Scheduled Exports by Category, p. 122.
[132] The Companies' Modeling Testimony, p. 158, n.131. "Generation added last 10 years = . . . 3,860 MW CCs (Dan River, WS Lee, Asheville, Lee, Sutton CCs) . . ."
[133] *See* **Exhibit 1** hereto, California Public Utilities Commission, Rulemaking R.20-11-003 (Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure

Q. WHY IS IT IMPORTANT THAT THE RELIABILITY OF IMPORTS WAS NOT A FACTOR IN THE CAISO AUGUST 2020 BLACKOUTS?

A. It is important to avoid over-procurement by the Companies based on the erroneous concept that non-firm imports are not reliable. Mr. Holeman correctly points-out that about 20 percent of the supply utilized by California utilities in the CAISO control area is imported power.[134] This contrasts with the 4 percent imported power contribution to the Companies' supply to meet the actual winter peaks in the winters of 2020/2021 and 2021/2022. He then incorrectly asserts that "This has presented problems when increasing temperatures across the broader region divert non-dedicated resources."[135] The demand when CAISO initiated the first blackout was at a typical 1-in-2 summer peak level. The second blackout was initiated the following day at an actual demand well below the 1-in-2 summer peak level. What matters is the magnitude of the load that must be met. "Increasing temperatures" had nothing to do with CAISO's failure to meet the demand on those two August 2020 days.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021), Prepared Opening Testimony of Bill Powers, P.E., On Behalf of the Protect Our Communities Foundation, January 11, 2021, p. 2.
[134] The Companies' Reliability Testimony, p. 78.
[135] Ibid.

Summary of the Direct Testimony of William E. Powers on Behalf of NC WARN and Charlotte Mecklenburg NAACP

N.C. Utilities Commission, Docket No. E-100, Sub 179

I greatly appreciate the opportunity to offer testimony before this Commission. I am William E. Powers, P.E. I have been involved in the fields of power plant operations and environmental engineering for over forty (40) years, and I have offered reports and testimony in numerous utility resource planning proceedings throughout the country.

On September 2, 2022, I caused to be filed with the Commission my pre-filed direct testimony. The purpose of my direct testimony was to explain several critical errors in the proposed Carbon Plans of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEC") (collectively, the "Companies"). In my direct testimony, my various criticisms were organized into the following six (6) topics:

I. Modeling—Methodology, Assumptions and Other Modeling Issues;

II. Near-Term Procurement Activity;

III. Near-Term Development Activity;

IV. Transmission Planning, Proactive Transmission and RZEP;

V. EE/DSM Issues / Grid Edge; and

VI. Reliability

The Companies' proposed Carbon Plan made multiple critical modeling errors. For example, the Companies' demand growth forecast is flawed. DEC's retail sales growth from 2016 through 2021, the most recent five-year period shown in the Carbon Plan, averaged 0.0 percent. Even more significantly, DEP's retail sales growth over the most recent five-year period (2016-2021) was -0.7. Despite these strong reasons to believe that load growth has stabilized or is shrinking, the Companies have forecasted load growth of 0.8 percent for DEC and 0.4 percent for DEP. These erroneously high forecasts are consistent with the Companies' history of overstating future demand growth in Integrated Resource Plan (IRP) proceedings.

The Companies also made several critical modeling errors regarding capital costs. For example, the Companies appear to have vastly understated the capital costs of natural gas Combustion Turbines ("CT") and Combined Cycles ("CC"). The Companies have recent experience with constructing both CTs and CCs. For example, the actual capital cost of the 560 MW Asheville CC, which came online in 2020, was $817 million. This is equivalent to a unit CC cost of about $1,460/kW. The 402 MW Lincoln CT is the most recent example of a CT built and owned by the Companies. The capital cost of the Lincoln CT was filed under seal. Instead of relying on these hard CC and CT capital cost numbers derived from recent, actual experience, the Companies opted to develop more favorable hypothetical CC and CT capital cost estimates for use in portfolio modeling.[1]

The Companies' capital cost projections are also flawed with respect to solar plus storage. Other investor-owned utilities operating in the markets of the Companies' sister operating companies view solar plus battery storage as a superior alternative to CTs for cost reasons alone. For instance, NextEra Energy, parent company of Florida Power & Light, states that "batteries are now more economic than gas-fired peakers (CTs), even at today's natural gas prices." *See* page 25 of direct testimony. For unaccountable reasons,

[1] The Companies treated capital cost estimates used in Carbon Plan modeling as proprietary information. NC WARN declined to sign an NDA to review the capital costs assumed by the Companies in the Carbon Plan for modeling purposes. However, in the Companies' precursor to the Carbon Plan, the 2020 Climate Report, the assumed CC capital cost of $650/kilowatt was less than half the actual $1,460/kilowatt capital cost of the Asheville CC. I assume the cost of CTs in the 2020 Climate Report is underestimated by a comparable factor.

the Companies' modeling of the cost of solar plus storage was inconsistent with the Companies' competitors.

The Companies' modeling related to the planning reserve margin was also flawed, and in my direct testimony, I discussed aspects of these errors in both the Modeling section and the Reliability section. In summary, the Companies' are operating with excessive reserves of firm assets as they seek to add substantial amounts of new firm assets, particularly CTs and CCs. Through data request responses received from the Companies, I determined the CT, coal, and DSM capacity that went unused by the Companies at the 2021 and 2022 winter peaks. This is a subset of the Companies' total supply assets. More than 7,000 MW of CT, coal, and DSM capacity went unused by the Companies at the 2021 and 2022 winter peaks. *See* p. 13 of direct testimony. The 2022 DEC/DEP coincident winter peak of 29,028 MW (January 27, 2022) was representative of the historic DEC/DEP "typical year" peak that is used to calculate the planning reserve margin. *See* pp. 17-20 of direct testimony. Considering only idle CT, coal, and DSM capacity, the Companies had reserves far in excess of the 17 percent PRM at the 2022 actual winter peak. Further, the Companies' Transmission Panel testified that the Companies assume reliance upon 2,000 MW of non-firm imports to meet winter peak, yet the Companies consistently import far less than this amount at the winter peak from neighboring balancing authorities while maintaining reserve margins far above 17 percent. In the Companies' Reliability Panel direct testimony, the Companies cited to the CAISO blackouts in August 2020 to illustrate the supposed flaws in relying upon non-firm imports. That testimony by the Companies is objectively wrong. I was an expert in that proceeding. Over-reliance on imports was not a significant factor in the CAISO August 2020 blackouts; instead, market mismanagement by CAISO – allowing 1,000s of MW of exports at the peak – was overwhelmingly the primary cause.

Regarding the Near-Term Procurement Activity topic, the Companies committed yet further mistakes. For example, the Companies made errors related to their analysis of the likely performance of solar plus storage. As described in my direct testimony, the Companies currently lag far behind their peers in implementing battery storage, and the Companies' proposed Carbon Plan illustrates the types of mistakes that have caused the Companies to fall behind. The Companies undersized the battery storage component of solar plus storage, and furthermore, the Companies failed to assume for modeling purposes that the storage component of solar plus storage can be charged from either the associated solar array or the grid. These errors constitute serious flaws which resulted in a minimal amount of battery storage in the Carbon Plan in the near term.

The Companies' proposed conversion from natural gas to "green hydrogen" is highly speculative and not supported by the evidence. The Companies propose a tremendous build-out of natural gas capacity—specifically, 800 MW to 2,400 MW of CCs and 6,400 MW to 10,900 MW of CTs. It would be impossible for the Companies to achieve carbon neutrality by 2050 with this substantial reliance upon natural gas. To overcome this problem, the Companies argue that their natural gas fleet can be converted to 100% green hydrogen. However, the Companies acknowledge such a green hydrogen conversion is an unproven prospect, pointing to "significant uncertainties" in the future supply of green hydrogen. Even gas turbine manufacturers, based on the high cost of green hydrogen production, forecast that green hydrogen will only be used sparingly in gas turbines located in geographic regions with high power costs. *See* pp. 41-42 of direct testimony. The

Companies are projecting only 5 percent of the heat content in its blended natural gas fuel will be provided by hydrogen in 2041.

I also testified that the Companies' natural gas price projections are erroneous. Natural gas prices are currently quite volatile, with the May 2022 Henry Hub price over $8 per million Btu. Yet the Companies' proposed Carbon Plan assumes a low base price for natural gas, under $4/MMBtu through 2032 rising to $5/MMBtu in 2050. This projection is at odds with the facts.

Regarding the Near-Term Development Activity issue, I testified that small modular reactors ("SMR") are an unproven option without any history of success in the power industry. There are currently no operational SMRs in the United States, and all efforts to develop an operational SMR have resulted in both cost overruns and delays. Furthermore, there are several additional problems with nuclear technology in general, including how to safely manage spent fuel and other waste streams for generations to come.

I also provided testimony on the Transmission Planning, Proactive Transmission and RZEP issue. The Companies claim that building large-scale solar in the "Red Zone" would be the least-cost solar energy alternative. This is not correct. These transmission upgrade costs reflect project developer preference to locate these projects in transmission-limited rural areas where land costs are low. The Companies imply that this is sufficient reason (*i.e.*, solar developer preference) for the proposed extremely extensive Red Zone Expansion Plan (RZEP). To the contrary, reliance on wholesale rooftop and parking lot solar plus storage in the Carbon Plan would largely eliminate transmission upgrades that would otherwise be necessary to interconnect utility-scale solar proposed in areas of the state with inadequate transmission capacity. Indeed, there are far less transmission cost impacts with smaller (< 5 MW) arrays connected at the distribution level, where, according to the Companies, over 95 percent of North Carolina's 4,350 MW of solar has been interconnected to date. *See* p. 50 of direct testimony. In my direct testimony, I explain why there is sufficient distribution level wholesale solar potential in or near demand centers to prioritize this solar resource.

Finally, my direct testimony discussed the Companies' inadequate commitment to EE/DSM and the "Grid Edge" program. Throughout the Companies' proposed Carbon Plan, the Grid Edge program is given first priority. Yet, by way of example, the Companies' growth projection for Net Energy Metering (NEM) has substantially declined between the 2020 Integrated Resource Plan proceeding and the present proceeding. This contradicts the "first priority" categorization of NEM, and may be partly driven by the Companies' less favorable (to NEM customers) proposed NEM tariffs in the Commission's Docket No. E-100 Sub 180. The Companies should be ordered to place greater priority on EE/DSM and the Grid Edge program.

This completes the summary of my direct testimony. I appreciate the Commission's consideration of these important issues.

MR. JIMENEZ: Good morning, Madam Chair. Nick Jimenez with the Southern Environmental Law Center. SACE, et al., and NCSEA jointly sponsored witness Jay Caspary. We have confirmed with all parties who had cross do not object to excusing Mr. Caspary. We also conferred with Commission counsel and understand the Commission has no questions. So we would move to enter at the appropriate time Mr. Caspary's prefiled direct testimony consisting of 25 pages, as well as his report filed in E-100, Sub 179 on July 15th, 2022 as Exhibit 2 to the Joint Comments of SACE, et al. and NCSEA as if given orally from the stand.

CHAIR MITCHELL: All right. Having heard no objection to your motion, Mr. Jimenez, the witness' testimony will be copied into the record as if given orally from the stand at the appropriate time. The report that you identify, is that an exhibit to his testimony or are you moving that in independently of his testimony?

MR. JIMENEZ: It's independently of his testimony. It's an exhibit to our comments.

CHAIR MITCHELL: All right. We will -- I'm going to hold on moving that into evidence, as comments are already considered to be in evidence, so the document is in evidence.

MR. JIMENEZ: Okay.

CHAIR MITCHELL: Did you all provide a summary of your witness' testimony?

MR. JIMENEZ: We have not.

CHAIR MITCHELL: Okay. Do you intend to?

MR. JIMENEZ: We certainly will if the Commission thinks it will be helpful.

CHAIR MITCHELL: Okay. We would request that you do provide a summary of his testimony, and that summary will be copied into the record as if given orally from the stand at the appropriate time as well.

MR. JIMENEZ: Okay. Thank you.

CHAIR MITCHELL: Any exhibits to Mr. Caspary's testimony?

MR. JIMENEZ: No.

CHAIR MITCHELL: Okay. All right. And Mr. Caspary is excused from participating as a witness in this expert witness hearing.

MR. JIMENEZ: All right. Thank you.

(Whereupon, the prefiled direct testimony of Jay Caspary and summary were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan	)))))	**DOCKET NO. E-100, SUB 179**

DIRECT TESTIMONY OF

JAY CASPARY

ON BEHALF OF

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

September 2, 2022

TABLE OF CONTENTS

I. Introduction 1

II. Proactive, Multi-Value Transmission Planning 4

III. Red Zone Transmission Expansion Plan 12

IV. Collaborative Planning Studies 16

V. Advanced Transmission Technologies.. 17

VI. Regional Integration 20

VII. Synchronizing Development of Carbon Plans with Transmission Planning Processes 23

VIII. Conclusion 25

I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Jay Caspary, and I prepared this testimony as Vice President of Grid Strategies LLC (Grid Strategies), a consulting firm based in the Washington, D.C. area. My business address is 194 Tice Road, P. O. Box 460, Higden, Arkansas 72067.

Q. PLEASE DESCRIBE GRID STRATEGIES.

A. Grid Strategies is a power sector consulting firm that supports clients working towards low-cost de-carbonization through the reliable and efficient integration of clean energy into electric grids.

Q. PLEASE DESCRIBE YOUR EXPERIENCE AND EDUCATION.

A. I have worked in the utility industry for over 40 years. At Grid Strategies, I am responsible for providing analysis and strategic guidance on transmission grid planning and operations to support a clean energy portfolio. Prior to joining Grid Strategies last fall, I worked at Southwest Power Pool ("SPP") for almost 20 years, where I directed the development of regional planning processes and approval of major transmission expansion projects, as well as facilitated collaborative interregional planning efforts. During my career at SPP, I served as Senior Policy Advisor for the U. S. Department of Energy's Office of Electricity Delivery and Energy Reliability ("OE") as part of the Obama Administration, with a focus on grid modernization. Prior to SPP, I served in several staff and managerial roles at Illinois Power.

In the course of my career, I have been actively involved in the bulk power industry where I have had the opportunity to provide leadership in collaborative planning efforts such as the recent National Renewable Energy Laboratory's ("NREL's") Interconnections Seam Study ("NREL Seams Study");[1] served as a technical reviewer for numerous national laboratory reports, academic articles, and renewable integration studies; and published academic articles and conference presentations on renewable integration and transmission issues. I have served on the Board of Directors for the Utility Wind (Variable-generation) Integration Group (now Energy Systems Integration Group, or "ESIG") for over a decade, been a member of the North American Reliability Corporation's Integrating Variable Generation Task Force and served as chair on several industry-utility research collaboratives including the Power Systems Engineering Research Center ("PSERC").

I have a Bachelor of Science degree in Electrical Engineering with an emphasis in Power Systems from the University of Illinois – Urbana / Champaign and have completed the course requirements for a Master's degree in Engineering from Iowa State University. My resume is attached to my report filed in this docket.[2]

---

[1] NREL Interconnection Seams Study (2021), available at: https://www.nrel.gov/analysis/seams.html.

[2] Joint Comments of the North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan*, Docket No. E-100, Sub 179, Exhibit 2, Jay Caspary, *Transmission Issues and Recommendations for Duke's Proposed Carbon*

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club.

Q. HAVE YOU APPEARED BEFORE THIS COMMISSION?

A. Yes, I presented on behalf of the North Carolina Sustainable Energy Association and the Carolinas Clean Energy Business Association in the technical conference for the 2020 IRP proceeding, *2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans*, Docket No. E-100, Sub 165.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss my report, *Transmission Issues and Recommendations for Duke's Proposed Carbon Plan*, which I prepared on behalf of the North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club.[3] My testimony covers the issue of "Transmission Planning, Proactive Transmission, and RZEP" identified in the Commission's July 29, 2022 *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines*.

Plan (July 15, 2022). Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=475236b3-4ee8-4480-80e2-ae5a1b986c0f.

3 *Id*.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. In this testimony I will discuss five main issues: 1) proactive multi-value transmission planning, 2) the "Red Zone Transmission Expansion Plan" (RZEP"), 3) collaborative planning studies, 4) advanced transmission technologies, 5) regional integration, and 6) synchronizing development of Carbon Plans with transmission planning processes.

II. Proactive, Multi-Value Transmission Planning

Q. WHAT IS "PROACTIVE" PLANNING AND HOW IS IT IMPLEMENTED IN THE CONTEXT OF TRANSMISSION INFRASTRUCTURE?

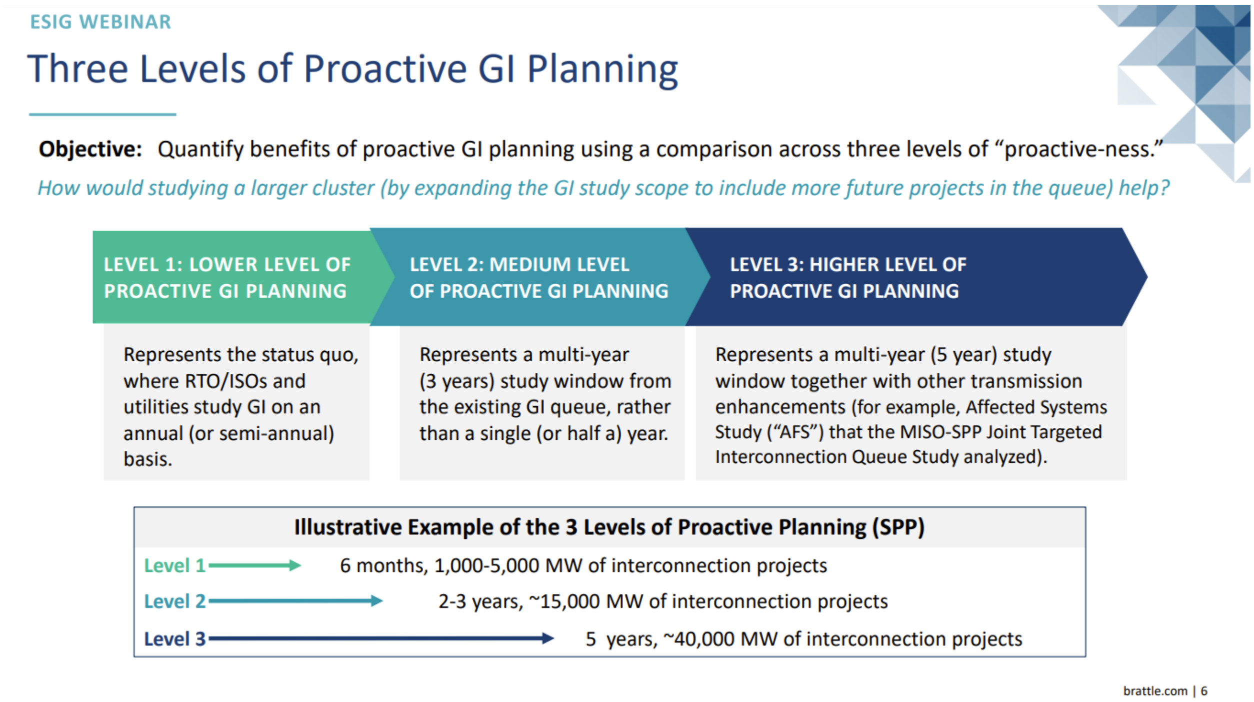
A. Proactive planning incorporates several future scenarios to frame decisions and better manage uncertainties. It requires stakeholders to develop scenarios that frame uncertainties regarding future resource mixes as well as other key parameters. Proactive planning is critical for long-lead-time assets, such as transmission infrastructure, which are lumpy, provide large economies of scale, and have very long useful lives. Proactive transmission planning looks forward, taking into account the new resources that could be enabled by new transmission, rather than only reacting to existing transmission constraints. Therefore, proactive transmission planning is central to developing the least-cost resource mix to meet future needs.

Traditional, reactive planning is conducted in a piecemeal fashion and spends more money overall on multiple small transmission projects, or small projects that are later replaced by a larger one, when one larger project could have done the job. It is penny wise and pound foolish. In contrast, proactive transmission planning picks that one project from the start that meets current and future transmission needs and saves through economies of scale. Proactive transmission planning also helps to identify and connect low-marginal-cost resources like solar and wind by building larger connections to high-value resource areas rather than taking the more costly piecemeal approach.

Q. PLEASE DESCRIBE IN MORE DETAIL WHAT A PROACTIVE TRANSMISSION PLANNING PROCESS LOOKS LIKE, ESPECIALLY IN RELATION TO THE TRADITIONAL "PIECEMEAL" APPROACH USED IN GENERATION INTERCONNECTION STUDIES/PROCESSES.

A. To start with, proactive planning involves looking forward in time. The following slide gives a good visual of this.[4]

[4] ESIG Webinar: *Proactive Planning for Generation Interconnection A Case Study of SPP and MISO*. Brattle Group, August 17, 2022. The slide is excerpted from a presentation by Bruce Tsuchida at the Brattle Group for a webinar titled *Proactive Planning for Generation Interconnection: A Case Study of SPP and MISO*. Although the presentation focuses on the narrower issue of "Generator Interconnection" ("GI") and much shorter timeframes, it shows the same idea.



The authors broke "proactive" planning into three levels, with level 1 representing the status quo, level 2 representing a medium level of planning and level 3 representing a higher level of proactive planning. The key distinguishing factor between the three levels is how long the planning period is and therefore the number of megawatts of interconnection projects under consideration. Basically, the farther out in time the study window extends, the more "proactive" the planning.

In a nutshell, proactive planning requires the transmission planner to:

1. Proactively plan for future generation and load by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.

2. Account for the full range of transmission projects' benefits, and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.

3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad

range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

4. Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.

5. Jointly plan across neighboring interregional systems to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

These are the five core principles of efficient transmission planning recommended in a report that I co-authored, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs.[5] One of the co-authors, Johannes Pfeifenberger, also gave a good summary in a recent presentation to the PJM Long-term Transmission Planning Workshop, including these five core principles and an overview of scenario-based planning and the values that go into multi-value transmission planning.[6]

Q. WHAT ARE THE BENEFITS OF PROACTIVE TRANSMISSION PLANNING?

A. Proactive transmission planning will reduce overall system costs and consumer bills in the long term. Importantly, these planning studies are conservative in quantifying projected benefits of approved transmission expansion plans compared to the actual benefits that are realized in grid

---

[5]Johannes Pfeifenberger, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* at 27-28 (2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf ("Brattle-Grid Strategies report").
[6]Johannes Pfeifenberger & Joseph DeLosa, *Proactive, Scenario-Based, Multi-Value Transmission Planning* (2022), https://www.brattle.com/wp-content/uploads/2022/06/Proactive-Scenario-Based-Multi-Value-Transmission-Planning.pdf.

operations. Long range, holistic (multi-value) proactive planning will result in least-regrets outcomes that will maximize net benefits to consumers for the future power system.

Q. WHAT IS "MULTI-VALUE" TRANSMISSION PLANNING AND HOW IS IT IMPLEMENTED?

A. Multi-value transmission planning requires a comprehensive assessment of the attributes of enabling infrastructure to support future electricity system needs. Multi-value transmission planning typically reduces overall system costs by identifying a portfolio of transmission expansion projects that not only address future reliability needs, but also improve grid operations and the resulting economic costs borne by customers while achieving public policy objectives. It looks at values beyond a simple analysis of production cost savings. Johannes Pfeifenberger again gave a good summary in his recent presentation to the PJM Long-term Transmission Planning Workshop.[7]

The Federal Energy Regulatory Commission's ("FERC") Notice of Proposed Rulemaking ("NOPR") in FERC Docket No. RM21-17 identified twelve unique benefits associated with long-term regional transmission

---

[7]Johannes Pfeifenberger & Joseph DeLosa, *Proactive, Scenario-Based, Multi-Value Transmission Planning* at slides 10-11 (2022), https://www.brattle.com/wp-content/uploads/2022/06/Proactive-Scenario-Based-Multi-Value-Transmission-Planning.pdf.

expansion which conventional transmission planning fails to fully capture.[8] These benefits include:

1) avoided or deferred reliability projects and aging infrastructure replacement,
2) either reduced loss of load probability or reduced planning reserve margin,
3) production cost savings,
4) reduced transmission energy losses,
5) reduction congestion due to transmission outages,
6) mitigation of extreme events and system contingencies,
7) mitigation of weather and load uncertainty,
8) capacity cost benefits from reduced peak energy losses,
9) deferred generation capacity investments,
10) access to lower-cost generation,
11) increased competition, and
12) increased market liquidity.

FERC described each of these benefits in more detail in its NOPR.[9] This is a good list, but multi-value planning does not necessarily need to include every one of these benefits in every instance. It can be tailored to the needs of the region.[10]

Duke seemed to endorse the concept of multi-value planning in testimony when it discussed the "secondary benefits" of the RZEP projects, but Duke's list of secondary benefits does not capture the benefits involved

---

[8] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028, Docket No. RM21-17-000, https://www.ferc.gov/media/rm21-17-000.
[9] *Id.* at 159.
[10] Brattle-Grid Strategies report at 55.

in multi-value transmission planning, and applying a multi-value framework would likely show the RZEP projects to be even more valuable.[11]

Q. DOES CONVENTIONAL INCREMENTAL TRANSMISSION PLANNING BASED ON THE LOWEST INITIAL INVESTMENT ACCURATELY VALUE THE BENEFITS OF TRANSMISSION UPGRADES?

A. No. Transmission plans based on lowest initial investment typically focus on identifying the lowest-cost initial investment that mitigates reliability issues and don't consider resource adequacy or reduction on customer reliability costs, ignoring savings from grid efficiency and addressing challenging operating conditions that will be experienced over the life of the asset and other savings.

Q. SHOULD PROACTIVE, MULTI-VALUE TRANSMISSION PLANNING BE APPLIED BOTH INTRAREGIONALLY AND INTERREGIONALLY?

A. Yes. Proactive multi-value transmission planning should be applied to both intra-regional and inter-regional studies to determine the optimal, least regrets portfolio of transmission expansion projects which maximize net benefits to consumers.

Q. HOW WOULD MULTI-VALUE TRANSMISSION PLANNING ANALYZE THE TRANSMISSION NEEDED FOR OFFSHORE WIND?

A. In its recent NOPR, the FERC proposes, but does not require, that planners consider quantifying 12 unique transmission-related benefits, mentioned above, to identify the most cost-effective transmission solutions. Studies to support large offshore wind developments typically require networked

---

[11] See Duke Transmission Panel p.26.

facilities to effectively deliver renewable resources and provide operating flexibility to support expected long-term needs. In early August 2022, Dominion received state approvals to proceed with 2.6GW of offshore wind development in the southeast corner of Virginia and related transmission expansion to integrate those facilities into the bulk power system. Dominion is projecting ultimate development of 5.2GW of offshore wind in the area. Duke needs to work with Dominion and relevant stakeholders through the interregional planning process to identify least regrets plans to maximize net benefits and integrate additional offshore wind resources to support long-term needs of both Duke and Dominion.

Q. DOES DUKE'S PROPOSED CARBON PLAN EMPLOY PROACTIVE AND MULTI-VALUE TRANSMISSION PLANNING?

A. Not really. Duke does recognize the need for more proactive planning.[12] While Duke describes its planning as proactive, it only focuses on needs through 2030, and Duke appears to be using a 10-year planning horizon.[13] That may be sufficient for compliance with North American Electric Reliability Corporation standards, but it is not effective for long-range planning. Duke has not considered a long enough planning horizon to support plans to address 2050 carbon-reduction requirements. We need 20- to 30-year plans. A 10-year planning horizon is only a fraction of the useful life for transmission assets. I do not see evidence that Duke applied the five core principles of efficient proactive transmission planning

[12] See Duke Transmission Panel p.14-22.
[13] Duke proposed Carbon Plan, App'x P at 4.

discussed above and it appears that Duke has not considered the long-term benefits of incremental investments to right-size plans in the near term for select facilities in key corridors.

Duke's proposed Carbon Plan also does not reflect multi-value transmission planning, which would be expected to identify more robust transmission expansion plans particularly for select facilities in key corridors. Duke's Transmission Panel discusses how it values transmission, in the context of the RZEP.[14] Both models that Duke uses focus on quantifying the reliability benefits of transmission investments.[15] That conventional approach does not capture the multiple values that I discussed above.

Q. HOW SHOULD THE COMMISSION'S 2022 CARBON PLAN EMPLOY PROACTIVE AND MULTI-VALUE TRANSMISSION PLANNING?

A. Proactive, scenario-based, multi-value planning needs to be used to mitigate risk and increase insurance value to avoid high-cost outcomes that can be regretful. Given uncertainty regarding future resource mix and other key parameters like the long-term impact of demand response and electrification to future needs, it's critical that future plans be based on scenarios that frame the future.

III. Red Zone Transmission Expansion Plan

Q. WHAT IS THE RZEP?

---

[14] Duke Transmission Panel pp.32-33.

[15] *Id.*

A. The RZEP comprises a group of primarily 115 and 230kV transmission line upgrades and rebuilds listed in Table P-3 of Duke's filing, which together add up to approximately $560 million of transmission expansion investments to support solar project integrations based on generator interconnection requests primarily in east central North Carolina. The RZEP also includes almost $200 million to cover the cost of three 100kV transmission line rebuilds.

Q. PLEASE DESCRIBE DUKE'S TRANSMISSION PLANNING PROCESS FOR THE RZEP.

A. Proactive transmission planning will be necessary to achieve the carbon reductions required by HB951. While Duke says that it engages in proactive planning in its proposed Carbon Plan, it is not truly "proactive" in the way I just described. First, Duke is only considering resource mix needs in 2030. Duke rightly says that its proposed RZEP projects are necessary to getting to the 2030 goal. But Duke doesn't seem to consider what will be needed in 2050, when new transmission assets installed today will only be approaching a fraction of their useful life.

Second, as Duke says throughout its testimony on transmission, it selected the RZEP projects to be able to connect 5.4GW of new solar by 2030, and that 5.4GW figure is based on Duke's proposed Carbon Plan.[16] So while the RZEP projects are necessary, truly "proactive" transmission planning would also take into account whether more low-cost solar could

[16] See esp. Duke Transmission Panel p.21 ("To meet this need...").

be unlocked by additional projects. Synapse's analysis showed more than 5.4GW of new solar as part of the least-cost path to 2030. And even Duke acknowledges that additional projects are necessary to reaching the 2030 goal but were not included in the RZEP.[17] Duke also acknowledges this "if you build it, they will come" effect in its supplemental solar study exhibits, when it says that building the RZEP projects will likely result in an uptick in interconnection requests because developers will know that the congestion has lifted.[18]

In short, I agree with Duke that the RZEP projects are necessary to achieving the 2030 goal, but there is a high likelihood that additional planning for transmission projects in addition to the RZEP projects is needed. The Commission should require Duke to proactively plan transmission for additional renewable resources in North Carolina that are sited outside of the RZEP map, such as a cluster of solar projects just south of Greenville.[19]

Q. ARE THE RZEP PROJECTS NECESSARY PARTS OF A LEAST-COST PATH TO THE 2030 AND 2050 CARBON-REDUCTION REQUIREMENTS?

A. Yes—they are necessary, but not sufficient. As already mentioned, Duke should proactively plan to meet the 2050 carbon-reduction requirements. Recent studies as well as experience in other jurisdictions show that

[17] See Duke Transmission Panel pp.30-31 (and supporting studies).
[18] See Duke Transmission Panel Exhibit 3, p.2 (PDF p.76) ("Note that...") (and same for DEP in Exh. 4).
[19] Duke Transmission Panel, Figure 2: 2022 DISIS Red-Zone Map, p. 35.

proactive transmission planning is a necessary component of any plan to support integration of renewable resources to achieve decarbonization goals and mandates for the bulk power system. Commitments to proactively expand transmission capacity will result in the timely and efficient procurement of the highest quality renewable resources at the lowest cost to consumers. Even though past practices iterate between resource plans and transmission plans, it would be much more efficient to plan resources and transmission at the same time to develop optimal plans.

Q. IS THERE A SIGNIFICANT RISK THAT THE RZEP PROJECTS WILL BE UNDER-UTILIZED?

A. No. I agree with Duke that the risk that RZEP projects will be underutilized in the future is low.[20] In fact, if I were starting fresh, I would consider right-sizing at least one of the projects. Right-sizing decisions need to be based on comprehensive engineering and economic analysis to address long-term needs. It is hard to identify specific recommendations given the wide range of options and limitations to potentially increasing the number of circuits in existing rights of way. For example, Duke could build double circuit capable structures but only string the first circuit initially, or increase the design voltage for select circuits but defer use at that capability until a future date to coincide with substation upgrades. The existing 230kV facilities from Robinson Plant – Rockingham – West End – Cape Fear, transverse the high-quality solar zones and appear to be excellent

[20] Duke Transmission Panel pp.37-38.

candidates for “right-sizing,” especially given the parallel Robinson Plant – Rockingham 115kV line is projected to overload. In particular, the $38M rebuild of the Robinson Plant – Rockingham 115kV line may be best designed for ultimate 230kV operation given the minimal incremental cost per mile of 230kV vs 115kV rebuilds and the economies of scale available in transmission expansion.

IV. Collaborative Planning Studies

Q. WHAT ARE SOME EXAMPLES OF COLLABORATIVE PLANNING STUDY PROCESSES THAT DUKE SHOULD BE LEVERAGING?

A. Coordinated and collaborative planning is a critical success factor in the design of an efficient and effective future grid. The bulk power system is a network of highly interconnected facilities, sometimes referred to as “seams” where interfaced, and real challenges may arise if the network is not managed properly. As a result, it is imperative that neighboring systems work together to identify and address future system needs in an open and transparent manner where the best solutions can be implemented to improve grid performance. The Commission should engage in collaborative planning processes and encourage Duke to provide some leadership to expand the current Southeastern Regional Transmission Planning (“SERTP”), and North Carolina Transmission Planning Collaborative (“NCTPC”) processes, while at the same time leveraging the DOE-funded Atlantic Offshore Wind Transmission Study, to better inform long-term needs of Duke and its neighbors.

Q. HOW COULD LEVERAGING COLLABORATIVE PLANNING STUDIES HELP THE COMMISSION ARRIVE AT THE LEAST-COST RELIABLE PATH TO THE 2030 AND 2050 CARBON-REDUCTION REQUIREMENTS IN H951?

A. Planning studies for SERTP and NCTPC are not effective in identifying future needs based on expected resource mix and system conditions in 2040, let alone 2050. The scope of these studies needs to be expanded to address future uncertainties and inform decisions regarding the replacement of aging infrastructure in key corridors.

V. Advanced Transmission Technologies

Q. WHAT ARE ADVANCED TRANSMISSION TECHNOLOGIES AND/OR GRID-ENHANCING TECHNOLOGIES?

A. Advanced Transmission Technologies ("ATTs") and Grid-Enhancing Technologies ("GETs") are terms that are sometimes used interchangeably in the bulk power industry. ATTs and GETs are non-traditional hardware and software solutions which incorporate capabilities driven by sensors and advanced technologies to improve the performance and utilization of existing transmission assets. Recent NOPRs from FERC have recommended that GETs including Dynamic Line Ratings ("DLR") and Advanced Power Flow Controllers be considered in future planning, as well as generation interconnection processes. Advanced Conductors which utilize carbon composite cores to minimize sag, which increases grid efficiencies by lowering losses, as well as allowing much higher operating temperatures, which result in significantly higher ratings and power densities, would be considered an ATT. Although GETs and ATTs are always evolving to improve their performance, cost, and capabilities, many of these devices have been used for decades and are considered proven technologies in power systems around the world.

Q. HOW COULD DEPLOYING ADVANCED TRANSMISSION TECHNOLOGIES HELP THE COMMISSION ARRIVE AT THE LEAST-COST RELIABLE PATH TO THE 2030 AND 2050 CARBON-REDUCTION REQUIREMENTS IN H951?

A. ATTs such as Advanced Conductors should be considered to accelerate the integration of renewable projects in key corridors when existing conductors are aging and in need of replacement due to condition concerns. Deploying ATTs can be a low-cost way to increase transmission capacity. Recently, a private equity firm and an advanced conductor startup even announced a joint venture that would offer transmission upgrades at no up-front cost, paid for entirely through savings.[21]

The Commission should require that Duke actively consider the multi-value benefits of GETs and ATTs in its planning processes. A requirement could mirror the New York Public Service Commission's recent orders requiring that the state's utilities consider GETs and ATTs in local planning processes and deploy them where they are cost-effective.[22]

---

[21] Ethan Howland, *Starwood Energy, TS Conductor launch JV to triple power line capacity, avoid new transmission obstacles*, Utility Dive, Aug. 26, 2022, https://www.utilitydive.com/news/starwood-ts-conductor-jv-advanced-power-line/630566/.

[22] Order of Local Transmission and Distribution Planning Process Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, New York Public Service Commission (September 9, 2021) at https://electricenergyonline.com/article/energy/category/t-d/56/917705/psc-directs-utilities-to-submit-transmission-proposals-that-support-state-s-aggressive-clean-energy-goals.html.

Q. DOES DUKE'S PROPOSED CARBON PLAN RELY ON GETS?

A. No. Duke has not evaluated the merits of GETs in its proposed Carbon Plan. While some would argue that GETs are more viable options to consider for improving near-term operations and should not be considered for long-term planning to solve reliability criteria violations, it is important for long-term planning to consider market efficiency and public policy benefits of the technologies. The benefits of GETs can be significant in relieving future congestion and creating "energy headroom" for renewable generation during most hours of the year. DLR can substantially increase the amount of renewable energy that can be integrated, enhancing the capability of the existing grid, as well as increase the cost-effectiveness of new multi-value projects evaluated through an improved long range planning process. In addition, data collected as a byproduct of DLR implementations over time can be used to update and improve the accuracy of long-term static ratings used for deterministic planning studies to ensure compliance with NERC reliability standards. As renewable penetrations increase to support decarbonization goals, it's important that probabilistic planning complement deterministic assessments to better manage future uncertainties.

Although GETs or ATTs cannot displace high-capacity backbone transmission expansion projects to support long-term needs, Duke should give due consideration to these technologies in their plans. Duke's Transmission Panel says that Duke is always investigating GETs and using them where it makes sense.[23] But I do not see real evidence of this in Duke's proposed Carbon Plan. GETs can be very cost-effective in improving grid operations and congestion management for both new and old transmission facilities and constraints due to outages, shifts in load, and/or shifts in generation patterns in the future.

VI. Regional Integration

Q. WHAT ARE THE BENEFITS OF IMPROVED REGIONAL AND INTERREGIONAL INTEGRATION?

A. Regional and interregional integration is important to achieve an efficient and effective bulk power system within North Carolina, as well as within the region surrounding North Carolina. Duke needs to better coordinate the planning and operations of its system in collaboration with neighbors, such as Dominion, to support offshore wind developments associated with the Coastal Virginia Offshore Wind Commercial Project ("CVOC") in the southeast corner of Virginia that are already approved by the Virginia State Corporation Commission with plans to expand in the future. Given that opportunity, it is important that Duke and Dominion work together to create effective coordinated plans for both systems.

Interregional transmission can provide large economic, reliability, and public policy benefits that can lower electricity costs. A team at Lawrence Berkeley National Laboratory recently conducted an empirical study of the value of transmission using locational marginal prices and found significant

[23] Duke Transmission Panel pp.44-45.

economic value, driven primarily by reducing congestion during only 5% of operating hours.[24] The team pointed out that conventional planning tends to miss this value by inadequately modeling these high-value periods.

Q. WHAT ARE THE IMPLICATIONS OF REGIONAL INTEGRATION FOR LEAST-COST PLANNING AND DEVELOPMENT OF A LEAST-COST RELIABLE CARBON PLAN?

A. I must stress that "least-cost" planning and development should not necessarily be driven solely by the lowest initial cost investments. A lowest-initial-cost planning approach can end up costing more in the long run as additional investments continue to be required. Long-term planning is especially important for long life assets like transmission infrastructure that will provide a multitude of reliability, economic, and resilience benefits. These benefits have not been considered in planning assessments to date, which have instead been focused on immediate cost savings. The overall efficiency of the bulk power system needs to be given a significant weight in decisions that will drive cost impositions on customers for decades to come. The risks and implications of overbuilding the transmission system are minimal compared to those imposed by the underinvestment in transmission facilities that enable and define markets.

The Duke electric power systems in the Carolinas have an opportunity to capture benefits for both DEC and DEP customers with effective planning and strategic decisions regarding the upcoming replacement of aging

[24]Dev. Millstein, et al., *Empirical Estimates of Transmission Value using Locational Marginal Prices* at 3 (2022), https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf.

assets in, around, and between the two systems. Planning for infrastructure must have a long-term focus and incorporate reasonable assumptions regarding the remaining life of transmission lines, particularly those in critical corridors. Transmission planning to address future needs must take advantage of asset management information to better inform investment decisions. It is not enough to just incorporate asset management decisions as an input into the utility's planning studies. Instead, those planning efforts need to work together in a proactive, holistic manner to identify opportunities for right-sizing aging assets that can defer or displace traditional transmission expansion needs in the future that would result from conservative planning assessments done in isolation.

The implications of not performing holistic, scenario-based, multi-value long range planning for major initiatives such as the Carbon Plan cannot be understated. Duke's proposed Carbon Plan needs to rely more on improved regional integration.

Q. HOW COULD REGIONAL INTEGRATION BE MADE A PART OF THE COMMISSION'S FINAL CARBON PLAN?

A. The Commission should require Duke to synchronize development of its proposed Carbon Plan with its transmission planning processes in the interests of efficiency and least-cost planning. The NCUC should direct Duke in its next proposed Carbon Plan to make changes to existing processes to expand the planning horizon and scope of the SERTP process and NCTPC studies to address 20-year and 30-year holistic planning studies with due consideration of transmission expansion to mitigate system stress associated with extreme weather, physical, or cybersecurity threats. In addition, the NCUC should direct Duke to make changes to existing processes to incorporate non-traditional solutions such as system reconfiguration alternatives and other GETs. Duke need not wait on mandates from FERC, but rather should work with neighbors and stakeholders to revise its planning processes in a proactive manner. At a minimum, the NCUC should not rush to adopt a Carbon Plan in this proceeding that relies too heavily on assuming very low regional integration.

VII. Synchronizing Development of Carbon Plans with Transmission Planning Processes

Q. WHAT DOES IT MEAN TO SYNCHRONIZE DEVELOPMENT OF THE CARBON PLAN WITH TRANSMISSION PLANNING? PLEASE DISCUSS WHETHER AND HOW TO ALIGN THE FERC-JURISDICTIONAL NCTPC PROCESS WITH NCUC CARBON PLAN PROCEEDINGS.

A. The processes in place to support resource and transmission expansion plans are disjointed and untimely in several respects. Transmission planning needs to be based on holistic, scenario-based, multi-value assessments that reflect different base assumptions about resources over a long-term planning horizon. The scope of studies performed by the NCPTC and SERTP needs to better inform regional and interregional plans to ensure least regrets plans which maximize net benefits and address the decarbonization requirements of HB951 through 2050.

The current process is insufficient. For example, Duke says that if the Commission acknowledges that the RZEP projects are necessary for reaching the 2030 goal, the NCTPC will consider the NCUC's position "strong evidence" that they should be approved in the 2022 Local Transmission Plan. This shows how the two processes are disconnected and the NCTPC could end up preventing the NCUC from complying with its obligation under state law to develop a least-cost plan that achieves the 2030 and 2050 goals.

Duke agrees that the NCTPC process should evolve and suggests that the NCTPC could consider some changes that could improve how it reviews projects related to the Carbon Plan. But Duke apparently opposes the NCUC initiating a proceeding aimed at establishing a proactive long-term transmission planning process. Meeting the state's carbon-reduction requirements will necessitate synchronizing transmission and resource planning. The NCUC's role in facilitating the transition to a carbon-free grid necessitates facilitating a transmission planning evolution, as well.

Q. WHY SHOULD THE COMMISSION CONSIDER SYNCHRONIZING DEVELOPMENT OF THE CARBON PLAN WITH TRANSMISSION PLANNING?

A. Better planning will inform better decisions. Uncertainty can be addressed with diverse scenarios that frame futures and drive approvals that are in the best interest of expected future grid operations which will minimize consumer costs. In the future, the Carbon Plan process needs to be improved by more proactive and holistic planning. The ability to co-optimize the resource and transmission expansion plans to support the future grid are important steps which will require better iterative solutions until better software tools and robust algorithms are developed to solve these complex issues.

VIII. Conclusion

Q. RECOGNIZING THAT REVIEWING ALL OF THE COMMENTS OF ALL THE INTERVENORS WAS OUTSIDE THE SCOPE OF YOUR WORK, OF THE COMMENTS OR EXPERT REPORTS THAT YOU REVIEWED, DID ANY COME TO SIMILAR CONCLUSIONS?

A. Yes. Very similar observations, conclusions and recommendations have been provided in the Gabel Associates report prepared for Tech Customers, and the Brattle report prepared for CPSA as well as CCEBA comments. The convergence of suggestions to improve the Carbon Plan is not a surprise, since better planning approaches have been demonstrated, and are being pursued in many parallel efforts now to improve the effectiveness of long-range transmission planning.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Summary of Testimony of Jay Caspary on Behalf of North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council

Docket No. E-100, Sub 179

My name is Jay Caspary. When I prepared my testimony I was Vice President of Grid Strategies LLC (Grid Strategies).[1] I have worked in the utility industry for over 40 years, including senior roles at Southwest Power Pool (SPP) and at Illinois Power. At Grid Strategies, I provided analysis and strategic guidance on transmission grid planning and operations.

The purpose of my testimony is to inform the North Carolina Utilities Commission (Commission) as to six main issues covered in my report, Transmission Issues and Recommendations for Duke's Proposed Carbon Plan: 1) proactive multi-value transmission planning, 2) the "Red Zone Transmission Expansion Plan" (RZEP), 3) collaborative planning studies, 4) advanced transmission technologies, 5) regional integration, and 6) synchronizing development of Carbon Plans with transmission planning processes.

(1) Proactive multi-value transmission planning incorporates future scenarios in order to frame decisions and better manage uncertainties. Rather than only reacting to generator interconnection requests, proactive planning looks forward and takes into account new resources that could be enabled by new transmission. Multi-value transmission planning takes account of the

[1] Mr. Caspary no longer works at Grid Strategies as of September 1, 2022.

actual value of transmission expansion, which typically is not fully captured by the conventional production cost savings analysis. In its transmission rulemaking in Docket No. RM21-17, the Federal Energy Regulatory Commission (FERC) provided a good list of twelve unique benefits associated with long-term regional transmission expansion that are not captured by the conventional analysis.

Proactive multi-value transmission planning saves money through efficient planning and helps to identify and connect low-marginal-cost resources like wind and solar at lower cost. It should be applied regionally and inter-regionally. Unfortunately, Duke's proposed Carbon Plan does not really employ proactive multi-value transmission planning. Its ten-year planning horizon is too short, and I do not see evidence that Duke applied the principles of proactive transmission planning nor a multi-value evaluation framework. Carbon Plans should be based on proactive scenario-based multi-value transmission planning.

(2) I agree with Duke that the RZEP upgrades are necessary—but not sufficient—to achieving the 2030 carbon-reduction requirement at least cost. However, the projects do not appear to be the product of proactive multi-value transmission planning as I have described. For example, proactive transmission planning would take into account whether more low-cost solar could be unlocked by additional projects. Furthermore, it is very likely that additional projects will be needed to reach the 2030 reduction level. I do not think it is likely that the RZEP projects will be underutilized; to the contrary, if I

were starting fresh I would consider right-sizing at least one of the projects, doubling the proposed voltage to take into account future needs.

(3) Coordinated and collaborative planning is critical to designing an efficient and effective future grid. Neighboring systems must work together to identify and address future system needs in an open and transparent manner to improve grid performance and avoid issues at the "seams" between different regions of the bulk power system. The Commission should engage in collaborative planning processes and encourage Duke to provide leadership to expand the current Southeastern Regional Transmission Planning (SERTP), and North Carolina Transmission Planning Collaborative (NCTPC) processes and leverage other existing studies such as the Atlantic Offshore Wind Transmission Study. Expanding these study processes will be important to achieving future carbon-reduction requirements at least cost.

(4) Advanced transmission technologies (ATTs) and grid-enhancing technologies (GETs)—sometimes used interchangeably—are non-traditional hardware and software solutions that incorporate advanced technologies to improve the performance and utilization of existing transmission assets. Examples include dynamic line ratings (DLR), advanced power flow controllers, and advanced conductors such as low-sag composite core conductors with embedded fiber optics. Although they cannot replace high-capacity backbone transmission expansion projects to support long-term needs, ATTs/GETs can be a low-cost way to increase transmission capacity, creating "energy headroom" for renewable generation, and to accelerate the interconnection of

new resources. Unfortunately, Duke's proposed Carbon Plan did not evaluate the use of ATTs/GETs.

(5) Regional integration is important to achieve an efficient and effective bulk power system within North Carolina, as well as within the region surrounding North Carolina. Interregional transmission can provide large economic, reliability, and public policy benefits that can lower electricity costs. It is crucial to understand that "least-cost" planning and development should not be driven solely by the lowest initial cost investments. An approach based on lowest initial investment can cost more in the long run as additional investments continue to be required, and higher operating costs, e.g., losses, are incurred. The Commission should direct Duke to synchronize development of its proposed Carbon Plans with its transmission planning processes, including regional and interregional transmission planning.

(6) Currently, the processes for resource and transmission expansion are disjointed and untimely. Synchronizing development of Carbon Plans with transmission planning will allow co-optimizing resource and transmission expansion plans to support the future grid, resulting in better decisions and least-regrets plans that maximize net benefits and achieve carbon-reduction requirements.

CHAIR MITCHELL: Any other counsel for any other parties' motions at this time?

(No response.)

CHAIR MITCHELL: All right. With that, any other preliminary matters before we turn back to the Public Staff Panel?

(No response.)

CHAIR MITCHELL: Okay. All right. Mr. Schauer, with you.

MR. SCHAUER: Thank you, Chair Mitchell.

CONTINUED CROSS EXAMINATION BY MR. SCHAUER:

Q Good morning.

A (Mr. Metz) Good morning.

Q Mr. Thomas, I'd like to start off on page 56 of your testimony.

A (Mr. Thomas) Okay. I'm there.

Q So at the top on line 1, you testify that Duke's four portfolios selected two CCs to be built by the beginning of 2029; is that correct?

A Wait. Did you say page 56?

Q Forty-fix (46).

A Oh, I'm sorry.

Q I might have misspoken.

A Okay. Yes. I'm there.

Q Is that correct?
A Can you restate the question?
Q That Duke's four portfolios select two CCs to be built by the beginning of 2029?
A The original four portfolios, yes.
Q All right. And the Supplemental Portfolio 5, which is endorsed by the Public Staff, selects one CC to be built by 2029 and one CC to be built by 2030; is that correct?
A That's correct. One CC was delayed.
Q All right. And for the Supplemental Portfolio 5, the modeling uses a no Appalachian fuel supply case; is that correct?
A That's correct.
Q All right. And I'd like to understand the assumptions of the no Appalachian fuel supply scenario that's used in Supplemental Portfolio 5. Do you have Duke's modeling panel direct testimony in front of you?
A Yes, I do. I also have our detailed recommendations from our initial comments, if that's what you're looking for, or I can go to the direct.
Q I think they say the same thing, but I'm going to talk about what I believe are three assumptions that are incorporated within the no Appalachian fuel supply.

A Sure. Can you point me to that?
Q On page 57 in the Snider et al. testimony, it summarizes the no Appalachian fuel supply case.
A Yes. I'm there.
Q All right. And am I correct that the no Appalachian fuel supply case means three things? First, Duke's existing CC fleet would be fueled by Transco Zone 4?
A That's correct.
Q All right. Then the second assumption is that there would be firm transportation of natural gas for two new CCs, correct?
A That's correct.
Q All right. And the third assumption is that no CC would operate on ultra-low sulfur diesel backup, correct?
A That's correct.
Q All right.
A That last one is because in Duke's original portfolios and the no App gas fuel supply, they fueled combined cycles fully with ultra-low sulfur diesel fuel in the month of January.
Q Do you recall that in the Public Staff's initial comments filed on July 15 -- July 15, the Public

Staff expressed concerns regarding future natural gas supply and deliverability?
A In general terms, yes, but I have those comments if you have a specific page.
Q Well, if you recall that in general --
A Yes.
Q -- that's fine.
A Yes. In general, yes.
Q. All right. Does the Public Staff still have concerns regarding future gas supply and deliverability?
A Yes. And Mr. Metz may elaborate, but yes, we do.
Q Sure. So I'd like to go back to the no Appalachian gas fuel supply assumptions. So the first assumption discusses Transco Zone 4. What is the basis for the Public Staff's assumption in Supplemental Portfolio 5 that Duke's existing CC fleet will be fueled by Transco Zone 4?
A Let Mr. Metz elaborate.
Q Yeah.
A (Mr. Metz) So it's sort of the -- you've probably heard the word balance too much, but this is a balance between modeling and operations. So in terms of modeling and the current Duke Energy fleet, Duke does

secure Zone 4 gassing for its combined cycle fleet or for its natural gas use because there's an Asset Management Agreement, more details probably than you want to probably hear right now. So we thought for purposes of modeling that since the existing natural gas fleet already can secure Zone 4 pricing, that it was appropriate to continue that current usage for modeling purposes looking into the future.

Q And my understanding is Zone 4 is Georgia and Alabama, is that correct, Transco Zone 4?

A Zone 4 comes a little bit into South Carolina, but yes.

Q Okay. And Duke's Asset Management Agreement, does it provide -- currently provide supply for all of Duke's CC fleet?

A My understanding of the Asset Management Agreement, that Duke Energy Progress and Duke Energy Carolinas essentially pool the amount of natural gas period regardless of which plan it goes to for its natural gas fleet.

Q And is there a firm pathway from Transco Zone 4 to all of Duke's existing CC fleet?

A So as we're tying back to the Asset Management Agreement, there is a composite of both firm and non-firm

overall for deliverability.
Q So just to revisit that answer, does Duke have firm supply from Transco Zone 4 for all of its existing CC fleet?
A I would have to go back and double check on all.
Q Okay. So the answer is you don't know?
A I don't know.
Q Okay. Thanks. Has the Public Staff or Duke provided detailed information in any of their filings on how Duke would secure natural gas from Transco Zone 4 to supply all of its existing CC fleet?
A Can you please restate the question?
Q Has the Public Staff or Duke provided detailed information in any of their filings in this proceeding on how Duke would secure firm natural gas supply from Zone -- Transco Zone 4 to supply its existing CC fleet?
A In that detail, no.
Q Mr. Metz, I think the next line of questions are with you as well. So the second component of the no Appalachian fuel supply assumption is that Duke would have firm transportation for its two new CCs, correct?
A So the -- Duke's assumptions for the App gas scenarios for their combined cycles would have firm

deliverability for -- of natural -- nat App gas, yes, that was my understanding.

Q Oh, I'm sorry. I'm speaking of the no Appalachian fuel supply case that the Public Staff relied on in the supplemental portfolio. That assumption, the Public Staff assumed that Duke would have firm fuel supply for the two new additional CCs that Duke intends to build in the near term, correct?

A That is correct. And --

CHAIR MITCHELL: Mr. Schauer, you need to speak up or speak into the mic because I'm having a hard time.

MR. SCHAUER: Sorry.

CHAIR MITCHELL: And I want to make sure I hear your questions.

MR. SCHAUER: Yes.

CHAIR MITCHELL: Okay.

MR. SCHAUER: Sorry, Chair Mitchell.

A And that is correct. And if you look at page 73 of our initial comments, we go into more detail of the reasoning behind the potential for firm transportation of new natural gas non App gas.

Q And at page 73 do you discuss the Transco Southside project?

A I would have to go back and double check if I called out that project by name, but they are the Williams Transco projects.

Q Okay. So even though you didn't call it out by name, your intention was to reference the Southside project?

A There's two projects in question, and I'm mixing up the names right now, so I can't remember the names right now.

Q Okay. But yesterday I believe you testified that the Public Staff assumed that the Transco Southside project would provide natural gas to Duke's two new CCs, correct?

A Correct.

Q All right. And you said you reviewed the Williams Transco website and found that the Southside project would provide 423,000 Dth per day; is that accurate?

A I believe, subject to check, on the actual Dth usage.

Q Okay. But it was between 400,000 and 423,000, subject to check?

A Subject to check.

Q Okay. And you said that the project would include upgrades to the Transco Pipeline somewhere in

Iredell County; is that correct?

A I believe they are starting at Station 165, and I cannot recall right now how far south those upgrades went.

Q Okay. And you testified that if Duke could secure all 423 Dth or all that was available because of the Southside project, that would be sufficient to fuel Duke's two new CCs in the near term?

A Under the assumption that they are both -- they move forward with the 1200-MW -- the approximately 1200-MW combined cycles, that's my understanding.

Q And what's the Public Staff's basis for assuming that Duke would be able to acquire all the capacity from the new Southside project?

A So this is -- again, as I stated earlier, this is the balance of modeling, that we are not approving or recommending approval, or has Duke asked for a CPCN in this particular docket. But, again, looking forward, say is there a possibility that we can have natural gas to the combined cycles and is that gas firm? Start going all the way back to the P1 through P4 portfolios, Duke had modeled the alternate scenario in the case that there was not firm transportation, so that way they assume for the month of January typically when the natural gas system is constrained, it would run on ultra-low sulfur diesel.

I believe that that was a good stress to look at how the system can operate, what cost would it operate at, and what would the emissions be as an alternate or a sensitivity to say if that transportation did not come available at a later point in time.

Q Thank you, but I'm not sure you answered my specific question, so I just want to restate it. So what is the Public Staff's basis for assuming that Duke would be able to acquire all of the capacity from the Southside project?

A From a modeling standpoint, that we believe it was appropriate to include at this time, again, for modeling, that the natural gas would be available. We're going to continue to monitor new natural gas pipeline or expansion of the natural gas pipeline as we move forward.

Q All right. And I understand that you believe it was appropriate to include, but I'm trying to understand what's the basis for you determining that it was appropriate to include that as an assumption?

A If Williams Transco says we're going to expand our natural gas pipeline, I think I made the assumption that it's reasonable to model that potential scenario as we look at all the different potential outcomes.

Q All right.

A (Mr. Thomas) And I think if I could just add real quick to this.

Q Please, Mr. Thomas.

A In terms of the modeling, I do just want to point out, you know -- well, actually, never mind. It’s confidential and I don’t want to get into that. I just saw the note on the comments, so sorry.

Q I’m not going to bring us into confidential session again. Why wasn’t the Southside project mentioned in the Public Staff’s Initial Comments or direct testimony?

A (Mr. Metz) One second. I’m looking back at the initial comments.

Q Okay. And please correct me if I missed it in either of those.

A So looking at our Initial Comments at page 73, “Given the recent proposal for Williams Transco upgrade projects, however, the Public Staff supports the use of Henry Hub Zone 4 and Zone 5 gas pricing for modeling purposes and planning.” So yes. So, again, for context, given the recent proposals, the recent proposals are found publicly on Williams Transco’s webpage.

Q Okay. So it wasn't referenced by name, but that quote that you just gave me was the reference you intended to use to refer to the Southside project?

A Again, I can't remember the exact names. There's two projects. There's one that goes through Virginia into North Carolina and almost horizontally, then there's the main trunk upgrade, so --

Q Yeah. I also reviewed Appendix N of the carbon plan, which -- in which Duke discussed fuel supply, and I noted that Duke makes no mention of the Southside project there, does it?

A Subject to check.

Q Right. And Duke also doesn't mention the Southside project in any of its direct testimonies or rebuttal testimonies; is that correct?

A I cannot recall.

Q Okay.

MR. SCHAUER: Chair Mitchell, I do have an exhibit I'd like to introduce. With the Chair's permission, I'd like to mark this as Tech Customers Public Staff Panel 1 Cross Exam Exhibit 1.

CHAIR MITCHELL: Can someone help Mr. Schauer so we can get this document marked?

MR. SCHAUER: All right. Chair Mitchell, I believe everyone has copies.

CHAIR MITCHELL: Go ahead.

Q So the exhibit I just handed you, if I could orient you to it.

CHAIR MITCHELL: Mr. Schauer, we've got to -- let's mark it first.

MR. SCHAUER: Oh, I'm sorry. Chair Mitchell, I move to mark the exhibit as Tech Customers Public Staff Panel 1 Cross Exam Exhibit 1.

CHAIR MITCHELL: All right. The document will be marked Tech Customers Public Staff Panel 1 Cross Examination Exhibit 1.

MR. SCHAUER: Thank you.

(Whereupon, Tech Customers Public Staff Panel 1 Cross Examination Exhibit 1 was marked for identification.)

Q So what I handed you is an exhibit I prepared. This shows a map from the Transco -- of the Transco Southside project which is from the Williams Transco website. Mr. Metz, when you reviewed the website, do you recall seeing this map on the website?

A Yes.

Q All right. And on the bottom I've included a map of Duke's existing generation assets, which is figure C2 from Appendix C of the Carbon Plan, just for reference.

Mr. Metz, if you look closely, the Transco map says that the Iredell station, which is the bottom left little square -- it's hard to read, I'm sorry for the size -- the Iredell station will provide 264,000 Dth. Do you see that, the 263.4 Mdth/d?

A Correct.

Q All right. And then I'm looking to the right of the Transco map and there's two more yellow dots, and those are in Northampton County and Hertford County, and they respectively will provide 120,000 Dth and 40,000 Dth. Do you see that?

A Yes.

Q So based on this map, it appears that the additional 400,000 Dth that are going to be provided because of the Southside project are going to appear both in Iredell County and then separately in the northeastern corner of the state in Northampton and Hertford. Am I understanding this map correctly?

A So it was my understanding that the -- when I was stating Station 165 before, I was referencing Station 166. It is my understanding that Station 166 -- or my view, again, not a natural gas pipeline planner -- that the modification at Station 166 would alleviate the approximately 400,000 Dth that I was referencing, then that could be directed down towards the bottom left and as well horizontally over to the right towards Hertford.

Q But as you -- based on this map, and I'm generally trying to understand this map, am I correct that it appears the alleviation caused by the upgrade at 166 will result in about 160,000 Dth being available in the northeast and about 260,000 being available in Iredell County?

A It was my understanding it's up to 160 to the east through potential future expansion, but the modification at Station 166 would allow the throughput down to that point.

Q So just to -- so I understand your testimony, is it your understanding that the modification at 166 would allow all 400,000 Dth to be available in Iredell County?

A No, because the system -- you're going to have system usage and system losses as you transition from Pennsylvania down to Iredell County. And, again, we're not using location specifics for purposes of the modeling, so don't know for certainty if Duke will potentially locate in Rockingham or if they would locate south of Iredell County.

Q But location specifics would impact whether or not Duke would be able to get firm supply of natural gas, correct?

A Oh, absolutely.

Q Okay. So looking at both the Transco map at the top and figure C2 at the bottom, assuming Duke can secure all the additional capacity from the Southside project, do you know how Duke is going to get 160,000 Dth of gas from the northeastern part of North Carolina to whichever brownfield site it locates a new CC?

A So if your question is asking of how they would build a pipeline out of predominantly -- I mean, it’s Dominion Energy North Carolina’s territory or Dominion’s territory down over into Duke Energy Progress, I don’t think that would be a reasonable pipeline expansion project. However, the assumption is that they’re going to probably branch off the main Williams Transco pipeline, the predominant trunk from Pennsylvania down to Iredell.

Q But am I correct in reading this map provided by Williams Transco that 160,000 Dth would only be available from this branch that breaks off to the east, to the northeastern part of our state?

A I would need to go back to review the detailed summary on the Williams Transco website for both of these projects.

Q Based on the Public Staff's Initial Comments, do you believe -- and the testimony here today, do you believe that the Public Staff has provided detailed information on how Duke could secure firm transportation from the Southside projects to its new CCs?

A What we looked at is pipeline projects that are for, pardon the pun, that are in the pipe that are potentially either underway or in review or has potential for being possible to interconnect, understanding also evaluating projects that have been delayed like the main MVP project, we thought it was reasonable for planning purposes within the model to allow that possibility of firm transportation.

Q Right. But you, I believe, earlier said you don't know how Duke would be able to get gas from the northeastern corner of the state to a CC at a brown site. Don't you think that's an important detail?

A Well, that's an important detail, but all the modeling assumptions for all the resources, I don't know how Duke is going to interconnect them, but these are modeling scenarios, and we put cost inputs as proxies to evaluate a gambit of events.

Mr. Thomas, do you want to --

A (Mr. Thomas) Yeah. I mean, I'd just kind of add to this. You know, there's a lot of uncertainty in the gas supply, right, so trying to understand, you know, not only what gasses might be needed in North Carolina to kind of maintain system reliability is an important factor in this modeling, but, you know, none of our -- our comments and our testimony repeatedly, you know, emphasize that nothing in a near-term action plan is approving a natural gas plant. And I think, you know, the CPCN proceeding for such a plant would be the place where we would, you know, have some uncertainty resolved around the Transco Southside Reliability project, other potential expansions, the MVP and MVP Southgate project. And obviously, you know, the prudence of a gas plant at that time I think would be analyzed not only in the context of that specific gas plant, but the changing conditions entirely that may, you know, that may potentially render such a gas plant, you know, not necessary. But I think we need to keep an eye on both the need for gas and the need for reliability, and that's why we felt it was reasonable in the expansion --

capacity expansion model to allow for that incremental capacity for gas CCs.

Q So I understand that this is not a CPCN proceeding, but we are talking about the near-term portfolio that we need to move forward on the carbon plan. And am I correct that the Public Staff Supplemental Portfolio 5 is affirming the need to build natural gas plants, but doesn't know where the gas for those plants will come from?

A I think that -- I know that witness Metz just testified that there's expansion projects in the works. Do we have a pipeline route to bring gas to whatever site that is eventually chosen for a CC? No. I don't have that -- that CPCN application, that pipeline route in front of me, but I think that that's going to be part of future considerations. You know, those pipeline costs, you know, are going to be an important determinant, and the route and ability to actually construct it are going to be important in terms of deciding whether or not that is in the best interest of ratepayers.

But I think we try to make a reasonable assumption that the gas pipeline system needs expansion, and there are significant needs for natural gas not only for electricity consumption, but for industrial customers. And so that gas has got to come from somewhere, and I think we thought it was reasonable to limit that gas to kind of acknowledge the existing projects in the pipeline, but to also acknowledge that there are limits to that and there will be challenges associated with it.

A (Mr. Metz) And for further context, is this -- this has been an ongoing observation of ours since 2020 comments from the IRP. For purposes of the Carbon Plan, if those William Transco projects were not called out, we would have landed at a different scenario for SP5.

Q So Mr. Thomas, I was just thinking about your testimony yesterday regarding overprocurement where you said even though you know you're going to need three cars over your lifetime, you're not going to buy all three cars now. Let's say you need a car in the near term and you don't know whether or not there's going to be gasoline in North Carolina, would you buy a Ford F150 or would it be more reliable to buy a Tesla?

A (Mr. Thomas) If I didn't know there was going to be gasoline in North Carolina. That's a good question. I think I'd have to -- I'd have to have a better understanding of why there would be no gas in North Carolina, but I think when I'm sitting at my computer doing the spreadsheet calculations to figure out what would be the right car to buy, I think it would be reasonable to try to entertain both options, but when I go to sign the paperwork, I think that's going to depend upon, you know, the knowledge I actually have at that time.

A (Mr. Metz) If I had perfect foresight, then I absolutely know what decision I would make, but the challenges here is that we don't have perfect foresight. There's a possibility with new developments and we thought they were reasonable for planning.

Q But there's also risks associated with those new developments not materializing?

A That is correct.

Q All right.

MR. SCHAUER: No further questions.

CHAIR MITCHELL: Ms. Grundmann.

MS. GRUNDMANN: Thank you, Chair Mitchell. Good morning, gentlemen. Carrie Grundmann on behalf of Walmart.

CROSS EXAMINATION BY MS. GRUNDMANN:

Q I think I just have really just a couple of questions, and they are for Mr. Metz and Mr. Thomas. And I'm going to be asking both of you if you agree with

portions of each other's testimony because they overlap.
But can we start, Mr. Thomas, with your testimony at page 42?
A (Mr. Thomas) Okay. I'm there.
Q Specifically looking at lines 4 to 6. You testified --
A Yes.
Q -- there that natural gas fuel consumption peaks apparently in both DEC and DEP in 2026; is that correct?
A Yes. And that's referencing Figure 5, and that's both across DEC and DEP. And I think I testified yesterday that, you know, this to me, the reason this is happening, because this is from the production cost models which do not have a carbon limit because of the way EnCompass functions, this is a reflection of the amount of renewable generation that's being added to the grid, and that is naturally displacing natural gas. And obviously, you know, natural gas is often called a transition or a bridge fuel, and I think that this graph is really showing you that, that you need it for system reliability to serve load in the early stages of the transition, but by the time you reach 2050, you know, you've really begun to phase out of that.

But obviously a lot of that depends on the prevalence of hydrogen. What's not shown in this graph is in P1 through P4. You know, Duke made assumptions about hydrogen eventually completely supplanting natural gas, which would allow those plants be more utilized, but there's a lot of uncertainty about the hydrogen economy, particularly in the face of recent events.

Q Mr. Thomas, thank you for that more fulsome explanation. I think my question just related to when it relates to the Company's near-term action plans with respect to new natural gas, you would agree with me that none of those proposed plants come online before 2026?

A Yes.

Q Okay. And so by the time these plants come online under the Company's proposal, would you agree with me, and I think part of your answer suggested this, that the plants that the Companies propose to build under the near-term action plan, sir, are more useful for reliability purposes and bridge purposes, as you indicated?

A If I could restate your question, you're saying that the existing plants are more utilized for -- or the new plants?

Q I'm focusing on the proposed plants that the

Companies want to build or have selected as part of its near-term action plan. When those plants are built and presumptively in service in late 2029, 2030, because you here indicate that natural gas consumption reaches its peak in 2026, when these new plants go online, are they predominantly to serve a reliability need?

A I think it depends on the plant. I think CTs, absolutely. I discuss that later in my testimony. The CT capacity factors, at least in the model, are very low. The CCs continue to serve, you know, both capacity and energy. And I'd note that, you know, what I -- I didn't really discuss much of my testimony, but these plants are also, you know, providing ancillary services, operating reserves that, you know, allow for not just to enable us to have sufficient capacity to meet demand, but also to be able to respond quickly and to provide the spinning reserves, the black starts, it's all those ancillary services that are required to maintain system reliability such as power quality and voltage support that are not necessarily reflected in the EnCompass model outputs.

Q And so then I'd like to turn to Mr. Metz's testimony on page 56, looking at the graphs that are shown there. And yesterday I believe there were some questions to you, Mr. Thomas, about the SERVM model and the LOLE. I think it was -- I just want to summarize your testimony. Let me know if I've misstated it. But yesterday I think you indicated and confirmed that Staff didn't actually have the ability to go in and run SERVM, but you're generally familiar with the program and you didn't really have any reason to question the results, and I think those results, though, are set forth in Mr. Metz's testimony; is that fair?

A Yeah. That's correct.

Q Okay. And then can I ask you both to turn to Mr. Snider with the modeling panel's direct testimony, specifically looking at page 202. And maybe keep your finger on Mr. Metz's testimony while we sort of toggle back and forth between Mr. Metz's testimony and page 202 of the modeling panel's testimony.

A I'm there.

Q Would you agree with me that if we are looking at the graphs that are on Mr. Metz's testimony and the graphs that are in the modeling panel's testimony on page 202, that they are identical except that the modeling panel's testimony also includes the results under SERVM for the Synapse optimized and the Gable/Strategen preferred portfolios?

A Yes. They're the same graphs, but we had only been really focusing and talking about the reliability of our SP5, and so we had simply removed the other model results.

Q Okay. And so when it comes to your prior testimony about not having any real concerns about the reliability or validity of the SERVM model's results, is that also true with what we see on page 202 of Mr. Snider's testimony?

A You're asking me if I have any reason to doubt the analysis of the alternative modeling portfolios in the SERVM model?

Q Correct.

A No, I do not.

Q Okay. And so then would you also agree with me, if we just take a look at what's identified as the Synapse optimized portfolio on page 202, do you see that in the 2030 time frame it is almost -- it is below the .253 LOLE threshold?

A Yes. And it's above that threshold in 2035.

Q But just focusing on 2030 --

A Yes.

Q -- for the time being --

A Yes.

Q -- you agree with me that it's below it, and that reflects that that portfolio as of 2030 is reliable based on the analysis of thousands of different model runs, correct?

A Yes.

Q Okay. And then you agree with me that when we look at 2035 that that portfolio does, under the Company's LOLE analysis, appear to exceed that LOLE threshold?

A Yes. That's what the graph shows.

Q And would you agree with me, and it's okay if it's subject to check, that the Company's threshold for the Synapse Optimized, that although the -- well, let me try to explain it again. The graph goes from 2030 to 2035. Would you agree with me that, subject to check, that for purposes of the Synapse Optimized that it actually doesn't exceed until 2035 as opposed to any prior year between 2030 and 2035?

A I think that's difficult to know because I believe Duke only runs certain years. They don't run this, you know, for -- for the whole planning horizon. They select certain years to run. So I couldn't know when it actually broached that limit.

Q If I'm correct, let's assume for purposes of my question that the reliability issues using the Company's

SERVM results aren't triggered until 2035, can you agree with me you understand the basis for my hypothetical?

A Yes. I do.

Q Okay. And are you aware as to whether the Synapse Optimized portfolio includes any new natural gas?

A I do not -- subject to check, I do not believe the Optimized does.

Q Okay. And so again, back to my hypothetical that the trigger for the reliability isn't until 2035, would the Company have sufficient time to build natural gas plants for a reliability purpose if it waited until the 2024 Carbon Plan and potentially later to put those issues back before the Commission if the reliability issues aren't triggered until 2035?

A So if I understand you correctly, you're asking me if your hypothetical is true and the Synapse Optimized portfolio is reliable until December 31st, 2034, and then suddenly in that 2035 it is not reliable, you're asking if the Commission would have time to make adjustments prior to that, veering into unreliability?

Q I think that's correct. If the Commission could wait for purposes of this proceeding to make a decision on natural gas and defer that to a future carbon plan proceeding.

A I think based upon this sole analysis here with the LOLE results, you could come away with that conclusion, but I'd also point out that I think that the Synapse model, while they did use EnCompass, I, you know, I -- they did change some of the commitment settings in terms of some of their production cost models, and I've played around with that a little bit and that does have an impact, but I think there could be time to adjust. It really depends on what kind of adjustment is necessary and what type of capacity needs to be installed. But I'd have to -- I'd have to review again the additions in the Synapse Optimized to see what kind of capacity it was calling for in that 2030 to 2035 time frame.

A (Mr. Metz) But we also -- sorry.

Q Oh, I'm sorry. I apologize.

A And we also have to look at what resources were selected because, again, looking at the model as it was projecting out to 2035, we may have, for lack of a better word, overbuilt in these early years and created a problem, and this had to essentially place more costs and more risk to fix the problem.

Q But you would agree with me that under the sort of prevailing phraseology that we may have heard more than a dozen times, under the Carbon Plan we can check and adjust, and that would include checking and adjusting in 24 months in 2024, correct?

A That’s correct, but I would be cautious if we’re going to over -- be overly procuring and just creating a further challenge for us down the road. Mr. Thomas?

A (Mr. Thomas) And I think one thing I would kind of point out here is the Synapse model, you know, assumed different -- I think different capital costs and then also used different commitment models for arriving at its preferred portfolio which did not add gas by 2030. But I think we need to recognize that there is fundamental differences between, you know, how Duke ran the model, how we ran some of our EnCompass models and how Synapse did that might, you know -- that under this hypothetical that the reliability issues only emerge in 2035, I think that that’s a risky hypothetical to make. They could just as easily appear in 2031.

I think it depends a lot upon, you know, the coal retirements and the firm capacity that can be obtained from some of Synapse’s more aggressive battery storage additions. So I think we need to weigh holistically the risk, and it’s maybe risky to go down -- I truly believe in the check and adjust strategy here, and I think that we need to look at that not only in the updates and the Carbon Plan proceedings, but also in future CPCN proceedings, but -- but yes. I think we need to maintain reliability, and we can't wait too long to discover that we're -- our system is not sufficiently reliable.

Q But wouldn't you agree with me that a fundamental principle to a natural gas plant providing a reliability function is to have a fuel source to be able to power it?

A Yes.

Q Okay. And do you happen to know the original expected date that the MVP project was supposed to be completed when it was originally proposed?

A Subject to check, but I think it was like 2020.

Q Okay. So we're two years behind that.

A Yeah.

Q And would you agree with me that if we waited a few more years -- well, let me back up. Do you understand that FERC has recently extended the construction permit for MVP by four years?

A I believe. So I think it currently has an in-service date of summer 2023.

Q And so if we were to wait until presumptively the 2024 Carbon Plan, if MVP is successful in coming online in 2023, we could -- would you agree with me that we would know a couple of things? That it's actually built. Would you agree with that?

A Yes. We would know the status of that.

Q We would potentially know whether the Company had, in fact, been successful in securing firm supply?

A We could. I don't know the status of that -- those negotiations, but that could be one source of uncertainty that would be resolved.

Q And would you also agree with me that regardless of the Commission's decision in this carbon plan, if the Company truly believed that it needed new natural gas, that nothing would prohibit it from proceeding to file a CPCN prior to the 2024 Carbon Plan?

A Yes. That's my understanding, that nothing would prohibit the Company from making such a filing, but we would review that, you know, vigorously, as any CPCN application.

Q Real briefly, and I apologize. I don't know -- Mr. Thomas, I believe you had some testimony in your direct testimony as it relates to offshore wind. And give me a second. I'll try to find it. Oh, it's page 34.

A Sure. And I just want to emphasize that I focus more on the modeling aspect and Mr. Metz on the near-term development, but go ahead.

Q Well, to the extent that I've asked the wrong person --

A Sure.

Q -- please let me know. But Mr. Thomas, what caught my eye was your testimony on page 34 about there being 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?

A Yes. And I think -- I believe Avangrid has testified that they would be open to negotiating with Duke, but, you know, I'm certain that there are those goals in Virginia as well.

Q But are you -- do you -- just curiosity. I believe that the -- I'm not going to reuse it, but I believe a copy of the Virginia Clean Economy Act was previously marked as an exhibit, but have you had any occasion to review that legislation?

A I'm generally familiar with the scope and some mandated resources and a renewable portfolio standard as

well, but I don’t know the exact quantities.
Q And so you’re familiar, then, under the Virginia Clean Economy Act that Dominion Virginia was statutorily authorized to choose to construct that project and does not have any statutory obligation to use a third party to develop offshore wind?
A If I recall correct, the VCA mandated that Dominion move forward with the CVOW project, but I -- my understanding was there was additional incremental offshore wind or renewable resource requirements beyond simply the one project that Dominion is building currently.
Q Well, we can obviously refer to the statute to consider that, correct?
A (Witness nods affirmatively.)
Q But you are familiar that Dominion Energy Virginia did opt to move forward with the Coastal Virginia Offshore Wind project as the owner, operator, and developer of that project, correct?
A My understanding is that they are currently, but there’s some -- I believe they recently entertained the idea of withdrawing the project due to some performance guarantees imposed by the Commission up in Virginia, but yes, I know that they have -- they’re

moving forward with that.
Q And that the -- I believe the project cost for that, I think it was approximately $9.6 billion?
A Subject to check, I believe so.
A (Mr. Metz) I believe the most recent estimate is 9.8 billion.
Q Thank you.
MS. GRUNDMANN: Those are all the questions that I have.
CHAIR MITCHELL: You're up, Duke.
MR. BREITSCHWERDT: Thank you, Chair Mitchell.
CROSS EXAMINATION BY MR. BREITSCHWERDT:
Q Gentlemen, how are you? Before I get started, I've got a few documents that I'd like to pass out. These are in the record of the proceeding, so I'm not going to mark them as exhibits. I think you'll be familiar with them, but I think passing them out will help expedite the process.
All right. So gentlemen, my questions or at least the first line of questions is going to be predominantly for Mr. Thomas. Mr. Metz, if you have input, certainly welcome that. Mr. Williamson, probably coffee time of the day versus Coke time of the day, but I don't have a lot of questions for you. And then Ms. Link

will have some questions for Mr. Metz towards the end.

So would like to start by focusing on near-term actions. And Mr. Thomas, I think your testimony and some of your testimony yesterday found that the Company's general approach to presenting multiple portfolios and then presenting a discrete near-term action plan was a reasonable approach for this initial Carbon Plan; is that right?

A (Mr. Thomas) Yes.

Q And you also -- well, would you agree with me that it was reasonable for the Companies in presenting the Carbon Plan to ask the Commission to select a certain discrete volume of resources, supply side resources, for execution between now and the next Carbon Plan update in 2024?

A Yes. I think that we may have different approaches on how we calculate that number, but yes.

Q Okay. And the first page in the materials that I handed out to you is something that I think you'll be familiar with, but this is page 20 of the Public Staff's comments that were filed on July 15th.

A Yes.

Q Familiar with that? And just to set the stage so to speak, this is preceding the Public Staff's more detailed recommendations in your comments where you requested/recommended the Companies undertake supplemental modeling. Do you recall that?

A Yes.

Q Okay. And that the second sentence, and I'll just read it briefly, "Public Staff requests that Duke complete P5 model run and determine if the short-term execution plan detailed in its Petition, particularly item 3(a), still aligns with the results from P5. Duke should provide the model results in a supplemental filing no later than August 19th, 2022. To the extent that actions identified in the short-term execution plan are validated by the P5 model run, the Public Staff recommends approval of those actions within the near-term execution plan." Is that your comments?

A Yes.

Q And item 3(a), that's item 3(a) from the Company's Petition which laid out the supply side resources, solar, solar plus storage, storage, wind, and gas, correct?

A Yes.

Q All right. And partly I wanted to come back to your comments just to reflect that this was July 15th, so approximately 60 days ago?

A Yes. I believe that's when we filed it. Yes.
Q All right. And just a significant amount has happened since then. The Companies very rapidly undertook this analysis, correct?
A Yes. I -- yes.
Q Filed it on August 19th, and then your testimony filed September 2nd, and we're moving very rapidly to this hearing where we are today.
A I think we've all been under compressed timelines here.
Q A compressed timeline. So turning to page 6 of your testimony where you're summarizing your testimony in the case, and I think you touched on this briefly yesterday at lines 12, starting on line 11 actually. It's "Finally, I discuss Duke's near-term procurement activities associated with an interim compliance date of 2032 and find them generally reasonable and recommend the Commission approve a revised 2022 Solar Procurement" -- "of 1200 MW." Did I read that correctly?
A You did, although I would note "generally reasonable" doesn't mean we completely agree on the quantities, and I discuss some differences later in my testimony.
Q Okay. Good. Well, that's --

A It’s directionally accurate, I guess maybe would have been more accurate.

Q Well, that’s what I want to talk about and explore, because at the end of the day the Commission is tasked with developing a Carbon Plan and has to select a discrete amount of resources to be executed or developed, procured between now and 2024.

A Yes.

Q Do you agree with that?

A Yes.

Q All right. So the second document which I expect you’ll be familiar with is this is Rebuttal Exhibit 1 from the modeling panel’s rebuttal testimony, but it’s also Table 1. Are you familiar with this?

A I am, yes.

Q Okay. And have you had a chance to fully review the modeling panel’s rebuttal testimony?

A Generally yes, but if you’d like me to reference a particular page.

Q Sure. Around pages 21 to 24, and you don’t have to go there. You’re welcome to. But they spend about three or four pages dissecting your page 63 table and then how that related contrasted to the near-term actions that the Companies presented in the Carbon Plan.

Is that your recollection?
A Yes. Yeah. They talk about the different years and the solar and storage resource selection specifically.
Q Okay. And so that was summarized generally in this rebuttal Table 1 which identifies the year supporting deployment, and then Duke's proposal or Public Staff proposal and also provides details on Intervenor alternative modeling proposals; is that accurate?
A Yeah. That's what the table shows, yes.
Q Okay. And can you -- well, maybe let's ask it this way. So would you agree with me that your Table 63 assumed both incremental solar and storage to be placed in service in the year 2029 as well as some -- what Duke called, I guess, earlier resources in '23 to '25 on the solar side and then some resources that were predetermined GSA? They were forced into the model?
A Yeah. I mean, and that would include the, you know, 441 MW of CPR solar and the approximately between 75 and 150 MW that might drop out of Tranche 2 as well.
Q Right. And so the third page, which we can spend time on if it's helpful, but this was from Rebuttal Table 2 on page 23 and walks through what the Companies' near-term actions included versus did not include versus

what the Public Staff did?
A Yes.
Q Okay. And so at the end of the day, do you agree with the representations in Rebuttal Table 1 of the volumes of solar storage standalone, onshore wind CTs and CCs represented here as the Public Staff's proposal?
A So I think that -- I think that generally if we're talking about an apples-to-apples comparison, I think that these are approximately fair comparisons, but I think -- I just want to note that, you know, when I prepared my Table 3 in the testimony, I think I was looking at -- you know, first of all, I think that the 2024 Carbon Plan will obviously be an opportunity to revisit this. There is no guarantee that a final order in that proceeding will be available in time to implement the 2025 procurement of solar and solar plus storage.
So I think what I attempted to do, and maybe I -- perhaps I should have elaborated on this more in my testimony, was to show the Commission, you know, this is what is being procured prior to 2030. This total quantity that I presented, which was more than what Duke had in their table and then they removed that in-service by the end of 2029, I think those resources are important for the Commission to see and to understand. And it also

shapes not only the near-term plan, but also, you know, where that rubber hits the road and the volumes that we're procuring in the 2022 solar procurement.

I think, you know, Duke I think stuck with their recommendation of, you know, the model picked 750 MW in 2026, and so the 2022 procurement should be that 750 MW. And I tried to take a more holistic view and say this is what we need over the next four years. Let's try to, you know, average that out with, you know, recognizing certain constraining factors like locations in -- locating some solar in DEC and recognizing the Red Zone upgrades aren't included, but trying to somewhat, you know, front load to not only stress the interconnection process to see what we can really achieve, but to also set us up for potentially exceeding those targets and being able to reach compliance earlier than 2032 which kind of, you know, complies with our, you know, looking at the importance of the 2030 deadline, but also recognizing the tradeoffs between cost, reliability, and executability with CO2 reductions.

Q Thank you for that. And just one clarifying point. You mentioned your proposal of 1200 MW for 2022 solar procurement. Would you agree with me that Duke's proposal effectively gets to the same place because they had assumed the 441 MW of CPRE would be in the baseline, so now Duke is also proposing 1200 MW for a 2022 procurement?

A Yes. I think if -- when we -- when I originally did the calculations in my testimony, I believe I had arrived at approximately -- if you were evenly to spread out this four-year procurement target over four years, I believe it was something around 1440 MW. But we recognize there's challenges associated, particularly in the near term, and so we tried to adjust that slightly to still front load and attempt to achieve a little bit earlier, but also to recognize those system constraints.

So I think we were trying to find a balance. And one thing I want to emphasize is the 750 MW chosen in 2026 is, you know, a subject of that interconnection limit, and the only way we'll know if we can exceed that is if we attempt to interconnect more than that. And I think the 1200 MW proposed both by Duke and by the Public Staff in their 2022 procurement volume, you know, would attempt to reach that balance and potentially hopefully achieve compliance earlier than 2032.

Q Thank you. And so we're aligned on the 2022 solar procurement volumes, and so we've got Duke's proposal of near-term actions and then we've got the Public Staff's proposals which have slightly lower or somewhat lower levels of standalone solar and then somewhat higher levels of paired storage and then standalone storage.

And just referring back to your testimony on page 6, and I think you said it was directionally consistent, I think where -- does the Public Staff agree with Duke's proposed near-term action plan as reasonable for execution and selection by the Commission between now and 2024?

A Well, I think the issues with, you know, the near-term action plan proposed by Duke are, you know, we want to make sure that we're appropriately getting the right resources and I think that, you know, the near-term action plan did not recognize, in my opinion -- the near-term action plan proposed by Duke did not recognize the additional benefits provided by solar paired with storage that were revealed in SP5, so I think that that's an important distinction to make.

And certainly when you're talking about thousands of MW, a difference of a few hundred here and there may not seem a lot, but 220 MW of additional solar plus storage, you know, and 130 MW of standalone storage potentially being able to displace a certain amount of standalone solar, I mean, that's -- I think that would be in the interest of ratepayers not only in the near term, but also as these resources are put into place and as they begin service.

So I think there's nuance there and maybe they might appear slight, but I think, you know, these are still a lot of facilities, still a lot of megawatts, and still a lot of -- some difference there that I think we need to acknowledge, because SP5 did allow that solar plus storage to provide more value in a more accurate representation, I believe, of how the system would actually be operated, and those differences I think need to be acknowledged.

Q Thank you for that, Mr. Thomas. I want to turn now to what's represented as the alternative proposals by the Tech Customers AGO, CPSA, and NCSEA, et al. Have you have had a chance to review the table specifically as it pertains to those alternative recommendations?

A Generally. You're talking about Rebuttal Table 1?

Q That's correct.

A Yeah. I've reviewed the table. I understand that some of these were pulled directly from model results or comments, but yes.

Q That's correct. And to the best of your knowledge, has Duke accurately presented the near-term actions of the other parties' alternative modeling?

A I believe so, yes.

Q Okay. And just for contrast, I think, you know, slight differences or however you characterized it between Duke's proposal and the Public Staff's proposal, you think -- would you agree with me that there are material differences between those two proposals for near-term actions to be selected by the Commission and the alternative plans presented by other parties?

A Yeah. I mean, looking at the table, I think, you know, the AGO is clearly the most aligned. The Attorney General's Office is most clearly aligned, with the exception of gas, but the other portfolios do call for what I would call significant differences, you know, 1 to 2 GW, so yes.

Q Yeah. And let's just draw down a little bit on that. So the bottom half of the table under the Differences columns reflect obviously differences from the Duke proposal. For Tech Customers, they add 350 MW of solar, but then they add additional 2900 MW in batteries, which is a significant deviation in the near

term from the Duke selectable resources, correct?
A Yeah. I would refer to that as significant, yes.
Q And then interesting, CPSA adds 1700 MW of solar and a thousand plus -- a thousand fifty plus MW of paired with solar storage, but eliminates standalone storage completely from their proposed portfolio.
A Yes. I believe that from this -- I'd have to look back at their actual results to verify, but from this table, yes, they shift almost entirely to solar and solar plus storage.
Q Right. And in contrast to that, NCSEA, the Synapse Optimized portfolio adds or takes away any paired storage and adds 3000 MW of standalone.
A Yes. That is correct. Yes.
Q You may recall they set 4000 MW of solar standalone and 4000 MW of storage standalone as their near-term actions?
A Yes. And, you know, I think that's -- I think we can discuss -- we don't need to get into it, but that, you know, obviously may reflect how the solar and storage is modeled, right, the fact that the standalone can charge from the grid versus the solar coupled cannot, and that may play into those exact numbers, but yes, I'd

agree the table is showing this.

Q Yeah. And just to follow up on some questions counsel for Walmart asked you a few minutes ago, you recall that she asked a hypothetical about the LOLE validation step the Companies undertook?

A Yes.

Q And specifically whether the Synapse Optimized portfolio was unreliable in December 31st of 2034 or 2031 based on the SERVM analysis the Companies undertook?

A Yes. It's difficult to know when it became unreliable, but somewhere in that time frame it would have.

Q And isn't the more -- would you agree with me the more fundamental question, considering that Synapse Optimized portfolio is recommending 4000 MW of solar and 4000 MW of storage to be interconnected in the near term by the end of 2028, that that's not executable?

A I wouldn't say it's not executable. I think it presents additional risks and challenges, but I don't know that I would say it's not executable. I also think that particularly with regards to the storage, right, we haven't seen a lot of interconnection of storage. Much of this would presumably be utility owned and competitively -- hopefully competitively procured, but we don’t really know how that will be interconnected, where it will be interconnected, whether it will be able to take advantage of surplus interconnection requests or replacement generator interconnection requests. So certainly those higher numbers present a challenge, but I wouldn’t call them impossible, necessarily, over the next four years.

Q But you would agree with me that based on the Public Staff’s recommendation and recognition that the solar interconnection constraints the Company used in Portfolios 2, 3, and 4, that those volumes significantly exceed what the Public Staff determined was reasonable for planning purposes?

A Yes. They did exceed what we found to be reasonable, yes.

Q Thank you. Could you turn to page 53 of your testimony, please?

A Fifty-three (53)? I’m there.

Q Okay. And on line 8 -- and you discussed this testimony some yesterday with counsel for Tech Customers, but this goes to the reasonableness of the Companies’ resource cost and technological characteristic assumptions using the Carbon Plan. Do you recall that?

A Yes.

Q And based on your detailed review of the carbon plan inputs and assumptions, you found those resource costs and technological characteristics to be reasonable; is that accurate?

A Generally, yes. I think we stressed a few of the models with changing some costs that kind of understand what the implication would be there in our investigation, but yes, we did not find them to be unreasonable.

Q Right. I want to specifically focus on the assumed cost for combined cycles and combustion turbines that you spoke about with counsel for Tech Customers yesterday. Do you recall that?

A Yes.

Q Okay. And both yourself and Mr. Metz explained over a series of questions that Duke's approach to calculating economies of scale adjustments and assuming that a new combined cycle or combustion turbine would be constructed at an existing site are reasonable assumptions. Do you agree with that?

A Yes. I believe that's what we testified to, yeah. And noting that we review those CT costs pretty extensively as well in the avoided cost documents.

Q All right. And would you agree with me that there's nothing in the Carbon Plan that suggests Duke is planning to construct a new single-unit combustion turbine at a greenfield site?

A No. The Carbon Plan is not site specific and, no, I would expect that Duke could make every effort to locate it at a brownfield site.

Q Okay. And do you have Appendix D to the Carbon Plan with you by chance?

A I don't have it.

Q That's all right.

A I think Dustin does.

Q I can --

MR. BREITSCHWERDT: Chair Mitchell, I'd like to introduce a cross exhibit, if I could, please. Chair Mitchell, whenever you're ready, I can mark this as a Duke Energy Public Staff Panel 1 Cross Examination Exhibit.

CHAIR MITCHELL: The document will be marked as Duke Energy Public Staff Panel 1 Cross Examination Exhibit 1.

MR. BREITSCHWERDT: Thank you.

(Whereupon, Duke Energy Public Staff Panel 1 Cross Examination Exhibit 1 was marked for identification.)

Q Mr. Thomas, have you had an opportunity to review the document?

A Yes.

Q And on the bottom half of the page, I will represent that this is Table D2 from Carbon Plan Appendix D. See that?

A Yes.

Q And that appendix and table summarizes the number of CTs the Company has, the various generating sites operated by DEC and DEP. Are you familiar with that generally?

A Yes.

Q And I'll represent to you that the top half of the exhibit is a summation of the data at the bottom half and identifies each of the sites the Company owns and operates and the number of units that are CT units that are operating there.

A Yes. This appears to be accurate.

Q Okay.

A I'd have to check, but it looks accurate.

Q All right. And would you agree, based on your knowledge and experience and what's represented here, that for every Company-owned site, that there are at least four CT units or there's other generation co-located at the site?

MR. BURNS: Madam Chair, I'd object, if I could, just to the establishment of the facts in the note section at the top half, how those facts have been established. I'm not sure if they've actually been introduced into evidence.

MR. BREITSCHWERDT: I'd be glad to spend some more time on that. Based on his knowledge and experience, if he can represent that he's familiar with these sites and the notes look accurate, then we can move this along.

CHAIR MITCHELL: All right. I'll sustain the objection. Take him through the background.

MR. BREITSCHWERDT: All right.

Q Mr. Thomas, do you see the Notes column on the right side of the upper chart?

A Yes.

Q And for the sites that are identified, would you agree with me that the Richmond Smith facility, there's, to the extent that you know, five combustion turbine units as well as that it's -- there's a combined cycle unit that's located at that site?

A (Mr. Metz) Yes. I would agree.

Q Okay. Thank you, Mr. Metz. And similarly for

Wayne there's both five CTs there as well as the H.F. Lee combined cycle facility?

A That is my understanding, yes.

Q Okay. And could you look down the remainder of the notes, and would you, based on your knowledge and experience with the Company's generating fleet, identify any facilities where it doesn't -- the notes don't seem to be accurate in terms of co-located combined cycles or multi-unit sites?

A The notes properly reflect what they're stating.

Q Okay. So based on your understanding, the Company has got this right and they note the number of combined cycles and CTs at their various generating sites?

A Yes.

Q Okay. Thank you. So based on this, would you agree with me that it's reasonably likely that the Company plans to construct a new combustion turbine at a site where there are existing CTs operating today and so they would not be a brownfield site? Would you agree with that?

A (Mr. Thomas) They would be a brownfield site?

Q They would be constructing in a brownfield site.

A I think that's a reasonable assumption, yes.

Q Okay. Thank you.

A The expectation, perhaps.

Q Thank you. All right. Could you turn to page 46 of your testimony, please? All right.

A I'm there.

Q All right. On line 13 you state that the Public Staff also finds Duke's natural gas combined cycle configurations and operable life assumptions to be reasonable. Do you see that?

A Yes.

Q And is it accurate, in your understanding, that Duke allowed the model to select between F-Class and J-Class units in the supplemental modeling?

A Yes. Both were permitted in the supplemental modeling.

Q And which unit was selected in the SP5 that the Public Staff found to be reasonable for planning purposes?

A For CCs the J-Class was selected.

Q And that's a 1200 MW unit?

A Yes.

Q And in all portfolios is it accurate that both the four -- P1 through P4 portfolios presented by the Companies in the initial Carbon Plan, as well as in the supplemental modeling, that the modeling selected J-Class units?

A I think the conclusion about that, the selection between the two can really only be drawn from SP5 and 6, because in P1 through P4 the F-Class was not an option to be selected, so it didn't have a choice. But in SP5 and SP6 it had a choice and it still selected the 1200 MW unit.

Q That's a good point. Thank you. Turning to your statement about operable life assumptions, do you see that?

A Yeah.

Q In the question you speak to the reasonableness of the Company's operable life assumptions?

A Yes.

Q And you said you found those to be reasonable. Just remind the Commission briefly, when you say "operable life," what do you mean by that?

A So in the -- there's two ways that the life of the unit is kind of used in the modeling. The first is the operable life in EnCompass, so that's the lifetime that the unit is online. And I think in that case it's essentially beyond the end of the horizon period in any case. And then it's used again in the calculation of the conversion of the capital cost in dollars per kW into the real levelized fixed charged rate that's used in -- it's used actually in EnCompass, and I believe in that case, subject to check, I believe it was 35 -- 35 years I believe, I'd have to double check, but it appeared reasonable for what we would expect such a unit to operate for.

A (Metz) It's 30 or 35. I can't recall the exact number.

Q So subject to check, 35. And if we looked at Chapter 2 it would say it was 35 years, subject to check?

A Subject to check.

Q All right. Thank you. And subject to check, do you recall that certain other Intervenors', Synapse and Attorney General's Office, experts used significantly shorter operable life of 20 years. Do you recall that?

A (Thomas) I do and, you know, I wouldn't necessarily call those assumptions unreasonable. I do think that those Intervenors are attempting to address the risk of stranded assets, of these assets becoming stranded and retired early, much like some coal units have all over the country. So I think it's reasonable modeling assumptions. Differences can be made, and I do think that that's a reasonable effort to attempt to identify that risk, so --

Q All right. Did you hear Mr. Snider's testimony sometime last week?

A I was here for it.

Q Okay. Do you recall Mr. Snider responding to the concerns about stranded asset risk by suggesting that one of three things will come into existence or are likely to come into existence by the late 2040s, either, one, the hydrogen economy will become viable; two, there will be an offset market that comes into an existence which is authorized by HB 951 to enable the amount of combined cycle generation the Companies would have online, or three, there's flexibility in the legislation to enable the Companies for reliability reasons to continue to operate past 2050 with some limited carbon emissions? Do you recall that testimony?

A Yes. I do recall, although I'd note that legislation limits those offsets to only I think 5 percent.

Q That's right. And he had a number of how many GWh hours a year that was.

A Yes. And that --

Q Pretty significant.
A Yeah.
Q Okay. Thank you. All right.
A I would just say “pretty significant” is subjective. I think it was about 8000 GWh and, subject to check, I think that’s less than 10 percent or so of system demand, so it’s something, but yeah, it’s not like extensive.
Q It’s 5 percent?
A Yeah.
Q All right. Do you recall that the Tech Customers, in their alternative resource plan by Gable and Strategen completely excluded combined cycles as a selectable resource?
A Subject to check, I -- subject to check.
Q Okay. And would you agree with me that that’s not a reasonable planning assumption, to completely eliminate combined cycles as a selectable resource in the Carbon Plan?
A I think from my perspective, there can be disagreements on modeling assumptions if the -- in that report if those resources are excluded. Much like in Duke’s alternative gas portfolios that they submitted with the original Carbon Plan, they prohibited the

selection of the larger J-Class CCs based upon fuel supply assumptions. The assumptions made about the lack of natural gas supply could have caused them to eliminate the selection of CCs from their modeling. I think that those -- you know, we've talked a lot about the risk of natural gas supply not being here and the CCs not being able to be supplied. And if someone made that conclusion, which I would not say that conclusion is unreasonable, they wouldn't necessarily want to eliminate CCs from being selected by the model.

However, I think that a more appropriate method might be to still allow the model to select the resource, but simply to limit the amount of gas that's available to the system. They would essentially accomplish the same thing, but one is a more physical constraint versus one is a more artificial constraint. So I think that the discussion about gas supply, it's very reasonable to have different opinions on whether we will get gas in the future. I don't know and I don't think anyone in this room knows for certain what we will have in the next six to 10 years.

Q Thank you, Mr. Thomas. And just to be clear, the Public Staff's SP5 and the assumptions that you found to be most reasonable for planning purposes assumed a 35-

year operable life and assumed that a combined cycle combustion turbine was an appropriate selectable resource in developing a least-cost plan for North Carolina?

A Yes. You know, like I said, I find that the assumptions Duke used in terms of that supply in SP5 were reasonable, but I'm just responding to your question if you thought it was unreasonable to prohibit a CC, and I would not agree necessarily that that's an unreasonable choice.

Q Thank you. Could you turn to page 51 of your testimony, please? So yesterday you received some questions from both counsel for Avangrid as well as counsel for Tech Customers regarding Duke's approach to modeling onshore wind resources delivered into DEC. Do you recall that?

A Yes.

Q And counsel for those parties seemed to be suggesting that based on their understanding of Duke's modeling approach and your testimony, that Duke may be conceding that if off system resources are selected as part of the Carbon Plan, then there would be some flexibility in the ownership requirements under House Bill 951. Do you recall that?

A I recall that line of questioning, yes.

Q Okay. And you address this issue in your understanding of the Company's modeling at page 51, lines 4 and 5 of your testimony.

A Yes.

Q Okay.

MR. BREITSCHWERDT: I've got one additional exhibit I'd like to pass out, please, to the Commission. Thank you. Chair Mitchell, I'd like to mark this as Duke Energy Public Staff Panel 1 Cross Examination Exhibit 2, please.

CHAIR MITCHELL: All right. The document will be marked as Duke Energy Public Staff Panel 1 Cross Examination Exhibit 2.

MR. BREITSCHWERDT: All right.

(Whereupon, Duke Energy Public Staff Panel 1 Cross Examination Exhibit 2 was marked for identification.)

Q Mr. Thomas, I'll represent to you that this is a data request from the Public Staff to Duke Energy, Data Request Number 13-5. Does it look accurate --

A Yes. Yes, it does.

Q -- and are you familiar with this document?

A I know that this was a data request sent. We sent quite a few. Yes.

Q Yes, you did. So the question that you asked was “Do the Companies assume any onshore/offshore wind that’s selected in the Carbon Plan must be utility owned or are they assuming that a PPA from a merchant generator would suffice?” Do you see that?

A I do.

Q And the Companies explain that their modeling assumptions are that any onshore or offshore wind shall be utility owned, in accordance with House Bill 951, and this, if you go on to the second paragraph, specifically explains that for DEC they were assuming that there were wheeling costs for imported wind into DEC. Do you see that?

A I do.

Q And while the data response doesn’t get into the details of how the costs were calculated in the model, are you familiar with or would you accept, subject to check, that the Companies assume that the unit that they were inputting into the model was a utility-owned asset versus a PPA?

A Yes. And I did actually -- after this conversation yesterday I did go back into the EnCompass model just to double check, and it does appear that this particular portion where I said Duke made the decision to model these resources as a PPA was incorrect. They did model these as utility-owned resources with -- similar to those in DEP with a wheeling charge.

I would -- you know, I think that Public Staff in general, and I think the Commission should be cautious of, you know, Duke acquiring off-system resources and to ensure that those are properly acquired. I don't think it's necessarily -- I worry about Duke going and simply building, you know, onshore wind facilities in MISO or PJM and then securing a path in the transmission cost there, but I will acknowledge that this testimony here is incorrect in terms of how it was modeled.

Q Thank you, Mr. Thomas. Those are all the questions I have for you. Ms. Link has some questions for Mr. Metz.

CHAIR MITCHELL: All right. Before we begin, Ms. Link, let's take our morning break. We'll be off the record now. We'll go back on at 11:15.

(Recess taken from 11:00 a.m. to 11:18 a.m.)

CHAIR MITCHELL: Go back on the record, please. Ms. Link, you may proceed.

MS. LINK: Thank you, Chair Mitchell. Good morning, gentlemen. My name is Vishwa Link on behalf of the Companies.

CROSS EXAMINATION BY MS. LINK:

Q Mr. Thomas, I'd like to start with you. I've got two areas. One area is about new nuclear. The other is about offshore wind.

A (Mr. Thomas) Sure.

Q So starting with new nuclear. I understood from your testimony yesterday that you agreed it was reasonable to include SMRs in the modeling, correct?

A Yes.

Q And you agree that the Companies made reasonable assumptions on commercial availability of SMRs, correct?

A Based on what we know today, I think they were reasonable, yes.

Q And you agreed that 2032 was a reasonable date for SMRs, correct?

A I think it's aggressive, but reasonable, yes.

Q And, in fact, P5 includes SMRs in mid 2032?

A I believe about 300 MW was selected in mid 2032, yes.

Q And you also noted that we can come back in 2024 and we can check and adjust these assumptions, correct?

A Yes.

Q All right. And you agreed, or would you agree that the predevelopment activities, like obtaining an early site permit, has value for customers because it is technology agnostic?

A Mr. Metz might be better to talk about the near-term development activities.

A (Mr. Metz) So in listening to my testimony is that we couldn't evaluate the exact actions that Duke wanted to take, but for understanding if you wanted to accomplish an aggressive goal to 2032, it was not unreasonable to move forward with those development activities.

Q Okay. Thank you. And so -- but the question I asked was does an early site permit have value for customers if you -- if the Companies were to obtain one for new nuclear?

A If we set an aggressive schedule, I believe that an early site permit, just in isolation of all the other factors that we need to consider, would be a -- would be a required step to move forward to meet that aggressive timeline.

Q Thank you.

A (Mr. Thomas) I'd also, just to add to that, you know, in the 2024 and 2026 proceedings, you know, there will be many updates and many uncertainties resolved and, you know, if SMRs become infeasible, if the upcoming, you know, expected nuclear renaissance fails like it did in 2000, you know, an early site permit at that point would not provide value to ratepayers. So I think it's -- there's risks here, but, you know, whether or not it will eventually provide value to ratepayers is really determinative on how the future plays out in terms of SMRs.

A (Mr. Metz) I believe this is also centric, because the models continue to economically select these resources in 2032. As soon as they are available, they are being selected.

Q Thank you. And Mr. Thomas, did I understand your testimony yesterday to be that not performing predevelopment activity could potentially sabotage efforts to be prepared for the resource in a particular year?

A (Mr. Thomas) I think that when you talk about, you know, long lead time items, then I don't know if I use the word sabotage, but I think that you increase your execution risk if you wait on performing the actions that are within your control.

Q Okay. Would you accept, subject to check, you did say sabotage?

A If I did, subject to check, yes. But, you know, I just want to caveat that the predevelopment activities should be, you know, reasonable and within scope and comply with kind of the resource needs as they're identified, right? If Duke started building a reactor vessel, I think that would be preemptive, right? But some studies that are understanding of the technology and the cost that could be incurred, those types of activities, I think, are reasonable on a long-term time frame.

Q Public Staff witness Boswell at page 9 does not recommend approval of the nuclear project development cost; is that correct?

A I don't have her testimony in front of me, but I'm sure you can ask her those questions. But subject to check, yes.

Q Okay. So if we -- if the Company does not pursue the near-term development activities for new nuclear, doesn't it mean that we would be sabotaging new nuclear being available in 2032?

A (Mr. Metz) Sorry. So it is my understanding that Duke did not come in and seek cost recovery for these activities. They were merely laying out a plan and that is -- was our -- me and Mr. Thomas' review was we're looking at what steps would be needed for that plan or our discussion review did not center on cost recovery.

A (Mr. Thomas) Yeah. I think if you have a copy of Ms. Boswell's testimony, I'd like to take a look back. I think that she was addressing more the cost recovery and deferral, where Mr. Metz was discussing more the activities that might be prudent.

Q Okay. Thank you. I will find -- get that paper copy for you.

A Thank you. I apologize for not having this. Didn't know I'd be asked cost recovery questions, but -- page 9?

Q So it is page 9.

A Yeah. Are you talking about page 9 --

MS. LUHR: I'm sorry. Can you repeat the question?

MS. LINK: Yes.

Q Public Staff witness Boswell at page 9 states that the Public Staff -- it's line 3 -- does not have the information necessary to determine which initial project development cost might be eligible for special treatment under North Carolina General Statute Section 62-110.7 and does not recommend approval of any nuclear project development cost at this time.

So what I'm trying to understand is if you gentlemen believe it is reasonable -- the SMRs are reasonable development costs, it's reasonable to expect them to be available in mid 2032, it could sabotage them being available. If the Company doesn't presume near term development activities, how do we reconcile that position with Ms. Boswell's position that the Public Staff is not recommending approval of any project development cost at this time? Is it simply just whether we're asking for cost recovery? I'm just trying to understand that distinction.

MS. LUHR: And I would object to this. I think these questions are more properly directed towards Ms. Boswell.

CHAIR MITCHELL: All right. I'm going to overrule the objection. I'll ask Mr. -- I'll ask the Panel to respond, recognizing that they're being asked about Ms. Boswell's testimony, and anticipate Ms. Boswell being asked the same question.

MS. GRUNDMANN: Chair Mitchell, I might add an additional objection. I believe counsel previously objected numerous times to the use of subjective phrases. I think that witness Thomas has previously indicated his lack of belief that he used the word sabotage, accepted it subject to check, so I think she hasn't provided any context for what the word "sabotage" means in her question, so I think it's a vague question.

CHAIR MITCHELL: Okay. And I'm going to overrule the objection. Go ahead.

A (Mr. Metz) So, again, deferring to Ms. Boswell to represent her testimony, but making the linkage between the two, it is more centric to cost recovery emphasis. The Public Staff does not have the information that is from Ms. Boswell's testimony. When you look over on page 26, starting at line 10, or I'll start with the question, "Are you disputing the cost and required activities that Duke has stated? No, but I do not have the means to measure or evaluate Duke's listed activities."

So, again, for purposes of modeling, we said okay, yes, if you want to meet an advanced goal, that it's more likely than not that you would probably have to do these types of activities. But however, as Ms. Boswell is pointing out to, if you want cost recovery, a more detailed analysis and review, as well as multiple other factors and Ms. Boswell can elaborate to, also has to be considered.

A (Mr. Thomas) And if I could just elaborate, that theme is throughout our entire testimony. We recommend addition of battery storage in the near-term action plan. We recommend, you know, procurement of solar plus storage. We recommend approval -- you know, we're moving forward on certain Red Zone expansion plans as part of the goals to meet 951, but in no way, when they continually make clear that these decisions on moving forward with certain activities do not constitute approval of cost recovery. This is not a cost recovery proceeding. And this would be appropriately addressed in a general rate case, a multi-year rate plan, or other cost recovery proceeding where the appropriate investigation would take place on prudence and reasonableness.

Q Well, thank you for that distinction. I guess my question is the development -- setting aside cost recovery, the development activities for new nuclear that are laid out in the long lead-time panel direct testimony -- do you happen to have that copy with you by any chance? And I could get you --

A I do not have it in front of me, no. Should have brought more binders.

Q Binder overload.

MS. LINK: Permission to approach. Oh, thank you. Thank you, counsel.

Q So I'm looking at page 32 of the long lead-time panel direct testimony. It's Table 2.

A (Mr. Metz) So page 32?

Q Yes, sir. Are you there?

A Yes.

Q Okay. So there on page 32 at Table 2 there are new nuclear near-term development activities. Do you see that?

A Yes. And that matches the table that I listed on page 26 of my testimony.

Q And my question is, are those near-term development activities the types of activities that would enable the Companies to be able to have SMRs available in 2032?

A Yes. Based upon my experience in the nuclear industry, these would be steps to move forward with that process. But it's like I tried to identify in my testimony, again, for illustrative purposes looking at 2022 of $5 million, I can't tell this Commission whether it should be $300,000 or $15 million. I think that's what we're trying to highlight in my testimony. I didn't have a means in this case to evaluate what actions and what should roll up into those total costs.

Q But the activities themselves are reasonable?

A Yes.

Q And the activities are necessary, wouldn't you say, to be able to ensure that if we come back in 2024 or 2026 and check and adjust and need SMRs in 2032, we should get started on those activities after the Commission order here, correct?

A I think it's my testimony that if you want to meet the -- if the Commission deems that they want SMR technologies for 2032, which is an aggressive schedule, these are actions and not limited to that would need to take place.

Q Thank you. Turning to an additional piece of your testimony yesterday, Mr. Thomas, I believe you said you had looked at some IRPs from other utilities, and they also had SMRs available in the early 2030s. Did I understand that correctly?

A (Mr. Thomas) Yes. There were some. I didn't -- I don't recall the exact dates where they were selected or implemented, but, you know, some IRPs did not have it at all. Some IRPs had them, but were not selected. And a smaller subset of that had them and had them selected.

Q Was one of those IRPs you reviewed Virginia Electric & Power Company's 2022 IRP update?
A Yes.
Q That was just filed September 1 of this year?
A Yes.
Q Okay. I have an exhibit to hand up.
MS. LINK: And Chair Mitchell, there's some handwritten notes at the top only because this was meant to be used on a different panel, and we will correct those and put them properly when we file them in the docket.
CHAIR MITCHELL: Okay.
MS. LINK: But may we have this marked DEC/DEP Public Staff Panel 1 Direct Cross Examination Exhibit 1?
CHAIR MITCHELL: I think -- I think we're at 3, right?
MS. LINK: Oh, my apologies.
CHAIR MITCHELL: Let's go 3. And so just for consistency, let's say Duke Energy Public Staff Panel 1 Direct Cross Examination Exhibit 3.
MS. LINK: Thank you.
(Whereupon, Duke Energy Public Staff Panel 1 Direct Cross Exhibit 3 was marked for identification.)

Q Gentlemen, do you have that Exhibit 3 in front of you?
A (Mr. Metz) Yes.
A (Mr. Thomas) Yes.
Q And it is just an excerpt of a much larger document, but the cover page is the Virginia Electric & Power Company 2022 update to their 2020 Integrated Resource Plan; is that right?
A Yes.
Q And it was filed at this Commission in Docket Number E-100, Sub 182 on September 1st, 2022?
A Subject to check, yes. I believe that’s the docket number.
Q Thank you. And so the second page is only an excerpt. It’s page 7. And it’s the Section 1.2.2 Small Modular Reactors.
A Yes. This discusses, particularly the second-to-last paragraph discusses how they were included in the model, but I don’t know, this page doesn’t discuss what was selected. But yes, these are the assumptions that were put into the model.
Q Okay. Thank you. And then the second-to-last paragraph states that “Based on the status of SMR development,“ -- the Companies anticipate -- “the Company

anticipates SMRs could be a feasible supply-side resource as soon as the early 2030s." Do you see that?

A Yes.

Q And then the last sentence of the page says "Based on updated capital operating and maintenance cost, continued progress of licensing timelines and new policy initiatives or legislative changes, it is conceivable that the deployment of SMRs could be further accelerated by the Company, with the first SMR being placed in service within a decade." Do you see that?

A Yes. And I'll also note that this -- to my knowledge, this IRP from Dominion does not request approval of any development costs or accounting deferral or any special treatment related to the cost of development that they appear to be already engaged in.

Q Fair enough. But that is an example of an IRP that you have reviewed that had SMRs coming in service in early -- in the early 2030s?

A They were selectable in the early 2030s, yes. I don't recall off the top of my head when the resource was first selected, but I do know some alternative plans did select SMRs.

Q Thank you.

A But I don't know in what year.

Q Thank you. Let's move to offshore wind, if we could. And starting with you, Mr. Metz, in your testimony you testified that offshore wind development times are 10 years at a minimum from lease acquisition to in-service date?

MR. JOSEY: Can you give him a page number, please?

MS. LINK: Of course.

Q Page 24.

A (Mr. Metz) I'm on page 24.

Q Okay. Do you see there at the top of page 24 the amount of time that you indicate offshore wind -- the offshore wind development time from the time of lease acquisition, that it's a minimum of 10 years?

A I don't believe it's -- I did not clarify lease acquisition. I just -- offshore wind development in the United States, the scale proposed by Duke in the carbon plan is nascent and expected to take approximately a decade at a minimum to achieve commercial operation.

Q Okay. A decade at a minimum.

A (Mr. Thomas) If I could just add to that, I'll note that the development of these leases is also an extensive process for BOEM when they're -- even before they put the lease up for auction. So, I mean, there's lots that goes into even defining those leases, getting them eligible for sale before even any bids are received.

Q Thank you for that clarification. So Mr. Metz, staying on that page, you recommend -- you recommend reevaluating the need for offshore wind in the 2024 Carbon Plan?

A (Mr. Metz) That is correct.

Q Okay. So let's take ourselves to the 2024 Carbon Plan, and we're reevaluating that need. If it takes 10 years at a minimum to develop an offshore wind facility, wouldn't we be saying that the earliest time offshore wind would be available for North Carolina customers is 2034?

A Absolutely not.

Q And why is that so?

A Because Duke Energy Wind Renewables is assuming that the Carolina Long Bay could be continuing the advancements of their project. To assume that a project is static and does not move, I can't speculate to what reason they would be doing that. That's their risk they took when they got the lease.

A (Mr. Thomas) And I'd also add that there's three lease areas off the coast of North Carolina, and I don't expect that Avangrid or TotalEnergies are going to make no efforts to develop their lease efforts -- their lease areas between now and the 2024 Carbon Plan. I have no reason to believe that they would just do nothing.

Q Okay. So I guess the possibility, then, is they could be available sooner than 2034 if we wait until 2024 to make a decision on pursuing development activities. Fair enough?

A (Mr. Thomas) Could you restate that question?

Q Sure. My original question was if we wait till 2024 to start pursuing, meaning Duke regulated companies, start pursuing development activities on offshore wind, doesn't that mean with the 10-year development time that offshore wind won't be available until 2034? My understanding was a resounding no to that question.

So then my question is, these other leases could be developed by either Duke Energy Renewables Wind or Avangrid or TotalEnergies, but that is not subject to the control of this Commission or subject to the control of the regulated Duke entities, correct?

A Yes. That's correct. I think those are three separate unregulated entities that are developing three separate lease areas, according to their own business plans and their financial analysis, and the Commission does not necessarily control what those companies do.

And I won't speak for Mr. Metz. He can elaborate, but, you know, I don't think that we've come out in this.

We've testified just yesterday that the 2024 Carbon Plan should -- you know, it could benefit from a more detailed analysis specifically of the three separate lease areas and how they compare and what is the best option for ratepayers. And I think that we all recognize that at least in SP5, offshore wind is still selected in the late 2040s or in the early 2040s, and I think what makes -- what Mr. Metz is really recommending against is we don't think the Commission should approve Duke Energy Progress to spend $155 million to acquire a lease and spend another $156 million in developing some of these resources for a resource that may not be needed until 2040, particularly considering that a lot of the development work, particularly with relation to the lease itself, can be done by entities that are not Duke Energy Progress, and that risk can be put on entities that are not, you know, cannot receive recovered -- rates recovered through ratepayers. I think that would be less risk for the ratepayers in general, and I think it supports the check and adjust plan, and I think it helps ratepayers -- it helps this Commission give an opportunity to evaluate all three lease areas in future

Carbon Plan proceedings and determine which is in the best interest of ratepayers.

A (Mr. Metz) And when you use the word balance, again, is when you look at the entire Carbon Plan and you look at the upgrades and projects that are all being presented, we are also trying to balance those costs, to the extent that we're going to do expansive transmission upgrades as listed in the Red Zone upgrade. That's one factor to consider.

To move forward with SMR deployment, those are costs that we're also potentially going to move forward with, to move forward with the uncertainties with Bad Creek Hydro, to move forward with all these other technologies, how we looked at this is these projects can move forward under unregulated business practice that they see fit, but yet here is another $300 million bucket, if you would, for cost, we just don't think it's appropriate at this time for the regulated utilities, in particular Duke Energy Progress customers or Duke Energy Carolinas, that we should move forward with this.

The model suggested with the model enhancements this isn't needed till the 2040s. There's time to wait, and that is a value.

Q And when you say the model selected in 2040, didn’t Portfolio 1 and Portfolio 2 pick offshore wind economically in the 2030 and ’31 time frame?

A I want to turn to Mr. Thomas a little bit to explain maybe the -- not extreme, but differences with the SP5 modeling where we believe that is an enhancement.

A (Mr. Thomas) Yeah. And I --

Q And I appreciate that. Is it possible to answer whether P1 and P2 pegged offshore wind economically in the 2030 and 2031 time frames first?

A There were blocks of offshore wind economically selected in those portfolios which we found to have some unreasonable modeling assumptions.

Q Okay. Thank you. So going back to the notion that the three unregulated or the three entities that are not regulated by this Commission would continue to develop those leases, and we could possibly meet a 2030 or 2032 date for offshore wind, are you familiar with the Avangrid testimony that in order to make those dates, meaning the 2030 date, they would need an offtaker for their agreement for their lease?

A (Mr. Metz) Subject to check.

Q Okay. And basically we would -- if we don’t -- if this Commission does not approve the decision to incur the development activities for offshore wind, aren’t we just -- aren't we subject to whatever these three unregulated entities want to do on their own time frame and at their own risk?

A Well, the short answer would be yes, but however, when looking at the Carbon Plan, the -- from a modeling standpoint, these projects were not economically selected in SP5 until way in the planning horizon into the 2040s.

Q Okay. Fair enough. A slightly different sort of area of inquiry with regard to offshore wind. I believe -- do you recall the exchange yesterday with Mr. Smith for Avangrid regarding whether future study or future due diligence for offshore wind is needed?

A (Mr. Thomas) Yes.

Q Okay. And the point of that future study or due diligence would be to find the least cost option under House Bill 951, correct?

A Yes.

Q Okay. And Mr. Thomas, I note at page 34 you note that there is no guarantee that the Kitty Hawk lease can be secured from Avangrid, because utilities in Virginia also have clean energy goals, correct?

A Yes. That is what my testimony says.

Q Okay. Can you explain a little bit more about

what you mean about no guarantees?
A Avangrid is a private -- is a company that's seeking to develop and sell the output of their offshore wind facility, and they may sell it to Duke if the terms and arrangements there are reasonable. They may sell it to an entity in PJM. They may sell it to the market in PJM. It's really up to them. And the Commission nor Duke has control over what they do.
Q And are you familiar with the Kitty Hawk lease, that it has been recently split into a Kitty Hawk North and Kitty Hawk South parcel?
A I believe so.
Q Okay. And the Kitty Hawk North parcel is scheduled to interconnect into Virginia Beach, Virginia?
A I haven't seen that interconnection study, but subject to check.
Q Okay. And then the Kitty Hawk South parcel could go to Virginia Beach or also could come down to North Carolina counties. Would you accept that, subject to check?
A Yeah. It's my understanding they have not submitted an interconnection request.
Q Okay. But in terms of the splitting of the lease at BOEM, the Bureau of Ocean Energy Management,

that south lease can interconnect into Virginia or down into North Carolina?

A Yeah. I think that's reasonable, yeah.

Q Okay. So to your point of you can't guarantee that it would be available to Duke, it's possible that entire Kitty Hawk lease could be interconnected into Virginia and PJM, correct?

A Yes. It's possible.

Q And Avangrid as a, you know, commercial enterprise, they would seek to develop that lease to its highest potential, correct?

A Yes. And I think, you know, sitting where we are right now, there's three lease areas off the coast of North Carolina. In 10 years there may be more. BOEM may lease more areas, right? So there's a lot of offshore wind plans I know in the pipeline and significant expansion of offshoring capacity in the US, so pardon me if I'm getting ahead of you there, but I think that thinking the only three options are these three leases is, you know, that may change over time as well.

Q But as we sit today, there's three?

A Yes.

Q And, in fact, there's two and a half, because Kitty Hawk is really split into north and south, and only south can come down to North Carolina?

A There's three distinct lease plots that could come into North Carolina.

Q Okay.

A (Mr. Metz) And it's not clear -- I can't speculate whether Avangrid, where they're at in the construction process, if they started even laying undersea cable or whether or not they can redirect or rerequest a new interconnection study at a different point. And I don't -- I do not know the ramifications of what that means into their SAP or potential copy there.

Q Okay. Are you aware that both the Kitty Hawk North and Kitty Hawk South parcels are still pending BOEM review for their construction operations plan?

A That is my understanding, yes.

Q And until you get a record of decision from BOEM, you can't proceed with construction?

A That is my understanding, yes.

Q So they can't be constructing yet on Kitty Hawk?

A Yes.

Q Fair? Okay. Thank you. So Mr. Thomas, back to you. In yesterday's inquiry with Mr. Smith, there was discussion of a study or a -- more due diligence, and I believe you said -- and thanks to YouTube I can verify, but that's okay -- I believe you said you require sufficient information to evaluate potential options and the more information the better. Does that sound about right to what you said yesterday?

A Yeah. It sounds about right.

Q Okay. So more information is better in this context, correct?

A Yes, but I think I -- you know, just to clarify, I think I was mostly just talking about Mr. Smith's suggestion about a study that could take place between now and the 2024 update, and how having additional information specifically on the characteristics and wind potential that's available at each site, how many turbines might be installed or what the wind speeds might be and the net capacity factor so that a relative comparison between the three sites could be used. I think I was really -- I believe I was referring to that particular discussion and line of questioning.

Q Okay. Thank you. I'm going to hand out an exhibit.

A Sure.

MS. LINK: And, again, Chair Mitchell, these were marked for a different panel, but may we have it marked Duke Energy Public Staff Panel 1 Direct Cross Examination Exhibit 4?

CHAIR MITCHELL: All right. The document will be marked for identification Duke Energy Public Staff Direct -- Public Staff Panel 1 Direct Cross Examination Exhibit 4.

(Duke Energy Public Staff Panel 1 Direct Cross Examination Exhibit 4 was marked for identification.)

Q Mr. Thomas and Mr. Metz, I've handed out Duke Energy Public Staff Panel 1 Direct Cross Examination Exhibit 4. Does that look familiar to you all?

A (Mr. Thomas) Yes. I recall this data request and response.

Q Okay. Was it propounded by you, by any chance?

A Yes. I believe I worked on this data request.

Q Okay. And so this is Avangrid Renewable's response to Public Staff's first set number 1 in this proceeding. And I'll give you a second to review it and just let me know when you're ready to roll.

A Yes. You can go ahead.

Q Thank you. So just to very briefly paraphrase what the request is, the Public Staff is asking Avangrid for the estimated levelized cost of energy for an offshore wind project in the Kitty Hawk region. Subpart (a) is asking for a minimum power purchase price that would meet Avangrid's internal rate of return, and subpart (b) is asking for a sale price based on a dollar/kW basis -- a minimum dollar/kW basis sale price, correct?

A Yes.

Q Okay. So if we follow up on our theme that the more information is better, the Public Staff tried to get more information out of Avangrid, did you not, on a PPA price or a sale price for the Kitty Hawk lease?

A Yes. I mean, we tried to get this information, but maybe it was a bit ambitious. I think we got good information here, but recognize the objection to the data request, and we did not seek a motion to compel.

A (Mr. Metz) And for context, this was to enhance the modeling inputs or compare and contrast the modeling inputs and make any adjustments as needed.

Q Thank you. So just to -- not to belabor it, but there was an objection that it was confidential, proprietary information, and you made it clear that the Staff did not seek a motion to compel.

So just on -- under the objection on that first page, right in the middle of the paragraph Avangrid says "While Avangrid can share certain information with the Public Staff to help further its analysis of these issues, Avangrid is unable to share full LCOE or power purchase agreement rates without a formal structure, and then it goes on to explain why. Fair enough?

A (Thomas) Yes.

Q Okay. So they didn't share a PPA price with the Staff. Turning to page 2, at the end of the top paragraph, Avangrid says "If the Commission were to design and implement such a process, for example, through a third-party study, of owner-provided inputs, as recommended in Avangrid Renewables' limited comments on RFP, Avangrid Renewables would look forward to sharing any and all input information requested with the Commission and the Public Staff." Do you see that?

A Yes.

Q Okay. And then under PPA Price, which is at the bottom of that page, going on to the next page, the last sentence of the top paragraph, Avangrid states, "As a result, while the Company appreciates the purpose of the Staff's question to approve price discovery for offshore wind, Avangrid Renewables cannot reasonably provide a PPA price at this time."

A Yes. I see that sentence.

Q Okay. So no PPA price was provided, even confidentially. And then going to the last page, on Terms of Potential Sale --

A Uh-huh.

Q -- nowhere in those last two paragraphs does Avangrid give a dollar-per-kW price for a potential sale, correct?

A Not of their plot, no. They provide some regional price trends, but no, there's no -- no price given for their plot.

Q Okay. So no price given for a PPA, no price given for the sale. There is a confidentiality agreement in this proceeding, correct?

A Not between us and Avangrid.

Q But between the parties, in general, there are confidentiality protections available, correct?

A Yeah. I'm aware. We don't sign those.

Q Right. You don't have to, but the rest of us do.

A Yes.

Q Okay. Thank you. Fair enough. So my question is, I know there's discussion of a third-party study, future study, future due diligence, where we have to believe that it will be the right environment where Avangrid would give their proprietary third-party information, and my question to you all is what would be different in that proceeding that we don’t have here today?

MS. LUHR: Objection. I think questions about confidentiality are more geared towards the legal proceedings and not something that our witnesses can answer.

MS. LINK: And Chair Mitchell, I’m not asking about confidentiality protections; I’m asking about process. It appears that Staff believes further study is needed, maybe further due diligence, and I’m asking what would that look like in a future proceeding that is different than what we have right here.

CHAIR MITCHELL: Okay. I’ll overrule the objection with that clarification and allow the question to proceed.

MR. SMITH: Madam Chair, I’d just like to join the objection insofar as the question in the data request is requesting information that is subject to a confidentiality agreement and, as such, Avangrid responded appropriately, and so that’s why it was not applied to an IRP proceeding, which would be a different proceeding not applicable to a confidentiality agreement.

CHAIR MITCHELL: I'm going to continue to overrule the objection. As I understand, the question is focused on a process involving confidential information. I'll allow the witness to answer the question.

A (Thomas) Could you please just restate your question again?

Q Of course. So my question is Avangrid's position is that a third-party study is necessary, and I would presume that process has some adequate confidentiality provisions, but this process here had confidentiality provisions, and I'm asking what, from the Public Staff's point of view, would be different about that study other than it would be later on?

A Sure.

Q Yeah. What's happening right now.

A Happy to address that. So first of all, I just want to kind of level set. The model that they've used for selecting these offshore wind resources, this is a generic -- essentially, a generic wind resource using the internally-derived cost and a capacity factor that was essentially a blend of estimated Class E factors in Carolina Long Bay and in Kitty Hawk. To my knowledge, there is no lease area that has that blended capacity factor. It was a generic resource and it was attempting simply to, you know, identify whether or not offshore wind, as a technology, would be part of a least cost solution. And I think if we were to -- if the Commission were to order, you know, some sort of third-party study that could receive information from Avangrid and from TotalEnergies and from Duke Energy Renewables Wind, the three lease owners in the area, related to key inputs such as your capacity factor and output profiles, you know, least cost -- least cost, potential network or estimated network upgrades based upon, you know, studies that we’ve seen, public policy requests, and other information that’s confidential, put all that together and then actually come up with not only from that study what could be the least cost, but also information that could conceivably go into the 2024 Carbon Plan. I think I said yesterday that normally, resources are not site specific in an IRP capacity expansion model, but for the purposes of offshore wind, when you only have three potential resources, it could be reasonable to separately model them and see which ones are selected, right? You might have less transmission cost associated with one, but the other one has a better capacity factor, there’s, you know, more outages associated with one because of hurricane risk, or there's always different functions and differences that could differentiate those three resources in the model that I think would be important to inform the 2024 Carbon Plan, because what I don't want is a selected generic 800-MW block resource that may not reflect the actual characteristics of Carolina Long Bay, and then have the Commission approve the purchase and transfer of Carolina Long Bay to DEP, knowing that the capacity factor used in the model is a blend of both Carolina Long Bay and Kitty Hawk, which is likely above what Carolina Long Bay, being the less productive resource, will ever achieve, right? So I think it's important to provide some differentiation there and to not make these expansive, you know, radio upgrades. We can study things. I mean, yes, it costs money to perform a transmission study, but it costs a lot less than to transfer a lease, perform preliminary transmission upgrades, and then find out that the capacity factors that were put into the model are an overestimation of what this Carolina Long Bay will ever achieve. And so I think, you know, given the SP5, which made some substantial modeling changes, and I can't tell you the reason why offshore wind was delayed by 10 years, but I have a feeling -- you know, my experience tends to suggest it’s probably because of the increased adoption of solar plus storage and the better dispatching permitted by that modeling decision. And so I think it’s important that if we can run sensitivities in 2024 that use the advanced modeling techniques and dispatch of storage and we’re still seeing 2040s, you know, that gives us time to evaluate all three sources and still get them in service at or before the date that they’re called for in the plan. I think it’s very important to just make that distinction, that basing the $300 plus million of expenditures by Duke based upon the EnCompass models that they used, I don’t think that’s appropriate at this time.

Q But if the Commission were to order such a study -- the Commission doesn’t have jurisdiction over any of these three commercial enterprises, correct?

A No, but I’m sure Duke Energy Progress and Duke Energy Renewables Wind have a working relationship and could enter into a nondisclosure agreement to exchange important information that would help inform the Carolina Long Bay lease evaluation.

A (Metz) Or secondly, this could be optional. I mean, the Commission can say, all right, if you want to come forth to the study, come forth, and if no one shows up, then I guess we get our answer.

Q So if no one shows up, no offshore wind for North Carolina?

A If no one shows up, to me, that would demonstrate that those projects were not serious or want to potentially sell their output to North Carolina.

Q Okay.

A (Thomas) And I'd just add to that, I think we're in a unique situation that there's three independent companies who own three separate lease areas, and as far as offshore -- as far as onboarding and bringing those on to a particular balancing authority, I think Duke Energy Progress is uniquely positioned to pick one of the three, the best cost for ratepayers, and there's a bit of a -- as far as offshore wind goes, there's a bit of a competitive market there. I know it's only three, but, you know, it's certainly better than just one. And I think it would not be appropriate to just simply pick a winner, Carolina Long Bay, you know, owned by Duke Energy Renewables Wind, at this point in time, particularly given the substantial delay in offshore wind that's afforded by SP5 and perhaps a bit more optimal deployment of battery storage resources and other renewables.

Q But this Commission could not compel any of the other entities, TotalEnergies or Avangrid, to sell their lease to Duke Energy Progress, correct?

A No, of course not, but I think those companies have a vested interest in selling to someone and participating in a study to have their site more fully evaluated, have their investment more fully evaluated by this Commission. Yes, the Commission can't order, you know, that this be -- a PPA be entered into or an asset transfer agreement be entered into with another company, but certainly they could, based on the results of a study, order Duke to open up a competitive procurement for offshore wind resources that would be open to those three leaseholders, and then through an independent administrator or evaluator, DEP could pick the most competitive of those three leases regardless of who owns it and whether it's a regulated affiliate or not. I think that's the important concept here, is we are just trying to make sure that ratepayers get the best bang for their buck in terms of offshore wind. It can be an expensive resource, but it does provide benefits in terms of its output profile, and so I think it's important to make sure that ratepayers, if this a cost effective resource and part of a least cost plan, that ratepayers are getting the best bang for their buck from these three separate entities that could potentially compete to provide that output.

Q Okay.

MS. LINK: I have no further questions.

CHAIR MITCHELL: All right. Redirect?

MR. JOSEY: I just have one question, then I'll hand it over to my co-counsel.

REDIRECT EXAMINATION BY MR. JOSEY:

Q Mr. Thomas, you were discussing with CPSA's counsel yesterday about procurement targets in SP5 versus SP--- or just P1. And when weighing the amount of MW to procure each year and in total, when you set a target number for an RFP, is it not important to balance that target number to ensure that you receive enough bids to make the bid process competitive and try to seek the lowest amount of, you know, the lowest bids, but also balance that with the ability to not procure so much -- so many MW that they -- that the bids know that they're going to win, essentially? Can you speak to that a little bit?

A (Thomas) Yes. I think -- you know, I think I've discussed it a little bit when I was pointing out, you know, that bids are -- conceivably in a competitive procurement everyone is bidding in, you know, with their sharpest pencils the best price that they can offer, you know, but that's going to be a range of potential offerings based upon the price. And I think we've seen, you know -- I mean, for example, you know, CPRE, a competitive procurement of renewal energy program, that had an avoided cost cap, but if it didn't, such as the 2022 solar RFP, you know, Tranche 3 of the CPRE was for 600 MW, and it had -- I don't believe it's con--- yeah -- it had 596 bid in. If there had been no way to cost cap, there would be no reason to continue. Every bidder that bid in would get a PPA at the bid-in price. You know, the target has been assessed and there's less that bids in. I think that's an extreme example here, and I recognize that 2022 solar procurement volume is fairly robust relative to the targets being discussed by some parties, but, you know, I think that the cushion does have to be aware that the higher that that target is, not only do you run into execution risk, but you also start to get in those high-level bids. And if there's a pretty decent spread, then you could start to get in very high-cost PPAs, high-cost asset transfers which can elevate risks and then cost to ratepayers.

MS. LUHR: I think most of my questions will be for Mr. Thomas.

REDIRECT EXAMINATION BY MS. LUHR:

Q So first, Mr. Thomas, yesterday counsel for Tech Customers asked you several questions related to difficulties with Duke’s modeling inputs. Were there any -- were there any other challenges related to validating Duke’s assumptions and inputs that you experienced?

A Yes. Thanks for asking. I think that, you know, the modeling part of it is one side of it, but I think Duke performed a bit of additional analysis, both on the front end and the back end, that made both modifying their inputs challenging and validating their outputs challenging. For example, EnCompass has a field in its modeling inputs that allow you to specify capital cost in dollars or in dollars-per-kW. Those are the figures that all of us are very familiar with. And then you can put other fields into that, such as the debt-to-equity ratio, AFDUC (sic) percent -- AFDUC percent and other financial inputs that will help, you know, convert that capital cost and dollars-per-kW into a levelized charge which is what the model optimizes over. Duke chooses to do that whole process outside of the model using a proprietary tool--- or using their own calculations and own spreadsheets. So much the same process, but simply they did that outside the model, so it made it difficult for folks to take the supply side data manual and then check it against the modeling inputs to kind of validate that there's a clear path from Duke's capital cost estimates to what was actually used in the model. Some Intervenors discussed this as well. So that made it challenging, and I hope that in future carbon plans Duke -- you know, I addressed this in comments a bit, but we'd like to see them, you know, convert to the EnCompass system, the native EnCompass system, make that easier, and that flows through to the outputs. You know, Duke did not calculate the revenue requirement for capital investments based upon the model. They took the capacity that was built and then they plugged that into an external spreadsheet that would then calculate the actual cost of these resources again based upon this real levelized fixed charge calculation that's external to the model. And I think that those -- I don't believe that those materially would have affected the results of the model, but it certainly made it harder for us and for other Intervenors doing modeling to validate both inputs and output calculations for PVR, for present value of revenue requirements.

Q Thank you. And then turning to questions from counsel for Kingfisher, yesterday you were asked several questions related to the utility ownership requirement in House Bill 951. Could you clarify the Public Staff's position regarding utility ownership of resources and PPAs under the Carbon Plan?

A Yes. I think I may have misspoke there, but consistent with our comments on September 9th, should the Commission decide that a PPA is a resource that can be -- that can be procured, you know, through a PPA under the Carbon Plan, we would -- we would not support recovery in base rates and a rate of return, or we'd at least have to see that evaluation, right, to compare a PPA versus a tear-down resource to find out what's in the best interest of customers.

Q And counsel for CPSA asked you if the near-term action plan should be consistent across all portfolios, and you indicated that your near-term action plan recommended in your testimony primarily supported SP5. Can you explain why you put so much emphasis on Portfolio 5?

A Yeah. So I think -- you know, we've -- and I think I addressed this slightly, but P1 through P4¸ you know, I would view those as kind of almost entirely separately from SP5 and SP6. And I think there are very fundamental changes not only to things like gas supply and dispatch of units, but also looking at, you know, removing, you know, cumulative caps on energy storage that were put in place, allowing EnCompass to economically dispatch the energy storage component of solar plus storage resources, I think those are fairly fundamental changes, and some of that's reflected in increased model run times, but I think that those are important changes because that's how you dispatch storage, right, you dispatch it however you want it. And it's clear to me that these changes resulted in, you know, delays in offshore wind, for example, that could result in allowing a more thorough study and more information. So that's why we kind of aligned our near-term action plan not to try to average out over P1 through P4 and our SP5, but really to focus on SP5 as, you know, with more -- we feel more appropriate modeling assumptions that validated some of these resource needs.

Q And Mr. Thomas, counsel for CCEBA asked you about resources that are not yet available, including those for which there is currently no supply chain, such as SMRs, and you've talked about how assumptions can change over time, including the kinds of resources or prices that might be available to us in the future.

MS. LUHR: So Chair Mitchell, at this time I would like to hand out some documents. I'm not going to ask for them to be moved into the record as exhibits, but I'll ask that Judicial Notice be taken of these. There are two documents. So the first document is -- and I've put exhibit stamps on the top, but we can disregard those for the sake of time. The first document is titled Duke Power Annual Plan. It was filed in Docket E-100, Sub 102 on August 30th, 2004. And the second document is titled Progress Energy Carolinas Resource Plan, also filed in Docket E-100, Sub 102, and this was filed on September 1, 2004.

CHAIR MITCHELL: All right. The Commission will take Judicial Notice of these two filings made with this Commission.

MS. LUHR: Thank you.

Q So Mr. Thomas, first I will refer to the document that has Duke Energy stamped on the top left, and this is the Duke Power Annual Plan from September 1, 2004. And if you can turn to the top of page 3, can you tell me what the planning horizon is for this document?

A (Thomas) Yes. It's the 2004 Annual Plan. It's a 15-year horizon.

Q Thank you. And if you'd turn to page 30, could

you read the highlighted language for me?
A Sure. It says “The Supply-Side Options selected for the expansion plan are subjected to an economic screening process to determine cost effective supply side technologies. Duke evaluates conventional, demonstrated, and emerging technologies. The technologies which pass a cost screen, a commercial availability screen, and a technical feasibility screen are considered viable Supply-Side technologies.”
Q Thank you. And if you’d turn to page 33, you’ll see a chart there labeled Screening Evaluation of Generation Technologies. Can you tell me, looking at the last column, which technologies the Company retained for economic screening?
A Yes. A combustion turbine, a combined cycle, and three types of -- or four types -- or three types of supercritical, subcritical, and fluidized -- circulized fuel -- circulating fluidized bed coal, and then a pump storage facility.
Q Thank you. And was wind included?
A No.
Q Solar PV?
A No.
Q Battery storage?

A No.

Q Okay. And then if you could turn to the second document, it’s got the Progress Energy stamp on the top left. This is the Progress Energy Carolinas Resource Plan from September 1, 2004. Let’s see. And if you could turn to page 2 and read the highlighted language.

A Yes. “Progress Energy Carolinas periodically assesses various generating technologies to ensure that projections for new resource additions capture new and emerging technologies over the planning horizon. This analysis involves a preliminary screening of the generation resource alternatives based on commercial availability, technical feasibility, and cost.”

Q Thank you. And if you turn to page 9, this is the Screening Evaluation of Generation Technologies. And, again, if you’ll look at the last column, can you tell me which technologies the Company retained for economic screening?

A Four different types of combustion turbines and a combined cycle facility and three different types of coal.

Q Did they include wind?

A No.

Q Solar PV?

A No.

Q Okay.

A And I'll just note that I don't believe battery storage is even included in this.

Q Thank you. So looking back at the Company's resource -- at Duke Power and Progress Energy's resource planning in 2004, what do these documents tell you about how assumptions, technologies, and costs can change over time?

A Yeah. So, I mean, this is -- and we all know this, that technologies advance quickly, and obviously 18 years ago no one thought that solar and battery storage and wind would be playing such a pivotal role in this decarbonization effort. And I think that, you know, one reason the Public Staff has kind of, you know, a lot of Intervenors and Duke have talked about what's happening by 2050, and overly relying on particular supply chains for nuclear and the risk of doubling, you know, certain capacities or relying on too much of, you know, lithium ion battery storage, I think this just, you know, emphasizes that this near-term approach, looking at this as perhaps more important because we don't know in 18 years when we're doing the 2040 Carbon Plan and half of us are happily retired, I think that's going to be very

-- you know, it's going to be a whole different landscape and potentially even, you know, have other technologies that are eliminated in Duke's current generation screening alternatives, right? They eliminate certain types of fuel cells or liquid air batteries. A lot of energy storage technologies are eliminated. You know, carbon capture and sequestration is eliminated, based on current knowledge, right? So I think so much can change between now and 2035, 2040, that we can't even foresee. And hopefully new technologies will emerge, and technologies not currently commercially available or economically viable will play a major role out beyond 2030, 2035, and into the future.

Q Thank you. I believe I only have one more question. Counsel for CPSA asked you a series of questions about meeting the interim target by 2030. What do you believe are the most important things for the Commission to consider when adopting its final carbon plan?

A The Public Staff, you know, we believe that targets in HB 951 of 2030 is important and we need to get there, but I think the Commission also needs to consider, you know, cost and execution risk, executability, and reliability as well. And 951, much like Senate Bill 3 which enacted the REPS mandates, provided the Commission flexibility to determine, you know, when these targets are met and to protect ratepayers from, you know, undue risk, unreliable grid, or excessive cost. And I think the Commission has to consider all of those, part of that three-legged stool, to make its decision on when -- what portfolio should be adopted and, you know, what interim compliance year should be met.

Q Thank you.

MS. LUHR: That's all the redirect we have.

CHAIR MITCHELL: All right. Questions from Commissioners? Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you, Madam Chair.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Metz, you had a very lengthy exchange with Mr. Schauer that has taken care of a lot of the questions that I had, but I do have a couple follow ups on the same point, being the assumptions about incremental gas availability with firm trans--- transportation that are used in Portfolio 5 and 6. And I know you were referring -- I don't know if you still have it there in front of you, but when Mr. Schauer was questioning you, he was making reference to the sort of summary table that's in the Duke Modeling and Near-Term Action Plan Panel Exhibit 1 that sort of lays out in tabular form the difference in assumptions between Duke's Portfolio 1 through 4 and the Public Staff 5 and 6. Do you have access to that?

A (Metz) We're looking.

Q Okay.

MR. THOMAS: It's this here, this table (indicating document)?

COMMISSIONER CLODFELTER: Yes. Well, it doesn't look like that.

MS. LUHR: Page 57.

COMMISSIONER CLODFELTER: It's page 3 of 29 in Exhibit 1. You know, I think I may be able to ask the question --

MR. THOMAS: Is it Rebuttal Table 2 and Rebuttal Table 3?

COMMISSIONER CLODFELTER: No, no. Let me see if I can ask you the question without you having to have the document in front of you.

Q One of the parameters that you varied in Portfolios 5 and 6 from what Duke had used, assumptions Duke had used in Portfolios 1 through 4 related to backup fuel supply for future CCs and CTs. And Duke had assumed in Portfolios 1 through 4 that any new CCs would be configured with low sulfur diesel backup, and that CTs would operate on low sulfur diesel for the month of January. In 5 and 6 you varied that assumption to assume that new CCs didn't have low sulfur diesel backup -- that's a tongue twister for me at least -- and that the CTs would operate on low sulfur diesel for only two weeks in January.

A (Metz) (Nods affirmatively.)

Q And my que--- that's accurate, consistent with your recollection, even though you don't have the document?

A Yes, sir.

Q My question to you is, is the reason for your variation in that assumption about the backup fuel source for the CCs and the CTs, is that derived from your assumption about the additional firm transportation zone for fuel availability through -- as a result of the Southside Reliability project, or is there some other reason for varying that assumption?

A That is in part. So I think the other is one of the observations that we were trying to see is understanding these are peaking resources for the combustion turbines during the month of January, that for modeling purposes we have a carbon cap for every given year, we were exploring -- and Mr. Thomas can jump in here -- we were exploring to say, well, if you run a combustion turbine for peaking purposes for the month of January on ultra low sulfur diesel, you would be emitting much more carbon. And we said, okay, well, are we getting an artificial result that doesn't match how we actually ran our system. So through past experience since I've been with the Public Staff, it's like we have never ran -- fortunately, knock on wood -- but we've never had to run our entire combustion turbine fleet off ultra low sulfur diesel, so we would never actually see those carbon emissions. What we have seen, though, is that during the -- notably, the 2018 polar vortex, that it was not because of a fuel constraint on the system, but an economic decision that it was actually more cost effective to run the CTs or part of the CTs off of that higher carbon-emitting resource at least for a week. So it was a little bit of art, for lack of a better word, for modeling purpose, to say we're going to make these assumptions because we think that more properly mimics system behaviors that have occurred and what we should be planning for. Mr. Thomas?

A (Thomas) Yeah. If I could just add on. If the model had hourly natural gas prices, you know, you wouldn't have to make these kind of assumptions, right, because that model would economically dispatch between the two, hourly model gas prices and hourly gas supply constraints, but it doesn't work like that. It has monthly gas supplies. And while the winter months are higher than other months, they still don't capture those peaks where the system is really strained and the polar vortex is coming through and we're seeing gas at 20, 30, 40, you know, a BTU, so I think that's kind of the assumption that we're making here, and we just thought that Duke overstated the amount of sulfur that they were going to use in the winter season, and so we wanted to dial that back a bit.

Q Based upon historical operations of the units.

A (Metz) Yes, sir.

Q Your answer was referring to the CTs. Would the answer be exactly the same for the new CCs, that you're assuming that they don't require any to be run on low sulfur at any point because historically, the CCs have not run on low sulfur?

A That is correct. And I would defer to -- for Duke of how they run their system. I think it would be extremely challenging to run an 800-MW combined cycle on ultra low sulfur fuel 24/7. I can't even imagine the logistics and the amount of trucks that would be lined up.

A (Thomas) And I'd also just -- you know, I didn't want to -- they don't have the backup, but I believe the CCs do use ultra low sulfur diesel for start up, so in the model they do still have that. Start up is a little bit different than full operations, but you still have to access that fuel like in the real world, but the start up uses a different type of fuel.

Q Well, unders--- thank you for the answer. It helps me understand why you made the assumptions you made, which is what I'm really -- my question is trying to probe, but I want to be sure I understand, that you are making -- you thought that assumption was valid, even though the assumption was going to apply to additional units on the system, units not now or in the past history in operation on the system, incremental units. It was still safe to make the same assumption as you made about the operating characteristics of the existing units.

A (Metz) And then that, in part, pivots to when -- in reading the Williams Transco expansion projects --

Q Okay.

A -- yes, we believe it was reasonable.

Q So you had a two-factor basis for that assumption.

A Yes, sir. And to go on further, more detailed information behind it -- I'll stop if you want me to.

Q No. I'll take the detail.

A So, and part of that conversation was, well, you have the -- and I don't mean any negativity towards this in terms of modeling, but you have the 1200-MW J-Class combined cycle which is going to use more natural gas -- it's just a function of the size -- but it's more efficient, and I get that. However, we also asked Duke, because we understand that there may be nuances in the modeling, we said, okay, include the slightly less efficient F Frame combined cycles that are only 800 -- approximately 800 MW. So will the model jump between -- sorry -- jump between either 800 or 1200 if we did introduce these potential modeling constraints due to lack of fuel supply. But for the model, it did not in this case, but that is something that we're also forward looking to say, yes, the model may have selected 1200 MW, but as time advances, we can scale that back down potentially to 800 MW when we're looking at a CPCN if we have future concerns as we continue to evaluate potential lack of firm transportation supply 365 service or notably during the month of January. And I would like to -- Duke did do a good job of trying to pick up that sensitivity that the Public Staff has advocated for from the 2020 IRPS, that it was an appropriate first step for Duke to say, yes, Public Staff, we've heard your concerns, there is a possibility of lack of supply and, therefore, the system will be constrained in January so we are going to restrict it.

Q Thank you for that. Again, one more follow up on this point. And this really is to any of the three of you. Are any of you familiar with the Motion to Intervene and Comments in Support filed by Piedmont Natural Gas Company in the FERC docket by Transco concerning the Southside Reliability Enhancement project? It was filed on June 28th of this year. Have either -- any of you reviewed that filing?

A (Thomas) I have not.

A (Metz) I have not reviewed -- I am cognizant of it, but I have not reviewed the filing.

Q Based on what you do know, are you aware that it's Piedmont's position that they support Transco's application because they have fully subscribed to 100 percent of the additional capacity that will be made available by the Southside Reliability project?

A (Metz) And that is the horizontal line, and it is a -- that specific topic is an active docket in Piedmont Natural Gas' annual review which I believe I filed testimony in and Public Staff witness Nader filed testimony in.

Q So it's your understanding that Piedmont is only subscribed for the incremental capacity on the lateral line running over to the Albemarle Sound area and not for any additional capacity that may come on the main line?

A That is my understanding, yes.

Q If it is, in fact, the case that Piedmont is also subscribed to all the additional main line path capacity, that's not consistent with your understanding, is it?

A That is not consistent with my understanding, and another -- a point that we're continuing to potentially evaluate here is the function of displacement. I don't know for certain at this point in time if Piedmont -- and not speaking on behalf of Piedmont, but if we have this new natural gas supply system across that horizontal, that could mean theoretically that there would be less gas needed to be pulled off the main line because it's just a different point -- a different point of service to some, so there's a function of displacement that we're continuing to evaluate and look at. Or stated differently, that line could free up capacity on the main Transco line as Piedmont grows into its load over time, theoretically.

Q Again, though, you have not reviewed Piedmont's actual filing and what they say in their filing with the FERC?

A I have not.

Q Okay. Then we'll stop with that questioning for you. I have a couple of just minor things I want to understand about your prefiled testimony, just to be sure I know what's going on. Mr. Metz, again, for you, on page 11 and 12, you have a footnote on page 11, but it really relates to -- the footnote relates to the chart that's on page 12. It's an interesting sequence there. But in the footnote you say you're still -- at the time you filed this, you were still reviewing supplemental model inputs, including some unexpected outputs relating to natural gas combined cycle capacity factors and then you refer to the chart. Have you completed that review and determined why you initially saw that unexpected output?

A We have not completed that review. We're continuing to do continued model runs and explore that possibility. It's a minor observation. What peaked my interest was the relatively higher than expected capacity factor. That doesn't make it wrong. And to give context, let's just say eyeballing, it's approximately 78 percent. While we have achieved that annual capacity factor on distinct combined cycles across the plant, my expectation was it was going to be -- for just looking at it, based upon trial by knowledge, is it should have been closer to 70, so maybe 72, I mean, looking at it across a fleet level. So from a modeling standpoint, it just seemed a little bit high in that given year, so if it was high, does that mean something else would have to generate in real time? This could be a modeling artifact. This could be perfectly reasonable. This is something that caught our attention that we're still continuing to evaluate.

Q Thank you for that. Let me ask you about the chart on page 12. Just, again, I'm not sure I'm understanding exactly what I'm seeing on that chart. Talk to me about the -- in the years 2022 through 2030, what I'm seeing there in the gap between the line on the capacity factor and then the bars for the production run. What am I looking at there? What is that gap telling me?

A So the production run MWh and that potential gap that's underlying it -- just trying to reorient myself back to the raw data coming into it. Mr. Thomas?

A (Thomas) I think -- I think I can maybe speak to this a little bit. I'm not familiar with the exact numbers used here, but I would say this is likely, since we're looking at the bars, are the number of GWh coming out, and then the capacity factor is the line. I think in those first years that's kind of reflecting that there's no new CC capacity being built there, so I expect that this is likely a function of the fact that the new CCs are coming in in '29 and 2030, and that gap there is just representing kind of higher utilization of existing natural gas assets. And then once you bring those other ones on, it all kind of eases up.

Q Thank you.

A Sure.

Q I needed you to help me make sense of the chart, and that's -- I think you've done that.

COMMISSIONER CLODFELTER: I think you've answered the other questions already in examination by other counsel, so that's all I have. Thank you.

CHAIR MITCHELL: Commissioner Duffley.

COMMISSIONER DUFFLEY: So I only have one question. It's for Mr. Williamson. I'm going to give you some air time.

MR. WILLIAMSON: All right.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q So if you could turn to page 40 of your testimony.

A (Williamson) I'm there.

Q And so on lines 6 through 8 you testify "The current annual residential DSM/EE rider amounts are $57.24 per year for DEC and $86.52 per year for DEP, including for low-income customers." And so my question is, do you know how these per-year amounts compare for DSM/EE residential customer charges in other states that have these programs? And I understand that there are some differentials in the programs and what's included and what's not included, but just your general sense, do you know how these amounts compare?

A So Duke Energy in North Carolina and South Carolina have very well developed EE portfolios compared to other states. They provide -- I think in the EE rider we get a list of the measures that they actually offer to customers within their programs, and it's in the roughly 500, 600 some odd different measures. The majority of them are for non-residential customers, but a good portion of them are for residential as well. But compared to other states, because of that volume of measured type offering, Duke Energy's EE rider, my opinion, would be higher than other states, noting that in South Carolina I believe the rates are a little higher than North Carolina's EE rates. But South Carolina is the only state that I have, off the top of my head, as far as what their EE rider consists of. And I think that's just a function of the accounting.

Q Okay. And if I wanted to try to look and compare, understanding their differences in programs, like where would I go to look for that information?

A With regard to --

Q To other programs, like let's say DSM/EE programs in Massachusetts or in a different region, potentially.

A I'm not quite sure how EE rates are advertised for other states and other utilities. There are probably reports from National Labs out there that might get into kind of an analysis of kind of how EE rates or EE portfolios in general, as far as savings, are compared, but I'm not sure where a particular document might be to kind of analyze other states.

Q Great. Thank you. I think National Labs is a good idea, so thank you for your testimony.

A Thank you.

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: More questions for you, Mr. Williamson. You're the star.

EXAMINATION BY COMMISSIONER HUGHES:

Q Are you familiar with the EE programs under the Inflation Reduction Act? Have you had a chance to kind of look through? I know we're waiting on guidance for those, but just at a high level and kind of a description of what's in that?

A (Williamson) So, unfortunately, I haven't had a chance to do a deep dive into the IRA to get a better understanding of what impacts. I do know actually this week, the EE collaborative has set up kind of a set-aside meeting to discuss the IRA and how it might have impact with the Company's portfolio. I believe those meeting schedules were sent out yesterday, actually, so good timing.

Q Okay. Thank you for that. The debate that we've had over the last couple days for a number of witnesses related to 1 percent, I think, higher numbers, lower numbers, I just want to be clear, I think you answered a lot of my questions to the Chair the other day, but the 1 percent that we are talking about for purposes of this debate is utility-funded programs as a percent of eligible loads, and that's the residential and the industrial and commercial that have an opt out. Is that your understanding?

A Correct. It's only the utility energy efficiency -- I think that's how they title it -- in their Carbon Plan and IRP, so it's specific to what they offer, and they grabbed that information from the realities that are occurring in the DSM/EE rider proceeding.

Q Okay. I know you haven't looked in the IRA. I have a little bit, and from what I understand, it's going to revolutionize the amount of money available for non-utility funded energy efficiency programs. So I'm concerned moving forward, have you thought about -- and maybe it's a question for the modeling group. I understand in the past, most of the funding for EE programs in North Carolina have come from utility-funded programs, but if even part of these projections that I'm reading about moving forward are true, just a significant part of funding in the future is going to come from non-utility funded programs. Have we taken that into account at all in kind of that 1 percent debate or, I mean, has that come up at all?

A   So I guess just for timing purposes, the impacts of what IRA could do to this -- the utility’s portfolio programs or how that might impact the amount of customer adoption based off of the utility’s influence, I’m not aware that there’s been any study into that. I would assume that it is on it--- I would assume that it’s on its way of being developed or being at least analyzed, but I would hope that in -- over the next coming months or certainly in the next Carbon Plan proceeding that there would be a more detailed analysis of what the IRA will do, not just to UEE forecasts, but to all the functions and facets that are within the IRA’s language.

Q   Yeah. And I -- oh, I’m sorry. Go ahead.

A   (Thomas) Sorry. If you don’t mind, I will just elaborate just a little bit on that. You know, I think that the IRA -- I’ve only passingly looked at some of the analysis of it, but -- listened to a couple podcasts, maybe, but I would agree that there are a lot of EE programs in there, but the effects on supply side resources, like renewables and storage, are pretty clearcut in terms of it’s this percent off because et cetera, but the demand side stuff is complicated because not only do you have these EE programs -- I believe there’s like -- weatherization is a big part of that, but also on the flip side you have, you know, big rebates for heat pumps, EVs, both used and new, so I think you've got these two -- because it does two things, right? It's trying to reduce energy usage, but it's also trying to electrify certain sectors, transportation, space and heating and stuff like that, so those are going to be obviously countervailing. And it's complicated. I don't want to be the person doing load forecasting that has to implement it, but I think that that's going to be playing out over the next year, but it's going to be really hard to discern, and it's more than just what EE programs are in there, but what kind of load are we going to add and how is that incrementally going to offset those EE gains.

Q Okay. And I appreciate that. So is it just safe to say that everything that's been put forth hasn't taken into consideration all these complications that are going to be coming up not in the long-term future, but we're going to know a lot more in the next six months, year -- I think some of them start as early as 2023 -- really significant rebates for EE --

A (Williamson) Sure.

Q -- for EE investments?

A Sure. And, I mean, as the Company will start to prepare its 2024 Carbon Plan, they should have plenty of real-world evidence of how this IRA is impacting not only its portfolios, but how customers are using these rebates and using these incentives that are coming from the IRA in order to take more control over how they're using power.

Q The related question for you, because I think it does get into your testimony, and we've been asked to take a position on the current cost recovery mechanism which I think plays into it, I think it's your opinion that a full cost recovery mechanism is justified. And I believe, if I'm reading some of the testimony from some of the Duke witnesses, that may be more of a targeted kind of review. Could you say a little bit more? Do I have that right, that you think that we should look at --

A I think a more -- a full review of the mechanism would definitely be a better use of not only the Public Staff's time, the Company's time, but also the Commission's time. I know in the Company witness Huber and Duff's testimony, they referenced the reserve margin adjustment factor, and I just wanted to kind of highlight that a full mechanism review would probably take anywhere from a year, maybe two, but in that very targeted approach to how it's been titled the RMAF, it took three rider proceedings to actually get it -- that one tar---

excuse me -- that one targeted one piece of language added to the mechanism, just one piece. And so I think it would be a much more appropriate time to look at everything all under one microscope at the same time with all the parties, and then that way we can hash out how this will -- adding this language will influence the incidents over here or how changing this function will impact another function over here, and just expedite the process a little bit.

Q Okay. That's what I took from your testimony. And that was before, again, the IRA was out, and we may now have -- I think one of the other witnesses talked about kind of a leveraged approach and what happens when we kind of mingle the funds from both IRA and from Duke. Does the cost recovery, is it designed in any way to deal with that kind of comingled funds in a big way?

A So the cost recovery mechanism is only going to take into account incentives that the customer accepts from the Company or if the customer participates in a free program where they just receive measures at no cost, but if a customer goes out and just takes a rebate or a discounted price option on an HVAC unit as a result of how this IRA is going to impact various measures, like I would think Mr. Thomas has described, those kinds of costs are -- those purchase costs won't be reflected in the DSM/EE rider, however, the Company will realize those savings as kind of naturally occurring. So the DSM/EE rider is more capturing how the utility is influencing purchase of DSM and EE measures, not necessarily how a customer is willingly going out into the market and seeing a deal and acting on that deal.

Q Okay.

CHAIR MITCHELL: All right. I'm going to pause there.

COMMISSIONER HUGHES: Well, I'm going to stop, so we don't have to get started.

CHAIR MITCHELL: All right. Let's go off the record, please. We've come to lunch break. We will be back on the record at 1:30.

(The hearing was recessed, to be continued at 1:30 p.m.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 179, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 27th day of September, 2022.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150