PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, September 26, 2022

TIME: 11:00 a.m. - 12:45 p.m.

DOCKET NO.: E-100, Sub 179

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: 24

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T A B L E   O F   C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL: All right. Good morning. Let's go back on the record, please. By my records we're -- by my notes, we're up with NCSEA's witness, Mr. Fitch.

MS. CRALLE JONES: Chair Mitchell, if we could do some preliminary motions, if it's appropriate time.

CHAIR MITCHELL: All right. Please proceed.

MS. CRALLE JONES: Good morning, Commissioners and Chair Mitchell, Cathy Cralle Jones on behalf of Appalachian Voices. With all parties having waived cross and the Commission indicating they had no questions, at this time, I would move that the direct testimony of Mr. McIlmoil and Dr. Kinkhabwala prefiled in this docket on September 2nd and consisting of 42 pages be copied at the appropriate time into the record as if given orally from the stand. And that the summary of that testimony filed on Friday, September 23rd also be copied into the record of hearing.

CHAIR MITCHELL: All right. Hearing no

objection to your motion, it is allowed.

(Whereupon, the prefiled direct testimony of Rory McIlmoil and Yunus Kinkhabwala and prefiled summary testimony of Rory McIlmoil and Yunus Kinkhabwala 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

In the Matter of:	)	**DIRECT TESTIMONY OF**
Duke Energy Progress, LLC, and	)	**RORY MCILMOIL AND**
Duke Energy Carolinas, LLC, 2022	)	**DR. YUNUS KINKHABWALA**
Biennial Integrated Resource Plans	)	**ON BEHALF OF**
and Carbon Plan	)	**APPALACHIAN VOICES**

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INTRODUCTION

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A: My name is Rory McIlmoil. My business address is 589 W. King Street, Boone, NC 28607. I am the Senior Energy Analyst at Appalachian Voices.

Q: WOULD YOU PLEASE ALSO INTRODUCE THE REST OF YOUR PANEL?

A: Yes. Also presenting with me today on behalf of Appalachian Voices is Dr. Yunus Kinkhabwala, with Physicians, Scientists, and Engineers for Healthy Energy (PSE Heathy Energy). Dr. Kinkhabwala will introduce himself.

Q: WHAT ARE YOUR PRIMARY RESPONSIBILITIES AS SENIOR ENERGY ANALYST AT APPALACHIAN VOICES?

A: In my role as Senior Energy Analyst, my responsibilities include researching energy and affordability policy models, analyzing the impact on low-income ratepayers and the environment of policies or rate structures my organization might support or oppose, and advocating for utility clean energy and low-income affordability programs and rate structures that equitably benefit families and local communities.

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: I graduated from Furman University with a Bachelor of Science in Earth and Environmental Science and received a Master of Arts in Global Environmental Policy from American University's School of International Service. I previously served as the Energy Program Manager with Downstream Strategies, an environmental and energy consulting firm based out of Morgantown, West Virginia, and joined Appalachian Voices in 2013 as the Energy Savings Program Manager, analyzing and advocating for equitable energy efficiency finance programs, rate structures and distributed solar policies through North Carolina's rural electric cooperatives.

I was promoted to Senior Energy Analyst in 2018 and have since focused my efforts on state energy policy. Appalachian Voices intervened in the 2019 Duke Energy Carolinas rate case, where I testified on the impact that the Companies' proposed rate increase at the time would have on energy cost burdens for low-income families. I have participated in the stakeholder process for the development of the North Carolina Clean Energy Plan and associated B-1 Working Group focused on Performance-Based Regulation, served as a leading project partner on the Energy Insecurity in the Southeast project led by the Nicholas Institute at Duke University, lobbied on House Bill 951 with a focus on impacts of the bill for low-income households, and over the past year have served as a co-leader of the sub-team tasked with assessing customer challenges related to affordability for the Low-Income Affordability Collaborative ("LIAC").

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("THE COMMISSION")?

A: Yes. As mentioned previously I served as an intervenor and expert witness representing Appalachian Voices and the Center for Biological Diversity in the Duke Energy Carolinas 2019 rate case.

Q: HAVE YOU PREVIOUSLY PROVIDED TESTIMONY OR COMMENT AS AN EXPERT BEFORE ANY OTHER REGULATORY BODIES OR FORUMS?

A: Yes. As a participant in the North Carolina Clean Energy Plan stakeholder process I submitted comments on behalf of Appalachian Voices on the draft Plan to the North Carolina Department of Environmental Quality.[1] I also on two occasions submitted comments on behalf of Appalachian Voices and partner organizations regarding the Commission's COVID disconnection moratorium and the Companies' disconnection and arrearage management policies in NCUC Docket M-100, Sub 158.[2,3] Again on behalf of Appalachian Voices, I produced and submitted comments on the Duke Energy Progress and Duke Energy Carolinas Integrated Resource Plan.[4] Finally, in conjunction with comments submitted by Appalachian Voices in this docket, I authored a report on *Addressing Low-Income Energy Affordability in the Carolina Carbon Plan.*[5]

Q: ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A: No.

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[1] Appalachian Voices. Comments on North Carolina's Clean Energy Plan. Submitted directly to the North Carolina Department of Environmental Quality via email and the online portal. September 9, 2019.
[2] Appalachian Voices, et al. Instituting a New Moratorium On Regulated Electric, Gas and Water Shutoffs to Protect Utility Customers and Public Health. NCUC Docket M-100 Sub 158. March 8, 2021.
[3] Appalachian Voices. Duke Energy Progress and Duke Energy Carolinas Joint Response, and Extension of the Limited Residential Disconnection Moratorium. NCUC Docket M-100, Sub 158. June 15, 2021.
[4] Appalachian Voices Comments on Duke Energy 2020 IRP. NCUC Docket E-100, Sub 165. May 27, 2021.
[5] Appalachian Voices Comments on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's 2022 Proposed Carbon Plan. NCUC Docket E-100, Sub 179. June 15, 2022.

Q: DR. KINKHABWALA, PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A: My name is Dr. Yunus Kinkhabwala. I am a clean energy scientist with Physicians, Scientists, and Engineers for Healthy Energy (PSE). My business address is: 1440 Broadway, Suite 750 Oakland, California 94612. PSE is a non-profit energy science and policy research institute that brings together experts in public health, science, and engineering to conduct and publish research on clean energy, energy and environment, and environmental public health, and to translate that research to a broad range of stakeholders.

Q: WHAT ARE YOUR PRIMARY RESPONSIBILITIES AS A CLEAN ENERGY SCIENTIST WITH PSE HEALTHY ENERGY?

A: My work focuses on the public health and economic impacts of clean energy transitions and how such impacts are distributed among populations. In my work with PSE, I have developed datasets from publicly available resources to represent household spending on energy and used such data to guide policies that were published in 2022, *Pathways to Energy Affordability in Colorado*, a report authored at the request of the Colorado Energy Office. Additionally, I have developed energy systems models supporting the development of a virtual power plant using grid edge resources for the purpose of replacing a peaker power plant situated in a historically disadvantaged community in Los Angeles. These models account for hourly benefits of investments in efficiency and both utility and behind-the-grid solar and storage. Furthermore, for the state of California's Strategic Growth

Council I have developed models to optimize the strategic siting of combined solar and storage resilience hubs which entails estimating the economic benefits of these distributed resources based on climate and building properties.

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: I have a Bachelor of Science degree in physics from the University of Illinois and received my PhD in Applied Physics from Cornell University as a National Science Foundation (NSF) Graduate Research Fellowship Program fellow where I developed predictive models of complex systems which led to methods to forecast small area demographic changes.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("THE COMMISSION")?

A: No.

Q: HAVE YOU PREVIOUSLY PROVIDED TESTIMONY OR COMMENT AS AN EXPERT BEFORE ANY OTHER REGULATORY BODIES OR FORUMS?

A: Yes. Together with PSE scientists, Dr. Elena Krieger, and Dr. Patrick Murphy, I reviewed and prepared comments on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's 2022 Proposed Carbon Plan, filed on July 15, 2022 in this docket.

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

A: I am testifying on behalf of Appalachian Voices.

Q: ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A: No.

Q: MR. MCILMOIL, HOW IS THE AFFORDABILTY PANEL'S TESTIMONY ORGANIZED?

A: Our testimony focuses on three particular topics as identified by Commission for hearing in its *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines* entered on July 29, 2022. Those topics are: **Cost**, with focus on affordability; **Near Term Procurement**, with focus on resource alternatives to gas plant expansion; and **EE/DSM/Grid Edge**, with emphasis on how targeting investment in these programs for low-income residential customers is a cost-effective way to control energy capacity demand while bridging the affordability gap for all customers.

Q: WHAT IS THE PURPOSE OF THE PANEL TESTIMONY IN THIS PROCEEDING?

A: The purpose of the first part of our testimony is to describe why affordability must be a central objective of the Carbon Plan. We will lay out for the Commission the scale and depth to which North Carolina households served by Duke Energy Carolinas and Duke Energy Progress already struggle to afford their electric bills and describe how that challenge has been worsening and will be exacerbated by the Carbon Plan, unless the Commission and the Companies actively work to include necessary analytics and mitigative investments as part of the plan. The next portion of our testimony briefly addresses alternative resources, including utility scale solar, offshore wind, and energy storage, that should be prioritized in lieu of expanding natural gas plants to reduce the cost of decarbonization and mitigate impacts to communities surrounding those plants and the environment. Finally, we will address how investments in energy efficiency and other grid edge resources targeted toward low-income households is a cost-effective method to lower energy demand while bridging the affordability gap for all customers. Our testimony concludes with recommendations to the Commission regarding how to effectively address and enhance affordability in the final Carbon Plan and recommended resource modeling that would avoid further build-out of natural gas plants.

TOPIC: COST: Least Cost and Rate Impacts for Customers

AFFORDABILITY MUST BE A CENTRAL OBJECTIVE OF THE CARBON PLAN

Q: THE COMPANIES DESCRIBE AFFORDABILITY AS ONE OF ITS FOUR CORE OBJECTIVES FOR THE CARBON PLAN. HOW WOULD YOU DESCRIBE CURRENT AFFORDABILITY CHALLENGES FOR COMPANIES' RESIDENTIAL CUSTOMERS?

A: The Companies' own data indicates that more than 980,000 residential households, representing nearly one-third (32%) of the total residential customer base served in North Carolina, qualify as low-income per federal poverty guidelines (less than 200% of the Federal Poverty Level, or "FPL").[6]

Q: HOW DOES HOUSEHOLD INCOME RELATE TO ENERGY AFFORDABILITY?

[6] DE Response to Appalachian Voices DR 1-17.

While qualifying as low-income serves as a foundational condition placing households at risk of experiencing affordability challenges, income level alone is not a direct predictor, but there is a correlation. I used the Companies' analytics produced for the Low-Income Affordability Collaborative (LIAC) to estimate that 231,165 low-income households (24% of all low-income households[7]) currently find themselves in an arrearage situation in which they (1) were behind on paying their average/regular bill amount for six or more months or (2) were behind by twice the amount (or more) of their average bill for two or more months, thus meeting the Companies' stringent definition of "arrears struggling" households.

Q: DOES THE COMPANIES' DEFINITION OF "ARREARS STRUGGLING HOUSEHOLDS" ADEQUATELY CAPTURE AFFORDABILITY CHALLENGES THAT LOW-INCOME CUSTOMERS FACE?

A: No. The Companies' definition of "arrears struggling" is extremely stringent. It does not capture low-income customers that may spend three to five months of the year – which may represent winter or summer months when their bills are the highest – being unable to afford their bill at the time it is due. As such, the number of low-income customers captured by the Companies' "arrears struggling" definition serves as a minimum representation of the population of low-income households that struggle to afford their monthly electric bill.

[7] See Joint N.C. Low-Income Affordability Collaborative Q. Progress Rep. at Appendix F, N.C. Util. Comm'n Docket E-7 Subs 1213, 1214, 1187 and E-2 Subs 1219, 1193 (Apr. 25, 2022), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=ae12f626-823d-4ae7-86c5bc4e49aa4208 ("Revised LIAC Customer Analytics") [hereinafter Joint N.C. Low-Income Affordability Collaborative].

Q: IS IT ONLY LOW-INCOME CUSTOMERS THAT FACE AFFORDABILITY CHALLENGES?

A: No. The Companies' analytics show that another 13% of non-low-income households also met the arrears definition, amounting to more than 277,000 households that are not low-income but that are still vulnerable to unaffordable electric bills and at risk of being disconnected for non-payment. Adding that value to the number of "arrears struggling" low-income households results in a total of more than a half-million households currently qualifying as "arrears struggling," representing nearly one-sixth of all households served by the Companies in North Carolina.

As of May 2022, the most recent month for which data has been published and the month when the Companies filed their proposed Carbon Plan, nearly 575,000 households, or 18.4% of the reported residential customer base at that time, were more than 30 days in arrears. Those customers owed a total of more than $213 million, for an average of $371 per customer in arrears[8], or more than three times the average monthly bill for residential customers of Duke Energy Progress and more than 2.5 times the average monthly bill for residential customers of Duke Energy Carolinas in 2020.[9]

Q: HAVE AFFORDABILITY CONDITIONS IMPROVED SINCE PRIOR TO AND DURING THE COVID-19 PANDEMIC?

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[8] NCUC COVID -19 State of Emergency Util. Reporting Data Through May 2022, N.C. Util. Comm'n Docket M-100 Sub 158 (July 1, 2022).

[9] US Department of Energy, Energy Information Administration. Form EIA-861. File Sales_Ult_Cust_2020.xlsx.

A: No. Conditions are worse. While data is not publicly available for pre-pandemic monthly arrearages, the Companies reported that nearly 499,000 total residential customers were 30-days in arrears in May 2020 – the first month for which such data was reported – owing approximately $116.7 million ($234 per customer in arrears).[10] By May 2021, the number of residential customers in arrears had declined by 8%, but the total amount of arrears had increased by nearly the same amount. From May 2021 to May 2022, the number of customers in arrears increased by 26%, while total arrears jumped by 79%, to $213 million, resulting in a 35% increase in the average amount owed. In fact, the three highest values for total arrears for the Companies' residential customers since the beginning of mandatory monthly reporting in April 2020 have occurred in the past three months of reporting: $222.3 million in March 2022, $226.4 million in April and $213.4 million in May. Additionally, both the number of customers in arrears and total arrears have been steadily increasing, overall, since January 2021, when the Companies reported a total of 429,672 residential customers in arrears and $105.7 million in total arrears.[11]

In sum, affordability challenges experienced by the Companies' residential customer base in North Carolina are worse than they have been since the start of the COVID-19 pandemic and are continuing to worsen.

[10] Exec. Order 124 Monthly Data for May, 2020 Rep. to the Governor, N.C. Util. Comm'n Docket M-100 Sub 158 (June 18, 2022).

[11] NCUC COVID -19 State of Emergency Util. Reporting Data Through May 2022, N.C. Util. Comm'n Docket M-100 Sub 158 (July 1, 2022).

Thus, as the Commission develops and the Companies embark on implementing a Carolinas Carbon Plan, affordability challenges must be addressed as a core part of the plan, not as an afterthought. Otherwise, existing affordability challenges and impacts are likely to worsen as more residential customers become vulnerable to falling into arrears and potentially being disconnected for non-payment.

Q: WHAT IS THE PRIMARY DRIVER OF AFFORDABILITY CHALLENGES FOR THE COMPANIES' LOW-INCOME AND OTHERWISE VULNERABLE CUSTOMERS?

A: Energy Inefficiency. As an active stakeholder in the LIAC process, I represented Appalachian Voices as a co-lead of Sub-team A, which was tasked with assessing customer challenges as they relate to affordability. In that role I served as a primary author of the assessment report, distilling the results of the analytics into a summary report that was presented to the broader LIAC stakeholder group. The Companies acknowledged that these factors were likely due to energy-inefficient building stock, heating and cooling systems and appliances, concluding that the findings "strongly suggest that improving a household's energy efficiency through air sealing, insulation, and energy efficient heating systems could substantially reduce a household's likelihood of experiencing a [disconnection for non-payment]."[12]

[12] See Joint N.C. Low-Income Affordability Collaborative at Appendix F.

Q: DO THE COMPANIES' LOW-INCOME PROGRAMS COUPLED WITH OTHER PUBLICLY AVAILABLE RESOURCES SUFFICIENTLY ADDRESS THOSE AFFORDABILITY CHALLENGES?

A: No. If the Companies' programs, and the state Weatherization Assistance Program, Low-Income Energy Assistance Program or Crisis Assistance Program (LIEAP/CIP) sufficiently addressed low-income affordability challenges, the current affordability gaps outlined above would not likely exist at the scale and breadth that they do today. For instance, the Companies' analytics for the LIAC showed just 2% of its residential customer base (7.5% of its low-income customer base) received LIEAP/CIP assistance for paying their electric bills during the March 2019 through February 2020 analytical period.[13] Statewide, less than 4,000 households received weatherization assistance funding, in 2021.[14]

Additionally, according to the LIAC Final Report, less than 0.1% of program-eligible customers have participated in the Duke Energy Carolinas Weatherization Program and Equipment Replacement Program, and the impact of the program for those that have participated is a reduction in the estimated electric energy burden of only 1% or less. The Companies also report that the Neighborhood Energy Savers Program has reached 7.8% and 10% of Duke Energy Carolinas and Duke Energy Progress' program eligible customers, respectively. While that is a laudable achievement, the

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[13] *Id.*

[14] North Carolina Weatherization Assistance Program. https://www.benefits.gov/benefit/1873. Accessed August 31, 2022.

nature of the program – in that it provides only education, energy assessments, and direct install measures rather than high-impact energy efficiency upgrades and improvements – limits the impact it has on the estimated electric energy burden for participating customers to a 0.4% burden reduction or less. Similar shortfalls characterize the Helping Home Fund, which serves less than 1,000 eligible households each year, and the Share the Light program, which serves only 5,000 households each year.[15]

While the Companies' existing programs are critical and provide tangible affordability and health-related benefits to its vulnerable customers, they serve only a small segment of the low-income customer base and have minimal impact on alleviating affordability challenges, reducing energy cost burdens or addressing peak winter and summer usage and demand in low-income households. And while there have been significant increases in funding for state weatherization and bill assistance programs during the COVID-19 pandemic, it still has not been enough to meet the scale and depth of need that exists.

Q: HOW WILL IMPLEMENTATION OF THE PROPOSED CARBON PLAN AFFECT EXISTING AFFORDABILITY CHALLENGES FOR LOW-INCOME AND OTHERWISE VULNERABLE CUSTOMERS?

A: Appalachian Voices submitted testimony and analysis in the Duke Energy Carolinas (DEC) 2019 rate case projecting how DEC's proposed rate

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[15] Joint North Carolina Low-Income Affordability Collaborative Quarterly Progress Report. Docket Nos. E-7, Subs 1213, 1214 and 1187 and E-2, Subs 1219 and 1193. At 19-30.

increase would impact low-income customers in terms of increased energy burdens.[16] As of 2019, the average household energy burden for the 332,000 low-income households (less than 150% FPL) served by DEC exceeded the 6% affordability threshold, while 141,000 of those households experienced a "severe" energy burden exceeding 10.9%.[17]

DEC's estimate of customer bill impacts in the initial rate case filing estimated an increase of $8.06 per month, which approximates the $8 estimated monthly impact of DEC residential customers in 2030 resulting from Portfolio 1 in the proposed Carbon Plan. Using the bill impact value from DEC's rate case filing, we calculated that such an increase would have resulted in more than 57,000 low-income households (17% of all low-income households) moving into the "severe" energy burden category.[18]

As a proxy for the 2030 expected impact on energy burdens for low-income DEC households as a result of the Carbon Plan, this impact from an arguably modest increase in monthly bills should not be underestimated. The Companies' LIAC analytics illustrate how energy burdens exceeding the 6% threshold impact increase the likelihood that a household will meet the definition of "arrears struggling" and/or be disconnected for non-payment. For the definition of arrears, the analytics showed that compared

[16] See N.C. Util. Comm'n Docket E-7 Sub 1214.

[17] APPLIED PUB. POL'Y RSCH. INST. FOR STUDY AND EVALUATION, LIHEAP ENERGY BURDEN EVALUATION STUDY 12 (July 2005), https://www.acf.hhs.gov/sites/default/files/documents/ocs/comm_liheap_energyburdenstudy_apprise.pdf.

[18] Direct Test. Of Rory McIlmoil for Ctr. Biological and Appalachian Voices, N.C. Util. Comm'n Docket E-7 Sub 1214 (Feb. 18, 2020).

to a 6% energy burden a household with a 10% energy burden is 36% more likely to meet the arrears definition, while a 12% burden level renders a household 52% more likely to meet the definition. For disconnections, the relative likelihoods are 8% and 10%, respectively.[19]

Without clearly targeted and sufficiently funded low-income energy efficiency and distributed energy programs, combined with increased bill assistance or discounted rate programs for low-income customers, the Carolinas Carbon Plan as proposed will only serve to exacerbate existing affordability challenges. The increase in costs for households already struggling to afford their bills projected by the Companies for each of the four proposed Carbon Plan portfolios will only make it harder for those households to afford future bills. As a result, the impacts associated with affordability challenges -- namely disconnections for non-payment -- can be expected to increase as well.

In the statistical analysis portion of the LIAC analytics the Companies report a “disconnected for non-pay” population of approximately 186,000 households that experienced a disconnection during the 12-months prior to the pandemic. This represents approximately 8% of the Companies’ total residential customer base and nearly half (47%) of the population of “arrears struggling” customers from which the disconnection sub-population was taken.[20] That is a significant number of households that experienced a loss

[19] See Joint N.C. Low-Income Affordability Collaborative at Appendix F.
[20] See Joint N.C. Low-Income Affordability Collaborative at Appendix F.

of electricity service because they could not afford to pay their bill. Again, this impact is likely only to grow if the Companies' proposed plan is approved and implemented without the inclusion of targeted investments that enhance affordability through energy efficiency, distributed energy resources, and bill assistance or other affordability programs.

THE PROPOSED CARBON PLAN LACKS ANY ATTEMPT TO MITIGATE AFFORDABILITY IMPACTS

Q: HOW DO THE COMPANIES APPROACH AFFORDABILITY IN THE PROPOSED CARBON PLAN AND SUPPORTING TESTIMONY, AND IS THAT APPROACH SUFFICIENT?

A: The Companies list "affordability" as one of four core objectives of the Carbon Plan, but then they refuse to define what they mean by affordability, either generally or in the context of the Carbon Plan. Instead, the Companies inappropriately conflate the terms "least cost" and "affordability" in its proposed plan and testimony. While related, these terms are not the same. "Least cost" does not mean "affordable," it merely means "less costly than the alternative."

Despite the fact that electric bills are unaffordable for hundreds of thousands of their residential customers, as detailed previously, the Companies continuously work to construct the perception that they already provide "affordable service," "affordable electricity" and "affordable rates." This construct is belied by the Companies' own analytics that show nearly

430,000 of its customers were in arrears in January of 2021 with those numbers steadily climbing to 575,000 customers as of May 2022.

For example, in its proposed plan and testimony, the Companies repeatedly claim affordable service as a hallmark.

> *"The Companies intend to take a multipronged approach to maintaining affordable and reliable service while also meeting CO2 emissions reduction targets."*[21] …

> *"The Companies are committed to the continued provision of affordable electricity for residents, businesses, industries, and communities in the Carolinas."*[22]

> *"Under the oversight of the Commission and the PSCSC, the Companies' current system is reliable, flexible, affordable and increasingly clean. Customers have benefitted from the Companies' diverse fleet of generation… providing reliable and affordable electricity that has contributed to the State's economic prosperity…"*[23]

> *"The Companies understand the critical importance of maintaining affordable and competitive rates, and we are focused on continuing to achieve efficiencies across the business to maintain our affordable rates."*[24]

While the Companies' four proposed portfolios may represent the "least cost" (e.g., "less costly") pathway relative to other options (in the

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[21] DUKE ENERGY, CAROLINAS CARBON PLAN Appendix E at 9 (May 16, 2022) (emphasis added) [hereinafter CAROLINAS CARBON PLAN].
[22] *Id.* at 20.
[23] DIRECT TESTIMONY OF KENDAL C. BOWMAN FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC. Docket E-100, Sub 179. At 9.
[24] *Id.* at 18.

Companies' opinion), all four portfolios result in an increase in customer bills, and none would be "affordable" for the substantial number of residential customers already struggling to afford their current electric bills. The Companies' approach is not sufficient.

Q: CAN YOU PROVIDE EXAMPLES OF HOW THE PROPOSED PLAN FALLS SHORT IN DEALING WITH AFFORDABILITY?

A: The Companies' approach to and perception of "affordability" should have evolved as a result of the LIAC process but appears to not have changed. The Companies mention "cost" and "affordability" together, but only present "cost" impacts, and nothing for "affordability" impacts. The Companies provide no definition of, or metrics related to, affordability, no reference to "affordability" definitions or affordability challenges identified and discussed throughout the LIAC process, and no analysis of impacts resulting from affordability challenges such as arrearages, disconnections or other impacts that may result from the implementation of any of the four carbon plan portfolios.

In fact, when Appalachian Voices requested the Companies to "[p]rovide any datasets, analysis, modeling, documentation, etc. Duke used or produced to determine how the estimated cost of each of the four portfolios will impact arrearages and disconnections for residential customers, particularly low-income customers," the Companies responded that "[t]he question seeks information that is outside of the scope of the Carbon Plan proceeding," and again reverted back to conflating "least cost" with affordability.[25] As arrearages and disconnections directly represent the outcomes of affordability challenges faced by Duke Energy's customers, however, the admission that the Companies consider such an analysis to be "outside the scope of" the Carbon Plan underscores their lack of commitment to addressing actual affordability concerns.

Finally, the Companies' perception that their affordability objective is a matter of presenting a "least cost" plan for reducing carbon emissions rather than of addressing existing and potential affordability challenges and impacts experienced by hundreds of thousands of households they serve is reflected in the exclusion from the Carbon Plan of any investments or programs that would reduce costs for residential customers or, at a minimum, offset future costs projected to result from the Carbon Plan.

Q: DO THE COMPANIES HAVE THE DATA AND TOOLS AVAILABLE TO MODEL THE IMPACTS OF THEIR PROPOSED CARBON PLAN PORTFOLIOS ON LOW- AND MODERATE-INCOME AFFORDABILITY CHALLENGES?

A: Yes, but they have chosen not to use those tools in their carbon planning process. During the initial discovery process, Appalachian Voices asked the Companies to provide details on "how Duke incorporated data and analysis from/of the detailed customer usage and demographics dataset produced by Duke and Acxiom for purposes of the [LIAC] for the purpose of analyzing the impact of the four carbon plan portfolios on customers of

[25] DE Response to Appalachian Voices DR. 1-7.

different income levels, housing tenure, housing type, race, age, region (urban vs. rural) and other customer segments analyzed for the LIAC." The Companies responded that "[a]t the time the Carbon Plan was being developed, the analytics and data pipelines used for the [LIAC] were still a work in progress. Because of this overlap in the timing, LIAC analytic results were not specifically included in the Carbon Plan. However, as stated in the Carbon Plan, the Companies are committed to use the findings from the LIAC going forward to expand the Companies' programs and support customers."[26]

The actual timeline of events belies this response. Duke Energy and Acxiom produced the initial version of the noted analytics in September 2021, with refinements and additions being performed for new versions provided to the LIAC in October, November, and December 2021, with the final version (including new statistical analysis) being provided in March 2022. The Companies submitted their proposed Carbon Plan on May 16, 2022.

In other words, the datasets for incorporating a deep analysis of potential affordability impacts on residential customers that would result under the four proposed Carbon Plan portfolios were available as early as September of 2021, while even the final version was available for six weeks prior to the Companies' submission of the Plan.

[26] DE Response to Appalachian Voices DR. 1-10.

Q: DO THE COMPANIES PROPOSE, AS AN INTEGRAL PART OF THE CARBON PLAN, ANY PROGRAMS OR INVESTMENTS TARGETED AT ADDRESSING LOW-INCOME AND OTHERWISE VULNERABLE CUSTOMER AFFORDABILITY CHALLENGES?

A: No. Despite the Companies' purported inclusion of affordability as a core Carbon Plan objective, the Companies neither propose nor incorporate any programs or investments in the Carbon Plan that directly target low-income and/or otherwise vulnerable customers. Instead, the Companies punt that responsibility to future years and other proceedings, stating, for instance, that "…[t]o ensure we are helping customers most in need now and in the future, we are taking steps with the input of the [LIAC] to advance new proposals that will help our residential customers that may be struggling to pay their bills."[27]

The Companies note future programs and other low-income approaches the Companies might or plan to request and adopt, including the potential expansion of income qualification for low-income energy efficiency programs to 300% of FPL, on-tariff energy efficiency financing, pursuing Commission approval of an Energy Burden Reduction Pilot program, and expanding the existing Neighborhood Energy Saver program.[28] While most of these potential programs and changes would benefit low-income households and address, to varied extents, customer affordability challenges and impacts, none were integrated directly into the

[27] *Id.* at 20.
[28] CAROLINAS CARBON PLAN, Appendix E at 9-10.

Carbon Plan, and none are being requested by the Companies as critical near-term development activities.

Q: HOW COULD OR SHOULD THE COMPANIES HAVE INCORPORATED TARGETED AFFORDABILITY PROGRAMS FOR LOW-INCOME AND OTHERWISE VULNERABLE CUSTOMERS IN THEIR PROPOSED CARBON PLAN?

A: If the Companies are genuinely committed to affordability as a core objective in the Carbon Plan they must go beyond a strict "least cost" approach and directly incorporate programs and investments that directly address affordability challenges and impacts for low-income and otherwise vulnerable households. This would include expanded bill assistance, low-income rate designs, and arrearage management programs that alleviate existing challenges customers face with affording their electric bills. It would include proactive and aggressive long-term investments in energy efficiency and demand-side management to reduce household and system costs related to winter and summer peak energy usage resulting from energy-inefficient buildings (insulation, air sealing, etc.), heating and cooling systems and appliances, particularly for low-income households.[29] It would involve expanding distributed solar options to include customer-owned and

[29] In fact, Appendix E of the CAROLINAS CARBON PLAN (at 28) argues for having included targeted low-income demand reduction programs, noting that "Within residential populations, the need exists to address low-income demand [given that] lower-income customers tend to contribute more [to demand] during peak. About a third of customers participating in residential [demand reduction] programs today (that are mainly summer programs) earn less than 200% of the poverty line."

community-based or shared solar programs that are accessible and targeted to low-income and otherwise economically vulnerable households.

Q: WOULD INVESTMENTS TO ADDRESS AFFORDABILTY CHALLENGES HAVE ANY IMPACT ON CAPACITY NEEDS, OR OTHER SYSTEM-WIDE COSTS?

A: Yes. Such investments not only enhance affordability and reduce the long-term need for funding bill assistance programs, but also contribute to decarbonization, improved grid reliability and resiliency, and reduce or avoid the need for new gas capacity and new transmission infrastructure, all of which lower costs for customers.

Q: ARE THERE OTHER STEPS THE COMMISSION AND COMPANIES CAN TAKE TO ENHANCE AFFORDABILITY IN THE CARBON PLAN?

A: Yes. A true commitment to affordability in the Carbon Plan requires modeling the potential for a regional competitive wholesale market and use of performance-based regulation and appropriate performance incentive mechanisms to enhance affordability, reliability, and carbon reductions compared to the currently proposed Carbon Plan.

Q: DO YOU AGREE WITH THE COMPANIES' REQUEST THAT THE COMMISSION AFFIRM IN ITS CARBON PLAN ORDER THAT EXPANDED LOW-INCOME PROGRAMS SHOULD BE CONSIDERED AND APPROVED IN A SEPARATE DOCKET? PLEASE EXPLAIN.

A: No, for reasons already detailed in my testimony and further explained below. First, if the Companies can propose and request approval of short-term development activities for resources that may not be constructed for several years, they can similarly request that the Commission provide conditional approval for the inclusion of low-income energy efficiency and distributed energy programs and investments that contribute to the mandated decarbonization goal and enhance affordability for customers. However, the Companies intentionally elected not to do so.

Second, if affordability is a "core objective" of the Carbon Plan, then the Companies should be required to incorporate affordability investments – particularly those that can contribute to decarbonization – as an integral part of the Carbon Plan.

Q: DO YOU AGREE WITH THE COMPANIES' PROPOSAL TO EXPAND THE DEFINITION OF INCOME QUALIFIED ELIGIBLE CUSTOMERS TO 300% OF FEDERAL POVERTY GUIDELINES? PLEASE EXPLAIN.

A: No. While we recognize that a substantial number of customers falling above the generally applied 200% of FPL threshold experience affordability challenges, we do not agree that the definition of income-qualified eligible customers should be expanded to 300% of FPL. As explained previously in my testimony, existing Company and public programs are starkly underfunded and reach only an extremely small portion of the low-income households (as currently defined - less than 200% FPL) in need of assistance. The shortfall in funding and population of households receiving assistance or participating in existing energy efficiency and bill assistance programs must be addressed first before any proposal to expand the eligibility definition is considered. Otherwise, if the population of eligible households expands, existing resources may be spread even thinner, reducing the per-household benefit, and/or reducing the ability of the households that struggle the most with affordability challenges to access the programs. If the Companies directly incorporate proposals and investments aimed at enhancing affordability into the Carbon Plan with its request to expand low-income program eligibility, our response might be different. They intentionally neglected to do so.

TOPIC: NEAR TERM PROCUREMENT

ALTERNATE RESOURCES TO GAS PLANTS: BENEFITS OF GRID EDGE RESOURCES

Q: DR. KINKHABWALA, PSE PREPARED A REPORT, "*REVIEW AND COMMENT ON THE DUKE ENERGY PROPOSED CARBON PLAN FOR THE CAROLINAS*," THAT WAS FILED WITH COMMENTS SUBMITTED ON BEHALF OF APPALACHIAN VOICES, IS THAT CORRECT?

A: Yes. I collaborated with Dr. Krieger and Dr. Murphy in the preparation of that report.

Q: DID THAT REPORT IDENTIFY ALTERNATIVES TO THE PROPOSED EXPANDED USE OF GAS PLANTS?

A: Yes. The proposed Plan includes 2.4 gigawatts (GW) of new gas combined cycle facilities and 0.8-1.1 GW of new gas combustion turbines. These plants would provide an estimated 14,700 GWh and 70 GWh of electricity in 2030, respectively. However, the Companies did not fully consider the potential of utility-scale solar, offshore wind, energy storage, or grid-edge alternatives to these investments. The Plan put unnecessary constraints on the timing and capacity of alternative resource deployment, including onshore and offshore wind, distributed energy resources, and energy efficiency. Enabling the EnCompass model to actively select these resources when cost-competitive would enable a fair comparison of their ability to meet energy and capacity needs. The proposed peaking gas combustion plants could likely be replaced with utility-scale energy storage, as has been occurring nationwide; additional peak needs could be met with offshore wind deployed earlier than proposed, energy efficiency, demand response, and distributed storage. As discussed more fully in our report submitted as comments on behalf of Appalachian Voices, energy needs could likely be met with a combination of demand-side efficiency savings and expanded offshore wind and solar (utility-scale and distributed).

TOPIC: EE/DSM/GRID EDGE

Q: DO YOU HAVE CONCERNS RELATING TO THE COMPANIES' TREATMENT OF GRID EDGE RESOURCES?

A: Yes. The Plan underutilizes grid edge resources including energy storage, solar, demand response, and energy efficiency by not enabling these resources to compete with utility-scale investments in the EnCompass modeling runs and capping their rollout at very low levels. These resources have the potential to not only obviate the need for new gas plant investments but can help reduce health-damaging air pollutant and greenhouse gas emissions, provide resilience, and add to grid flexibility.

Q: CAN YOU PLEASE EXPLAIN WHAT THE VALUE IS, TO THE GRID AND TO CUSTOMERS, OF GRID-EDGE RESOURCES, SUCH AS ENERGY EFFICIENCY AND DISTRIBUTED GENERATION AND STORAGE?

A: Grid-edge resources hold a wide range of potential benefits for both the electric grid and for customers. Energy efficiency investments, such as weatherization and efficient appliances, reduce customer energy use and bills, while simultaneously offsetting the need to build utility-scale generation resources and subsequently mitigating the costs that get passed on to customers. Weatherization can also help keep homes cool in summer and warm in winter, protecting vulnerable populations from the cold and from heat stroke. Distributed solar resources, inclusive of both behind-the-meter and community solar systems, can provide consistent bills and savings for adopters while similarly offsetting the need for utility-scale generation. Energy storage systems can help provide demand management, integrate renewable energy resources, and provide resilience in the case of emergencies.

All of these resources, if they displace fossil fuel generation, hold the potential to reduce utility-scale greenhouse gas and health-damaging air pollutant emissions. Additional grid edge resources include, but are not limited to, vehicle-to-grid systems and smart appliances that can participate in demand response. These resources collectively hold the potential to provide flexibility, and may provide location-specific grid benefits such as deferral of distribution system investments and reduction in peak demand.

Q: THE COMPANIES MAINTAIN THAT THE FIRST PILLAR OF ENERGY TRANSITION AND THE CARBON PLAN IS TO "SHRINK THE CHALLENGE" BY REDUCING ENERGY REQUIREMENTS AND LOAD PATTERNS THROUGH GRID EDGE PROGRAMS. WHAT ROLE DOES ENERGY EFFICIENCY INVESTMENT PLAY IN REDUCING DEMAND, PARTICULARLY AS RELATES TO LOW-INCOME HOUSEHOLDS?

A: Energy efficiency, as Duke notes, can help reduce the challenge of meeting electricity demand requirements. As such, it behooves Duke to expand its energy efficiency targets. As detailed in our report, we estimated that if Duke achieved efficiency levels equal 1% of retail sales per year (which Duke Energy Carolina has achieved historically[30]), inclusive of non-behavioral investments with multi-year measure lifespans, that Duke would save an additional 4,700 GWh and reduce demand by 800 MW by 2030. Achieving 2% savings per year would provide 14,300 GWh of energy savings and 2,500 MW of demand reductions beyond Duke's current proposal. Such investments would greatly reduce the need to build new gas plants. For example, as detailed in our report for Appalachian Voices in this matter, using our simulated portfolio of household energy use, we estimated that investing in energy efficiency and other grid edge resources for just the households with energy cost burdens greater than 6% would reduce energy cost burdens for 90% of these households to less than the 6% threshold with a blend of on-bill financing. Simultaneously, the investments could

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[30] Bradley-Wright, F., H. Pohnan, & M. Shober (2022). "Energy Efficiency in the Southeast: Fourth Annual Report." Southern Alliance for Clean Energy." Available at: https://cleanenergy.org/wp-content/uploads/Energy-Efficiency-in-the-Southeast-Fourth-Annual-Report.pdf

annually save 2,800 GWh in electricity use in the Companies' North Carolina service area alone, which represents approximately 25% of the total electricity use of these households. This proportion agrees with estimates from the US Department of Energy[31]~~.~~

DUKE CARBON PLAN ENERGY EFFICIENCY TARGETS

Q: THE COMPANIES DESCRIBE THEIR PROPOSED ENERGY EFFICIENCY TARGET OF 1% OF ELIGIBLE RETAIL SALES AS "AGGRESSIVE." DO YOU AGREE?

A: No. The proposed energy efficiency targets in the Carbon Plan are not aggressive. The Companies target savings of 1% of eligible load per year, but only about two-thirds of their combined load is eligible. As other parties have testified,[32] this goal represents a lower percentage of retail sales than Duke has achieved historically. The Companies claim that efficiency levels cannot expand beyond current targets because they depend entirely on "customer preferences,"[33] but Duke's own programs and energy efficiency savings demonstrate that programmatic investments in energy efficiency can lead to demand reductions. It is unclear why Duke credits customer preference over its own energy efficiency programs. Efficiency programs across the country have effectively achieved significantly higher savings

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[31] US DOE. EnergySavers Tips on Saving Money & Energy at Home. Available at: https://www.energy.gov/sites/prod/files/energy_savers.pdf

[32] JOINT COMMENTS OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, SIERRA CLUB, AND NATURAL RESOURCES DEFENSE COUNCIL, DOCKET NO. E-100, SUB 179 p. 24. July 15, 2022. Available at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=c6afa7f2-ac61-439c-b406-98b42e4ca04e

[33] DIRECT TESTIMONY OF LON HUBER AND TIM DUFF FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC. P. 18 L. 6. DOCKET NO. E-100, SUB 179. August 19, 2022.

than the Companies' goals: many states achieve nearly 2% or more of retail sales per year.[34]

The Companies argue that they should not be beholden to targets based on retail sales because some customers are permitted to opt out of efficiency programs. However, this approach not only fails to consider that these customers could be a potentially low-cost valuable resource, but also that other factors, such as funding from the recently passed Inflation Reduction Act, could contribute to the adoption of energy efficiency measures for all customers. Moreover, there are large segments of eligible customers who have significant energy efficiency potential that has not been realized. For example, current efficiency savings for low-income households -- who comprise one-third of the Companies' customers – are negligible.[35] The expansion of targeted programs for these households would enable greater overall savings in addition to a reduction in energy cost burdens for those who need it most. Finally, the Companies rely significantly on behavioral interventions for which they ascribe a single year of savings. The expansion of investments in weatherization, appliances, and other non-behavioral measures with multi-year measure lifetimes

[34] Berg, W., E. Cooper, and M. DiMascio. 2022. State Energy Efficiency Scorecard: 2021 Progress Report. Washington, DC: ACEEE. Available at: aceee.org/research-report/u2201.

[35] Bradley-Wright, F., H. Pohnan, & M. Shober (2022). "Energy Efficiency in the Southeast: Fourth Annual Report." Southern Alliance for Clean Energy." Available at: https://cleanenergy.org/wp-content/uploads/Energy-Efficiency-in-the-Southeast-Fourth-Annual-Report.pdf

should increase the Companies' potential annual electricity and demand savings.

Q: THE COMPANIES CONTEND THAT ENERGY EFFICIENCY TARGETS BASED ON RETAIL SALES IS NOT AN ACCURATE OR ILLUSTRATIVE COMPARISON BETWEEN STATES. DO YOU AGREE?

A: We believe that using retail sales is a valid comparison, and so does Duke in some contexts — they use retail sales for comparison to other utilities in their comments.[36] Duke provides a comparison of what it suggests would be equivalent retail savings if other states saved the same average residential kWh as Duke would at a 1% savings rate.[37] The Table provided is confusing and misleading. Duke has very high residential usage (in kWh) compared to nearly all the other states shown, suggesting that houses in Duke territory likely have very high energy use intensity and probably have more low-hanging fruit in terms of energy efficiency investments than the comparison states. Many of the comparison states, such as California, Massachusetts, and Vermont, have achieved roughly 2% energy efficiency for many years in a row, meaning the cheapest measures have likely been implemented and efficiency savings should be harder in these states, yet savings remain high. However, even following Duke's logic (namely, that it is harder for Duke to achieve 1% savings in terms of retail sales because the total kWh reductions required would be higher), this Table demonstrates

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[36] DIRECT TESTIMONY OF LON HUBER AND TIM DUFF FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC. P. 11 Fig. 1. DOCKET NO. E-100, SUB 179. August 19, 2022.
[37] DIRECT TESTIMONY OF LON HUBER AND TIM DUFF FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC. P. 27 Table 2. DOCKET NO. E-100, SUB 179. August 19, 2022.

that such savings should be possible. The **"**equivalent" savings for Massachusetts are given as 1.73% — but it achieved 2.34% of retail sales in 2021[38] (these savings are for all sectors, not just residential). The equivalent savings for Vermont are supposedly 1.84%, but Vermont achieved 1.97% of retail sales in 2021. Meanwhile, Duke is targeting 1% of *eligible* load — a lower value than 1% of retail sales. Higher targets are clearly achievable. We believe a comparison to percentage of retail sales is valid because states that have implemented historic efficiency measures are inherently going to see lower kWh of annual savings in each incremental year because the easiest measures get implemented first.

Q: DO YOU CONSIDER THE DEPLOYMENT RATES OF OTHER GRID EDGE RESOURCES TO BE ADEQUATE?

A: No. The Companies do not adequately address the potential expansion of distributed energy resources, such as rooftop solar or demand response. Their modeling software does not enable demand response, energy efficiency, nor many other resources, to be selected as a resource that can offset the need for new gas power plants. These resources could potentially be significantly cheaper than the utility-scale resources the Companies propose, but grid edge resources are not allowed to effectively compete in the model. We agree with the Attorney General's Office[39] that efficiency

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[38] Berg, W., E. Cooper, and M. DiMascio. 2022. State Energy Efficiency Scorecard: 2021 Progress Report. Washington, DC: ACEEE. Available at: aceee.org/research-report/u2201.
[39] COMMENTS OF THE ATTORNEY GENERAL'S OFFICE, DOCKET NO. E-100, SUB 179. July 15, 2022. Available at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=fa173cb9-6ed8-4a84-a474-546cf27e3ad3

should be a selectable resource, alongside other grid-edge resources. Even if not included here, the Companies should include a more aggressive efficiency scenario (e.g., 2% savings in retail sales per year) and include grid edge resources as a selectable resource in all future Carbon Plan iterations. Furthermore, the extension of tax credits and proposed allocation of billions of dollars in financing and rebates for household-level clean energy adoption, including for efficiency measures and rooftop solar, within the 2022 Inflation Reduction Act suggests that the Companies' modeling is likely an underestimate of future clean energy adoption rates.

ENERGY COST BURDENS AND AFFORDABILITY

Q: HOW WOULD YOU CHARACTERIZE THE AFFORDABILITY AND ENERGY COST BURDEN CHALLENGES OF CUSTOMERS IN DUKE'S NORTH CAROLINA TERRITORY?

A: Nearly all households with incomes less than the FPL experience undue financial burden without bill assistance, using the standard definition of "high" energy cost burdens being those greater than 6% of gross household income. Over half of households in Duke Energy's North Carolina territory earning between one and two times the federal poverty level (100-200% FPL) also have energy cost burdens over 6%. In terms of bill assistance alone, it would cost over $600 million annually to pay down all these bills to the 6% threshold, a sum far in excess of the current amount available. However, through targeted use of grid edge resources such as efficiency, demand response, and community solar alongside financing strategies, this annual sum could be reduced by up to 95% if all low-income households participated. Moreover, such investments typically pay for themselves, as described above. These resources also, as noted previously, can contribute to achieving carbon targets and reducing the emissions of health-damaging air pollutants from fossil fuel combustion. Such investments, therefore, are clearly of great value and should be pursued with great urgency to reap the financial benefits as soon as possible. Each year without implementation of available energy efficiency upgrades is a year of increased financial burden on low-income customers and a wasted opportunity for decarbonization and air pollutant emissions reductions. Given the limited amount of progress that has been made thus far for low-income households,[40] there remains great potential for future savings.

Q: HOW DOES THE COMPANIES' PROPOSED CARBON PLAN AFFECT AFFORDABILITY AND ENERGY COST BURDENS?

A: The proposed Carbon Plan holds direct and indirect implications for affordability. Although rates are determined separately, utility-scale investments and fossil fuel costs are passed on to customers. As such, unnecessary capital investments may exacerbate affordability challenges, and escalating natural gas prices pose a risk to customers. Meanwhile, direct investments in energy efficiency can reduce customer bills. If the

[40] Bradley-Wright, F., H. Pohnan, & M. Shober (2022). "Energy Efficiency in the Southeast: Fourth Annual Report." Southern Alliance for Clean Energy." Available at: https://cleanenergy.org/wp-content/uploads/Energy-Efficiency-in-the-Southeast-Fourth-Annual-Report.pdf

Companies expanded their energy efficiency targets and incorporated affordability metrics as recommended by LIAC, more households would be able to reduce their energy bills without leaving behind the neediest households. As noted above, historically, low-income efficiency savings have been negligible. The Companies in their response comments suggested the need to expand their low-income efficiency programs.[41] Such investments could be bolstered by funding from the Inflation Reduction Act. While the Companies assert that low-income efficiency programs are not cost-effective,[42] we suggest that ascribing a value to non-energy societal benefits, such as a reduction in energy cost burdens and emission reductions, may indeed show that these investments are cost-effective on a societal level.

The Companies also suggest that relying on demand reduction through energy efficiency investments is “risky” because customer preference may limit adoption, but we assert that the proposed alternative — namely, investments in expanded gas infrastructure — is riskier due to the potential for stranded assets and the reliance on fossil fuels whose volatile prices may be passed on to customers. Similarly, the proposed investment in small modular nuclear reactors, an entirely unproven resource, is significantly riskier than any energy efficiency investments.

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[41] DIRECT TESTIMONY OF LON HUBER AND TIM DUFF FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC. P. 31 L. 21. DOCKET NO. E-100, SUB 179. August 19, 2022.

[42] DIRECT TESTIMONY OF LON HUBER AND TIM DUFF FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC. P. 32 L. 7. DOCKET NO. E-100, SUB 179. August 19, 2022.

The Companies also propose expanding eligible "low-income" populations from those earning under 200% FPL to those earning under 300% FPL. While I agree with other testimony[43] that such changes in definition should be made in collaboration with the LIAC, I also note that any increase in the number of eligible customers should be associated with an increase in available funding, and funding targeted at those households earning under 200% FPL should not be reduced but rather should be increased. Furthermore, we estimate that around 75% of households with incomes less than 200% FPL have energy cost burdens greater than 6%, while the cost burden for households between 200% and 300% FPL is only 5%. The definition of low-income households as less than 200% FPL is a reasonable cutoff for households that experience undue financial burden and for whom the financial benefits of lower energy bills will be most impactful. Any program targeted specifically at households in the 200-300% FPL range should be on top of existing investment and go above and beyond the investments for households earning 200% FPL and should not replace those existing investments.

Q: HOW COULD MODIFICATIONS TO THE COMPANIES' PROPOSED CARBON PLAN HELP IMPROVE AFFORDABILITY?

[43] JOINT COMMENTS OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, SIERRA CLUB, AND NATURAL RESOURCES DEFENSE COUNCIL, DOCKET NO. E-100, SUB 179 p. 24. July 15, 2022. Available at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=c6afa7f2-ac61-439c-b406-98b42e4ca04e

A: Setting more ambitious targets for savings from grid edge resources will benefit all customers. Investments in these resources have been shown to have wide ranging benefits including added grid resilience, peak shaving, and reduced transmission costs. Furthermore, separate targets should be set specifically for low-income households. These households have historically seen the least savings from Duke's programs and are also the households that would benefit the most from efficiency and affordability investments. Bill savings for these households would result in societal benefits that extend beyond the already substantial benefits that arise from reduced carbon emissions and capacity. The roughly 900,000 households that are energy burdened would see an average annual savings of $650 per year. Until affordability is appropriately incorporated into planning alongside grid edge resources, however, this large financial boon to low-income homes will remain largely ignored as most current programs serve miniscule fractions of these households.

<u>RECOMMENDATIONS FOR THE COMMISSION</u>

Q: WHAT ARE THE PANEL'S RECOMMENDATIONS TO THE COMMISSION CONCERNING AFFORDABILITY?

A: Decarbonizing the grid through a transition to clean, renewable energy resources; battery storage; and substantial investments in energy efficiency and demand-side management is critical for North Carolina. That transition must proceed rapidly to confront the worst impacts of climate change and protect public health. However, it is abundantly clear that the implementation of any of the Companies' four Carbon Plan portfolios will exacerbate both the challenges and impacts low-income households already experience due to the unaffordability of their electric and total energy bills. As such, any plan which guides the energy transition must, as a core and integrated objective of the plan, directly address existing and future energy affordability challenges and impacts for North Carolina households, especially low-income and otherwise vulnerable households. Doing so can and will contribute to the achievement of both the state's decarbonization goals as well as the improvement of the economic and public health of North Carolina's residents.

To that end, as it develops the final Carbon Plan for this biennial period, we request that the Commission:

1. Require that the Companies define and develop metrics for assessing "affordability" in a manner that describes actual experiences and impacts faced by its residential customers. We therefore recommend that the Commission require the Companies adopt the definition of affordability codified by the California Public Utilities Commission and proposed by the LIAC Sub-team B, as "the degree to which a representative household is able to pay for an essential utility service charge, given its socioeconomic status."

2. Require that the final Carbon Plan incorporate substantial investments in, and model the affordability and carbon reduction benefits of, customer bill assistance and arrearage management programs (such as

those proposed through the LIAC), low-income weatherization and other energy efficiency investments, and low-income distributed energy and demand reduction investments. The Commission should require the analysis to include impacts on low-income customer bills (specifically, average actual bills, not just average bills for a certain quantity of electricity consumption, to ensure that efficiency benefits are reflected), electricity cost burdens, arrearages, disconnections for non-payment, and carbon emissions via the avoidance of the "need" to build new methane gas generation.

3. Reject the Companies' proposal to expand the definition of income-qualified eligible customers for low-income assistance and energy efficiency programs to 300% of Federal Poverty Guidelines.

4. Require the Companies to model as a sensitivity analysis how a regional competitive wholesale market and legislatively approved performance-based regulation would impact resource selection and portfolio costs for the Carbon Plan, and by extension, carbon emissions and customer affordability.

Q: WHAT ARE THE PANEL'S RECOMMENDATIONS TO THE COMMISSION CONCERNING RESOURCE INVESTMENTS?

A: We recommend that that the Commission disallow the build-out of new gas power infrastructure, which risks passing on volatile gas costs and stranded asset costs to customers. Instead, we recommend that the Commission require Duke to enable energy efficiency, offshore wind, utility-scale storage, distributed solar and storage, demand response, and other alternative utility-scale and grid-edge resources to compete within the EnCompass model rather than be capped at arbitrarily low deployment rates.

Q: DOES THIS CONCLUDE THE PANEL'S TESTIMONY?

A: Yes.

Appalachian Voices' Summary of Direct Testimony of

Rory McIlmoil and Dr. Yunus Kinkhabwala

Carolinas Carbon Plan
Docket No. E-100, Sub 179

The purpose of the panel testimony is: first, to address the failure to adequately address affordability concerns and rate impacts for customers in the Companies' proposed Carbon Plan; second, to discuss the benefits of grid edge technologies and the Companies' underutilization of such resources; and finally, to present appropriate recommendations to the Commission.

The panel's affordability testimony focuses on: cost, with a focus on affordability for low-income and otherwise economically vulnerable ratepayers; near term procurement, looking at alternative technologies beyond the expansion of additional gas fired power generation; and EE/DSM/Grid Edge resources, with an emphasis on how targeting investment in those programs for low-income residential customers is a cost-effective way to control energy demand and reduce carbon emissions while mitigating affordability impacts.

Affordability must genuinely be a central objective of the Carbon Plan because methods exist to reduce carbon emissions while simultaneously reducing energy bills and energy burdens for low-income households. Moreover, the number of households served by the Companies that are in arrears, and deeply so, is significant and unsustainable. The Carbon Plan will exacerbate this problem unless key analytics and mitigative investment targets are incorporated into the Plan itself. Nearly one-third of all residential customers in the Companies' North Carolina service base qualify as low-income under federal poverty guidelines. The panel used the Companies' analytics produced for the Low-Income Affordability Collaborative (LIAC) to estimate that 231,165 low-income households (nearly a quarter of all low-income households) have spent six or more months behind on paying their average/regular bill or were behind by two or more times their average bill for two or more months, thereby meeting the Companies' stringent definition of "arrears struggling" households. "Arrears struggling" as defined by the Companies does not include those low-income customers who may spend three to five months of the year – possibly including the hottest or coldest months when electric bills tend to be highest – being unable to afford their bill when it is due, and thus vulnerable to disconnection for non-payment. Another 277,000 non-low-income households also meet the Companies' arrears struggling definition.

In total, more than half a million customers, or nearly one sixth of the Companies' residential customers in North Carolina, qualify per the Companies' definition as "arrears struggling." Further, as of May 2022, more than 570,000 residential customers were reported as being at least 30 days in arrears, owing a total of more than $213 million. The Covid-19 pandemic has exacerbated those arrearages, which increased sharply over the May 2021 to May 2022 period. One primary driver of affordability challenges is energy inefficiency, which is not currently adequately addressed by existing programs because they serve only a very small segment of the low-income customer base, do not sufficiently reduce energy cost burdens, and do not sufficiently address peak winter and summer usage in low-income households.

The proposed Carbon Plan is likely to exacerbate, rather than alleviate, affordability challenges for vulnerable customers. Although the Companies list "affordability" as one of the four core objectives of the proposed Carbon Plan, the Plan lacks any attempt to mitigate affordability impacts. Instead of actually addressing affordability, the Companies inappropriately conflate the concepts of affordability and "least cost." "Least cost" simply means "less costly than the alternative," not necessarily affordable. Despite the arrearage problems described previously, the Companies nonetheless claim to provide "affordable service," "affordable electricity," and "affordable rates" throughout the proposed Plan and their witness testimony. When asked for any analysis of how each of the four Carbon Plan portfolios will impact arrearages and disconnections for residential customers, the Companies responded that the question sought information outside the scope of the Carbon Plan proceeding.

The Carbon Plan contains no proposals for any new programs or investments targeting low-income or otherwise vulnerable customers and defer that responsibility to future years and other proceedings. If the Companies seriously intended to address affordability as a core objective of the Carbon Plan, they must go beyond a "least cost" approach and incorporate directed programs and investments targeted to address affordability challenges. Such programs and investments should include arrearage management programs, community and distributed solar options, long-term investments in energy efficiency and demand-side management, as well as expanded bill assistance, and low-income rate designs. Such improvements would not only enhance affordability but would contribute to decarbonization, improved grid reliability and resiliency, and reduce the need for additional capacity and transmission infrastructure, all further lowering customer costs.

The proposed Carbon Plan currently includes 2.4 gigawatts (GW) of new gas combined cycle facilities and 0.8-1.1 GW of new gas combustion turbines, for a total of 14,470 GWh of gas-dependent electricity in 2030. As proposed, the Plan puts unnecessary constraints on the timing and capacity of alternative resource deployment, including on- and offshore wind, distributed energy resources such as solar, and energy efficiency. Moreover, the Plan cannot determine the true “least cost” set of resources since it excludes grid edge resources from the EnCompass modeling runs and caps their rollout at low levels. Updating the EnCompass model to actively select these resources when they are cost-competitive would enable a fair comparison of their ability to meet capacity needs. The proposed peaking gas combustion plans could likely be replaced with utility-scale energy storage, a nationwide trend, and additional peak needs could be met with offshore wind deployed earlier than proposed, as well as with energy efficiency, demand response, and distributed storage. These resources have the potential to obviate the need for new gas plant investments and speed decarbonization, improve grid resilience and flexibility, and reduce health impairments from air pollution. Use of these resources, including energy efficiency investments such as weatherization and distributed energy such as solar, can also contribute to affordability by reducing demand and therefore costs, providing more consistent bills and savings. Additional grid edge resources, such as vehicle-to-grid systems and smart appliances can provide additional flexibility and location-specific grid benefits such as deferral of distribution system investments and reduction in peak demand.

Finally, increased investment in energy efficiency and other grid edge resources targeted toward low-income households is a cost-effective method to lower energy demand and peak loads while bridging the affordability gap for all customers. Increasing energy efficiency targets to 2 percent of retail sales per year from the proposed target of 1 percent of eligible load could provide 14,300 GWh of energy savings and 2,500 MW of demand reductions beyond the Companies’ current proposal, greatly reducing the need to construct new gas plants. While many states and utilities across the country have consistently achieved greater efficiency targets, the Companies’ target of 1 percent is roughly the same as

Companies' current historical pattern of achievement and thus not ambitious as the Companies claim. Moreover, the majority of the proposed efficiency targets are based on short-term behavioral interventions so that their benefits do not accumulate over time as they would for targets associated with physical improvements that last typically between 10 to 20 years. Additionally, Duke's comparatively high residential use suggests significant improvements can be made through enhanced energy efficiency investments in the North Carolina service area. Targeted grid-edge resources such as efficiency, demand response, and community solar alongside financing strategies such as the resources included in the 2022 Inflation Reduction Act have the potential to greatly improve affordability. We estimate that such resources could reduce the energy affordability gap - the total amount of money spent on energy beyond 6% of household incomes - for North Carolina's low-income and vulnerable households in the Companies' service territory by as much as 95% if all households participated. By contrast, unnecessary capital investments in the construction of new gas plants have the potential to exacerbate affordability challenges, particularly considering escalating natural gas prices.

The Carbon Plan must, as a core and integrated objective of the plan, directly address existing and future energy affordability challenges and impacts for North Carolina households, particularly those low-income and otherwise vulnerable households. Doing so will also contribute to the achievement of the state's decarbonization goals as well as the improvement of economic and public health of North Carolinians. The Panel therefore makes several recommendations to the Commission. Briefly, those are that the Commission: 1) require the Companies to define and assess affordability as a key component of the Plan; 2) require that the final Plan incorporate substantial investments in and model the affordability and decarbonization benefits of customer bill assistance and arrearage management programs, energy efficiency investments, and distributed energy and demand reduction investments; 3) reject the Companies' proposal to expand the definition of income-qualified eligible customers for low-income assistance and energy efficiency programs to 300% of Federal Poverty Guidelines; 4) require the Companies to model how a regional competitive wholesale market and performance-based regulation would impact resource selection and portfolio costs for the Carbon Plan and, by extension, carbon emissions and customer affordability; 5) disallow the build-out of new natural gas power infrastructure and require the Companies to enable alternative energy and grid-edge resources to compete within the Encompass model rather than be capped at arbitrarily low deployment rates.

This concludes the summary of the panel's direct testimony.

MS. CRALLE JONES: And I would also ask that Mr. McIlmoil and Dr. Kinkhabwala be excused at this time from appearing at the hearing of this matter.

CHAIR MITCHELL: Your witnesses are excused.

MS. CRALLE JONES: Thank you.

CHAIR MITCHELL: Thank you, Ms. Cralle Jones.

MS. BONVECCHIO: Good morning, Chair Mitchell and Commissioners. Andrea Bonvecchio for Environmental Working Group. All parties have indicated that they agree to waive cross examination of EWG witness Dr. Arjun Makhijani. We therefore would move that the Commission excuse Dr. Makhijani from participating in this expert hearing, and that his prefiled direct testimony consisting of 44 pages filed on September 2, 2022, with a correction filed on September 12, 2022, as well as his eight-page testimony summary filed on September 23, 2022, be copied into the record as if given orally from the stand at the appropriate time.

CHAIR MITCHELL: All right. Hearing no

objection to your motion, it is allowed.

MS. BONVECCHIO: Thank you, Chair Mitchell.

CHAIR MITCHELL: Thank you.

(Whereupon, the prefiled direct testimony of Arjun Makhijani and prefiled summary testimony of Arjun Makhijani 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

In the Matter of:	)	
Duke Energy Progress, LLC, and	)	**DIRECT TESTIMONY OF**
Duke Energy Carolinas, LLC, 2022	)	**ARJUN MAKHIJANI, Ph.D.**
Biennial Integrated Resource Plans	)	**ON BEHALF OF THE**
and Carbon Plan	)	**ENVIRONMENTAL WORKING GROUP**

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I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A: My name is Dr. Arjun Makhijani. My business address is P.O. Box 5324, Takoma Park, MD 20913. I am the President of the Institute for Energy and Environmental Research.

Q: WHAT ARE YOUR PRIMARY RESPONSIBILITIES AS THE PRESIDENT OF THE INSTITUTE FOR ENERGY AND ENVIRONMENTAL RESEARCH?

A: In my role as the President of the Institute for Energy and Environmental Research, my responsibilities include being the principal researcher and writer on projects, being responsible for the fiscal soundness of the Institute and reporting to the Board about its finances and the substance of the work.

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: I hold a Bachelor of Engineering (Electrical) from the University of Bombay, a Master of Science in Electrical Engineering from Washington State University, and a Ph.D. in Engineering specializing in nuclear fusion from the Electrical Engineering and Computer Sciences department of the University of California at Berkeley.

Over the past forty years, I have produced various studies and articles on nuclear fuel cycle-related issues, including nuclear energy, nuclear weapons production, testing, and nuclear waste (both power and weapons-related). My energy work goes back over fifty years. My most recent comprehensive work on renewable energy is *Prosperous, Renewable Maryland: Roadmap for a Healthy, Economical, and Equitable Energy Future*, which is based on hour-by-hour modeling of the Maryland electricity sector, as well as energy justice considerations in a transition to renewable energy. I am the principal author of the first study ever done on conservation potential in the U.S. economy (1971).

In the last decade, I have authored or co-authored numerous articles and reports relating to the transition to a decarbonized energy system, including on land use, energy justice, electrification of buildings that now use fossil fuels and the cost of distributed solar for new residential construction. I am a member of the Mitigation Work Group of the Maryland Commission on Climate Change and a member of the Advisory Council of the state-created non-profit agency, the Maryland Clean Energy Center.

I have served as a consultant on energy issues to utilities, including the Tennessee Valley Authority ("TVA"), the Edison Electric Institute, the Lawrence Berkeley National Laboratory, and several agencies of the United Nations. In 2007, I was elected a Fellow of the American Physical Society, an honor granted to at most one-half-of-one-percent of the Society's members. I am a co-author of Investment Planning in the Energy Sector, which was produced in the 1970s during one of my consulting contracts with Lawrence Berkeley National Laboratory.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("THE COMMISSION")?

A: No.

Q: HAVE YOU PREVIOUSLY PROVIDED TESTIMONY OR COMMENT AS AN EXPERT BEFORE ANY OTHER REGULATORY BODIES OR FORUMS?

A: Yes. I presented testimony before the California Public Utilities Commission's *En Banc* hearing as an energy expert for the Just Solutions Collective on the integration of affordability, decarbonization, and modernization of the electric grid.[1] I have provided comments and presented testimony on behalf of the Institute for Energy and Environmental Research before the Public Service Commission of Maryland.[2] I have also presented testimony before the United States Nuclear Regulatory Commission's Atomic Safety and Licensing Board. Further, I have

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[1] Testimony on Integrating Equity and Affordability into Energy Transition in California. The California Public Utilities Commission Affordability Proceeding Phase 3 *En Banc* hearing (2022). Available online: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/en-banc/makhijani-slides-w-alt-image-and-link-text.pdf.

[2] Presentation on Net Metering and Distributed Energy Resources, *In the Matter of the Investigation Into the Technical and Financial Barriers to the Deployment of Small Distributed Energy Resources*, the Public Service Commission of Maryland, Public Conference 40 (2015); Comments regarding report by Gabel Associates, Inc. on the advisability of establishing an opt-in electric affordability program for residential and small business customers. *In the Matter of the Advisability of Establishing an Opt-In Electric Affordability Program for Residential and Small Business Customers*, the Public Service Commission of Maryland, Public Conference 47 (2017); Comments regarding the Electric Universal Service Program Proposed Operations Plan for Fiscal Year 2019. *In the Matter of the Electric Universal Service Program*, the Public Service Commission of Maryland, Case No. 8903 (2018).

presented testimony on behalf of Southern Alliance for Clean Energy before the Georgia Public Service Commission.[3]

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

A: I am testifying on behalf of the Environmental Working Group.

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

A: The purpose of my testimony is: 1) to address the costs, risks, and reliability of the proposed new nuclear technology and nuclear generation in the Carbon Plan filed on May 16, 2022 by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP) (collectively, "Duke Energy"); 2) to address the cost and schedule challenges associated with Duke Energy's proposed reliance on Small Modular Reactors ("SMRs") and advanced nuclear reactors as well as certain technical risks, given the history of such reactor programs and proposals; 3) to address the need for the Commission to acknowledge the reality and history associated with nuclear power from both large and small reactors and the unlikeliness of fitting into a least-cost profile that achieves the carbon reduction goals of North Carolina House Bill 951 ("HB 951"); and 4) to point out the need for additional portfolios because Duke Energy's proposed portfolios were similar in most major respects, including the very large amount of new

[3] Testimony on Georgia Power Company's Integrated Resource Plan, Georgia Public Service Commission Docket No. 24505-U (2007).

nuclear energy planned in all of them, and because they did not include technologies that could make decarbonization more efficient, cost-effective, and resilient.

Q: HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A: The remainder of my testimony consists of two parts and two subparts which are organized consistent with the outline provided in ordering paragraph 1 of the Commission's *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines* entered on July 29, 2022.

- <u>Part II</u> will address the topic that the Commission has identified in part as "Near-Term Development Activity—prudence of development work and need for long-lead time resources." <u>Part II</u> contains two subparts: <u>subpart (A.)</u> will address the costs, risks, and reliability of Duke Energy's proposed new nuclear technology and generation, and <u>subpart (B.)</u> will address the cost, schedule, and technical challenges associated with Duke Energy's proposed reliance on SMRs and advanced nuclear reactors.
- In light of the above, in <u>Part III</u>, I will discuss for the Commission's consideration a framework for a range of portfolios that will help meet the requirements of HB 951 to design the least cost plan and meet or exceed present grid reliability levels.

II. TOPIC: NEAR-TERM DEVELOPMENT ACTIVITY—PRUDENCE OF DEVELOPMENT WORK AND NEED FOR LONG-LEAD TIME RESOURCES

A. Costs, Risks, and Reliability of Duke Energy's Proposed New Nuclear Technology and Nuclear Generation

Q: CAN YOU PLEASE PROVIDE EXAMPLES OF HISTORICAL DELAYS AND COST OVERRUNS ASSOCIATED WITH DEVELOPING AND CONSTRUCTING NUCLEAR FACILITIES?

A: A "nuclear renaissance" was proclaimed in the 2000s and quickly fizzled out. Plans for 34 reactors were announced[4] and construction started on only four proposed reactors. Of those that did not materialize, six were proposed and cancelled by Duke Energy. In the case of Duke Energy's proposal for two reactors at the Shearon Harris site, the company signed a construction contract, but abandoned the licensing effort after that.[5] Additionally, Duke Energy abandoned plans to construct two reactors at the William States Lee III site in 2017, after the Nuclear Regulatory Commission ("NRC") had completed its licensing review.[6] In all, Duke Energy pursued plans for six new nuclear units within eight years; no nuclear capacity resulted from these efforts.

Two of the four "nuclear renaissance" reactors that broke ground and proceeded with construction were Summer Units 2 and 3 in South

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[4] Larry Parker & Mark Holt, Nuclear Power: Outlook for New U.S. Reactors, Table 1 (Cong. Rsch. Serv., 2007), https://sgp.fas.org/crs/misc/RL33442.pdf.
[5] Mark Holt, Nuclear Energy Policy 6–9 (Cong. Rsch. Serv., 2014), https://sgp.fas.org/crs/misc/RL33558.pdf.
[6] World Nuclear News, *Duke Seeks to Cancel Plans for Lee AP1000s*, (Aug. 29, 2017), https://www.world-nuclear-news.org/NN-Duke-seeks-to-cancel-plans-for-Lee-AP1000s-2908175.html.

Carolina. Construction on both was abandoned after an expenditure of $9 billion.[7] The other two, Vogtle Units 3 and 4 in Georgia have faced serious cost overruns and delays. The initial cost estimate of $14 billion for both units has skyrocketed to more than $30 billion.[8] The planned starting dates for the Vogtle units of 2016 and 2017 have since gone by and the current estimate for a start-up date is 2023.[9]

The experience of the failed "nuclear renaissance"—when things were supposed to be more efficient and cost effective—has been considerably worse than the first round of major construction during which more than 120 announced nuclear units were cancelled.[10] In that round, a similar number of units, including those now owned by Duke Energy, were actually built and commissioned. This approximately 50-50 record is not good; but it did yield the largest fleet of nuclear power reactors in the world. Things have gone backwards since that time: if the two Vogtle units come online, as appears likely, the record of the "nuclear renaissance" would be considerably worse—a completion success rate of about six percent.

It has been no different with France, a leading western country in nuclear power generation. Its new reactor design, the 1,600-megawatt EPR,

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[7] Akela Lacy, *South Carolina Spent $9 Billion to Dig a Hole in the Ground and Then Fill it Back in*, The Intercept (Feb. 6, 2019), https://theintercept.com/2019/02/06/south-caroline-green-new-deal-south-carolina-nuclear-energy/.
[8] *See* David Schlissel, Southern Company's Troubled Vogtle Nuclear Project (Inst. for Energy Econs. and Fin. Analysis 2022), https://ieefa.org/wp-content/uploads/2022/01/Southern-Companys-Troubled-Vogtle-Nuclear-Project_January-2022.pdf.
[9] Kristi E. Swartz, *Plant Vogtle Hits New Delays; Costs Surge Near $30B*, E&E NEWS (Feb. 18, 2022), https://www.eenews.net/articles/plant-vogtle-hits-new-delays-costs-surge-near-30b/.
[10] Larry Parker & Mark Holt, Nuclear Power: Outlook for New U.S. Reactors, CRS-3 (Cong. Rsch. Serv., 2007), https://sgp.fas.org/crs/misc/RL33442.pdf.

was offered to Finland at a price of 3 billion euros and construction was supposed to be completed in 2009. The reactor finally began power production for the grid on a test basis in the first part of 2022; a mishap shut it down, and test production is set to be completed (after repairs) in December 2022.[11] In the meantime, the cost has almost quadrupled to 11 billion euros.[12]

The record in France itself is also not promising. Costs for the Flamanville Nuclear Power Plant EPR have ballooned from an estimated 3.3 billion euros to 12.7 billion euros and the scheduled commissioning has been delayed from an initial estimate of 2012 to 2023.[13]

Finally, it is essential to note that the nuclear industry in western countries, centered in the United States and France, does not have a promising record of learning from experience. On the contrary, costs in both countries increased as more reactors were built.[14]

Q: CAN YOU PLEASE DESCRIBE WHAT YOU MEAN BY A FAILED "NUCLEAR RENAISSANCE?"

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[11] World Nuclear News, *Olkiluoto 3 test production to continue until December*, (June 16, 2022), https://www.world-nuclear-news.org/Articles/Olkiluoto-3-test-production-to-continue-until-Dece.

[12] Schneider et al., The World Nuclear Industry Status Report 2019, p. 66 (Sep. 2019), https://www.worldnuclearreport.org/IMG/pdf/wnisr2019-v2-hr.pdf.

[13] Schneider et al., The World Nuclear Industry Report 2021, pp. 92-94 (Sep. 2021), https://www.worldnuclearreport.org/IMG/pdf/wnisr2021-lr.pdf.

[14] Jonathan G Koomey & Nathan E Hultman, A Reactor-Level Analysis of Busbar Costs for US Nuclear Plants, 1970–2005, 35 Energy Pol'y 5630 (2007); Arnulf Grubler, The French Pressurised Water Reactor Programme, Energy Technology Innovation: Learning from Historical Successes and Failures, p. 146 (Arnulf Grubler & Charlie Wilson eds., 2013).

A: In nearly two decades, no proposed new nuclear reactor has been completed or supplied power to the grid. The two Vogtle reactors in Georgia, the only ones still under construction, represent about six percent of the 34 announced reactors, presuming they are completed. It is worth repeating that six of the unrealized "nuclear renaissance" reactors were proposed by Duke Energy, which spent resources on them for licensing and contracting processes.

Q: FOR NUCLEAR POWER REACTORS THAT HAVE REACHED THE POINT OF OPERATION, HAVE ANY BEEN PREMATURELY RETIRED?

A: Yes. Several reactors have been retired before their license expiry.

Q: CAN YOU PLEASE DISCUSS WHY NUCLEAR POWER REACTORS HAVE BEEN RETIRED DESPITE BEING LICENSED TO OPERATE BEYOND THE TIME OF THEIR RETIREMENT?

A: High operating costs have been one of the main reasons the number of operating reactors dropped from 104 at the close of 2010 to 92 in July 2022. Losses from operating an uneconomical plant can be considerable.

For instance, in 2018, NextEra estimated that it would save customers nearly $300 million (present value) by prematurely shutting down the Duane Arnold reactor and generating wind power instead. Reactors have also been shut down for issues related to steam generator replacement. This was the case for two reactors in California (San Onofre) and one in Florida (Crystal River). The latter belongs to Duke Energy; it was shut down for refueling, steam generator replacement, and a power uprate. It was shut down permanently in 2013 due to problems and delays associated with the steam generator replacement.[15]

Q: CAN YOU PLEASE SUMMARIZE AND COMMENT ON THE FINAL RESOURCE ADDITIONS OF EACH PORTFOLIO FOR 2050 IN DUKE ENERGY'S CAROLINAS CARBON PLAN?

A: As indicated in Appendix E, Table E-71 of the Carolinas Carbon Plan, all four portfolios in the Carolinas Carbon Plan contain either 9,900 MW or 10,200 MW of new nuclear in 2050, which includes SMR and advanced nuclear with integrated storage reactor design options. The highest nuclear capacity is only about three percent greater than the lowest.

The combined combustion turbine and combined cycle gas-fired generation capacity is also similar, ranging from 8,800 MW to 9,900 MW across scenarios in 2050. The portfolios are also the same or similar in other major respects, such as the amount of onshore wind, the level of efficiency assumed, the amount of pumped hydro storage, and solar power capacity. Offshore wind capacity varies across portfolios from 0 to 3,200 MW; however, even the highest level would be a small fraction of generation

[15] Duke Energy News Release, *Crystal River Nuclear Plant to be retired; company evaluating sites for potential new gas-fueled generation*, (Feb. 5, 2013), https://news.duke-energy.com/releases/crystal-river-nuclear-plant-to-be-retired;-company-evaluating-sites-for-potential-new-gas-fueled-generation.

requirements in 2050. Battery capacity varies somewhat across portfolios, from a low of 5,900 MW to a high of 7,400 MW in the year 2050.

Q: IN YOUR OPINION, DOES DUKE ENERGY'S "NEW SUPPLY-SIDE RESOURCE CAPITAL COST SENSITIVITY ANALYSIS"[16] CONSIDER HISTORICAL COST ESCALATIONS AS DEMONSTRATED BY THE FAILED "NUCLEAR RENAISSANCE?"

A: No. Duke Energy did a capital cost sensitivity for nuclear and estimated the present value of cumulative impacts at $4 billion for a proposed portfolio of about 10,000 MW. This does not reflect historical or recent cost escalations. The cost of just two Vogtle reactors under construction had cost overruns of more than $16 billion, about $7 billion per gigawatt of capacity. Duke Energy is proposing to build 10 gigawatts of capacity. Moreover, corporations also spent money on the "nuclear renaissance" projects that were cancelled, including six proposed by Duke Energy.

Had Duke Energy's sensitivity analysis reflected real-life experience, its estimate would have been well over an order of magnitude more than Duke Energy's calculations. Moreover, even the very low estimate of $4 billion was not examined for its impact on the mix of generation in their four proposed portfolios. Cost estimates of SMRs and

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[16] Duke Energy, Carolinas Carbon Plan Chapter 3 at 14-15 (May 16, 2022) (hereinafter "Carolinas Carbon Plan").

advanced reactors also depend in part on mass manufacturing components more than larger present-day reactors.

A sensitivity analysis should take into account the possibility that there may not be sufficient orders for such reactors to establish the lower costs anticipated by the time Duke Energy orders its reactors.

Q: IN YOUR OPINION, DOES A COST GAP EXIST BETWEEN NUCLEAR AND RENEWABLE POWER?

A: Yes. Renewable energy, specifically wind and solar, has come down rapidly in cost in the last 10 to 15 years. Lazard, a Wall Street firm, publishes cost estimates of electricity generation from new power plants towards the end of each calendar year. In its 2021 edition, it showed unsubsidized levelized cost declines for generation from utility-scale solar power plants from $359 per megawatt-hour (MWh) in 2009 to $36/MWh in 2021.[17] The corresponding values for onshore wind were $135/MWh in 2009 to $38 per MWh in 2021.[18] Offshore wind costs have also declined, but the history is based on European experience, where many offshore wind farms have been built. In 2021, Lazard estimated the range of offshore wind electricity cost as between $66 and $100/MWh.[19]

In contrast, the estimated unsubsidized costs of nuclear electricity have risen from an estimated $123/MWh in 2009 to $167/MWh in 2021.[20]

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[17] Lazard's Levelized Cost of Energy Analysis—Version 15.0, 8 (Oct. 2021), https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf.
[18] *Id.*
[19] *Id.* at 17.
[20] *Id.* at 8.

The potential range of costs estimated for 2021is also large—between $131/MWh and $204/MWh in 2021.[21] Of course, this presumes the reactors are built and commissioned.

Solar is increasingly coupled with storage (as is the case in the Duke Energy portfolios as well). Hence the utility-scale solar-plus-storage cost is of interest. The costs of solar plus storage have also been declining rapidly. The National Renewable Energy Laboratory ("NREL") estimated that the unsubsidized levelized cost of utility-scale solar plus large-scale storage was $88/MWh in 2020 and that it declined to $77/MWh in 2021; this represents a decrease of over 12% in levelized cost in a single year.[22] The 2021 cost estimate of utility-scale solar with storage was less than half the estimated cost of nuclear; as noted, in contrast to solar, nuclear costs have tended to rise.

The above estimates are of unsubsidized costs. The practical economic realities will change as a result of the newly enacted Inflation Reduction Act with subsidies for nuclear, renewables, and storage. In the case of solar with storage, the installed cost of utility scale projects with the investment tax credit in 2021 was only about $30/MWh.[23] If storage equal

[21] *Id.* at 2.
[22] Vignesh Ramasamy et al., U.S. Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021, p. 47 (Nat'l Energy Renewable Lab'y, 2021), https://www.nrel.gov/docs/fy22osti/80694.pdf. The estimate does not include the investment tax credit: "In this year's report, we calculate LCOE assuming long-term steady-state financing assumptions, with no investment tax credit and with interest rates higher than current historically low levels." p. 44.
[23] Joachim Seel et al., Batteries Included: Top 10 Findings from Berkeley Lab Research on the Growth of Hybrid Power Plants in the United States, Lawrence Berkeley National Laboratory, p. 6 (2022), https://eta-publications.lbl.gov/sites/default/files/berkeley_lab-_battery_included_-_top_10_hybrid_research.pdf.

to the capacity of the solar installation were added, the "price adder" to the cost of electricity would be $20/MWh.[24] Nuclear costs will most likely remain well above this level even with a comparable subsidy, such as a 30% investment tax credit. Finally, the clear trendline for solar-plus storage costs is sharply downward, so that costs are likely to remain low even when subsidies expire by 2034. As noted, the trendline for nuclear is in the opposite direction.

Q: IN YOUR OPINION, WOULD NEW NUCLEAR DESIGNS, SUCH AS LIGHT WATER COOLED SMRS AND NON-LIGHT-WATER-COOLED ADVANCED REACTORS, HAVE DIFFICULTY COMPETING ON A COST BASIS WITH MORE ESTABLISHED RENEWABLE POWER GENERATION METHODS?

A: Yes. Several evaluations of the cost of electricity from SMRs have come up with high estimates. For example, in its 2019 Integrated Resource Plan ("IRP"), Idaho Power estimated a cost of $121 per megawatt hour for a NuScale plant operating at a 90% capacity factor.[25] More recently, Australia's Commonwealth Scientific and Industrial Research Organisation ("CSIRO") has estimated that the cost of generating electricity from an

[24] *Id.* at p. 6, Figure 4.
[25] Integrated Resource Plan 2019, IDAHO POWER, Appendix C (2020), https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twentyyear-plan/.

SMR would be between A$136 and A$326 (Australian dollars) (about $95 to $228 in U.S. dollars) per megawatt hour.[26]

As I have noted already, costs of solar would remain well below the cost of nuclear even when storage equal to 100% of the solar capacity is added. While a full comparison of a high variable renewable portfolio with a high nuclear portfolio would be done on a system basis (as indicted in the portfolios I suggested for evaluation in my July statement[27] and also in this testimony), the margin between the high cost of nuclear and the low cost of renewables plus storage is so large that nuclear would have great difficulty competing with renewables.

Q: CAN YOU PLEASE EXPLAIN WHETHER SMRS ARE ECONOMICALLY SUITABLE FOR RESPONDING TO VARIABILITY.

A: SMRs are not economically viable even at 90% or 95% average capacity factor. If SMRs respond to the variability of wind and solar by adjusting power output downward when renewable output is high and upward when renewable output falls, their average capacity factor will fall. Thus, the most important component of cost—capital cost—will be spread out over a smaller number of megawatt hours, raising the per unit cost of electricity.

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[26] Paul Graham, et al., Commonwealth Scientific and Industrial Research Organization, p. 76 at Apx Table B.9 (July 2022), https://www.csiro.au/-/media/News-releases/2022/GenCost-2022/GenCost2021-22Final_20220708.pdf. An exchange rate of A$1 = USD$0.70 was used. It has varied from a little below to a little above that rate in recent weeks. A historical chart of the Australian dollar to U.S. dollar exchange rate is available at https://www.macrotrends.net/2551/australian-us-dollar-exchange-rate-historical-chart.
[27] Initial Comments of Environmental Working Group, Attachment A.

For instance, costs per megawatt-hour of SMR electricity would increase by about 25% if annual capacity factor falls from 95% to 75%.[28]

Q: CAN YOU PLEASE EXPLAIN THE PRIMARY DIFFERENCE BETWEEN LARGE NUCLEAR POWER PLANT REACTORS AND SMRS?

A: 1,000 MW is the usual reference size for large nuclear reactors though they can be a couple of hundred megawatts smaller; of course, there are also designs larger than 1,000 MW. Large reactors have generally been chosen because they offer economies of scale. SMRs are modular, i.e., standardized, reactors that are relatively small, usually meaning 300 MW or less per reactor. Of course, nuclear plants often have more than one unit; that would generally be the case for SMRs.

Q: IN YOUR OPINION, DO SMRS OFFER ECONOMIES OF SCALE?

A: No. The term "economies of scale" means that, all else being equal, the cost per kilowatt of capacity of a larger reactor would be less than that of a smaller unit. The total cost of an SMR would be lower because the capacity and, hence, electricity generation per unit would be lower. The cost per unit of capacity matters because that is the main determinant of the cost of electricity from nuclear power.

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[28] M.V. Ramana, *Eyes Wide Shut: Problems with the Utah Associated Municipal Power Systems Proposal to Construct NuScale Small Modular Nuclear Reactors*, Oregon Phys. for Soc. Resp., p. 15 (2020), https://www.oregonpsr.org/small_modular_reactors_smrs.

The cost per kilowatt of nuclear reactor capacity tends to decrease with increasing size because the amount of steel, cement, other materials, and the number of welds (and the required labor), etc., do not increase linearly with size.

Loss of economies of scale would tend to make capital cost per kilowatt higher. For example, most of the early small reactors built in the United States shut down early because they could not compete economically.[29]

Q: ARE THERE WAYS TO COMPENSATE FOR THE POORER ECONOMICS OF SMALL REACTORS?

A: SMR proponents propose mass manufacturing and assembly-line style construction as one means of overcoming the loss of economies of scale. This, in turn, implies that there must be a considerable order book for SMRs to compensate, in whole or in part, for the loss of economies of scale. They also have simplified designs as a way to lower costs.

Q: HOW COULD MODULARITY AND FACTORY MANUFACTURING COMPENSATE FOR THE POORER ECONOMICS OF SMALL REACTORS?

A: Mass manufacturing is a standard way to lower costs for industrial products dating back to the famous Ford Model T assembly lines. A current example

[29] M.V. Ramana, *The forgotten history of small nuclear reactors*, Inst. of Electrical and Electronics Eng'rs Spectrum (Apr. 2015), https://spectrum.ieee.org/the-forgotten-history-of-small-nuclearreactors#toggle-gdpr.

of an expensive investment that is mass manufactured would be large passenger aircraft such as Boeing Dreamliners, Boeing 737s, and Airbus 350s. Much of the savings would arise from modularity and factory manufacturing.[30]

Proponents of SMRs acknowledge that a significant order book will be necessary for the projected economies of standardizing the design to be realized. The first units would therefore be more expensive. Industry proponents estimate that the order book would have to be in the dozens to one hundred reactors;[31] independent estimates put the order book requirement in the hundreds or reactors (at least) for an assembly approach to compensate for the loss of economies of scale.[32] Moreover, all this would need to happen on the schedule that Duke Energy envisions for adding reactors—for each substantially different design. Most importantly, it would need to happen on a schedule that is consonant with the decarbonization requirements of HB 951.[33]

In this context, it is important to note that in reality costs increased as more plants were built in the United States and France, the countries with

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[30] Giorgio Locatelli et al., Small Modular Reactors: A Comprehensive Overview of their Economics and Strategic Aspects, 73 Prog. Nucl. Energy 75 (2014).

[31] Arjun Makhijani, Light Water Designs of Small Modular Reactors: Facts and Analysis, Institute for Energy and Environmental Research, p. 5 (Sept. 2013), http://ieer.org/wp/wp-content/uploads/2013/08/SmallModularReactors.RevisedSept2013.pdf; Heba Hashem, Westinghouse: Taking care of business, Nuclear Energy Insider, (Feb. 12, 2014).

[32] *See* Alexander Glaser et al., Small Modular Reactors: A Window on Nuclear Energy (Princeton Univ., 2015), https://acee.princeton.edu/wp-content/uploads/2015/06/Andlinger-Nuclear-Distillate.pdf.

[33] *See* Arjun Makhijani, Light Water Designs of Small Modular Reactors: Facts and Analysis, Institute for Energy and Environmental Research, pp. 5-7 (Sept. 2013), http://ieer.org/wp/wp-content/uploads/2013/08/SmallModularReactors.RevisedSept2013.pdf.

the highest numbers of nuclear plants.[34] As a result, there is no guarantee that even with a substantial order book, costs will decline to the estimated levels.

After this monumental task, even if SMRs were to consistently achieve the same per-unit costs as the present large reactors, they would still be an economic failure, given the high costs of large reactors.[35]

Q: CAN YOU PROVIDE EXAMPLES OF SMRS DEPLOYED AT A COMMERCIAL SCALE IN THE UNITED STATES?

A: There are none.

Q: ARE THERE ANY SMRS THAT EXIST IN THE UNITED STATES?

A: No SMRs have been built in the United States.

Q: WHAT REACTOR DESIGNS HAS DUKE ENERGY IDENTIFIED AS VIABLE FOR CONTRIBUTING TO THE 70% CO_2 EMISSIONS REDUCTIONS TARGET SET OUT IN HB 951?

A: In Appendix L, Table L-5 of the Carolinas Carbon Plan,[36] Duke Energy identifies two SMRs and two advanced reactors that are scheduled to be built and in commercial operation by the end of 2029. These designs include:

- Natrium Reactor Liquid Sodium-cooled

[34] Jonathan G Koomey & Nathan E Hultman, A Reactor-Level Analysis of Busbar Costs for US Nuclear Plants, 1970–2005, 35 Energy Pol'y 5630 (2007); Arnulf Grubler, The French Pressurised Water Reactor Programme, Energy Technology Innovation: Learning from Historical Successes and Failures, p. 146 (Arnulf Grubler & Charlie Wilson eds., 2013).
[35] Arjun Makhijani & M. V. Ramana, Can Small Modular Reactors Help Mitigate Climate Change?, 77 Bull. at. Sci. 207 (2021), https://www.tandfonline.com/doi/full/10.1080/00963402.2021.1941600.
[36] Duke Energy, Carolinas Carbon Plan Appendix L, Table L-5 at p. 10.

- Xe-100 Reactor Helium Gas-cooled High Temperature
- BWRX-300 Reactor Light Water-cooled ("BWR")
- VOYGR Reactor Light Water-cooled (PWR), i.e., NuScale's latest design.

Duke Energy plans to use only light-water-cooled designs for the 70% target in two of its portfolios.[37]

Q: HAVE ANY OF THE REACTOR DESIGNS IDENTIFIED BY DUKE ENERGY IN APPENDIX L, TABLE L-5 OF THE CAROLINAS CARBON PLAN BEEN APPROVED BY THE NRC?

A: No. Only one of the reactor designs, NuScale, has provisional certification for its 50 MW version; it may be granted full certification in the near future. However, the VOYGR NuScale reactor listed by Duke Energy is a 77 MW reactor, a capacity more than 50% above the capacity of the certified reactor. This larger capacity reactor will have to be certified in a separate process. The NRC website states that this version is in the pre-application stage.[38]

Q: HAVE ANY REACTOR DESIGNS IDENTIFIED BY DUKE ENERGY IN APPENDIX L, TABLE L-5 OF THE CAROLINAS CARBON PLAN BEEN CONSTRUCTED?

A: No.

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[37] Duke Energy, Carolinas Carbon Plan Appendix E, Table E-39 at p. 35 and E-69 at p. 77.

[38] U.S. United States Nuclear Regulatory Commission, Standard Design Approval (SDA) Application – NuScale US460 (last updated on July 12, 2022), https://www.nrc.gov/reactors/new-reactors/smr/nuscale-720-sda.html.

Q: WHAT IS THE EARLIEST DATE WHEN ANY REACTOR DESIGN IDENTIFIED BY DUKE ENERGY IN APPENDIX L, TABLE L-5 OF THE CAROLINAS CARBON PLAN WILL COME ONLINE?

A: According to Table L-5 in Appendix L, three of the listed designs are "expected" to be online in 2028. However, none of these designs have been certified. Two are non-light-water designs. The NuScale design has an expected online date of 2029. This has been greatly delayed. In 2008, NuScale officials expected an online date of 2015-2016; it took until 2016 for NuScale to even submit its application for certification—for the 50 MW design. However, NuScale's Idaho project, which would be the first for commercial production, is now going to be based on a 77 MW reactor, that has not been certified and is still in the pre-application stage. This is the version of the NuScale reactor that Duke Energy has included in its list. The historical record is not promising for commissioning on schedule.

Duke Energy should carefully evaluate this record of delays and changes in preparing the schedule for the dates at which it proposes to add SMRs and advanced reactors to its portfolio.

Q: CAN YOU DISCUSS THE POTENTIAL DEPLOYMENT ISSUES WITH EACH REACTOR DESIGN IDENTIFIED BY DUKE ENERGY IN APPENDIX L, TABLE L-5 OF THE CAROLINAS CARBON PLAN?

A:

- The BWRX-300 Reactor Light Water-cooled by GE Hitachi is a relatively new SMR; its conceptual design only started in 2017.[39] The BWRX-300 is based on GE-HITACHI's Economical Simplified Boiling Water Reactor design, which was never constructed anywhere in the world and has a checkered certification history; the design was changed nine times before the 10th version was certified. The BWRX-300 has not been licensed for construction, has not been submitted for formal certification to any national safety regulator, and therefore, has never been constructed anywhere in the word. It would be prudent to anticipate significant delays in the "expected" 2028 commissioning date announced for the first reactor.
- As noted, certification of the 77 MW VOYGR Reactor Light-Water-cooled design by NuScale is in the pre-application stage and has faced significant deployment delays.
- The certification of the Natrium Reactor Liquid Sodium-cooled by TerraPower and GE Hitachi was in the pre-application phase as of mid-August 2022.[40] It should be noted that the proposed fuel is High Assay Low-Enriched Uranium ("HALEU"), which has

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[39] Int'l Atomic Energy Agency, Advances in Small Modular Reactor Technology Developments: A Supplement T: Advanced Reactors Information System (ARIS) 2020 Ed. 93 (2020), https://aris.iaea.org/Publications/SMR_Book_2020.pdf.
[40] U.S. Nuclear Regulatory Commission, Natrium — Project Overview (last updated on August 15, 2022), https://www.nrc.gov/reactors/new-reactors/advanced/licensing-activities/pre-application-activities/natrium.html.

uranium enrichments between 5% and 20%.[41] HALEU fuel is not used for any commercial reactor in the United States and is not currently commercially produced in the United States. Unlike SMR designs that would use fuel of up to 5% enrichment, the current practice, HALEU implies security and certification considerations related to the enrichment of the fuel. Specifically, enrichment greater than 10% may raise proliferation concerns because other countries, including non-nuclear weapon states, may want to follow the United States' example.[42]

- Pre-application stage certification activities for the Gas-cooled High Temperature Xe-100 reactor by X-energy started in 2018. The reactor was still in the pre-application stage as of June 30, 2022.[43] The Xe-100 appears likely to also use HALEU. The Office of Nuclear Energy is the supporting the manufacture of HALEU graphite fuel pebbles by X-Energy,[44] which is developing the Xe-100 reactor. The pre-application White Paper on the fuel that the NRC is reviewing states that the Xe-100 would use low-enriched

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[41] Office of Nuclear Energy, *What is High-Assay Low-Enriched Uranium (HALEU)?*, https://www.energy.gov/ne/articles/what-high-assay-low-enriched-uranium-haleu.

[42] For a discussion on security issues associated with various levels of reactor fuel enrichment, *see* Edwin Lyman, "Advanced" Isn't Always Better: Assessing the Safety, Security and Environmental Impacts of Non-Light Water Reactors, Union of Concerned Scientists (March 2021), https://www.ucsusa.org/sites/default/files/2021-05/ucs-rpt-AR-3.21-web_Mayrev.pdf.

[43] U.S. Nuclear Regulatory Commission, Xe-100 — Project Overview, (last updated on June 30, 2022), https://www.nrc.gov/reactors/new-reactors/advanced/licensing-activities/pre-application-activities/xe-100.html.

[44] Office of Nuclear Energy, X-energy's TRISO-X Fuel Fabrication Facility to Produce Fuel for Advanced Nuclear Reactors, Department of Energy pp. 4, 17 (April 8, 2022), https://www.energy.gov/ne/articles/x-energys-triso-x-fuel-fabrication-facility-produce-fuel-advanced-nuclear-reactors.

uranium ("LEU") fuel; however, the same document defines LEU as "<20%" enrichment.[45] This is unusual, since it is normal practice to distinguish between the LEU now used in commercial reactors, which is up to 5% enrichment, and LEU which has enrichments between 5% and 20%, and call it HALEU, due to its greater proliferation implications. Finally, the International Atomic Energy Agency, in its 2020 edition on SMRs states that the Xe-100 reactor would use 15.5% enriched fuel.[46] It therefore appears that the Xe-100 reactor will be using HALEU fuel and that its licensing process may face the same additional fuel review as the Natrium reactor on this account.

Q: IN YOUR OPINION, ARE DUKE ENERGY'S PORTFOLIOS SPECULATIVE GIVEN ITS RELIANCE ON SMRS BEING DEPLOYED AS EARLY AS 2032?

A: Yes. The history of SMRs is replete with substantial delays and changes. Certification processes are prolonged. Neither of the proposed light-water designs is certified. While the light-water designs are based on the same principles as current commercial reactors, their designs have been modified

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[45] X-Energy, LLC, Submission of X Energy, LLC (X-energy) Xe-100 Topical Report: TRISO-X Pebble Fuel Qualification Methodology, Revision 2, Enclosure 3: X Energy, LLC Xe-100 Topical Report: TRISO-X Pebble Fuel Qualification Methodology, (Non-Proprietary), pdf. p. 24 (Sept. 2, 2021), https://www.nrc.gov/docs/ML2124/ML21246A289.pdf.

[46] International Atomic Energy Agency, Advances in Small Modular Reactor Technology Developments: A Supplement to IAEA Advanced Reactors Information System (ARIS), 2020 Ed. p. 175 (Sept. 2020), https://aris.iaea.org/Publications/SMR_Book_2020.pdf.

in part to reduce costs. Thus, the first reactors may face more than the usual amount of teething troubles; this would delay subsequent reactors.

Q: CAN YOU DISCUSS THE POTENTIAL OPERATIONAL RISKS ASSOCIATED WITH THE RAPID DEPLOYMENT OF NUCLEAR TECHNOLOGY?

A: David Lochbaum, a nuclear engineer with extensive experience in the nuclear industry, in Non-Governmental Organizations, and in the NRC, has shown that reactor operational risks follow a "bathtub curve" – high in the early years due to factors such as material imperfections and mistakes in assembly, low in the middle years, and rising again with age due to age-related degradation.[47]

For instance, Three Mile Island Unit 2 was just over a year old when the infamous 1979 accident occurred. Chernobyl Unit 4 was also relatively new – construction was completed in 1983; the accident occurred in 1986.

An analysis of early risks, relative to the average, would therefore be a prudent part of planning if the Commission approves the exploration of new designs, especially in view of the rapid rate at which new reactor designs would be commissioned.

New designs or modifications of existing designs raise the risk of such early operational difficulties. For instance, the NuScale reactors will have their steam generators inside the reactor vessel. In contrast, existing

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[47] David Lochbaum, *Nuclear power in the future: risks of a lifetime*, Bulletin of the Atomic Scientists (Feb. 24 2016), https://thebulletin.org/2016/02/nuclear-power-in-the-future-risks-of-a-lifetime/.

commercial pressurized water reactors ("PWRs") have their steam generators outside the reactor vessel but within the secondary containment where they can be repaired or replaced. Problems with steam generators, which have had to be prematurely replaced in existing PWRs, would be more complex with the steam generator inside the reactor vessel.

Q: IS IT YOUR POSITION THAT DUKE ENERGY'S PORTFOLIOS PRESENT SIGNIFICANT SCHEDULE AND COST RISKS GIVEN ITS RELIANCE ON SMRS AND ADVANCED REACTORS BEING DEPLOYED AS EARLY AS 2032 AND THEN EACH YEAR AFTER THAT?

A: Yes. I have outlined the serious and varied risks associated with reliance on either light water SMRs on a schedule that is very optimistic, given the many delays that even light-water SMRs have experienced. It is essential, given this experience, not to take the announced dates of commercial operation of first-of-a-kind reactors at face value; instead, a careful evaluation of the overall history and the specific history of each reactor is called for to assess the cost and schedule risks. This is necessary for light-water-cooled SMRs and even more necessary for the two non-light-water designs that Duke Energy has selected. As I have noted, none of these designs have even been certified. Duke Energy's timeline and schedule[48] make no allowance for delays in the commissioning dates of the four first-

[48] Duke Energy, Carolinas Carbon Plan Appendix L, Figures L-3 and L-4 at pp. 12-13.

of-a-kind reactors, not to mention making allowances for those reactors to operate for some time to work out and resolve any teething troubles.

Q: CAN YOU DISCUSS HOW RELIANCE ON BOTH NEW AND EXISTING NUCLEAR POWER CAN DESTABILIZE SIGNIFICANT PARTS OF THE DUKE ENERGY ELECTRICITY SYSTEM?

A: Numerous factors in Duke Energy's proposed Carbon Plan create risks of a deterioration of reliability. Reliance on relatively long lead-time new nuclear is one of them. In addition, Duke Energy would be adding about 10,000 MW to its already substantial North Carolina portfolio of ~~7,500~~ 5,150 MW; this creates additional risks.

Specifically, nuclear power plants need grid electricity to operate safely and produce power. Plants only have enough emergency power supply to keep them in safe shutdown mode. A loss of grid power over a wide area with high concentrations of nuclear power plants could destabilize significant parts of the Duke Energy electricity system (and perhaps beyond) because a large amount of electric generating capacity would be taken offline—capacity which requires grid power to be restored for power generation to resume.

Q: CAN YOU PROVIDE EXAMPLES OF EVENTS THAT CAN IMPACT DUKE ENERGY'S ELECTRICITY SYSTEM IF THERE IS RELIANCE ON BOTH NEW AND EXISTING NUCLEAR POWER?

A: For instance, an earthquake on August 23, 2011, shut down the North Anna nuclear plant in Virginia for months. The ground-shaking was felt over a wide swath of eastern North America from Georgia to Maine and Quebec; it was felt all over North and South Carolina – that is the entire Duke Energy DEC and DEP region. A similar event (or an even larger one, comparable to the 1886 Charleston Earthquake), could paralyze the electricity system for a significant time. Duke Energy's proposed Carbon Plan has not analyzed such an eventuality, even though the United States Geological Survey recognizes the significant earthquake potential in the Southeastern United States.[49] This vulnerability is not about whether such an event might trigger an accident – that is a matter for the NRC to consider. It is about the increased exposure of the electricity system to a widespread nuclear plant shutdown (for instance for inspections and/or potential repairs) in case of an earthquake comparable to or greater than the 2011 Virginia event.

As another example, extreme weather events are intensifying; they could cause outages in large sections of the grid. Hurricane Ida in 2021 provided an example of all transmission lines into a major city, New Orleans, failing simultaneously. This creates risks since nuclear power plants need grid energy to restart supplying power.

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[49] U.S. Geological Survey, Improved Earthquake Monitoring in the Central and Eastern United States in Support of Seismic Assessments for critical facilities, Open-File Report 2011-1101 (2011), https://pubs.usgs.gov/of/2011/1101/pdf/OF11-1101.pdf.

A prolonged, decades-long reliance on existing nuclear capacity may also create reliability issues. It would be prudent to examine such an eventuality, given the recent events in France that have led to high prices and large unplanned outages. Specifically, the discovery of stress corrosion cracking in reactors in late 2021 led to far less capacity being available than normal. France's energy regulator has stated that it will take years to fix the problem.

As another example, adding about 10,000 MW to the existing ~~7,500~~ 5,150 MW of nuclear in North Carolina would create large new demands on water resources, increasing vulnerability in times of heat waves—when capacity is most needed. High summer water temperatures have already caused occasional de-rating of nuclear plants. For instance, some French nuclear power plants were de-rated during the 2003 heat wave, significantly reducing available capacity. The problem of derating due to high water temperature will tend to arise during the summer peak demand season, creating pressure on the grid during that critical period. A recent analysis of empirical data on nuclear plant performance showed that the rate of nuclear power plant outages due to climate change was more than seven times greater in the decade of the 2010s compared to the 1990s. The negative impacts were due to factors as varied as droughts, hurricanes, and, as noted in a recent article in the journal *Nature Energy*, an "excessive presence of jellyfish, which have been shown to flourish in warmer waters under the effect of climate change."[50] The quantity of water required and the vulnerabilities that that would create for the grid is a critical factor for assessing any decarbonization plan.

It should be noted that solar photovoltaic and wind power plants need essentially no water for their operation. The opportunity costs imposed on competing uses and resources, like fish, which would also be impacted by the heating of water resources, also need to be addressed in the context of a warming climate and least cost planning.

Q: IN YOUR OPINION, WHAT ROLE SHOULD ADVANCED NUCLEAR ENERGY PLAY IN TRANSITIONING FROM CARBON-INTENSIVE GENERATION SUCH AS COAL OR NATURAL GAS?

A: Based on a variety of factors, no reliance should be placed on SMRs and non-light-water advanced nuclear energy technologies to achieve the decarbonization goals of HB 951. They are costly; their schedules are likely to be delayed relative to the dates in Duke Energy's portfolios; and the risks and uncertainties involved are far too large to even put reliable upper limits on costs and delays. The history of the failed nuclear renaissance is most relevant here. After more than 15 years, not a single reactor of the dozens announced has produced any electricity to date, despite modular designs and simplified licensing that combined the construction and operating

[50] Ali Ahmad, *Increase in Frequency of Nuclear Power Outages Due to Changing Climate*, 6 Nature Energy pp. 755, 756 (July 2021).

licenses—two separate processes in the twentieth century—into a single license.

Moreover, renewable energy and storage are available at a much lower cost. Other non-nuclear advanced technologies are available to meet all the needs of replacing fossil fuel generation without resorting to costly and untried new nuclear technologies with known risk factors that are substantial.

The non-light water reactors that Duke Energy has selected face added risks. There are no operational commercial reactors in the United States, small or large, that use the proposed design approaches in the Xe-100 and Natrium reactors. The latter is a sodium-cooled design whose concept goes back to the earliest days of nuclear power. Tens of billions of dollars have been spent worldwide to commercialize this design; yet, neither consistently reliable operation across reactors or time periods or economics of production has yet been achieved. In addition, the Natrium design would add molten salt storage, which has not been used in association with nuclear reactors.

Gas-cooled, graphite-moderated reactors have also had a troubled history both in the United States and Germany. While the design is not vulnerable to meltdowns, it is susceptible to fires and incursions of water.

Past commercial experience is not promising; all four commercial reactors built in the United States and Germany were shut down early.[51]

There is therefore ample reason to be even more prudent when proposing to rely on non-light-water SMR designs by a date certain to meet the HB 951 2050 target while achieving reasonable costs.

Q: IS IT YOUR POSITION THAT NEAR-TERM DEVELOPMENT ACTIVITIES RELATED TO ADVANCED NUCLEAR REACTOR TECHNOLOGY ON DUKE ENERGY'S PART ARE NOT PRUDENT AT THIS TIME?

A: They are not prudent investments at this time. Given the risks, status, hurdles, and history, no expenditures are justified at this time. DEP and DEC witness Regis Repko states that "initial development work is needed both to gather information to provide a more refined cost estimate to the Commission in future proceedings, as well as to allow the Companies to be positioned to implement such resources on a timeline consistent with the Companies' modeled portfolios."[52] Duke Energy should have looked at its six-reactor failed nuclear renaissance experience before proposing a high risk, high capacity new nuclear portfolio of reactors that do not even have certification. Their prospects are poor and much lower cost alternatives are available.

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[51] M. V. Ramana, *The checkered operational history of high-temperature gas-cooled reactors*, Bulletin of the Atomic Scientists, Vol. 72, No. 3 (2016).

[52] Docket No. E-100, Sub 179, Direct Testimony of Regis Repko et al. for Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, pp. 8-9 (Aug. 19, 2022).

In light of this, expenditure of ratepayer funds is not justified at this time. Should one or more new nuclear technologies progress in an unexpected positive direction in terms of certification, cost, and scheduling in the next few years, the issue of new nuclear technologies can be revisited at that time with due focus on the more promising reactor types.

B. Technical Challenges and Operational Problems Associated with Duke Energy's Proposed Reliance on SMRs and Advanced Nuclear Reactors

Q: CAN YOU DISCUSS THE POTENTIAL OPERATIONAL RISKS ASSOCIATED WITH DUKE ENERGY'S PROPOSED SMRS AND ADVANCED NUCLEAR REACTORS?

A: The new nuclear technologies as a set pose a significant risk given the fact that they are new, have never been built for commercial operation, and therefore, have never operated commercially. I have already alluded to the concept of the "bathtub curve," which demonstrates that there are more problems in the early and late parts of the operating life of reactors.

An analysis of early risks, relative to the average, would therefore be a prudent part of planning if the Commission approves the exploration of new designs at some point, especially in view of the rapid rate at which new reactor designs are proposed to be commissioned.

There are also specific risks associated with the different designs, especially the advanced reactors. Sodium leaks have historically plagued many sodium-cooled reactors. The Monju sodium-cooled nuclear reactor is an example of the "bathtub curve" as applied to this case. It was shut down due to a sodium leak and fire in 1995, having been completed in 1994. It remained shut until 2010, when it was reopened and suffered another accident, leading to permanent shut down.[53]

The poor operating history of graphite moderator reactors should also be evaluated. Four reactors of this type were all shut down with operating lifetimes between just 7 and 10 years. The Peach Bottom reactor in the United States started having operational problems in just over a year after commissioning.[54]

New waste types may also pose issues. As noted, graphite poses a risk of fires. Its storage will present different issues than those of light-water reactor spent fuel. Disposal will also present challenges specific to the fuel type in addition to the issues generally connected with long-lived radionuclides in high-level radioactive waste. A portion of the graphite will become carbon-14 during reactor operation. This is a radioactive isotope of carbon; when oxidized it becomes radioactive carbon dioxide that dissolves in water and is emitted to the air, thereby posing the risk of making food and water radioactive. For instance, in the 1990s an EPA scientific subcommittee of the Radiation Advisory Committee concluded that demonstrating that the disposal of light-water reactor spent fuel in an

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[53] For the 1995 sodium leak accident *see* Thomas B. Cochran et al., Fast Breeder Reactor Programs: History and Status, Int'l Panel on Fissile Materials, p. 54 (2010), http://ipfmlibrary.org/rr08.pdf; For the permanent shut down, *see* World Nuclear News, *Japanese government says Monju will be scrapped*, (Dec. 22, 2016), https://www.world-nuclear-news.org/NP-Japanese-government-says-Monju-will-be-scrapped-2212164.html.

[54] M. V. Ramana, *The checkered operational history of high-temperature gas-cooled reactors*, Bulletin of the Atomic Scientists, Vol. 72, No. 3 (2016).

unsaturated repository zone, such as the proposed Yucca Mountain repository, would meet the release limit on carbon-14 in the prevailing regulation (40 CFR 191, Table 1) could pose significant challenges.[55]

Q: CAN YOU DISCUSS SOME OF THE ISSUES THE TWO MOLTEN SALT MICRO-REACTOR DESIGNS IDENTIFIED IN APPENDIX L, TABLE L-5 OF THE CAROLINAS CARBON PLAN WOULD LIKELY FACE IF DUKE ENERGY PURSUES THEM?

A: Experience with molten salt reactors is very limited. Two have been built in the United States; neither was designed to generate power. The first was an aircraft reactor experiment; it operated for 100 hours. The second was a pilot reactor of just 8 megawatts thermal—the Molten Salt Reactor Experiment—built and operated at Oak Ridge National Laboratory; the heat generated by the reactor was dissipated into the air (by design); no electricity was generated. This molten fluoride fuel reactor had a short, four-year operational period from 1966 to 1969 (inclusive) during which it experienced several problems. As my colleague Dr. M.V. Ramana and I noted in our 2021 article for the Bulletin of the Atomic Scientists, "Over the four years, its operations were interrupted 225 times due to various problems, including sudden, usually unscheduled, shutdowns (called

[55] Environmental Protection Agency, An SAB Report: Review of Gaseous Release of Carbon-14: Review by the Radiation Advisory Committee, of the Release of Carbon-14 in Gaseous Form from High-Level Waste Disposal, p. 2 (1993), https://www.nrc.gov/docs/ML0413/ML041330429.pdf. Disclosure: I was a member of the EPA subcommittee that reviewed the issue.

"scrams") and fuel draining down the freeze valve (a component often touted as a safety feature in molten-salt reactor designs) . . . ."[56]

Molten salt waste containing fission products may also pose significantly more difficult problems of long-term high-level waste than the ceramic fuel pellets used in light water reactors. While the specific post-closure issues with the proposed reactors will likely differ somewhat from the ones in Duke Energy's table and may be less complex in the absence of uranium-233 (which is a post-closure issue for the Oak Ridge reactor), it is still worth noting that post closure costs of this reactor, whose size is in between the two micro-reactors in Table L-5, run into hundreds of millions of dollars.[57]

Q: CAN YOU PROVIDE EXAMPLES OF THE AMOUNT OF DEVELOPMENT THAT MUST FIRST OCCUR TO HAVE DUKE ENERGY'S PROPOSED SMRS ONLINE IN 2032?

A: The proposed reactors have to be certified, the combined construction and operating licenses have to be obtained, and the first reactors listed in Appendix L, Table L-5 of the Carolinas Carbon Plan have to be built on time at something resembling the costs assumed by Duke Energy. Even so, for Duke Energy to bring the first SMR reactor online for commercial operation in mid-2032, it would have to get a construction and operating

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[56] Arjun Makhijani & M. V. Ramana, *Can Small Modular Reactors Help Mitigate Climate Change?*, 77 Bull. at. Sci. 207 (2021).
[57] *Id.*

license in 2026, begin initial construction in early 2028, and carry out full-scale construction activities starting in mid-2029, according to Duke Energy's own schedule.[58] This is approximately coincident with the currently projected completion of SMRs identified in Appendix L, Table L-5 with no allowance for delays and no allowances for a learning curve on the initial reactors to overcome the early part of the "bathtub curve."

Q: CAN YOU PROVIDE EXAMPLES OF FACTORS THAT MAY DELAY COMPLIANCE WITH THE EMISSIONS REDUCTIONS TARGET SET OUT IN HB 951 IF ALL PORTFOLIOS PROPOSED BY DUKE ENERGY RELY ON SMR CAPACITY?

A: There could be a variety of delays – in certification of the reactors (since none of the specific reactors identified in Appendix L, Table L-5 of the Carolinas Carbon Plan are certified), for instance. Another risk is that the companies proposing to build the first projects may abandon them. For instance, the TVA pulled out of the mPower, Babcock & Wilcox project in 2017, after six years and considerable expenditures. The projects may face substantial cost escalations, as has already occurred with the NuScale project proposed to be built in Idaho. That project was announced as a 720 MW project in 2015 but was downsized to 462 MW in 2021.[59] Even so, as of October 2021, 28 subscribers had signed contracts to purchase only 101

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[58] Duke Energy, Carolinas Carbon Plan Appendix L, Figures L-3 and L-4 at pp. 12-13.
[59] NuclearNewsWire, *UAMPS Downsizes NuScale SMR Plans*, Nuclear News, (July 21, 2021) at https://www.ans.org/news/article-3087/uamps-downsizes-nuscale-smr-plans/.

MW, or just 22% of the *reduced* capacity; 2 utilities had signed Letters of Intent ("LOI") to explore purchasing another 38% of the reduced capacity; other utilities were exploring LOIs as of October 2021.[60] The October 2021 contractual subscription of 101 MW was down from the "approximately 244 MW" of "[p]articipation" that was claimed in May 2019 by the Utah Associated Municipal Power Systems.[61] Further cost increases may cause parties to pull out or reduce their subscriptions; they may also result in a failure to get firm subscriptions for much or most of the power. These eventualities may even result in project abandonment.

The extension of the investment tax credit under the Inflation Reduction Act and the low cost of solar plus storage increases the likelihood that nuclear projects will be abandoned due to the yawning cost gaps. Such setbacks could also make it difficult to consider follow-on projects, such as those proposed by Duke Energy, as reasonable and prudent investments.

Q: SHOULD COMPLIANCE WITH THE REQUIREMENTS OF HB 951 REST ON THE SUCCESSFUL DEVELOPMENT AND CONSTRUCTION OF NEW NUCLEAR FACILITIES?

A: No. It is far too risky and costly when there are other options available. Furthermore, if there is unexpected progress in terms of cost and expedited

[60] PUET Committee, Carbon-Free Technologies: Opportunities and Challenges, Utah Associated Municipal Power Systems (UAMPS), pdf p. 17, (Oct. 21, 2021), https://ieefa.org/wp-content/uploads/2022/02/October-2021-UAMPS-presentation.pdf.

[61] Leadership in Nuclear Energy Commission Meeting, Presentation by Doug Hunter, (May 16, 2019), https://line.idaho.gov/wp-content/uploads/2019/05/2019-0516-UAMPS-slides.pdf.

schedules in the next few years in one or more of Duke Energy's identified reactor types, the issue could be more appropriately revisited at that time.

Q: IN YOUR OPINION, HAS DUKE ENERGY THOROUGHLY PRESENTED TO THE COMMISSION THE POTENTIAL TECHNICAL CHALLENGES AND OPERATIONAL PROBLEMS ASSOCIATED WITH ITS PROPOSED SMRS AND ADVANCED NUCLEAR REACTORS IN ITS CAROLINAS CARBON PLAN?

A: No.

III. RECOMMENDATIONS

Q: WHAT ARE YOUR RECOMMENDATIONS FOR THE COMMISSION CONCERNING MODIFICATIONS TO DUKE ENERGY'S RELIANCE ON EXISTING NUCLEAR GENERATION AND ADVANCED NUCLEAR TECHNOLOGY?

A: Given the reality of Duke Energy's heavy reliance on both existing nuclear generation and advanced nuclear technology in its proposed Carolinas Carbon Plan, my recommendations for the Commission are as follows:

No more than one portfolio should include new nuclear. If such a portfolio is included, the obstacles and risks should be explicitly discussed, including the issues that Duke Energy has not covered or covered only in passing. My opinion, especially in view of the Inflation Reduction Act (which was enacted after my written submission in this docket in July

2022[62]), is that it would be far better to examine a diversity of portfolios without any one of them containing new nuclear power plants. Existing nuclear plants can be maintained in one or more of them. The following list contains four portfolios of the type and variety that should be developed in detail; two of them retain existing nuclear; two do not.

1. **EWG Portfolio 1: Balanced Solar and Wind with Existing Resources**.

   A Portfolio in which onshore and offshore wind generation combine to approximately equal annual solar generation, both of which would be significantly larger than in the Duke Energy P2 Portfolio (with wind having to increase more than solar). Balanced wind and solar generation provide seasonal balance to better meet summer and winter loads with lower stress on non-generation resources. Existing nuclear resources would be retained. New hydrogen generation resources would be included, but instead of CT and CC resources, light and medium duty fuel cells would be evaluated. No new natural gas resources would be built. Considerably faster transportation electrification would be included in light of plans by major manufacturers and countries that are major markets for vehicles. Vehicle-to-Grid ("V2G") technology would be included. While Duke Energy did not include V2G in its proposed portfolios, deeming it to be in its "commercial infancy,"[63] it is

[62] Initial Comments of Environmental Working Group, Attachment A.
[63] Duke Energy, Carolinas Carbon Plan Appendix G at p. 44.

noteworthy that the company has since applied to the Commission to team up with Ford to implement V2G in North Carolina on a pilot basis. In its application to the Commission for ratepayer funds for this program, Duke Energy stated that it would start with a small pilot, initially enrolling 35 to 100 vehicles.[64] Based on this experience, it envisions taking the V2G pilot to a "commercialized" pilot stage, which, over five years would enroll thousands of F-150 Lightning leaseholders, and reduce their lease costs by directly paying Ford when it leases the vehicles.[65] Duke Energy would use the batteries in the vehicles to supply power to the grid to shift demand and estimates that the commercial pilot would result in a positive benefit-cost ratios for all three tests it applied – the "Utility Cost Test" ("UCT"), the Total Resource Cost ("TRC") test, and the Ratepayer Impact Measure ("RIM") test. Duke Energy estimates the benefit-cost ratios to be 1.24, 2.56, and 1.24 respectively.[66] Duke Energy may also enroll customers with solar energy, stationary battery storage, and combine that with V2G, with a maximum capacity of 20 kilowatts per installation.[67] If the results are positive, Duke Energy has gone even farther, stating that the "Company may seek to develop full-scale commercialized offerings *during the duration of this Pilot*, if interim measured results lead the Company to

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[64] Application for Approval of Vehicle-To-Grid Pilot Program, Docket No. E-7, Sub 1275, filed Aug. 16, 2022. at p. 3.
[65] *Id.* at p. 2 and Attachment A, p. 7.
[66] *Id.* at Attachment B, p. 8.
[67] *Id.* at Exhibit 1, p. 2.

do so."[68] That would put V2G, which is existing advanced technology, very far ahead any of the proposed new nuclear reactors. As noted, none of Duke Energy's proposed nuclear reactor designs have been certified, much less built. In fact, Duke Energy estimates that the V2G demand response market could ultimately be in the range of 15% to 25% of EVs.[69] When EVs become the most common type of vehicle, and rooftop solar and stationary batteries are much more common, this demand response approach could provide thousands of megawatts of demand response power of the very kind that is most compatible with variable renewable energy. Hydrogen would be produced with electricity that would otherwise be curtailed and used for peaking power generation loads not otherwise met by battery storage, V2G, and demand response shifting. Hydrogen would not be put into existing natural gas pipelines; rather it would be produced electrolytically on site (preferred) or transported in dedicated pipelines if necessary.

2. **EWG Portfolio 2: Balanced Solar and Wind with High Resilience**. This would be similar to EWG Portfolio 1 with the following differences. Efficiency for existing loads (i.e., not including electrification of transportation or heating conversions from gas, propane, and fuel oil) would increase by 2% per year to 2030, 1.5% per year from 2031 to 2035, and 1% per year from 2036-to 2050, with the

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[68] *Id.* at p. 2 (emphasis added).
[69] *Id.* at Exhibit 1, p. 3.

appropriate higher incentives and standards put in place to achieve the higher levels. There would be much more investment in efficiency in low-and moderate-income households. Explicit quantitative resilience criteria would be defined, including service of essential loads for a pre-specified period and the number of people who would be so served in emergencies. A significant fraction, or possibly all, of units of the Self-Optimizing Grid (400 customers or 2 megawatts peak load) would be designed as microgrids with the goal of serving essential loads within the neighborhoods for a pre-determined number of days. V2G would be more intensively represented and integrated with the Self-Optimizing Grid. Demand response would be significantly deeper than in Duke Energy’s P3 portfolio; it would be generalized to offer contracts to all loads that can reasonably be shifted within a 24-hour period (though with the expectation of varied participation levels at specific times, depending on the load). All hydrogen production would be at the power station sites. Pipeline leaks would thereby be avoided.

3. **EWG Portfolio 3: Fully renewable with high resilience with existing nuclear retired**.

This would be like EWG Portfolio 2 but existing nuclear would be retired at the current license expiry dates between 2030 and the mid-2040s. Deployment of renewable energy, storage, efficiency, V2G, and aggregated demand response resources would be accelerated and expanded to meet requirements consistent with nuclear plant retirement dates. More hydrogen would be produced than in EWG Portfolio 2 and EWG Portfolio 3 for use in large fuel-cell-based combined heat and power plants and for heavy industries like cement plants. All the hydrogen needed for electricity generation would be produced with Duke Energy generated electricity that would otherwise be curtailed. The option of developing medium and large-scale solar with dual agricultural use, for instance for grazing (known as agrivoltaics), would also be included.

4. **EWG Portfolio 4: Fully renewable with high resilience, existing nuclear retired, distributed wind, and thermal storage for heating**. This would be similar to EWG Portfolio 3 with the following differences. There would be significant inclusion of front-of-the-meter distributed wind in Self-Optimized Grid resources as well as other distributed electricity production. Seasonal thermal storage would be implemented as part of many self-optimized grid units, other microgrids, including public purpose microgrids, and new commercial and residential developments as appropriate. Seasonal thermal storage can provide energy supply diversity in the summer and winter seasons by complementing other types of storage; it would also further tap into solar and wind that might be otherwise curtailed—a supply that would be expected to be more plentiful in fully renewable portfolios.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Summary of Testimony of Dr. Arjun Makhijani on behalf of The Environmental Working Group

The purpose of my testimony is, first, to address the costs, risks, and reliability of the proposed new nuclear technology and nuclear generation in the Carbon Plan filed in Docket No. E-100, Sub 179 by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (together "Duke Energy"); second, to address the cost and schedule challenges associated with Duke Energy's proposed reliance on Small Modular Reactors ("SMRs") and Advanced Reactors as well as certain technical risks, given the history of such reactor programs and proposals; third, to address the need for the Commission to consider the reality and history of cost increases and delays associated with new nuclear power plants from both large and small reactors as well as the serious risks that reliance on new nuclear reactors, at present uncertified, will result in a failure to meet the targets mandated by HB 951; and fourth, to outline additional portfolios that include a fuller range of new technologies and that do not involve new nuclear reactors to enable a least cost determination within the decarbonization and reliability goals of HB 951.

The "nuclear renaissance" announced in the decade of the 2000s has been a failure. Only about 6 percent of the announced reactors are on track to be built and brought online with many years of delay and huge cost escalations (assuming Vogtle units 3 and 4 are completed). This is much worse than the approximately 50-50 record of completions of nuclear reactors in the twentieth century. Duke Energy's efforts during the "nuclear renaissance" have been part of this "renaissance" failure: none of the six reactors Duke Energy proposed ever began construction. All were abandoned or indefinitely delayed. Duke Energy has not taken this history and the costs associated with it into account for the lessons they may hold going forward.

Meanwhile, several prior constructed reactors have been retired before their license expiry; high operating costs have been a leading cause. For instance, NextEra estimated it would save its customers an estimated $300 million by early shutdown of its Duane Arnold reactor and generating wind power instead. Other reactors, including Duke's Crystal River plant, have been shut down for issues related to steam generator replacement.

All four portfolios of Duke Energy's proposed Carbon Plan are very similar in the year 2050. New nuclear ranges from 9,900 MW to 10,200 MW, a mere 3 percent difference. The combined combustion turbine and combined cycle gas-fired generation capacity totals are also similar, as are the amounts of onshore wind, pumped hydro storage, energy efficiency, and solar capacity. Offshore wind capacity does vary from 0 to 3,200 MW; however, even the 3,200 MW figure represents a small fraction of generation requirements in 2050. Battery storage capacity varies somewhat across portfolios, from 5,900 to 7,400 MW.

Duke Energy's "New Supply-Side Resource Capital Cost Sensitivity Analysis" fails to consider historical nuclear cost escalations. Its cumulative impact sensitivity of $4 billion (present value) for a proposed portfolio of about 10 gigawatts does not reflect recent reactor construction cost escalations. For instance, Vogtle units 3 and 4 in Georgia have had cost escalations of around $7 billion *per gigawatt*. By this measure, Duke Energy underestimated capital cost sensitivity by well over an order of magnitude. In addition, there were planned reactors that were cancelled or indefinitely postponed at significant cost, including six proposed by Duke Energy. Moreover, even the very low estimate of $4 billion was not examined for its impact on the mix of generation in the four proposed portfolios.

A significant cost gap exists between nuclear and renewable power generation. According to estimates by the Wall Street firm Lazard, unsubsidized utility-scale solar generation costs declined from $359 per megawatt-hour (MWh) in 2009 to $36 per MWh in 2021. Onshore wind declined from $135 per MWh to $38 per MWh over the same period. Estimates for offshore wind range from $66 to $100 per MWh. Costs of utility-scale solar plus large-scale storage are also declining; they dropped from $88 per MWh in 2020 to $77 per MWh in 2021, a decrease of over 12% in a single year. By contrast, the estimated unsubsidized costs of nuclear energy generation have *risen* from $123 per MWh in 2009 to $167 per MWh in 2021 (range: $131 per MWh to $204 per MWh). Costs of nuclear in both France and the United States, the leading western nuclear energy countries, have increased as more reactors were built. The 2021 cost estimate of utility-scale solar with storage was less than half of the estimated cost of nuclear power, which tends to rise. Actual costs of solar plus storage with the investment tax credit were only $30 per MWh in 2021. Nuclear costs, even with a comparable credit, are likely to be far higher.

The nuclear cost problem will be aggravated if SMRs are used to respond to the variability of wind and solar by adjusting reactor output downward when renewable output is high and upward when renewable output falls. That will cause their average capacity factor to decrease from the usual 90% to 95% for nuclear plants. For instance, costs per MWh of SMR electricity would increase by about 25% if the annual capacity factor fell from 95% to 75%.

SMRs are relatively small, usually 300 MW or less per reactor, compared with a typical 1,000 MW for large nuclear reactors. Other things being equal, smaller reactors would cost more per unit of capacity due to loss of economies of scale. Higher costs have resulted in most early small reactors built in the United States being retired early. Besides simplification of design, the hoped-for success of SMRs depends largely upon the assumption that mass manufacturing and assembly-line-style construction will compensate for the loss of economies of scale. Early adopters of SMR are likely to incur higher costs until a supply chain is established. Even if SMRs were to consistently achieve the same per unit costs as present large reactors, they would still be economically unviable, given the high costs of large reactors.

Duke has identified two SMRs and two Advanced Reactors in its proposed Carbon Plan that are “expected” to be online in 2028 or 2029: the Natrium liquid sodium-cooled reactor; Xe-100 helium gas-cooled high temperature reactor; BWRX-300 light water reactor, a boiling water design; and the 77 MW VOYGR light water reactor, a pressurized water design. None of these reactor designs has yet been certified by Nuclear Regulatory Commission (“NRC”). The NuScale reactor has provisional certification for its 50 MW version and may soon be granted full certification. But Duke Energy lists the 77 MW version, which is not certified; the NRC lists it as being in the pre-application stage. The BWRX-300 reactor is an SMR based on GE-Hitachi’s Economical Simplified Boiling Water Reactor design, which has never been constructed anywhere in the world and which has a checkered certification history. Its design was changed nine times before the tenth version was certified. The BWRX-300 has not been licensed for construction or submitted for formal certification to any national safety regulator. It would be prudent to anticipate significant delays in the “expected” 2028 or 2029 online dates listed by Duke Energy. For instance, the NuScale design has already faced significant deployment delays; NuScale had initially announced a commercial operation date of 2015-2016 for its smaller version; but it did not even submit an application for certification until 2016. The Natrium Reactor liquid sodium-cooled was in the pre-application stage as of mid-August 2022. The proposed High Assay Low-Enriched Uranium ("HALEU") fuel (uranium enrichment between 5% and 20%) is not used for any commercial reactor in the United States. It is not currently commercially produced in the United States. Unlike SMR designs that would use fuel of up to 5% enrichment, which is the current practice in large reactors, HALEU use involves additional security and certification considerations. Pre-application stage activities began in 2018 for the Gas-cooled High Temperature Xe-100 reactor by X-energy; it was still in the pre-application stage as of June 30, 2022. The Xe-100 also appears likely to use HALEU and therefore faces the same enrichment scrutiny. In sum, the history of these designs is replete with delays and uncertainties. Duke Energy should carefully evaluate this in preparing the schedule for the dates at which it proposes to add SMRs and Advanced Reactors to its portfolio.

Reactor operational risks tend to follow a "bathtub curve": high in the early years due to factors such as material imperfections and assembly mistakes, low in the middle years, and rising risks with age-related degradation. New SMR features raise the risk of early operational difficulties. For instance, the steam generator is inside the reactor vessel in the NuScale reactor design (as distinct from outside the reactor in current pressurized water reactors ("PWR")). Problems with steam generators, which have had to be prematurely replaced in existing PWRs, would be more complex with the steam generator inside the reactor vessel.

Duke Energy's proposed addition of 10,000 MW to its existing North Carolina portfolio of 5,150 MW could impact significant parts of its electrical system. Nuclear power plants need grid electricity to operate safely and produce power. They only have enough emergency power to keep them in safe shutdown mode. The loss of grid power over a wide area with high concentrations of nuclear plants could therefore destabilize significant parts of the Duke Energy electricity system. Detailed examples are discussed in my testimony and describe how large swaths of nuclear power generation could be taken offline by natural disasters such as hurricanes, which are increasing in frequency and intensity with climate change, or earthquakes, even if the plants are not damaged. For instance, the North Anna plant in Virginia was shut down for months following an earthquake in 2011. Nuclear power generation also requires very large volumes of water for operation, increasing the risk of de-rating during heat waves, the very time when the plants will be most needed. The possibility of de-rating during peak summer demand should be analyzed prior to increasing reliance on nuclear energy by building new plants.

In addition to the risks and technological challenges described previously, my testimony details specific risks associated with the different designs in the proposed Carbon Plan, particularly with the Advanced Reactors. Sodium leaks have historically plagued sodium-cooled reactors, which have not been commercialized despite tens of billions of dollars of expenditures worldwide. Graphite moderated reactors have a poor operating history. Graphite also poses the risk of fires.

New waste types may also raise issues. Specifically, storage and disposal of new waste types will present different or additional challenges to those of light-water reactor spent fuel. A portion of graphite, for example, becomes carbon-14 during reactor operation. This radioactive isotope of carbon, when oxidized, becomes radioactive carbon dioxide that dissolves in water and is emitted into the air, posing risks of food and water contamination. Experience with the molten salt micro-reactor designs, identified in Appendix L, Table L-5 of the Carbon Plan, is extremely limited. Two have been built in the United States; neither was designed to generate electricity. The first, an aircraft reactor experiment, operated for just 100 hours. The second was a pilot reactor of 8 MW-thermal, built and operated at Oak Ridge National Laboratory; it experienced more than 200 interruptions, including many unscheduled ones, in its four-year operational period in the 1960s.

Duke Energy's timetable proposed for the first SMR reactor online in mid-2032, includes starting full scale construction activities in mid-2029 at about the same time or just after the first SMRs are "expected" to come online. Duke Energy's schedule makes no allowance for delays in the commissioning dates of the first-movers, not to mention making allowances for those reactors to operate for some time to work out and resolve any teething troubles. Finally, the extension of the investment tax credit under the Inflation Reduction Act and the low cost of solar plus storage increases the likelihood that currently planned nuclear projects will be abandoned. This possibility should be seriously examined before SMRs or Advanced Reactors are included in any Carbon Plan.

There has been no new nuclear power generated from any of the dozens of reactors announced in the last 15 years, despite modular designs and simplified licensing. Nuclear energy costs have tended to rise; in contrast renewable energy and storage costs have drastically declined and are now much lower than nuclear costs per unit of electricity generation even with storage included.

In view of the above, I recommend that the Commission require that Duke Energy develop portfolios that do not include new nuclear but include other new technologies like fuel cells, vehicle-to-grid ("V2G"), and thermal energy storage. It is noteworthy that, after having dismissed V2G as being in its "commercial infancy" in its proposed Carbon Plan, Duke Energy has proposed a small V2G pilot that it may expand to a "commercialized" pilot stage involving thousands of vehicles and, pending data, even to a full commercial offering during the pilot. Four portfolios are proposed in my submitted testimony. Two of the portfolios would, among other features, retain existing nuclear power plants, balance solar and wind, and expand demand response. The other two would retire existing nuclear plants when their licenses expire and be fully renewable with high reliability resilience after that. One would also include distributed wind, including as part of some sections of Duke Energy's proposed Self-Optimized Grid units.

This concludes the summary of my direct testimony. Thank you for your time.

CHAIR MITCHELL: All right. Any other preliminary matters for the Commission?

(No response.)

CHAIR MITCHELL: All right. You-all may call your witness.

MS. THOMPSON: Thank you, Chair Mitchell. Bear with me just one moment so I can get situated here. Thank you. My witness has anticipated me calling him to the stand. Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club, jointly with the North Carolina Sustainable Energy Association call Tyler Fitch to the stand.

CHAIR MITCHELL: All right. Good morning, Mr. Fitch. Do you prefer to be sworn or affirmed?

THE WITNESS: Sworn is okay.

Whereupon,

TYLER FITCH,

having first been duly sworn, was examined and testified as follows:

CHAIR MITCHELL: All right.

DIRECT EXAMINATION BY MS. THOMPSON:

Q. Mr. Fitch, please state your name, title, and business address for the record.

A. Good morning, Commissioners. Pleasure to be before you today. My name is Tyler Fitch. I'm a senior associate at Synapse Energy Economics. My business address is 1350 Connecticut Avenue, Northwest, Number 412, Washington, DC.

Q. And please briefly describe your role and responsibilities as Synapse Energy Economics.

A. I consult with public -- public interest organizations and state agencies across the Southeast on resource planning issues, but also resiliency, rate design, and EV market design.

Q. And, Mr. Fitch, did you cause to be prefiled in this docket on September 2, 2022, direct testimony consisting of 62 pages in both confidential and public versions?

A. I did.

Q. Do you have any changes or corrections to your prefiled testimony at this time?

A. I do not.

Q. So if the questions put to you in your testimony were asked at the hearing today, would your answers be the same?

A. They would.

Q. And did you also have an exhibit to your testimony?

A. I did.

Q. Was the exhibit to your testimony prepared by you or under your direction?

A. It was prepared by me.

MS. THOMPSON: Chair Mitchell, I would move to have both the public and confidential versions of Mr. Fitch's prefiled testimony entered into the record as if given orally from the stand, and for his confidential testimony to remain under seal.

CHAIR MITCHELL: All right. Hearing no objection to that motion, it is allowed.

(Whereupon, the prefiled direct testimony of Tyler Fitch was 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 AND EXHIBITS OF

TYLER FITCH

ON BEHALF OF

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, AND THE SIERRA CLUB

September 2, 2022

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EXHIBITS

I. <u>Introduction, Qualifications, and *Carbon-Free by 2050* Report</u>

Q. PLEASE STATE YOUR NAME, ORGANIZATION, AND POSITION.

A. My name is Tyler Fitch. I am a Senior Associate with Synapse Energy Economics, Incorporated ("Synapse").

Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A. Synapse is a research and consulting firm specializing in energy and environmental issues, including transportation electrification, electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, wholesale electricity markets, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, state energy offices, environmental organizations, federal government agencies, and utilities.

Q. SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. At Synapse, I conduct analysis and contribute to testimony and publications that focus on a variety of issues relating to the electricity system, including: integrated resource planning; ratemaking and rate design; system resilience; plant economics in organized energy markets; and electric vehicle (EV) market formation.

Much of my work is informed by modeling analyses of the electricity system. These may include spreadsheet- or Python-based analysis, or analysis using industry-standard electricity system models, such as EnCompass or the National Renewable Energy Laboratory's System Advisor Model.

Before joining Synapse, I worked at Vote Solar, where I led regulatory intervention on rate design, valuation of distributed energy resources, and resource planning in the Southeast. In my capacity as regulatory director at Vote Solar and Senior Associate at Synapse, I have provided expert testimony to public utilities commissions in Virginia, North Carolina, South Carolina, and Georgia. I hold a Master of Science from the University of Michigan and a Bachelor of Science in Environmental Sciences from the University of North Carolina at Chapel Hill. I provide a copy of my current resume, attached as Exhibit TF-1 to this testimony.

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 (collectively, the Coalition of Low-Cost Energy and Net-Zero Intervenors or "CLEAN Intervenors").

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I previously provided testimony in Duke Energy Carolinas' and Duke Energy Progress' most recent rate cases (Docket Nos. E-7, Sub 1214 and E-2, Sub 1219).

Q. PROVIDE A VERY BRIEF OVERVIEW OF YOUR TESTIMONY.

A. My testimony is submitted pursuant to the North Carolina Utilities Commission's July 29 order allowing expert testimony on a number of topics related to the Commission's development of a Carbon Plan to meet North Carolina's House Bill 951 ("HB 951") carbon-reduction requirements.[1] This testimony draws from "Carbon-Free by 2050: Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers" (the *"Carbon-Free by 2050 report"*), which my team at Synapse prepared for the CLEAN Intervenors in this proceeding. Those parties included the *Carbon-Free by 2050* report as an attachment to their comments filed on July 20, 2022.[2] I also identify shared conclusions with other parties based on their previous submissions in this proceeding and respond to testimony submitted by Duke Energy witnesses.[3]

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. In Section 2, I briefly summarize my findings and recommendations for the Commission.

[1] North Carolina Utilities Commission (2022, July). Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines. Docket No. E-100 Sub 179. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=8df88a56-f058-44e2-a40b-f9e712284b4a.

[2] Supplemental Joint Comments of NCSEA, SACE, Sierra Club, and NRDC (July 20, 2022). Docket No. E-100, Sub 179. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=6b9bc4ed-5c8d-4871-8393-072d0730100f.

[3] Although I do not respond to every point in other parties' previous filings that relates to issues covered in my testimony, that does not imply agreement or disagreement with those filings. For example, many findings in the Brattle Report filed by the Clean Power Suppliers' Association regarding the need for large-scale deployment of renewables and storage are directionally similar to the findings in my report.

Sections 3 through 7 are organized according to the issue categories identified in the Commission's July 29 order. In those sections, I discuss my findings and conclusions for issues related to "Modeling—Methodology, assumptions, and other modeling issues;" "Coal Unit Retirement Schedule;" "Near-Term Procurement Activity—Solar, Solar Plus Storage, Standalone Storage, Onshore Wind, Natural Gas Generation;" "EE / DSM / Grid Edge; and "Cost."

For each issue category addressed, I evaluate the proposed carbon plan filed with the Commission by Duke Energy Progress ("DEP") and Duke Energy Carolinas ("DEC," and together "Duke Energy," "Duke" or "the Companies") on May 16, 2022, describe the revisions made by Synapse in the *Carbon-Free by 2050* report, and describe the overall impact that these revisions had on our modeling results.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE APPROACH USED TO PERFORM THE ANALYSIS IN THE *CARBON-FREE BY 2050* REPORT.

A. In preparing the *Carbon-Free by 2050* report, Synapse conducted capacity expansion and production cost modeling analysis of the combined Duke Energy system in the Carolinas to evaluate how Duke can cost-effectively meet North Carolina House Bill 951's carbon-reduction requirements while delivering power reliably. The analysis I used to develop the report relies on the same underlying EnCompass database that Duke used to develop the portfolios in its proposed carbon plan filing, with several important revisions. Specifically, my team modified several of Duke's model settings to better align with modeling best practices and we updated several inputs and assumptions to better represent current and likely future conditions. The *Carbon-Free by 2050* report explains these modifications and presents the new resource portfolios we developed based on these revisions to the model. These portfolios would achieve the required carbon reductions on time and more cost-effectively than any of Duke's proposed portfolios.

The *Carbon-Free by 2050* report includes three modeling scenarios. The *Duke Resources* scenario mimics the resource pathway identified by Duke Energy's Portfolio 1 with Alternate Fuel ("P1A") in its proposed carbon plan filing,[4] using Synapse's revised inputs to better represent costs. Synapse selected the P1A portfolio as the basis for comparison because it is the only portfolio that meets the 2030 carbon-reduction requirement while assuming that firm transportation for Appalachian gas cannot be secured. This assumption avoids the operational risk of relying on firm gas transport that may not become available, while also avoiding the risk of failure to achieve the 2030 interim requirement. The *Optimized* scenario allows EnCompass to select the most cost-effective portfolio based on these revised inputs that continues to meet carbon-reduction and reliability requirements. Finally, the *Regional Resources* scenario uses the same settings as the *Optimized* scenario, but allows EnCompass to select Midwest wind resources, procured via power purchase agreements through the PJM Interconnection ("PJM"). The report

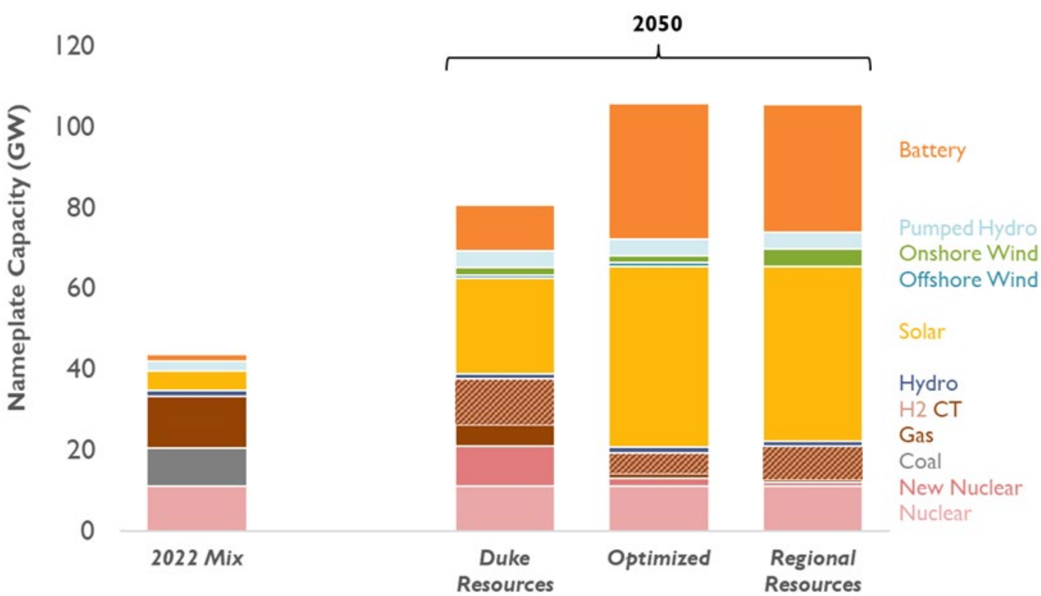
[4] Duke Energy Carolinas Carbon Plan Appendix E ("Appendix E"), p. 85.

also reviews several additional steps implemented by Duke in the development of their proposed carbon plan portfolios.

Q. PROVIDE A SUMMARY OF THE FINDINGS IN THE *CARBON-FREE BY 2050* REPORT.

A. The *Optimized* portfolio developed in EnCompass for the *Carbon-Free by 2050* report achieves HB 951's carbon-reduction requirements while delivering power reliably at a substantial savings compared to the portfolio produced by Duke Energy's $P1_A$ scenario. Figure 1, below, shows total capacity by resource type in 2022 and 2050 for each scenario modeled by Synapse.

Figure 1. Capacity by Resource Type, 2022 and 2050, by Scenario



Source: Carbon-Free by 2050 Report, p. 2.

Table 1, below, shows the net present value revenue requirements from 2022–2050 for each scenario.

Table 1. Net Present Value Revenue Requirement by Scenario

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8
2050 NPVRR ($B)	$121.2	$103.5	$98.1

Source: Carbon-Free by 2050 Report, p. 2.

Compared to the *Duke Resources* scenario, the portfolios developed by the *Optimized* and *Regional Resources* scenarios better utilize solar, storage, and energy efficiency resources through 2050, while avoiding investment in new gas, minimizing exposure to uncertain hydrogen and small modular nuclear technologies, maintaining the Companies' prescribed reserve margin, and serving 100 percent of load in all modeled hours. As a result, when compared to the *Duke Resources* portfolio, these portfolios achieve cost savings ranging from $700 million for the *Optimized* scenario and $2.4 billion for the *Regional Resources* scenario by 2030 to $17.7 billion for the *Optimized* scenario and $23.1 billion for the *Regional Resources* scenario by 2050.

II. Findings and Recommendations

Q. PLEASE SUMMARIZE YOUR FINDINGS ON ISSUES RELATED TO "MODELING—METHODOLOGY, ASSUMPTIONS, AND OTHER MODELING ISSUES."

A. My findings are as follows:

1. The Companies' capital cost projections favor gas and nuclear resources over solar and offshore wind resources when compared to reference cost forecasts;
2. Short-term differences in Synapse and Duke Energy gas price forecasts due to differences in when gas futures forecasts were

created underscore the commodity price risk to ratepayers inherent to gas-fired resources;

3. Enabling access to regional zero-carbon resources could unlock substantial savings for ratepayers;
4. Duke's transmission assumptions embedded in EnCompass constrain potential transmission solutions that could both benefit ratepayers and facilitate deployment of carbon-free energy resources;
5. Duke's analysis includes several inputs and assumptions that could lock in fossil resource investments, creating risk of noncompliance with HB 951 requirements and adding additional economic and operational risk;
6. Revised inputs used to develop the supplemental P5 and P6 portfolios only partially address faulty assumptions in Duke's modeling; and
7. Multiple issues with Duke's EnCompass data sharing process in this proceeding inhibited effective intervenor review and collaborative problem-solving.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON ISSUES RELATED TO "MODELING — METHODOLOGY, ASSUMPTIONS, AND OTHER MODELING ISSUES."

A. I recommend that the Commission direct the following steps in further Carbon Plan modeling:

1. To the extent that the Commission deems them necessary, implement reliability requirements as changes to model requirements rather than manual adjustments to model outputs;
2. Use capital cost estimates from all-source requests for proposals, where possible, and supplement with a neutral, industry-standard reference for capital cost projections for all technology types;
3. Consider purchases of cost-effective power from neighboring regions, including resources not to be owned by Duke Energy, to "shrink the challenge" of meeting net load with zero-carbon power;
4. Implement additional analyses that assess the potential benefit of additional transmission and regional coordination;
5. Make several changes to modeling inputs to avoid locking in costly legacy and fossil resources, including:
   a. a 2030 HB 951 compliance year,
   b. a 15-year or longer planning horizon,

c. a more realistic assumption about availability of "advanced" nuclear resources,
d. testing more realistic (higher) gas price forecasts,
e. more appropriate gas unit lifetimes,
f. removing "black out" years for off-shore wind, and
g. using more conservative estimates on hydrogen availability and retrofit feasibility;

6. Incorporate several modeling revisions related to the proposed changes in supplemental portfolios P5 and P6, including allowing storage in solar-plus-storage configurations to charge directly from the grid; co-optimizing carbon offsets at a higher price point (if the Commission deems inclusion of offsets appropriate), and utilization of a full-period capacity optimization.
7. Implement several changes to the Carbon Plan's EnCompass data sharing process in the future, focusing on allowing sufficient time for Duke and intervenors to build shared understanding and manage contingencies in sharing model data.

Q. PLEASE SUMMARIZE YOUR FINDINGS ON ISSUES AND RECOMMENDATIONS RELATED TO "COAL UNIT RETIREMENT SCHEDULE."

A. Duke Energy's manual adjustment of coal retirement dates lacks analytical justification and would result in additional costs to ratepayers.

I recommend that the Commission make all efforts to implement the most economic coal retirement dates for Cliffside unit 5, Marshall units 1 and 2, and Mayo unit 1, including evaluation of clean energy and zero-carbon resources to address transmission and generation concerns, in further development of a Carbon Plan.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ON ISSUES RELATED TO "NEAR-TERM PROCUREMENT ACTIVITY — SOLAR, SOLAR PLUS STORAGE, STANDALONE STORAGE, ONSHORE WIND, NATURAL GAS GENERATION."

A. I find the following:

1. The Inflation Reduction Act ("IRA") will likely impact both the inputs and outputs of resource planning analysis conducted to date in this proceeding.
2. The *Carbon-Free by 2050's* short-term action plan focuses on flexible, modular solar and storage resources to chart a cost-effective, "no-regrets" pathway that will protect ratepayers from the risks associated with fuel price spikes and speculative technologies that have not yet been commercialized. Further, this no-regrets pathway is better positioned to take advantage of the cost reductions for solar, wind, and battery storage made possible by the IRA.

In light of those findings, I recommend that the Commission's Carbon Plan avoid procurement plans that would "lock in" resource or investment pathways, and instead, that the plan capitalize on no-regrets renewable resources that are expected to decrease in cost as the IRA is implemented. Therefore, I recommend that the Commission align near-term procurement plans with the cost-effective portfolios identified by the *Optimized* and *Regional Resources* scenarios and direct the Companies to bolster their ability to interconnect solar and storage resources in the short term.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS ON ISSUES RELATED TO "EE / DSM / GRID EDGE."

A. Duke Energy's base and high energy efficiency targets are below many of its industry peers. Ratepayers could save as much as $2.9 billion through additional investment in energy efficiency.[5]

Accordingly, I recommend that further Carbon Plan modeling expand incremental efficiency savings targets to 1.5 percent of total retail

[5] Carbon Free by 2050 Report, Table 10: Net Present Revenue Requirement over Time, Energy Efficiency Sensitivities p. 27.

load and invest in utility energy efficiency programming to achieve that target.

Q. PLEASE SUMMARIZE YOUR FINDINGS ON ISSUES RELATED TO "COST."

A. The *Duke Resources* portfolio (which, as explained previously, simulates Duke Energy's P1A portfolio using Synapse's revised cost estimates) would cost ratepayers $121.2 billion on an NPVRR basis through 2050.[6] Using those same revised cost estimates, the *Optimized* and *Regional Resources* portfolios presented in the *Carbon-Free by 2050* report would cost $103.5 billion and $98.1 billion, respectively.

III. <u>Issues Related To "Modeling — Methodology, Assumptions, and Other Modeling Issues"</u>

A. Duke Energy's Post-Modeling Manual Changes to Portfolios Deviate from Best Practices and Create Costs for Ratepayers.

Q. BRIEFLY SUMMARIZE THE MANUAL CHANGES MADE BY DUKE ENERGY TO THE PORTFOLIOS INCLUDED IN ITS PROPOSED CARBON PLAN FILING.

A. Duke Energy over-rode EnCompass's ability to optimize for the most economic resource selections in three ways: First, Duke manually delayed the coal retirement dates that EnCompass identified as economically optimal. Second, it replaced several hundred megawatts ("MW") of battery storage with gas combustion turbines. And third, Duke manually added gas combustion turbines and small modular nuclear reactors based on

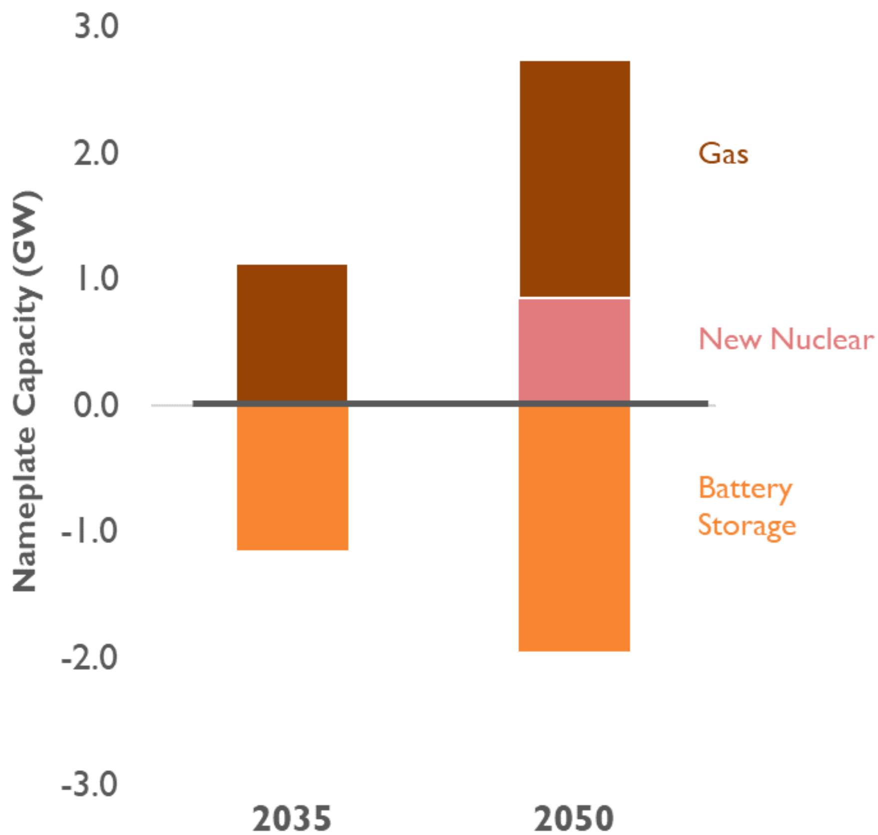
[6] By comparison, Duke reported that this portfolio (P1A) would only cost $104.1 billion.

supplemental resource adequacy analyses.[7] The resulting portfolios differ substantially from the economically optimal portfolio identified by EnCompass.

Q. WHAT WAS THE CUMULATIVE IMPACT OF THOSE CHANGES?

A. Figure 3 shows the cumulative effect of Duke Energy's changes to its EnCompass modeling results on Duke's proposed Portfolio 1.

Figure 2. Manual Changes to Duke Energy Carbon Plan Portfolio 1 through 2035 and 2050



Source: Carbon-Free by 2050 Report, p. 35.

[7] Pages 27-35 of the *Carbon-Free by 2050* report include a more comprehensive description of Duke Energy's manual adjustments.

Through 2035, Duke Energy's overrides to EnCompass cause an additional 1 gigawatt ("GW") of gas combustion turbines to be added to the system, at the expense of 1 GW of battery storage technologies. By 2050, these manual changes result in the addition of nearly 3 GW of gas and nuclear capacity, and the removal of 2 GW of battery storage capacity. These new gas plants would then need to be converted to burn 100 percent zero-carbon hydrogen, when it is not yet known whether that conversion is feasible, or what the cost will be. Any new nuclear plants would rely on technologies that are not commercially available today. For context, 2022 generation capacity across DEC and DEP is roughly 40 GW; these manual revisions represent an eighth of 2022 generating capacity.

Q. PROVIDE YOUR EVALUATION OF WHETHER THESE CHANGES ARE CONSISTENT WITH BEST PRACTICES IN RESOURCE PLANNING.

A. No, they are not. The EnCompass economic optimization algorithm works by testing thousands of potential resource portfolios and identifying which are able to meet environmental requirements (e.g., carbon limits), energy and capacity needs, and reserve margin and reliability requirements most cost-effectively. Manual changes to the resource portfolios identified by the model are, by definition, a deviation from the economically optimal portfolio identified by EnCompass and are therefore likely to result in increased costs to ratepayers. The selective nature of the Companies' manual overrides (i.e., replacing battery storage resources with gas combustion turbines and, in some cases, new nuclear resources) underscores the departure from objective, resource-neutral economic optimization. Tech

Customers[8] and the Attorney General's Office ("AGO") Strategen Report[9] similarly express concerns in their reports that Duke's manual constraints and "out of model adjustments" limit the utility of its modeling and result in non-optimal results.

Q. SUMMARIZE DUKE'S JUSTIFICATIONS FOR THESE CHANGES AND PROVIDE YOUR RESPONSE.

A. Duke Energy justifies these manual changes based on the results of several post-EnCompass analyses.[10] Duke witnesses Glen Snider, Bobby McMurry, Michael Quinto and Matt Kalemba ("Snider et al.") frame capacity expansion modeling as a "first screen"[11] and claim that the additional analytical steps taken by Duke are "necessary" for demonstrating reliability.[12]

I agree with the Duke witnesses that the capacity expansion model is not the *only* necessary tool for resource planning, but I would add that it is the best tool for identifying an economically optimal resource mix. As explained in the *Carbon-Free by 2050* report, a resource-neutral way to ensure reliability would be to change the reliability requirement

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[8] Gabel Associates (2022, July). Review of the Duke Carbon Plan and Presentation of a Preferred Portfolio. Prepared for Tech Customers ("Tech Customers Gabel Report"). Gabel report, pp. 10, 47-48.
[9] Strategen Consulting (2022). Analysis of the Duke Energy 2022 Carbon Plan. Prepared for the North Carolina Attorney General's Office ("AGO Strategen report"), pp. 8-10.
[10] Pages 30-34 of the *Carbon-Free by 2050* provide a summary of these post-EnCompass analyses.
[11] Direct Testimony of Glen Snider, Bobby McMurry, Michael Quinto and Matt Kalemba for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, p. 91, ll. 11-12.
[12] *Ibid.,* p. 197, ll. 4-6.

requirements of the capacity expansion model, rather than manipulating the outputs.[13] This could include, for example, changes to planning reserve margin levels or seasonality, proposing different effective load carrying capability ratings to different resources, or even using a more detailed daily load curve for capacity expansion modeling. Instead, the approach taken by Duke in its portfolio development departs from the resource-neutral, cost-optimal approach.

I do not agree with the Duke witnesses' assertion that the Companies' post-modeling changes are commonly understood as a necessary step in resource planning. The DEC and DEP 2020 Integrated Resource Plans ("IRPs"), for instance, do not include any "Resource Adequacy and Reliability Verification" step that incorporates additional runs of the Strategic Energy & Risk Valuation Model ("SERVM") after the capacity expansion model runs.[14] Instead, the IRPs describe, in detail, the resource adequacy study conducted by Astrapé and the selection of the 17 percent reserve margin--both of which informed the inputs to the IRPs, rather than any changes to the outputs.[15]

Duke witnesses were only able to identify one other IRP that conducted a similar analysis, which was Public Service New Mexico's

[13] *Carbon-Free by 2050* report, pp. 32-33.
[14] Duke Energy Carolinas Integrated Resource Plan 2020 Biennial Report, pp. 63-75.
[15] *Ibid.*

("PNM") 2020 IRP.[16] PNM's use of SERVM in that planning process differs from Duke's in several ways, however:

3. PNM's SERVM analysis is done at multiple levels of assumed regional coordination, rather than assuming no regional coordination;
4. PNM uses SERVM analysis of this type to characterize potential future resource adequacy issues, rather than as a justification for any manual changes to resource portfolios;
5. PNM's "No New Combustion" portfolio meets 2040 loss of load expectation standards under base-case regional imports assumptions.

Thus, the configuration, analytical function, and results of this analysis are not consistent with Duke's use of SERVM as a post-optimization portfolio editing tool.

Q. PROVIDE YOUR PERSPECTIVE ON SNIDER ET AL.'S USE OF THEIR SERVM LOSS OF LOAD EXPECTATION ANALYTICAL MODEL ON INTERVENOR PORTFOLIOS.[17]

A. As with their own portfolios, the Companies' use of SERVM in this way lacks analytical justification and departs from best practices used in other resource planning processes. It also effectively undoes the increased transparency afforded by using the EnCompass tool by introducing another "black box" into the analytical pipeline, as identified by the AGO Strategen report.[18]

Q. BASED ON THIS FINDING, WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

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[16] Snider et al., p. 95.
[17] Snider et al., pp. 202-205.
[18] AGO Strategen Report, pp. 9-10.

A. I recommend that the Commission reject the manual changes made by Duke to its portfolios because they deviate from least-cost resource planning and lack an economic or resource adequacy justification. If the Companies believe that additional reliability or resource adequacy analyses are necessary, they should implement these in advance of capacity expansion modeling (via resource adequacy studies and/or effective load carrying capability studies) and allow optimization software to choose the most economic resource pathway that meets reliability requirements. At present, the manual revisions add dependence on gas and nuclear resources with no clear benefit to ratepayers.

B. Compared to Industry-Standard References, Duke's Capital Cost Projections Tilt the Playing Field Toward Nuclear and Gas Resources.

Q. HOW DO DUKE'S COST ASSUMPTIONS COMPARE TO THOSE THAT SYNAPSE USED IN ITS *CARBON-FREE BY 2050* REPORT?

A. Duke bases its capital cost forecasts on internal and external sources, including Guidehouse for renewable and storage costs, Burns & McDonnell for thermal costs, and energy consultants and manufacturers for other resources.[19] A Duke discovery response indicates that Duke sourced the BWRX small modular nuclear reactor capital cost forecast, for example, directly from the manufacturer.[20]

[19] Duke Energy response to Public Staff Data Request 3-3. Although this response was confidential, counsel for Duke Energy confirmed that the information in the foregoing sentence could be presented in the public, unredacted version of this testimony.
[20] Duke Energy response to NCSEA-SELC Data Request 3-17.

Synapse's *Carbon-Free by 2050* uses the National Renewable Energy Laboratory's 2022 Annual Technology Baseline's ("NREL ATB") capital cost projections for solar, solar plus storage, on- and off-shore wind, and battery resources. For gas resources and small modular reactor ("SMR") nuclear units, Synapse used cost estimates from the Energy Information Administration's 2022 Annual Energy Outlook ("EIA AEO"). While the results of an all-source request for proposal ("RFP") would be the best source of market cost data in the near term, in the absence of this information, Synapse's use of publicly available, industry standard resources provides a benchmark against which to evaluate Duke's cost projections.[21]

Figure 4 shows a comparison between Synapse and Duke capital cost estimates for generation resources by technology:

[BEGIN CONFIDENTIAL]

[21] As an example, the South Carolina Public Service Commission directed Duke Energy to use NREL ATB cost forecasts in the Companies' 2020 Modified Integrated Resource Plans. *See:* South Carolina Public Service Commission Order No. 2021-447, retrieved at: https://dms.psc.sc.gov/Attachments/Order/28c909bb-889f-4095-b364-1ab8359ee799.

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Duke's capital cost projections are relatively more expensive than the NREL ATB reference for standalone solar, solar plus storage, offshore wind and 4-hour storage resources. In contrast, Duke's estimates are less expensive than the EIA AEO reference for nuclear SMRs and gas combined-cycle and combustion turbine units. To an extent, deviations across different forecasts for individual resource projections are to be expected. However, the pattern of renewable costs that are higher than industry standards and conventional fossil and steam resource costs that are lower than industry standards presents cause for concern. The Tech Customers also expressed concern with Duke's cost projections favoring gas over renewable resources.[22]

[22] Tech Customers Gabel Report, p. 8.

Q. WHAT IMPLICATIONS DID THESE CAPITAL COST ASSUMPTIONS HAVE ON DUKE'S PROPOSED PORTFOLIOS?

A. Capital cost projections drive the selection of resources based on EnCompass' economic optimization. Differences in resource costs will therefore affect which portfolio EnCompass identifies as economically optimal. And of course, capital cost assumptions affect the total projected net present value revenue requirement of each portfolio.

Q. PROVIDE YOUR RESPONSE TO DUKE'S WITNESSES' CLAIMS THAT CAPITAL COST ASSUMPTIONS USED IN THE *CARBON-FREE BY 2050* REPORT ARE INAPPROPRIATE.[23]

A. Synapse's analysis used industry-standard, publicly available capital cost projections developed by expert U.S. government researchers. For gas-fired resources, our team confirmed that our approach was consistent with the approach used by Duke for applying EIA AEO price forecasts in its own analysis.[24] We deliberately sourced our capital cost inputs to maintain transparency and neutrality in resource selection.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION WITH REGARD TO CAPITAL COST ASSUMPTIONS?

A. Given the impact of capital cost projections on modeling results and selected portfolios, utilities and regulators should ensure that cost projections are publicly available, high-quality, and neutral across resources. To achieve this, the Commission should direct Duke to issue regional, all-source RFPs for energy and capacity resources for use in

[23] Snider et al., pp. 192-197.
[24] Duke Energy Carolinas and Duke Energy Progress Response to NC Public Staff Data Request 10-3.

resource procurement and price discovery. These prices may be supplemented as needed by NREL ATB and EIA AEO for the purposes of further Carbon Plan modeling and analysis.

C. Differences in Synapse and Duke's Fuel Price Forecasts Show Inherent Commodity Price Risk Associated with Gas-Fired Resources.

Q. BRIEFLY SUMMARIZE DUKE'S METHODOLOGY FOR DEVELOPING GAS PRICE FORECASTS AND COMPARE IT TO SYNAPSE'S METHODOLOGY.

A. Duke relies on near-term gas market futures prices from NYMEX and a long-term fundamental forecast based on an average of the 2021 EIA Annual Energy Outlook and proprietary sources, including forecasts from Wood Mackenzie and IHS, and also blends projected costs of hydrogen into its price forecast.

Synapse used a forecasting methodology similar to Duke's, with the following revisions:

(i) Synapse relied on a more recent (June 2022) set of NYMEX futures prices;

(ii) Synapse used the more recent 2022 AEO instead of the 2021 AEO, and exclusively relied on the 2022 AEO instead of averaging the AEO with proprietary sources.

Q. DESCRIBE HOW THE SYNAPSE AND DUKE GAS PRICE FORECASTS DIFFER.

A. Figure 5, below, compares the short-term gas price forecasts developed based on the Synapse and Duke methodologies.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

In the short term, Synapse and Duke's gas price forecasts sharply diverge. Synapse's use of more current data reflects the impact of recent global events on gas commodity prices.

Q. WHAT IMPACT DO GAS PRICE FORECASTS HAVE ON THE RESOURCES SELECTED IN EACH PORTFOLIO AND THE COST OF EACH PORTFOLIO?

A. Lower gas prices will result in lower total production costs. Use of a lower gas price will signal to the EnCompass model that a gas plant is relatively less expensive to operate, which will drive the model to select more gas plants. Gas plants are generally less capital-intensive than renewable projects but have large operating costs, composed mostly of fuel costs, which are passed directly to customers through the fuel rider. Therefore, relying on low gas prices deflates one of the main components of the net present value of revenue requirements for gas resources. This will both (1) drive the model to build more gas plants than is economically optimal and (2) understate the likely costs associated with operating and maintaining gas plants.

Q. WHY IS IT CONCERNING THAT DUKE'S FORECAST IS SO MUCH LOWER THAN SYNAPSE'S GAS PRICE FORECAST?

A. Synapse's gas price forecast better reflects the influence of recent market factors and geopolitical events. Gas prices are inherently tied to commodity pricing dynamics, and North Carolina ratepayers' exposure to commodity price risk is directly related to the magnitude of dependence on gas fuel in Duke's portfolio. Several other intervenors shared this concern with Duke's price forecast, especially in light of recent global events that have driven up gas prices, including the Public Staff[25] and the AGO.[26]

D. Regional Wind Power Purchase Agreements Drive Substantial, Zero-Carbon Savings for Ratepayers.

Q. DID THE *CARBON-FREE BY 2050* SCENARIOS INCLUDE CONSIDERATION OF ANY RESOURCES OUTSIDE THE CAROLINAS?

A. Yes. The *Carbon-Free by 2050* report includes a *Regional Resources* scenario that allows the model to select onshore wind power purchase agreements ("PPAs") from the Midcontinent Independent System Operator ("MISO") region, transferred to Duke's territory through PJM.[27] Duke

[25] Public Staff Report, pp. 70-74.
[26] AGO Strategen Report, pp. 23-4.
[27] The *Carbon-Free by 2050* report includes additional details on modeling Midwest wind resources in Appendix A on page A-13.

criticized this assumption, claiming that the costs and transmission needs are too high to make this a feasible option.[28] In our analysis, however, even including the firm PJM border rate for these imports, EnCompass still found these PPAs to be cost-effective. Future carbon and transmission planning should draw on the North Carolina Transmission Planning Collaborative's 2021 Public Policy Study to inform transmission investments necessary to bring in low-cost Midwest wind resources.[29]

Q. HOW DOES THE AVAILABILITY OF MIDWEST WIND PPAS IN THE *REGIONAL RESOURCES* PORTFOLIO AFFECT ITS COST RELATIVE TO THE OTHER PORTFOLIOS IN THE *CARBON-FREE BY 2050* REPORT?

A. Table 3, below shows the differences in total cost for each scenario assessed in the *Carbon Free By 2050* report.

Table 2. Net Present Value Revenue Requirement, by Scenario

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8
2050 NPVRR ($B)	$121.2	$103.5	$98.1

Compared to the *Optimized* scenario, the *Regional Resources* scenario achieves incremental savings of $1.7 billion by 2030 and $5.4 billion by 2050.

Q. BASED ON THIS FINDING, WHAT IS YOUR RECOMMENDATIONS TO THE COMMISSION?

[28] Direct Testimony of Roberts and Farver, Duke Energy Carolinas and Duke Energy Progress, pp. 59-61.
[29] *See*: *Carbon-Free by 2050* report, p. 14.

A. When zero-carbon resources from outside the Carolinas are made available for selection by the model, they can provide significant cost savings to North Carolina ratepayers, on the order of billions of dollars. The Tech Customers make a similar point in their report.[30] Given that the Carbon Plan will be designed to identify the least-cost pathway to meet carbon requirements, and that regional resources have the potential to "shrink the challenge" of reducing carbon by cost-effectively reducing net load in the Carolinas, the Commission should consider these resources. I recommend that the Commission consider both firm and non-firm power purchase agreements of zero-carbon power from outside the Carolinas in developing the Carbon Plan and directing further modeling.

E. The Carbon Plan Should Consider a Range of Transmission Options to Identify Least-Cost Resource Pathways.

Q. BRIEFLY DESCRIBE TRANSMISSION ASSUMPTIONS DUKE RELIED ON IN MODELING ITS CARBON PLAN.

A. Duke's EnCompass database, which forms the foundation for each of its proposed scenarios, includes the following embedded assumptions about regional transmission and coordination from 2022 to 2050:

1. Transmission capacity between DEC and DEP is constant over the 2022-2050 planning period, with no option to expand capacity;
2. DEC and DEP are maintained as separate balancing authorities over the 2022-2050 planning period;
3. Neither DEC nor DEP is allowed to purchase or sell energy or capacity from neighboring regions over the 2022-2050 planning period;

[30] Tech Customer Gabel Report, p. 8.

4. As a result, inter-regional transmission is not modeled, and any economic improvements resulting from inter-regional transmission are not incorporated into the analysis;

5. Neither DEC nor DEP is allowed to procure resources from outside of their service areas, with the exception of onshore wind in PJM for DEC;

6. The level of capacity assistance from neighbors (for purposes of calculating planning reserve margin) is expected to be constant over the planning period; and

7. No regionalization entities or institutions, such as energy imbalance markets or regional transmission organizations, are modeled over the planning period.

The only exception to the above is the inclusion of a "Future purchase" resource in each portfolio that allows Duke Energy to economically purchase zero-carbon power in the final years of each planning portfolio.[31]

Q. WHAT ARE THE IMPLICATIONS OF THESE EMBEDDED ASSUMPTIONS ON THE PORTFOLIOS PRODUCED BY DUKE?

A. Duke's reliance on a static transmission configuration in its EnCompass modeling, and its decision not to evaluate transmission sensitivities or alternatives, means that the Companies did not assess the cost, reliability, operational, or carbon impacts of any of the potential transmission developments enumerated above. By omitting consideration of these transmission options, Duke's proposed carbon plan filing artificially constrains the resource pathways and solutions available to meet HB 951 requirements.

[31] Duke Energy (2022). Carolinas Carbon Plan Modeling Analysis Overview. Docket No. E-100 Sub 179.

Q. IS THIS APPROACH CONSISTENT WITH LEAST-COST RESOURCE PLANNING?

A. No, especially in the context of long-term decarbonization planning. High-quality studies of power sector decarbonization consistently underscore the critical role of transmission in bolstering resource adequacy and enabling delivery of high-quality solar and wind resources to serve load.[32] The Tech Customers share our concerns with Duke's static approach, stating that "Duke did not engage in a holistic portfolio and scenario-based planning process or optimize its transmission strategy to address public policy and reliability needs. Instead, each transmission and interconnection investment category was developed piecemeal and integrated into Duke's proposed carbon plan."[33]

Duke tacitly acknowledges the problems with such an approach by including "Future Purchase" resources, which come from outside the region, in its portfolios in the final years of its carbon plan. This reflects the critical role that regional transactions can play in reliably and cost-effectively operating a low- and zero-carbon grid.

Q. BASED ON THIS FINDING, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. The Commission should ensure that carbon planning includes consideration of all reasonable transmission and regional coordination

[32] *See:* Princeton Net Zero America study (2020); MIT Value of Inter-regional Coordination study (2021); Electric Power Research Institute Powering Decarbonization: Strategies for Net-Zero CO2 emissions (2021); and NREL Seams Study (2017).
[33] Tech Customers Gabel report, p. 15.

options that could be part of a least-cost plan for ratepayers. To the extent that the Commission deems that a distinct process from integrated resource planning is required (and that the existing public policy request function of the North Carolina Transmission Planning Collaborative is unable to fulfill this role), the Commission should initiate a new proceeding for pursuing long-term, prospective regional transmission planning and consideration of regional coordination. In any case, consideration of options in this proceeding should include a wide set of transmission and coordination alternatives, rather than being constrained by a single set of assumptions embedded in the EnCompass model.

F. Long-Term Planning Should Avoid Path Dependence and Lock-In Risks.

Q. BRIEFLY INTRODUCE THE CONCEPT OF PATH DEPENDENCE AS IT RELATES TO RESOURCE PLANNING.

A. Path dependence is a concept where past events constrain the set of solutions or decisions that are available in the future.[34] A similar term, "lock-in," describes previous events or decisions that commit an entity to future actions based on a past decision.

Given the multi-decade lifetimes of most generation resources, path dependence is a consistent feature of electricity resource planning. Historically, alternative generation options were not competitive, and load

[34] Liebowitz, S., & Margolis, S. (1995, April). Path Dependence, Lock-In, and History. *Journal of Law, Economics, and Organization, pp. 205-226.* Retrieved at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=1706450.

and consumer growth were relatively consistent.[35] But with renewable and storage costs falling, slow load growth and electrification adding uncertainty to load forecasts, and states and utilities adopting decarbonization trajectories, path dependence presents an increasing risk to ratepayers and to compliance with carbon reduction requirements. For example, near-term investments in carbon-emitting resources can preclude the ability to invest in cost-effective renewable resources. Investments in long-lived fossil infrastructure can also lock a power system into a certain level of carbon emissions for the lifetime of the resource, called "committed emissions."[36]

To avoid risks arising from path dependence and lock-in, utilities should prioritize least-regrets resource decisions in the short term, while minimizing or deferring decisions that would commit the utility to a given pathway in the face of uncertain planning constructs, policies, and costs.[37]

Q. HOW DOES CAPACITY EXPANSION MODELING ASSESS THE RISK ASSOCIATED WITH LOCKING IN SPECIFIC RESOURCES, SPECIFICALLY FOSSIL RESOURCES?

A. There is no single model output that can indicate the level of path dependence of one portfolio versus another. The best way to assess the

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[35] Weston, F. (2009, May). Integrated Resource Planning: History and Principles. *The Regulatory Assistance Project.* Retrieved at: https://www.raponline.org/wp-content/uploads/2016/05/rap-weston-integratedresourceplanningoverview-2009-05-20.pdf.

[36] Shearer, C., Tong, D., Fofrich, R., Davis, S. (2020, September). Committed Emissions of the U.S. Power Sector, 2000-2018. AGU Advances. Retrieved at: https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2020AV000162.

[37] *See:* Northern States Power Company (2020). Upper Midwest Integrated Resource Plan, 2020-2034. p. 90. Retrieved at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/The-Resource-Plan-No-Appendices.pdf.

lock-in risk of a portfolio or a resource is to run sensitivities—that is, to see how it performs when you change a series of key inputs and assumptions (for example, higher or lower gas prices, the cost of alternatives) and then assess the results. If, for example, the decision to lock in a resource is favorable under only a narrow set of conditions and will incur high costs for ratepayers under many other likely conditions, then there is a high risk associated with locking in that resource. On the flip side, if a resource is found to perform well under a wide range of assumptions, then it is less likely to lock ratepayers into otherwise avoidable costs.

Q. DESCRIBE ANY PATH DEPENDENCE RISKS THAT YOU HAVE IDENTIFIED IN DUKE'S PROPOSED CARBON PLAN ENCOMPASS ANALYSIS AND FILING.

A. I observe the following path dependence risk factors in Duke's proposed carbon plan filing:

1. **Delay in projected achievement of HB 951's 70 percent carbon reduction requirement.** Several portfolios in Duke's carbon plan filing delay meeting HB 951's carbon reduction requirement, doing so in 2032 or 2034 instead of 2030. This reduces flexibility if unforeseen delays occur and increases the risk of noncompliance with HB 951's carbon reduction requirements.

2. **Short planning horizon.** Duke divided the planning horizon in its EnCompass modeling into a series of 8-year segments and a final 5-year segment (i.e., 2022-2029, 2030-2037, 2038-2045, and 2046-

2050),[38] Given the multi-decade transition contemplated in this proceeding, an eight-year horizon is a short-term approach that will not integrate long-term planning dynamics, including carbon reduction requirements.

3. **Continued investment in gas plants.** Duke plans to continue investing in gas plants, on the assumptions that (1) low-cost Appalachian gas will be available to supply existing and new combined-cycle plants ("CCs"); and (2) it will be economic in the future to convert and operate combustion turbines on hydrogen. But both are high risk assumptions: The first assumption carries risk because the pipeline necessary to supply Appalachian gas is not yet completed.[39] Without the completed pipeline, Duke may not have access to sufficient firm gas capacity to fuel its CCs, as the AGO notes in the Strategen report.[40] The second assumption is risky because it presumes that retrofits will be technically feasible and cost-effective and requires hydrogen to be available at the price and quantity needed to compete with other fuels. In the event that technical issues prevent cost-effective turbine conversion or a sufficient supply of zero-carbon hydrogen is not available, existing and planned gas plants risk becoming obsolete, and the burden of paying off these stranded

[38] Pages B-15 and B-16 of Appendix B of the *Carbon-Free by 2050* report contain more information on Duke Energy and Synapse EnCompass planning horizons.
[39] Snider et al., p. 178.
[40] AGO Strategen Report, p. 26.

assets will fall on either shareholders or Duke ratepayers. Other intervenors expressed concern about the risks of Duke planning its system around hydrogen, including the Public Staff[41] and the AGO.[42]

4. **Concurrent construction of non-commercial nuclear technologies.** Duke's proposed portfolios include up to 21 new advanced and small modular nuclear reactors to be built between 2033 and 2050. This schedule would require, on average, construction of just over one new unit per year and would entail concurrent construction on multiple units before the first unit has successfully achieved operation.[43] Concurrent development of these uncertain, not-yet-commercialized resources could lock in additional costs for ratepayers in the event of cost over-runs or operational problems. Synapse is not alone in its concerns around small modular nuclear reactors: the Tech Customers also express similar concerns around locking customers in to speculative technologies.[44]

Q. BRIEFLY DESCRIBE HOW THE *CARBON-FREE BY 2050* SCENARIOS AVOID PATH DEPENDENCY RISKS.

A. The *Carbon-Free by 2050* EnCompass analysis employs the following inputs and parameters to avoid path dependency risks:

[41] Comments of the Public Staff ("Comments of the Public Staff") (2022, July). North Carolina Utilities Commission. Docket No. E-100, Sub 179, pp. 95-96.
[42] AGO Strategen Report, p. 30.
[43] Pages A-11 and A-12 of Appendix A of the *Carbon-Free by 2050* report contain additional discussion of Duke Energy's nuclear availability settings.
[44] Tech Customer Gabel, p. 58.

5. **2030 achievement date for 70 percent reduction requirement.** This approach maintains the HB 951's default deadline for achievement of the 70 percent carbon reduction and allows for flexibility in later planning proceedings in the event that the Commission determines that a delay is warranted.

6. **15-year planning horizon.** Synapse's EnCompass analysis uses a 15-year planning horizon, which strikes an appropriate balance between computational complexity and integrating long-run portfolio requirements, such as carbon reduction requirements.

7. **Adjusted lifetime and hydrogen assumptions for gas-fired resources.** EnCompass analysis in the *Carbon-Free by 2050* report allows existing gas units to be retired if it is more economic to do so, rather than be converted to 100 percent hydrogen combustion. Newly constructed gas-fired resources are assumed to have an operating life of 25 years and a depreciation lifetime of 20 years in order to avoid stranded asset risk as carbon requirements decline toward zero by 2050.

8. **National reference cost and less ambitious deployment timeline for non-commercial nuclear technologies.** The *Carbon-Free by 2050* report uses national reference costs and anticipates a less ambitious deployment timeline for new nuclear resources to maintain a conservative approach to cost assumptions for projects with a high amount of uncertainty, allow for learning by doing, and avoid lock-in.

Q. AFTER ACCOUNTING FOR PATH DEPENDENCE RISKS, WHAT SELECTIONS DID ENCOMPASS ECONOMIC OPTIMIZATION MAKE IN THE *CARBON-FREE BY 2050* PORTFOLIOS?

A. In the scenarios where EnCompass was allowed to economically optimize resources in the *Carbon-Free by 2050* report, the model did not select any additional gas-fired resources and opted for the retirement of some gas-fired units, rather than conversion to 100 percent hydrogen combustion.[45] The *Regional Resources* scenario did not reach the 4-unit availability limit set for additional nuclear resources.[46]

Q. BRIEFLY SUMMARIZE DUKE'S DISCUSSION OF "OUTCOME-ORIENTED ASSUMPTIONS" AND PROVIDE YOUR RESPONSE.

A. Duke Energy witnesses Snider et al. claim several times in testimony that certain inputs to the *Carbon-Free by 2050* analysis are "outcome-oriented."[47] In a sense, this description is correct: The assumptions developed for the *Carbon-Free by 2050* analysis are designed to approximate present and projected future conditions, with the intended outcome of producing a portfolio that provides cost-effective, reliable power for North Carolina ratepayers while meeting HB 951's carbon-reduction requirements. This is the outcome that resource planning is designed to produce, and, while Duke witnesses may disagree with the empirical or analytical justification for these assumptions, the implication that the

[45] See Section 3 of the *Carbon-Free by 2050* report.
[46] See Page C-3 of the *Carbon-Free by 2050* report, Appendix C.
[47] Snider et al., p. 185-195.

Carbon-Free by 2050 assumptions are intended to produce something other than cost-effective, reliable, and sustainable power is not accurate.

As an example, the *Carbon-Free by 2050* assumption of a 25-year operating lifetime and 20-year depreciation lifetime for gas-fired resources is not intended to produce a specific resource outcome, but instead is based on basic risk management principles. Carbon emissions associated with these resources are regulated by HB 951, which requires that emissions reach zero by 2050. If the technology and infrastructure to decarbonize these resources (i.e., zero-carbon hydrogen supply and transport) does not develop as contemplated in Duke Energy's carbon plan filing, these conservative lifetime assumptions minimize stranded asset risk for Duke and its ratepayers.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION RELATED TO PATH DEPENDENCE?

A. Given the potential negative impacts of path dependence in the context of the Carbon Plan and the numerous risks arising from path dependence in Duke's proposal, the Commission should incorporate several revisions into future Carbon Plan modeling to reduce the risks associated with high path dependence. These include:

1. Lengthening the optimization horizon for capacity expansion analysis;
2. Maintaining a 2030 achievement date for achieving the 70 percent carbon reduction requirement, and applying reasonable lifetime assumptions to new-construction gas-fired units;

3. Placing stringent limits on the assumed supply of zero-carbon hydrogen and the technical and cost feasibility of hydrogen retrofits; and
4. Maintaining conservative cost and availability assumptions for new nuclear units.

G. Duke's Supplemental P5 and P6 Portfolios Do Not Adequately Address Modeling Issues Associated with Duke's Proposed Portfolios.

Q. HAVE YOU REVIEWED THE P5 AND P6 PORTFOLIOS THAT DUKE DESCRIBED IN ITS FILING TO THE COMMISSION ON JULY 28,[48] THE RESULTS OF WHICH WERE INCLUDED IN DUKE'S AUGUST 19 TESTIMONY?

A. Given the importance of an in-depth understanding of modeling results and the short time period for intervenors to review the P5 and P6 results, I did not perform a detailed review of the process of modeling those scenarios or of the resulting portfolios for this testimony. However, I did review the revisions to model inputs for the P5 and P6 scenarios.

Q. DO THESE REVISIONS CORRECT THE MODELING ISSUES IDENTIFIED IN THIS TESTIMONY AND THE *CARBON-FREE BY 2050* REPORT?

A. No. Table 4, below, shows issues that were improved or not improved by selected P5 and P6 revisions to model inputs.

[48] Duke Energy filing Re: Development of Supplemental Modeling Portfolios, Docket No. E-100 Sub 179. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=c60326e0-4390-46ef-9b92-0face09a187b.

Table 3. Evaluation of Selected Changes Present in Duke Energy Supplemental Portfolios 5 and 6

#	Model Change	Improvement to Carbon Plan modeling?	Explanation / Comments
1	Delay of HB 951 compliance date	No	Delay of HB 951 compliance date exacerbates risk of non-compliance
3	Dynamic dispatch of solar plus storage	Yes	More precise simulation of solar plus storage capabilities; IRA may impact battery charging requirements
4	Remove cumulative limits on 4- and 6-hour batteries	Yes	Deployment limits distort final results
5	Remove H_2 blending with gas	Yes	Insufficient support for sufficient zero-carbon hydrogen; Duke Energy's offset and hydrogen-fueled combustion turbine approach is not appropriate
6	Model solar as PPA for 45%	Yes	More precise estimate of solar costs
7	Low energy efficiency case	No	Higher level of energy efficiency is achievable and lowers total system cost
8	Remove access to Appalachian gas	Yes	Better reflects real-world conditions
13	Validate selection of gas plants through a full-period capacity expansion optimization	Yes	Still necessary, even with changes to hydrogen treatment

Q. PROVIDE ADDITIONAL COMMENTS ON ITEM 3 ("DYNAMIC DISPATCH OF SOLAR PLUS STORAGE") FROM THE TABLE ABOVE.

A. I generally agree with the Public Staff's finding that Duke's fixed-dispatch treatment of solar plus storage resources is an imprecise method for modeling the contribution of these resources, and that dynamic dispatch would provide additional insight.[49] While I relied on Duke's fixed solar-plus-storage dispatch curves in the *Carbon-Free by 2050* report for consistency with Duke's method, I support the Public Staff's recommendation to model dynamic dispatch for these resources.

I also agree with Public Staff's perspective that storage resources deployed in a solar-plus-storage configuration should have the capability of charging directly from the grid.[50] Changes to clean energy tax credits resulting from the IRA will further ease configuration requirements and further support grid charging.

Q. PROVIDE ADDITIONAL COMMENTS ON ITEM 5 ("REMOVE H_2 BLENDING WITH GAS") FROM THE TABLE ABOVE.

A. While I think it is appropriate to apply a skeptical eye toward hydrogen supply assumptions, Duke's implementation of this revision is contradictory. Duke's proposed implementation details for Item 5 indicate, for example, that hydrogen turbines would be removed as an option, but that combustion turbines built after 2040 could operate on 100 percent

[49] Comments of the Public Staff, Duke Energy Progress, LLC and Duke Energy Carolinas, LLC 2022 Carbon Plan, Docket No. E-100, Sub 179. July 16, 2022. P. 119-126.
[50] Comments of the Public Staff, pp. 123-124.

hydrogen.[51] These assumptions apply conflicting expectations of hydrogen availability and therefore have limited analytical value. I recommend that, in addition to a scenario without any zero-carbon hydrogen availability, the Commission direct modeling of a hydrogen scenario with very low availability (maximum 5 percent capacity factor for all hydrogen-fueled units), no option for hydrogen conversion, and conservative hydrogen cost assumptions.

Duke also discusses a different treatment of carbon emissions in its implementation details for Item 5 that is not aligned with resource planning best practices. The availability and price of carbon offsets in 2050 is uncertain, and these costs should be included alongside other relevant costs for economic optimization. I recommend that any further modeling not assume any supply of carbon offsets in the portfolio's final years. To the extent that the model is allowed to select carbon offsets, the model should include multiple price levels, including a high offset level of $250 per ton or greater, and they should be integrated into economic optimization.

Q. PROVIDE ADDITIONAL COMMENTS ON ITEM 7 ("LOW ENERGY EFFICIENCY CASE") FROM THE TABLE ABOVE.

A. As discussed previously, and as explained in detail in the *Carbon-Free by 2050* report, energy efficiency is a cost-effective resource for Duke ratepayers, and Duke should expand, rather than reduce, the impact of

[51] Duke Energy filing Re: Development of Supplemental Modeling Portfolios, Docket No. E-100 Sub 179. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=c60326e0-4390-46ef-9b92-0face09a187b.

energy efficiency. I also recommend that the Commission decline to use the low EE case for planning purposes.

Q. PROVIDE ADDITIONAL COMMENTS ON ITEM 13 ("VALIDATE SELECTION OF GAS PLANTS THROUGH A FULL-PERIOD CAPACITY EXPANSION OPTIMIZATION") FROM THE TABLE ABOVE.

A. I do not agree with Duke's statement that its treatment of hydrogen fuel renders full-period optimization capacity expansion unnecessary. Even without hydrogen conversion, carbon requirements are expected to put pressure on gas resources to lower emissions rates, which will drive down capacity factors over time. Resources with lower utilization and higher costs are less attractive in an economic optimization and will be less likely to be selected by the EnCompass model. With a short optimization period, the model may not see the falling utilization and rising costs as it makes its near-term resource planning decisions. I therefore recommend that the Commission direct the Company to include a full-period capacity expansion optimization.

Q. BASED ON YOUR REVIEW OF PROPOSED PORTFOLIOS P5 AND P6, DO YOU HAVE A RECOMMENDATION TO THE COMMISSION?

A. I recommend that further modeling directed by the Commission implement items number 4, 6, and 8 in Table 4, above. Additionally, I make the following recommendations to the Commission on developing its Carbon Plan and further Carbon Plan modeling:

1. Allow storage deployed alongside solar to charge directly from the grid;

2. In scenarios that include carbon offsets or allowance costs, they should be modeled at multiple price levels and included as a relevant cost in capacity expansion optimization; and

3. Include a full-period capacity expansion optimization.

H. The 2022 Carbon Plan Modeling Process Did Not Facilitate Shared Understanding or Collaboration Across Stakeholders.

Q. WHAT ARE THE BENEFITS OF COLLABORATIVE MODELING AND ANALYSIS IN RESOURCE PLANNING PROCEEDINGS?

A. Collaborative modeling can build a shared analytical foundation (i.e., understanding of the modeling tools) for evaluating future resource needs and potential resources available to meet those needs. When multiple parties share this analytical foundation, they can craft robust solutions together and find areas of agreement. Collaborative problem solving, however, requires a commitment to sharing lessons learned and findings, maintaining transparency and problem-solving on the part of all participants.

Modeling tools that are common across stakeholders (such as EnCompass in this proceeding) are valuable assets for collaboration and problem-solving because they facilitate organization and sharing of vast amounts of information and clarify the analytical approach to many of the thorny issues present in resource planning. With the support of a well-defined and resourced collaboration process, EnCompass could form the backbone of effective collaboration and shared problem-solving.

Q. PLEASE IDENTIFY ANY BARRIERS TO EFFECTIVE COLLABORATION YOU OBSERVED IN THE COURSE OF YOUR WORK IN THIS PROCEEDING.

A. The Synapse team encountered several barriers in its review and analysis of the EnCompass database shared by Duke in this proceeding.[52] These barriers included the following:

1. The data files were not properly transferred to intervenors by Duke, which caused initial model runs to fail and delayed the start of our modeling analysis.
2. There were inconsistencies between database inputs and provided outputs that led to substantial delays in EnCompass modeling and prevented intervenors from validating Duke's results;[53]
3. Key data inputs were functionally impossible to parse without additional input spreadsheets from Duke, which were only provided through discovery; and
4. Duke conducted additional modeling steps outside of EnCompass. Other parties were not able to reproduce this analysis without additional licensed software (for which Synapse did not have a license) and Duke did not provide a detailed explanation of how the analysis was conducted.

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[52] These barriers are discussed in detail in Appendix B of the *Carbon-Free by 2050* report.

[53] Duke Energy (2022, June). EnCompass Input Data: Declining Cost Adder Issue and Resolution. Docket No. E-100 Sub 179.

Q. ARE YOU AWARE OF ANY OTHER PARTIES THAT ENCOUNTERED ISSUES WITH DUKE'S ENCOMPASS DATABASE?

A. Yes. The Public Staff described encountering similar issues in their comments to the Commission in this proceeding.[54] These issues ultimately prevented the Public Staff from submitting its own proposed carbon plan in this proceeding.

Q. ARE YOU AWARE OF OTHER PROCEEDINGS WHERE ENCOMPASS COLLABORATION AND VALIDATION HAS OCCURRED SUCCESSFULLY?

A. Yes. It is my understanding that utilities and stakeholders successfully shared and validated resource planning model data in proceedings with Xcel in Colorado, Xcel in Minnesota, and Duke Energy in Indiana.

Q. PROVIDE YOUR RECOMMENDATIONS TO THE COMMISSION ON FACILITATING MORE EFFECTIVE COLLABORATION IN FUTURE CARBON PLAN AND RESOURCE PLANNING MODELING PROCESSES.

A. I provide the following recommendations:

1. **Longer collaboration process, including sharing of all data during plan development.** Model review, sharing, and validation is an effort- and time-intensive undertaking, and the results of this proceeding show how just a few validation issues can seriously impact stakeholders' ability to provide additional insight to the Commission. EnCompass collaboration should include the sharing of contemporary model data at the outset of the process and occur over a longer

[54] Comments of the Public Staff. p. 36-37.

timescale. This would allow parties to have substantive conversations about model inputs and methodology and avoid validation issues.

2. **Higher transparency for model inputs.** For model inputs that are not transparently derived from public sources, the utility should provide the derivation of these inputs proactively, rather than through the discovery process.

3. **Transparency for out-of-model resource planning steps.** To the extent that the Commission finds the use of out-of-model planning steps appropriate, the utility should take all necessary steps to render the inputs, methodology, and outputs of those steps transparent for collaborators.

IV. Issues related to "Coal Unit Retirement Schedule"

I. Duke Energy's Coal Retirement Methodology Delayed Coal Retirement Dates Without Adequate Justification and at a Cost to Ratepayers.

Q. BRIEFLY SUMMARIZE DUKE'S COAL RETIREMENT METHODOLOGY AS IMPLEMENTED IN ITS PROPOSED CARBON PLAN FILING.

A. In developing its proposed carbon plan, Duke used a multi-step process for selecting coal unit retirement dates. First, it conducted capacity expansion runs with fixed retirement dates to establish projected capital investments and operations and maintenance costs for each unit. It used those cost projections in a run that allowed EnCompass to economically retire its coal units. After EnCompass selected the most economic retirement dates for the coal fleet, Duke manually delayed the retirement year for several of its coal units.[55] Table 5, below, shows the economic retirement year identified by Duke's EnCompass run and the retirement year proposed by Duke for each of its coal units.

Table 4. Duke Coal Units, Modeled and Proposed Retirement Dates

Unit	Super- or Sub-Critical	Construction Year	Winter Capacity (MW)	Economic Retirement Year	Proposed Retirement Year
Belews Creek 1	Super	1974	1,110	2030	2036
Belews Creek 2	Super	1974	1,110	2030	2036
Cliffside 5	Sub	1972	546	2026	2026
Marshall 1	Sub	1965	380	2026	2029
Marshall 2	Sub	1966	380	2026	2029
Marshall 3	Super	1969	658	2034	2033
Marshall 4	Super	1970	660	2034	2033
Mayo 1	Sub	1983	713	2026	2029
Roxboro 1	Sub	1966	380	2029	2029
Roxboro 2	Sub	1966	673	2029	2029
Roxboro 3	Sub	1973	689	2030	2028-2034
Roxboro 4	Sub	1980	711	2030	2028-2034

Source: Carbon-Free by 2050, Appendix D. Proposed retirement dates are from Duke Energy Portfolio 1.[56]

Q. IS THIS METHODOLOGY CONSISTENT WITH LEAST-COST RESOURCE PLANNING?

A. No. When EnCompass retires any existing unit, it does so because the energy and capacity provided by that unit could more economically be provided by other resources. Stated another way, the costs to operate the unit exceed the value of the energy and capacity it provides. In short, EnCompass identified coal units for retirement on the schedule it did

[55] Pages 28-29 of the *Carbon-Free by 2050* report contain a summary of Duke Energy's coal retirement methodology.

[56] Although the information in Table 5 was derived in part from confidential data, counsel for Duke Energy confirmed that Table 5 could be presented in the public, unredacted version of this testimony.

because continuing to operate them was more expensive for ratepayers than retiring them. The manual delays implemented by Duke keep these units online, at ratepayers' expense. Moreover, in almost all cases Duke's proposed retirement dates are years later than the "Earliest Practicable" retirement years identified in the Companies' 2020 IRPs.[57] Maintaining these units past their economic retirement dates could cost Duke ratepayers $1.4 billion, before accounting for fuel costs, variable operations & maintenance costs, or lost securitization benefits.[58] Duke challenges our estimates of the costs required to sustain its coal plants, stating that my analysis overstates the costs by $1 billion.[59] But Duke has not justified its low cost assumptions, which could be proven wrong in the future. If actual future fixed operations and maintenance plus ongoing capital costs exceed Duke's projections, ratepayers could end up shouldering the cost premium, absent a disallowance. My use of a projection based on actual incurred costs, rather than a hypothetical schedule with no built-in accountability mechanism, provides a reasonable and transparent basis for estimating these costs.

Q. DUKE ASSERTS THAT THE MANUAL DELAYS TO COAL RETIREMENTS WERE NECESSARY TO MAINTAIN RELIABILITY. HOW DO YOU RESPOND?

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[57] *See:* Duke Energy Carolinas Integrated Resource Plan 2020 Biennial Report, p. 175; and Duke Energy Progress Integrated Resource Plan 2020 Biennial Report, p. 174.
[58] *Carbon-Free by 2050*, p. 29.
[59] Snider et al., pp 141-143.

A. There may be power supply and reliability concerns with retiring coal capacity, which may require the development of replacement generation and transmission resources to provide the same energy, capacity, and ancillary services previously provided by the retiring coal units. Modeling specific power flow requirements is not a suitable task for a resource planning tool like EnCompass, and is better understood through power flow modeling and approximated in EnCompass using earliest possible retirement dates. The "Earliest Practicable" retirement dates developed at the direction of the Commission for the Companies' 2020 IRPs were designed to accommodate construction of replacement resources. Almost all of Duke's manual adjustments in this case extend for years beyond those "Earliest Practicable" dates, however, without sufficient justification for why these extensions are necessary.

Duke witnesses Roberts and Farver contend that Duke Energy's justifications for the manual delays are sufficiently detailed, but their discussion of specific unit retirements continues to rely on high-level assumptions rather than detailed requirements and timelines.[60] For example, witnesses Roberts and Farver repeat Duke's assertion in its proposed carbon plan that "Belews Creek units will continue to operate into the 2030s" and state that Duke has not yet evaluated requirements for retirement of these units: "DEC plans to evaluate transmission upgrades to

[60] Testimony of Duke Energy Witnesses Roberts and Farver, Docket No. E-100 Sub 179 ("Roberts and Farver"), p. 52-55.p

enable retirements as the planned retirement approaches."[61] This approach is opposed to the more appropriate approach of allowing EnCompass optimization to identify the most cost-effective retirement dates for these units.

Q. DESCRIBE ANY REVISIONS TO THE COAL UNIT RETIREMENT DATES YOU IMPLEMENTED IN THE *CARBON-FREE BY 2050* SCENARIOS.

A. In the *Optimized* and *Regional Resources* scenarios, Synapse allowed Duke's coal units to be retired at the economic date identified by EnCompass, with no additional delay to retirement.[62]

Q. HOW DID THESE REVISIONS IMPACT THE RESULTS OF THE *CARBON-FREE BY 2050 SCENARIOS?*

A. Table 6, below, shows the coal retirement dates selected by EnCompass in the *Optimized* and *Regional Resources* scenarios compared to the *Duke Resources* scenario.

Table 5. Retirement Year for Selected Coal Units by Scenario

Coal Unit	Capacity (MW)	Retirement Year		
		Duke Resources	*Optimized*	*Regional Resources*
Belews Creek 1-2	2,220	2036	2034	2030
Cliffside 5	546	2026	2023	2023
Marshall 1-2	760	2028	2026	2026
Marshall 3-4	1,318	2032	2032	2032
Mayo 1	713	2028	2028	2028
Roxboro 1-2	1,053	2028	2028	2028
Roxboro 3-4	1,400	2027	2027	2027

[61] Roberts and Farver, p. 53, ll. 14-16.
[62] *Carbon-Free by 2050*, pp. 12-13, 18-19.

Source: Carbon-Free by 2050, p. 17-18.

Even without building incremental gas combustion turbine or combined-cycle resources, we find that accelerating retirement of coal units compared to Duke's proposal is still in the best interest of ratepayers.[63]

Q. IS RELIABILITY MAINTAINED IN THE SYNAPSE SCENARIOS, EVEN WITH THE ACCELERATED RETIREMENT OF SOME UNITS COMPARED TO *DUKE RESOURCES*?

A. Yes. Even after implementing the retirements identified above, the *Optimized* and *Regional Resources* portfolios continue to meet reserve margin requirements every month and meet 100 percent load in all hours modeled in production cost modeling.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH REGARD TO COAL RETIREMENTS?

A. First, the Commission's Carbon Plan should adopt the economic retirement schedule identified by EnCompass rather than delayed retirement dates. For retirement years that the Companies claim are not operationally feasible, the Companies should provide compelling justification of the transmission and generation requirements, provide an explanation as to why procurement and development of alternative resources is not feasible in the given timeframe, and develop a proposed timeline for developing these resources and retiring these units as early as practicable.

Second, the Commission should direct the Companies to begin preparations for the retirement of coal units with economic retirement years

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[63] *Carbon-Free by 2050,* pp. 18-19.

identified in the next six years. According to Duke's retirement analysis, these include Cliffside unit 5, Marshall units 1 and 2 and Mayo unit 1. For each of these units, Duke should specifically identify the transmission and generation requirements for retiring these units and make preparations for procuring and developing resources to address those requirements via all-source procurement.

Third, for the remaining coal units, the Companies should continue to use endogenous coal retirement analysis to assess the economic position of these units. The Commission should direct the Companies to develop specific generation or transmission resource requirements required for the retirement of these units to ensure expeditious retirement in the future.

V. <u>Issues related to "Near-Term procurement activity — solar, solar plus storage, standalone storage, onshore wind, natural gas generation"</u>

A. The Carbon-Free by 2050 Scenarios Provide a Roadmap to Near-Term Procurement in the Best Interest of Ratepayers.

Q. PROVIDE THE SHORT-TERM RECOMMENDATIONS THAT ARE INCLUDED IN THE *CARBON-FREE BY 2050* REPORT.

A. Table 9, below, presents recommendations to the Commission for short-term actions to reliably meet North Carolina's carbon reduction requirements at least cost.

Table 6. Carbon-Free by 2050 Short-Term Recommendations

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2030		

Energy Efficiency	1.5 percent of retail load	• Expand utility energy efficiency savings targets to 1.5 percent of total retail load
Distributed Energy Resources	At least 1 GW by 2035	• Develop and support programs to empower customer-owned energy resources to accelerate contribution to grid needs
Additional Solar	7,200 MW	• Invest in transmission projects to unlock additional cost-effective solar power • Begin procurement of 4 GW of new solar 2022-2024 with target in-service dates of 2025-2028 • Develop interconnection methods that will be robust long-term
Battery Storage	5,600 MW	• Begin procurement for 4 GW of stand-alone storage with target in-service dates of 2025-2028 • Invest in operational capabilities for capitalizing on energy storage resources for grid services
Onshore Wind *(in-state)*	900 MW	• Engage with communities on onshore wind siting • Prepare for continued advancement of onshore wind, long-term
Onshore Wind *(Midwest)*	2,500 MW	• Engage in inter-regional coordination with PJM for facilitating power purchase • Integrate Midwest wind import into short-term transmission planning
Offshore Wind	800 MW	• Initiate development and permitting activities for 800 MW (or larger tranches if more cost-effective), with eye toward potential additional procurement long-term
Proposed Resource Selections: Options for Long-Term Cost-Effective Carbon Reductions		
Coal Retirement	--	• Develop retirement plans for coal units consistent with economic optimization
Transmission Planning	--	• Develop processes for long-term, prospective and regional transmission planning that can cost-effectively meet economic and carbon reduction requirements of HB 951
Pumped Storage Hydro	1,700 MW	• Conduct feasibility study, develop EPC strategy, and apply at FERC for re-licensing
Hydrogen Planning	--	• Develop more detailed hydrogen fuel cost planning methodology • Conduct studies of hydrogen transport, storage, and distribution • Integrate cost of production and distribution into resource planning

Source: Carbon-Free by 2050 report, p. 4-5.

I summarize the conclusions and recommendations of the *Carbon-Free by 2050* report on pages 4-5 and 43-45 of the *Carbon-Free by 2050* report.

B. The Inflation Reduction Act Underscores the Need for Near-Term Flexibility.

Q. ARE THERE ANY DEVELOPMENTS SINCE THE ISSUANCE OF THE *CARBON-FREE BY 2050* REPORT THAT MIGHT AFFECT LEAST-COST PLANNING TO MEET CARBON REQUIREMENTS?

A. Yes. The passage of the federal Inflation Reduction Act ("IRA") on August 16, 2022 has "major implications" for power generation in the United States,[64] and the IRA's tax incentive and electrification provisions would directly impact many of the factors that are used as inputs into capacity expansion analysis in this proceeding. A detailed review of the IRA is beyond the scope of this testimony, but based on my current understanding of the IRA's provisions and analyses of the impacts of the Act on the power sector,[65] I anticipate wide-ranging impacts on Carbon Plan analysis which are not fully incorporated into Duke's proposed carbon plan filing, the

[64] Proctor, D. (2022, August 12). "Renewable Energy, Electrification Big Winners in Inflation Reduction Act." *POWER Magazine.* Retrieved at: https://www.powermag.com/renewable-energy-electrification-big-winners-in-inflation-reduction-act/.

[65] *See:* Mahajan, M., Ashmoree, O., Rissman, J., Orvis, R., & Gopal, A. (2022, August). Modeling the Inflation Reduction Act Using the Energy Policy Simulator. *Energy Innovation*. Retrieved by: https://energyinnovation.org/wp-content/uploads/2022/08/Modeling-the-Inflation-Reduction-Act-with-the-US-Energy-Policy-Simulator_August.pdf;
Jenkins, J., Mayfield, E., Farbes, J., Jones, R., Patankar, N., Xu, Q., & Schivley, G. (2022, August). Preliminary Report; The Climate and Energy Impacts of the Inflation Reduction Act of 2022. REPEAT Project, Princeton, NJ. Retrieved at: https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-04.pdf; and
King, B., Larsen, J., & Kolus, H. (2022, July). A Congressional Climate Breakthrough. *Rhodium Group.* Retrieved at: https://rhg.com/research/inflation-reduction-act/.

Carbon-Free by 2050 report, or initial comments by other parties in this proceeding.

Q. IN LIGHT OF THE INFLATION REDUCTION ACT, HOW SHOULD THE COMMISSION VIEW THE ANALYSES PRESENTED IN THIS PROCEEDING AND THE DEVELOPMENT OF ITS SHORT-TERM ACTION PLAN?

A. The need to incorporate impacts of recent events on integrated resource planning is not unique to the IRA or this proceeding; instead, it is an inevitable part of the resource planning and deliberation process. The scale of changes to the energy landscape in the IRA, however, warrants additional attention. As just one example, since the IRA lifts the offshore wind moratorium, Duke's restrictions on OSW based on the moratorium are no longer appropriate. In light of these changes, plans that maintain flexibility in the short term and that are likely to take advantage of cost-reductions facilitated by IRA provisions will be better able to adapt to changing circumstances.

Q. WHICH ACTIONS COULD THE COMMISSION DIRECT IN THE SHORT TERM THAT WOULD MAINTAIN FLEXIBILITY AND AVOID LOCK-IN?

A. I recommend that the Commission prioritize the following actions in their short-term execution plan:

1. **Invest in flexible, modular solar and storage resources.** Given their modular design, relatively quick construction times, and geographic flexibility, solar and storage resources represent flexible options with little risk of lock-in or path dependence. Large-scale deployment of solar, in particular, is a common feature of not only the *Carbon-Free by 2050* portfolios, but also the portfolios proposed by the Clean Power Suppliers' Association, Tech Customers and Duke. Further, the tax credits extended by the IRA have a ten-year eligibility

window; efforts made to maximize the value of these credits in the near term will benefit ratepayers.

2. Pursue actions that would expand resource options, including wind deployment capability, transmission planning, and coal retirement. These include continued development of capability for deploying on- and off-shore wind resources in the Carolinas and developing transmission planning processes that can unlock additional resource options.
3. Avoid investments in gas and nuclear resources that would commit North Carolina ratepayers to a specific resource pathway or set of actions in the future. Gas combustion turbine and combined-cycle resources lack the same modularity as solar and storage resources, and they commit the Carolinas to supporting these resources and managing additional carbon emissions for decades. Similarly, long construction timelines associated with new nuclear resources could lock in capital expenditure that would be more effective elsewhere.

VI. Issues Related to "EE / DSM / Grid Edge."

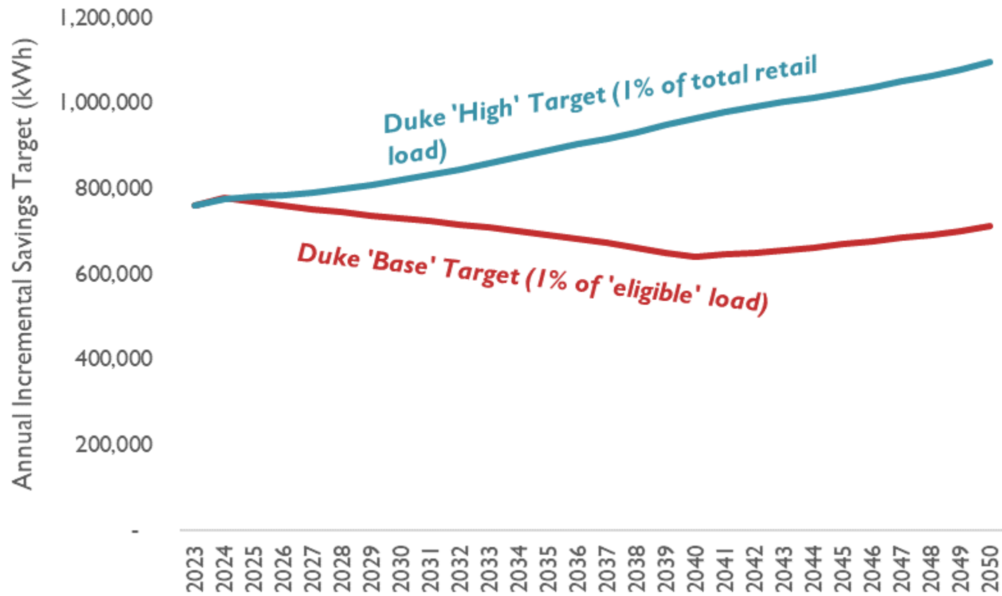
A. Savings from Expanded Demand-side Resources Benefit Ratepayers.

Q. BRIEFLY SUMMARIZE DUKE ENERGY'S APPROACH TO DEMAND-SIDE RESOURCES AND ENERGY EFFICIENCY IN ITS PROPOSED CARBON PLAN FILING.

A. Duke Energy modeled energy efficiency as a decrement to load based on two different forecasts of annual incremental savings. Specifically, the Company's "Base" energy efficiency forecast assumes incremental annual energy savings of one percent of Duke's retail load, net of load that has opted out of energy efficiency programs. The "High" forecast assumes savings equivalent to 1 percent of total retail load.[66] Figure 2, below, shows annual incremental savings targets for the "Base" and "High" forecasts used in developing Duke's portfolios.

[66] Appendix E, p. 16.

Figure 5. Duke Energy Carolinas Annual Incremental Savings Target



Source: Derived from Duke Energy response to NC Public Staff Data Request 15-2.[67]

Notably, Duke Energy's base savings target anticipates a decrease in annual incremental energy efficiency savings over the long-term.

Q. ARE DUKE ENERGY'S ENERGY EFFICIENCY FORECASTS REASONABLE?

A. Yes and no. Duke Energy's "Base" forecast predicts increasing annual incremental savings in the short term followed by a roughly 15-year decline in annual incremental savings. Even the "High" EE forecast is just below the average savings level achieved in 2018 by peer utilities as reviewed in the American Council for an Energy Efficiency's 2020 Utility Energy

[67] Although this response was confidential, counsel for Duke Energy confirmed that Figure 2 could be presented in the public, unredacted version of this testimony.

Efficiency Scorecard.[68] However, DEC and DEP's energy efficiency savings performance comes in below more than 20 of its large utility peers, including Entergy in Arkansas, Xcel in Colorado, MidAmerican in Iowa, and Duke Energy in Ohio.[69] Importantly, while these scorecards are useful benchmarks, they are only a snapshot of recent achievements, and do not capture anticipated future energy efficiency savings driven by policy changes, technology improvements, or other factors.

Q. HOW DID SYNAPSE GENERATE ITS ENERGY EFFICIENCY FORECAST USED IN THE *CARBON-FREE BY 2050* SCENARIOS?

A. Synapse identified 1.5 percent of retail load as an appropriate long-term incremental savings target for DEC and DEP to maximize customer benefits from cost-effective energy efficiency. The *Carbon-Free by 2050* scenarios use a 1.5 percent incremental savings target because it represented an achievable increase in energy efficiency savings, in line with peer utilities.[70] Multiple policy developments since 2020, including decoupling via HB 951 and the energy efficiency elements of the IRA, have also paved the way for more energy efficiency in the Carolinas.[71] Synapse proportionally scaled Duke's existing utility energy efficiency programs and

[68] Relf, G., Cooper, E. Goyal, A., Waters, C. (2020, February). 2020 Utility Energy Efficiency Scorecard. American Council for an Energy Efficient Economy. P.26. Retrieved at: https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf.
[69] *Ibid.*
[70] 13 out of the 52 surveyed utilities achieved incremental savings of 1.5% or more in 2018, according to the ACEEE 2020 Utility Energy Efficiency Scorecard.
[71] *See:* Ungar, L. & Ratner, A. (2022, August). Congress Is Set to Vote on the Largest Efficiency Investments in History. *American Council for an Energy-Efficient Economy.* Retrieved at: https://www.aceee.org/blog-post/2022/08/congress-set-vote-largest-efficiency-investments-history.

costs to meet that target.[72] The result of using Synapse's forecast is that the *Carbon-Free by 2050* scenarios maximize ratepayer savings from cost-effective energy efficiency resources.

Q. WERE THERE ANY OTHER DIFFERENCES IN DEMAND-SIDE RESOURCES BETWEEN THE SCENARIOS YOU MODELED IN *CARBON-FREE BY 2050* AND DUKE ENERGY CARBON PLAN SCENARIOS?

A. Yes. Synapse's load forecast relies on Duke Energy's "High" rooftop solar deployment projections, rather than the Company's base projection. Duke explains that the "High" rooftop solar sensitivity is intended to represent continued policy support for this resource, including the extension of the investment tax credit ("ITC").[73] Given the extension of the ITC via the IRA, Synapse's use of the Duke high forecast is warranted. In EnCompass, this additional demand-side solar functions as a reduction to aggregate load during the hours where solar PV is generating.[74]

Q. WHAT WERE THE IMPACTS OF INCREASED ENERGY EFFICIENCY ON THE *CARBON-FREE BY 2050* SCENARIOS?

A. To quantify the benefit of energy efficiency in the *Carbon-Free by* 2050 scenarios and assess how the *Optimized* scenario would respond to lower demand-side savings, Synapse evaluated a low energy efficiency sensitivity which reduced incremental savings from 1.5 percent to 1 percent

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[72] The *Carbon-Free by 2050* report's Appendix A includes a discussion of Synapse's energy efficiency forecast methodology on pages A6-A8.
[73] Appendix E, p. 17.
[74] The *Carbon-Free by 2050* report's Appendix A includes a discussion of Synapse's rooftop solar forecast.

of retail load. Table 2 shows the net present value revenue requirement for the base *Optimized* scenario and the low-EE sensitivity.

Table 7: Impact of Energy Efficiency on Optimized Results

Results (2022-2050)	*Optimized*	*Optimized Low EE*
2030 NPVRR ($B)	$36.0	$36.0
2040 NPVRR ($B)	$69.8	$71.0
2050 NPVRR ($B)	$103.5	$106.4

While the *Optimized* scenario and *Optimized Low EE* sensitivity are roughly equivalent in the earliest years, the 1.5 percent energy efficiency target saves customers $2.9 billion on a net present value basis over time compared to the *Optimized Low EE* sensitivity.

Q. SUMMARIZE AND RESPOND TO DUKE ENERGY WITNESSES' DISCUSSION OF SYNAPSE'S DEMAND-SIDE MODELING ASSUMPTIONS.

A. Duke Energy criticizes Synapse (and other intervenors) for assuming higher levels of EE savings and behind-the-meter solar PV adoption, and therefore lower net load than in Duke's base case.[75] While Duke claims that these projections are overly optimistic and may not be achievable, evidence supports the higher projections for both energy efficiency and behind-the-meter-solar. For energy efficiency, the Companies are expected to achieve incremental savings of one percent of retail load in the short term, even without any additional programming toward a long-term goal.[76] For behind-the-meter solar, the Companies characterize their "High" projection as

[75] Snider et al., page 186.
[76] Carbon-Free by 2050 Report Appendix A, p. A-7.

representing a future in which policy developments such as an extension of the ITC would continue to support rooftop solar growth in the Carolinas; this policy development has occurred as a part of the passage of the IRA.[77]

Duke also incorrectly claims that demand-side resource projections pose a unique risk to system reliability.[78] Integrated resource planning contemplates procurement of demand- *and* supply-side resources with a relatively long planning horizon and an iterative cadence. Reconciling actual versus projected demand-side resource procurement is a routine part of resource planning, just as IRPs might evolve based on real-world adjustments to supply-side procurement (e.g., construction delays of non-commercialized nuclear resources). As described above, evidence supports the projections used in the *Carbon-Free by 2050* report as reasonable for the purposes of the Carbon Plan. Using unreasonably low projections would artificially suppress the contribution of demand-side resources to "shrinking the challenge" of reducing carbon emissions while meeting energy and capacity needs and maintaining reliability.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS REGARDING DEMAND-SIDE RESOURCES.

A. My analysis shows that additional investment in demand-side resources can save North Carolina ratepayers billions of dollars in the long-term. This

[77] Friedman, S., Stoel, J., Sullivan, M. A., Wickett, J., & Lovelis, H. (2022, August). The IRA's transformative tax incentives for solar energy projects and manufacturing operations. *JD Supra.* Retrieved at: https://www.jdsupra.com/legalnews/the-ira-s-transformative-tax-incentives-4082010/.
[78] Snider et al., p. 189, ll. 8-13.

position is supported by other intervenors, including the Attorney General[79] and Tech Customers.[80] Therefore, I recommend that the Commission integrate higher energy efficiency and behind-the-meter solar forecasts in its Carbon Plan, and direct the Companies to develop programs that are able to accommodate these increased forecasts.

Q. DO YOU HAVE ANY COMMENTS ON INCLUDING ENERGY EFFICIENCY AS A SELECTABLE RESOURCE IN RESOURCE PLANNING MODELING?

A. When adequate pricing, timing, and deployment information is available and efficiency programs are suitably flexible, including energy efficiency as a selectable resource in modeling can provide an even greater level of precision in resource planning. The Attorney General recommends in the Strategen report that Duke allow EnCompass to select demand-side resources as a potential resource in future plans.[81] The results of Synapse's analysis in the *Carbon-Free by 2050* report indicate that additional energy efficiency is cost-effective for North Carolina ratepayers; I would expect that if selectable energy efficiency resources were appropriately configured in the EnCompass model, it would select incremental efficiency beyond the Companies' 1 percent of retail load target.

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[79] AGO Strategen report, pages 41-45.
[80] Tech Customers Gabel report, pages 37-42.
[81] AGO Strategen report, pages 41-42.

VII. Issues related to "Cost."

B. The Carbon-Free by 2050 Report's Revised NPVRR Projections Finds that Duke's $P1_A$ Portfolio is the Most Expensive for Ratepayers.

Q. DID SYNAPSE MODEL ANY OF DUKE'S SCENARIOS IN THE *CARBON-FREE BY 2050* REPORT?

A. Yes. Synapse modeled the set of resources identified by the $P1_A$ portfolio identified in Duke's proposed carbon plan filing. These results are presented in the *Duke Resources* scenario in the *Carbon-Free by 2050* report.

Q. BRIEFLY SUMMARIZE THE REVISED INPUTS THAT SYNAPSE MADE IN ITS *CARBON-FREE BY 2050* REPORT THAT AFFECTED ANALYSIS OF THE *DUKE RESOURCES* SCENARIO.

A. Synapse made several revisions to the cost inputs that affect net-present-value revenue requirement projections for the *Duke Resources*. These include:

1. Revised gas and hydrogen price forecasts, as discussed above;
2. Revised capital expenditure projections for all candidate resources, as discussed above; and
3. Revised fixed operations and maintenance costs and ongoing capital investments for existing coal plants, as discussed above.[82]

Q. HOW DID THESE REVISIONS AFFECT THE COST PROJECTIONS?

A. Based on these revisions, Synapse's analysis found that the $P1_A$ portfolio would cost ratepayers considerably more than what Duke projected in their proposed carbon plan filing. Table 7, below, compares Duke's net-present-

[82] Pages 9-12 of the *Carbon-Free by 2050 Report* present a comprehensive list of revisions made by Synapse to EnCompass inputs.

value revenue requirement projection for portfolios $P1_A$ with that created by Synapse in the *Carbon-Free by 2050* report.

Table 8. Net Present Value Revenue Requirement for $P1_A$, Duke vs. Synapse

Results (2022-2050)	NPVRR
Duke Energy Carbon Plan Filing – *$P1_A$*	$104.1
Carbon-Free by 2050 Report – Duke Resources	$121.2

Source: Duke Energy Carbon Plan Appendix E, p. 90 and Carbon-Free by 2050, p. 24.[83]

Q. HOW DOES THAT COMPARE WITH OTHER SYNAPSE SCENARIOS IN THE *CARBON-FREE BY 2050* REPORT?

A. In the *Carbon-Free by 2050* report, we found that the *Optimized* and *Regional Resources* portfolios were substantially more cost-effective than the *Duke Resources* portfolio. Table 8, below, shows net-present-value revenue requirement for each of the portfolios over time.

Table 9. Net Present Value Revenue Requirement over Time by Scenario

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8
2050 NPVRR ($B)	$121.2	$103.5	$98.1

Source: Carbon-Free by 2050, p. 22.

In the short and long term, the *Duke Resources* portfolio, which mimics the resources from Duke's proposed $P1_A$, costs substantially more to ratepayers than either the *Optimized* or *Regional Resources* portfolio.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[83] Minor differences may result from different methodologies for aggregating costs for NPVRR.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Tyler Fitch on behalf of North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 2nd day of September, 2022.

s/ Gudrun Thompson

Gudrun Thompson

MS. THOMPSON: And I would also move to have the exhibit attached to Mr. Fitch's prefiled testimony identified as premarked.

CHAIR MITCHELL: All right. The exhibit will be identified as it was when premarked.

(Exhibit TF-1 was identified as it was marked when prefiled.)

Q. Mr. Fitch, did you also prepare a summary of your testimony?

A. I did.

MS. THOMPSON: And, Chair Mitchell, I would also move to have Mr. Fitch's summary, which has been filed in the Sub 179-A docket, entered into the record as though given orally from the stand.

CHAIR MITCHELL: All right. That motion is allowed.

(Whereupon, the prefiled summary testimony of Tyler Fitch was copied into the record as if given orally from the stand.)

Summary of Testimony of Tyler Fitch 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 Tyler Fitch. I am a Senior Associate at Synapse Energy Economics, Inc. (Synapse). In this role I employ industry-standard electricity system models, such as EnCompass, to analyze the electricity system and consult and advise state consumer advocates, public utilities commission staff, attorneys general, state energy offices, environmental organizations, federal government agencies, and utilities on integrated resource planning; ratemaking and rate design; system resilience, and related topics.

The purpose of my testimony is to help inform the North Carolina Utilities Commission (Commission), by using modeling analysis, as to the near- and long-term actions necessary to achieve North Carolina's carbon-reduction requirements in a reliable and least-cost manner. Based on my team's reasonable revisions to Duke Energy's modeling inputs, the Synapse optimized portfolios better utilize solar, storage, and energy efficiency while requiring less near-term investment in new gas, small modular nuclear and hydrogen-dependent resources, all while maintaining Duke Energy's planning reserve margin, meeting load in all modeled hours and saving ratepayers billions of dollars by 2050.

In light of the significant changes to the energy landscape enacted by the Inflation Reduction Act, resource plans that maintain flexibility in the short term while capitalizing on cost-saving opportunities will be more adaptable to a changing landscape. Solar and battery storage resources are modular, flexible resources for which the IRA makes tax credits available. Developing robust transmission planning processes, retiring coal-fired generation, and enabling greater wind deployment now will expand the resources options available in the future. Meanwhile, investing in gas and nuclear resources now would commit ratepayers to financially supporting these resources (and to the carbon emissions from gas generation) for decades to come, tying up capital that could be more effectively spent elsewhere.

The near-term actions laid out in Table 6 in my testimony, reproduced below, are informed by the capacity expansion and production cost modeling analysis Synapse completed, developing resource portfolios consistent with House Bill 951's emission reduction requirements for the combined Duke Energy system using the EnCompass platform. In focusing on a near-term action plan, this Commission will be able to defer decisions that would commit Duke Energy to a certain level of carbon emissions or would preclude the ability to invest in more cost-effective resources which are not necessary to be made at this time.

Table 6. Carbon Free by 2050 Short-Term Recommendations

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2030		
Energy Efficiency	1.5 percent of retail load	• Expand utility energy efficiency savings targets to 1.5 percent of total retail load
Distributed Energy Resources	At least 1 GW by 2035	• Develop and support programs to empower customer-owned energy resources to accelerate contribution to grid needs
Additional Solar	7,200 MW	• Invest in transmission projects to unlock additional cost-effective solar power

		• Begin procurement of 4 GW of new solar 2022-2024 with target in-service dates of 2025-2028 • Develop interconnection methods that will be robust long-term
Battery Storage	5,600 MW	• Begin procurement for 4 GW of stand-alone storage with target in-service dates of 2025-2028 • Invest in operational capabilities for capitalizing on energy storage resources for grid services
Onshore Wind *(in-state)*	900 MW	• Engage with communities on onshore wind siting • Prepare for continued advancement of onshore wind, long-term
Onshore Wind *(Midwest)*	2,500 MW	• Engage in inter-regional coordination with PJM for facilitating power purchase • Integrate Midwest wind import into short-term transmission planning
Offshore Wind	800 MW	• Initiate development and permitting activities for 800 MW (or larger tranches if more cost-effective), with eye toward potential additional procurement long-term
Proposed Resource Selections: Options for Long-Term Cost-Effective Carbon Reductions		
Coal Retirement	--	• Develop retirement plans for coal units consistent with economic optimization
Transmission Planning	**--**	• Develop processes for long-term, prospective and regional transmission planning that can cost-effectively meet economic and carbon reduction requirements of HB 951
Pumped Storage Hydro	1,700 MW	• Conduct feasibility study, develop EPC strategy, and apply at FERC for re-licensing
Hydrogen Planning	--	• Develop more detailed hydrogen fuel cost planning methodology • Conduct studies of hydrogen transport, storage, and distribution • Integrate cost of production and distribution into resource planning

My testimony also highlights how making Midwest Wind PPA resources available for selection by the model achieved substantial additional savings.

Considering a broader range of transmission assumptions, such as increasing transmission capacity and allowing the utilities to buy and sell energy and capacity from neighbors over the planning horizon, will unlock lower-cost resource pathways. Decarbonization planning is incomplete without a consideration of transmission upgrades and regional coordination alternatives.

Duke Energy witnesses' testimony describes the results of a supplemental analysis conducted by the Companies to estimate the future reliability of several portfolios. The Companies found that the Synapse portfolio meets requirements through 2034, allowing the Commission to continue to check and adjust the plans as they evolve through the 2020s and 2030s.

In addition to presenting the results of Synapse's modeling of optimized resource portfolios developed with EnCompass, I offer my critique of Duke Energy's proposed portfolios and the methodology and assumptions used to develop them.

Publicly available and industry standard capital cost assumptions should be used to further ensure objectivity, in the absence of cost data from an all-source request for proposals. The cost estimates Duke Energy uses for solar, storage, and offshore wind resources are higher than industry benchmarks. The cost estimates used for small modular nuclear reactors and gas combined-cycle and combustion turbine units are lower than industry benchmarks. While reasonable cost forecasts may deviate, a pattern of cost assumptions that favor gas over renewable resources will drive the economic selection of such resources by the model.

In the future, Duke Energy's use of EnCompass should enable all parties to share an analytical foundation, but all parties must be committed to transparency in order to collaborate on problem-solving. Inconsistency between shared inputs and outputs, providing key additional inputs through discovery only, and conducting additional steps outside of EnCompass with little transparency of process created barriers to effective collaboration. By sharing model data at the outset of the planning process and over a longer timescale, proactively providing any inputs that are not derived from public sources prior to the discovery process, and making all out-of-model methodologies transparent, utilities and stakeholders should be able to validate future carbon plan iterations.

My testimony highlights how the manual changes Duke Energy made to its portfolios undermine the objective, resource-neutral, economic optimization performed by EnCompass. Capacity expansion models have a long-established resource adequacy regime that uses reserve margin studies and effective load carrying capabilities to ensure reliability across a portfolio of resources. I find that Duke Energy's manual over-rides are not appropriate or consistent with established resource adequacy practices. I also detail how Duke Energy's coal retirement methodology delays plant retirement dates in a manner that is inconsistent with least-cost planning and at ratepayer expense. While retiring coal capacity may create the need for replacement energy, capacity, and ancillary service resources, replacement resources can be appropriately accounted for in resource planning. Duke Energy's proposed retirement dates are extended, by contrast without sufficient justification. To meet the economically optimal retirement schedule selected by EnCompass, Duke Energy should identify the specific transmission and generation requirements necessary for retiring those units selected to be retired within the next six years.

Synapse's EnCompass analysis also assumes an incremental energy efficient savings target that is in line with peer utilities. In contrast, Duke Energy's energy efficiency forecast falls below the savings realized by many of its peer utilities. The recent extension of the investment tax credit in the Inflation Reduction Act supports the use of Duke Energy's "High" rooftop solar adoption assumption. These assumptions are prudent for long-range planning with iterative opportunities to reconcile actual load reductions with planning projections, just as supply-side procurements will necessarily need to be adjusted to meet real-world dynamics.

Ultimately, Synapse modeling of Duke Energy's Portfolio 1-Alt, using revised inputs as outlined in my direct testimony, found that cost to ratepayers are likely to be significantly higher than projected by Duke Energy. Using the same set of inputs and assumptions that better reflect real-world conditions, Synapse's proposed portfolios would cost billions less over through 2050, as illustrated by Table 9 in my direct testimony, reproduced below.

Table 9. Net Present Value Revenue Requirement Over Time by Scenario

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8

2050 NPVRR ($B)	$121.2	$103.5	$98.1

With its first Carbon Plan, the Commission is beginning a process that will transform North Carolina’s energy economy, and it’s critical that the Commission use the most accurate view of resource needs and options to ensure that our electricity system is maximizing the benefit for everyone. My testimony and the *Carbon-Free by 2050* report show the potential benefit to North Carolina ratepayers when more accurate assumptions are included and points the way toward a Carbon Plan in the public interest moving forward.

MS. THOMPSON: Thank you, Chair Mitchell. The witness is available for cross examination and questions from the Commission.

CHAIR MITCHELL: All right. Avangrid?

CROSS EXAMINATION BY MR. SMITH:

Q. Good morning. Ben Smith representing Avangrid Renewables LLC. Good morning, Mr. Fitch. Just a few questions for you.

A. Sure.

Q. You led the Synapse modeling work in this docket; is that correct?

A. That's correct.

Q. And in that modeling work, you relied upon some Duke inputs and assumptions; isn't that correct?

A. Yes, we relied on Duke's inputs and assumptions as much as we could, subject to some revision- -- or reasonable revisions in our modeling.

Q. Thank you. And isn't it true that the Duke generic profile of offshore wind was one of those inputs or assumptions that you relied upon?

A. That's correct.

Q. Would the Synapse modeling conclusions have looked any different, had you used offshore wind profiles with, sort of, larger energy profile? For

instance, 1,300-megawatt rather than 800 megawatts?
A. Sorry, I got confused by the last part of your question. Are you asking about the, sort of, blocks that the capacity expansion could pick, or are we talking about, sort of, like dispatch curves and capacity factor?
Q. I'm talking about the blocks, but let me restate just so it's clear.
A. Okay.
Q. Would the Synapse modeling conclusions have looked different had you used offshore wind profiles with larger blocks?
A. Yes, it would and -- sorry. Go ahead. I'm finished.
Q. Okay. And would it be fair, in your modeling work, to use a generic profile with 1,300-megawatt blocks rather than 800-megawatt blocks since the three offshore wind sites all profile at more than 1,300 megawatts capacity?
A. Yeah, I think that's a reasonable assumption to make.
MR. SMITH: Nothing further.
CHAIR MITCHELL: All right. CCEBA?
MR. BURNS: Thank you, Madam Chair.

CROSS EXAMINATION BY MR. BURNS:

Q. John Burns for CCEBA. Mr. Fitch, I have a very similar line of questions, but want to discuss with you the conclusions that you drew, or at least the modeling results that you reached with regard to solar plus storage.

As I understand -- and I'm looking at the Duke Public Staff Panel 1 Direct Cross Exhibit 1, which I'm going to hand you a copy of. Page 2 of that is marked Rebuttal Table 1. I'm just gonna show this to you, because it's a summation.

(Pause.)

Q. On that document, page 2 of that document, there's a chart, which you're looking at the right one. I handed it to you with the right one up, sorry. It says page 1 of 3 in the top right corner, but it was given to everybody as part of one exhibit, so.

When you look there, it says NCSEA, et al.; do you see that line underneath the --

A. I do.

Q. -- top of the chart? And it shows solar of 4,000 and BESS paired with solar at zero.

As I understand from your response to Mr. Smith, you assumed, in your modeling, the same or similar assumptions to what you saw in Duke's original modeling; is that right?

A. That's right. And in this case we did use that static dispatch curve for solar plus storage that I think we've already talked about, or I think there's been discussion of in this hearing already.

Q. Okay. If you modeled it -- based upon your knowledge and experience, are you able to make any projections as to whether there would have been any differences to the results of your model had you modeled it with the variable dispatch or the dynamic dispatch?

A. Yeah. Yes, I can do that.

Q. And what would -- what would you expect those results to show?

A. I would expect -- the way to think -- the way that I think about this dispatch curve is it's single method of operation for the solar plus storage resource that we're talking about. And in the case where it can be dynamically dispatched, we could see lots of different types of adjustment based on the low curve for the day, based on other resources that are online, things like that. So I think using the dynamic dispatch that has been discussed is sort of a strict improvement to the economic value of those resources.

Q. And would they -- would the model that you used have generated more use of solar plus storage had you modeled it with dynamic dispatch?

A. It's difficult to comment with specificity about how much -- how many more megawatts would have been procured if things had been different. But what I can say is that using dynamic dispatch would have put upward pressure more or less on procurement for those resources.

So to put it another way, I would expect more procurement of those resource, but the magnitude of that increase is very difficult to know or make predictions about.

Q. Did you review SP5 and SP6?

A. I did review the inputs but not the outputs in great detail.

Q. Okay. Thank you. That's all the questions I have for you at this time. Thank you, Mr. Fitch.

A. Thank you.

CHAIR MITCHELL: CIGFUR?

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Good morning, Mr. Fitch. Just a couple of questions for you. First I want to turn your attention to the carbon-free by 2050 report that you co-authored on behalf of NCSEA, et al., as filed in this docket on July 20th.

Do you have a copy of that with you?

A. I have the public version in front of me.

Q. Excellent. Synapse included a summary of three different sensitivities it ran using EnCompass' production cost modeling function; is that right?

A. To my recollection, we did run several. I'm not sure the number is three, but around there, subject to check, I suppose.

Q. Okay. And can you turn with me to Table 9 on page 26?

A. (Witness peruses document.)

Sure.

Q. Excellent. And this table shows the net present value revenue requirements for the high gas sensitivities performed; is that right?

A. That's right.

Q. And Table 10, if you wouldn't mind turning to the next page, shows the net present value revenue requirement over time for the energy efficiency sensitivities performed; is that correct?

A. That's correct.

Q. Can you help me understand why there is not a similar table for the REGI sensitivity that was performed?

A. I'm just gonna take a moment to review this.

Q. Sure.

A. (Witness peruses document.)

My recollection is that, to an extent, it's difficult to account for REGI -- the REGI carbon price and payback, because of that, sort of, revenue-neutral nature of it. And so because of that, it would have been -- this is just my recollection of our reasoning here. It would have been confusing, potentially, to include that table.

Q. So it was not included; is that correct?

A. That table is not included in this report.

Q. And it was also not produced in discovery; is that correct?

A. Not to my -- not to my recollection.

Q. Thank you. No further questions.

CHAIR MITCHELL: All right. CPSA?

MR. SNOWDEN: CPSA does not have any questions for this witness.

CHAIR MITCHELL: Okay. EJCAN?

MR. BLUMENTHAL: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. BLUMENTHAL:

Q. Ethan Blumenthal with Environmental Justice Community Action Network, Down East Coal Ash Environment and Social Justice Collective, Redtailed Hawk Coalition, and the Robeson County Cooperative for Sustainable Development, thanks.

Just a couple of quick questions for you. If you wouldn't mind turning to page 40 of your testimony and reading the two sentences beginning on line 12.

A. I'm seeing it start, "With a short optimization period"; is that right?

Q. Yes.

A. Okay. "With a short optimization period, the model may not see the following utilization and arising costs as it makes its near-term resource planning decisions." And that's in reference to gas CCs and CTs. "I, therefore, recommend that the Commission direct the Company to include a full period capacity expansion optimization."

Q. Thank you. Can you, in this context, explain what a short optimization period, what you're referring to with that term?

A. Sure. So one of the settings that you can include in EnCompass, in general, is a planning period. And essentially that's how far is this algorithm going to look out forward to minimize or optimize on costs. So you could think about doing this in the case of the Carbon Plan, all 28 years or even longer than that if you wanted, or you could think as short as one year.

And one of the reasons why we balance this is because it's very computationally difficult to do it over the whole capacity period, or the whole optimization period, like 28 years. So what's done is something called segmentation, which is splitting -- and I think we talked about this previously -- splitting the entire period into eight-year chunks, something like that.

And I think, in general, the issue with that -- in the past, when the electricity industry, in general, was sort of -- had several static trends, eight-year optimization periods made a lot of sense because you could look at something like electricity -- or total load that seemed to be, you know, relatively predictable at least, or gas prices that were relatively predictable, but that didn't include things like a decline in carbon cap, which is essentially, in our modeling, producing an incredible transition in resources.

So for that reason, in this case, the planning period and the optimization period is important, because using, for example, an eight-year planning period, EnCompass is choosing what is optimal from 2022 to 2030. And it might choose a carbon emitting unit like a gas CT or a gas CC, and it would see, okay, this unit might be okay to meet the 70 percent reduction target in 2030. But, essentially, EnCompass isn't testing how it's going to do over the entire period.

So we have to engage, especially, I think, with these things like declining carbon cost caps, it's really important to allow things like EnCompass to look further out, have a longer horizon.

And so in our -- what we used in our analysis was a 15-year period, which essentially splits it in half, right, it's 28 years. So '22 to '37 and then '38 to '50. Yeah, I think my math's correct on that. So I think those are some of the dynamics that are important here.

And yeah, I think especially like the sentence sort of illuminates for, I think, carbon emissions in particular, it's really important to look at how long our planning periods are.

Q. Thank you. So I think you may have addressed this somewhat in your answer, but I just want to make sure we have it clear. Within the optimization period, how does it, or does it account for system costs and benefits as they accrue past that optimization period?

A. Yeah, this is another good question. And this segmentation, essentially there is no accounting for what happens after. So in the eight-year example, EnCompass is asking what resource deployment should we do over the next eight years, but it's not looking at 2031 through 2050. And the reason you still see investments in actually resources is because all the capital recovery is levelized.

So when you include, like, a CC, for instance, it's only recovering, you know, 1/35 or 1/20 depending on your assumptions of that every year. But any case, after that period is over, there is no accounting for costs or benefits for any of those resources.

So with an eight-year period, you're modeling and choosing resources for '22 to 2030 without looking in the future, and then '31 to '38 without looking in the future, '39 to '46 without looking in the future, on and on.

Q. One final question on this line.

So with the difference between the Duke Energy portfolios using an 8-year optimization window and Synapse using a 15, what would that difference have on affordability of the system -- modeling affordability for the system?

A. That's a good question, and it can be difficult to answer because, again, there are so many different values that we're juggling when we're putting together an EnCompass model like this. So are we -- the longer model runs might mean it's more difficult to revise the model as we go, you know, in terms of run time. But more specificity in, you know, hourly dispatch or something like that could help.

So what I would expect is, over the period, a longer optimization period, like 15 years, I would expect to see, in general, that over the entire period, sort of '22 to '50, you would see lower costs overall. But again, there's a lot of juggling and it's difficult to say.

Q. I appreciate that. Now, just one more line of questioning, if you wouldn't mind turning to page 59 of your testimony. And let's go ahead and do the same, I guess, first three sentences starting on line 4 starting with "Duke also incorrectly claims."

A. All right. And you want me to read?

Q. Yeah, please.

A. And you said through which line?

Q. Through the end of the parenthetical on 11.

A. Okay. "Duke also incorrectly claims that demand-side resource projections pose a unique risk to system reliability. Integrated resource planning contemplates procurement of demand and supply-side resources with a relatively long planning horizon and iterative cadence. Reconciling actual versus projected demand-side resource procurement is a routine part of resource planning just as IRPs might evolve based on real-world adjustments to supply-side procurement; e.g., construction delays of non-commercialized nuclear resources."

So I think what this set of sentences is getting at is a concept that we've heard about a lot in this hearing, which is the idea of checking and adjusting. So, like, this is an iterative process, so every two years we'll get an opportunity to say what's working and what's not. And I think the point I'm making here is that applies to demand-side resources as well.

So if we set, for example, a higher target for incremental savings, we'll be able to check and adjust in two years and say does this -- are we meeting this; are there adjustments we need to make in terms of policy or anything like that. And I think the other point that I'm trying to, sort of, illuminate here is there's no inherent risk with demand-side resources of looking -- or pulling out the drawer where demand-side resources are and finding them not there when you need them. Because just like any other resource, we will check every two years and make sure the resource adequacy is working exactly as it needs to.

Q. I think you somewhat got to the next question, which is, so how would you compare -- when utilizing a benchmark for EE/DSM, say, 1 percent of achievable retail load, how would you compare the risk of that benchmark being set too high versus that benchmark being set too low?

A. Sure. And one thing I think it's really important to put out here, in terms of how I'm thinking about reliability with the Synapse EnCompass model that folks have been assessing over the last two months or so, in terms of reliability, that is a priority for Synapse in our EnCompass modeling because it's table stakes for any resource planning you do.

And the reason that we structured our model the way we did with imitating as many Duke resources as possible -- or excuse me, decisions as possible, was to maintain that reliability. And one place where we mimicked Duke's -- one place where we mimicked Duke's settings precisely was on the commitment issue.

So just like Duke Energy's capacity expansion and production cost models, the Synapse model used partial commitment for capacity expansion, and it used full commitment for production cost modeling. So just when I'm thinking about the reliability risks, for instance, of energy efficiency, I'm feeling confident in what Synapse is putting out, because again, it mimics Dukes choices on that precisely.

And in terms of energy efficiency, I think the risk with having a goal that's too low is there -- you could be leaving money on the table, so to speak. There is an issue where, if we don't have a goal -- or if we don't have a target that's higher than -- or that's hitting what's possible, then we may have energy efficiency investments that we're not making, which our modeling shows is worse for ratepayers.

And I think having a lower target that's sort in line, you know, with what's been achieved in previous years, which is my understanding of why the 1 percent of retail load, it could potentially be more executable or have less executability risks. But I think what our modeling show is that you also leave benefits for ratepayers on the table.

Q. Okay. Thank you. No further questions.

CHAIR MITCHELL: All right. Tech Customers?

MR. SCHAUER: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. SCHAUER:

Q. Craig Schauer on behalf of the Tech Customers.

Mr. Fitch, if you could take a look at page 4 of your testimony, line 20.

A. Just a moment.

(Witness peruses document.)

Q. You make the statement on line 20 that you use the same underlying EnCompass database that Duke used to develop the portfolios in its proposed Carbon Plan filing; do you see that?

A. I do.

Q. So you received the database from Duke, correct?

A. I did.

Q. Did you have any challenges using that database?

A. Yes, and I think we detail this in our testimony. But we did have several challenges using this database. I'll just list them, although I think we've talked about them, or I think they've been discussed in this hearing previously.

But the first was an issue with either the upload of the upload of the database which caused one of the files to be corrupted and meant that when, for instance, our Synapse team ran the model, it did not work and it threw an error. And that was actually the beginning of our relationship with Anchor Power in this proceeding was when that error got thrown. So that was the first piece.

And then the second piece was a disconnect between the inputs database that we received and the outputs that were presented in Duke Energy's Carbon Plan. And are specifically the output documents they received in this EnCompass share. And this was a matter of -- at least a matter of one dataset being in the wrong place, more or less.

And unfortunately, even with that revision, what we found was that even using the correct version, which was 6.0.4, which we did use in the beginning before deciding to switch, which if you-all recall did not end super well for us in terms of timing, the Synapse team was still not able to -- to validate the results that Duke was showing.

And just to address some things that folks have -- just to address how this went for us, when I look at the capacity expansion configuration that Duke Energy uses, they use this MIP stop basis of 25. So that's 25 basis points, which is pretty low. And they also use, in terms of these outages, something that's called capacity duration. So instead of using something like random outages for the capacity expansion at least, they simply reduced the capacity -- or reduced the capacity of those units to approximate the idea that sometimes they are offline.

The reason I bring those up is because the MIP stop basis being so low and using this approximation of outages means that there is less randomness. There's very little randomness, in fact, in the capacity expansion modeling. And for that reason, we expect it get precisely the same results. And we did not get that.

It's a matter of 10s or 100 megawatts potentially between years and between models, which is not huge, but it does undermine confidence that, for example, Synapse's database is working correctly. So that was an issue as well.

And the last one is that, for example, the capital costs were given to us in a version using this real levelized fixed-cost recovery rate, which we were not able to reproduce without asking for the supporting spreadsheets in discovery. Which meant that for an extremely important component of many of the resources that were chosen, we essentially had to wait, go through the discovery process in order to contend with that in a meaningful way.

That's my memory of the issues that we had, but it may not be comprehensive of all the issues, but I do think I talk about them in my testimony.

Q. I apologize, I did not see that in your testimony which is why I wanted to ask. Last question.

How long have you been using EnCompass?

A. Sure, yeah. The first project I led in EnCompass started in 2021, but at Synapse -- Synapse is actually one of the first clients of Anchor Power Solutions, and the relationship started in either 2015 or 2016, and as part of coming online at Synapse last year, I received training on the EnCompass model that lasted over several days. I have, like, a phone call/text relationship with at least one person in Anchor Power, and I obviously had the benefit of the team at Synapse who had been working with this model for essentially as long as it's been commercially available.

Q. And how long has the model been commercially available?

A. I think since 2015 or '16. That's my recollection, but I'm not sure.

Q. Thank you. No further questions.

CHAIR MITCHELL: All right. Walmart?

MS. GRUNDMANN: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. GRUNDMANN:

Q. Good morning. My name is Carrie Grundmann on behalf of Walmart. I'd like to direct you to page 41 of your testimony. Over the course of several pages, you talk about the concept of collaborative modeling, and on page 43 of your testimony, you mention some successful collaborative modeling that took place with Xcel in Colorado and Minnesota and then Duke Energy in Indiana.

Can you tell me how you're aware of those three instances?

A. Sure. It was just consultation with my teammates at Synapse who would work on those projects. And because of their confidential nature, I don't have a lot of specifics of exactly how those stakeholder processes went, other than a characterization that they resulted in validation and they were, I think, effective ways to build consensus.

Q. So do you have any -- I think you said that due to confidentiality, you may have limited, but do you have any understanding as to what made those process more collaborative than this particular process?

A. Yeah. I have a couple, sort of, best practices ideas that I think were common to those.

Q. Okay. Can you share those, please?

A. Sure. I think one is, simply put, time. Sixty days -- or in this case, I think -- I think the Duke staff were pressed to be able to put together a final model in the time they needed to. And I think also the intervenors were pressed to be able to review that and revise it with any level of confidence. And I do think that we put together a product that is high quality, but I think there was time pressure on Synapse as well as all the other intervenors and consultants. So I think having a longer time span is important. And --

Q. Let me stop you there.

Do you have any recommendations or ideas as to what amount of time you would believe would be necessary?

A. I don't think there is a, sort of, Goldilocks number that's available out there. But what I will say is there is a balance. Because, for example, Duke Energy will be updating this model over time, changing the inputs based on, for example, the IRA. And so there may be some potential inefficiencies if the period is very long for collaboration.

But I think, for understanding this complex model -- and I think we've all heard about how complex this model is -- it does take weeks. It takes months to really understand all the nuts and bolts and be able to make changes and see what those do.

So I think my high-level recommendation is that I think that three-month timeline would be -- would be, kind of, like, the lower end of what I think a really comprehensive process could look like.

Q. Okay. And what's another best practice that would you have recommended?

A. I would say visibility into the model. So the Duke stakeholder process that we engaged in in this process where there was -- there were inputs shared with us in a high-level way through sort of PowerPoints. Those are helpful for understanding, at high level, what sort of references, for example, Duke Energy is using. Or at a high level, again what, sort of, structuring decisions they'd make.

But the EnCompass model is very complex, and not only a matter of what inputs you're using, but how they're implemented. And that is very difficult to explain on a PowerPoint slide. So I think what one has to do to really make this an effective process is have the transparency of sharing the database with enough time that intervenors can really get to understand it and ask questions and have, I think, sort of an open dialogue about why, for example, Duke Energy made the decisions it did and what alternatives are out there, things like that.

Q. Do you have any other recommendations, other than those two?

A. Not right now.

Q. Okay. Do you happen to know whether the stakeholder process that involved Duke Energy in Indiana, whether that was a voluntary process or whether that was something that was ordered by the Commission in Indiana?

A. I don't know that.

Q. Thank you. That's all the questions I have.

CHAIR MITCHELL: All right. Public Staff?

CROSS EXAMINATION BY MS. LUHR:

Q. Good morning. Nadia Luhr with the Public Staff.

So you said earlier today that you mimicked Duke's settings for unit commitments exactly; is that correct?

A. That's right.

Q. Did you change any other settings in the production cost modeling runs, such as using a typical day instead of all calendar days?

A. Yeah. I appreciate that question. We did use -- we increased the MIP stop basis from -- or to

200 basis points, and we also used a typical week, is what the name of that, sort of, structure is that's -- it's sort of -- it's -- essentially uses, like, a typical seven days for a month -- hourly.

Q. Okay. And what might be the impact of those changes on the production cost results?

A. I'm glad you asked that. And again, I think the most -- the most important thing, or one thing I really want to stress is that the commitment practice was the same between the EnCompass -- or the Synapse modeling and the Duke Energy modeling. So I think for the MIP stop basis, I'm gonna go into the gory details here. But essentially EnCompass is a linear programming algorithm at its heart, and it wants to work with continuous values.

So EnCompass would like to procure 386.7 megawatts of storage, but that's simply not how it's done in the real world. You know, we round up to 400 or down to 200, something like that. And so in every case, whatever the MIP stop basis is, the -- EnCompass will solve to this, like, exact precise continuous number of, for example, resource acquisitions. And then from there it sort of back-solves and it says how close can we get to that, sort of, like, abstract optimal portfolio using the blocks that are available to us.

And essentially what this MIP stop basis asks is how close do we need to get. So by increasing that, essentially, you allow the model to find one that's good enough earlier and go with it.

But what I do want to point out is that, in all those cases, the model's solving towards this optimal basis, and so I wouldn't expect to see, for example, a different set of resources if you used -- or a drastically different set of resources if you decreased that MIP stop basis. So I think there is -- it, sort of, allows the model to run over a quicker time frame.

And then the typical week structure, I think it finds a happy medium between -- between the kind of, like, full, as robust as you possibly can in terms of hourly dispatch and the typical day -- or the typical day that we've talked about in this proceeding already. So again, that's sort of an abstraction that allows for a faster run time.

Q. Thank you. And if you can turn to pages 50 and 51 of your testimony, to Table 6.

A. I hope that table is readable, I know it's kind of funny that way.

Q. So it looks as though your portfolio adds significantly higher quantities of solar and storage in the near term than Duke's portfolios; is that accurate?

A. That's accurate.

Q. And in your modeling, do you use the same transmission cost adders that Duke used for new capacity resources?

A. I did.

Q. Do you think that the interconnection of higher levels of solar and storage in the near term than Duke anticipates would necessitates higher transmission costs than Duke used?

A. Yeah, it's a good question and I'm happy to talk about it. So I heard in previous discussion that the transmission adder was roughly equivalent with the red zone upgrades, essentially, if you sort of summed up what the red zone upgrades could actuate, and compare that to the transmission adder that EnCompass uses, they'd be relatively similar. So I do think it's a good approximation for incremental transmission.

But I think, to the extent possible, when transmission planning is able to be coordinated for sort of maximizing solar deployment, for instance, within all the other requirements, so transmission planning, like, reliability and resource adequacy, I think there is potential room for both economies of scale but also, sort of, like, marginal gains.

So like I said, in general I think it's a good prediction for what transmission costs could be because they are notoriously difficult to, sort of, predict from here.

Q. Okay. Thank you. That's all I have.

CHAIR MITCHELL: All right. Redirect?

MS. THOMPSON: Yes. Thank you, Chair Mitchell. Bear with me just one moment, please.

REDIRECT EXAMINATION BY MS. THOMPSON:

Q. Mr. Fitch, in response to a question from Mr. Blumenthal, you alluded to 1 percent of retail load, and I think you were alluding to that as the target that Duke is using in this -- that Duke is proposing.

Did I understand you correctly?

A. Yes.

Q. And do you recall that Duke's target is, in fact, 1 percent of eligible load that is net of opt-outs?

A. I do recall that.

Q. Let's see. In response to Ms. Luhr and Mr. Blumenthal, you mention this issue of unit commitment and alluded to the fact that Synapse used the same time unit commitment settings that Duke had used in its EnCompass modeling.

Did I understand you correctly?

A. You did.

Q. Okay. There's been a fair amount of confusion on this issue, I think, in this hearing, so I just want to make -- make sure we clear this up, hopefully once and for all.

Did SACE. Et al. and NCSEA provide Synapse's inputs for its EnCompass modeling to Duke Energy pursuant to Companies' request for intervenor modeling files?

A. That's my understanding, yes. I provided to SACE, et al. and NCSEA, and I assume that they were provided, so yes.

Q. Thank you. So those modeling files that SACE and NCSEA -- or that you provided to SACE and NCSEA that we -- NCSEA that we then provided to Duke, do you recall that those included a file that was named Index.xlsx?

A. I do. And the .xlsx is just the extension, that means it's an Excel spreadsheet, but yes.

Q. Okay. So it's a tongue-twister, so when I refer to that filename henceforth, I'll just call it index. What was in that index file?

A. So -- sure. The index file contains, essentially, all of the -- let me start earlier. What we're talking about is an export of the database that Synapse used to put together its portfolios -- its scenarios. So what needs to be included in that export is the data, all, changes that we made in terms of different capital costs, things like that. And then what the configuration of each of the scenarios we ran was. So that index file is -- has all the configurations of the scenarios in it.

Q. And when you say it has all the configurations of the scenarios, would that allow someone reviewing those documents to understand what settings Synapse used?

A. Yes, it would.

MS. THOMPSON: Okay. I have a couple of exhibits I would like to have passed out, if I may, Chair Mitchell. And I'll just ask my co-counsel to assist me. If you could pass out one of each of these, please.

Chair Mitchell, I would like to mark the document that says "Excerpt of Index.xlsx Lookup Values" tab at the left-hand -- at the top left corner for identification as SACE, et al. Fitch Redirect Examination Exhibit 1.

CHAIR MITCHELL: All right. Document will be marked as SACE, et al. Fitch Redirect Examination Exhibit 1.

(SACE, et al. Fitch Redirect Examination Exhibit 1 was marked for identification.)

MS. THOMPSON: And then the second document that says "Excerpt of Index.xlxs Scenario Settings" tab at the top left, I would like to mark that for identification as SACE. Et al. Fitch Redirect Examination Exhibit 2.

CHAIR MITCHELL: All right. The document will be marked as SACE, et al. Fitch Redirect Examination Exhibit 2.

MS. THOMPSON: Thank you, Chair Mitchell.

(SACE, et al. Fitch Redirect Examination Exhibit 2 marked for identification.)

Q. Mr. Fitch, could you -- do you have copies of

the two documents?
A. I do.
Q. Could you please refer to SACE, et al. Fitch Redirect Examination Exhibit 1? That's the one with the lookup values tab in the top left corner.
A. I've got it.
Q. Do you recognize what is reproduced here in the exhibit?
A. I do. This is an excerpt of a much longer list of input descriptions and options that work, sort of, as a key for understanding the scenario settings. So for every option on the scenario settings tab, it shows what the choices are and, sort of, what they mean. So I do recognize it, yes.
Q. And would you agree with me that this is an excerpt of the lookup values tab from the index file that was shared by Synapse with NCSEA and SACE, et al. and afterwards produced to Duke?
A. Yeah. And the lookup values tab is the same for every EnCompass export, so this is -- this is in that one and any other EnCompass export.
Q. Okay. Can you please explain what is shown in each of the columns of this table that is in the exhibit?

A. Sure. So there are two columns on the table. The left one, input description, indicate -- or has a series of, sort of, categories that could be -- of categories where there's multiple settings available. And the right-side options indicates how much settings are available. And in cases where it's not clear, what each setting means.

And I'm not exactly sure on this, but I think the scenario settings, in general, tend to be integers like zero through three instead of names like full, partial, and none. So in this case, there's, sort of, a key there for what zero means, what one means, et cetera.

Q. Okay. So just to make sure I'm understanding you right, because you started losing me when you were talking about integers, under options, those are the different commitment options that can be used when running EnCompass?

MR. BREITSCHWERDT: Chair Mitchell, I'd object. I think it's not clear how this is redirect, if there's some concern about how -- well, maybe I'll stop there. I'd object that this is well beyond the scope of any questions asked, and I'd like to understand how this is redirect.

MS. THOMPSON: Yes, Chair Mitchell, thank you. There were questions from -- well, there was a question from Ms. Luhr about the commitment settings. And Ms. Luhr's witness, Mr. Thomas, had, I think, a misapprehension that was in his testimony regarding the settings that Duke -- excuse me, the settings that Synapse had used in modeling its portfolios. And I think this is a point that needs to be cleared up in the record.

CHAIR MITCHELL: All right. I'll overrule the objection.

Q. Moving right along. Under options, those are the different commitment options that can be used when running EnCompass?

A. That's right.

Q. Okay. And I will ask you, what is the significance of the commitment setting when you're modeling in EnCompass? Actually, strike that. I think you explained that already.

Let's turn to the other document marked SACE, et al. Fitch Redirect Examination Exhibit 2, the one with scenario settings in the top left corner.

A. I've got it.

Q. Okay. Can you explain what is in -- what this document is reproducing here?

A. Sure. So this is, again, an excerpt of a much larger spreadsheet where the rows indicate a series of scenarios that you've specified -- that one has specified, and the columns indicate all the different possible settings, some of which I talked with Ms. Luhr about.

So in this case, this is an excerpt where it has the scenarios on the left side and then one of the settings that's available here, commitment option or commit opt on the right.

Q. Okay. And what does the commit opt setting indicate?

A. That is -- that is the commitment option which is -- it's abbreviated because of string storage space in the model. But yes, it means commitment option.

Q. So it's the -- are you saying it's the unit commitment setting for each of the scenarios that are listed on the left-hand side?

A. That's probably clearer, yes.

Q. Okay. On the -- in the right-hand column under commit opt, let's go down to optimize -- where it says optimized CAPEX under scenario in the left-hand column, what is that?

A. Sure. So that's the label that we use for the capacity expansion portion of the optimized scenario that we present in the carbon-free by 2050 report.

Q. Okay. And is the same true for the Duke resources CAPEX and regional resources CAPEX?

A. That's right.

Q. And then in the right-hand column for each of those scenarios, it lists the unit commitment setting as one.

What does that mean?

A. So that one is -- essentially, we use the lookup values, the previous exhibit key to understand what the one means. So in this case the one means partial commitment.

Q. Okay. So just to make this abundantly clear, my understanding that this spreadsheet that was excerpted here shows that Synapse used the partial commitment setting in capacity expansion modeling for its optimized Duke resources and regional resources scenarios?

A. That's right.

Q. And why did you do that?

A. To mimic Duke's settings with its own capacity expansion scenarios in its EnCompass database.

Q. Okay. Looking father down in the scenario column where it says optimized PC, Duke resources PC, and regional resources PC, what do those represent?

A. The PC stands for production cost, so those are the production cost runs that inform the ultimate PVRR that shows up in the carbon-free report.

Q. Okay. And then looking in that commit opt column, it shows that Synapse used the zero unit commitment setting in its production cost modeling for those scenarios?

A. That's correct.

Q. Can you remind us what that unit commitment setting zero represents?

A. That represents full commitment. And the zero is because the default values are often zero in EnCompass. So if the default is full commitment, zero is -- if the default is full commitment in EnCompass, in general, it's zero for these, and it represents full commitment.

Q. Okay. And was that the same setting that Duke used in its production cost modeling?

A. It was.
Q. Thank you. That's all the questions I have.
MS. THOMPSON: Thank you, Chair Mitchell.
CHAIR MITCHELL: All right. We'll take questions from Commissioners. Commissioner Clodfelter? Okay. Duffley? Okay.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Let's see. Good morning still. So I have a few questions, and it's mainly just to understand your testimony and to see exactly what you're asking of the Commission. So we'll go backwards, since I'm at the end of your testimony. So on page 49 and 47, you're talking about coal retirements and the delay of coal retirements. And you ask that the Commission seek more information from Duke, and for Duke to basically provide more compelling justification.
And so can you talk to me a little bit about exactly what does that look like and what additional information that you think is required.
A. Sure. I'd be happy to. So the reason I wrote this is, for example, subject to check, in the Carbon Plan filing that Duke made, it indicated that the Belews Creek units, for instance, would -- it

indicated in this section about retirement delays that those units would just -- would operate into the 2030s. That's a quote from the Carbon Plan.

Even though I think, from the 2020 IRPs, the earliest practical -- or practicable retirement date for those units was 2030. So that just sort of gives an example of disconnect that I saw in the Carbon Plan versus this previous earliest practicable retirement date. I'll try not to stumble on that word too much.

So I think what would be helpful to understand, in terms of what is reasonable in terms of delay or what's reasonable in terms of when those units are retired is, what specific projects are required, or what specific projects is Duke representing are required to make this -- to actuate these retirements; where are those in the development timeline; where are their costs; how -- or what are the timeline for implementation exactly, sort of, you know, is this 24 months, is it 18 months, and where are we today.

So I think it goes without saying, maybe, that there are -- there can be transmission reliability concerns with retiring these units, but, obviously, resources can be procured to replace those. And I think the place that we're flying in the dark a little bit here is what specific projects are we talking about here, what's the timeline for this, where are we in that on that timeline.

Q. Okay. Thank you. And then moving to page 43. Are you there?

A. I am, sorry.

Q. So you talk about the collaborative process and collaboration, and I'd like, if you could, to give me some context here. You mention Xcel in Colorado, Xcel in Minnesota, and then Duke Energy in Indiana.

Are -- are -- is Xcel and Duke Energy, are they leaders and first movers in sharing this -- this type of resource planning model data? And then once you answer that, are there other utilities doing this type of collaboration, and if so, what are they doing?

A. Sure. That's a great question, and I will not represent to my knowledge on, sort of, all the resource planning and transparency practices across the United States is comprehensive, but I'll do what I can here.

My understanding is that the emergence of models with the kind of transparency that allows stakeholders to, kind of, get their hands dirty and understand is a matter of the last couple of years.

And the interest for stakeholders to do that is a matter of the last couple of years. So we're talking this is very contemporary and there's changes in every cycle that's happening across the United States.

So I think these are three good case studies, absolutely, in terms of sharing data with the stakeholders, in terms of being able to validate the data, the outputs versus the inputs that we're getting, things like that. So in terms of whether they're leaders, it's hard to know, because this isn't something I've comprehensively studied, but they are, I think, good examples for us to look to here.

And then there are other stakeholder practices that are done, and one that I'm thinking of is -- unfortunately, I can't remember the name of the utility, and I'd be happy to file a late-filed exhibit or something like that in the Southwest that allowed, for example, stakeholders to select a series of inputs that the utility used in their own, sort of, production of their model results. So there was, sort of, like, a stakeholder scenario.

And that method isn't without its pitfalls, but I think it can be really clarifying to understanding how these decisions with inputs can change what the outputs look like.

So I guess to answer your question, I would say these are definitely -- these are good case studies to look at, and I think new practices are, sort of, arriving as we speak.

Q. Okay. Thank you for that. And then, on page 39, you make a recommendation regarding carbon offsets.

And can you further explain your reasoning behind this recommendation?

A. Sure. So what we're doing in this case, looking out to what the carbon governance is going to look like in 2050, is just -- it's very difficult. I mean, we've seen -- so I have sympathy for you-all, I suppose. So we've seen carbon offset markets, sort of, emerge and then collapse because of some issue with permanence or leakage or measurement even.

These carbon offsets are notoriously difficult to, sort of, confirm that this carbon has been sequestered and will be sequestered permanently. Which is, in the case of at least land-based carbon offsets, what we're talking about. So I think it's a question of, in these cases we'd seen some carbon offset markets or values sort of emerge and collapse, things like that, there hasn't really been stability there yet.

And I think the other piece of it is that, in terms of economy-wide carbon emissions projections, oftentimes carbon offsets are saved, when we're talking about economy-wide decarbonization, for the most difficult to decarbonize sectors. Things like industrial processes where, you know, metallurgical coal is just something you need.

So -- gosh, I kind of lost my train of thought there. Oh, yeah. So in using offsets for the electricity sector, which is one where we have many tools for decarbonization, might be premature. And I think the real risk that we run here is moving forward assuming that there's going to be this, for lack of a better word, bailout in the final years of the plan, and finding ourselves in a place where perhaps we haven't procured the right resources because there may not be an offset market at the end of the day. And I think that's something that, you know, we talk about -- we use the "term stranded" assets to talk about that.

So I guess my concern is offsets have -- we haven't seen a really stable long-term market for them yet, and there is potential risks with assuming that those will be there in 30 years.

Q. And I think you mention this in your testimony as well, carbon offsets are not regulated currently; is that accurate?

A. I'm not -- I'm not a -- I haven't done a large amount of research on that topic, but I don't understand there to be any, sort of, highly regulated offset available today.

Q. Okay. Thank you.

A. At least not -- there are some regimes that have emerged, like REGI, for example, which do some of that, but in North Carolina, I haven't seen anything. Or in North Carolina, I don't believe there's a highly regulated high-quality offset market today.

Q. Okay. Thank you. On page 37, so you mention on line 3 that the IRA may impact battery charging requirements. And in your opinion, how -- how will it -- how will it impact those requirements?

A. My understanding is that the investment tax credit previously, before the IRA, required that solar plus storage installations required the storage to charge directly from the solar via DC couple, that kind of thing. And I haven't done -- I haven't done a really, really deep dive on the IRA to date, but my understanding is that the tax credits that are available through the IRA remove that requirement.

And so AC charging is possible in that case, which makes the resource much more flexible, like the dynamic dispatch that we talked about earlier.

Q. Okay. Thank you. And then on page 34, also another just clarification question. You mention, on lines 8 and 9, "The regional resources scenario did not reach the four-unit availability limit set for additional nuclear resources."

Could you explain that a bit further?

A. Yeah, absolutely. So one of the revisions that we made to the Duke database was changing the availability of SMRs, or advanced nuclear resources, things like that. And part of the reason we did that was we wanted to avoid concurrent development of what is a resource that has not been commercially proven yet. So, essentially, developing, for example, seven units at the same time that take seven years could increase the risk that I think the electricity system sort of sustains by developing all these units at the same time.

So what Synapse did, what we did in our modeling, was restrict, essentially, so that concurrent development of these resources couldn't happen, more or less. So I can't remember the dates exactly right now, but what that meant was that, over the course of the planning period, 2022 to 2050, there were sort of room for four of these units to be built.

And just to clarify, that was an availability constraint that Synapse put on the EnCompass database that we got. And so when I say that regional resources scenario did not reach that availability limit, what I mean is the regional resources scenario did not build four, it built less than four SMRs.

Q. Okay. Thank you for that clarification. And then, on page 28, you talk about how the Commission should initiate a new -- I'll wait for you to get there.

A. Thank you.

Q. So you talk about how the Commission should initiate a new proceeding for pursuing long-term prospective regional planning and consideration of regional coordination. So when you say consideration of regional coordination, can you expand on this point on exactly what you mean with that -- those two words?

A. Sure. First thing I'll say is, in general, that the Commission -- this is one potential action that the Commission could take to explore transmission coordination and planning. And I give it as a recommendation, but I think this is -- I think the Commission understands that this is a critical issue and there's lots of different ways to tackle it.

In terms of regional coordination, what I'm referring to is the concept that, especially with variable renewable energy, being able to integrate that energy over a larger region allows for more economic value from those resources, more or less. That has something do with law of large numbers, where if you have these resources that are variable but you're over a larger area, then on average you could get sort of like a more predictable stream, things like that.

And in particular, when we're looking at decarbonization, that's potentially a very powerful tool. So I think you-all are aware that across the rest of the United States there are regional coordination structures like MISOs -- or ISOs and RTOs. And those do provide -- those do provide and allow for transmission projects that, sort of, multiple values, reliability, economic value, resource adequacy, and even just sort of reducing the cost of integrating more zero-carbon resources.

So there's lots of ways to tackle, I think, regional coordination, and I think that's a really thorny topic, especially because implementation is so difficult, which is why I proposed potentially -- or recommended potentially a different proceeding. But that was sort of my thinking was integrating over a larger region, so to include other states around the Carolinas.

Q. So, obviously, we're not in an RTO currently, so is that proceeding, like, to look into an RTO or is it -- is that correct?

A. You know, there's, I think, a legislatively -- a legislatively initiated proceeding in South Carolina that's looking at regional coordination generally. And one of those is, you know, full RTO, full divestment, that type of thing. But there's also energy imbalance markets and things like that.

Essentially, there are many tools in the toolkit. So I'm not -- I think it might make sense to look at several options instead of saying, you know, yea or nay on an RTO.

Q. Okay. And that's where I was going next, that what would you hope to accomplish out of this docket.

And so I was trying to figure out was it RTO, were you looking at that, or an energy imbalance market, or were you looking specifically for just imports through or building transmission through the SERTP process and the NCTPC process?

A. I think those are all on the table, and in terms of implementation, it's difficult. But it could be as simple as NCTPC using, sort of, a multivalue approach instead of thinking only about -- either thinking only about local reliability or public policy requests. So again, there's kind of a spectrum here.

Q. Okay. Thank you for that.

(Pause.)

Q. And then my last clarification question is on page 6.

A. All right. I'm there.

Q. Okay. So with your optimized model and your regional resources model, there's a larger piece of the pie from the solar.

And where is that solar -- it may just be generic solar, but my question is, where is that solar coming from? Is it coming from new build within North Carolina? Or is it from resources outside of North Carolina? And if it's from resources outside of

North Carolina, is it coming in from PJM? Is it coming in from the South?

A. That's a good question, and I don't think it's incredibly clear, and so I'm happy to clear it up. All the solar you see there and the storage is all within region. It's all within the Duke Energy DEC/DEP balancing authority. So none of that's being imported. And, essentially, what we're seeing here is EnCompass selecting that much solar subject to the transmission adder and the deployment limitations we've talked about. But all of that is within region, yeah.

Q. Okay. Thank you very much.

A. Thank you.

CHAIR MITCHELL: Who has questions?

Okay. Commissioner Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Just a couple here.

So what -- is there a deduction or an inference that you would have the Commission draw with regard to the difficulties experienced, in terms of running the model?

A. I would say that this is the North Carolina Utilities Commission's first run with EnCompass in an IRP. And it's Duke Energy Carolinas, Duke Energy

Progress' first run, and for many intervenors, it's their first look at it. So I think learning is -- I think growing pains are something that we should expect. But I think I try to give recommendations in my testimony for ways that we could improve it.

Q. So it's more -- what you want the Commission to get out of it is more educational than informational base?

A. Well, in terms of what I think is good, is going to lead to potentially smoother proceedings and more shared understanding and more collaborative problem solving in the future, I think things like more transparency, longer timelines are going to be important, and I think will at least give us a better shot at coming to a Carbon Plan that's, you know, in the best public interest.

Q. And do you have a -- sort of the same question as a certain deduction or inference that the Commission should draw from the fact that Synapse had an inability, at least, to validate Duke's numbers?

A. I would say I'm confident in my team. I'm confident in Synapse as an organization. I'm confident that our approach to the EnCompass model was the appropriate one in all cases. Or at least the appropriate one in terms of import and validation. And my thinking is that -- is that the validation issue could likely be from some other input problem where there was one tiny change that was made somewhere deep inside the model that was a difference between what we got and what the outputs looked like that we also got.

I think simply put, these are really complex models, and moving them from place to place is difficult. And even maintaining version control when -- I'm not sure how big the Duke Energy modeling team is, but I'm assuming it's big, that's difficult.

So in terms of a deduction that I would have -- that I would have the Commission take, I would say I do think it's -- I do think the validation issue is a problem, because it's hard to be confident that our models are running correctly when that's not the case. But I think I might chalk it up to just the time, the compressed timeline on this.

Q. So do you or don't you -- is the inability to validate significant to the -- the results that we see with the scenarios?

A. I would say it does. The reason that we validate is to make sure that our model works exactly like Duke Energy's model does. And I think we and the intervenors got very close, very, very close to validating and getting exactly the same result. And so for that reason, I do have confidence that, you know, for example, the Synapse EnCompass scenarios do model appropriately.

But the lack of validation creates a risk that there's some tiny piece of this that's working in a way that's not expected. And that's just -- that's just an unfortunate thing we have to work with here.

Q. Thank you.

CHAIR MITCHELL: All right.

Commissioner Hughes?

EXAMINATION BY COMMISSIONER HUGHES:

Q. I have a modeling itch I hope you can scratch. You're the first modeling specialist I've had since I started worrying about this. But, you know, we're being asked to infer a lot of -- a lot of value and information from these present value numbers. And in some cases, there's large deltas, but in some cases, really small deltas. So I'm just curious if you could say a little bit about something we haven't heard a lot about, which is the discount factor that's used for calculating these.

And then kind of on a related note, the

inflation factor that's used. I saw, in here, you talk a little bit about inflation of PPAs, but -- in your model write-up. But could you just talk a little bit about those? And there was any test, because we're in this weird macro world of kind of changing those, and does it change the order of everything?

A. Yeah, these are good questions. I'm happy to talk about them. And I know you said you have a modeling itch, but I think I may be a little long-winded, so I hope I don't scratch too much.

But I would say, on the inflation, which is the easier one, when we were configuring this model, inflation wasn't the, sort of, public policy issue that we're hearing about in the newspaper on a regular basis. And so we used what is typical for us, which is taking some kind of long-term inflation estimate that's produced by one of the branch banks of the federal reserve. So something like 2.5 percent, and we just apply that to everything basically.

The inflation issues that we're seeing today are difficult because broad-based inflation that sort of affects the value of the dollar on everything might not change differentially to resources subject to the same inflation. Differentially, there might not actually be that much difference if they're subject to inflation.

But I think it is something to keep in mind here. And one part of modeling is -- one part of modeling is that keeping -- it's very difficult to get the most up-to-date thing into your model as quickly as possible.

In terms of the PVRR, it's a really good question, and I'm glad you're focusing on it. The way that we calculate it, which I believe is the way that Duke calculates it, is using a discount rate that's equal to the weighted average cost of capital for Duke Energy. So you calculate an annual cost of, you know, carrying all these capital investments of fuel, all that stuff, and then over time you discount by the weighted average cost of capital.

That can be helpful and is what I understand to be very common across resource planning, in general, but I think if you really dug into it, there might be -- some people might recommend, you know, a social discount level that's less, because obviously, we're talking about ratepayer dollars here.

So it's an interesting policy question. I think we, sort of, default to the weighted average cost of capital because that's -- I guess that's sort of the structure that we adopt here. But it's a good question.

Q. Yeah. You got an issue that I've had since I've been here is that, you know, is the customers' discount factor -- discount rate the same as a major corporation. And I'm thinking of our average customer. I'm not sure that's the case, but that goes down a rabbit hole that I don't want to pull this group into. But I appreciate that.

Just a follow-up on the inflation. One of the things that we've heard, sort of, as strategies for making different choices, and it comes up a lot, is the idea, you know, of hedging, of locking things in. So, I mean, the thing that I noticed was, particularly for your PPAs, you do, kind of, inflate those.

A. Uh-huh.

Q. But from what I understand, one of the advantages of a PPA is, in general, the way I think we've structured them in the past, is to lock in a rate, and it doesn't inflate. So it's actually becoming a much better deal as you -- you know, as you move forward than, say, something that is gonna require the payment of fuel cost and those kind of things.

So I don't know if this is a small issue or a big issue, I'm not sure if this issue makes sense, but I just -- I just wondered like how are those things treated? Again, you know, I'm not sure how big a deal it is in this particular model, but you're up here and might as well.

A. I'd say my understanding is that PPAs can be structured to the, sort of, the cost of -- cost-per-megawatt hour can be structured to either increase with inflation or stay flat. And I think, as a conservative approach, we just chose to inflate those numbers, just because that would avoid this issue where maybe they were undervalued at the end or over time.

But I think I wouldn't expect it to have a very large effect on the -- on the results, in part because the -- in part because there aren't that many PPAs that are available because of -- because of the third party and Duke Energy ownership issues. But it's definitely something we can look into. And I think depending on the structures that are dominant in terms of PPAs in the Carolinas, it might make sense to use something different. I think there's just two separate ways of approximating what a PPA looks like.

Q. Okay. I'll stop there. I don't want to pull people in. But I really appreciate those things. Thanks. No other questions.

CHAIR MITCHELL: Commissioner McKissick?

EXAMINATION BY COMMISSIONER McKISSICK:

Q. Just a few questions for you, and I certainly appreciate your testimony.

I think you said early on in your testimony you became familiar with EnCompass around 2015, and that you began using it in 2021; is that correct?

A. I apologize if I misspoke. I meant to say that Synapse Energy Economics, the consulting firm, started their practice with EnCompass in 2015 or 2016. And I came on to Synapse in 2021 and began my training then.

Q. I see. So when you joined them in 2021, that's when you became familiar with EnCompass?

A. Yeah. And I'd been -- I'd analyzed the results of IRPs in the past, so I had some familiarity there. But that was my introduction to the, kind of, like, guts of EnCompass in particular.

Q. And I take it Synapse usually is looking at results of EnCompass and comparing it against what alternative outcomes might be typically?

A. Synapse typically -- I think that's a fair characterization. Typically we -- especially when we have another EnCompass database to look at that a company produces. We can look at that one, assess what we think of those assumptions, change those to the extent that we want to, and then see how that affects the portfolio that, sort of, emerges on the other side.

Q. And with that overview and experience, based upon the way Duke has used EnCompass, what do you find to be perhaps concerning? And when I say that, I'm thinking perhaps limitations that were done or adjustments outside of the model, if you could speak to that.

A. Well, that's a pretty large topic, and I'm trying to think about how to best answer it here. I would say in -- there's a couple of different ways to think about this. There are several quantitative input assumptions, like capital costs or gas -- gas projections that we -- we thought could be revised and we made revisions in our model. And I think there is also assumptions about how much deployment is possible, which is something you need to do to get your model to be actionable like we've talked about, and we made revisions on those too.

I think, in general, my concern is when

several things are kept in stasis -- kept stable, just as they are today, things like, for example, energy efficiency where there's -- you know, Duke Energy Carolinas, I think, hit 1 percent of retail a year ago, and there's really like an expectation of growth -- essentially, by locking those kind of predictions in and saying, you know, this is in statis here and we're gonna expect that continues like that through the rest of the future. That's lost opportunity to capitalize on those types of resources.

And so I think that's true for demand-side resources, in general. It's very difficult to model, but I also think it's important to think about what the capabilities are there.

And then another one that's very difficult to model but was sort of kept status quo in these models was the, sort of, transmission regime that we're working with here. Again, these are thorny questions, but I think they -- we should think about what assumptions are being embedded when we are thinking about the analytical value of this tool.

Q.   And in terms of the number of, I guess, solar interconnections that might be imposed or that were imposed with the way Duke kind of adjusted the model, what were your thoughts about that?

A. So that's another case where I think the fact that our model procured more solar than Duke's when we -- when using the assumptions that we did indicates that EnCompass thinks that there is, you know, economic value to be had by procuring these resources. And to make the inference, there's economic value left on the table when that procurement doesn't happen, you know, in a way similar to what we sort of project here.

So I think that's kind of the major issue is the risk of losing out on these resources that provide, you know, important value here. In terms of what I -- what I used to create the projections that I did, I'd say I looked at the -- I looked at the developments that have happened recently with interconnection, like the move to clustering, for example, and looked at, sort of, historically what Duke Energy's interconnection has looked like and made, essentially, a reasonable assumption that there was, you know, greater ability to do this.

I think even things like -- even things like transmission planning that work a little differently, or the -- yeah, there's potentially many process improvements we could make that could make the interconnection easier. And if we lock in, again, the deployment that we have today, then we assume that none of those happen, more or less, and I think that's a risk.

Q. Okay. Now, on page 50 of your testimony, at the very bottom there's a Table 6 relating to carbon-free by 2050 short-term recommendations. Now, what I want you to do are two things. First, I want you to review what you have in this chart; and then secondly, I'd like you to contrast it to what Duke has as it relates to its portfolios and the recommendations that they have, in terms of what might be done near-term.

A. I just want to make sure I understand your question. You're saying you'd like to review this table and compare and contrast with what that looks like in the Duke --

Q. Yes, exactly.

A. Okay. I will -- I'll do my best here, but what I'll say is I didn't -- I didn't review the results of the SP5 and SP6 portfolios in great detail. And I also don't have, for example, Duke's Short-Term Action Plan in front of me, so this is going to be high level, I guess.

MS. THOMPSON: Commission McKissick -- Chair Mitchell, may I approach the witness with a copy of what's been marked and I think admitted Modeling and Near-Term Actions Panel Rebuttal Exhibit 1, which is a chart that might aid Mr. Fitch in having an efficient answer to the question?

CHAIR MITCHELL: You may.

MS. THOMPSON: Thank you.

(Pause.)

THE WITNESS: All right. So I'll just kind of go row by row here.

Q. Sure.

A. All right. On energy efficiency, obviously, what we're looking at here is 1.5 percent of retail load as an incremental savings target, and that is higher than both Duke's base and high projections. And that -- the way that we modeled it, sort of, ramps up to there in 2030, I think, is when it hits 1.5 percent. So that's a greater investment energy efficiency.

For distributed energy resources, the EnCompass scenarios we used Duke Energy's high DER adoption, which anticipates a little bit of acceleration in the rate over a '22 to 2050. Yeah, 2022 to 2050. So at 2035, it's -- there's some separation between Duke's projections and what I -- what we have, but I think it's meaningful, so more DERs.

Additional solar, there's already been a lot of, I think, hearing time on this, but the Synapse models anticipate more procurement of solar. So, in particular, I think we're talking about 4 gigawatts 2022, 2024 procurement timeline. So that's greater than I think what -- what Duke Energy has, sort of, projected.

And similar for battery storage. I think our model sees a lot of value in battery storage to integrate these resources and provide capacity, so we procure a lot of this.

For onshore wind, it's very helpful to have this now. Based on -- based on this exhibit that Ms. Thompson handed me, it looks roughly the same, and I think that's -- this shows that there is value and diversity of variable renewable energy resources.

And then for onshore wind Midwest, this is a resource that Synapse introduced into the model that's a PPA, a sort of third-party-owned solar that's procured through PJM. And we included the firm point-to-point cost of importing these resources, which is quite high, to be clear. And we found that our model selected that significantly. Just showing, I guess, the value of regional procurement, in general.

And then for offshore wind, I believe ours is broadly consistent with what Duke Energy has. Let me -- yes, I think that's right. I can keep going through the -- the kind of options for long-term procurement if that's helpful.

Q. I think you've touched upon most of the issues I was concerned about or had interest in. Now, let's talk a little bit about the -- what I'll call onshore wind in with PJM.

I mean, you factored in the additional substantial cost, what's related to transmission upgrades or improvements that would be necessary for that to occur in your model; is that correct?

A. Yeah. We used PJM's firm point-to-point transmission costs, which I'm hesitant to rattle off the numbers, so I won't. But we did use that, and we had an inflate at 2.5 percent over year-to-year, and it was every year incurred.

Q. And even with that adjustment, it showed as if that was a viable option that automatically kicked in a newer model projection?

A. That's right. And I think that speaks to just the value -- or just the capacity factor of the Midwest wind. I mean, driving through there you get a sense of what the power of that wind is like. And for that reason, capacity factors and even costs are -- capacity factors are high, costs are low, and for that reason it's cheap zero-carbon energy.

Q. Very good. Well, I think you've covered the things I was concerned about, in terms of contrasting and comparison, so appreciate your testimony. Thank you. No further questions.

CHAIR MITCHELL: All right.

Commissioner Kemerait?

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. Thank you. And most of my questions have now been answered. I just have one follow-up clarifying question, and it relates to energy efficiency, and I don't think you need to look at it, but the table on page 37 where you state, "Higher level of energy efficiency is achievable and lowers total system cost."

And I think that your -- your testimony is that Duke's proposal of 1 percent of eligible retail load being the target would leave benefits for ratepayers on the table, I think is what you said earlier. So Duke's testimony several days ago, or last week, was that the 1 percent would be the target that they would try to improve upon that, if possible.

And so with that kind of assumption of 1 percent and hopefully improving upon that, can you describe whether your view about leaving benefits to ratepayers on the table would still be valid based upon that idea, try to do better if possible than the -- from the 1 percent?

A. That's a great question, and this is a tricky issue that spans IRP and I think rate design and rate case issues, which I know are also going to be something under your consideration soon. I'd say that what we're showing here is the economic value of wind. There is more energy efficiency and demand-side resources available. And I think that's helpful to the Commission to just say, to the extent that we can continue to procure this at a similar price to what Duke's paying for now, it's good, it makes sense.

But I think implementation is a difficult thing with energy efficiency. And I think the tools that the Commission could use to do that include just gathering data on this topic, and potentially could be something that could be subject -- and I don't want to get into this in detail, but it could be something that could be subject to the performance-based ratemaking. But I think this is sort of before the Commission today.

So I think there's -- my worry with "we'll see what we can do" is that it's very difficult to hold someone accountable to "we'll see what we can do." So I think, you know, setting incremental higher targets and all -- using the other tools that are available to the Commission could be a way to find some accountability and potentially access some of these benefits.

Q. Okay. Thank you.

CHAIR MITCHELL: Commissioner Hughes?

EXAMINATION BY COMMISSIONER HUGHES:

Q. Yeah, another modeling itch related to how you're modeling EE and DSM.

Are you familiar with the cost recovery mechanism that we have in North Carolina at all?

A. I wouldn't -- I don't think I can testify with a lot of confidence on that mechanism.

Q. Well -- so when you're mod- -- when you're modeling the cost of EE and DSM, customer cost --

because that's what we're talking about, is the PVRR -- are you just taking, sort of, a historic cost and inflating it? Are you taking whatever Duke had in their model and just inflating it? Or are you making any kind of -- so you're not -- you're not looking at actually how we pass it on to the actual individual customer?

A. So what we did in this case was we used the cost stream that was identified in Duke Energy's modeling. It's sort of the -- you know, programatically, what kind of procurement are we doing, what are we expecting in terms of behavioral energy efficiency savings, and we did proportionately scale that up to meet the 1.5 percent of retail load. And we did the same thing for attended costs for each of the categories. And then those are a separate cost steam that we integrated into the PVRR at the end there.

So I think broadly, for the purposes of how the PVRR was calculated in Duke Energy's versus Synapse's, they're consistent. I don't have as much confidence on exactly how that implements into the rider -- or the mechanism, rather.

Q. No, no, I appreciate that, but you did it the same way, so I think we have a chance with the Duke

Modeling Panel hopefully later today. Thanks.

CHAIR MITCHELL: All right.

Commissioner Clodfelter?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Fitch, I do have one question for you, just to be sure I was understanding something correctly that's in your official report, the carbon-free by 2050. Do you have that?

A. I do.

Q. I just -- I think -- I think I understand it correctly, but I want you to confirm that with me in Appendix B, page 15.

A. I'm making my way there. Okay.

Q. You talk about the different results from running Version 6.0.9 and 6.0.4. And I think I understand what you're telling me there is that, in 6.0.9, the model was assuming that the listed units there would run on 100 percent gas, whereas in 6 -- what I want to confirm is that, in 6.0.4, the model assumes that the units co-fire at the existing actual percentages that those units are capable of today, right?

A. That's right, yeah.

Q. So what I'm seeing in Table B-1, then, is the present value revenue requirement difference between running those units 100 percent on gas and running them as they are currently configured to run.

Am I understanding that table correctly?

A. That's my -- that's my -- that's my understanding of the table, yes, is that it assumes that -- my understanding is this is a physical constraint of these units, that they're not able to run actually 100 percent on gas today, but there's some co-firing that has to happen for these specific units. And in the 6.0.9, there was a bug where it was able to run completely on gas.

So the change in PVRR that we're looking at, the increase is just because there is a -- we're adding coal back into the mix, which just a higher dollar-per-megawatt-hour, sort of, fuel. So more or less what I'm saying is I think that your understanding is correct.

Q. Okay. That's what I wanted to be sure of. Thank you.

A. Thank for allowing that clarification.

EXAMINATION BY CHAIR MITCHELL:

Q. Okay. I have just a few questions for you. Let's stick with the coal retirements just for a minute.

So is it your -- is it Synapse's position or is it your position that the Companies' out-of-model delays for those coal units -- for certain coal units was inappropriate?

A. I would say it was not sufficiently justified in the current filing.

Q. Okay. So do I understand correctly -- and correct me if I'm wrong here, but do I understand correctly that the modeling that you-all did allowed the model or the -- let me say it differently.

The portfolio you-all came up with -- portfolios you-all came up with allowed the model to select the retirement dates for the coal units?

A. That's right, yeah. So we've talked about endogeneity, this is another example of that.

Q. Okay. And, sort of, having corrected the issue that Commissioner Clodfelter just discussed with you that's set forth on B-15, the modeling that you-all did allowed the model to select the retirement dates taking into account that some of those units co-fire?

A. Yeah, that's right.

Q. Okay. And on page 49 of your testimony, you indicate that, as I understand it, that when the

Companies delay retirement dates out of model, they should provide compelling justification for doing so. And you specifically mention transmission and generation retirements, feasibility of a procurement of development -- and development of alternative resources, and timelines for developing resources and retiring the units as early as practicable.

You -- did you -- have you heard any of the testimony given in this hearing room by any of the Duke panels on this issue?

A. I've heard a significant amount of the testimony, but I'm not -- I haven't heard all of it and I'm not exactly sure if you're referencing a single topic, what that -- what was said.

Q. Well -- okay. On this -- on the issue of the retirement dates for certain coal units.

Do you -- I mean, is it your position that the Companies haven't provided compelling justification for those out-of-model delays?

A. Based on what I reviewed, that is my -- that's correct.

Q. Okay. Okay. Let me move on. Ms. Luhr asked you a couple of questions, and one of them was, did Synapse use a typical week structure. I think that's what she said, at least that's what I'm remembering.

What is a typical week structure? What does that mean? Why is that important? Help me understand how that even fits into what we're talking about.

A. Sure. So I think what Ms. Luhr asked me, my recollection is that she asked if we used the typical day structure, which is similar. Which is one of several options for, sort of, like, time-of-day structures you could use. And Duke Energy has, in their testimony, talked at length about the potential issues with the typical day. And I think we -- I believe, in the Snider rebuttal testimony, there is several graphs that sort of indicate there's this peak and there's a valley, and that type of thing.

So that's typical day. And what that attempts to do is, for a given month, include sort of the highest -- the peak demand for that month, and also what the lowest point at that month looks like. And the reason that's important is because there are, you know, minimum capacities for some of these units, and so you want -- one wants to get a sense of what minimum load looks like.

So the typical week, essentially, condenses the four weeks of every month into seven days, seven

24-hour periods, and then runs hourly dispatch on that. So it's kind of -- it avoids some of the artifacts of the typical day structure, but it allows for a little more flexibility in terms of run time.
Q. So it's just easier on the model to do typical week versus typical day, meaning that sort of the practical limitations of the model that we've discussed earlier in this hearing. Okay. I'm just trying to understand.
So did -- and I think you were shaking your head yes, but if I -- I'm trying to understand the difference between the typical day structure and the typical week structure.
A. Sure.
Q. And is it -- so Duke used typical day?
A. Yeah. I mean, I'll just try to make this as clear as I can. What Duke Energy used was typical -- typical day for capacity expansion. And it used 8760 for production cost. 8760 being every hour of the year. And I guess the thing to say about typical day, week, and 8760 is typical day includes this artifact-type thing that includes, like, a sharp peak and a trough and that kind of thing. And the typical week, I think, does a similar kind of -- a similar kind

of summing together, but it integrates over seven days.

So in Synapse's view, those days are represented -- or that week is, sort of, representative of the month and avoids some of the pitfalls of what you see in typical day, but it also avoids having to run 8760, basically.

So just -- yeah, just to be completely clear, Duke used typical day for CAPEX and 8760 for production cost. And we used typical day for CAPEX and typical week for production cost. And I think the other thing to say about typical week is, especially with the storage unit redeployment that we're talking about, it's important to have consecutive days, and that's why I think it was important to do, to use something that has consecutive days, like typical week.

Q. Explain that -- that last sentence.

A. Sorry. Essentially, if you -- if one was modeling a single day for -- and had a lot of storage on the system, one could more or less deplete the storage over the course of the day and then find that everything is fine, everything works okay. But there may be an issue with the, sort of, total amount of banked energy that's available.

So using consecutive days allows you to more robustly check if those issues are going to be -- are gonna limit the model's operation in some way.

Q. Okay. But does using a week versus a day obfuscate the issue that Duke testified about, about there could be days when the battery isn't charged because -- due to weather? And so if you're looking at a week versus a day, you might be ascribing more value to the battery than it can provide to the system? Or am I just misunderstanding the issues?

A. I think -- I think the more consecutive days you model, the closer to accuracy, or the closer to real-world operations you get. So I would say that typical week is -- allows for, kind of, like, a better understanding of storage operations compared to typical day. But I don't think it would include any inappropriate -- I don't think it's overvalued I guess is what I'm saying.

Q. Okay. And so really the different -- so for the difference between the Synapse modeling and the Duke modeling is in the production cost aspect of the modeling. So Duke's looking at every single hour --

A. Uh-huh.

Q. -- and Synapse is looking at a week?

A. Uh-huh.

Q. And in my mind, and I am not a modeler, but looking at every hour provides the most granularity, the most information that you can then extrapolate from -- versus looking at a week.

So why -- help me understand, and you may have already said this and I'm just -- you're gonna have to say it again, why is looking at a -- why does looking at a week versus every hour give you a better picture of ultimate costs, production costs?

A. I think it's a balancing decision that has to do with, kind of, like, the realities of modeling run time, things like that. So that's definitely an aspect that comes in here. The difficult thing for -- let's see. Our understanding is that typical week would not introduce any sort of artifacts that would overvalue something like storage. We feel like it's sufficient for that.

I mean, we could think about it as -- trying to do math off the top of my head, but I think it's, like, 2- or 3,000 hours versus 8,000 hours, something like that.

Q. Okay. And do you -- did you-all discuss this anywhere in your -- either in your -- I didn't see it in your testimony, and I could have missed it, and I didn't see it in the report.

A. I don't think that the typical week -- the typical week description, we don't go into that detail, no.

Q. Okay. Okay. All right.

A. It might be helpful to say that, when we found the model issue, the model versioning issue, the 6.0.4 to 6.0.9 issue, and we were given the extension of five days, we did have to rerun every single run over that five days. And that was, like, a 24-hour-per-day process. And we were running things as quickly as we could and including them in the reports. So the typical week was helpful, or the typical week allowed for some more flexibility there --

Q. Okay.

A. -- in terms of just -- yeah, integrating the version change.

Q. Okay. Understood.

CHAIR MITCHELL: Let's see. All right. I think that is all for me. What we're gonna do is break for lunch, so we'll be off the record. We will come back on the record at 1:30 and we will resume with questions on Commissioners' questions. And I'll just say it again, 1:30.

(The hearing was adjourned at 12:45 p.m. and set to reconvene at 1:30 p.m. on Monday, September 26, 2022.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was conducted, do hereby certify that any witnesses whose testimony may appear in the foregoing hearing were duly sworn; that the foregoing proceedings were taken by me to the best of my ability and thereafter reduced to typewritten format under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 29th day of September, 2022.

JOANN BUNZE, RPR
Notary Public #200707300112