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May 28, 2021

VIA ELECTRONIC FILING

Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Reply Comments
Docket No. E-100, Sub 165

Dear Ms. Campbell:

Please find enclosed for filing the Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (collectively, the "Companies") in connection with the above-referenced proceeding.

Portions of the Reply Comments contain confidential information and are being filed under seal and under separate cover. The Companies will make this information available to other parties pursuant to an appropriate confidentiality agreement.

If you have any questions, please let me know.

Sincerely,

Jack E. Jirak

cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 165

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans	)))	DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC REPLY COMMENTS

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and Duke Energy Progress, LLC

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

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UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 165

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
2020 Biennial Integrated Resource Plans and	)	DUKE ENERGY CAROLINAS
Related 2020 REPS Compliance Plans	)	AND DUKE ENERGY PROGRESS'
	)	REPLY COMMENTS

INTRODUCTION

The 2020 Integrated Resource Plans (each an "IRP" and together the "IRPs") of Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke," "Duke Energy," or the "Companies") provide a comprehensive overview of the Companies' in-depth analysis of the long-range needs of the Duke Energy system over a range of potential future scenarios. Extensive in their scope and exhaustive in their depth of analysis, the IRPs identify the least-cost, reasonable and prudent means of meeting Duke Energy's customers' energy and capacity needs under a variety of conditions that could be experienced in the future and should be accepted by the Commission for the reasons further described herein.

Duke Energy appreciates the constructive feedback received from a variety of stakeholders both in the context of this proceeding as well the feedback received in the extensive stakeholder efforts that were conducted prior to the proceeding. The IRPs reflect many aspects of the feedback previously received, and future IRPs will continue to evolve based on feedback received in this docket.

Duke Energy has adopted near- and long-term carbon emissions reduction goals: the near-term CO_2 emissions reduction goal is at least 50% by 2030 and the long-term goal net-zero CO_2 emissions by 2050. These corporate goals are consistent with and informed by the many customer and stakeholder voices that have expressed a strong desire for a cleaner energy future. Duke Energy seeks to deliver that future while keeping energy affordable and reliable for all of our North Carolina and South Carolina customers. In this vein, the 2020 DEC and DEP IRPs go beyond delivering just a single "least cost, reliable plan" but also include a broad range of scenarios to achieve varying levels of carbon reduction, including (i) pathways to achieve up to 70% CO_2 emissions reduction by 2030, (ii) an "earliest practicable" coal retirement portfolio as requested by the Commission in Docket No. E-100, Sub 157,[1] and (iii) presenting a "no new gas" alternative portfolio at the request of stakeholders.

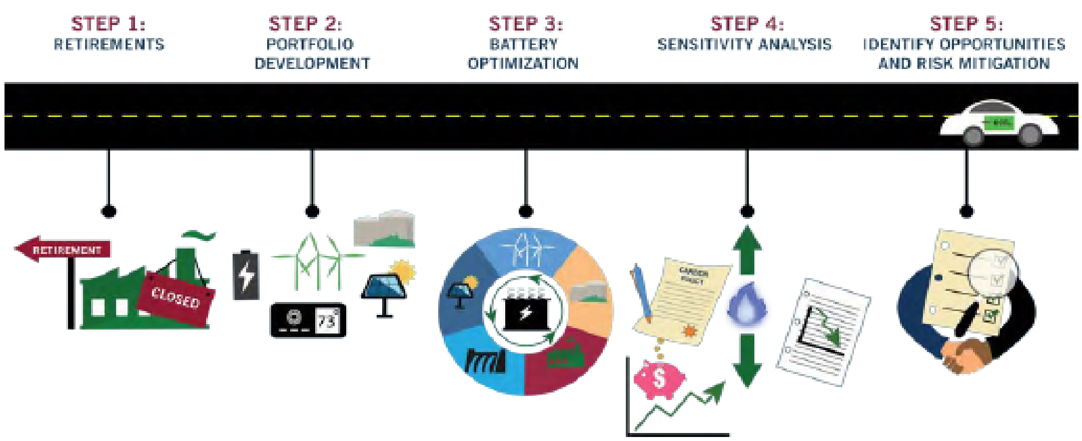
The 2020 DEC and DEP IRPs reflect aggressive pursuit of additional renewables in the Carolinas, adding two to four times the already nation-leading levels of solar capacity over the 15-year planning horizon, and for the first time the IRPs include both onshore and offshore wind as viable resource alternatives in several portfolios. Grid and technology improvements also play an ever-important role in the road to decarbonization, and the 2020 IRPs include detailed information on the Companies' plans for increased energy storage, accelerated use of new technologies, and the grid investments needed to support coal retirements while ensuring power system reliability is maintained. Finally, natural gas generation continues to play a crucial role as a flexible, reliable, economic, and proven resource that will "keep the lights on" in the Companies' journey towards toward net-zero emissions by 2050.

[1] *Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans*, Docket No. E-100, Sub 157 (April 6, 2020) ("2019 IRP Update Order").

a. <u>2020 IRPs Analyze Varying Pathways for a Cleaner Energy Future while Balancing Affordability and Power System Reliability</u>

The DEC and DEP 2020 IRPs are designed to ensure the reliable supply of power for customers while balancing affordability, environmental considerations, and other factors such as diversity of generation supply. As detailed in Chapter 12 of the 2020 IRPs, developing the IRPs is a complex analytical process of evaluating the system that exists today and planning for the system of the future.

Figure 1: IRP Road Map[2]



As a result of this extensive resource planning process, the six portfolios presented in the 2020 IRPs comprise a total plan that will be adapted over time to account for changing regulatory standards, technology developments, and future state and federal policy mandates. In order to assist the Commission, policymakers and other stakeholders in their consideration of the alternative policy and regulatory pathways presented in the 2020 IRPs, the Companies also included analyses (i) comparing total incremental resource costs associated with each resource portfolio, (ii) highlighting the trade-offs between costs, carbon reductions, and dependency on technological and policy advancements, and

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[2] *See* DEC 2020 IRP at 90; DEP 2020 IRP at 93.

(iii) comparing the associated average monthly residential customer bill impact of each of the portfolios.

The following table summarizes the six generation portfolios modeled and evaluated in the 2020 IRPs, each of which keeps Duke Energy on a trajectory to meet its short- and long-term CO_2 goals:

Table 1: DEC/DEP Combined Portfolio Results Table from 2020 IRPs

DUKE ENERGY. PROGRESS

DEP / DEC COMBINED SYSTEM PORTFOLIO RESULTS TABLE

	Base without Carbon Policy	Base with Carbon Policy	Earliest Practicable Coal Retirements	70% CO_2 Reduction: High Wind	70% CO_2 Reduction: High SMR	No New Gas Generation
PORTFOLIO	A	B	C	D	E	F
System CO_2 Reduction (2030 | 2035)[1]	56% 53%	59% 62%	64% 64%	70% 73%	71% 74%	65% 73%
Present Value Revenue Requirement (PVRR) [$B][2]	$79.8	$82.5	$84.1	$100.5	$95.5	$108.1
Estimated Transmission Investment Required [$B][3]	$0.9	$1.8	$1.3	$7.5	$3.1	$8.9
Total Solar [MW][4, 5] by 2035	8,650	12,300	12,400	16,250	16,250	16,400
Incremental Onshore Wind [MW][4] by 2035	0	750	1,350	2,850	2,850	3,150
Incremental Offshore Wind [MW][4] by 2035	0	0	0	2,650	250	2,650
Incremental SMR Capacity [MW][4] by 2035	0	0	0	0	1,350	700
Incremental Storage [MW][4, 6] by 2035	1,050	2,200	2,200	4,400	4,400	7,400
Incremental Gas [MW][4] by 2035	9,600	7,350	9,600	6,400	6,100	0
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][7] by 2035	2,050	2,050	2,050	3,350	3,350	3,350
Remaining Dual Fuel Coal Capacity [MW][4, 8] by 2035	3,050	3,050	0	0	0	2,200
Coal Retirements	Most Economic	Most Economic	Earliest Practicable	Earliest Practicable[9]	Earliest Practicable[9]	Most Economic[10]
Dependency on Technology & Policy Advancement						

The extensive analysis and discussion of these portfolios in the 2020 IRPs, including their relative costs, provide a comprehensive view of options for a cleaner energy future as the Commission, stakeholders, policy makers, and the Companies collaborate on the best path forward for North Carolina.

As the Commission is aware, the IRP is developed as a "snapshot in time" to provide insight into future energy plans for the Carolinas based on the best available information at the time the plan was prepared. The IRP process is lengthy, complex, and performed in a dynamic and uncertain legislative and regulatory environment. For example, subsequent to the September 1, 2020 DEC and DEP IRP filings, a new Presidential administration was elected, and various energy proposals are being discussed at the federal and state levels. There is no doubt that future technologies and future policy enacted by state and federal lawmakers will influence future IRPs. With this backdrop of uncertainty, the 2020 DEC and DEP IRPs present a comprehensive analysis of six potential resource planning pathways for our Carolinas customers, while still meeting the high level of reliability required to safely power our customers' needs.

A consistent theme reflected in numerous consumer statements of position filed with the Commission and provided in public witness testimony is a call for accelerated retirement of the Companies' remaining coal plants, less or no reliance on natural gas or other fossil fuels, and greater or total reliance upon renewable resources, energy storage, demand side management ("DSM"), and energy efficiency ("EE"). These same general themes are expressed in the comments filed by many of the intervenors to this docket. Duke Energy shares our stakeholders' interest in transitioning to a cleaner energy future; however, a careful examination of intervenor comments and alternative resource proposals reveals their analysis is biased toward pre-determined results, is supported by technically-inferior approaches to analyzing the complex issues considered in the 2020 IRPs, and, most importantly, fail to plan for "real world" operations in the Carolinas. Only the Companies' IRPs present the comprehensive and sophisticated analyses needed and have developed the portfolios of new supply and demand-side options under numerous scenarios necessary to effectively balance reliability, customer affordability, and environmental considerations while planning for operating DEC's and DEP's power systems in the real world. Unlike the Companies, who have responsibility for providing reliable power 24 hours a day, 365 days a year, under any conditions, no intervenor prepared a resource adequacy study to ensure the integrity and reliability of the DEC and DEP grids under their proposed generation mix.

As highlighted above, the Companies' 2020 IRPs received significant stakeholder interest and have been subjected to substantial scrutiny. The Companies have made extensive, good faith efforts to engage with stakeholders regarding the 2020 IRPs and plan to continue to do so in the future. As part of the Companies' process to prepare the 2020 IRPs, Duke Energy held a series of stakeholder sessions and received input from more than 200 stakeholders representing diverse customer, environmental, clean energy, and policy interests. These efforts included:

- holding multiple professionally-facilitated stakeholder meetings prior to the filing of the 2020 IRPs, and one after to explain results;
- creating an IRP engagement website; and
- developing a first-of-its-kind utility-supported, interactive and web enabled "Portfolio Screening Tool" accessible at https://screeningtool.duke-energy.com/ that allows stakeholders to test the reliability implications of a proposed resource portfolio over a 7-day winter, spring or summer period in DEC and DEP's service territory.

These efforts, summarized in the Stakeholder Engagement Summary Report developed by ICF International and presented as Attachment 1 to these Reply Comments, demonstrate the Companies' significant commitment to engaging with stakeholders as part of developing the 2020 IRPs. In addition to these direct stakeholder engagement efforts, just two days after filing the 2020 IRPs, on September 3, 2021, the Companies also set up an FTP site for interested parties and uploaded approximately 350 MB of data and supporting documents for the IRP and Resource Adequacy Study to allow an early and thorough review of the modeling, analysis, inputs and assumptions used to build the 2020 IRPs, without the need for initial data requests from intervenors. In addition, since the IRPs were filed September 1, 2020, DEC and DEP have responded to more than 3,000 data requests combined in this proceeding and the South Carolina 2020 IRP proceedings, which overlapping parties/counsel in both states have been able to access. DEC and DEP's 2020 IRPs withstand scrutiny and, as discussed in more detail herein, should be accepted by the Commission.

b. The Companies IRPs Plan for Significant Decarbonization while also Planning for a Diverse Portfolio of Demand-Side and Supply-Side Resources that Ensure System Reliability

The Companies are in the midst of an unprecedented, long-term transition from a legacy fleet that historically included significant coal generation towards a new mix of cleaner generation, including renewables, battery storage systems, and efficient natural gas across the Companies' systems. The Companies and the Commission must prudently and judiciously plan for and execute this transition in a way that protects power system reliability and ensures continued customer affordability.

It is important to note that every portfolio and every resource type carries risks and benefits, and only the Companies' objectively- and holistically-developed resource plans adequately balance such considerations. Some parties would have the Commission disavow natural gas generation without acknowledging, much less fairly considering, the critical role natural gas resources have in providing immediate carbon reductions relative to the coal resources they are replacing, while simultaneously providing reliable and flexible system resource needed to incorporate additional variable and intermittent renewable resources onto the system. Further, many interveners suggest replacing coal with singular reliance on variable and intermittent renewables paired with emerging battery storage technologies without consideration of the reliability and economic risks such a strategy would place on customers.

In light of the long-term energy transition that is underway, the 2020 IRPs support a diverse mix of proven dispatchable technologies along with prudent levels of emerging storage and renewable resources that will be necessary to ensure that the Companies are both meeting the reliability needs of the system and also prioritizing customer affordability. Unfortunately, these priorities of resource diversity, operational reliability and customer affordability do not appear to be shared by many intervenors, which instead advocate for or against specific technologies, depending upon the mission or financial interests of the organizations they represent.

An unbalanced and unproven resource mix resulting from intervenor-introduced biases in system planning could have critical consequences for customers introducing both economic and reliability risks. Recent experiences in Texas and California underscore the importance of keeping all reasonable generation and infrastructure options on the table and available to customers, particularly during this time of energy transition. Despite touting foundational regulatory principles of designing a portfolio to ensure adequate and reliable service at least cost, many intervener comments approach this proceeding from a very narrow focus pointing only to certain perceived risks of portfolios within the IRP while completely ignoring associated risks with their own results-oriented proposals. The Companies respectfully recommend the Commission critically assess the technical objectivity of alternative recommendations by intervening parties and undertake a holistic view of the 2020 IRPs recognizing the need to maintain real world system reliability and customer affordability as resource portfolio transitions toward a lower carbon footprint.

c. The 2020 IRPs Meet the Requirements for Acceptance, as Recommended by Public Staff

Commission Rule R8-60 requires all North Carolina electric suppliers to file comprehensive biennial IRPs with the Commission on September 1 of each evenly-numbered year, with updates to the biennial IRPs on September 1 of each odd-numbered year. The Commission accepted DEC and DEP's 2019 IRP Updates in its April 6, 2020 *2019 IRP Update Order* in Docket No. E-100, Sub 157. DEC and DEP filed their biennial 2020 IRPs on September 1, 2020.[3] Pursuant to Commission Rule R8-60(m), on September 18, 2020, DEC and DEP hosted a virtual stakeholder meeting with interested parties to review their 2020 IRPs. The Commission held virtual public hearings on the 2020 IRPs, which were scheduled for April 14, April 19, May 5, May 12, May 17, and May 26, 2021.

In its February 26, 2021 Comments, the Public Staff generally supports the Companies' 2020 IRPs and Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plans as compliant with Commission rules and requirements. Some specific findings by the Public Staff include:

- The Commission should accept for planning purposes both of the Companies' 2020 IRP base case portfolios with and without CO_2 policy.[4] The Public Staff believes that both base case portfolios provide reasonable

[3] The Companies subsequently filed administrative and technical corrections to the IRPs and Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plans on September 2, 2020, September 16, 2020, and November 6, 2020.
[4] Public Staff Initial Comments at 8, 15.

short-term action plans, while maintaining flexibility to respond to an uncertain regulatory environment;[5]

- The economic, weather-related, and demographic assumptions underlying DEC's and DEP's 2020 peak and energy forecasts are reasonable for planning purposes, while continued review and revision of statistical and econometric forecasting practices may be warranted;[6]
- Generally, the assumptions in the Resource Adequacy Study are adequate for planning purposes; however, the Public Staff notes that the effect of extremely low temperatures on load is still not well understood and recommends that Duke continue to utilize AMI data to improve this predicted relationship;[7]
- The Storage Estimated Load Carrying Capability ("ELCC") study is reasonable for planning purposes;[8]
- DEC and DEP's forecasted DSM and EE program savings are in compliance with Commission Rule R8-60 and previous Commission orders, as well as the presentation of data related to those savings;[9]
- The results of DEC and DEP's Market Potential Study for DSM/EE should be considered acceptable and reasonable for purposes of including in the 2020 IRPs;[10]

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[5] *Id*. at 8.
[6] *Id* at 46-47.
[7] *Id.* at 75.
[8] *Id.* at 78.
[9] *Id.* at 50.
[10] *Id.* at 60.

- DEC and DEP should be able to meet their general and solar energy REPS obligations during the planning period, and their poultry and swine waste set-asides in 2020, without exceeding their cost caps, although DEC and DEP's ability to comply with the poultry and swine waste set-aside requirements for 2021 and 2022 is dependent on the performance of waste-to-energy developers under current contacts. DEC's and DEP's 2020 REPS Compliance Plans should be approved as filed.[11]

No party opposed the Companies' 2020 REPS Compliance Plans. The Companies respectfully submit that their 2020 IRPs and REPS Compliance Plans meet all applicable statutory and Commission requirements and should be approved.

REPLY TO INTERVENOR COMMENTS

Pursuant to North Carolina Utilities Commission ("the Commission") Rule R8-60(k) and the Commission's April 19, 2021 *Order Granting Extension of Time*, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (and collectively "Duke Energy" or "the Companies"), hereby submit their Reply Comments to the initial comments filed by the following parties: the Public Staff; the North Carolina Attorney General's Office ("AGO"); Vote Solar; the City of Charlotte; the joint comments of the City of Asheville and Buncombe County; the joint comments of the North Carolina Sustainable Energy Association ("NCSEA") and Carolinas Clean Energy Business Association ("CCEBA"); the joint comments of the Southern Alliance for Clean Energy ("SACE"), the Natural Resources Defense Council ("NRDC"), and the Sierra Club ("Environmental Parties"); and the corrected joint partial initial comments of NCSEA/

[11] *Id.* at 181.

CCEBA and Environmental Parties (collectively, "Joint Synapse Sponsors"); the joint comments of NC WARN, Inc. ("NC WARN") and the Center for Biological Diversity ("CBD"); and the joint comments of Apple Inc., Facebook, Inc. and Google LLC (the "Tech Customers") in this docket.

The following provides a brief overview of the Companies' comments with respect to the recommendations of various intervenors.[12] The Companies respond in more detail to each of these in Section I- XX of these Reply Comments.

- **Perspective and Accountability Matter** – The Public Staff—charged with representing the using and consuming public—concludes that that the Commission should accept for planning purposes both of the Duke base case portfolios, Portfolio A – Base Case without Carbon Policy, and Portfolio B – Base with Carbon Policy. NCSEA/CCEBA, Vote Solar, the Environmental Parties, Tech Customers, and NC WARN/CBD fail to advance technically-objective arguments or to approach the IRPs from a holistic view. Instead, these intervenors present studies conducted by consultants designed to advance their organizational interests, which generally include a nearly singular focus on expanding the deployment of solar, battery storage and DSM and as the "preferred plan" for DEC and DEP to meet customers' future capacity and energy needs with little or no meaningful consideration of power supply reliability or customer cost.

[12] DEC and DEP will not respond to all allegations raised in the parties' voluminous initial comments in these reply comments, as many of these allegations have been raised and rejected in previous IRP proceedings. The Companies' lack of reply to a specific comment by another party should not be construed as an acceptance of their argument. Because of some overlapping topics, the Companies have generally organized these reply comments by subject area, rather than by intervenor.

- **Short Term Action Plans** – As recognized by the Public Staff, both DEC's and DEP's short term action plans, as presented in Chapter 14 of the 2020 IRPs, are the same across all six portfolios, indicating that the Companies' near-term plans will remain consistent no matter which portfolio pathway develops in the future. (Sect. IX.A.)
- **Load Forecast** – The Companies' load forecasts were deemed reasonable by the Public Staff. The Companies commit to continuous improvement of load forecasting methodologies. (Sect. II.)
- **Resource Adequacy** – The February cold weather event in Texas and subsequent blackouts illustrate the importance of robust resource adequacy planning. The Companies' own experience with cold weather events that have challenged real-time system reliability in the Carolinas also demonstrate the need for sufficient planning reserves. As such, the Companies conducted comprehensive resource adequacy studies utilizing nationally-recognized experts Astrapé Consulting, including pre-study collaborative discussions with the Public Staff, AGO, and South Carolina Office of Regulatory Staff. These complex and sophisticated studies determined that continued use of a 17% winter planning reserve margin is needed to maintain resource adequacy. The Public Staff found the assumptions used in DEC's and DEP's resource adequacy studies to be adequate for planning purposes. The Companies' 17% winter reserve margin target is among the lowest in the Southeast and recommendations by other intervenors to further lower the reserve margin are not reasonable and would put resource adequacy at risk for DEC's and DEP's customers. (Sect. III.)

- **Planning for Transmission Reliability and Grid Operations** – The Companies provided greater detail about transmission system operations and costs in their 2020 IRPs than ever before and will continue to refine their transmission planning going forward as appropriate for IRP purposes, recognizing the difficulties in developing generic transmission assumptions. Over-reliance on transmission import capability creates risks to ensuring an adequate, reliable, and economical supply of electric power to customers in North Carolina. The Companies have taken a reasonable approach to assessing the value of interconnected neighbor assistance from utilities throughout the Southeast as part of resource adequacy studies. The Companies must also take a deliberate approach to reliably integrating intermittent and energy limited resources ensuring sufficient enabling grid infrastructure to maintain reliability is incorporated in the planning process. (Sect. IV.)
- **Natural Gas Price Forecasting and Availability** – The Companies' natural gas price forecast used for developing the 2020 IRPs is consistent with the methodology used in DEC's and DEP's IRPs and IRP updates since 2015. The Companies' use of 10 years of market natural gas pricing is not contested by the Public Staff in this proceeding and its use has been accepted by this Commission in past five IRP proceedings. Market prices for natural gas have been demonstrated to be reasonably liquid, and the Companies' past experience demonstrates that relying upon market prices has proven to be more accurate and appropriate for customers than past fundamental forecasts in the nearer-term. (Sect. V.)

- **Coal Retirement Analysis** – The Companies fully complied with the Commission's orders to evaluate alternative coal retirement scenarios. The Companies conducted a robust and rigorous analysis to determine the most economic and earliest practicable coal retirement dates. The challenge of planning for the transition of 10 GW of coal resulted in a retirement analysis that is unparalleled in complexity and magnitude within the industry. The Companies' use of capacity expansion, production cost, and detailed dynamic coal cost models provided sophisticated and transparent results for the economic coal retirement analysis and fully meet the Commission's directives. (Sect. VI.B.)
- **Planning for CO_2 Regulations and Other Environmental Issues** – All of the portfolios presented in the Companies' IRPs are consistent with the Companies' 2030 and 2050 climate goals. The alternative planning portfolios that achieve more rapid carbon reductions are also consistent with Governor Cooper's Executive Order 80 but would require advancement in technologies and supportive federal and state policies. They would also have increased costs to customers relative to the two Base Cases. The Companies will continue to evaluate, plan for, and respond to future changes in environmental law and regulations, while preserving system reliability and balancing customer affordability. (Sect. VII.)
- **New Natural Gas Resources** –NERC's President and CEO, Mr. James Robb, recently testified to Congress that natural gas is the "fuel that keeps the lights on" and "will remain essential to reliability" as utilities' transition their fleets from central-station fossil fueled generation to relying on more distributed variable and intermittent renewable generation and new and, as of yet, unproven, technologies

such as battery storage. New Natural gas resources are a key component of the Companies' clean energy transition and allow the Companies to accelerate coal retirements, provide system flexibility for managing variable energy resources, such as solar, while balancing the goals of reducing carbon emissions while maintaining system reliability and customer affordability. Some new natural gas resources are necessary to transition the fleet, and their inclusion is consistent with the Companies' long-term climate modeling. These resources were also demonstrated to be economic for customers in the Companies' IRPs under a number of retirement scenarios. Natural gas resources are a mature and well understood technology that are essential to a diverse portfolio of resources, while exclusive reliance on a narrow scope of emergent technologies to replace retiring coal presents undue economic and operational risks. (Sect. VIII.)

- **Solar as a Resource** – All six of the Companies' portfolios add significant solar over the next 15 years and the cost and operational capabilities of solar technology are changing rapidly. Solar cost and operating assumptions used in the 2020 IRPs were based on the best available information at the time the resource plans were developed. The 2021 IRP updates will reflect the extension of the December 2020 solar ITC amendments and will recognize marketplace adoption of single-axis tracking technology rather than the combination of fixed tilt and tracking that was assumed in the 2020 IRPs. The Companies will continue to evaluate how processes such as Queue Reform may improve the efficiency of adding more solar and other distributed energy resources to the Companies' systems. (Sect. XI.)

- **Storage as a Resource** – The 2020 IRPs are also planning to add significant battery storage over the next 15 years and—similar to solar—the cost and operational capabilities of storage technology are changing rapidly. The Companies' battery cost and Effective Load Carrying Capability ("ELCC") assumptions used in the 2020 IRPs are prudent and reflect how these resources are expected to be deployed given the unique load and resource characteristics of the Carolinas. The Public Staff found the Companies' storage ELCC study to be reasonable for planning purposes. The battery storage contribution to winter peak capacity demand are based on a comprehensive ELCC study that evaluated the synergistic effects that solar has on the capacity value of storage, and the results of the study were appropriately applied in the development of the 2020 IRPs. As solar and battery storage become a more significant part of DEC's and DEP's system operations it will be critical to study, plan for, and develop effective solutions to integrate these technologies and to understand their limitations, especially during winter periods when DEC and DEP have the greatest loss of load risks. Lessons learned from ERCOT and other parts of the Country must also inform the Companies' resource planning for utilizing these new technologies. (Sect. XII.)
- **Energy Efficiency and Demand Side Management** – The Companies are recognized as "Leaders in the Southeast" on deploying EE. The 2020 IRPs' DSM resource forecast represents reasonably expected load reductions based on a detailed Market Potential Study accepted by the Public Staff. The Companies continue to evaluate winter peak drivers in a deliberate effort to address and explore potential future opportunities to reduce the need for additional supply side

resources. The Companies are also committed to continued stakeholder engagement through the EE Collaborative to identify additional cost-effective EE and DSM opportunities. (Sect. XIII.)

- **Preliminary Response to Synapse First Corrected Report** – Synapse's first corrected Synapse Report is simply not credible and a second corrected Report has now been filed by the Joint Synapse Sponsors. If the Synapse Report actually did what the Joint Synapse Sponsors say that it does—"outlines a cleaner and cheaper energy future than Duke's IRPs"— and could be demonstrated to ensure power system reliability, then it should be give substantial weight by the Commission. However, based on the Companies' review—and consistent with the Companies' findings in their review of the prior 2018 Synapse study—the Companies have determined that the first corrected Synapse Report is grossly inaccurate in its modeling, extremely unrealistic in many of its assumptions, and lacks the regulatory rigor that the Companies' Carolinas IRP organization proudly employs to ensure IRPs filed with this Commission are capable of adequately, reliably, and affordably providing increasingly clean electric service to customers over the next 15 years. Neither the Companies nor the Public Staff have been able to scrutinize the second corrected Synapse Report for additional fundamental flaws, and the Commission should not rely upon it at least until it has been subject to critical review. (Sect. XVI.)

RESPONSES TO SPECIFIC RECOMMENDATIONS AND CRITICISMS

I. DEC and DEP Appreciate the IRP Comments from Our Customers, Communities, Municipal Partners, and Stakeholders

The Companies appreciate the consumer statements of position filed by many of our customers and other stakeholders, as well as the public witness testimony, regarding the DEC and DEP 2020 IRPs. The City of Charlotte, the City of Asheville, and Buncombe County intervened and filed initial comments, and additional consumer statements of position were filed by the Town of Cary, the City of Raleigh, the Town of Hillsborough, the City of Durham, the City of Wilmington, the Town of Carrboro, Durham County, the City of Greensboro, Orange County, the Town of Chapel Hill, the Town of Boone, and the Town of Matthews, among others. A clear message from these comments, which is consistent with the conversations held as part of the Companies' stakeholder process utilized in developing the 2020 IRPs, is that accelerating the transition to cleaner energy is a shared priority for our communities, as it is for Duke Energy.

Importantly, many of our communities have adopted local government renewable energy and greenhouse gas ("GHG") reduction targets. As many of the municipal comments filed with the Commission note, Duke Energy has been and will continue to be an essential partner as the municipalities implement these local government climate and clean energy plans and related priorities. The Companies value the strong partnerships we have with our communities and municipal partners and agree that the 2020 IRPs and Duke Energy's net-zero carbon emission goal by 2050 begin to address many of the local government renewable energy and GHG emission reduction goals.

The local government comments[13] stress a desire for the Companies to add and rely upon significant amounts of distributed energy resources ("DERs") and retire their remaining coal units as soon as possible. Although these issues are addressed in greater detail in other sections of these reply comments, the Companies note that DERs are an important resource in meeting Duke Energy's own climate goals. The 2020 IRPs demonstrate DEC's and DEP's plans to add significant incremental renewables and battery storage capacity – adding two to four times the current solar capacity over the 15-year planning horizon, increasing battery storage capacity on the Companies' systems to levels well beyond that installed nationally today, and for the first time including both onshore and offshore wind as viable resource alternatives in most portfolios over the 15-year planning period. When evaluating solar as a resource option, the Companies evaluate both the risks and operational limitations of this technology, as well as the benefits of increasing clean energy to serve customers in North Carolina. In addition, the Companies support accelerated retirement of coal units and have included comprehensive retirement analyses in the 2020 IRPs, but must consider reliability and affordability as we continue the clean energy transition. The pace at which North Carolina continues the transition, while maintaining reliability and affordability, is a critical decision that requires input from customers, stakeholders, and policy leaders and the Companies welcome the continued discussion and collaboration with our municipal partners and communities.

[13] Additional points made in some of these municipal comments relate to energy efficiency, all-source procurement and evaluation of transmission alternatives and are discussed in greater detail in other sections of these reply comments. Many of the municipal comments express support for expanded electric vehicle ("EV") programs and rate designs. The Companies continue to support expanded EV offerings, for example the pilot programs approved by the Commission in Docket Nos. E-2, Sub 1197 and E-7, Sub 1195, and will address EV rate designs as part of their comprehensive rate design stakeholder process recently initiated following the Companies' most recent general rate cases. This issue is further discussed in Section XI of these Reply Comments.

II. Load and Energy Forecasts

A. Public Staff Supports 2020 IRPs Load Forecasts

The Public Staff generally found DEC and DEP's 2020 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements.[14] The Public Staff summarized its review of the load forecasts, and made a few recommendations to the Commission regarding the review of load forecasting methodology on page 17.

1. The Companies acknowledge the Public Staff discussions of peak demand forecast error.

The Public Staff discussed its analysis of the historical accuracy of DEC and DEP's load forecasts at pages 43-47 of its initial comments. The Public Staff noted the "degree of uncertainty associated with any forecasting methodology" that attempts to quantify whether historical relationships of customers' electricity usage with weather and other economic variables during peak periods and throughout the month will continue in the future.[15] The Companies acknowledge the Public Staff's peak demand forecast error concerns, specifically regarding under-forecasting DEP's winter peak. Inaccuracy challenges occur in the weather-normalization process and may increase whenever the actual daily average temperature on the day of peak lies outside of the normal distribution of the 30 years of historical temperatures used to normalize the actual peak. For example, only 9 of the 30 years in the peak normal history used in the 2019 IRP (which was also used in the analysis for the 2020 IRP) had a peak temperature that was above the 2020 actual peak temperature, which was a historically mild winter. The peak forecast model

[14] Public Staff Initial Comments at 38-47.
[15] Public Staff Initial Comments at 38.

objective is to provide a reasonable forecast of future peak demand under the assumption of normal peak conditions. The Companies note that extreme historical peak demand and weather conditions are captured both in the history used by the peak model, as well as in the weather normalization processes.

2. The Companies accept Public Staff's recommendation to continue to review their load forecasting methodology.

The Public Staff recommends that the Companies should "continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and employ appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events."[16] The Companies agree with the Public Staff's recommendation to review and revise the load forecast process to improve accuracy as part of the ongoing resource planning process, and currently incorporate this continuous improvement mindset into their processes.[17] Note that the historically mild peak temperature of 2020 is now incorporated into the updated peak normal for the 2020 IRP—an enhancement to the load forecast process implemented in 2018. The result is partially responsible for the lower peak forecast for year 2021 in the 2020 IRP compared to the 2019's IRP 2021 peak forecast.[18] Despite the most recent 2 years of historically mild winter demand, the peak forecast must still reflect the historical reality of the multiple extreme winter demands experienced within the past 6 years.

In summary, the variance between DEP's forecasted peak and weather adjusted actual peak may be more reflective of DEP's diverse territory and its weather conditions,

[16] Public Staff Initial Comments at 17.
[17] Environmental Parties recommend at page 17 of their comments that "Duke should research the potential for load forecast errors due to economic forecast errors or other causes." The Companies assert that this commitment to ongoing review also addresses Environmental Parties' recommendation.
[18] 14,434 MW in 2019 IRP versus 14,118 MW in 2020 IRP for the 2021 winter peak forecast, a 2.2% decline, or 316 MW.

and unique economic and heating source challenges facing this territory compared to DEC, particularly during very mild or extreme winter conditions. The Companies will continue to review the load forecast process for improvement opportunities, including determining if there are ways to enhance the peak weather-normalization process during extreme cold or mild peak seasons.

III. Resource Adequacy and Reserve Margins

A. The Companies Resource Adequacy Study and 17% Reserve Margins are Reasonable, Lower than Peer Utilities in the Southeast and Adequate for Resource Planning Purposes

The Companies retained Astrapé Consulting[19] to conduct new resource adequacy studies to support development of the 2020 IRPs. The Companies utilized a stakeholder process in the development of the resource adequacy studies that included participation from the Public Staff, the Attorney General's Office ("AGO") as well as the South Carolina Office of Regulatory Staff ("ORS"). The Public Staff noted the Companies' efforts to include the perspective of other stakeholders in updating its Resource Adequacy Study.[20] The results of the resource adequacy studies are discussed in Chapter 9 of the DEC and DEP 2020 IRPs, and the studies were included as Attachment III to the 2020 IRPs ("2020 Resource Adequacy Study").

The 2020 Resource Adequacy Studies determined the reserve margin required to meet the one day in ten years loss of load expectation (0.1 LOLE) standard. As discussed in Chapter 9 of the 2020 IRPs and summarized below, actual historic operating reserves demonstrate that planning to this standard does not result in excess planning reserves.[21]

[19] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé also conducted resource adequacy studies for DEC and DEP in 2012 and 2016.
[20] Public Staff Initial Comments at 75.
[21] DEC 2020 IRP at 69; DEP 2020 IRP at 71.

The studies determined that a 16.0% reserve margin for DEC is needed to satisfy 0.1 LOLE and a 19.25% reserve margin for DEP is needed to satisfy 0.1 LOLE. The study determined that a 16.75% reserve margin is needed to satisfy 0.1 LOLE for the DEC/DEP combined case which was simulated to determine the reliability benefit of the two utilities operating as a single Balancing Authority ("BA"). Based on results of the individual base cases, combined case and sensitivities, Astrapé recommended continued use of a 17% planning reserve margin and the Companies used this target in developing their 2020 IRPs.

The February cold weather event in Texas and the subsequent blackouts illustrate the ongoing potential for severe weather and the importance of robust resource adequacy planning. As shown in Table 2 below, the Companies' 17% winter reserve margin target is among the lowest in the Southeast according to recent analysis by the South Carolina ORS.

Table 2: ORS Comparison of Southeast Utility Reserve Margin Targets[22]

Table 10
Comparison of Utility Winter Peak Reserve Margins

Utility	Winter Peak Reserve Margin
DEP/DEC	17%
Dominion Energy South Carolina	21%
Southern Company	26%
TVA	25%
Louisville Gas and Electric/ Kentucky Utilities	17% to 25%
Florida Power and Light Co.	20%

[22] Direct Testimony of Anthony M. Sandonato on behalf of the SC ORS Exhibit AMS-1, at 41, and Exhibit AMS-2, at 42, P.S.C.S.C. Docket Nos. 2019-224-E and 2019-225-E (filed Feb. 5, 2021).

Although some intervenors comment extensively on the 2020 Resource Adequacy Study, it is important to note that the Public Staff found that the assumptions used in DEC's and DEP's 2020 Resource Adequacy Study are adequate for planning purposes.[23] Recommendations by other intervenors to further lower the reserve margin will put resource adequacy at risk for DEC's and DEP's customers. The Companies address intervenor criticisms in the following paragraphs.

B. The Companies Undertook a Reasonable Approach to Cold Weather and Load Modeling and Intervenor Arguments Should Be Rejected

In their initial comments, NCSEA/CCEBA and their consultants Brendan Kirby and Dr. Justin Sharp, and SACE/Sierra Club/NRDC and their consultant James Wilson, commented on the Companies' and Astrapé's resource adequacy studies and the historic weather data and load modeling that was used. The Companies address these parties commentary and major critiques of the Resource Adequacy Study, as follows:

1. The 2020 Resource Adequacy Study's weighting of historic weather years was appropriate.

The Resource Adequacy Study appropriately relied upon 39 years of historic weather data to project weather that may occur for the study year. Each weather year was given an equal probability of occurrence in the study.

NCSEA/CCEBA's Sharp Report make the following claims:

- "Typically, the atmospheric sciences community uses the most recent 30 consecutive years to develop climatological normals, as recommended by the World Meteorological Organization for about a century. However, recently, the National Climate Data Center (NCDC) has begun providing supplemental

[23] Public Staff Initial Comments at 75.

data with 5-, 10-, 15- and 20- year periods, because 30-year averages are often unrepresentative of the *current* climate because it is changing, and the longer record dampens the trends. Ironically, some of the new shorter duration products being provided by NCDC have been provided in response to stakeholder feedback from the energy industry."[24]

- "[T]he climate record Duke uses indicates that the extreme peak that occurred in January 1985 was an extremely rare event, that the number of cold events is declining over time, and thus, so are wintertime loads, including extreme peaks. Climate science backs up these findings and indicates that the number of exceptionally cold days will continue to decline in the future."[25]
- "Duke analysis shows that required reserve margins drop to 13.25% for DEC and 14.75% for DEP if historic weather years beginning in 1990 are used instead of 1980."[26]
- "The Commission should direct Duke to reduce the probability of 1980's extreme cold events in the synthetic load derivation to once in a century (a factor of 2.5) to reflect the lowering likelihood of extreme cold events in all of the analysis: IRP, RA, DSM, Storage, to assure that resources are aligned with need and are consistently valued."[27]

Environmental Parties and the J. Wilson Report make the following related comments:

- "In addition, the Companies' resource adequacy studies used 39 years of temperature data (1980-2018), weighted equally, which includes many

[24] NCSEA/CCEBA Initial Comments Exhibit 4 Sharp Report, at 2-3.
[25] *Id.* at 3.
[26] NCSEA/CCEBA Initial Comments Exhibit 1, at 5.
[27] *Id.* at 31.

instances of very extreme cold that have not been seen in these areas, or only rarely, for decades. This overstates the likely frequency of such extreme cold going forward, therefore amplifying the effect of overstating the impact of extreme cold on winter peak loads."[28]

In reply to these intervenor comments, the Companies do not refute that removing the 1980-1989 decade from the resource adequacy analysis, which contains the two coldest weather years in the 39 year data set used by Astrapé, would lower the reserve margin results. The major flaw with ignoring the coldest weather years as these intervenors recommend, however, is that it eliminates a known planning and reliability risk that customers face. The Companies have the obligation to continually, affordably, and reliably serve load, and it is prudent to prepare for temperatures that have occurred historically even if they have not occurred recently. The most accurate way to capture extreme weather risk is by representing the frequency of cold weather events based on historical data. Each of the 39 weather years has an equal probability of being selected by the model, so the years with extreme cold weather were not given any more weight than milder years. Removing the most extreme weather years artificially deflates the reserve margin and allows the probability of firm load shed to be higher than industry norms for the Duke service territories, which in turn puts customers more at risk. If weather from 1985 (which represents the coldest year in the last 39 years) occurs again, and the Companies have a 17% reserve margin, it is expected that there will still be a high likelihood of load shed, but if weather from less extreme cold weather years such as 2014, 2015, and 2018 were to occur again, the risk will be better managed. However, if 1985 weather is removed from

[28] Environmental Parties Partial Initial Comments Attachment 5 J. Wilson Report, at 6.

the Resource Adequacy Study arbitrarily and the reserve margin is lowered, the Companies would now expect to have increased reliability risk even in these less extreme weather years due to a lower planning reserve margin. This rationale goes against the purpose of the study, which is to maintain reliability in all but a few extreme periods. The Companies would be doing customers a disservice in excluding risks that they knew were possible.

There is no basis for assuming 1985 or 1982 weather will never occur again in the next 39 years. As previously noted, the Public Staff found that the assumptions used in the Resource Adequacy Study are adequate for planning purposes.[29] The South Carolina ORS has also expressed support for the Companies' not excluding historical weather from its resource adequacy studies, explaining "extreme low temperatures, which, at least historically, have had a low probability of occurring (2 out of 39 years), have a significant impact on reliability when they do occur."[30]

In fact, the recent events seen in the Electric Reliability Council of Texas ("ERCOT") and the Southwest Power Pool ("SPP") demonstrate that the risk of extreme weather is not diminishing and remains an ongoing threat as temperatures reached extremes in the region and both ERCOT and SPP had to shed customer load due to capacity deficiencies. Importantly, the recent ERCOT extreme weather, which resulted in consecutive days of lost load across the state of Texas, had not been seen since 1989, over 30 years ago.

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[29] Public Staff Initial Comments at 75.
[30] Surrebuttal testimony of Stephen J. Baron on behalf of The South Carolina Office of Regulatory Staff, at 3, P.S.C.S.C. Docket Nos. 2019-224-E and 2019-225-E (filed April 15, 2021).

The risk of (and need to plan for) extreme weather events is also an important issue being analyzed by the utility industry. EPRI recently released a report concluding that extreme weather events are occurring more, not less, frequently. The EPRI report states:

> "Cold events are less cold on average but are increasing in frequency. The pace of record low temps is less than half of record high temps in the U.S. in the most recent two decades; this demonstrates "less cold on average". Yet in the most recent decades, we are seeing a weaker winter jet stream that "allows" cold air from polar Canada to dip down into the northern half of the U.S. with greater frequency (e.g., creating cut–off lows, sometimes referred to as the Polar Vortex)." [31]

NCSEA/CCEBA consultant Dr. Sharp acknowledges the possibility of long duration cold waves and the uncertainty regarding future polar vortex events:

> "We acknowledge that the events in Texas in February 2021 indicate that historic, long duration cold waves are still possible, and it is important for the utility sector to understand how their frequency, extent and longevity are evolving in time. The media has speculated that cold waves like the one that impacted Texas are becoming more likely due to climate change. This is due to a misrepresentation of an active and evolving research area on the impacts of a warming Arctic on the stability of the polar vortex. Some atmospheric scientists believe that the polar vortex is now more likely to break up, sending cold air south as it does. Because the air in the Arctic is now warmer, these cold waves will not be as intense, but there is speculation that they may penetrate further south. However, this work is in its early stages, is not supported by meteorological observations or global climate model simulations at this time and there is no scientific consensus on it." [32]

A resource adequacy planner must include a realistic representation of the risks and it is not prudent to remove data points simply because they include extreme weather. The frequency of these extreme weather events is exactly what should be captured in a resource adequacy study. Again, the intervenors who have critiqued the Companies/Astrapé's Resource Adequacy Study did not prepare their own resource adequacy studies, nor do

[31] Electric Power Research Institute, Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy, at 4-2 (Jan 28, 2021), *available for free download at:* Product Abstract (epri.com).

[32] NCSEA/CCEBA Initial Comments Exhibit 4 at 15.

they have the Companies' reliability requirements to serve customers and their commentary and recommendations should be given little weight by the Commission, as compared to the detailed study presented by the Companies as well the comments of the Public Staff in North Carolina and ORS in South Carolina.

2. Rare weather events should not be excluded from the Resource Adequacy Study.

The Companies also disagree with the results-oriented recommendation by NCSEA/CCEBA's Kirby Report statement that:

> "high reserve requirements and low capacity value assigned to solar generation in the IRP are driven by the inclusion of high winter peak loads resulting from rare, short, and easily forecast extreme cold weather events. These events should not be included in the IRP or RA analysis BUT if they are then storage and DSM solutions should be designed to address them."[33]

In reply to these intervenor comments, the Companies assert that such a contention lacks merit and pre-assumes a desired result. The LOLE analysis is precisely looking for these types of events as extreme cold weather events present the highest loss of load risk to DEC and DEP customers. While the Companies do consider storage and demand response programs as well as other technologies for meeting customer demand, these cold weather events should not be excluded from the IRP or resource adequacy studies and the Companies do not think it is prudent to exclusively rely on pre-selected resources to plan for such potential extreme weather events. Mr. Kirby's analysis is not technically objective and conflates resource adequacy with planning to meet the resource need to achieve a pre-determined outcome. This approach to planning, if adopted, may introduce reliability risk and may not be least cost for customers.

[33]NCSEA/CCEBA Initial Comments Exhibit 1, Kirby Report at 17.

3. 2020 Resource Adequacy Study's load regression modeling was appropriate and will continue to be reviewed.

A number of interveners comment on the 2020 Resource Adequacy Study's load regression modeling.

The Public Staff makes the following comments:

- "Generally, the Public Staff believes the assumptions in the Resource Adequacy Study are adequate for planning purposes; however, the Public Staff notes that the effect of extremely low temperatures on load is still not well understood and recommends that Duke continue to utilize AMI [Advanced Metering Infrastructure] data to improve this predicted relationship."[34]

NCSEA/CCEBA relying on the Kirby Report make the following claims:

- "Duke's Resource Adequacy studies use 39 years of hourly historic weather data (1980-2018), but because actual load data corresponding with the weather data is [not] available during many of those years, Duke has relied on synthesized load data that extrapolates results to cover extreme temperatures where no actual load data exists. Critically, this synthetic load during years where actual data is unavailable results in many of the most extreme cold weather load spikes in Duke's modeling. These load spikes, projected during winter mornings, cause Duke's loss-of-load probability to skew heavily towards winter morning hours.[35]

Environmental Parties relying on the Wilson Report make the following argument:

[34] Public Staff Initial Comments at 75.
[35] NCSEA/CCEBA Initial Comments at 26.

- There are three "flaws" with the Companies' extrapolation approach: (1) the extrapolation approach assumes that when temperatures drop to extremely low temperatures (15, 10, 5 degrees and even lower), each additional degree will increase loads by the same amount as occurs at around 20 degrees. But for the lowest temperatures, the relationship between temperature and load is much weaker;[36] (2) the regression approach itself employed a simplistic and flawed way to estimate the impact of incremental cold on loads. The more important flaw in the regression approach was to include observations for temperatures up to 21 degrees. The same regression analysis, but excluding the higher than 21-degree temperatures, provides a much lower and more reasonable estimate of the impact of incremental cold on load at lower temperatures;[37] (3) the details of how the MW/degree results of the regressions were applied to determine the final loads used in the RA Studies led to some extreme and nonsensical load values.[38]

In reply to these intervenor comments, the Companies explain that in order to measure the impact of weather on load, Astrapé developed a highly-sophisticated artificial neural network ("ANN") analysis to predict how load will respond to historic temperatures based on how load actually responded to weather during the five-year period from January 2014 to September 2019 (this period of time was used as the model "training dataset"). The ANN develops weather-to-load relationships by season based on the actual information available in the training dataset to create synthetic load shapes for the past 39

[36] Environmental Parties Partial Initial Comments Attachment 5, J. Wilson Report at 12.
[37] *Id.* at 14.
[38] *Id.* at 15.

years of weather (1980-2018). The intent of this analysis is to predict how load will respond under a variety of weather conditions given that the extreme cold weather experienced in earlier years has not occurred during the five-year training dataset. Because extreme temperatures can be rare, they will not always occur during the recent five-year training dataset. As such, an improvement is required to adjust the ANN results for the extreme temperatures not seen in the training dataset. For this improvement, Astrapé created a linear regression which predicts the expected load based on a linear relationship developed between recent low temperature hours and the resulting historical hourly load.

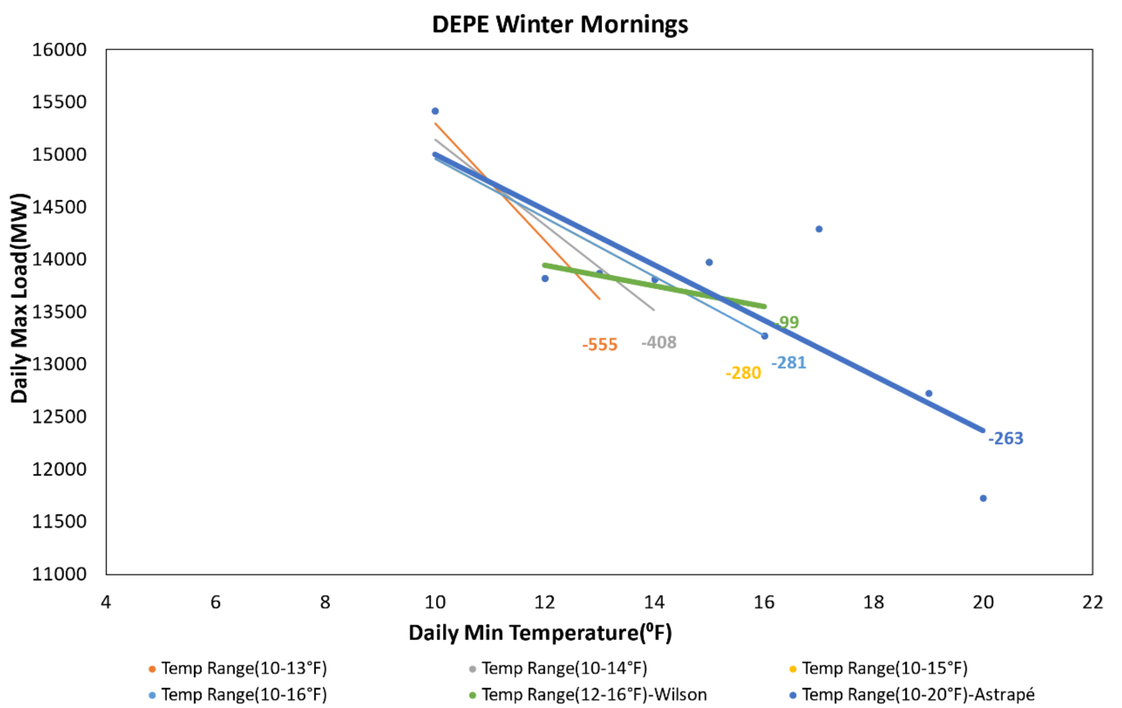
The J. Wilson Report was particularly critical of this regression and the author proposed using alternative regression equations for DEC and DEP-E. For the DEP-E equation, Mr. Wilson used the same data as Astrapé but selected different points to form the regression equations which are then used to correct the peak loads during extreme weather. The data for DEP-E can be seen in Figure 2 below. Temperature is plotted on the x-axis and load is plotted on the y-axis. As temperature decreases, load increases and the value on each trendline represents the load response in MW per degree for that trendline. For example, the "(10-20 F)-Astrapé" trendline shows that for every degree below 20°F, load is expected to increase by 263 MW. Compare the "(10-20°F)-Astrapé" trendline with the J. Wilson Report's trendline, which is labeled "(12-16°F)-Wilson."[39] Based on Astrapé and the Companies' review, it appears that Mr. Wilson selected a set of points that produces the lowest load response possible (99 MW per degree). As shown in the figure, he included only four points in his trendline and also removed the coldest temperature at 10 degrees. Mr. Wilson's rationale for removing this temperature, is that it

[39] Wilson trendline adapted from Partial Initial Comments of Environmental Parties Attachment 5, Figure JFW-2 at 16.

is an outlier which he defines as "an observation that lies an abnormal distance from the trend reflected in the other members of the population…"[40] Given that a resource adequacy study examines the system behavior during extreme weather periods, historical data points with extreme weather, while infrequent, are vital for the accuracy of the study because they provide the most useful information in relation to load response. By removing this data point, Mr. Wilson is removing one of the more valuable data points the Companies can rely on to estimate cold weather loads. Figure 2 shows various other regression trendlines reflecting different temperature thresholds which are all much more representative of the 263 MW per degree relationship that Astrapé ultimately used compared to the 99 MW per degree relationship recommended by Mr. Wilson. This analysis shows that even though there are a range of regression trendlines that could have been utilized, the one ultimately chosen does not "overstate the impact of incremental cold on load at the lowest temperatures," as alleged by Mr. Wilson.[41]

[40] Reference SELC response to Duke Data Request 1-29(b) in South Carolina Docket No. 2019-224-E and 2019-225-E.
[41] Environmental Parties Partial Initial Comments Attachment 5, at 12.

Figure 2: DEP East Load Response to Cold Weather Regression Trendlines



Furthermore, the Companies held several stakeholder meetings with the Public Staff, the AGO and the ORS as part of the development of the 2020 Resource Adequacy Study. These stakeholder meetings were used to discuss major assumptions in the study, including the cold weather peak load modeling. The regression equations were presented and explained to these consumer advocate stakeholders and the Companies requested feedback on the major assumptions in the Study prior to performing the simulations for the Study. No specific concerns were identified or feedback provided in relation to the regression inputs, so Astrapé moved forward with the assumptions in the Study.

The load variability modeled for DEC in the Resource Adequacy Study resulted in an 18% variance above winter weather normal load in the most extreme cold weather year (1985) out of the 39 year history. For DEP, the variance above winter weather normal load in the most extreme cold weather year was 21%.[42] For comparison, the actual variance in load seen in the recent ERCOT extreme weather event was 29% above the weather normal forecast.

Using ERCOT's recent extreme cold weather as a benchmark further demonstrates the Companies' load variability to be reasonable. ERCOT's analysis of demand and reserves in the ERCOT region showed that the weather normal forecast going into the winter was 59,567 MW[43] and while ERCOT does not report the actual load at the coldest temperatures due to load shedding procedures, ERCOT projected a peak load of 76,819 MW.[44] This represents an actual load 29% ((76,819 MW / 59,567 MW) -1) above the weather normal forecast developed prior to the winter season. The load reached 69,692 MW[45] on Sunday February 14, 2021, before the cold temperatures arrived on Monday February 15, 2021 and Tuesday February 16, 2021, reflecting a 17% variance from the forecast on a weekend. It is also noted that the latest ERCOT Winter Assessment assumed an extreme scenario would produce loads only 16% above the expected weather normal forecast.[46] Obviously, ERCOT, which had not seen temperatures this extreme since 1989, under-forecasted load for these extreme cold events. By comparison, the 18% - 21% variance above the weather normal load forecast for the most extreme cold weather year modeled for the Companies in the 2020 Resource Adequacy Study was much lower than

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[42] DEC and DEP 2020 Resource Adequacy Studies Table 3.
[43] *See* ERCOT, *Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2020-2029,* at 22, (Dec. 5, 2019) available at:
http://www.ercot.com/content/wcm/lists/167023/CapacityDemandandReserveReport-Dec2019.pdf.
[44] Bill Magness—President & Chief Executive Offer ERCOT, *Review of February 2021 Extreme Cold Weather Event-ERCOT Presentation,* at 19 (Feb. 24, 2021), available at:
http://www.ercot.com/content/wcm/key_documents_lists/225373/2.2_ERCOT_Presentation.pdf.
[45] ERCOT, *Hourly Load Data Archives,* 2021 ERCOT Hourly Load Data (2021), *available for download at* http://www.ercot.com/gridinfo/load/load_hist.
[46] *News Release: Seasonal Assessments Show Sufficient Generation for Winter and Spring* (Nov. 5, 2020), *available at: http://www.ercot.com/news/releases/show/216844*.

the actual 29% variance above the weather normal load forecast realized in the ERCOT extreme winter event.

Astrapé and the Companies certainly recognize the significance of accurately modeling cold weather impacts on load in a resource adequacy study. While methodologies can always be improved, until future extreme cold temperatures are actually experienced, the load response for those extreme temperatures will continue to be a projection using the best data available, which Astrapé and the Companies believe were utilized in the resource adequacy studies. As seen in Texas and surrounding regions in February of this year, it is critical to understand the real world operational impact that cold weather has on loads. These actual events provide data points to be included in the modeling and the analysis should be continually reviewed as the Companies move forward.

4. The Resource Adequacy Study's cold weather outage modeling was appropriate.

To understand the impact that cold temperatures have on system outages, Astrapé analyzed the Companies' unit outage data for the period 2016-2019. The average capacity offline below 10 degrees for DEC and DEP combined was approximately 400 MW. Astrapé appropriately applied this "outage penalty" at temperatures below 10 degrees in the study.[47]

Environmental Parties' Wilson Report argues that a value closer to 200 MW would be a better estimate of cold weather outages in future years for the purposes of the resource adequacy analyses.[48]

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[47] 2020 DEC and DEP Resource Adequacy Study, Section III.F.
[48] *Id.* at 27.

NCSEA/CCEBA's Kirby Report also claims that the Companies' Resource Adequacy Study compounded the extreme weather winter peak concerns by arbitrarily increasing conventional generation outages: "Generator outages remained in line with 2016 expectations, but additional cold weather outages of 260 MW for DEC were included for temperatures less than 10 degrees. An additional 140 MW of cold weather outages were included for DEP."[49]

In reply to these intervenor comments, the Companies and Astrapé stand by using 400 MW as the cold weather outage value. Importantly, in Astrapé's expert opinion, 400 MW is an appropriate amount given the information shown in Table CA5 of the Resource Adequacy Study Confidential Appendix[50] which showed that during the January 2018 polar vortex, both DEC and DEP had a combined **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of cold weather-related outages when temperatures reached 10.28 degrees. Additionally, the J. Wilson Report attempts to disqualify using the outage data from January 2, 2018, to calibrate the cold weather outages because "this was a quite unusual date – the outage was very early Tuesday morning following a three-day New Year's weekend."[51] When asked through discovery to further explain the relevance of this statement, the report's author responded that "[t]here are many ways the unusual circumstances of this date (the morning following the 3-day New Year's weekend) could have impacted the plant staff's ability to address the circumstances that led to the outage. Many people are traveling on the last day of a holiday weekend, and could be delayed and

[49] Initial Comments of NCSEA and CCEBA Exhibit 1, at 6.
[50] The Resource Adequacy Study was included as Attachment III to the Companies' 2020 IRPs and the Resource Adequacy Study Confidential Appendix was filed under seal with the Companies' 2020 IRPs.
[51] Partial Initial Comments of Environmental Parties Attachment 5, at 26.

not get their normal sleep…"[52] This perplexing justification for disqualifying otherwise proper data evidences Mr. Wilson's pattern of not presenting a technically objective analysis and ignoring data that is not helpful to the outcome he hopes to achieve in this docket.

Finally, using ERCOT's recent February cold weather event as a benchmark again, ERCOT saw approximately 27.6 GW (or, 27,600 MW) of weather related generation offline at the highest point in time during the cold weather event (total generation offline due to all causes was approximately 52,000 MW).[53] The incremental 400 MW assumed for the combined DEC and DEP systems during cold weather events was significantly lower than what actually occurred during the ERCOT event. 400 MW is equivalent to losing a portion of a single combined cycle unit in extreme temperatures below 10 degrees. At extremely cold temperatures, system components can fail and while the Companies have invested in winter hardening of their units, it is expected there will continue to be challenges regarding unit availability during extreme weather and it is appropriate to plan for those challenges as part of the resource adequacy study.

C. Neighbor Assistance was Appropriately Modeled in the Resource Adequacy Study

NCSEA/CCEBA's Kirby Report asserts that the Companies should assume support from entire Southeast Energy Exchange Market ("SEEM") footprint and on page 28 recommends that, "[t]he Commission should direct Duke to recognize that DEC and DEP

[52] Reference SELC response to Duke Data Request 1-31(a) in South Carolina Docket No. 2019-224-E and 2019-225-E.

[53] Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event, April 27, 2021, ERCOT, available at: PowerPoint Presentation (ercot.com), at 8.

operate within the Eastern Interconnection. Modeling should fully represent the opportunities for reliability support and economic exchanges that the interconnection provides. Duke should also be directed to expand efforts to coordinate regionally, both operationally and for transmission expansion."[54]

The Companies disagree with Mr. Kirby's recommendation to model the entire SEEM footprint, although, notably, Astrapé did model all of the larger entities in the SEEM footprint in the resource adequacy study except for Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), and Associated Electric Cooperative, Inc. (AECI). The few SEEM participants that were not included represent only approximately 15,000 MW of resources compared to over 200,000 MW of resources that were included in the study.[55] Adding these additional entities to the neighboring footprint would not have a meaningful impact on the study results or conclusions. Thus, in planning for resource adequacy, the Companies, through the 2020 Resource Adequacy Study developed by Astrapé, do plan for neighbor assistance and coordinated operations with other southeastern utilities that is reasonably reflective of the Companies' real world operations today.

The Companies note that the Resource Adequacy Study also provided results for an "Island Case" where each Company is responsible for serving their own load without neighbor assistance.[56] The purpose was to compare the Island Case results to the Base Case for each Company to determine the level of reliance on neighboring electric systems

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[54] NCSEA/CCEBA Initial Comments Exhibit 1, Kirby Report at 28.
[55] 2020 DEC IRP Attachment III, Section III.B of the 2020 Resource Adequacy Study report which describes the study topology and the neighboring systems that were modeled in the study.
[56] 2020 DEC IRP Attachment III, 2020 Resource Adequacy Study, Executive Summary at 5, and Section V at 45.

for serving load. For DEC, the Island Case requires a reserve margin of 22.5% to satisfy 0.1 LOLE compared to a 16.0% reserve margin for the Base Case which includes capacity support from neighboring systems. For DEP, the Island Case requires a reserve margin of 25.5% compared to 19.25% for the Base Case. Thus, DEC is relying on market assistance to satisfy approximately one third of its 22.5% required reserves and DEP is relying on market assistance to satisfy approximately one fourth of its 25.5% required reserves.

As noted in the Executive summary of the Resource Adequacy Study reports, Astrapé believes the Companies have taken a "moderate to aggressive approach (i.e. taking significant credit for neighboring regions) to modeling neighboring assistance compared to other surrounding entities such as PJM Interconnection L.L.C. (PJM) [57] and Midcontinent Independent System Operator (MISO)."[58, 59] Also as noted in the Executive Summary of the Resource Adequacy Study reports and Chapter 9 of the IRPs, utilities around the country are continuing to retire and replace fossil-fuel resources with more intermittent or energy limited resources such as solar, wind, and battery storage. For example, Dominion Energy Virginia has made substantial changes to its resource plans as the 2020 Resource Adequacy Study was being conducted and plans to add substantial solar and other renewables to its system that could cause more significant winter reliability stress than what was modeled by Astrapé in developing the resource adequacy study. Dominion

[57] PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin compared to 6.5% assumed for DEC and 6.25% assumed for DEP. https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx p.11.
[58] MISO limits external assistance to an Unforced Capacity (UCAP) of 2,331 MW which represents approximately 1.8% of its reserve margin compared to 6.5% assumed for DEC and 6.25% assumed for DEP. https://www.misoenergy.org/api/documents/getbymediaid/80578.
[59] 2020 Resource Adequacy Study report, at 7.

Energy Virginia's 2020 IRP[60] highlights that Dominion will "likely need to import a significant amount of energy during the winter" which coincides with the same period that the Companies have the greatest need for capacity support. Additionally, PJM now considers the DOM Zone[61] to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, ***[Dominion Energy Virginia] would likely need to import a significant amount of energy during the winter***, but would need to export or store significant amounts of energy during the spring and fall.[62]

As another benchmarking example, California experienced rolling blackouts in 2020 during extreme weather conditions as the ability to rely on imported power has declined and has shifted away from dispatchable fossil-fuel resources and put greater reliance on intermittent resources.[63] Although the outages were caused by a confluence of numerous events, limited import capability was identified as a contributing factor.[64] Potential changes to surrounding resource portfolios may lead to less confidence in market assistance in the future to meet early morning winter peak loads.

[60] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq*., Case No. PUR-2020-00035, 2020 Plan (May 1, 2020) ("Dominion Energy Virginia 2020 IRP").
[61] https://www.pjm.com/library/~/media/about-pjm/pjm-zones.ashx.
[62] Dominion Energy Virginia 2020 IRP at 40.
[63] https://www.greentechmedia.com/articles/read/how-californias-shift-from-natural-gas-to-solar-is-playing-a-role-in-rolling-blackouts.
[64] EPRI: Resource Adequacy Challenges: Issues Identified Through Recent Experience in California, at 8, available at https://www.epri.com/research/products/000000003002019972.

The lessons from these recent events and studies is that changes in neighboring systems' resource portfolios and load profiles will be an important consideration in future resource adequacy studies. To the extent historic diversification between the Companies and neighboring systems declines, the historic reliability benefits the Companies have experienced from being an interconnected system will also decline. As the Companies and neighbors reduce dependence on dispatchable fossil fuels and increase dependence on variable and intermittent resources, it is important to ensure this transformation is undertaken in a prudent manner that does not impact reliability to customers.

In sum, the Companies' view aligns with recent testimony to Congress by NERC President and CEO, Mr. James Robb, included as <u>Attachment 2</u> of these reply comments, that "[i]t is imperative to understand and plan for the different operating characteristics of variable, inverter-based resources. This includes time to study, plan for, and develop effective solutions to the challenges."[65] The Companies will continue to analyze these increasingly complex issues relating to neighbor assistance in future resource adequacy studies to ensure prudent planning will lead to reliable service for the Companies' customers.

D. Duke Appropriately Developed Solar Profiles for use in the Resource Adequacy Study

As previously noted, Astrapé modeled 39 years (1980-2018) of historic weather data in the Resource Adequacy Study. Solar units were simulated with thirty-nine solar shapes representing the thirty-nine years of weather. The solar shapes were developed by

[65] James R. Robb, North American Electric Reliability Corporation, Testimony Before United States Senate Committee on Energy and Natural Resources, Full Committee Hearing on the Reliability, Resiliency, and Affordability of Electric Service (March 11, 2021) (NERC Robb March 11, 2021 Testimony to Congress"), at 9 included as Attachment 2.

Astrapé using data downloaded from the National Renewable Energy Laboratory ("NREL") National Solar Radiation Database ("NSRDB") Data Viewer. However, since NREL's dataset only includes hourly solar data beginning 1998, Astrapé synthesized hourly solar data for 1980 through 1997 by matching similar days from 1998-2019 with days from 1980-1997 based on peak load and time-of-year.

NCSEA/CCEBA and the Sharp Report assert that this method of synthesizing hourly solar data to be without merit, suggesting that, "though solar generation and load are both driven by atmospheric parameters, there is categorically no foundation in atmospheric science to suggest any skill in such a methodology. We suspect that it is likely no better than using a random number generator to assign the shapes."[66] The Sharp Report also notes that a similar methodology for creating solar data was also deployed in the "Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study", which is used to determine the Effective Load Carrying Capability ("ELCC") of solar, and used in the IRP.[67]

In reply to these intervenor comments, and as noted above, Astrapé used an approach to maintain the relationship observed between load and solar from 1998-2018 and applied this relationship to the 1980-1997 time period. Most importantly, however, this critique has no impact on the Astrapé analysis because LOLE occurs in hours when solar has little to no output. If solar was not on the system, the utilities would have shed load regardless since solar would not have been contributing capacity to meet the early morning winter peak loads.

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[66] NCSEA/CCEBA Exhibit 4 at 13-14.
[67] NCSEA/CCEBA Exhibit 4 at 14.

E. The Winter Peak Study and Resource Adequacy Study Are Not "Highly Inconsistent" as Claimed by Environmental Parties

The Environmental Parties assert based on analysis presented in the J. Wilson Report that the results of the Companies' Winter Peak Study[68] and the Resource Adequacy Studies were "highly inconsistent."[69] Specifically, the Wilson Report suggests this by pointing out that the Winter Peak Study identified a "Study Peak Day," which had the highest winter coincident peak demand, while the Resource Adequacy Studies modeled load values over 13% higher than the highest load on the Study Peak Day and the vast majority of loss of load scenarios in the RA Studies occurred at loads in excess of the Study Peak Day's highest load.[70]

As background, the Companies engaged nationally-recognized experts Tierra Resource Consultants in partnership with Dunsky Energy Consulting and Proctor Engineering Group to study DEC's and DEP's winter peak capacity needs and define a proposed solution set of EE/DSM customer programs and technologies that together could offer opportunities to enable the Companies to more effectively manage energy demand during winter peak periods (the "Winter Peak Study").

In reply to the Environmental Parties' comments on this issue, the Companies note that the Winter Peak Study and the Resource Adequacy Study are two entirely separate studies conducted for two very different purposes. The Winter Peak Study selected an actual 2018 winter peak load event for study purposes. The study examined the shape and drivers behind extreme winter events to design demand-side programs and rate solutions to reduce customer load; however, study results were not driven by the potential magnitude

[68] The Winter Peak Study is also referred to as the "Winter Peak Demand Reduction Potential Assessment."
[69] Environmental Parties' Partial Initial Comments at 15.
[70] Environmental Parties' Partial Initial Comments Attachment 2, at 9.

of an extreme winter event. In contrast, the highest loads in the Resource Adequacy Study represent more severe weather that could occur for the 2024 study year based on 39 years of historic weather rather than just 2018 weather. Any conclusion that Environmental Parties' J. Wilson Report attempts to draw from this comparison is invalid because he is essentially comparing "apples to oranges" as the 2020 Resource Adequacy Study represents loads that could occur in the 2024 study year while the Winter Peak Study is evaluating a single load event from 2018. The Companies further note that use of a higher peak load assumption in the Winter Peak Study would not change the study program solution set. Environmental Parties claim that the Winter Peak Study and the Resource Adequacy Studies were highly inconsistent is of little significance and should be disregarded.

F. Historic Operating Reserves Are Correctly Represented in the 2020 IRPs and NC WARN/CBD's Criticisms are Grossly Inaccurate and Should be Ignored

The Companies' 2020 IRPs presented Table 9-A (replicated in Table 3 for DEC and Table 4 for DEP below) showing actual historic operating reserves to demonstrate that planning to the 0.1 LOLE target has not resulted in carrying an excess amount of planning reserves. For the period 2014-2019, the DEC table shows a total of 13 occurrences when operating reserves declined below 10%, with four occurrences below 5% and three occurrences below 2%. The lowest operating reserve of 0.2% occurred on January 7, 2014.

Table 3: 2020 DEC IRP Table 9-A DEC Actual Historic Operation Reserves

RANK (LOWEST TO HIGHEST OPERATING RESERVES)	DATE	PEAK DEMAND (MW)	OPERATING RESERVES* (%)	IRP RESERVE MARGIN** (%)
1	1/7/2014	18,626	0.2	24.8
2	2/20/2015	18,589	1.2	27.6
3	1/8/2015	17,974	1.9	27.6
4	1/30/2014	19,151	2.4	24.8
5	01/02/18	20,890	5.3	21.2
6	01/25/19	16,906	5.9	24.1
7	03/06/19	17,124	6.6	24.1
8	1/24/2014	18,550	7.0	24.8
9	01/31/19	18,875	7.2	24.1
10	2/19/2015	17,427	7.6	27.6
11	01/05/18	21,620	8.0	21.2
12	12/06/18	17,742	9.3	21.2
13	01/11/19	17,705	9.5	24.1

*Operating Reserves represent an estimate based on the last snapshot of projected reserves at the peak for each respective day and include the effects of DR programs that were activated at the time of the peak.

**IRP Reserve Margin reflects the projected reserve margin based on normal weather peak from the previous year's IRP.

For DEP, the table shows a total of 10 occurrences when operating reserves declined below 10%, with six occurrences below 5% and three occurrences below 2%. Operating reserves of -1.6% occurred on February 20, 2015, meaning the Company was relying on non-firm energy to meet load and was still unable to maintain adequate firm operating reserves.

Table 4: 2020 DEP IRP Table 9-A DEP Actual Historic Operation Reserves

RANK (LOWEST TO HIGHEST OPERATING RESERVES)	DATE	PEAK DEMAND (MW)	OPERATING RESERVE* (%)	IRP RESERVE MARGIN ** (%)
1	02/20/15	15,515	-1.6	31.7
2	01/07/14	14,159	0.2	33.6
3	01/07/18	15,718	1.7	24.8
4	01/02/18	15,129	2.8	24.8
5	01/08/14	13,907	4.5	33.6
6	01/08/18	14,835	4.6	24.8
7	01/05/18	15,048	7.6	24.8
8	01/03/18	14,512	8.5	24.8
9	01/08/15	14,454	9.2	31.7
10	01/16/18	13,207	9.8	24.8

*Operating Reserves represent an estimate based on the last snapshot of projected reserves at the peak for each respective day and include the effects of DR programs that were activated at the time of the peak.
**IRP Reserve Margin reflects the projected reserve margin based on normal weather peak from the previous year's IRP.

The DEC and DEP tables also show that planning reserves were well in excess of the current 17% winter reserve margin target for each of these occurrences. DEC planning reserve margins ranged from 21% to 28% and DEP planning reserve margins ranged from 25% to 34%. Thus, the 2020 IRPs conclude—based on recent actual operational experience—that it is almost certain that DEC and DEP would have experienced load shed events during some of these occurrences had the reserve margin going into the winter been at 17%.[71]

NC WARN/CBD erroneously allege that the Companies understated their actual operating reserve margins.[72] NC WARN/CBD discuss IRP tables 9-A and claim that "these supposed periods of low [operating reserve margins] are actually the result of errors and omissions from the IRPs."[73] In support of their claim, NC WARN/CBD and their

[71] 2020 DEC IRP, Chapter 9 at 69; 2020 DEP IRP, Chapter 9 at 72.
[72] NC WARN/CBD Initial Comments, at 6-11.
[73] NC WARN/CBD Initial Comments, at 8.

consultant Mr. Powers mistakenly point to the Companies' response to SELC Data Request 2-12 that asked for greater detail regarding the "refinements to peak history" that were discussed in the Companies' 2020 IRPs. The Companies' data request response provided a description of the refinements made to the peak load history and provided historic peak demands before and after the refinements. NC WARN/CBD then erroneously substituted the load data reflecting the refinements into the Table 9-A operating reserves table. This substitution is fundamentally incorrect and in no way supports the proposition asserted by NC WARN/CBD.

The Companies note that NC WARN/CBD and the Powers Report are also incorrectly comparing system load (also referred to as IRP load) provided in response to SELC data request 2-12 to total BA load reflected in Table 9-A of the IRP. The two load definitions are significantly different. The BA loads (presented in Table 9-A) produced by the Companies' energy control center are made up of loads for the entire BA, which are not subject to revision. System load (IRP load) is calculated, by beginning with BA loads and removing the wholesale loads that are not served by the Company. For DEC, the two load definitions can vary by approximately 2,500 MW. The revisions noted in the data request response were to system load only and are not applicable to the BA load. Thus, the system loads provided in SELC data request 2-12 are correct and the BA loads provided in Table 9-A of the IRPs are also correct. The Powers Report misapprehends the meaning of the data and then wrongly accuses the Companies' IRPs of being inaccurate.

Furthermore, NC WARN claims, "[i]n addition to omitting non-firm energy purchases from its [operating reserve margin] calculations, Duke Energy also omits to mention that substantial amounts of its own supply assets were unnecessarily idle during crucial winter peak events."[74] This claim is simply false and can be explained by comparing the data request response provided in NC WARN/CBD"s Attachment 6 with the supplemental response to that data request provided on March 26, 2021 by the Companies. The response included in Attachment 6 and presented in Table 5 reflects generators that show availability even though they are in Forced Outage, Maintenance Outage, or Pseudo-tied into PJM's BA as shown in Table 5 below.

Table 5: Excerpt from NC WARN/CBD Initial Comments, Attachment 6

Offline Units/Groups

Unit/Group	Reason	Loading	Available
DARLINGTON CO. CT 01	Forced Outage	0	63
DARLINGTON CO. CT 05	Forced Outage	0	59
DARLINGTON CO. CT 08	Reliability	0	0
DARLINGTON CO. CT 10	Out of Economics	0	61
MARSHALL HYDRO	Maint Outage	0	0
NCEMC HAMLET CT 02	Out of Economics	0	56
NCEMC HAMLET CT 03	Out of Economics	0	56
RICHMOND CO. CT 04	Forced Outage	0	168
SUTTON CT 04	Out of Economics	0	51

This data is not correct, and, when compared with the Companies' March 26, 2021 Supplemental Response for the same units for the same operating date, 1/7/2018, as reflected in Table 6, you can see the highlighted errors and how NC WARN's Attachment 6 data would be misinterpreted as reflecting that the Companies had extra reserves on this high winter load day. Furthermore Darlington Co. CT 10 was deemed a collateral damage risk to start and was declared "emergency start only – just prior to shedding firm load"

[74] NC WARN/CBD Initial Comments Attachment 1 Powers Report, at 14.

during this time period and the Hamlet CTs 02 and 03 are pseudo-tied into the PJM BA and thus not available to serve DEC/DEP load.

Table 6: Supplemental Response to NC WARN/CBD Data Request 4-5

Offline Units/Groups

Unit/Group	Reason	Loading	Available
DARLINGTON CO. CT 01	Forced Outage	0	0
DARLINGTON CO. CT 05	Forced Outage	0	0
DARLINGTON CO. CT 08	Reliability	0	0
DARLINGTON CO. CT 10	Out of Economics	0	61
MARSHALL HYDRO	Maint Outage	0	0
NCEMC HAMLET CT 02	Pseudo-tied to PJM	0	0
NCEMC HAMLET CT 03	Pseudo-tied to PJM	0	0
RICHMOND CO. CT 04	Forced Outage	0	0
SUTTON CT 04	Out of Economics	0	51

These types of errors propagate to the data for the other dates in the same data request. The irrationality of NC WARN/CBD's assertion that DEP had "substantial amounts of its own supply assets [available that were] unnecessarily idle" can also be demonstrated by DEP's system operators' real-world response to this challenging extreme weather event. Specifically, on 2/20/2015, 1/2/2018, 1/7/2018, 1/15/2018, and 1/18/2018, DEP implemented emergency actions including curtailing large industrial customers over the winter peak hours, an action DEP's system operators would not have taken with excess capacity on the system.

In sum, NC WARN/CBD's and the Powers Report's claim that the operating reserve data presented in Chapter 9 of the 2020 IRPs is erroneous is grossly inaccurate and should be ignored. Furthermore, the data reflected in Attachment 6 of NC WARN and CBD's Initial Comments is in error as compared with the supplemental response provided on March 26, 2021, and thus led to the false conclusion that the Companies had excess capacity during the days of high winter peak demand. These comments and NC WARN/CBD's related recommendations should be disregarded.

G. NCSEA/CCEBA and Environmental Parties' Reserve Margin Recommendations Would Not Provide Resource Adequacy for the Companies and Customers and Should Be Rejected

NCSEA/CCEBA's Kirby Report recommends that the "Commission should direct Duke to set reserve requirements on a risk neutral economic basis rather than forcing a 0.1 LOLE regardless of cost." [75]

As previously noted, the 2020 Resource Adequacy Studies determined the reserve margin required to meet the one day in ten years loss of load expectation (0.1 LOLE) standard. While no party specifically endorsed use of the 0.1 LOLE standard, the Companies note that the Public Staff, NCSEA/CCEBA's other consultant Energy and Environmental Economics, Inc. ("E3"), and Environmental Parties, all commented that 0.1 LOLE is a common industry standard for establishing planning reserve margins.[76,77,78] Also, none of the parties objected to the use of 0.1 LOLE standard in the resource adequacy stakeholder process. Further, the actual operating reserves information presented in Chapter 9 of the 2020 IRPs and discussed earlier in these reply comments, demonstrates that planning to the 0.1 LOLE standard has not resulted in carrying an excess amount of planning reserves based on the Companies' real world operational experience during extreme weather events.

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[75] NCSEA/CCEBA Exhibit 1, Kirby Report at 31.
[76] Public Staff Initial Comments at 66.
[77] NCSEA/CCEBA Initial Comments Exhibit 2, E3 Report at 39.
[78] Environmental Parties Partial Initial Comments at 13.

Astrapé and Duke believe that the physical reliability metric targeting a 0.1 LOLE should be used for determining the planning reserve margin because customers expect to have adequate and reliable power during extreme weather conditions. For informational purposes, Astrapé also evaluated resource adequacy from a customer cost perspective by analyzing total system costs[79] across various reserve margin levels for the Base Case for DEC and DEP.[80] The risk neutral reserve margin represents the weighted average results of all weather years, load forecast uncertainty, and unit performance iterations at each reserve margin level and represents the yearly expected value on a year in and year out basis. The risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. As reserves are added, system energy costs decline and shield customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

For DEP, the difference in the reserve margin required to meet the 0.1 LOLE target (19.25%) versus the risk neutral economic reserve margin (10.25%) is significant.[81] Setting the DEP reserve margin at 10% would not meet reliability standards and would put customers at risk of more frequent firm load shed events. The 10% reserve margin

[79] System costs = system energy costs plus capacity costs of incremental reserves. System energy costs include production costs + net purchases + loss of reserves costs + unserved energy costs while system capacity costs include the fixed capital and fixed Operations and Maintenance (FOM) for CT capacity. Unserved energy costs equal the value of lost load times the expected unserved energy.

[80] *See* 2020 DEC IRP Attachment III, 2020 Resource Adequacy Study, Executive Summary at 11, and Section VI for economic results.

[81] Given the significant level of solar on the DEP system, summer reserve margins are approximately 12% greater than winter reserve margins. Thus, the risk neutral reserve margin of 10.25% for DEP is significantly lower than the 19.25% reserve margin required to meet 0.1 LOLE since there is little economic benefit of additional reserves in the summer and the majority of the savings seen in adding additional capacity is only being realized in the winter.

recommendation from the Kirby Report is also far below any utility planning target in the region, as noted earlier, and should be rejected.

Environmental Parties, relying on the J. Wilson Report, similarly suggest that, accepting Mr. Wilson's critiques "the 14.5% summer planning reserve margin that was in place until the 2016 IRP, which would provide a 16.5% winter reserve margin, would be more than adequate."[82]

Environmental Parties' results-oriented recommendation is puzzling and without rational basis because a 14.5% summer reserve margin for the Companies does not result in a 16.5% winter reserve margin. In fact, if DEP plans the system to meet a 14.5% summer reserve margin, its winter reserve margin will be less than 5% due to its high solar penetration which has the net effect of increasing the summer reserve margin significantly more than winter reserve margin. This relationship is shown throughout the Resource Adequacy Study and accompanying reports.[83] This recommendation demonstrates that either the author does not understand the fundamental relationship between summer and winter reserve margins for the Companies or it lays bare that he is presenting a non-technically objective recommendation that would not meet the Companies' resource adequacy needs and would create future reliability risks for the Companies and customers. This recommendation is simply not credible and Environmental Parties' J. Wilson Report's apparent suggestion of reverting back to the 14.5% summer reserve margin target that was in place prior to 2016 is nonsensical and should be rejected.

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[82] Partial Initial Comments of Environmental Parties Attachment 5, Wilson Report at 8.
[83] 2020 DEC IRP Attachment III, 2020 DEP Resource Adequacy Study Report Table ES-2, at 8.

IV. Planning for Transmission Reliability in the 2020 IRPs

The Companies are required under NCUC Rule R8-60 to address the adequacy of its transmission system, as well as take into account system operations and transmission and distribution costs in evaluating resource options to reliably serve customers over the 15-year planning period.[84] The DEC and DEP 2020 IRPs address the Companies planned grid investments under the various portfolios in Chapter 7, and transmission projects in the planning stages or under construction are presented in Appendix L.

DEC's and DEP's planning for transmission system reliability is also governed by NERC planning standards as well as FERC and State transmission service and generator interconnection requests requirements. Both the NERC standard TPL-001 studies for transmission system reliability, as well as transmission service and generator interconnection request studies can result in the need for transmission network upgrades. Implementing these transmission network upgrades usually requires existing transmission circuits to be taken out of service for the period of time necessary to construct and place in service the network upgrade. Some network upgrades require two or more shoulder season outages to construct due to the need for the circuit to be in-service during the summer and winter peak seasons. Furthermore, some network upgrades have interdependencies on other network upgrades. Thus, similar to closing I-40 or another major interstate highway during the busy summer vacation season, congestion occurs. NERC operating standards, such as TOP-001[85] also severely limit DEC's and DEP's ability to remove several transmission circuits at one time to facilitate network upgrades for generator

[84] NCUC Rule R8-60(g), (i)(5).
[85] NERC Reliability Standard TOP-001 requires DEC and DEP to be able to withstand a worst case contingency such as a loss of a generator or loss of a transmission line.

interconnection while meeting the NERC mandatory TPL-001 required upgrades within the timeline specified. Some transmission circuits cannot be removed at all during peak seasons due to needing to maintain single contingency operations for reliability. Finally, due to the significant amount of time needed for siting and permitting, as well as outage coordination needed to ensure reliability and facilitate network upgrades, transmission system network upgrades will remain a deliberate but necessarily slow process due to mandatory compliance with NERC reliability standards as well as state laws related to siting and permitting. This context highlights the important role that planning for future transmission to reliably serve customers has as a component of the 2020 IRPs and will continue to have for future resource planning.

A. DEC and DEP will Continue to Refine their Transmission Planning and System Production Cost Estimates based on Future Coal Retirements, as recommended by Public Staff.

In the *2018 IRP Order*, the Commission directed DEC and DEP to identify all major transmission and distribution upgrades that will be required to support the alternative resource portfolios along with the best current estimate of costs of constructing and operating such upgrades.[86] Thus, DEC and DEP determined and provided cost estimates for transmission network upgrades that would be needed for integrating the resources identified in the DEC and DEP IRP portfolio scenarios. These transmission network upgrade cost estimates are represented in the DEC/DEP Combined System Portfolio Results Table on page 16 of the 2020 DEC and DEP IRPs shown below in Table 7. In

[86] *Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans*, at 9 Docket No. E-100, Sub 157 (April 6, 2020) ("2018 IRP Order").

addition, Chapter 7, Grid Requirements, describes in detail how the cost estimates were derived.[87]

Table 7: DEC/DEP Combined Portfolio Results Table from 2020 IRPs –Transmission

DUKE ENERGY.
CAROLINAS

DEC / DEP COMBINED SYSTEM PORTFOLIO RESULTS TABLE

	Base without Carbon Policy		Base with Carbon Policy		Earliest Practicable Coal Retirements		70% CO_2 Reduction: High Wind		70% CO_2 Reduction: High SMR		No New Gas Generation	
PORTFOLIO	A		B		C		D		E		F	
System CO_2 Reduction (2030 | 2035)[1]	56%	53%	59%	62%	64%	64%	70%	73%	71%	74%	65%	73%
Present Value Revenue Requirement (PVRR) [$B][2]	$79.8		$82.5		$84.1		$100.5		$95.5		$108.1	
Estimated Transmission Investment Required [$B][3]	$0.9		$1.8		$1.3		$7.5		$3.1		$8.9	
Total Solar [MW][4, 5] by 2035	8,650		12,300		12,400		16,250		16,250		16,400	
Incremental Onshore Wind [MW][4] by 2035	0		750		1,350		2,850		2,850		3,150	
Incremental Offshore Wind [MW][4] by 2035	0		0		0		2,650		250		2,650	
Incremental SMR Capacity [MW][4] by 2035	0		0		0		0		1,350		700	
Incremental Storage [MW][4, 6] by 2035	1,050		2,200		2,200		4,400		4,400		7,400	
Incremental Gas [MW][4] by 2035	9,600		7,350		9,600		6,400		6,100		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][7] by 2035	2,050		2,050		2,050		3,350		3,350		3,350	
Remaining Dual Fuel Coal Capacity [MW][4, 8] by 2035	3,050		3,050		0		0		0		2,200	
Coal Retirements	Most Economic		Most Economic		Earliest Practicable		Earliest Practicable[9]		Earliest Practicable[9]		Most Economic[10]	
Dependency on Technology & Policy Advancement	○		◔		◑		◕		●		●	

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline
[2]PVRRs exclude the cost of CO_2 as tax. Including CO_2 costs as tax would increase PVRRs by ~$11-$16B. The PVRRs were presented through 2050 to fairly evaluate the capital cost impact associated with differing service lives
[3]Represents an estimated nominal transmission investment; cost is included in PVRR calculation
[4]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon
[5]Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected)
[6]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro
[7]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour
[8]Remaining coal units are capable of co-firing on natural gas, all coal-only units that rely exclusively on coal are retired before 2030
[9]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit and Roxboro 1&2 to EOY 2029 for integration of offshore wind/SMR by 2030
[10]Most Economic retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind by 2030

LEGEND:
● Completely dependent
◕ Mostly dependent
◑ Moderately dependent
◔ Slightly dependent
○ Not dependent

Duke Energy Carolinas Integrated Resource Plan 2020 Biennial Report
| PAGE 16 of 405

The Public Staff believes the model inputs relied upon by Duke are reasonable for planning purposes but notes that cost savings from the replacement generation may not materialize for numerous reasons including failure of critical equipment, higher than estimated fuel costs, higher than estimated construction costs, and the ultimate selection of replacement resources other than what is modeled.[88] As discussed extensively in the 2019

[87] DEC 2020 IRP at 16, DEP 2020 IRP at 16.
[88] Public Staff Initial Comments at 108.

rate cases[89] and in the current 2020 IRPs, the Companies' future transmission investment requirements are dynamic and correlated to the timing of planned coal unit retirements as well as the type and location of replacement generation. Retiring existing coal generating facilities that support the grid and integrating incremental resources forecasted in the 2020 IRPs will require significant investment in the DEC and DEP transmission systems.

Moreover, as described in Chapter 11 and Appendix A of the respective 2020 IRPs, if replacement generation that can provide similar ancillary services, as well as real power needs, is not located at the site of the retiring coal facility, transmission investments will generally be required to accommodate the unit's retirement in order to maintain regional grid stability. Furthermore, a range of additional transmission network upgrades will be required depending on the type and location of the replacement generation being interconnected with the grid. As more certainty is known regarding the timing of replacement and incremental resources, the options considered with respect to type and location, as well as capability (Megawatts, MVA), definitive transmission studies can be performed resulting in more accurate network upgrade cost estimates.

In addition, further refinements around cost estimates for off-system capacity purchases will be included in future IRPs to the extent off-system purchases are contemplated in the plan. Similar to on-system resources, more accurate cost estimates for off-system capacity purchases require more certainty regarding the timing of options for contracted off-system capacity purchase, the type and location, the capability (Megawatts), the available existing firm import capability and any upgrades to facilitate additional needed firm import capability, and estimating the cost for any affected system transmission

[89] *See* Pre-filed Rebuttal Testimony of Steve Immel, at 10-11, Docket No. E-7, Sub 1214 (filed March 4, 2020).

upgrades needed to import the off-system capacity resource. Furthermore, there are several risks associated with planning for and relying on off-system capacity resources as described below in section IV.D below. In sum, the Companies believe the Public Staff's recommendation is reasonable and will continue to refine their transmission planning and system production cost estimates based on added certainty with replacement resources for coal retirement plans in future IRPs.

B. DEC/DEP do not Support Including Generic Network Upgrade Cost Estimates Within the Capacity Expansion Model in the Same Manner as Transmission Interconnection Costs as Recommended by Public Staff.

The Public Staff's comments recommend that the Companies should "attempt to include network upgrade cost estimates within the capacity expansion model in the same manner as transmission interconnection costs."[90] As new capacity resource options (each with different operating attributes, different geographic considerations and different potential transmission requirements) are forecasted to be added to the system, the Companies agree that it would be useful in understanding the total cost of a resource option. However, the Companies believe it is not appropriate to include a generic network upgrade cost estimate in the optimization of the resources selected in the capacity expansion model due to lack of comparable and equivalent cost estimates across technologies.

As background, in developing the 2020 IRP portfolios, the cost of the resources, including their generic interconnection costs, were included in the capacity expansion optimization modeling process. However, no additional transmission system network upgrades typical for the specific resources were assumed in the cost of the resource in the resource selection process. After the optimization process, based on the capacity of solar,

[90] Public Staff Initial Comments at 146.

onshore wind, and storage capacity selected, an estimated incremental transmission system network upgrade cost was applied to the cost of the portfolio. In portfolios where offshore wind was prescriptively incorporated, additional estimated transmission costs specific to offshore wind were included in those portfolios' PVRRs, as well. A transmission system network upgrade cost was not applied to new traditional central generation, not because the Companies expect there will be none, but the nature of transmission upgrade costs for traditional centralized generation are extremely site specific and can vary greatly based on the location, other resources on the system, as well as the size (MW), MVA, and operating capabilities of the generator modeled. A transmission system network upgrade cost was included after the selection of the resource in the PVRR for renewables and storage based on recent integration studies for these technologies and the capacities the system upgrade costs integrated. Essentially, all network upgrade costs were factored in after completion of, or "outside", of the capacity expansion optimization modeling process.

The network transmission upgrade costs were intentionally excluded from the optimization to preserve a more fair comparison of the value of the technologies to the system. Only after the resources were included in the portfolios were these costs added to the PVRRs for each of the portfolios. The Companies believe that DEC and DEP should not include these costs in the selection and optimization of the portfolios in the capacity expansion modeling, as recommended by the Public Staff, primarily due to issues around developing a generic transmission system network upgrade cost for traditional central generation. However, this is an issue that the Companies can discuss with Public Staff in the future.

C. The Companies Will Continue to Take a Reasonable Approach to Neighbor Assistance in the Resource Planning Process but do not Agree that Increased Focus on Building Transmission Import Capability will Ensure the Availability of an Adequate and Reliable Supply of Electric Power to DEC's and DEP's Customers

The AGO suggests that Duke should have "gone further" to examine the potential benefits of neighbor assistance, commenting that "Duke's resource adequacy studies do not adequately investigate how neighbor assistance might impact the reserve margin and capacity costs. While Duke has conducted useful testing on the ties between utilities, it has neglected to pursue a number of promising solutions."[91] The AGO suggests that the Companies could potentially reduce their reserve margins by more heavily relying on neighboring systems, such as PJM, suggesting that "some of PJM's resources could be used to help Duke achieve resource adequacy."[92] The AGO recommends that the Companies should "identify how best to increase neighbor assistance" and specifically focuses on the fact that "Duke has no planned transmission upgrade projects to support sharing outside of DEC and DEP."[93]

In response to this recommendation,[94] the Companies recognize that resource adequacy is a balance between investing in additional capacity to ensure reliability while not imposing excessive costs on customers to ensure that reliability. The AGO is correct that lowering the reserve margin could result in cost savings for customers but the tradeoff is increased resource adequacy planning risk and increased power system reliability challenges in real time. As discussed in Section III. C. of these Reply Comments, the 2020

[91] AGO Initial Comments at 19.
[92] *Id.*
[93] *Id.*
[94] Since DEP has the earliest capacity need to meet the required 17% planning reserve margin, this response will primarily focus on DEP's IRP.

Resource Adequacy Studies present a robust analysis supporting the 17% target reserve margins and, in the opinion of Astrapé, DEC and DEP are taking a moderate to aggressive approach to modeling neighboring assistance in the 2020 Resource Adequacy Study.[95] The Companies have concerns that taking a "too aggressive" approach to neighbor assistance would impair the State's policy that "that the availability of an adequate and reliable supply of electric power . . . to the people, economy and government of North Carolina is a matter of public policy."[96]

Focusing on the AGO's specific recommendation that the Companies assume increased assistance from neighboring areas, specifically PJM, would be available to reliably serve customers in North Carolina, the Companies believe such generalized assumptions about "excess capacity" in PJM needs to be carefully evaluated. For example, significant capacity uncertainty is likely to persist over the next few years due to FERC's Minimum Offer Price Rule resulting in significant Nuclear capacity being at risk in PJM. For example, Exelon recently stated that 8.9GW of Nuclear capacity in Northern Illinois is at high risk of premature closure, with two of the four stations closing as early as the second half of 2021.[97] Furthermore, PJM does not solicit capacity in their Base Residual Auction for the purpose of resale outside PJM, such as to serve DEC's and DEP's native load customers in North Carolina.

The Companies also question whether other utilities in PJM closer to home will have excess capacity during the winter when DEC and DEP have the greatest resource

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[95] 2020 Resource Adequacy Study report, at 7.

[96] N.C. Gen. Stat. § 62-2(3).

[97] Anna Duquiatan, *A look at Exelon's 4 economically challenged nuclear plants in Illinois*, S&P Global Market Intelligence, available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/a-look-at-exelon-s-4-economically-challenged-nuclear-plants-in-illinois-60342724.

adequacy need and loss of load risk. As discussed in Section III. C. of these Reply Comments, Dominion Energy Virginia recently stated in its 2020 IRP that it "would likely need to import a significant amount of energy during the winter but would need to export significant amounts of energy during the spring and fall" due to significantly increasing solar capacity on its system.[98]

DEC and DEP engage in prudently using neighboring emergency assistance and capacity imports for meeting resource adequacy needs. Currently, DEC and DEP are members of the VACAR Reserve Sharing Group ("RSG") and preserve Transmission Reliability Margin import capability for accessing emergency energy reserves based on the following allocations with other RSG members shown in Table 8. This emergency assistance can be provided if the member has not declared the reserve unavailable due to native load needs.

Table 8: VACAR RSG Reserve Allocations

Member Company	Reserve Commitment
DEC	533
Dominion Energy	573
DEP	407
Santee Cooper	192
DESC	201
Total	**1906**

As noted in the AGO's comments, DEP already relies on interties and non-firm purchases to reduce its reserve margin by 6.25%, which represents approximately one quarter of DEP's total reserve margin required to meet the one day in ten-year LOLE standard. It is also important to note that in addition to reliance on non-firm purchases and

[98] Dominion Energy Virginia 2020 IRP at 97-98.

interties, DEP currently imports over 1600 MW of its IRP-defined firm capacity resources resulting in a significant reliance on off-system resources and transmission capability to serve firm customer load.

D. Overreliance on Neighbor Assistance Creates Real World Risks

The Companies appreciate the AGO's recognition that "[r]esource adequacy is extremely important" and recognition that the recent events in ERCOT provide a real world reminder that "resource adequacy can be a matter of life and death."[99] Based on the Companies planning expertise and real world operational experience, relying on higher levels of imported non-firm energy for serving extreme cold weather peak demand would be essentially rolling the dice with respect to providing reliable electric service for customers.

Similar to past weather systems in the Southeast, there is a high likelihood in the future that neighboring systems will experience the same extreme cold or hot weather as the DEC and DEP systems. In this scenario, if the neighboring system providing non-firm energy loses a generator or transmission line, the non-firm energy can easily need to be withdrawn leaving DEC or DEP in a position where it needs to shed firm customer load similar to the occurrence for South Carolina Electric and Gas on January 7, 2014 described below.

There are potentially significant system risks with relying on significant incremental import capability for future resource plan needs that include, but are not limited to:

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[99] AGO Initial Comments at 22.

1) Delay in resource availability – if required transmission network upgrades on the DEP/DEC transmission systems or neighboring transmission systems are delayed due to sitting, permitting, or construction issues, these delays can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource.

2) Loss of local ancillary benefits that are inherent with an on-system resource (e.g. Voltage/Reactive Support, Inertia/Frequency Response, AGC/Regulation for balancing renewable output) may require more on-system transmission upgrades such as adding SVCs for voltage support.

3) Curtailment due to transmission constraints in neighboring areas.

4) Transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.

Another risk with importing power is being overly reliant on non-firm energy assistance from neighboring systems for serving peak demand. Even if new transmission were constructed and import constraints reduced, there would still be a need for non-firm energy to be available in real time emergencies when operating reserves are limited. Transmission capability to make non-firm energy purchases is typically available today during extreme cold weather because each Balancing Authority is keeping all resources within their load serving areas for serving high peak native loads. However, because they are keeping all resources within their own load serving areas, typically there is limited to no available non-firm energy for purchase.

A real-life example of this risk occurred during the January 7, 2014 polar vortex. During the morning peak demand hours of this polar vortex, DEC was providing (selling)

South Carolina Electric and Gas (SCE&G – now Dominion Energy South Carolina) with emergency energy (not capacity). DEC lost a generator on its system and had to withdraw the emergency energy it was providing to SCE&G. This action resulted in SCE&G having to shed firm customer load.[100] Other events over recent years have also demonstrated that DEC and DEP can be challenged to maintain reliable system operations in the face of extreme weather, as detailed in Table 9-A of the 2020 IRPs, as presented in Section III. F. above. For example, on February 20, 2015, the Companies were fortunate that non-firm energy was available for purchase and was a last resort needed to avoid firm load shed. Therefore, DEC and DEP cannot rely on non-firm purchases to ensure reliable electric service for our customers, as required under North Carolina's Public Utilities Act.

E. No Action is Needed in Response to the NCSEA/CCEBA Grid Strategies Report Today. Future Policy Support Would be Needed to Promote Significant Transmission Expansions Outside of Least Cost Resource Planning

The NCSEA/CCEBA Grid Strategies Report comments on the critical importance of transmission assumptions in the Companies' 2020 IRPs and suggests the "optionality provided by a strong electric transmission network are significant and will not be captured to the benefit of customers with incremental, least cost expansion planning, especially if planning models are based on known commitments and do not reflect expected conditions for the future."[101] The Companies do not dispute the importance of a strong electric transmission network, but disagree with the Grid Strategies Report's assertion that the Companies should deviate from least cost planning for their native load customers in order

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[100] *Polar Vortex Review*, North American Electric Reliability Corporation, at 2, available at: https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[101] NCSEA/CCEBA Initial Comments Exhibit 5, Grid Strategies Report at 1.

to significantly expand their transmission systems to increase import capability or support large-scale new renewable generation. DEC and DEP are bound to adhere to least cost integrated resource planning under the Public Utilities Act and NCUC Rule R8-60 as a component of their IRPs' evaluation of resource options.[102] If the Commission or the General Assembly wishes for DEC and DEP to deviate from these statutes to plan for the transmission investment needed to facilitate an integrated least cost resource planning portfolio, then a change in energy policy will be needed.

The Grid Strategies Report also makes the following recommendations related to DEC and DEP's transmission planning assumptions for future IRPs:

1) The economies of scale with bulk transmission upgrades to enable better integration of its Carolina operating companies, as well as integration of large-scale renewable developments, specifically off-shore wind resources;
2) The results of improved collaborative planning efforts with neighboring systems such as the ongoing North Carolina Transmission Planning Collaborative ("NCTPC") study with scenarios from the Southeast Wind Coalition that are in process;
3) Better asset management planning practices to inform planning decisions regarding long-range transmission expansion needs to leverage existing corridors; and
4) More rigor in analysis and assumptions regarding projects and costs to support future resource needs, in particular imports and off-shore wind

[102] N.C. Gen. Stat. § 62-2(a)(3a); NCUC Rule R8-60(c); (g).

developments that may be best addressed in partnership with neighboring systems.[103]

In response to Grid Strategies' first recommendation, DEC and DEP do not disagree with this general recommendation provided it aligns with the State's least cost planning mandate. As noted above and described in the 2020 IRPs, the Companies cannot plan and construct speculative transmission projects to serve future large-scale renewable developments, such as off-shore wind resources, without further policy support from the State or approval by the Commission. The Companies have evaluated the costs of adding off-shore wind generation as part of the 2020 IRP portfolio development process; however, the 2020 IRPs also identified that policy support and technology advancements would be needed to pursue offshore wind generation in the future. If the General Assembly finds investing in expanded transmission projects to support a specific generating resource as serving the public interest in North Carolina, then such projects can be implemented through proper legislation or Commission Order. Today, however, the Companies are limited to planning for least cost.

In the nearer term, however, the new Queue Reform process, once approved by FERC, will enable equitable sharing of network upgrade costs for interconnecting multiple resources under a given set of network upgrades.

In response to Grid Strategies' second recommendation, DEC and DEP do plan to incorporate any updated published NCTPC study results related to importing off-shore wind generation from different locations in future IRPs.[104]

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[103] NCSEA/CCEBA Initial Comments Exhibit 5, Grid Strategies Report at 1.
[104] 2020 DEP IRP Appendix G pages 315-317.

In response to Grid Strategies' third recommendation, DEC and DEP always consider transmission planning options related to using existing unused rights-of-way, reconductoring versus greenfield construction, and are now considering non-traditional solutions for transmission expansion needs.

In response to Grid Strategies' fourth recommendation, as stated in Appendix L of the 2020 DEC and DEP IRPs:

> DEC and DEP participate in several regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. Each reliability group's reliability purposes are to:
>
> - Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
> - Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
> - Ensure interconnected system compliance with NERC Reliability Standards. Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year future periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Furthermore, DEC and DEP, as members of SERTP, participate in interregional transmission planning with FRCC, MISO, PJM, SCRTP, and SPP as identified in Attachment N-1 of the DEC and DEP Joint Open Access Transmission Tariff.[105] These interregional transmission planning groups provide for:

> "coordination between the public utility transmission providers in the SERTP and the SCRTP (i) with respect to an interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could

[105] Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC, Duke Energy Florida LLC, and Duke Energy Progress, LLC, Attachment N-1, available at: http://www.ferc.duke-energy.com/Tariffs/Joint_OATT.pdf.

> address transmission needs more efficiently or cost effectively than transmission facilities included in the respective regional or local transmission plans."[106]

In sum, the Companies continue to plan for new transmission investments to support their integrated resource planning and future selection of resources to reliably serve customers' future capacity and energy needs in North Carolina and see no reason for the Commission to take any action in response to the NCSEA/CCEBA Grid Strategies Report at this time.

V. Natural Gas Price Forecasting and Availability

A. 2020 IRPs Natural Gas Price Forecasting Methodology is Consistent with Prior IRPs and is Reasonable for Planning Purposes

The Companies' natural gas price forecast used for the 2020 IRP is consistent with the methodology used in DEC's and DEP's IRPs and IRP Updates since 2015. The Companies use ten years of monthly pricing from the observable market of natural gas pricing from 2021 through 2030. This market pricing period is followed by four years of transition from market prices to fundamental prices from 2031 through 2034, with the full fundamental forecast in effect starting in 2035. The Companies use of market pricing is based on transacted natural gas pricing from the spring of 2020. The transacted market pricing demonstrates liquidity in the natural gas market at the prices used in the IRP. The Companies have previously demonstrated that the natural gas transaction market is robust and again was able to obtain price quotes from several large financial institutions and other firms.[107]

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[106] *Id*. at Attachment N-1 - The SERTP engages in interregional coordination as described in Attachment N-1 – FRCC, Attachment N-1 – MISO, Attachment N-1– PJM, Attachment N-1 – SCRTP, and Attachment N-1 – SPP.

[107] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans,* at 39, Docket No. E-100, Sub 147 (June 27, 2017) ("Based on DEP and DEC's 2015 IRP updates and Duke witness Snider's

The Companies also developed natural gas price forecasts for high and low gas price sensitivities and scenarios. The high and low gas price forecasts were developed by the same market to fundamental transition schedule using high and low market and fundamental view of natural gas pricing. The high and low market price curves were developed using statistical analysis on the market prices to determine 10th and 90th percentile probabilities. The high and low fundamental natural gas prices were derived using the Companies' base fundamental forecast and the EIA's 2020 Annual Energy Outlook ("AEO") natural gas price forecasts from its Reference Case, Low Oil and Gas Supply Case, and High Oil and Gas Supply Case. These forecasts present a broad range of natural gas pricing for use in determining the sensitivity of the system to these inputs and the robustness of portfolios in high and low pricing scenarios.

B. The Companies have followed a Consistent Natural Gas Price Forecasting Methodology since 2015, which the Commission has accepted in past IRP proceedings and is not Opposed by Public Staff in this Proceeding

The use of ten years of market prices before transition to full fundamentals has been evaluated by the Public Staff in past IRP proceedings and accepted by the Commission as reasonable for planning purposes since 2015. In the 2016 IRP Order, this issue was contested and the Commission specifically determined that "[b]ased on DEP and DEC's 2015 IRP updates and Duke witness Snider's extensive testimony on this subject in the 2016 avoided cost hearing, the Commission accepts that the fuel forecasting methodology utilized by DEP and DEC is appropriate for Integrated Resource Planning in this docket."[108]

extensive testimony on this subject in the 2016 avoided cost hearing, the Commission accepts that the fuel forecasting methodology utilized by DEP and DEC is appropriate for Integrated Resource Planning in this docket.").

[108] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans* at 39, Docket No. E-100, Sub 147 (June 27, 2017).

Then again, in the 2018 IRP Order, the Commission noted Duke's comments that "using 10 years of forward market natural gas prices in their IRPs is appropriate for evaluating future generation needs and allows for an appropriate head-to-head comparison of long-term purchase power obligations from QFs required under PURPA"[109] and accepted the 2018 IRPs as reasonable for planning purposes.

The Public Staff's comments in this proceeding do not oppose the Companies' natural gas pricing forecast methodology, essentially finding that this aspect of the 2020 IRPs is again appropriate for IRP purposes in this docket.[110]

C. The Companies Disagree with NCSEA and CCEBA's Argument that the Companies' Natural Gas Price Forecast Methodology is Flawed and Biased Downward

As part of their joint initial comments, NCSEA and CCEBA included as Exhibit 3 a report submitted by Kevin Lucas of Solar Energy Industries Association ("SEIA"), the national trade association for the U.S. solar industry, entitled, "Comments on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans" ("SEIA Lucas Report") In Section IV of the SEIA Lucas Report, Mr. Lucas is critical of the Companies' natural gas forecasts and claims that they are flawed because they incorporate actual market prices, despite this methodology previously being reviewed and accepted by this Commission. As an initial matter, the use of fundamental market prices that are in excess of actual market prices as argued for by Mr. Lucas is flawed and would result in significant risk of customer overpayments if the same logic was followed in the upcoming avoided cost docket.

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[109] *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses* at 41, 91-92, Docket No. E-100, Sub 157 (Aug. 27, 2019).
[110] Public Staff Initial Comments at 89.

As an employee of SEIA and as an advocate for the solar industry, NCSEA and CCEBA consultant Mr. Lucas understands that convincing the Commission to ignore the actual nearer-term market price of natural gas and instead direct the Companies to rely on higher economic forecasts in their IRPs, the solar development community would be poised for significant monetary gain as his arguments would be carried forward to the upcoming avoided cost proceedings in North Carolina and South Carolina. Although the Companies will address a few of his flawed arguments below, it is important for the Commission to understand that the historic use of fundamental price forecasts as suggested by Mr. Lucas has resulted in significant "over-payment risk" and excess costs to customers both realized historically and on a prospective basis.

Contrary to the SEIA Lucas Report's arguments, the use of near term market prices is appropriate with demonstrated liquidity. Near term use of fundamental natural gas forecasts was thoroughly discussed in recent avoided cost Docket Nos. E-100, Sub 148 and Sub 158, and, in the last decade fundamental forecasts tend to lag the structural changes in the natural gas market. The lagging nature of these fundamental forecasts, which are only updated once or twice per year, have been demonstrated in recent history to overstate the forward market price of natural gas. Changes to the market as speculated by the fundamental forecasts can take longer to develop and are therefore more appropriate only in the absence of demonstrated liquid market based pricing.

On page 46 of his report, Mr. Lucas claims that the "prices of natural gas futures are best described as highly volatile." Highly volatile is a very subjective term. On pages 46-54 of his report, Mr. Lucas presents several selective graphs and charts on natural gas future prices, but he does not mention larger problems with using fundamental price forecasts when a liquid transactable market is available. Simply put, fundamental forecasts can vary significantly over time and can vary from one forecast provider to the next. So, while there are multiple fundamental price forecasts at any point in time there is only a single forward market price at any point in time.

Figure 3 below very simply illustrates three central points:

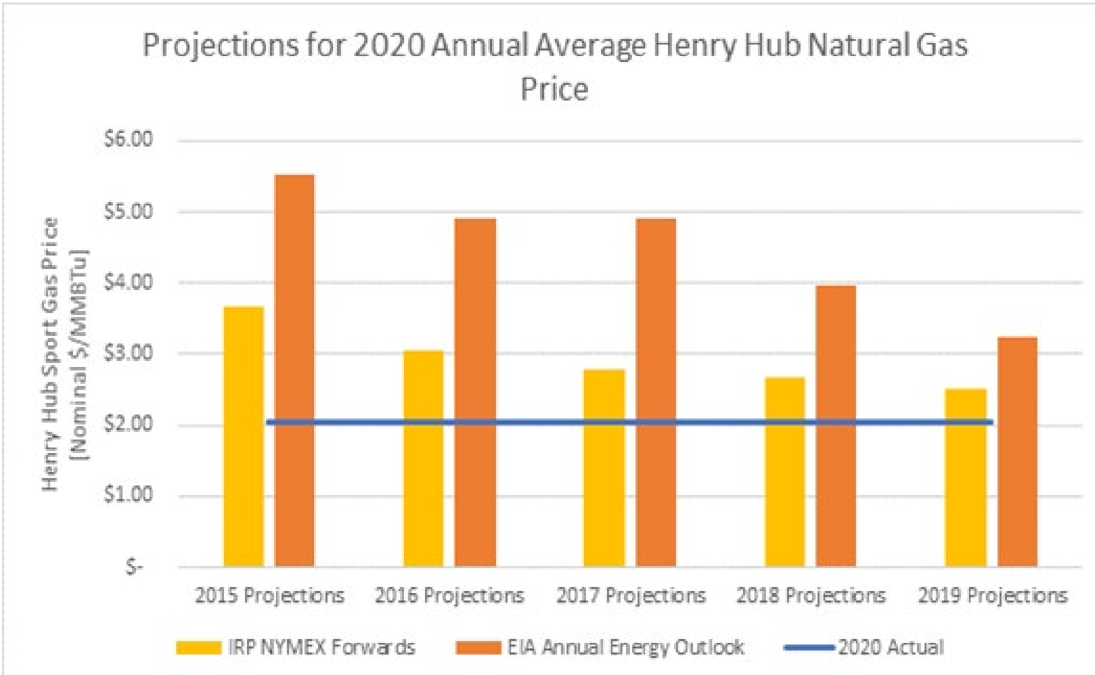
1) Fundamental price forecasts have consistently overstated the market over the last several years;

2) Fundamental price forecasts can move significantly from one year to the next displaying greater year-to-year variance than the actual forward market; and

3) Fundamental price forecasts differ from one forecast to the next while there is a single market price.

Figure 3 below shows the historic views for annual average 2020 Henry Hub prices for the five years leading up to 2020. The yellow bars in the graph below represent the 2020 NYMEX Forward market prices used in the 2015, 2016 and 2017, 2018 and 2019 IRPs. The orange bars are the 2020 annual average projections from the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook from 2015, 2016, 2017, 2018 and 2019. The blue line reflects the actual 2020 Henry Hub annual average spot prices as published by the EIA.

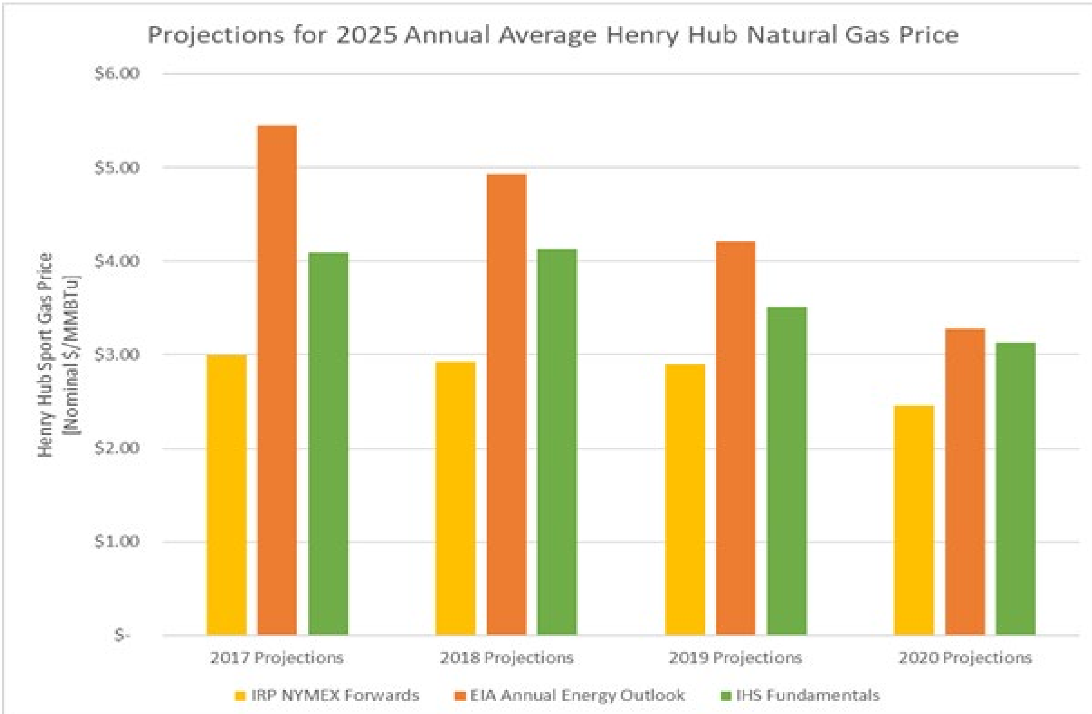
Figure 3: Benchmarking 2020 Average Henry Hub Natural Gas Price to Prior Years Forecasts



As discussed above, and as seen in the Figure, the NYMEX Forward projections were more consistent with the actual 2020 price as compared to the price projected for 2020 in the fundamental forecasts. IHS was not the Companies' fundamental gas forecast provider in 2015 and 2016 so they were omitted from Figure 3 above.

Taking these same forecasts and adding in the Companies' current fundamental gas price provider, IHS, we can see a similar trend evolving for 2025. NYMEX Market prices are more stable on a year-to-year basis as the long-term fundamental forecasts continue to come down over time recognizing the longer-term stability in the market. While we don't know what the price in 2025 will be, we can see that over time, from the Figure 3 above and Figure 4 below, in the near and midterm, the fundamental forecasts have recognized the market and adjust their forecasts accordingly. Finally, Figure 4 below also shows the discrepancy between differing fundamental forecasts' views of the future market price (EIA versus HIS) relative to a single market view.

Figure 4: Projections for 2025 Annual Average Henry Hub Natural Gas Price



The SEIA Lucas Report also argues that the Companies' use of market prices for years 1 through 10, transitioned linearly to a fundamentals-based forecast from years 11 to 15, before utilizing a fundamentals-based forecast from year 16 forward is "inappropriate," and ultimately concludes that the lack of liquidity in the market is fatal to the Companies' methodology.[111] This contention itself is incorrect as the current IRP uses full fundamental pricing in year 15 and not 16. The Companies transition from years 11 to 14, before utilizing a fundamentals-based forecast from year 15 forward. Additionally, the analysis supporting Mr. Lucas's argument simplistically looks at only the short-term nature of the

[111] NCSEA/CCEBA Exhibit 3, SEIA Lucas Report at 39.

NYMEX futures market and then presumes that there is limited availability to transact significant volumes in the longer term Over-The-Counter ("OTC") swap market. These assumptions are simply incorrect. The Solar Industry sponsored Lucas Report goes on to challenge the robustness of the OTC forward market and the prices that result from those swaps. However, this analysis is mistaken that transactable market prices over the ten-year period are not robust. Simply put, the robustness of a market can be demonstrated by the fact that there are multiple brokers that will transact natural gas swaps over this period. In addition, when seeking quotes for OTC swaps, market participants have narrow price differentials between quoted bid prices and offer prices which is another indication of the liquidity and robustness of the market. In conclusion, the Companies' natural gas price forecast methodology is appropriate as consistently recognized by the Commission and intervenor arguments to the contrary should be rejected by the Commission.

D. The Companies Agree to the Public Staff's Recommendation to Include a Limited DS Hub Gas Portfolio in the 2021 IRP Updates.

Based upon discussions with the Public Staff since the filing of the Public Staff's Initial Comments on the 2020 IRPs, the Public Staff would like for DEC and DEP to include a sensitivity in their respective 2021 IRP Updates that places limits on the availability of Dominion Southpoint Hub gas in order to address the uncertainty regarding the availability of new natural gas pipelines or expansion of existing pipelines. The Companies agrees to model in the 2021 IRP Updates a sensitivity portfolio, separate from the Companies' updates to the base planning cases, that would limit Dominion Southpoint Gas to levels that would only allow DEC to supply its existing gas combined cycle ("CC") fleet plus one new CC with Dominion South trading hub gas and DEP to supply its existing and future CC plants from Transco Zone 4 or Zone 5 gas, through 2030, as recommended by the Public Staff.

VI. Existing System Resources Assumptions

A. DEC and DEP will Continue to Update the Commission and Stakeholders on Plans for Subsequent License Renewals of Existing Nuclear Units in Future IRPs.

The Public Staff recommends "that the Commission continue to direct Duke and Dominion in future IRPs to include a discussion and evaluation of potential [subsequent license renewal ("SLR")] for each of their existing nuclear units, including an anticipated schedule for SLR application submission and review, and an evaluation of the risks and required costs for upgrades."[112]

The Companies view their nuclear fleet as viable and necessary resources to provide reliable, cost-effective, clean energy to North Carolina customers in the future. As such, the Companies intend to pursue SLR of existing nuclear facilities, beginning with a submittal for Oconee Nuclear Station in 2021. An SLR application for each nuclear plant will follow, approximately three years from the previous SLR application submittal. A team of highly skilled and experienced employees, including nuclear engineers, scientists, environmental experts, regulatory specialists and other subject matter experts, is supporting SLR application work across the fleet.

The Companies have provided SLR application updates in recently filed IRPs and agree to continue to do so in future IRPs as the SLR filing process progresses and as SLR schedules are finalized. The Companies first presented plans for SLR of their nuclear units in the 2019 IRP. Prior to the filing of the 2019 IRP, the Companies performed analysis to

[112] Public Staff Initial Comments at 101.

determine the cost-effectiveness of SLR for each of their nuclear stations. SLR was found to create significant value and savings for customers as compared to retirement of the nuclear facilities. This information was provided in discovery in the 2019 IRP Update proceeding.

The nuclear units' license expirations begin in 2030. Federal regulations provide that if an SLR application is filed at least five (5) years in advance of license expiration, then the existing license will not be deemed to have expired until the application has been finally determined. This is commonly referred to as the "timely renewal" rule and provides protection that allows continued operation if the NRC review and approval is delayed beyond license expiration. Units at the Robinson Nuclear Plant, Oconee Nuclear Station and Brunswick Nuclear Plant have licenses that expire before 2034—Robinson Nuclear Plant in 2030, Oconee Nuclear Station in 2033 and Brunswick Nuclear Plant in 2034—meaning that all three SLR applications for these plants should be filed before 2029 (five years in advance of license expiration) to meet the timely renewal rule.

As mentioned above, the Public Staff has recommended that an evaluation of the risks and required costs for upgrades be included in future update and biennial IRP filings. The Public Staff further states that "each utility should also file a cost analysis to demonstrate that continued operation of each individual nuclear unit or plant is in the best economic interest for ratepayers. This "cost analysis" should be filed in the next biannual IRP (2022) and again in 2024. The Commission should require the Utilities to work with the Public Staff to develop the requirements of the "cost analysis" report prior to the 2022

IRP filing. Further, Duke and Dominion should continue to reflect any such relicensing plans in future IRPs."[113]

The Companies have evaluated the economics of extending the operating life of their existing nuclear fleet numerous times and consistently determined that it was widely economic to do so. These evaluations show that even in disadvantageous scenarios, such a scenario with no energy policy to incentivize carbon free resources, such as the Companies nuclear fleet, extending these units' operating lives remains economic. In any scenario with higher natural gas prices or the introduction of a carbon policy, nuclear fleet economics become even more attractive. The Companies will continue to evaluate the viability of their nuclear fleet, especially if new policy developments that may have significant impact the ongoing operations of nuclear generation. However, the Companies disagree with the Public Staff's recommendation to include a cost analysis to demonstrate that the continued operation of each individual nuclear unit is necessary or an effective use of resources. The existing nuclear fleet provides reliable, cost-effective, carbon free generation serving approximately half of the customers' electricity needs in the Carolinas. Given the desire for numerous other sensitivities and scenario analyses that are more impactful to the resource plan, the Companies believe that internal and external resources used in developing the IRP are more appropriately allocated to studying these other factors in the 2022 and 2024 IRPs.

The Companies' nuclear fleet is at the core of Duke Energy's commitment to affordable and reliable energy. Furthermore, the existing nuclear fleet is foundational to achieving carbon reduction goals of at least 50% by 2030 and Net Zero by 2050. The

[113] Public Staff Initial Comments at 101.

retirement of existing nuclear assets and required replacement generation presents significant cost, execution and carbon reduction risks. Importantly, obtaining a subsequent license renewal provides the option but not the obligation to operate the units an additional 20 years. If, in the future, significant cost pressures face the industry it may be appropriate at such time to perform the type of detailed cost analysis envisioned by the Public Staff. However, at this point in time, given the overwhelming cost effectiveness of the existing nuclear fleet relative to reliable baseload generation replacement alternatives it is simply premature to include detailed cost analysis in the 2022 comprehensive IRP filing.

Notwithstanding the stated objections to a formal retirement analysis, the Companies agree to provide insights of a risk evaluation that has been performed for SLR in the 2022 biennial IRP. Additionally, a relatively nascent effort to capture necessary upgrades required for 80-year operation of the nuclear units has just begun. As insights from this effort become available, the Companies will include updates in future IRPs.

B. Coal Retirement Analysis

1. The Companies' coal retirement analyses were appropriately conducted in compliance with the Commission's past IRP orders.

As ordered by the Commission in previous orders accepting the Companies' 2018 IRPs and 2019 IRP update reports, DEC's and DEP's 2020 IRPs included two coal retirement analyses: 1) a Most Economic Coal Retirement Analysis and 2) an Earliest Practicable Coal Retirement Analysis.[114] The Public Staff, AGO, NCSEA/CCEBA, NCWARN/CBD and the Synapse Report all directed portions of their initial comments toward the Companies' coal retirement analyses, with varying criticisms or alleged

[114] *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses* at 90 Docket No. E-100, Sub 157 (August 27, 2019) ("2018 IRP Order").

shortcomings. As set forth below, the Companies' coal retirement analyses were appropriately conducted and should be accepted by the Commission.

a. Background: Commission Orders requiring coal retirement analyses.

The *2018 IRP Order* provided the following instruction to the Companies regarding coal retirement analyses to be addressed in the 2020 IRPs:

> To address the issue of economic retirement of aging coal plants, in the 2020 IRPs DEC and DEP shall include an analysis that removes any assumption that their coal-fired generating units will remain in the resource portfolio until they are fully depreciated. Instead, the utilities shall model the continued operation of these plants under least cost principles, including by way of competition with alternative new resources. In this exercise the full costs of disposal of coal combustion wastes shall be included in making any comparison with alternative resources. If such analysis concludes that continued operation of the utilities' existing coal-fired units until they are fully depreciated is the least cost resource alternative, then the utilities 2020 IRPs shall separately model an alternative scenario premised on advanced retirement of one or more of such units and shall include in that alternative scenario an analysis of the difference in cost from the base case and preferred case scenarios.

In its *2019 IRP Order*, the Commission provided the following instruction,

> Acknowledging these factors and the high level nature of the November 4, 2019, submission, the Commission nonetheless finds good cause to direct that for their 2020 IRPs DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company's existing coal-fired generating units are retired by the earliest practicable date. The Commission contemplates that the Companies will build upon the work that formed the basis of the November 4, 2019 submission, and the objective is to further develop the "illustrative" scenarios in that filing by subjecting them to the more rigorous IRP process. The "earliest practicable date" shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified in the quoted passage above. In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.

> DEC and DEP stated in their November 4, 2019 submission that the "illustrative scenarios" did not identify or include the costs of network transmission upgrades and other major grid investments necessary to support an alternative resource portfolio in which all coal-fired generating units have been retired and the replacement resources that will include a much larger number of geographically dispersed renewable energy and energy storage resources, many of which will not be under direct control of the grid operator. The Commission expects that the "earliest practicable date" chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances – all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.
>
> The Commission recognizes the significant effort needed to undertake this work but determines that such an effort is essential for properly vetting any alternative scenarios and for comparing the alternatives to the Companies' proposed Base Case plans. Finally, the Companies should note that the directive in this order supplements and does not supersede the directive in the Commission's August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission's directive that the Companies present one or more "earliest practicable date" retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.[115]

b. Overview: Coal retirement analyses performed in 2020 IRPs.

To fulfill the Commission requirements set forth in the *2018 IRP Order* and *2019 IRP Order*, detailed above, the Companies developed the following two coal retirement scenarios, which are discussed in detail below:

- Most Economic Coal Retirement Analysis

[115] *Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans* at 8-9, Docket No. E-100, Sub 157 (April 6, 2020) ("2019 IRP Order").

- Earliest Practicable Coal Retirement Scenario

Intervenors, including the AGO and the Public Staff, expressed interest for the coal retirement analysis to be performed endogenously in a capacity expansion model.[116] Although the Companies appreciate the conceptual idea of using the capacity expansion model to perform all resource optimization in a single computational process, this approach was not practical in this case due to limitations of the capacity expansion model, the complexity of analysis, and the magnitude of the coal retirements being contemplated. Furthermore, because the Companies are switching to the EnCompass model as discussed with interested parties in the stakeholder process, DEC and DEP will also continue to evaluate the capabilities and enhancements that the new modeling software will provide with respect to co-optimizing retirements of the Companies' coal fleet. To the extent the Companies determine the EnCompass software is able to be leveraged to better optimize coal retirement dates and replacement options, the Companies will agree to perform that analysis in the comprehensive IRP filing in 2022. Regardless, the Companies will continue to provide an in depth explanation of the model used and how it provides a transparent and reliable result in the quantitative analysis appendix of the IRP.

The Companies provide more detail below, but retirement analysis in general examines the potential retirement of a generator, or in this case a set of generators (the Companies' coal generation fleet) and attempts to answer two questions: 1) *when* is the appropriate time to retire each plant being studied and once retired 2) *what* is the appropriate resource to replace the retired coal plant, or the "When" and the "What"? The complexities arise because there are essentially two different types of system modeling

[116] Public Staff Initial Comments at 110. AGO Initial Comments Attachment 1 Stratagen Report at 5-6.

tools in resource planning that can and are used in answering the when and the what. One is a capacity expansion model, generally used for screening resource alternatives to meet future needs; the other is a detailed production cost model, used to examine detailed system operations and cost data hour-by-hour for all years in the planning horizon. The general issue at hand is that there are differing ways to apply these tools to perform the retirement analysis in order to best answer the "when" to retire as well as the "what" to replace it with. Given the complexities of the retirement analysis in the Companies' IRPs, the critical question is how to best utilize these two models. The Companies used the more detailed production cost model in an iterative manner to identify the "when" to retire question while using both models to identify the best "what" to replace it with.

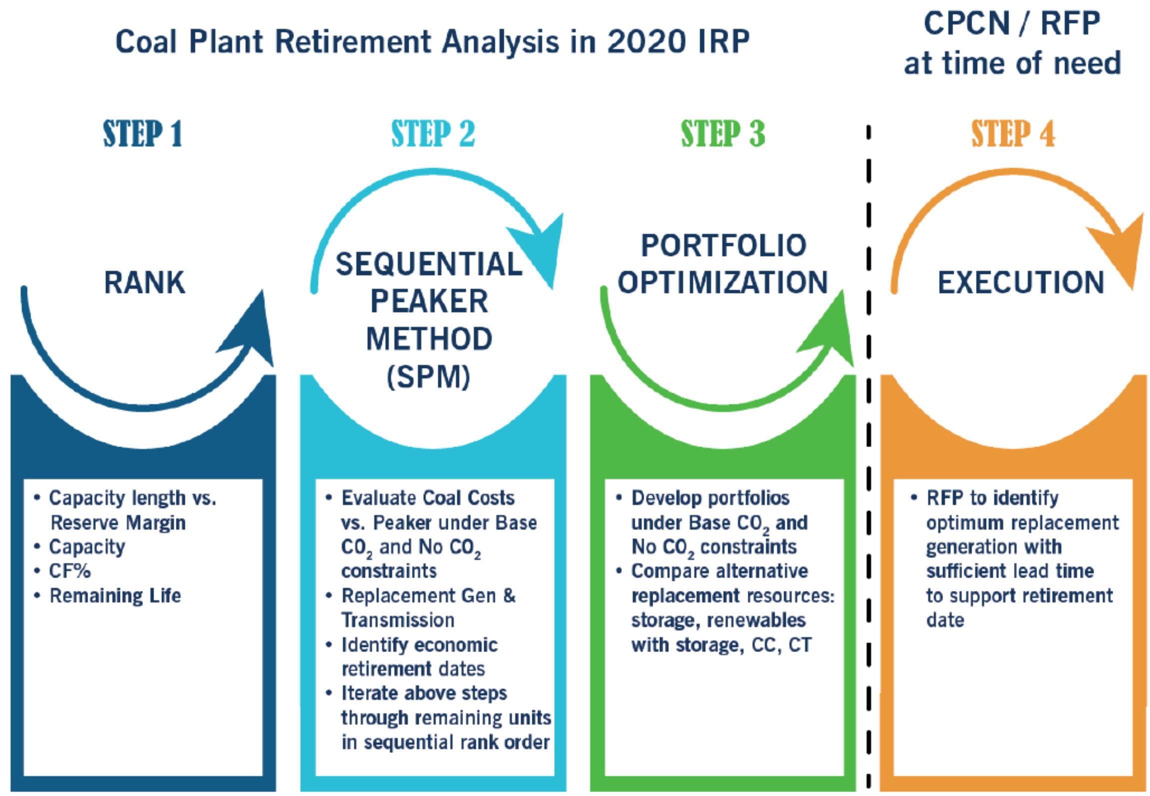
The Companies' 2020 IRPs' coal retirement analysis was more complex than the typical use of capacity expansion models, in part, because the Companies were acting under direction from the Commission to perform comprehensive coal retirement analyses for all of the Companies' coal units in the 2020 IRPs. The Commission directives included a requirement to perform analyses to determine earliest practicable retirement dates "not constrained by least cost planning principles," as well as economic retirement dates (using least cost planning principles) with consideration of practical factors such as "transmission and distribution infrastructure investments that will be required to make a successful transition." This required consideration of transmission and distribution implications of retirements and replacement generation in both scenarios. The Earliest Practicable Coal Retirement analysis sets aside normal least cost planning principles to determine the earliest date at which the coal units could be retired, which makes this Commission-mandated study objective not compatible with a least-cost model optimization. In addition, the scale of the transition, the complexity of accurately quantifying the on-going costs of the coal units, and the incorporation of transmission and distribution impacts in the economic retirement analysis necessitated a more detailed analysis as discussed below.

c. Most Economic Coal Retirement Analysis.

As laid out above, the most economic coal retirement analysis seeks to determine the point at which the coal units are deemed to be most economic to retire. The results of this analysis were directed by the Commission to be the foundation of the base case portfolios in the IRPs.

To determine the most economic retirement dates, the Companies conducted a four (4) step retirement analysis. The first three steps are included in the IRP, as determining the order in which to evaluate the coal units, the iterative process of production cost modeling to determine the most economic retirement date for each of the coal station groups, and then finally, the capacity expansion optimization to determine the resource which best fills the capacity and energy needs of the system depending on the scenario. The fourth step is the execution step that occurs outside of the IRP. When the retirement date is finalized, the replacement resources will be determined based on the needs of the system at the time. Below is a diagram of the four step process in Figure 5.

Figure 5: Most Economic Retirement Analysis Process from 2020 IRPs



As discussed above the retirement analysis has to determine two outputs, the "when" (coal units should be retired) and the "what" (should the replacement resource be). Doing these simultaneously presented several challenges. To determine the most economic retirement date, a year-by-year analysis of each coal station group was required. To do this, the on-going investment in the coal units had to be quantified. Because the investment and operations and maintenance costs may change year-to-year based on the maintenance cycles, units' operations changing throughout time, which other units are on the system at the time, and the projected retirement year, running the Most Economic Retirement Analysis was more complex than simply inputting a single stream of investment costs into the model and letting it select the most economic retirement year. Over months of collaboration and discussion, the Companies decided that an iterative analysis in a granular production cost model would yield a more accurate depiction of the units' operations and corresponding costs. This also allowed the detailed system cost results to be married with the detailed and changing savings due to earlier retirement of the coal units. This iterative process also provided a transparent view as to how different factors of production cost changes, coal plant costs changes, and replacement capacity costs factors into the determination of the most economic retirement date of the coal station group.

d. Earliest Practicable Coal Retirement Scenario.

To comply with the Commission's directives discussed above, the Companies performed an alternative analysis setting aside normal least cost planning principles to determine the earliest practicable coal retirement dates. This exercise relied on evaluating lead times for replacement resources at the quantities required to maintain a reliable system and leveraging existing infrastructure to accelerate the retirement of the coal units.

As with the most economic coal retirement analysis, coal capacity that could be retired without requiring replacement capacity was accelerated as possible, subject to transmission projects currently underway. This applied to Allen Station, with the expected retirement of three of the units (units 2, 3 and 4) by the end of 2021, and the remaining two units (units 1 and 5) remaining online until the end of 2023 when the necessary transmission projects are expected to be completed. The Companies then included the benefits of the demand side measures of Energy Efficiency and Demand Response, the replacement of purchase power contracts with in-kind resource contracts, and renewable additions as contemplated in the Base Case with Carbon Policy portfolio. Off-system capacity was determined to be too uncertain to be reasonably relied upon for this analysis.

To further accelerate the timelines of retiring coal, the Companies considered how to minimize the time to site, permit, construct, and obtain regulatory approval for the replacement capacity resources and supporting infrastructure. In many cases the utilization of existing transmission grid capacity, gas infrastructure, cooling water access, and land availability at existing coal plants would allow for more rapid replacement than contemplated timelines for offsite green field replacement capacity. Furthermore, from the perspective of earliest practicable retirements, the implementation of additional distributed resources beyond those already assume in the plan was not a viable alternative given the more immediate need for significant amounts of firm dispatchable replacement generation to maintain system reliability. As such, the practicality of replacement capacity at the retiring sites made the "earliest practicable" option difficult in many cases as it leverages the existing infrastructure at the sites and hence avoids the time that would be required to construct additional grid infrastructure associated with replacement generation built at new greenfield sites.

This earliest practicable analysis results in all coal generation being retired by 2030, a transition of over 10 GW of coal retired in North Carolina at a pace unparalleled in the industry. Replacement resources included peaking and base load natural gas, as well as accelerated implementation of economic battery storage in the Base Case with Carbon Policy Portfolio and consistent additions of solar and onshore wind in the Carolinas.

e. Public Staff generally supports the Companies' coal retirement analyses and the Companies agree to continue to refine their analyses as recommended by Public Staff.

The Public Staff is generally supportive of the Companies' coal retirement analysis but identified one minor concern with the methodology used to perform the most economic coal retirement analysis. Specifically, the Public Staff commented that the peaking gas resource used to determine the "when" may not reflect the actual savings of the retirement if the actual replacement resource was something other than a peaking gas CT.[117] As discussed above, any potential for changing the replacement resource is unlikely to drastically change the retirement analysis used to establish the retirement date which was then used in the capacity expansion and portfolio development step.

The Public Staff recognized the challenges of quantifying impacts to the transmission system with the retirement of the coal assets.[118] The Public Staff recommended that the Companies analyze transmission impacts and file a more detailed plan with refined cost estimates. When ultimately retiring these coal units, the Companies will certainly factor many of the Public Staff's recommendations into their analysis and planning, and the Companies agree with Public Staff that cost estimates of needed transmission upgrades required are wholly dependent on how the replacement resources materialize. The location, generation (and possibly load profile for energy storage) and other units remaining on the system at the time of retirement are all factors that could impact and change these costs as they are unknowable until replacement resources have been identified, firm timelines have been established and transmission requirements have been studied.

Overall the Public Staff believes the model inputs relied upon are reasonable for planning purposes.[119] The Public Staff also suggests that some of the uncertainty in the analysis could be relieved if the Companies were to endogenously determine the retirement dates through a capacity expansion model.[120] As mentioned above, System Optimizer, the capacity expansion model used in the IRPs, is a screening tool. The model can be used to

[117] Public Staff Initial Comments at 103.
[118] Public Staff Initial Comments at 108.
[119] Public Staff Initial Comments at 108.
[120] Public Staff Initial Comments at 110.

help identify cost-effective system resources, but in best practices of resource planning, screening in a capacity expansion model will be followed with analysis from detailed production cost model runs to refine, optimize and verify screening results. While capacity expansion models are helpful in quickly assessing a broad range of potential portfolios, the Companies rely on their production cost modeling to verify the results.

To simplify analyses to determine least cost portfolio compositions, capacity expansion models such as System Optimizer run thousands of simulations over long time horizons, typically 20 or more years. To remain computationally practical, the optimization screening model uses general representations of system dispatch periods rather than a full hourly production cost simulation for each hour of the study period. System Optimizer uses this "representative hours" approach, in which average load values in each representative time bucket are compared to the thousands of portfolio simulations. This model approach does not consider chronology, but rather multiplies each of these representative hour time buckets of load and generation by the number of those hours in each month, to simulate the system's operation over an entire month. This is repeated for every month over the planning horizon and compiled together to create a net present value for each portfolio. The model uses this simplifying approach to run iterations of thousands of portfolios to determine which mix of resources minimizes the PVRR of the system over planning horizon.

This computational simplification used by capacity expansion models prevents such models from providing a single stand-alone approach for analyzing the retirement economics of the Companies' coal fleets. Analyzing the capacity additions with a growing system the size of DEC and DEP can be challenging to get accurate and reliable results.

The analysis is further complicated if the model also must select the economic retirement dates of nearly 10,000 MW, rather than relying on the retirement dates as an input and the resource additions are optimized around it. Finally, the lack of hourly detail for capacity expansion models limit their ability to accurately value energy storage, which is more accurately represented in a detailed production cost model that simulates system operations every hour of every year in the study.

The Companies utilize a dynamic cost model which estimates the on-going capital based on the expected unit operation and the reality that as a unit approaches retirement capital and O&M investments are minimized. The companies dynamic cost model is further discussed later in this section.

Contrary to the criticism of some intervenors,[121] the Companies' dynamic cost modeling used in the 2020 IRP coal retirement analyses improves the coal retirement evaluation. The ongoing capital and fixed operations and maintenance costs of the coal units are critically important components of determining the economic retirement dates. The dynamic cost model for coal units is a significant improvement over retirement analysis in a capacity expansion model.

While changes in production cost are captured in this analysis, much of the economic evaluation depends on the capital and fixed operations and maintenance costs of the coal units compared to the same costs for new capacity, as discussed above and in detail in the 2020 IRPs[122] The dynamic cost model uses assumptions that will appropriately lower maintenance costs, if the unit is expected to retire in the near term. In practice today,

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[121] *See* AGO Initial Comments at 12-13 (criticizing coal retirement analyses because Duke did not use a computer model to economically retire coal).
[122] *See* DEC 2020 IRP at p. 80; DEP 2020 IRP at p. 83.

as a unit's projected retirement date nears, the Companies will continue to invest less and less in the unit, investing just enough to get the unit to its retirement date. The dynamic cost model for the existing coal units captures this "wind down" in investment costs. This approach is a much better approximation of actual costs being invested in and used to maintain these units. Compared to sole use of a capacity expansion model as proposed by the Public Staff, the approach used in the IRP provides significant benefit and insight as expansion models are only able to evaluate a single, unchanging stream of costs into the future which does not adjust with changes in the actual retirement date of the unit.

Additionally, the dynamic cost model more accurately projects future investments and costs in the coal units by using projected service hours, generation levels, and carbon emissions to identify if different operation levels or modes of operation can reduce costs. Maintenance cycles are typically based on service hours. To the extent that maintenance may be able to be deferred, reduced or eliminated, while maintaining unit reliability, the model can reduce costs to reflect these parameters. To get an accurate forecast of these costs, a granular, hourly production cost model, which maintains the chronology of the hours in a year to accurately reflect how much the unit might run is required.

As discussed above, many capacity expansion models, such as System Optimizer, average similar hours together into time buckets to more quickly evaluate numerous portfolio options and how a system would dispatch against that representative hour. In this process, the operation of a unit may be overstated or understated because the model does not see the explicit higher or lower loads from hour to hour, and how the unit would operate in the transition from one-time bucket to another. When an hourly production cost model is used, a unit's flexibilities and cost savings between different time periods are appropriately reflected in the model and carried over into the dynamic cost modeling tool to appropriately reflect the cost of maintaining the units which would not be possible in the approach recommended by the Public Staff. The more sophisticated approach presented in the IRP yields a more reliable and trustworthy representation of how the unit is expected to operate and as such, how much investment will be made in the unit to more accurately determine the economical retirement of the units.

A final benefit of the Companies' coal retirement analysis approach is the step-by-step evaluation process and dynamic cost modeling also capture cost shifting. If a unit is retired and consequently another unit is forced to run more to meet system energy needs, the differences in those operation profiles and associated unit costs are captured in the Sequential Peaker Method used within the IRP. Appropriately shifting costs from one unit to another, if the unit is called on to operate more because another unit has retired ahead of it in the capacity expansion model, is more difficult to capture in capacity expansion models as these models use static on-going costs streams as previously discussed. The step-by-step unit evaluation performed by the Companies also provides transparency. With the Sequential Peaker Method, the Companies can isolate that a unit was deemed economic to retire in a particular year because the accurately modeled costs to maintain and operate a unit were more costly to the system than the replacement capacity.

For the reasons listed above, the Companies believe given the capabilities of the current models, the approach used in the 2020 IRP yielded the most economic retirement dates. The Companies commit to further evaluating if EnCompass can provide the necessary functionality to accurately capture changing cost and value over time as done in the Companies' coal retirement analysis in the 2020 IRP.

f. The AGO's concerns regarding the Companies' coal retirement analysis is misleading or misinformed.

The AGO presents myriad issues it has with the Companies' coal retirement analyses. The AGO concludes that (1) some elements of the coal retirement analyses do not appear to be based on reasonable assumptions, (2) the 2020 IRPs do not provide sufficient information to validate Duke's methods and assumptions for determining both the economically optimal and earliest practicable retirement dates for its coal plants, and (3) Duke's approach unnecessarily silos coal retirements from its overall resource planning processes.[123] Furthermore, the AGO recommends (1) Duke should consider an alternative method for determining the most economic retirement dates for its coal assets, (2) Duke should utilize a commercial software model that can select coal asset retirement dates while simultaneously optimizing Duke's overall resource portfolio(s), and (3) if warranted, Duke could then propose a later "earliest practicable" retirement date.[124] However, the AGO argues that a coal unit retirement should not be delayed solely because the Companies identified a preferred replacement resource prior to the model selecting that unit's retirement date and replacement resource(s) on its own.

The AGO begins their discussion with a high level case for accelerated coal retirements suggesting that operating coal plants longer than necessary imposes significant costs on customers.[125] The AGO presents a high-level revenue requirement analysis of maintaining the coal units as a percent of total revenue requirement shown in the IRP. Unfortunately, this is a flawed and misleading characterization of the coal units' cost relative to the system, as only costs that may vary across portfolios are included in the

[123] AGO Initial Comments at 8-13.
[124] AGO Initial Comments at 4, 16.
[125] AGO Initial Comments at 9-11.

PVRR in the IRP. In contrast, the total revenue requirement of the system includes much more than what is shown in the IRP analysis.

The AGO also suggests that "Duke's coal units are quite inefficient" and "provide very little energy value" based upon the expected generation these units will provide into the future from the IRP modeling.[126] As discussed above, while it is important to look at the value of the energy provided by these units, both during peak times and throughout the year, the complete picture of retiring the Companies' coal assets includes the cost to replace the retiring capacity.

The Companies contend that the coal units still provide significant capacity and energy value during peak times. The table below shows the capacity factors of the coal units during the first week in January 2018 when the Companies experienced an extended period of cold weather resulting in high sustained loads. It is important for the Commission and the AGO to understand the critical reliability role coal units serve during cold weather events such as those recently experienced in Texas. When retiring these units, replacement generation resources will be required to fill the reliability function currently provided by the coal resources. The following table demonstrates the need for replacement resources that can provide sustained levels of output during extended high demand periods.

[126] AGO Initial Comments at 10-11.

Table 9: Coal unit capacity factors from 1/2/2018 through 1/8/2018

Coal Station	Unit	Utility	Winter Capacity (MW)	1/2/2018 - 1/8/2018 Capacity Factor
Allen	1	DEC	167	82%
Allen	2	DEC	167	60%
Allen	3	DEC	270	67%
Allen	4	DEC	267	87%
Allen	5	DEC	259	72%
Belews Creek	1	DEC	1,110	99%
Belews Creek	2	DEC	1,110	100%
Cliffside	5	DEC	546	95%
Cliffside	6	DEC	849	93%
Marshall	1	DEC	380	96%
Marshall	2	DEC	380	95%
Marshall	3	DEC	658	68%
Marshall	4	DEC	660	100%
Mayo		DEP	746	95%
Roxboro	1	DEP	380	100%
Roxboro	2	DEP	673	93%
Roxboro	3	DEP	711	94%
Roxboro	4	DEP	698	99%

The analysis performed in the IRP showed the alternative of retiring and replacing the unit was sometimes delayed due to the cost of replacement generations. Based on the table above and the replacement cost analysis, while the mission of the coal units continues to change, the peak capacity and sustained generation capability of the coal units shows value that factors into the analysis to determine when to retire. The economic retirement analysis in the IRP looked at the convergence of retirement dates in both Base Case With Carbon Policy and Without Carbon Policy scenarios, and considers the changing mission and run time of these units, while also evaluating how to decrease investment in these units over time as their run times change and retirement approaches. As described above, the Companies process for evaluating coal retirements was detailed, focused, and exhaustive, incorporating both detailed production cost and dynamic capital and fixed operations and maintenance cost modeling to assess timing for retiring the coal units. This allowed the Companies to identify and prioritize the factors that provided the greatest benefits to the system, such as maintenance costs in coal units, and the replacement capacity costs to maintain a reliable system.

The Strategen Report filed by the AGO also wrongly suggests that the Companies have a "financial incentive" to continue operating the coal-fired units versus retiring those units sooner.[127] However, continued recovery of the costs of these used and useful assets was not considered in the IRPs' coal retirement analysis. The recovery of costs for the coal units, which have remained used and useful throughout their service lives, was explicitly excluded from the retirement analysis and the IRP as a whole. Whether it is economic for a unit to retire in 2025 or in 2035, the Companies put no weight into the remaining net book value of the asset at time of retirement and assume no accelerated recovery. Minimizing incremental future costs was the only economic factor considered in the retirement studies presented in the IRP while recovery of historic costs did not factor into the analysis as assumed by the AGO. As recognized by the Public Staff, "Duke's retirement analysis is agnostic to how the remaining book value of coal plants is recovered when their retirement dates are accelerated."[128]

Overall, the Companies' approach to the coal retirement analyses was appropriate. The economic retirement dates were evaluated in both the Base Case With Carbon Policy and Without Carbon Policy scenarios, to determine retirement dates that were applicable for use in the optimization of the base cases. The separate analysis allowed for detailed modeling and transparency on the factors dictating the economics to retire. The ranking

[127] AGO Initial Comments Attachment 1 Stratagen Report, at 5.
[128] Public Staff Initial Comments at 104.

and grouping of units used in the coal retirement analysis was prudent due to driving factors for economics and engineering and technical constraints of operating the system and some simplification of iterative analysis.

The AGO is also critical of the Companies' earliest practicable coal retirement analysis, stating that the inclusion of natural gas to accelerate the coal retirement unnecessarily delays the retirement of the coal units. The earliest practicable coal retirements appropriately and reasonably identified the use of natural gas resources, at retiring coal sites with existing natural gas and existing transmission infrastructure, as an efficient and cost-effective path to expedite the replacement of the coal resources through utilization of existing grid infrastructure while avoided the time and expense of constructing new supporting infrastructure for replacement generation built at greenfield sites. While some of the earlier retired coal units may have more peaking generation profiles when viewed on an annual basis these units can be called upon to run multiple days in a row during a cold weather high demand week such as that recently experienced by ERCOT as previously discussed. This fact highlights the difficulties in trying to replace a significant number of coal units with short duration hourly battery storage, as further discussed in Section XII. C.

Furthermore, the AGO and their California-based consultant do not recognize, understand or acknowledge the infeasibility of replacing a substantial portion of the entire coal fleet with intermittent resources or emergent battery storage technology on an expedited basis. To put this in perspective the total installed battery storage resources on the U.S. power system at the time the 2020 IRP was prepared was just over 1,000 MW as compared to the 10,000 MW of coal being retired in the earliest practicable scenario. So not only would over reliance on battery storage in the earliest practicable coal retirement case result in inadequate system reliability, it would also assume DEC and DEP could, in a highly expedited manner, procure and install significantly more battery storage than existed on the U.S. power system in 2020. Simply put, the AGO's critiques are without merit and should be rejected.

g. Joint Synapse Sponsors' comments on coal retirement analyses are biased and unsubstantiated.

The Joint Synapse Sponsors and the Synapse Report, present several issues with the Companies' coal retirement analysis, of which many have already been addressed and refuted above. The Companies have shown that their methodology is indeed robust, with the convergence of results across carbon and no carbon policy scenarios and are appropriately detailed and accurately reflect how costs and benefits of coal assets present themselves throughout time in a transparent analysis. As discussed above in detail, the coal retirement analysis the Companies used was developed to accurately and precisely identify the most economic coal unit retirement dates, recognizing the limitations of typical capacity expansion models to capture dynamic costing of the assets over time. A combination of capacity expansion, iterative production cost modeling, and dynamic capital and fixed cost modeling for the coal units provides a thorough and rigorous analysis of the economics of coal in the Companies generation portfolio for the base cases.

The Joint Synapse Sponsors lodge accusations that the Companies' methodology was intended to produce the same results as the filed depreciation studies presented in the 2019 rate cases.[129] While this is blatantly false, the similar, though not exact, results further validate the results of the analysis that macro economic trends as contemplated in the

[129] Joint Synapse Sponsors Initial Comments at 22.

depreciation study are consistent with micro level analysis conducted in the Companies' coal retirement analysis. Furthermore, similar retirement dates are not unreasonable as units only have a finite period, typically about a decade or less, to be accelerated from their current depreciable lives so economic retirement dates that are within a couple of years of prior retirement dates should not be surprising.

The Joint Synapse Sponsors are also critical of the ranking process used to determine the order in which the coal station groups were identified.[130] The ranking process was essential to determine the most economic coal retirement analysis. To conduct an iterative analysis, the Companies had to determine an order in which to evaluate the units. The Companies evaluated many factors when determining the ranking, including the capacity of the coal station group being evaluated, the capacity factor of those units, the age of the units, and the capacity of the units. Through the evaluation of these factors, it was determined that a dominating factor in determining the economics of the retirement date was the cost of the replacement resources compared to the total cost to maintain the coal units. While the production cost value of the units certainly contribute, as more capacity had to be replaced, the less likely it was economic to accelerate the unit's retirement. Further, if no replacement capacity was required because the retirement did not cause capacity to be below the planning reserve margin, coal units that were smaller, less efficient, with fewer economies of scale, could be retired without any replacement capacity cost.

While the Joint Synapse Sponsors are skeptical and critical of the Companies' approach to ranking the units, the Companies believe this ranking process resulted in the

[130] Joint Synapse Sponsors Initial Comments at 21.

most economic retirement dates by accurately reflecting the operations of the units, the investment changes with earlier retirements, and minimizing the replacement capacity needed to retire the coal capacity.

The Joint Synapse Sponsors comments and the Synapse Report also criticize the Companies' use of the Sequential Peaker Method.[131] The Sequential Peaker Method is a retirement methodology used specifically to evaluate the appropriate coal retirement dates for the 2020 DEC and DEP IRPs. The Companies have a unique challenge in transitioning over 10,000 MW of coal capacity in the Carolinas to equally reliable capacity and energy production. As previously stated, the major benefits of using the Sequential Peaker Method include the following:

- Detailed Hourly System Production Cost – The Sequential Peaker Method allows the Companies to use an hourly detailed and chronological production cost model to more accurately project the operations of these coal plants and the overall cost of the system. This step used PROSYM, a detailed production cost model that looks at each hour in the planning horizon as opposed to the capacity expansion model, System Optimizer, which uses a simplified subset of representative hours throughout the year. The simplified computations do not address operating reserve requirements, unit flexibility, and limitations such as changing heat rates throughout the operating range, ramp rates, minimum load restrictions, outages, must run requirements and the unit's ability to use multiple fuels.

[131] Joint Synapse Sponsors Initial Comments at 21-23.

- Ongoing Capital and Fixed O&M Cost Impact – The Capacity Expansion Model uses a forward-looking approach that cannot reflect the reduction of unit capital and O&M cost prior to retirement. The Companies have a dynamic capital and O&M cost projection model that estimates the ongoing capital based on the expected unit operation and the reality that as a unit approaches retirement capital and O&M investments are minimized. The Sequential Peaker Method in which every year is evaluated independently can include the cost reductions prior to retirement while the use of a Capacity Expansion Model cannot.
- Transparency – The Sequential Peaker Method allows station-by-station evaluation on a year-by-year basis to accurately project the most economic retirement date for each of these stations. The Sequential Peaker Method uses an iterative approach, evaluating a coal unit or group of units at a time, to quantify the value of the coal units to the overall system, recognizing that the value of a unit to the system is dependent on the retirements that occur before it. Capacity expansion models are sometimes viewed as a "black box" that produce results without clarity as to how the decision was made. The Sequential Peaker Method offers increased clarity and repeatable calculations.

Of note, the Sequential Peaker Method was used only to identify the economic retirement dates of the coal units and does not imply a natural gas peaker will necessarily replace the retiring unit. This is an important point since the retirement dates determined in the Sequential Peaker Method became input into the capacity expansion model referenced to assist in the selection of the appropriate replacement resource as used in the development of the Base Case Portfolios.

Analyzing and optimizing the retirement of more than 10,000 MW of coal units to safely, reliably, and affordably replace this number of plants while the rest of the resource mix is also changing presents unique challenges. In fact, the Companies are not aware of any other utility in the nation that has attempted to solely use a capacity expansion model to simultaneously co-optimize both the date of retirement and to select the replacement resources required for a retirement analysis of this magnitude on a system as large and complex as DEC's and DEP's. Used in isolation, System Optimizer was determined not to be the most robust method for co-optimizing retirement dates and replacement resource selections for coal retirements in the DEC and DEP systems given the issues previously discussed. As stated, System Optimizer is a capacity screening model; it does not have the flexibility to accurately capture changing cost assumptions. Additionally, the simplifying hourly analysis that System Optimizer uses with the representative hours approach, as discussed above in these reply comments, is not designed to capture inter-hour variation yielding less accurate system operation projections.

The Companies conducted a detailed, thorough and objective retirement analysis to evaluate the economic value of the coal fleet over time. Despite the arguments of these intervenors, the Companies produced the most economic retirement dates for use as the Base Case input assumptions as directed by the Commission in a sophisticated, transparent and robust manner.

h. NC WARN/CBD's criticisms of the coal retirement analysis and its alternative recommendations should be rejected.

NC WARN/CBD draws inaccurate conclusions based on public information and by relying upon inappropriate assumptions that are in contrast with assumptions made in the Companies' 2020 IRPs. NC WARN/CBD claims that the earliest practicable coal retirement portfolio should be both significantly modified and significantly accelerated with battery storage displacing new gas fired generation in 2022, citing a variety of cost estimates. The Companies, however, merely used the peaking gas unit as a proxy, which is the Companies' least expensive form of capacity. When it comes to the capacity expansion and optimization steps, the resource selected is not necessarily a peaking gas unit. The Companies view it as unlikely that other more capital intensive resources such as standalone storage, or a combination of resources, such as renewables paired with storage, would further economically accelerate coal retirements. Additionally, the acceleration of retirements in the Companies' retirement analyses and subsequent replacement with resources like batteries and solar would not be economic for customers given the higher costs in the near term as compared to the price declines projected over the next decade.

NC WARN/CBD also claims that the Companies' Earliest Practicable coal retirements portfolio should be modified to (1) substitute imported power from existing natural gas-fired CC's or advanced CTs in neighboring balancing areas for Duke Energy's coal units; (2) retrofit battery storage to existing utility-scale solar for peaking power; and (3) expand behind-the-meter solar and battery storage.[132] NC WARN/CBD also submitted

[132] NC WARN/CBD Initial Comments at 33.

a report from their consultant William Powers ("Powers Report") with their initial comments, which presents a "Modified Practicable Coal Retirements" proposal consisting of "Cliffside 6 gas-only beginning *2022*, *all other coal retired 2022*, replaced to the extent justifiable on reliability grounds, with seasonal (winter & summer) firm imports via bilateral contracts with existing CC or advanced CT plants in neighboring balancing areas."[133]

The NC WARN/CBD proposal is simply not "practical" or realistic and has no basis in legitimate resource planning or resource adequacy evaluation. First, when asked in discovery to identify which natural gas-fired CC and advanced CT plants in neighboring balancing areas NC WARN/CBD and their consultant Mr. Powers assert the Companies should be relying upon as part of these intervenors' proposed "Modified Practicable Coal Retirements" portfolio, NC WARN/CBD responded, "Individual CC and advanced CT units, and other alternative resources have not been identified," and went on to generally claim that there is substantial available excess capacity in PJM and Southern Companies' systems.[134]

Next, even accepting NC WARN/CBD's absurd argument that unspecified assumed generation resources in neighboring balancing authorities could somehow be used as a replacement for coal generation, the concern that these alternative resources could reliably accelerate retiring coal could only apply to non-peaker replacement generation in the IRP. By definition the Sequential Peaker Method picks the appropriate retirement date when an actual peaker was determined to be economic compared to the retiring coal unit. When the optimization step chose the limited amounts of storage and some combined

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[133] NC WARN/CBD Initial Comments, Powers Report at 27 (emphasis added).
[134] NC WARN/CBD Response to DEC and DEP 2020 IRP Data Request No. 1-7(d).

cycles rather than a peaker, further retirement acceleration really boils down to, given the higher capital costs of CCs and battery storage systems, if there is enough production cost benefits from those resources to overcome the higher capital costs of those units and still warrant acceleration. Finally, when asked in discovery to provide "all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information upon which you or Mr. Powers relied upon or which support the "Modified Practicable Coal Retirements" proposal, NC WARN/CBD simply referred the Companies to the "137 footnotes referencing authorities which are, in general, publicly available" in their initial comments.[135] In other words, NC WARN/CBD provided no actual modeling to support their proposal. When justifying the capital cost savings of the "Modified Practicable Coal Retirements" proposal, the Powers Report uses a drastically simplified approach with a misrepresentation of costs for solar and wind, a drastically low assumption for storage, and inflated and inaccurate cost estimates for natural gas, as discussed in the CT Cost assumptions section of the Companies reply comments.

In sum, NC WARN/CBD's results-oriented analysis is not based on reasonable resource planning principles, is apparently not supported by any modeling whatsoever, and should be rejected as not credible or reasonable for purposes of ensuring the Companies can reliably serve their customers capacity and energy needs in the future.

[135] NC WARN/CBD Response to DEC and DEP 2020 IRP Data Request No. 1-3.

VII. Planning for CO_2 Regulation and Other Environmental Issues

A. DEC/DEP Will Continue to Evaluate, Plan For and Respond to Future Changes in Environmental Law and Regulations

In evaluating future resource options to provide reliable electric service to customers, NCUC Rule R8-60(g) requires the Companies to evaluate environmental impacts and the costs of complying with environmental regulations. The Public Staff recognizes shifting public opinion towards climate change and some form of climate regulation and recommends that "Duke continue to include a section in its IRPs discussing potential carbon legislation and regulations."[136]

As regulated utilities, DEC and DEP are obligated to develop IRPs that plan for and comply with the policies and environmental regulations in effect at the time of filing. Consistent with NC requirements, the IRPs include the Portfolio A "Base Case Without Carbon Policy" that plans for capacity resources to adequately and reliably serve anticipated peak electrical load, including applicable planning reserve margins, at least cost and complies with applicable state and federal environmental regulations in effect today. The Companies also present Portfolio B "Base Case with Carbon Policy" that was developed to similarly meet least cost planning principles with the assumptions of future regulations on carbon dioxide emissions. To show the impact potential new policies may have on future resource additions, the 2020 IRPs also include portfolios with more ambitious carbon emission reduction targets, but which would require supportive policy. Specifically, all portfolios except the Base Without Carbon Policy would require enabling policy changes. These portfolios reflect ongoing policy conversations and stakeholder interest.

[136] Public Staff Initial Comments at 167-168.

It is important to note that future policy could take several forms, including a direct mandate to reduce carbon emissions by a specific percentage by a certain year, a policy that would include consideration of carbon emissions (or a carbon adder) in planning, a policy to mandate coal retirements, participation in a carbon market, or a clean energy standard – all of which have been under discussion in North Carolina. Some of these policies are also being discussed at the federal level. What all of these policies have in common is that they would mandate changes to the least cost portfolio of resources needed to reliably serve customers relative to a regulatory construct without carbon policy as exists today.

How planning is altered would be dependent on the specifics of the policy enacted. For example, certain policies may not significantly change near term resource selection but could affect system dispatch. Other policies would have more impact on the expansion plan than dispatch, and some policies may affect both. A policy mandating accelerated coal retirements would require the expedited build out of replacement capacity resources. This type of policy could be consistent with the "Earliest Practicable Coal Retirements" portfolios presented in the 2020 IRPs, depending on the retirement dates. In contrast, it is expected that North Carolina joining the Regional Greenhouse Gas Initiative ("RGGI") would not have a significant near-term impact on resource planning due to the relatively modest allowance price. Rather, joining RGGI would likely alter dispatch, rather than change the capacity mix.

Another policy approach—a mandated carbon adder in the form of an allowance price or a carbon tax—would directly affect least-cost planning by making the economics of carbon emitting generation (coal and natural gas) less attractive from both a resource selection and system dispatch perspective. In comparison, renewables would be more economical, and least-cost planning would presumably select additional carbon free resources and storage technologies. However, the technological characteristics of these resources would not change. So to meet DEC's and DEP's regulatory obligation to serve load, there may still be some amount of carbon emitting capacity (presumably existing and incremental natural gas capacity) needed for system operability. This type of policy is most similar to the Base Case with Carbon Policy modeled in the 2020 IRPs, depending on the carbon price and escalation rate that may be selected. While a carbon price in dispatch would, in the short-term, affect the merit order of fossil units, a carbon price on emissions could have a long-term effect of shifting resource planning to lower emitting generation. The overall impact on planning would be directly related to when a carbon price is imposed, the level of the carbon price, and how that price escalates over time.

A clean energy standard or similar policy could establish targets for percent energy derived from zero or low emitting resources. If this form of policy mechanism is enacted, it would also impact the mix of resources in order to fulfill such a regulatory mandate while still reliably meeting customer demand. Similar to other policy design considerations, the timing and stringency of targets would influence the level of impact on resource planning.

Finally, another possible policy outcome may result in no direct regulation at all on carbon in the form of an allowance price, tax or a cap on carbon emissions. Rather, emerging federal policy may move toward more of a "carrot approach" as opposed to a "stick approach." Such potential policy may involve significant expansion of federal or state policies that incentivize carbon free resources through tax incentives and direct research and development funding. From a planning perspective, this potential policy path would look like the Base Case Without Carbon portfolio in the IRP but would lower the costs to build certain carbon free resources as a result of tax credits or other policy incentives.

The point in highlighting all of these varied energy policy pathways is that, at this time, because these policies are conceptual, there is significant uncertainty in how resource planning could be affected.

The Companies are also subject to extensive regulations by the Federal Energy Regulatory Commission and state and federal environmental agencies. State environmental agencies and the U.S. Environmental Protection Agency ("USEPA") are charged with and responsible for setting regulations to protect human health and the environment, informed by rigorous science and studies, including potential regulations on carbon emissions. State and federal legislation and regulation drive the incorporation of environmental attributes and risk into the cost of any particular resource. For example, at the federal level, regulations pursuant to the Clean Air Act, Clean Water Act, and Resource Conservation and Recovery Act have increased the operating costs for coal generating units.

As required by Rule R8-60(g), the Companies will continue to account for the costs associated with state and federal laws and promulgated regulations in evaluating resource planning options in future IRPs. DEC and DEP will also continue to monitor policy discussions at the state and federal level and evaluate the potential impact of policies on the Companies' resource planning and operations. As policies evolve and are finally enacted, whether through legislation that is signed into law or regulations that are promulgated, the Companies would reflect those changes in future IRPs and other disclosures. The Companies agree that the Public Staff's recommendation to continue to include a section in its IRPs discussing potential carbon legislation and regulations is reasonable and appropriate to keep the Commission apprised of continuing policy and regulatory developments in this area.

B. The IRPs are Consistent with the N.C. DEQ Clean Energy Plan and Keep Duke Energy on a Path to Achieve Net Zero Carbon Emissions by 2050

Energy policy in North Carolina is evolving at a rapid pace, and the Companies are leaders in evaluating, advocating for, and implementing plans to deliver affordable, reliable and less carbon-intensive power to our customers. The Public Staff recognize that "[a]ll portfolios keep Duke Energy on a trajectory to meet its near term enterprise carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050."[137] However, the Public Staff also expresses concerns that there is a "disconnect between the net-zero goal set by Duke Energy Corporation (parent company), and the natural gas generation dominated expansion plans set out by DEC and DEP (operating companies)." The Public Staff highlights that the North Carolina Department of Environmental Quality ("DEQ") Clean Energy Plan ("CEP") developed in response to Governor Cooper's 2019 Executive Order No. 80 ("EO 80") "calls on Duke to reduce CO_2 emissions at substantially greater levels than Duke's stated corporate goals" and proposes "a goal to reduce electric sector emissions 70% below 2005 levels by 2030 and attain carbon neutrality by 2050."[138] The Public Staff asserts that "none of Duke's plans meet the carbon neutrality goal by 2050."[139]

[137] Public Staff Initial Comments at 129.
[138] Public Staff Initial Comments at 5-6.
[139] *Id.*

Additionally, the AGO expresses concerns that the Companies IRPs are "inconsistent with the North Carolina Clean Energy Plan" and "contrary to the climate objectives of Duke Energy's net zero goal."[140] Other intervenors offer similar critiques to varying degrees.

As an initial matter, the assertion that the Companies' IRPs are inconsistent with the CEP goals and Duke Energy net zero by 2050 goal is not accurate. The Companies' IRPs presented two portfolios (Portfolio D 70% CO_2 Reduction High Wind case and Portfolio E 70% CO_2 Reduction High SMR case) that would achieve 70 percent reduction in CO_2 emissions by 2030, consistent with the CEP goal.[141] Notably, each of the IRP portfolios achieve emissions reductions well above 50% by 2030 and all six portfolios keep Duke Energy on track to achieve net zero emissions by 2050. Thus, the IRP portfolios are entirely consistent with Duke Energy's goals.

As discussed above and explained in the 2020 IRPs, enabling policies and further technological developments will be required for the Companies to achieve the 70% reduction goal.[142] The specific compliance obligation for DEC and DEP from any potential state policy would depend on a number of factors that at this time are unknown, and dependent on the type of policy enacted and technological advancements in carbon free resources and long duration storage technologies. The two IRP portfolios that would achieve the CEP goal of 70% reduction by 2030 contemplate different resource mixes and technologies, reflecting the policy and technological uncertainties that exist at this time.

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[140] AGO Initial Comments at 3.
[141] See DEC 2020 IRP at 15.
[142] See DEC 2020 IRP at 14-15; DEP 2020 IRP at 14-15.

Further, because the time horizon for the IRPs is 15 years and does not span to 2050, the IRPs do not explicitly model the 2050 goals. Recognizing the purpose of IRPs, it is not appropriate for the IRPs to try to forecast what technologies and climate policies may look like in 2040 or 2050. The IRP lays out how the Companies will safely and reliably serve customers over the next 15-year planning period, as required by NCUC Rule R8-60(c). The IRPs are updated annually and comprehensively developed every two years. As policies and technologies evolve, fuel and technology costs change, load forecasts adjust, new laws are enacted, and regulations are promulgated, these changes will be taken into account. Simply put, the IRPs represent a snapshot in time, versus a vehicle to set and codify climate policy. The carbon sensitivities included in the Companies' 2020 IRPs adequately recognize the potential for shifting legal and regulatory requirements around carbon policy and climate change. However, because the Companies cannot set policy, the carbon pricing sensitivities and alternative portfolios in the IRPs are used as a proxy for future policies, in order for the Companies, the Commission, interested stakeholders and our customers to better understand how resource planning may respond to future policy changes. It is neither appropriate nor a prudent use of resources – and customers' dollars – to conduct an analysis of uncertain technologies and uncertain energy policies through 2050.

In addition to being outside the mandated timeframe of the IRP, detailed analysis of a 2050 plan would need to include variables such as available technologies in 2050, associated technology cost and performance characteristics at that point in time, an assessment of the 2050 global, federal, and state macro-economic and policy landscape, the form and function of a potential future carbon offset market, an assessment of economy-wide electrification impacts on the load forecast and projections of 2050 commodity prices and rare earth mineral costs to name just a few. Such an analysis would be extremely speculative and subject to such uncertainty that it brings into question the value of such an undertaking in the context of an IRP.[143] If the IRPs were required to look out through 2050, that could grossly increase the cost and complexities of the IRP process—ultimately paid for by customers—with limited benefit, particularly given that the Companies file comprehensive IRPs every other year. In sum, the Companies disagree with the stated concerns of the Public Staff and the AGO that DEP and DEC are not actively planning to meet the significant carbon emissions reductions goals presented in the CEP and to achieve Duke Energy's longer-term net zero goal as one future policy pathway for the State. To the contrary, the 2020 IRPs clearly demonstrate DEC's and DEP's commitment to plan for potential future carbon emission regulation and policies—whether adopted to meet the CEP goals or at differing levels of emissions reductions—and the Companies are committed to continuing to work with the Public Staff, the AGO and other stakeholders in the policy arena to determine the most reasonable and prudent carbon emissions reduction pathway for the State, our customers and the communities we serve.

C. Duke Energy is Actively Addressing Methane Emissions as Part of its Commitment to a Cleaner Energy Future

During the public hearings, the Companies have heard customer concerns about the carbon intensity of methane as a health and climate risk that the Commission should consider in reviewing the Companies' IRPs. Undeniably, new reliable, flexible, and high-

[143] Notably, Duke Energy's Climate Report does seek to identify and address these uncertainties and demonstrates that getting to net zero emissions by 2050 would require new dispatchable, zero carbon technologies that are not commercially available today, and for which cost projections remain highly speculative. Duke Energy 2020 Climate Report at 22, accessible at https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/climate-report-2020.pdf?la=en&rev=97b8053ac148481baa2d389f35.

capacity factor natural gas generation is a key part of the Companies' nation-leading plans to retire approximately 10,000 MW coal generation and transition the Companies' to net zero emissions by 2050. A methane reduction goal is also an integral part and natural extension of Duke Energy's overall comprehensive climate strategy to reduce carbon emissions from electricity generation to net zero by 2050.

As background and for the Commission's information, Duke Energy is committed to eliminating methane emissions by 2030 across the supply chain with definitive plans under way to meet that goal including significant investment in our gas operations to date. This strategy requires close collaboration with regulators, policymakers and stakeholders, and by taking a leadership role regarding methane emissions, including upstream impacts. To that end, Duke Energy has taken a number of steps to address methane across the supply chain. The Corporation has joined ONE Future,[144] a coalition of natural gas companies working to voluntarily reduce methane emissions across the national supply chain. Duke Energy and the Companies actively seek to purchase natural gas that is produced and transported responsibly to reduce methane emissions. Duke Energy has already completed an industry-leading step by eliminating all cast iron and bare steel main piping in its systems, a major contributor to methane leakage. Duke Energy also reports Scope 1, 2 and 3 greenhouse gas emissions in our CDP response and the 2020 Sustainability Report. While many of these initiatives are outside the scope of IRP for DEC and DEP, they demonstrate the Corporation's commitment and active management focus on reducing methane emissions from utility operations in the Carolinas.

[144] *See* https://onefuture.us/.

D. The Public Staff Finds Duke's CO_2 Assumptions in Portfolio B Reasonable and Supports Planning for Future Carbon Cost Risk

The Public Staff believes "that the current national political climate, potential state action stemming from recommendations made in the CEP, shifts in public opinion regarding climate change and carbon regulation, and commercial and industrial customers' increased support of green energy, all support the expectation that future limits on carbon are more likely than not. The Public Staff finds Duke's CO_2 assumptions in Portfolio B to be reasonable, and therefore assigns significant weight to the carbon cost risk identified above."[145]

The Companies agree there are a multitude of factors that support the transition away from higher carbon-emitting generation, and that the carbon price proxy used in Portfolio B is intended to capture potential future climate policy, as discussed above. The Companies would also clarify that there are additional policies beyond carbon regulation that could affect coal generation, including more stringent environmental regulations under the Clean Air Act, the Clean Water Act and the Resource Conservation and Recovery Act. Because of the confluence of social and economic factors toward lower emitting generation, the Companies' IRPs present several portfolios that would align with different policy circumstances. For example, Portfolio C reflects a policy scenario in which retiring coal units as early as practicable is mandated, either explicitly or through policies that place additional economic pressure on coal generation. As is noted throughout the 2020 IRPs, Portfolios B, C, D, E and F are dependent on policy changes to varying degrees, and the specifics of those policies would ultimately guide the resource mix selection. The Companies also agree with the Public Staff's comment that uncertainty around carbon

[145] Public Staff Initial Comments at 167.

legislation may diminish prior to the Companies' next comprehensive IRPs in 2022 and that DEC and DEP can integrate updated regulatory requirements to inform its IRPs at that time.[146]

VIII. New Natural Gas Resources

The Public Staff,[147] the AGO,[148] NCSEA/CCEBA,[149] NC WARN/CBD,[150] the Joint Synapse Sponsor's Initial Comments,[151] the Tech Customers,[152] Vote Solar,[153] the City of Charlotte,[154] and the City of Asheville/Buncombe County,[155] all express varying degrees of concern that DEC and DEP's reliance upon incremental natural gas generation in the 2020 IRPs is contrary to Duke Energy's carbon reduction goals, contrary to North Carolina carbon reduction goals under Executive Order 80 and/or the Clean Energy Plan, and/or would lead to stranded natural gas assets.

These commenters raise either cautious concern or strident opposition to new natural gas generation's role in the portfolios for a variety of reasons—from the purely environmental interests of the Environmental Parties, and NC WARN/CBD in reducing carbon emissions at any costs, to more balanced concerns of environmental stewardship and managing costs by the Cites of Charlotte, Raleigh, and Asheville/Buncombe County, to NCSEA/CCEBA's, Vote Solar and SEIA's policy and financial interests in expanding market share for building solar and batteries through mandating future procurements of

[146] Public Staff Initial Comments at 167.
[147] Public Staff Initial Comments at 11-12; 109-110; 160-68.
[148] AGO Initial Comments at 27.
[149] NCCEBA/NCSEA Initial Comments at 21.
[150] NC WARN/CBD Initial Comments at 5-7; 26-27.
[151] Joint Synapse Report Initial Comments at 2; 12-13; 25.
[152] Tech Customers Initial Comments at 4-7.
[153] Vote Solar Initial Comments at 4-6 and Exhibit.
[154] City of Charlotte at 9.
[155] City of Asheville/Buncombe County at 3.

those technologies. The future role of natural gas resources in ensuring reliable and affordable service to our customers is a critical issue for the Commission to understand from a holistic viewpoint in assessing the 2020 IRPs as well as future IRPs. The Companies' robust analysis of the "need" for new natural gas generation—as well as the feasibility and cost of a "No New Gas" portfolio for our customers—will continue to be important issues as the legislative and regulatory framework evolves and technologies advance over time. The following sections will reply to specific arguments raised by intervenors.

A. Arguments About Forced Early Retirements or "Stranded Assets" Cannot be Squared with the Companies' 2020 IRP Analysis

Several intervening parties stridently argue that planning for incremental natural gas generation to reliably serve customers creates "stranded asset" risk for the Companies and customers. The Public Staff also expresses some concerns that the Companies' "anticipated buildout of natural gas in Portfolios A and B could result in the forced early retirement of natural gas assets if carbon legislation is enacted in the future. If this occurred, a situation similar to the early retirement of coal assets proposed in this IRP would arise with natural gas assets."[156] The Public Staff explains that "should natural gas assets be forced to retire early due to carbon legislation that was not anticipated at the time the assets were built, ratepayers could be required to pay for service from replacement resources while still paying for the replaced assets."[157]

This is an extremely important issue that should be thoughtfully considered and holistically assessed by the Commission. Overall, the Companies' 2020 IRPs demonstrate

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[156] Public Staff Initial Comments at 12.
[157] Public Staff Initial Comments at 7-8.

that natural gas generation is a valuable resource for customers as one component of a broader least cost-compliant transition plan that decarbonizes the Companies' portfolios toward net-zero emissions by 2050. The Companies agree with the Public Staff that future policies could change, and the economics of continuing to build new natural gas generation or continuing to operate existing natural gas generation could change such that reliance on these resources would no longer be prudent and in the best interests of customers. In fact, the Companies' 2020 IRPs examined a scenario shortening the lifespan of gas assets to only 25 years as a proxy for such a policy change, but they were still economically selected to meet customer demand.

Natural gas generation resources keep prices low today and going forward while providing high levels of reliability for customers. Natural gas-fired generation is a proven and cost-effective dispatchable technology that has a long history of reliably serving customers with the ability to provide baseload, intermediate, and peaking energy needs in a flexible manner as needed to replace retiring coal resources. Importantly, attempting to retire remaining coal units on the system without natural gas as part of the replacement resource portfolio would introduce significant risks associated with increased dependence on emerging technologies such as battery storage technologies. While the Companies have emerging storage technologies in their respective resource plans, over reliance in the near-term on such an emerging technology will certainly expose customers to much greater economic and operations risk than that presented from investment in natural gas resources. This is a point that is often either overlooked, or completely ignored, when addressing specific technology risks of a resource plan.

As discussed further below, the flexibility and reliability of the technology also aids system operators in ensuring a reliable system by providing the ramping and dispatchability for the greater integration of intermittent renewable resources. Additionally, throughout time, combustion turbine technology will continue to serve the system in the future, whether it's fired with natural gas or another lower or non-carbon emitting fuel, such as hydrogen. Importantly, the 2020 IRPs are not static and do not seek approval to construct any or all new natural gas generation in the portfolios at this time. The Commission will decide whether specific, proposed new natural gas generation is in the public interest as part of the comprehensive CPCN process.

B. New Natural Gas Generation Technologies are an Essential Bridge to a Net-Zero Carbon Future

The 2020 IRPs demonstrate that a diverse mix of resources is needed to meet growing system demand and to replace the energy and capacity from retirements of older less efficient units. Planning for a mix of complementary new low- or no-carbon resources and reliable and proven dispatchable technologies, such as natural gas, is critically important for ensuring reliability and de-risking the transition as compared to a transition that relies on a single or narrow scope of technologies. In recent testimony to Congress, referenced above, the NERC President and CEO, Mr. James Robb, highlighted the critical role current and new gas generation resources will play in transitioning the current generation fleet:

> Natural gas is ***essential to a reliable transition***. As variable resources continue to replace other generation sources, ***natural gas will remain essential to reliability***. In many areas, natural gas-fueled generation is needed to meet energy demand during shoulder periods between times of high and low renewable energy availability. And on a daily basis in areas with ***significant solar generation***, the mismatch between the solar generation peak and the electric load peak ***necessitates a very flexible generation resource to fill the gap. Natural gas generation is best***

> ***positioned to play that role***. The ***criticality of natural gas as the "fuel that keeps the lights on" will remain*** unless or until very large-scale battery deployments are feasible or an alternative flexible fuel such as hydrogen can be developed.[158]

The comprehensive analysis supporting the DEC and DEP 2020 IRPs demonstrates that natural gas must be part of the diverse mix of resources to reliably serve North Carolina customers as we continue the clean energy transition.

C. Natural Gas Generation Also Plays an Important Role in Integrating Renewables and Managing Reliability Risk of Transforming the Grid

Vote Solar and other parties that oppose planning for new natural gas generation fail to appreciate (and also have no accountability for) the reliability and operational risk as well as financial risk, of leaning too heavily on any single type of generation if the Companies retire their significant coal fleets as planned and then do not build dispatchable gas-fired capacity as part of their generation portfolios. Indeed, Vote Solar's climate policy advocate, Mr. Fitch, admits in a discovery response that he did not focus on reliability risks of not meeting customer load in his evaluation of the climate risks facing DEC and DEP, and asserts, "Mr. Fitch expects that the Companies will manage reliability risks just as they manage all relevant business risks, in line with prudent business management."[159] In other words, Mr. Fitch is not concerned about planning for reliability, because he trusts the Companies to do so.

The Companies' 2020 IRPs are precisely designed to prudently manage reliability risks in order to ensure power supply reliability for our customers. As discussed above, the Companies' prudent planning to manage reliability risks includes ensuring dependable, firm, dispatchable incremental gas generation resources with onsite backup fuel are

[158] See Attachment 2, NERC Robb March 11, 2021 Testimony to Congress at 9-10.
[159] *See* Attachment 3, Vote Solar Response to DEC and DEP Interrogatory Request 1-9.

available to ensure reliable electric service for our customers and for meeting the reliability requirements in NERC's standards for many years to come. Importantly, this responsibility also includes ensuring the Companies have the capability to manage the operating characteristics of variable, inverter-based resources. NERC President and CEO, Mr. Robb, addressed these challenges in his March 2021 testimony to Congress, explaining that "[a]s variable resources continue to replace other generation sources, natural gas will remain essential to reliability."[160] During this period of significant transition, both current and new gas generation resources will play a critical role integrating more variable generation resources as the "fuel that keeps the lights on" through providing "bulk energy" and "balancing energy" as traditional baseload generation plants are retired.

> "The bulk power system is undergoing major transformation that must be understood and planned for to preserve reliability. A rapidly changing generation resource mix is driving this transformation. Traditional baseload generation plants are retiring, while significant amounts of new natural gas and variable generation resources are being developed. During this transition, natural gas-fired generation is becoming more critical to provide both "bulk energy" and "balancing energy" to support the integration of variable resources."[161]

The Companies agree (and our 2020 IRPs demonstrate) that dispatchable natural gas is needed today and will be needed in the future to supplement additional solar resources due to the fact that customer demand, at the time of the DEC and DEP system peaks, is not correlated with solar generation output in the Carolinas.[162] Winter peak demand occurs early morning, when little to no solar energy is available or reliably dependable.

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[160] *Id.*
[161] *See* Attachment 2, NERC Robb March 11, 2021 Testimony to Congress at 1.
[162] DEC 2020 IRP at p. 130, 136, 139. DEP 2020 IRP, at 132, 136, 140.

Natural gas resources are also needed to back stand renewables, to ensure reliable service in a variety of hourly, daily and weekly conditions. Figures 6 and 7 below present examples of the role of natural gas in the DEP service territory is serving both as flexible ramping resources, and back standing low solar output. Battery storage can help, but as pointed out above, limitations of battery storage mean this technology can only be part of the solution. The important point to recognize is that the future will call for a range of technologies that will evolve over time, including renewables, storage, as well as proven dependable and dispatchable resources such as natural gas.

Figure 6: DEP Operating Experience by Energy Source (Mar 2 – Mar 11, 2021)

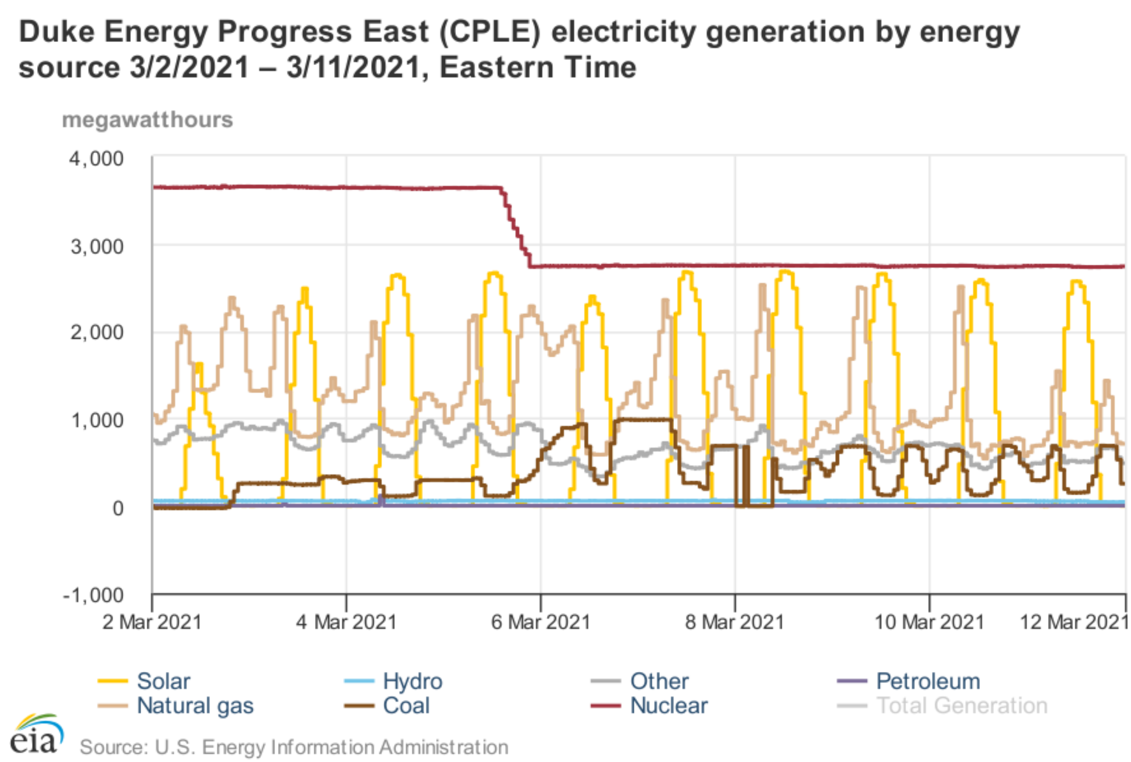

Figure 7: DEP Operating Experience by Energy Source (Feb 8-Feb. 16, 2021)

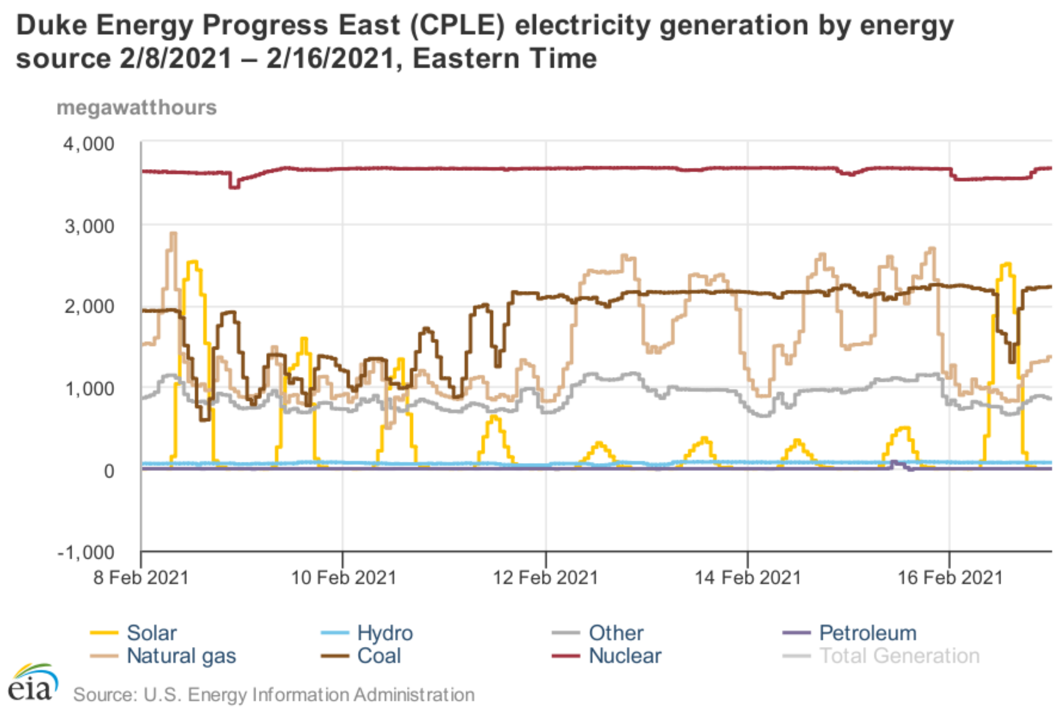

Figure 7 shows the role of natural gas as a flexible compliment to intermittent resources such as solar. The generation profiles show that gas must ramp up in the Carolinas several hours before solar output starts, turn down as solar output climbs during the day, and then come back on or turn up in the evening as the sun sets. Storage can help with the shifting of energy to curtail peaks and reduce ramps. However, in periods such as those in Figure 7, during multi-day periods of very low solar output, gas becomes an invaluable back stand to solar. This extended time of high load and low solar output means that batteries charged exclusively on solar would not have been able to fill the demand in the Carolinas, as further discussed in Section XI. C. It should be noted that the data presented in Figure 7 reflects the same February 2021 period as the events in ERCOT and shows the value that gas provided to the DEP system when solar output was dramatically reduced for multiple days in a row.

D. New Natural Gas Generation is Consistent with Duke Energy Climate Goals, the N.C. DEQ Clean Energy Plan, and Foreseeable Future State or Federal Climate Policy

Contrary to the assertions of certain intervenors, the role of natural gas in the 2020 IRP portfolios is not inconsistent with the Companies' long-term goals, the Clean Energy Plan or foreseeable future state or federal climate policy. The concerns about stranded natural gas assets overstated and overlook the vital contribution of natural gas for maintaining reliability and ignore the evolving role of natural gas assets as the system transitions toward net zero emissions.

1. Adding incremental natural gas is not inconsistent with Duke Energy's long-term climate goals.

Duke Energy has specifically analyzed the role and economic value of natural gas under shorter asset lives and in ambitious carbon reduction scenarios, both in the DEC/DEP IRPs and the Corporation's 2020 Climate Report. These analyses showed that new gas units continue to be used and useful by providing capacity value and maintaining reliability. While the Companies' IRP focus on the next 15 years, Duke Energy's Climate Report examined the long-term role of natural gas assets as the Corporation transitions to net zero. The modeling for the Climate Report shows that the Corporation can meet its 2050 net zero goal and respond to climate policy while retaining natural gas capacity on the system for reliability and peak capacity, making it used and useful to reliably serve customers. Both the 2020 IRPs analysis and the Climate Report analysis examined economic sensitivities of shorter depreciable lives of natural gas units examining 25-year and 20-year book lives, respectively.[163] The climate modeling reflected the value of dispatchable natural gas resources to meet reserve margins through 2050. These resources

[163] DEC 2020 IRP, at 169, 172. DEP 2020 IRP, at 168,171.

are needed not just for a few hours at a time, as current battery technologies provide, but for dispatchability over longer timeframes. In the long run, consistent with the Companies' Climate goals, the illustrative portfolio examined in Climate Report shows that by 2050, natural gas will account for about 6% of generation.[164] Gas units operated at these low capacity factors contribute minimal emissions and are consistent with a net zero goal, while keeping costs lower for customers. This evolution in the role of natural gas reinforces its long-term economic value to customers allowing for significant near-term reductions in carbon relative to the coal resources it is replacing while migrating to more of reliability resource longer-term. Additionally, new gas units specified in the DEC/DEP IRPs may be designed or retrofitted to be hydrogen-capable, and could provide dispatchable carbon-free power once green hydrogen technology reaches commercial maturity. Because the timeframe for technology maturation is outside of the 15-year planning horizon in the IRPs, the Companies included a discussion of hydrogen as a possible future resource option.[165]

Similar to the No New Gas portfolio in the DEC and DEP IRPs, the Climate Report also explored a sensitivity where no new natural gas electricity generation was added. In addition to being the most expensive option, a no new gas portfolio would require coal units to run longer to meet customer load.[166] This presents its own policy risks, particularly if environmental regulations on coal become more stringent, or other carbon policy is enacted. That is why the 2020 IRPs holistically evaluate the reliability needs, costs, operating characteristics and risks associated with <u>all</u> forms of energy. The DEC and DEP IRPs demonstrate there are multiple technology portfolios to reduce emissions that

[164] Duke Energy 2020 Climate Report at p. 26.
[165] See DEC 2020 IRP, at p. 136, 141, 319-320. DEP 2020 IRP, at p. 137, 141, 313-314
[166] Duke Energy 2020 Climate Report at p. 29; and DEC IRP at p. 94.

represent varying levels of policy dependency, technology risk and costs. In conclusion, the reliance upon natural gas generation in the 2020 IRPs supports Duke Energy's corporate carbon reduction goals.

2. Adding incremental natural gas is also consistent with current or foreseeable future state or federal climate policy.

It is incorrect to assume state or federal climate policy will preclude the use of natural gas for electricity and these assets will be "stranded" as a result. As discussed above, there are numerous uncertainties as to the timing and form of future policies, as well as the specific compliance obligations that DEC and DEP may have under such policies. Recent congressional proposals for a clean energy standard include partial credit for natural gas units, recognizing the importance of these resources in reducing emissions.[167] Current regulatory programs for emissions reduction, including the successful trading programs for sulfur dioxide and nitrogen oxides, include mechanisms for allowance purchases and alternative compliance approaches. The reasons these mechanisms exist in policies is to allow flexibility to achieve compliance at the lowest cost possible rather than a one-size-fits-all mandate. Given the ramifications of recent wide spread outage events in other states, it is also becoming increasingly clear that policy mandates will strive to ensure the reliability of the electric grid. Indeed, federal clean energy proposals have also included alternative compliance mechanisms that are designed to protect reliability. The specific compliance approach that DEC and DEP would employ would be dependent on numerous factors, including available technologies and costs, potential operational and dispatch changes, and an evaluation of system reliability risks.

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[167] *See* Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act, 117th Cong. (March 2, 2021) *H.R. 1512 accessible at* https://www.congress.gov/bill/117th-congress/house-bill/1512/text.

Because state and federal carbon policy are still evolving, the carbon pricing sensitivities in the IRPs along with the multiple portfolios analyzed serve as a proxy for future policies in order to understand how resource planning may respond to future regulatory changes. As discussed earlier, the way in which resource planning could be affected by carbon legislation at the state or federal level is dependent on the specifics of the policies enacted. For example, if a federal carbon price was enacted, the cost per ton of carbon dioxide, the escalation rate, and whether that pricing extends to all sectors including transportation could dramatically affect electrification of other sectors and resulting load forecasts. If a national clean energy standard is enacted and natural gas receives partial credit, as has been included in recently proposed legislation (CLEAN Future Act), that would affect the most economic resource mix for compliance and further support the role of natural gas for maintaining reliability. Future potential policies addressing, transmission permitting, carbon allowance market structures, carbon taxes, alternative compliance mechanisms, land use policies at the federal, state and local levels, tax incentives, as well as planning reserve requirements are just a few other policy provisions that could affect future resource planning. It is also important to note that carbon policy has been under consideration by Congress for over a decade so the timing of when legislation and mandatory new regulations may be put into effect remains uncertain.

3. Independent studies support the role of natural gas in a net zero future.

Advocacy groups and their retained consultants in this proceeding are highly critical of the Companies' least cost Base Plan portfolios' selection of new natural gas generation citing the potential risk of forced early retirements due to future climate legislation "policy risk." However, external, independent studies have also supported the role of natural gas in a net zero future. Other modeling efforts by well-established and respected organizations, including the National Renewable Energy Laboratory ("NREL") Carbon-Free Resource Integration Study,[168] the Princeton University Net-Zero America study [169] and the Columbia University School of International and Public Affairs research[170] show a continued role for new natural gas capacity, even while planning for an ambitious carbon policy.

As a brief overview, the NREL study examined the integration of carbon-free resources in the Carolinas to meet 70% by 2030, and net zero by 2050 carbon constraints. The study found new gas capacity in the policy case reflected the need for dispatchable resources to meet planning reserve margins.

The Princeton University modeling, conducted by researchers at the Andlinger Center for Energy and the Environment, showed that to ensure reliability, all net zero policy scenarios retained firm generating capacity through 2050. The model favored gas plants with declining utilization rates and burning an increasing blend of hydrogen for firm capacity to meet an ambitious 2050 carbon emissions reduction target.

The Columbia University study examining the role of natural gas in the U.S. energy mix and supporting the need for pipeline infrastructure notes that studies consistently show there is no "quick replacement" for gas (and by extension as a replacement for retiring

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[168] Sergi, B., B. Hodge, D. Steinberg, G. Brinkman, S. Haase, M. Emmanuel, and O. Fernandez. *Duke Energy Carbon-Free Resource Integration Study: Capacity Expansion Findings and Production Cost Modeling Plan*. NREL/PR-5D00-78386. NREL, Nov. 10, 2020, https://www.osti.gov/biblio/1726047.

[169] E. Larson, C. Greig, J. Jenkins, E. Mayfield, A. Pascale, C. Zhang, J. Drossman, R. Williams, S. Pacala, R. Socolow, EJ Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts,* interim report, Princeton University, Princeton, NJ, December 15, 2020. https://acee.princeton.edu/rapidswitch/projects/net-zero-america-project/.

[170] Blanton, M. Lott, and K. Smith. Investing in the U.S. Natural Gas Pipeline System to Support Net-Zero Targets. Columbia University, New York, NY, April 2021, https://www.energypolicy.columbia.edu/research/report/investing-us-natural-gas-pipeline-system-support-net-zero-targets.

coal), as it currently provides a huge volume of energy that can be stored for long durations. The study also concludes that due to a lack of readily available zero-carbon fuel substitutes, natural gas will remain in the energy mix for decades to come, even as operations change and emissions associated with its use decline. Other studies have reached similar conclusions on the evolving, but critical role of dispatchable gas capacity in decarbonization efforts.

E. The Vote Solar Carbon Stranding and Climate Risk Report is Results-Oriented and has Fatal Flaws

Vote Solar filed with its initial comments direct testimony filed by Tyler Fitch, regulatory manager at Vote Solar, in the South Carolina 2020 IRP proceeding[171] ("Fitch SC Testimony"), as well as an accompanying exhibit: a policy paper entitled "Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plan" ("Carbon Stranding and Climate Risk Report") authored by Mr. Fitch on behalf of the Energy Transition Institute.[172] The Energy Transition Institute appears to have been formed in early 2019 and the Carbon Stranding and Climate Risk Report appears to have been published to advance the interests of the solar industry in North Carolina.[173] In the Fitch SC Testimony and supporting Carbon Stranding and Climate Risk Report, the author heavily criticizes the Companies' 2020 IRPs and erroneously claims that for the Companies' to comply with Duke Energy's stated carbon reduction goals, stranded fossil

[171] *See* Vote Solar Initial Comments Attachment 1 ("Fitch SC Testimony") as filed Feb, 5, 2021 in PSCSC Docket Nos. 2019-224-E and 2019-225-E.
[172] *See* Vote Solar Initial Comments Attachment 3.
[173] *See* Vote Solar Initial Comments Attachment 3, at 4. Contributors to the Carbon Stranding Report include executives of solar development companies operating in North Carolina including Cypress Creek Renewables (Tyler Norris), PineGate Renewables (Steve Levitas), and Carolina Solar Energy (Richard Harkrader).

resources including new natural gas resources will necessarily result and create significant cost risk for customers. The Companies disagree for a number of reasons.

Importantly, Mr. Fitch and Vote Solar do not share the same responsibility as the Companies for the provision of reliable energy that not only achieves environmental goals but that is also affordable for customers. The Fitch SC Testimony relies on a simplistic analysis based on flawed technical assumptions and calculations to present a heavily-biased assessment of potential for stranded costs, leading to inaccurate and unrealistic conclusions. The report assumes fossil units will continue to operate as they do today through 2050 and imposes an artificial emissions cap. Vote Solar's climate policy advocate also grossly inflates his calculations of stranded costs, presumably for shock value.

The Fitch SC Testimony and Carbon Stranding and Climate Risk Report's analysis does not have to stand up to regulatory scrutiny in the manner that the Companies' resource plans do, which leaves him free to draw conclusions based on inaccurate and unrealistic assumptions. The Carbon Stranding and Climate Risk Report has not been scientifically peer reviewed nor subject to regulatory scrutiny of the Public Staff. As a result, the underlying report has a concerning lack of modeling rigor coupled with numerous inputs and assumptions that are simply wrong.

Moreover, the Fitch SC Testimony suggests it does not provide a robust review of climate-related risks on the Companies' assets and operations and, instead, is intended as an "overview [that] is helpful for understanding the order of magnitude of climate-related risks and the substantial implications for the Companies' plans, assets, and operations in to [sic] the future." Unfortunately, the Fitch SC Testimony and Carbon Stranding and

Climate Risk Report present a heavily-biased and results-oriented analysis that is significantly flawed on several fronts.

1. The Companies' IRPs demonstrate the economic viability of gas assets over their useful planning lives.

First, the central premise of Vote Solar's comment and supporting analysis—that natural gas assets will be "stranded" under the 2020 IRPs—is simply false. The 2020 IRPs reasonably modeled an appropriate lifespan for natural gas units under different decarbonization trajectories and the results determined natural gas to be least cost. Natural gas units were modeled in the IRPs based on their appropriate lifespan. The cost-effective use of natural gas units to replace retiring coal units will immediately reduce emissions and is consistent with sound resource planning principles and supports the Companies' corporate climate goals both of which ensure maintaining power system reliability.

The IRPs also examined a scenario shortening the lifespan of gas assets to 25 years and they were still economically selected to meet customer demand with minimal cost impact.[174] In contrast, the Carbon Stranding and Climate Risk Report overstates costs by using exceptionally long asset lives of 40 years (out to 2075) and a flawed discount rate assumption that is inconsistent with the utility view as presented in the 2020 IRPs. This is also an inaccurate representation of the 35-year book life of the natural gas assets planned for in the 2020 IRPs. Relying on this incorrect assumption inflates the period of purportedly stranded costs by extending the useful lives of units past their projected retirement dates.

[174] DEC 2020 IRP, at 169 (Table A-9), 172, DEP 2020 IRP at 168 (Table A-9), 171.

2. Carbon Stranding and Climate Risk Report uses simplistic modeling, flawed inputs and is based upon erroneous assumptions.

Critically, Mr. Fitch does not use production cost modeling software to project the future operations of the generation fleet, which leads to inaccurate generation and emissions projections, used as the basis of his analysis. Unlike the Companies' IRPs, the Carbon Stranding and Climate Risk Report fails to recognize or account for changes in customer demand, fuel costs, technology costs, system operations, or changing dispatch of fleet resources into the future. By failing to model hourly electricity load, the Carbon Stranding and Climate Risk Report ignores this critical need – which is a basic requirement of the IRPs in planning a system that serves customer load reliably every hour.

Through discovery, Vote Solar provided the work papers and code developed in the Python-based model that the author used to develop the Carbon Stranding and Climate Risk Report for ETI. Companies' personnel with significant expertise in Python programming have reviewed the input files, data files, and code Witness Fitch used to perform his climate risk analysis. This review revealed that Witness Fitch relied upon numerous inaccurate assumptions, flawed model construction, and incorrect inputs, and thus his analysis and conclusions should not be given any weight by the Commission in these proceedings.

First, the Carbon Stranding and Climate Risk Report's analysis assumes that recent 2016-2018 capacity factors of fossil generation units are indicative of future capacity factors, a false assumption. There is no rational basis to assume that coal and natural gas will operate the same in 2050 as they did in 2016-2018. With future shadow pricing reflecting a carbon policy, these capacity factors would be much lower, resulting in lower CO_2 emissions. The Vote Solar's assumption is wholly unrealistic and inconsistent with both the Companies' IRPs and the Duke Energy Climate Report, which clearly show an evolving role for natural gas units as coal is retired and more renewable energy and energy storage is added to the system. Mr. Fitch undermines his own argument here, because his report acknowledges that operating gas units at low capacity factors (on the order of 5%) "contributes very little to total emissions."[175] The Duke Energy Climate Report demonstrates the evolving role of natural gas units, contributing about 6% of generation by 2050.[176] The effect of Mr. Fitch calculating carbon emissions using historical capacity factors is to grossly inflate the predicted emissions of these units. For example, the Companies' IRPs show emissions in 2030 for the Base Case with Carbon Policy at 31.8 million tons for DEC and DEP combined. This is close to what Mr. Fitch claims for emissions 20 years later, in 2050. His analysis also does not consider dual-fuel capability or the potential for hydrogen blending for reducing emissions. Although the IRPs did not model the system out to 2050, Duke Energy's Climate Report shows enterprise-wide emissions (including Carolinas, Florida and Midwest) at approximately 8 million tons in 2050, or about one-fifth of the emissions upon which Mr. Fitch bases his calculations.[177]

Second, the Carbon Stranding and Climate Risk Report assumes emission factors for the Belews Creek, Marshall, and Cliffside coal units indicating that they will use coal as the sole fuel through their respective retirement dates. Included in the base case portfolios, the DEC IRP comments that these three coal station are natural gas co-firing (dual fuel) capable.[178] The ability to also burn lower emission natural gas reduces the emissions factors going forward, compared to those used in the Carbon Stranding and

[175] Vote Solar Initial Comments Attachment 3, at 46.
[176] Duke Energy 2020 Climate Report at p. 26.
[177] Duke Energy 2020 Climate Report at p. 27.
[178] See DEC 2020 IRP at 307.

Climate Risk Report. These inaccurate emissions factors, again result in overstating the future CO_2 emissions from these generators.

Lastly, there is no indication given in the 2020 IRPs that the Companies will—at any cost and risk to customers—pursue a linear approach to the goal of net zero carbon emissions as the Fitch SC Testimony and Carbon Stranding and Climate Risk Report assumes in his analysis. This fact is clearly seen with the different pathways presented in the IRPs.[179] For these reasons, the hypothetical CO_2 emissions projections, assumed fleet operations and potential risk of "stranded" or unplanned early retirements of natural gas units presented in Vote Solar's Carbon Stranding and Climate Risk Report and Fitch SC Testimony are not credible and should not be relied upon by the Commission.

3. The Carbon Stranding and Climate Risk Report's criteria for stranding assets is also flawed.

The Fitch SC Testimony explains that the Carbon Stranding and Climate Risk Report measured "stranded cost" as the unrecovered remaining book value of the unit in question at the time the unit is deemed unable to operate (and hence "stranded") based on an arbitrary carbon emissions cap.[180] The analysis deems a fossil unit "pulled out of operation" when the assumed emissions of that unit causes the fleet to exceed the imaginary carbon cap in any year. There are several issues with this approach. To begin with, the straight-line declining carbon cap as a forcing function for retirements or stranding is an inaccurate and completely unreasonable assumption. Regulatory programs for emissions reduction include mechanisms for alternative compliance approaches, as these programs recognize that the operation of any one unit or the total emissions from the generating fleet

[179] See DEC 2020 IRP, at 8.
[180] Vote Solar Initial Comments Attachment 1.

can vary year to year and certain units may need to be kept online to ensure reliable power system operations. Emissions reductions tend to be "lumpy" as higher emitting units are retired, environmental controls are installed, or changes are made to operations. This causes large reductions in emissions reductions to occur in some years, while in other years emissions may be flat. A hard cap that forces units offline, as Mr. Fitch has assumed, is neither realistic nor practicable.

Further, the Carbon Stranding and Climate Risk Report models a zero emissions standard of emissions in 2050, rather than net zero emissions consistent with Duke Energy's climate goals, federal policy proposals and North Carolina's Clean Energy Plan. This assumption by design means all carbon-emitting generation is forced to retire and become stranded in 2050, if not sooner. By imposing this fundamentally-different approach to capping carbon emission (*e.g.*, assuming units go offline when the emissions cap is exceeded in any year), the Carbon Stranding and Climate Risk Report ignores the engineering realities in the generation and delivery of electricity, including adjustments to dispatch, replacement of higher emitting resources with lower or zero emitting resources, and the necessity of reliably serving customer demand.

Not only is this assumption overly simplistic, but it does not reflect the reality of how carbon regulations are likely to evolve, nor does it reflect the Companies' planning trajectory and path for achieving "net-zero."

Further, the Companies recognize that factors outside of their control may impact year-to-year emissions, while the Carbon Stranding and Climate Risk Report analysis uses a hard-and-fast rule that is not truly reflective of the Companies' path to net-zero.

The Carbon Stranding and Climate Risk Report also ignores the Companies' 2030 goal of 50% reduction, as discussed in the 2020 IRPs.[181] This omission is significant, as the Companies' planned annual emissions reductions from 2020 to 2030 are more gradual than the rate of reduction projected later in the 2030s and 2040s. This is because deep decarbonization (particularly for DEC and DEP as national leaders today in low carbon intensity and the provision of carbon-free generation) can only be made possible through significant advancement of low carbon and carbon free technologies, such as long duration storage, carbon capture, utilization, and sequestration, hydrogen, RNG, off-shore wind and small modular and advanced nuclear reactors.

4. Planning for a "no new natural gas future" would require significant technological and policy advancements and would be significantly more expensive for customers.

Vote Solar's comments fail to acknowledge the affordability and reliability benefits of natural gas, while simultaneously omitting the holistic view of the commensurate risks of other technologies that would be needed if natural gas was excluded from the transition plan.

Transitioning the fleet away from coal and meeting future load growth in the Carolinas without building new gas units, as shown in the 2020 IRPs, is the most expensive option for our customers and will likely require coal units to operate longer.[182] It would also present risks associated with new technologies and challenges to reliability that could impact customers.

As more renewables and natural gas have been added to the system and coal units retired, the carbon intensity of the Carolinas fleet has declined and emissions in DEC and

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[181] DEC 2020 IRP, at 8; DEP 2020 IRP, at 8.
[182] DEC 2020 IRP, at 16-17, 94; DEP 2020 IRP, at 16-17, 97.

DEP have already been reduced 50% since 2005. As the Companies' plan for the future, this type of trend will hold true, and older, less efficient generation will see their role reduced, as more renewable and newer, efficient generation comes online, displacing units with higher emissions.

IX. Overview of IRP Portfolio Development

A. DEC's and DEP's respective Short Term Action Plans are consistent between the With Carbon and Without Carbon Base Cases and the Public Staff Recommends that the Commission Accept These Two Portfolios as Reasonable for Planning Purposes

Each year, the Companies' IRPs and IRP Updates include a chapter presenting their Short Term Action Plan ("STAP") in accordance with NCUC Rule R8-60(h)(3). The STAP provides the Companies' expected resource additions and retirements over the first five years of the 15-year planning period. The STAP, as presented in Chapter 14 of the 2020 IRPs, includes resource additions that may be acquired through PURPA PPA purchases, utility-built resources and legislative programs such as CPRE.[183] The retirements provided in the STAP include both utility-owned asset retirements and existing PPA contract expirations. The STAP is presented in both a summary table (Table 14-B[184]) as well as a more detailed discussion of the Companies' expected plans in this chapter.

In its 2020 IRP Comments, the Public Staff provides a summary of the Companies' STAP and presents no opposition to the STAP as presented in the Companies' IRPs.[185] Importantly, the Public Staff points out that the Companies' STAPs are the same across all

[183] DEC 2020 IRP, at 114; DEP 2020 IRP, at 115.
[184] DEC 2020 IRP, at 120; DEP 2020 IRP, at 121.
[185] Public Staff Initial Comments, at 141-142.

six presented portfolios, indicating that the Companies' near-term plans will remain consistent no matter which portfolio pathway develops in the future.[186]

B. DEC's and DEP's First Year of Avoidable Capacity Need are Reasonable for Planning and Avoided Cost Purposes

In its 2018 IRP comments on DEC and DEP's IRPs, the Public Staff recommended that the Utilities include a statement of need defining the first year of avoidable capacity need for purposes of calculating avoided capacity payments.[187]

As recommended, the Companies' 2020 IRPs include Chapter 13 that presents a detailed discussion and quantification of DEC's and DEP's first year of avoidable capacity need, calculated including only those assets considered as designated or mandated (projects that are either underway/approved with a CPCN or required to meet statutory requirements). Those assets are considered to have a greater likelihood of completion.

The Public Staff notes that "the Commission did not issue any specific directives related to the statement of capacity need in the 2018 IRP Order; however, the Utilities voluntarily provided these statements with some of the requested information."[188]

The Public Staff states that it "believes that Duke has addressed each of our recommendations in the 2018 IRP related to the first year of capacity need"[189] However, the Public Staff raises an additional issue for the Commission to consider regarding the first year of need calculation. The issue is related to DEC's planned deployment of the Integrated Volt-Var Control ("IVVC") program. IVVC is a part of DEC's Grid Improvement Plan ("GIP") and has been included as a resource in this year's IRP. While

[186] Public Staff Initial Comments, at 147.
[187] Initial Comments of the Public Staff, at 89-92Docket No. E-100, Sub 157 (filed March 7, 2019).
[188] Public Staff Initial Comments, at 84.
[189] Public Staff Initial Comments, at 85.

IVVC is included in the overall IRP, for the calculation of the First Capacity Need, the Company chose to exclude the impacts of IVVC for the DEC system since the GIP had not yet been approved by this Commission in DEC's 2019 rate case proceeding at the time DEC's 2020 IRP was being developed. IVVC—which has now been approved as part of the Commission's general rate case order in Docket No. E-7, Sub 1214—would provide approximately 174 MW of peak shaving capabilities by 2026.[190]

The Public Staff correctly states, "If IVVC had been treated as a designated resource, DEC's first year of capacity need for the purposes of calculating avoided capacity rates would be 2028" as opposed to 2026 as presented in the IRP.[191]

Excluding IVVC in the calculation of the first capacity need in the 2020 IRPs is appropriate because the Commission had not yet issued an order in DEC's 2019 general rate case regarding DEC's deferral accounting request relating to GIP investments, including IVVC costs. At the time the 2020 IRP was developed, DEC was uncertain of the timing and level of deployment of the IVVC project over the three-year planned GIP deployment timeline if the Company's request were to be denied.[192]

The Companies and Public Staff have discussed this issue and as such, Public Staff states that "due to this uncertainty, and the streamlined proceedings in Docket No. E-100, Sub 167, at this time, the Public Staff accepts the exclusion of IVVC from the calculation of the first year of need."[193]

[190] *See* 2020 DEC IRP, at 100.
[191] Public Staff Initial Comments, at 86.
[192] See the Joint Testimony of Jay W. Oliver and Jane L. McManeus in Compliance with Commission Order Requesting GIP Information, Docket No. E-7, Sub 1214, at 14, (filed August 5, 2020).
[193] Public Staff Initial Comments, at 86. The Public Staff further comments that its "acceptance of this exclusion for purposes of this proceeding should not be taken as an admission on the Public Staff's part that any potential delay in the implementation of IVVC, because of Commission denial of deferral accounting treatment, be considered prudent and reasonable."

Because the Commission has now approved the DEC GIP, including IVVC, the Companies will adjust the calculation of the first year of capacity need in the upcoming 2021 IRP update to be filed in September 2021.

C. Public Staff's Comments on the DEC and DEP Expansion Plans are Reasonable.

The Public Staff comments on the relatively low additions of renewables in Portfolio A and points out concerns with meeting the Companies' long-term carbon reduction goals with this amount of renewable additions.[194] While no renewables are economically selected in Portfolio A, it still accounts for the addition of nearly 5,000 MW of solar added in this portfolio through 2030, combined between the utilities bringing the DEC and DEP total to over 8,600 MW of installed solar. Moreover, this addition of planned renewables, made up of mandated, designed, and queue materialization, along with a transition out of coal capacity to less carbon intense natural gas capacity, keeps the Companies on track for achieving greater than 50% CO_2 reduction by 2030. The Companies have been open and transparent that technology and policy advancements will be needed to achieve its long-term carbon reduction goals, and this is evident in Portfolio A. It is clear the Companies have a path to 50% reduction by 2030, but continuous and programmatic additions of renewables are not yet economic in a scenario with little policy or technological advancement aid.

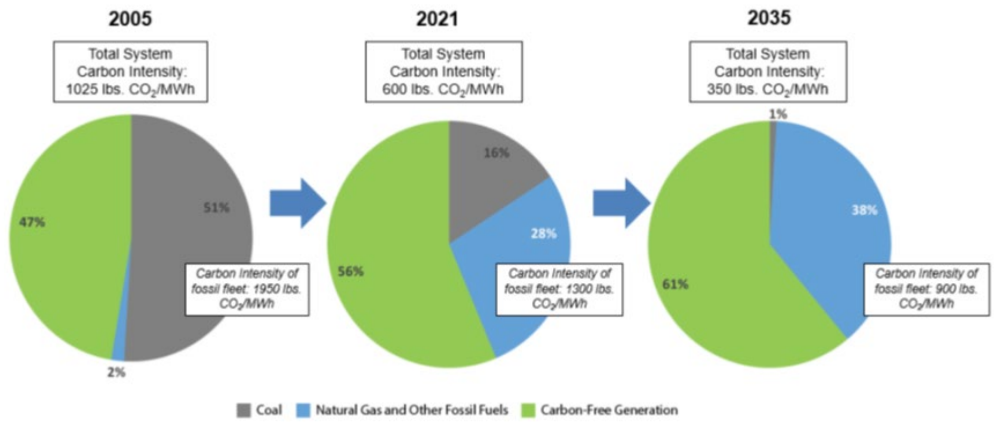
The Public Staff also comments on the perceived disconnects between the enterprise's net zero carbon goal and its natural gas additions.[195] As discussed in the 2020 IRPs and Duke's Climate Report, the role of natural gas will change over time, just as older

[194] Public Staff Initial Comments, at 129.
[195] Public Staff Initial Comments, at 129.

and less efficient units in the fleet are being offset with more efficient and less expensive generation to operate the system. In the near term, gas will allow the Companies to more expeditiously retire coal, while providing flexibility and backstanding the intermittency of renewables. In extended weather events, such as those seen in Texas in February 2021, natural gas can provide long reliable generation, when properly invested in for reliability, as has been done for the Carolinas gas fleet. In the decades to come, as new long duration storage and zero emitting load following resources become available, the role of the gas fleet will again change to supplying peak capacity with low annual emissions. Additionally, natural gas units may also be designed or could be retrofitted to run on carbon neutral fuels or have their emissions utilized or sequestered. While there are many answers to figure out along the way, the Companies will continue to reconcile providing a reliable and affordable system while striving to provide an increasingly clean generation fleet.

While the Companies are focusing on how they can continue to cost effectively and reliably integrate less carbon intense resources, the prospects of emerging technologies that can supply bulk carbon free resources are also being evaluated in this IRP. It is recognized that reductions between 2020 and 2030 may be more gradual than between 2005 and 2020, which represented the system shift from nearly over 50% of its generation supplied by coal to less than 20% of its energy from coal in 2021, as shown in Figure 8 in the Executive Summaries of the IRP on page 10 and Figure 8 below.

Figure 8: Combined System Carbon Reduction Trajectory (Base CO_2) Figure from the Executive Summary Companies' 2020 IRPs



Additionally, to reach net-zero in 2050, large strides will need to be made with the future of Zero Emitting Load Following Resource (ZELFR) technologies and other bulk carbon free resources from 2035 through mid-century. The Companies analysis of small modular reactors ("SMRs"), offshore wind, accelerated coal retirements, and no new gas generation are important analyses to help inform regulators and policy makers, both of what is needed to achieve these lofty goals, but also what it may cost, and how to maintain a reliable system. The alternative portfolios, while not economically selected according to constraints of the system, are nonetheless informative, and a useful exercise to continue thinking about the cost, risks, and environmental benefits of these different resource types.

The Companies will continue to evaluate potential energy policy and technology that can shape the Carolinas' energy future. The IRP is an appropriate forum for this analysis and starting the conversation. As policy winds blow across the states and across the country, the Companies will continue to evaluate approaches to planning the system that achieve affordability, reliability, and carbon reduction goals.

D. The Companies' Modeling Already Evaluates the Cost-Effectiveness of Solar as an Energy-Only Resource, as Recommended by NCSEA/CCEBA's SEIA Lucas Report

NCSEA/CCEBA and the SEIA Lucas Report criticize the Companies for failing to allow their IRP model to add new capacity or PPAs unless there was a capacity need, eliminating the potential to incorporate less-expensive energy-only resources earlier in the planning horizon.[196] The Companies actually agree with these comments to the extent they are focused on evaluating the cost-effectiveness of energy-only resources. In fact, the Companies employed this concept in developing their 2020 IRPs. Energy-only resources refer to resources that are added despite the lack of a capacity need but are available to reduce the cost of the system by lowering energy costs.

Standalone solar (solar not paired with storage) contributes one percent or less of its capacity towards the winter capacity planning reserve margin; as such it is almost wholly an energy-only resource. From a planning perspective, solar is not a substitute for dispatchable capacity resources in an IRP as it cannot meet growth in winter peak demand nor can solar replace retiring coal generation that currently meets winter peak demand needs that occur in non-daylight hours. However, solar resources can serve to reduce marginal system energy needs during daylight hours and the associated fuel consumption of the energy it is displacing. This is why standalone solar is referred to as an energy-only resource which is selected in the expansion model when it can economically displace daytime energy produced from the system's marginal generator irrespective of system capacity needs. To illustrate this point, the DEC capacity expansion run for Base Case with Carbon Policy begins to economically select additional solar in DEC in 2025, a year

[196] *See* NCSEA/CCEBA Initial Comments, at 22-23; Exhibit 2, SEIA Lucas Report at 73.

in which there is no capacity need. Accordingly, the Companies agree, to an extent, with NCSEA/CCEBA's recommendation to consider procuring additional, undesignated standalone solar (i.e., over and above what is required to meet policy mandates) when it is economically advantageous for our customers to do so.

E. NC WARN/CBD's Claim that Duke has "Vastly Understated"[197] Gas Turbine Capital Cost is Significantly Flawed, has No Basis in Fact and Should Be Rejected

NC WARN/CBD and its Powers Report allege the following:[198]

- "Duke Energy's capital cost assumptions for gas turbine power plants, $650/kW for combined cycle and $550/kW for combustion turbines, are less than one-half what they should be to reflect Duke Energy's actual costs."
- "The capital cost of the 560 MW Asheville combined cycle plant, which came online in 2020, is $817 million. This is equivalent to a unit cost of about $1,460/kW, over double Duke Energy's assumed combined cycle cost of $650/kW."
- "The same NREL database that Duke Energy referenced as the basis for its battery storage cost in its *2020 Climate Report* identifies a generic mid-range capital cost for combined cycle plants of $1,055/kW in 2021, declining only slightly to $964/kW in 2035. Duke Energy's combined cycle capital cost forecast is too low."
- "Powers Engineering assumes the combined cycle cost multiplier of the Asheville combined cycle plant, which is more than double Duke Energy's generic combined cycle cost assumption, also applies to new combustion

[197] Initial Comments of NC WARN/CDB, at 29.
[198] Initial Comments of NC WARN/CDB, Attachment 1, at 4-5.

> turbines. This is equivalent to a unit combustion turbine cost of approximately \$1,250/kW, compared to Duke Energy's assumed combustion turbine cost of \$550/kW. Also, the NREL database referenced by Duke Energy identifies a generic mid-range capital cost for combustion turbines of \$969/kW in 2021, declining only slightly to \$879/kW in 2035. Duke Energy's combustion turbine capital cost forecast is too low."

In reply to NC WARN/CBD comments, the Companies note that the Commission found that public convenience and necessity required the construction of the two 280 MW CC units in the timeframe provided under the Mountain Energy Act to allow DEP to retire the coal units at the Asheville Plant and avoid significant capital investments and environmental controls required by CAMA if the coal units at the Asheville Plant remained in operation.[199] The Companies further note that in the absence of new transmission infrastructure into the DEP-West region, smaller CC units were identified as needed in order to comply with NERC reliability standards. The Companies constructed two combined-cycle power blocks, each with one (1) F-class combustion turbine ("CT"), one (1) heat recovery steam generator ("HRSG"), and one (1) steam turbine ("ST"). This equipment configuration is also referred to as two 1x1 CCs. The 1x1 CCs are more expensive on a \$/kW basis compared to the larger 2x1 J-frame CCs included in the Companies' IRPs. Additionally, because it is critical to keep the Asheville CC units in operation during peak conditions, the design basis for the CC units included bypass stacks to allow continued generation of power during steam turbine outages and cold weather hardening features to allow the units to reliably operate down to a temperature of -16

[199] Order Granting Application In Part, With Conditions, and Denying Application In Part, at 7 Docket No. E-2, Sub 1089, (March 28, 2016).

degrees Fahrenheit. Thus, the cost of the Asheville CCs is not representative of the Companies' cost to build a larger CC facility in other parts of its service territories.

NC WARN/CBD and the Powers Report nonsensically concluded that the Asheville CC cost must be representative of the Companies' cost to build other generic combined cycle facilities.[200] The Powers Report further erroneously concluded that "the combined cycle cost multiplier of the Asheville combined cycle plant, which is more than double Duke Energy's generic combined cycle cost assumption, also applies to new combustion turbines."[201]

NC WARN/CBD and Mr. Powers also reference CT and CC costs from NREL in an effort to support their claim that the Companies' costs are too low. The Companies note that the NREL cost data for CT and CC natural gas technologies is based on data from the Energy Information Administration ("EIA").[202,203] The Companies' 2020 IRPs assume generic F-class CT additions for peaking purposes. Note however, that the NREL CT cost reflects the average of the advanced and conventional systems as reported by EIA and assumes a plant size of 171 MW.[204] The EIA advanced CT cost is based on an F-class CT with a unit rating of approximately 240 MW and the EIA conventional CT cost is based on 2 x LM6000 aeroderivative CTs with a net output of approximately 100 MW.[205] Aeroderivative CTs have a much higher cost on a $/kW basis compared to an F-class CT,

[200] Initial Comments of NC WARN/CBD, Attachment 1, at 4.
[201] *Id.* at 5.
[202] EIA develops capital cost and performance characteristics for utility scale generating technologies for use in EIA's Annual Energy Outlook.
[203] https://atb.nrel.gov/electricity/2020/index.php?t=ei#n_vj3fy999
[204] *Id.*
[205] EIA Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020, Table 2, at III, available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

and the aeroderivative CT is not the type of CT that the Companies would build strictly for peaking purposes. Based on the 2020 EIA data, the capital cost of the aeroderivative CT is approximately 65% greater than the single F-class CT.[206] Further, the EIA data for the F-class CT reflects the cost to build a single unit at a greenfield installation and thus does not reflect the economies of scale associated with building multiple units at a site and spreading infrastructure costs among multiple units.[207] These economies of scale savings for customers are reflected in the Companies' CT cost estimate. Thus, the NREL CT cost data does not provide a valid comparison to the Companies' CT cost estimate.

The NREL CC cost reflects the average of the advanced and conventional systems as reported by EIA and assumes a plant size of 750 MW.[208] The EIA advanced CC cost is based on a 2x1 equipment configuration using 2 x H-class CTs with a unit rating of approximately 1,083 MW and the EIA conventional CC cost is based on a 1x1 equipment configuration using a single H-class CT with a rating of approximately 418 MW.[209] In comparison, the Companies' generic CC is based on a 2x1 equipment configuration using 2 x J-class CTs with a unit rating of 1,224 MW. Again, the NREL CC cost estimate does not provide a valid comparison to the Companies' CC cost estimate.

The Companies believe that the CT and CC costs used in development of its IRPs provide reasonable estimates for the cost of future natural gas capacity and the use of higher CT and CC estimates would result in the non-optimal selection of resources in the IRP resulting in higher costs to customers. It is also notable that the Companies have multiple

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[206] *Id.*
[207] *Id.* at 6-1.
[208] https://atb.nrel.gov/electricity/2020/index.php?t=ei#n_vj3fy999
[209] EIA Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020, Table 2, at III, available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

brownfield sites with potential future use for baseload and peaking installations that may further reduce the cost of future resource additions compared to the assumptions used in the IRP.

Finally, the Companies note the lack of sophistication in the methodology used by the NC WARN/CBD Powers Report to arrive at illogical conclusions regarding the Companies' cost to build gas turbine plants. The Companies believe that the conclusions reached by NC WARN/CBD and the analysis presented in the Powers Report regarding the Companies' CT and CC costs are significantly flawed, not supported by fact and recommend their findings be rejected by the Commission.

X. Solar and Battery Storage ELCC

A. Duke Appropriately Captured the Synergies Between Solar and Battery Storage in determining ELCC Values and Intervenor Criticisms Should be Rejected

NCSEA/CCEBA's E3 Report suggests that:

- "The interactive effects of solar and storage on the DEC system can only be fully understood by developing an ELCC surface that determines the combined capacity value of different portfolios of solar and storage (see Figure 5)."[210]
- "Duke should update the 2018 Solar ELCC Study to include an ELCC surface analysis that demonstrates the increasing diversity benefit associated with solar and storage installations. This recommendation is also critical in developing an optimized capacity expansion."[211]

[210] NCSEA/CCEBA Initial Comments, Exhibit 2 E3 Report at 35
[211] *Id*.

In response, the Companies first note that the Public Staff found the Storage ELCC Study to be reasonable for planning purposes.[212] Further, the E3 Report agrees that dispatch-limited resources such as solar and energy storage should be evaluated using the ELCC approach to accurately characterize their contribution toward reducing the frequency of loss of load events.[213] E3 also commented that "Duke should be commended for its use of Effective Load Carrying Capability (ELCC) metrics to determine the capacity credit for renewables and energy storage, in keeping with industry best practice."[214] The Storage ELCC Study was included as Attachment IV to the Companies' 2020 IRPs.

In reply to Mr. Olson's criticisms, the Companies do not believe the recommendation to use an ELCC surface is necessary or appropriate to capture the interactive effects of solar and storage. First, the Companies disagree that the Storage ELCC Study ignores the diversity benefit of solar and storage being added together. To the contrary, the Storage ELCC Study takes full advantage of the synergies between solar and storage. The Storage ELCC Study analyzed substantial penetrations of storage ranging from 400 MW to 1,600 MW for DEC and from 800 MW to 3,200 MW for DEP across two different solar tranches each. The solar tranches are not inconsequential: 4,000 MW and 5,500 MW of solar were studied for DEP while 2,700 MW and 4,500 MW were studied for DEC. The synergy is reflected in the storage capacity values. While solar is creating some of the opportunity for storage to supply capacity, the system should only see that credit when storage is selected in the portfolio since the benefit will not materialize until then. The Storage ELCC Study as filed provides all the information needed surrounding

[212] Public Staff Initial Comments, at 78.
[213] NCSEA/CCEBA Initial Comments, Exhibit 2 E3 Report at 12.
[214] NCSEA/CCEBA Initial Comments, Exhibit 2 E3 Report at 3.

the capacity value of storage with the synergies between storage and solar included, and the Companies use this information to calculate marginal incremental storage ELCC values to be used in the expansion planning process. Accordingly, the E3 Report's recommendations on behalf of NCSEA/CCEBA should be rejected.

B. The Full Value of Battery Storage to the Companies' Systems, Including the Impacts of Solar on Battery Storage, was Appropriately Accounted for through Detailed Production Cost Modeling in the Companies' 2020 IRPs

NCSEA/CCEBA's E3 Report also comments:

- Duke's use of a multi-step portfolio development process does not adequately capture the diversity benefits associated with renewables and storage. By evaluating the benefits of solar and storage at separate points in the capacity expansion process, diversity benefits are ignored, leading to other technologies being chosen at a higher cost.[215]
- The use of an ELCC surface allows for the capacity expansion model to incorporate the dynamic synergies of the resources when added to the system.[216]

E3 is correct that the Companies employed a sequential, rather than single step, approach to optimization. However, E3's characterization of the result—a purported devaluing of the solar capacity—is incorrect. To the contrary, E3's comments actually support the need to use a robust production cost model, rather than sole reliance on an expansion planning screening model, to more accurately capture the full value of storage on the Companies' systems. This is precisely why the Companies went through the more

[215] NCSEA/CCEBA Initial Comments, Exhibit 2 E3 Report at 34.
[216] NCSEA/CCEBA Initial Comments, Exhibit 2 E3 Report at 23.

detailed approach as explained in detail in Chapter 11 of the IRPs, and as further explained through extensive discovery.

It is true that the Companies evaluated the economic impact of batteries after the capacity expansion model selected replacement resources given the limitations of the portfolio optimization screening tools. However, batteries were robustly evaluated in the Companies' production cost model. As part of the modeling, the Companies replaced CTs that were economically selected in the portfolio development in the capacity expansion model with the equivalent firm amount of battery capacity, according to the Companies' ELCC study of batteries. The extra step of using the production cost model was to fairly evaluate the value of storage using the model best suited for storage valuation. Storage benefits can best be measured in production cost models that examine hour by hour dispatch of the system and identify periods when storage should charge and discharge to lower the overall cost of the system. These nuances of chronology and high and low load hours are muted in the capacity expansion model, as hour aggregation and general simplifications are performed by the model to speed up processing time. The robust approach used by the Companies ensured batteries were given a fair evaluation in economic selection in the base case portfolios. In short, Mr. Olson's claim that the Companies have not captured the total synergistic effects of solar and storage by using the sequential modeling approach is incorrect.

C. The E3 Report's Flawed Modeling Assumptions Result in Artificially Higher Solar ELCC Values for DEC Compared to the Astrapé Study

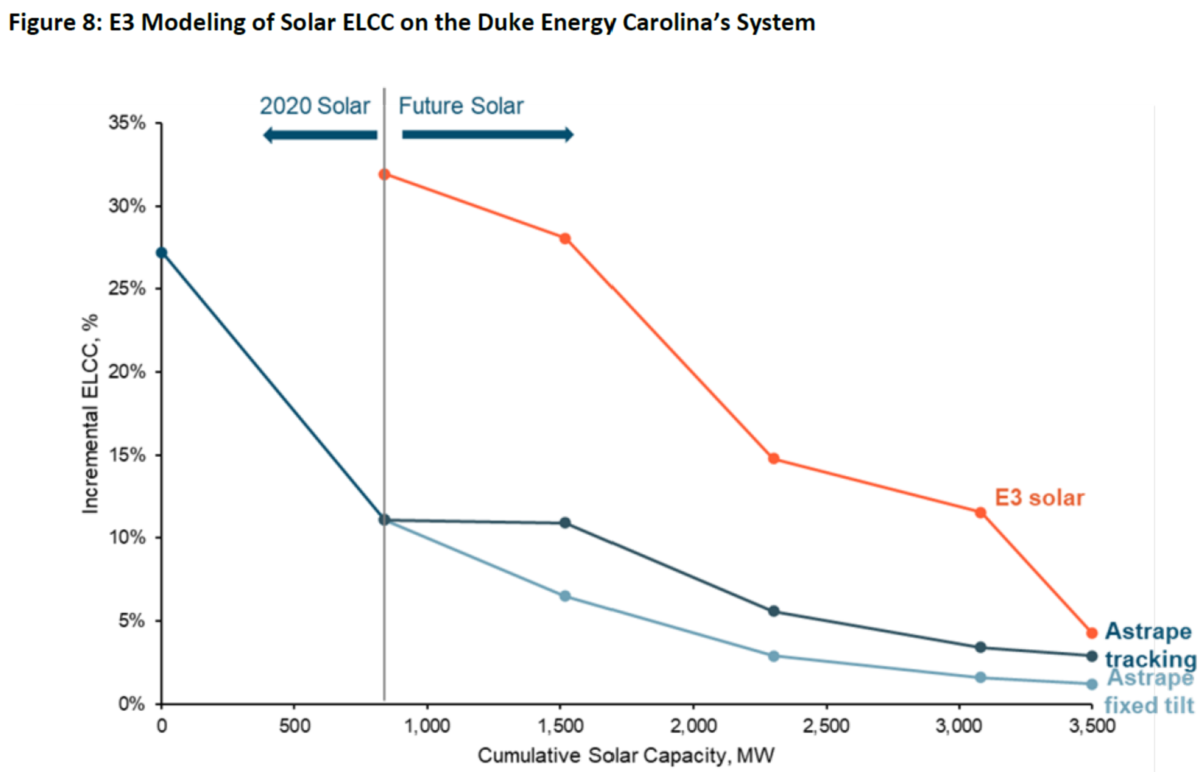
NCSEA/CCEBA's E3 Report states the following:

- "E3 used its RECAP model to calculate the ELCC of solar on the DEC system, incorporating recommended updates outlined in Section 4.1."[217]
- "As shown [E3 Report, Figure 8], the initial E3 ELCC values of solar are significantly higher than Astrapé's values, with the ultimate results converging at higher penetrations around 3,500 MW. Based on the modeling performed by E3, it is not possible to allocate the differences to each individual recommendation as they are modeled as a package. However, it is accurate to say that all the recommendations made by E3 would have the effect of increasing the solar ELCC values compared to the Astrapé study."[218]

As noted above, E3 used its RECAP model to calculate the ELCC of solar on the DEC system. For reference, pasted below is Figure 8 from page 31 of the E3 Report (shown below as Figure 9) which shows results of the E3 ELCC analysis for DEC compared to the Astrapé ELCC study results. As one would expect from NCSEA/CCEBA's expert, the initial E3 ELCC values of solar are significantly higher than Astrapé's values, with the ultimate results converging at higher solar penetrations around 3,500 MW.

[217] NCSEA/CCEBA Initial Comments, Exhibit 2 E3 Report at 30.
[218] NCSEA/CCEBA Initial Comments, Exhibit 2 E3 Report at 31.

Figure 9: Incremental Solar ELCC Comparisons for DEC



The Companies note that Mr. Olson's arguments to increase the solar capacity value hinge on artificially creating more LOLE risk in the summer by improperly modifying several key assumptions regarding load, winter demand response capability, and ignoring cold weather outages which increase winter reliability risk. It is also important to note that E3 calculated annual average solar ELCC values as opposed to seasonal values for summer and winter. The expansion planning analysis conducted by the Companies is driven by incremental winter ELCC values because the winter reserve margin requirement drives future capacity needs. Incremental winter capacity value is the capacity value of the next MW to be added in the winter season. The incremental capacity value is critically important because as solar and storage penetrations increase, their incremental capacity values decline. The adjustments E3 made to input assumptions likely has minimal impact on the winter ELCC values. If winter ELCC values for solar were provided by E3, the Companies expect that they would be in line with Astrapé's analysis since loads are highest in the winter morning hours when solar output is very low. This information was requested through discovery but NCSEA and CCEBA responded that "[t]his data cannot be provided because RECAP calculated ELCC on an annual rather than seasonal basis."[219] E3's flawed adjustments to input assumptions and the impact on ELCC modeling are discussed more fully below.

1. Load data.

E3 used 2040 load data in its ELCC analysis. It is not logical for the Companies to base their reliability for the 2021-2035 planning period on a 2040 load forecast. While system size likely has a very small impact on solar ELCCs in a system as large as DEC and DEP, the more impactful part of using the 2040 loads is that E3 uses summer forecasted loads that are significantly higher than the winter forecast, which improperly shifts some of the LOLE to the summer during the planning period. For example, the 2024 average DEC load in the Resource Adequacy Study across all weather years was 17,976 MW in the winter and 18,456 MW in the summer with a difference of 480 MW. For 2040, E3 used an average winter load across all weather years of 20,606 MW and 21,552 MW in the summer with a difference of 946 MW. The larger difference between summer and winter load in the E3 analysis decreases summer reserves relative to winter reserves resulting in a shift of some LOLE to the summer. Further, the uncertainty around load and the seasonal reliability risk is much more uncertain in the 2040 timeframe and thus it is inaccurate to

[219] NCSEA and CCEBA response to Duke Data Request 2-5.

base decisions made for 2021-2035 solely on a 2040 load forecast. E3's recommendation of using 2040 load is not supported and should be rejected.

2. Demand response.

E3 used demand response assumptions from the Winter Peak Demand Reduction Potential Assessment (also referred to as the Winter Peak Study)[220] for study year 2041 in its ELCC analysis. It is important to realize that the incremental demand reduction potential identified in the Winter Peak Study will not be fully realized until 2041. Thus, the incremental demand reduction is projected to slowly ramp up to higher levels over the next 20 years. It is illogical for the Companies to assume 2041 demand reduction projections when assessing near term resource needs in the IRP. E3's demand response assumptions are flawed and should be rejected.

3. Cold weather outages.

As seen in Texas in February of this year, outages during cold weather events can be significant, making winter a major reliability concern. Because Astrapé models seasonal outage rates as they have occurred in history, and also captures additional cold weather outages below 10 degrees, LOLE in the winter increases compared to the summer. Excluding cold weather outages is one of the input changes made by E3 that would have caused its analysis to show more summer LOLE for DEC. E3 should include seasonal and cold weather generator outages in their modeling to achieve an accurate picture of the seasonal LOLE risk.

[220] The Winter Peak Study was completed in December 2020, after the filing of the Companies' 2020 IRPs in September 2020.

4. Modeling impacts of E3's flawed assumptions.

The E3 Report states that the DEP system was modeled using RECAP and, given the significant amounts of solar and limited storage on the system, there were no material differences between the E3 modeled values and the values used in the Duke IRP.[221] After reviewing the results for DEP, as provided in response to discovery,[222] even with higher demand response (E3 assumed 1045.7 MW in the winter), 2040 load, and the removal of cold weather outages, E3 calculates 5 MW of capacity contribution for all the solar tranches evaluated, or essentially 0% capacity value. This is consistent with Astrapé's finding that 100% of the LOLE is in the winter and the winter capacity value of solar is very small.

For DEC, E3 utilized 2040 load rather than 2024 load used by Astrapé, increased winter demand response from 442 MW to 1,212 MW (which reflects demand response accomplishments projected for year 2041), and excluded cold weather outages on the generation fleet. With all of these flawed changes, a portion of the overall LOLE is shifted to the summer resulting in higher annual average ELCC values in the E3 analysis. The seasonal LOLE differences between the Astrapé analysis and the E3 analysis can be seen in Table 10 below which shows that the shift to winter LOLE as solar is added is at a slower rate in the E3 analysis. These alternate assumptions increase the annual average ELCC as shown in the E3 Report's analysis with E3 and Astrapé ELCC results converging at higher penetrations of solar around 3,500 MW. As previously noted, these results have no bearing on the incremental winter solar ELCC values which drive the capacity requirements in the

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[221] Direct Testimony of Arne Olson testifying on behalf of the South Carolina Solar Business Alliance; SC Docket Nos. 2019-224-E and 2019-225-E, at 25 (filed Feb. 5, 2021).

[222] Reference CCEBA's response to DEC and DEP's Request for Production Nos. 1-24a and 1-24b in South Carolina Docket Nos. 2019-224-E and 2019-225-E.

Companies capacity expansion modeling. The incremental winter solar ELCC is still very low as demonstrated in the DEP analysis conducted by both E3 and Astrapé.

Table 10. Astrapé vs. E3 DEC Seasonal LOLE at Different Solar Penetrations

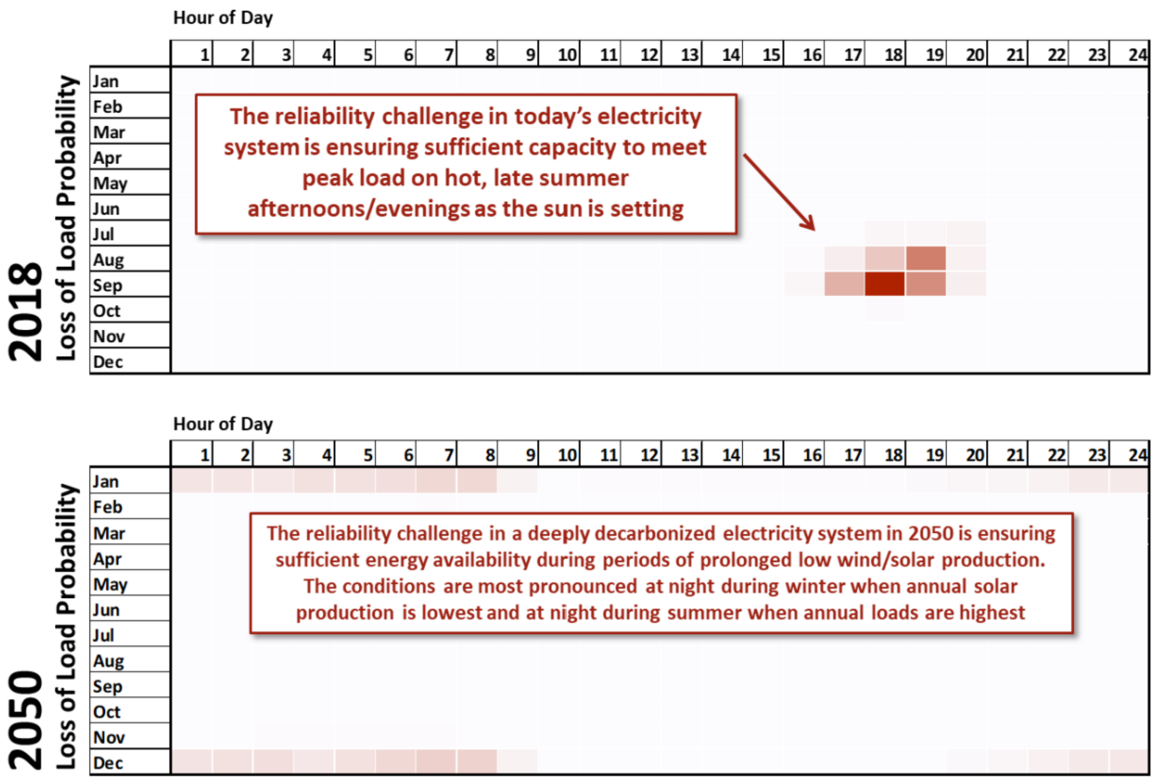
	Astrapé 2018 Solar ELCC		**E3 Solar ELCC[223]**	
Solar Penetration	Winter LOLE	Summer LOLE	Winter LOLE	Summer LOLE
840	69%	31%	46%	54%
1,520	79%	21%	62%	38%
2,300	89%	11%	66%	34%
3,080	93%	7%	74%	26%
3,500	93%	7%	76%	24%

In E3's own findings in other jurisdictions and shown in the Figure 10 below,[224] E3 finds that as more solar is added to the system, it is expected that LOLE risk will shift to the winter during periods when the sun is not shining. For the Companies, this is especially true since the net loads in the studies are most extreme in the winter mornings. The Astrapé ELCC studies were appropriately conducted and provide proper ELCC assumptions for use in the planning process. The critiques that E3 provides are inconsequential to the winter solar ELCC values calculated by Astrapé and used within the Companies' IRPs. E3's criticisms of the Companies ELCC values are flawed and should be rejected.

[223] Calculated based upon data obtained from CCEBA's response to DEC and DEP's Request for Production No. 1-24a in South Carolina Docket Nos. 2019-224-E and 2019-225-E.

[224] Energy and Environmental Economics, Inc., *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California*, at 32 (June 19, 2019), available at: E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf (ethree.com).

Figure 10: E3 Distribution of Loss-of-Load Probability by Month-Hour (High Electrification Scenario) for California

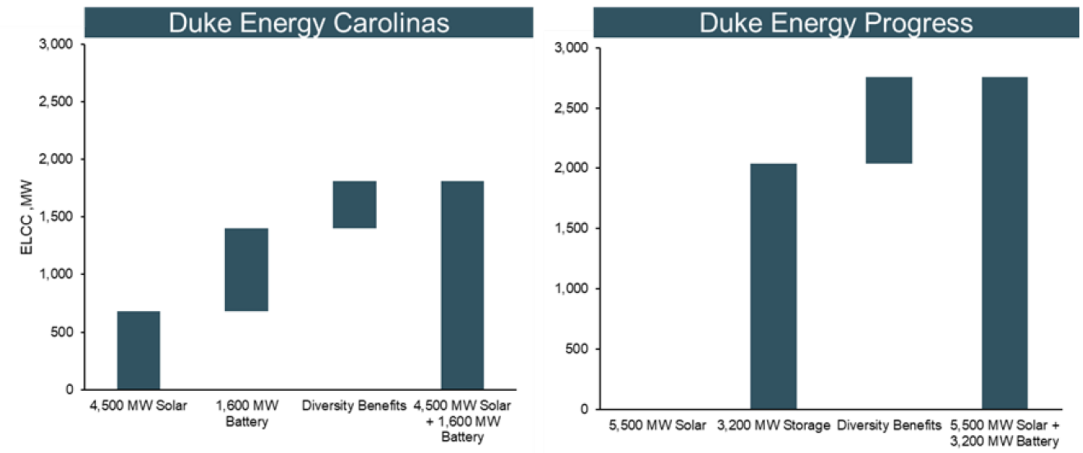


D. E3 Report's Evaluation of Solar and Battery Storage Synergies and ELCC Values is Problematic

Aside from E3's flawed adjustments to input assumptions, the Companies and Astrapé note other concerning aspects regarding results of the E3 RECAP analysis. Pages 32-33 of the E3 Report discuss the diversity benefits between solar and storage. Figure 11 below (Figure 9 from the E3 Report) shows the analysis conducted by E3 in its RECAP model for DEC and DEP showing quantification of ELCC and diversity benefits from solar and a 4-hour storage device. The main point made by E3 in this section of the Report is to show what they believe to be the additional benefit of the combined solar and storage capacity value compared to the individual capacity values.

Figure 11: E3 Quantification of Diversity Benefits from Solar and Storage

Figure 9: Quantification of ELCC and Diversity Benefits from Solar and a 4-hour Storage Device



The Companies agree with the underlying point that storage and solar have synergistic values. As previously discussed however, the Storage ELCC Study already takes advantage of the solar and storage relationship because significant solar was included in the Storage ELCC Study. Also as noted earlier, the values shown in Figure 11 above (E3 Figure 9) are not winter or summer capacity values but rather reflect annual values, which are not comparable to the capacity values used in the Companies' IRPs. As an example, E3 found the average annual ELCC value of solar for DEC to be 15% (679 MW/4,500 MW = 15%).[225] This 15% average annual ELCC is not useful for expansion planning purposes. The capacity values used in the IRP require seasonal ELCC values due to seasonal capacity requirements.

The most problematic portion of this E3 analysis is the calculated value for standalone storage. As an example, the previous Figure shows that E3's assessment quantified the ELCC of 1,600 MW of 4-hour stand-alone storage with 0 MW of solar

[225] Reference CCEBA's response to DEC and DEP's Request for Production No. 1-24b in South Carolina Docket Nos. 2019-224-E and 2019-225-E.

assumed in DEC to be less than 50%. The standalone storage would result in 721 MW[226] out of 1,600 MW nameplate capacity which represents a 45% average ELCC. This brings skepticism to the analysis performed by E3 in its RECAP model. Astrapé views the E3 values as exceptionally low for an average ELCC of 4-hour storage even with no solar included which raises questions of the modeling framework. Based on E3's analysis in a system with no solar, DEC would only include a 45% capacity credit in its expansion planning models for the first 1,600 MW of standalone storage, which is well below the values used by the Companies. Although the Companies cannot provide a direct comparison of Astrapé standalone storage results (which include solar on the system) to the E3 standalone storage results (which assume no solar on the system), the Companies and Astrapé would expect the 4-hour standalone storage results to be significantly greater than the 45% capacity value determined by E3. Further, because the capacity value calculated by E3 for standalone 4-hour storage is so low, it is likely that the portion allocated as diversity benefit in the E3 analysis is overstated.

Finally, it is noted that in inspecting the E3 ELCC results,[227] the E3 RECAP model seemed to produce substantially more reliability problems in February compared to January. This is a non-intuitive and concerning result as temperature and load are typically more extreme in January than in February, and this result does not align with Astrapé's own analysis that there is significantly more reliability risk in January than in February. For the highest solar penetration analyzed for DEC, E3's RECAP model determined 44% of the LOLE occurred in February while only 22% occurred in January. In comparison,

[226] Reference CCEBA's response to DEC and DEP's Request for Production No. 1-24b in South Carolina Docket Nos. 2019-224-E and 2019-225-E.
[227] Reference CCEBA's response to DEC and DEP's Request for Production No. 1-24a in South Carolina Docket Nos. 2019-224-E and 2019-225-E.

Table B.1 from the 2020 DEC Resource Adequacy Study report shows 75% of the total annual LOLE occurs in January and 17% in February. Thus, in addition to E3's flawed changes to input assumptions noted previously, E3's calculation of an unusually low capacity value for a 4-hour standalone battery and non-intuitive monthly allocation of LOLE results call into question the reasonableness of the E3 modeling framework and validity of the study results. The Companies believe that the E3 study is flawed and the results and recommendations from E3 should be dismissed by the Commission.

E. E3 Report's Recommendation that the Companies Employ Unforced Capacity ("UCAP") Planning Reserve Margin Would Have Minimal Impact on the IRP and Selection of Resources While Requiring the Companies to Significantly Re-Design Their Planning Reserve Margin Process

NCSEA/CCEBA's E3 Report comments:

- "Duke's current use of an ICAP PRM, paired with ELCC values for solar and storage compares apples with oranges and disadvantages renewables and storage assets. Currently, thermal firm resources are credited their full nameplate capacity while renewable and storage assets are credited with an ELCC value that is by definition equivalent to perfect capacity. Duke improperly assumes that dispatchable resources do not suffer forced outages in its capacity expansion modeling, disadvantaging renewable resources."[228]
- "Duke's implementation of its planning reserve margin ("PRM") is flawed and skews the results to understate solar's actual capacity value relative to firm resources such as natural gas generation. In particular, when evaluating the relative capacity contributions of competing resources to load, Duke assumed

[228] NCSEA/CCEBA Initial Comments, Exhibit 2 at 34.

100% availability of fossil fuel generation – thus *excluding forced outages* – while utilizing ELCC for solar – a measure that *includes such outages*. This apples-to-oranges calculation inaccurately discounts solar's ability to meet projected energy and capacity needs."[229]

The Companies disagree with E3's recommendation. As background, installed capacity, or ICAP, and unforced capacity, or UCAP, are industry terms for tracking the capacity contributing to the planning reserve margin. ICAP refers to the maximum amount of electricity a generator is designed to reliably produce seasonally, or what is sometimes referred to as net dependable capacity. However, despite this rating, power plants are usually not able to produce this maximum output 100% of the time due to unit forced outages or deratings. In contrast, UCAP which is used within certain RTOs refers to the average amount of electricity that is actually available at any given time after discounting the time that the facility is unavailable due to outages or deratings. As an example, assume a generator has a seasonal net dependable capacity rating of 100 MW and an annual outage rate of 5%. For this example, the ICAP rating would be 100 MW and the UCAP rating would be 95 MW [100 MW x (1 – 5%)]. As the Olson Report fairly notes, "ICAP or UCAP [Planning Reserve Margins] are simply accounting conventions, so each can accurately quantify the required reserve margin to meet a reliability threshold." [230]

The 17% reserve margin resulting from the Resource Adequacy Studies and used in the 2020 IRPs reflects the installed capacity of the resource or in RTO terms used ICAP accounting. DEC and DEP have consistently used the ICAP accounting methodological approach in both North Carolina and South Carolina IRPs for many years. Importantly, as

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[229] Initial Comments of NCSEA and CCEBA, at 36.
[230] NCSEA/CCEBA Initial Comments, Exhibit 2 at 16.

seen in the recent ERCOT reliability event, the forced outage rate of a unit can vary from annual averages. As explained in the Companies' resource adequacy studies, the variable nature of outages is dynamically captured in the loss of load analysis rather than an after the fact accounting adjustment.

It is necessary to calculate ELCC values for non-dispatchable and energy limited resources to properly account for the reliability impact of these resource in the IRP process. However, contrary to NCSEA and CCEBA claims that "Duke assumed 100% availability of fossil fuel generation – thus *excluding forced outages* – while utilizing ELCC for solar – a measure that *includes such outages,*"[231] the Companies note that the solar and storage capacity value studies conducted by Astrapé <u>did not</u> include forced outages for these resources in determination of the ELCC values. In effect, solar and storage ELCC values slightly overstate the true capacity value of these resources since outage rates were not included in the determination of ELCC. Thus, the Companies' ICAP accounting process treats all resources equitably since outage rates are not included for any resource in capacity accounting. Further, to only discount the capacity of dispatchable resources in the capacity expansion process (i.e., UCAP accounting) would unfairly disadvantage dispatchable resources given that solar and storage ELCCs have not been reduced by an outage rate.

As noted by the E3 Report, use of a UCAP planning reserve margin would require a significant redesign of the current planning reserve margin process.[232] While some RTO's use UCAP accounting, ICAP is the consistent accounting method used by Southeast utilities. The Companies ICAP approach is consistent with past IRPs and neither the Public Staff nor the NCUC have objected to this approach. The Companies believe that the current

[231] *Id*. at 36.
[232] NCSEA/CCEBA Initial Comments, Exhibit 2 at 35.

capacity accounting process treats all resource types fairly and converting to UCAP accounting would have little impact on the expansion plan and the selection of resources. E3's criticisms of the Companies ICAP accounting are not supported in fact and should be rejected.

XI. Solar as a Resource in 2020 IRPs

A. Solar Modeling Assumptions.

1. DEC/DEP Agree to Public Staff's Recommendation to Present More Detailed Analysis of Solar Capacity Factors and Operating Assumptions in Next IRP.

The Public Staff recommends that the Companies provide a more detailed analysis of proposed solar capacity factors in its next IRP, since limited knowledge of capacity factors exists for solar with tracking and onshore wind in the Carolinas.[233] The Companies are planning to evaluate capacity factor assumptions for solar resources in preparation for the 2022 Comprehensive IRP filing. Additionally, the Companies are evaluating options for improving onshore Carolina wind capacity factor assumptions, and expect to incorporate at least some of those improvements in the 2021 IRP Update filing.

2. Interconnection limits and importance of planning for real world conditions.

The SEIA Lucas Report sponsored by NCSEA/CCEBA takes issue with the Companies' 500 MW solar interconnection limit and recommends that "Duke should remove the 500 MW limit from its Base Case and instead model the higher 900 MW limit from its high renewables sensitivity."[234] The AGO similarly comments that "[t]he base cases in the 2020 IRPs assume what appear to be rather low amounts of annual solar and

[233] Public Staff Initial Comments, at 98.
[234] NCSEA/CCEBA Initial Comments Exhibit 3, SEIA Lucas Report at 34.

wind interconnections. These assumptions appear to be based on wind and solar's historic deployment rates. However, Duke has not provided sufficient justification as to why these rates would persist for the entire planning period."[235]

In response to the AGO's request for further justification the Companies are attaching Public Staff Data Request 17-10, included as Attachment 4 to these Reply Comments. As explained in more detail in that response, due to timing and physical constraints, there is a limitation on the amount of new generation that can be interconnected to the Companies' systems each year. The process through which new requests to interconnect to the Companies' systems and the studies that evaluate the potential interconnection is time consuming and complex. The complexity and time required only increase as more generation is added to the distribution and transmission systems. Today, significant portions of the DEC and DEP systems are identified as "constrained," meaning that significant transmission upgrades are required in order to add additional generation. Once the interconnection study process is complete, the construction of the network upgrades is dependent on a number of factors, including: other work taking place on the transmission system (*i.e.* customer connections, maintenance, other interconnection construction and general transmission projects), generator outages which can change power flows on the system, and projected energy demand on the system. Generally, over the course of the year there are only about 24 weeks (during the shoulder months) when transmission outages can take place.

The 500 MW constraint is also fully consistent with the average number of megawatts interconnected each year from 2014-2019, a period during which the Company

[235] AGO Initial Comments at 27.

completed nation-leading amounts of solar projects. While the Companies did interconnect 744 MW in 2017, only 556 MW were interconnected in 2018 and 267 MW were interconnected in 2019. The average over the time period was 527 MW. Given the saturation of solar on the DEC and DEP systems, maintaining the pace of interconnecting new solar at the rate of the 2017 time period will be challenging. This is evidenced further by the fact that the Companies interconnected only 320 MW in 2020. For the period 2014-2020, the Companies historical average experience is even closer to 500 MW at 497 MW.

NCSEA/CCEBA also suggest that a significantly higher interconnection limit should be feasible due to "the reforms made to Duke's interconnection process."[236] The Companies' "queue reform" effort, which was recently approved by the Commission, will allow for "cluster studies" of groups of projects seeking interconnection to the Companies' system. These changes to the manner in which proposed generators are studied should improve the efficiency of transmission impact studies by eliminating the sequential method that projects are currently studied under and spreading the costs of larger upgrades across multiple projects. However, that will not change the fact substantial portions of the system have little or no remaining capacity and therefore require substantial upgrades, that larger projects can lead to more complex interconnection solutions on the system with more network upgrades required; and, that in many cases, future projects will be sited further from that infrastructure, potentially requiring more time consuming right-of-way acquisition and more complex projects just to reach the existing transmission infrastructure. Thus, queue reform alone is not enough to increase the amount of new solar capacity that can actually be installed and interconnected to the system in a given year.

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[236] NCSEA/CCEBA Initial Comments at 16.

Additionally, it is important to note that interconnection constraints in the 2020 IRP were not limited to solar resources. Combustion Turbines (CTs) were limited to five 457 MW units, and Combined Cycles (CCs) were limited to two 1,224 MW units in both DEC and DEP in any given year. Given the lack of experience with wind energy in the Carolinas, onshore Carolinas wind resources were also limited to 150 MW in each jurisdiction annually.

While it is true that in order to meet various climate goals, interconnection of solar and other renewable capacity will need to increase, for base planning assumptions, the 500 MW constraint is prudent and reasonable at this time. The Companies will continue to evaluate interconnection constraints for all resources and will update those constraints as efforts to increase the efficiencies of interconnections evolve over time.

Finally, with respect to interconnection constraints assumed in other "studies," the "much higher limits . . . rising to 1,800 MW" used in the Synapse Report appears arbitrary, without any identifiable basis. NCSEA/CCEBA's assertion that Synapse's study presents a "reasonable and feasible schedule of deployment" is unsupported and seemingly baseless.[237]

3. The 2020 IRPs solar technology assumptions were reasonable and the Companies will update these assumptions for future IRPs.

The E3 Report sponsored by NCSEA/CCEBA recommends that the Companies "[a]ssume all new utility scale solar to be built in the future uses single-axis tracking."[238] The E3 Report suggests that "Duke's assumption of fixed-tilt solar instead of tracking diminishes

[237] NCSEA/CCEBA Initial Comments at 16.
[238] NCSEA/CCEBA Initial Comments, Exhibit 2 at 5.

the capacity value of solar. Currently, nearly all the utility scale solar being built in the US is tracking solar which has improved ELCCs due to its ability to track the sun."[239] Additionally, the AGO suggests that, "Duke's failure to reconsider these problematic assumptions and account for newer solar technologies like solar tracking systems in its IRPs starkly contrasts with Duke Energy's embrace of green hydrogen and other more exotic technologies."[240]

In response to these criticisms, the Companies note that they modeled combinations of fixed tilt and single-axis tracking ("SAT") solar facilities to develop the projected portfolio of solar resources that would be installed on DEC's and DEP's systems in the future. The assumptions were reasonably developed based on projects operating on the Companies' systems at the time inputs to the IRP were being developed, as well as, results from CPRE Tranche 1, which gave insight to the types of facilities developers were actually designing in the Carolinas. In both DEP and DEC, the vast majority of installed solar MWs, which are primarily PURPA sourced solar assets, are fixed tilt solar facilities. For future standalone solar, whether that is future solar associated with HB 589 programs or economically selected solar, the Companies assumed 60% of the MWs would be single-axis tracking solar and 40% of the MW would be fixed tilt solar based on the results of CPRE Tranche 1. As shown in Figure 12 below, the Companies' include six different categories of solar to represent the types of facilities that are existing and projected to come on to the system in the future. Figures 12, 13, and 14 below show those types of solar on the DEP and DEC systems at the end of 2020 and projections of the types of solar to be added in the future.

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[239] NCSEA/CCEBA Initial Comments, Exhibit 2 at 4.
[240] AGO Initial Comments at 28.

Figure 12: Categories of Solar Included in 2020 IRPs

	% Fixed Tilt	% Tracking
Third Party Non-Curtailable	100%	0%
Third Party Curtailable	95%	5%
Utility Owned	92%	8%
HB589 and Future	40%	60%
CPRE S+S	0%	100%
Future S+S	50%	50%

Figure 13: Categories of Solar Projected on DEP System in 2020 IRPs

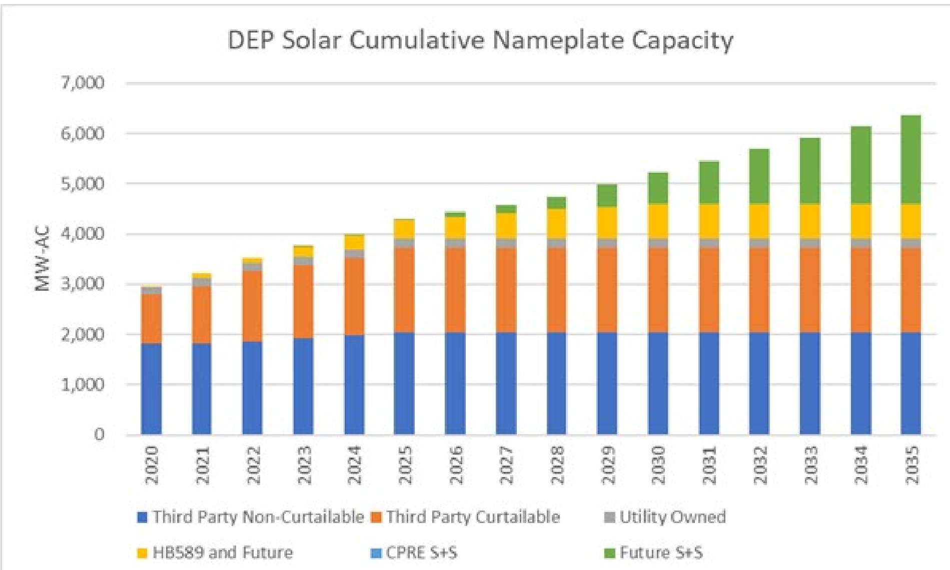
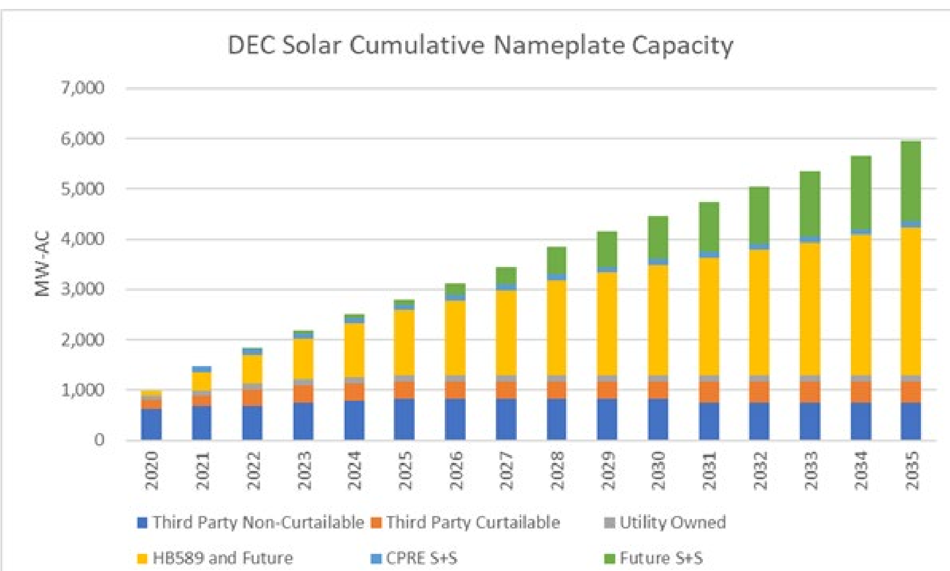


Figure 14: Categories of Solar Projected on DEC System in 2020 IRP



The assumption that future solar would be 60% Tracking and 40% Fixed Tilt is based on the information available at the time the IRP was developed. At that time, the results from CPRE Tranche 1 showed that approximately 60% of standalone solar projects were single-axis tracking projects, while the remaining 40% of projects were fixed tilt. After filing the IRP, the results of CPRE Tranche 2 became known and 100% of solar projects were designed as single-axis tracking projects.

The SEIA Lucas Report recommends that "Duke should update several of its assumptions related to system mix. It is clearly not the case that 100% of PURPA projects are currently, or will be always in the future, fixed-tilt. Duke should perform an analysis on its current PURPA fleet to determine the actual mix of fixed-tilt and single-axis tracking projects and use these in its baseline assumptions."[241] As stated above, the vast majority of installed solar MWs, which are primarily PURPA sourced solar assets, are fixed tilt solar facilities. As the existing solar fleet evolves, the assumption of fixed tilt versus single axis tracking systems on the Duke system will also be updated in future IRPs.

For example, in the 2021 IRP Update, the Companies will reflect 100% single-axis tracking for all new solar including Tranche 2 CPRE projects and economically selected solar. However, for purposes of the 2020 IRP, the assumption that 100% of existing solar assets are fixed-tilt was reasonable. Additionally, those existing facilities are not expected to change from fixed-tilt to tracking. The Companies will continue to evaluate the type of solar configurations that PURPA facilities are using and make adjustments to their assumptions based on this information in future IRPs.

[241] NCSEA/CCEBA Initial Comments, Exhibit 3 at 34.

It is also notable that the relative impact of modifying the percentage of fixed versus tracking solar assumption in terms of the value provided by standalone solar facilities is not significant. Based on the results of the 2018 Solar ELCC study, and the assumed blend of fixed tilt and single axis tracking solar resources, incremental new solar, reflected by the yellow "HB589 and Future" blocks in the charts above, was assumed to provide 1% of its nameplate capacity towards meeting winter peak demand. Importantly, had the Company assumed that incremental new solar was 100% single axis tracking, the contribution to winter peak demand would have only increased from 1% to 3% of nameplate capacity. Putting those values into perspective, the impact in DEP would have been to increase the capacity value of the approximately 600 MW of incremental standalone solar from 6 MW under the IRP assumptions to 18 MW in the alternative case. In DEC, the capacity value of approximately 3,000 MW of incremental new standalone solar would have increased from 30 MW to 90 MW.

B. Solar Cost Assumptions.

1. The Companies plan to incorporate the December 2020 Solar ITC Extension in Future IRPs.

The SEIA Lucas Report comments that the Companies "capital cost assumptions for solar are reasonable."[242] However, SEIA's solar policy advocate, Mr. Lucas, also asserts that "[t]he Commission should direct Duke to update its modeling to reflect the new reality of the federal ITC extension and safe harbor provisions."[243] The Companies agree that the legislation passed by Congress in December 2020 that extended the solar

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[242] NCSEA/CCEBA Initial Comments, Exhibit 3 at 34.
[243] *Id.* at 18.

Investment Tax Credit stepdown by two years and extended "safe harbor" provisions for projects in-service by the end of 2025 should be included in the 2021 IRP Update.

2. Solar FOM Assumptions.

While the SEIA Lucas Report determined that DEC's and DEP's capacity cost assumptions for solar resources are reasonable, the author also claims that the Companies' solar fixed operations and maintenance ("FOM") costs are too high.[244] SEIA recommends that since the Companies' PV Solar capital costs are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** lower than the NREL ATB Moderate PV Solar capital costs, then the Companies should use a similar discount for FOM costs.[245] While it is true that the Companies' solar capital cost projections are approximately 20% less than the NREL ATB Moderate case, this fact is only coincidental. The Companies did not develop their capital costs to be intentionally 20% less than NREL ATB Moderate case. To the contrary, the Companies' solar costs are specifically developed to represent the cost to construct and operate a solar facility in the Carolinas. To apply a 20% reduction to the NREL ATB fixed O&M costs, as recommended by the SEIA Lucas Report, merely because the Companies' solar capital costs were 20% below NREL would result in fixed O&M costs that are not representative of forecasted fixed O&M costs in the Carolinas. Accordingly, this recommendation should be rejected.

C. The Companies Highlight the Critical Importance of Analyzing and Planning for Real World Conditions in the Carolinas in Evaluating Solar as a Capacity Resource.

The Companies' 2020 IRPs demonstrate DEC's and DEP's plans to add significant incremental solar capacity over the 15-year planning period. When evaluating solar as a

[244] NCSEA/CCEBA Initial Comments, Exhibit 3 at 19.
[245] NCSEA/CCEBA Initial Comments, Exhibit 3 at 20.

resource option, the Companies evaluate both the risks and operational limitations of this technology as well as the benefits of increasing clean energy to serve customers in North Carolina. The Companies view solar as an important resource in meeting its carbon reduction goals, and the Companies recognize the significant support that customers and communities from Asheville to Charlotte to Raleigh have identified for integrating solar as a major component of future resource plans. Intervenors including the AGO, the Tech Customers, NCSEA/CCEBA, and NC WARN/CBD all advocate for the Commission to assume the most aggressive assumptions for the resource planning value of solar to be achieved at the least cost.

While there is significant support for expanding solar, it is important to note that DEC and DEP are the only entities in these dockets with the privilege and obligation to provide adequate, safe, and reliable service to our customers now and in the future. As the NERC President and CEO, Mr. James Robb, recently highlighted for Congress, "[i]t is imperative to understand and plan for the different operating characteristics of variable, inverter-based resources [which] includes time to study, plan for, and develop effective solutions to the challenges."[246] Consistent with Mr. Robb's comments, it is critical for the Companies and the Commission to undertake a technically objective and holistic assessment of the value of solar and to analyze and plan for real world conditions in the Carolinas.

For example, the Companies must plan for the operational realities of solar output in the Carolinas, especially during winter peak periods when DEC and DEP have greatest loss of load risk. Figures 15 and 16 highlight realized winter solar output from installed

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[246] Attachment 2, NERC Robb March 11, 2021 Testimony to Congress at 9.

solar facilities in the DEP Balancing Authority in North Carolina and South Carolina during two recent seven-day periods in winter 2020/2021. Importantly, these figures demonstrate that weather in the Companies' Balancing Authorities can lead to several consecutive days of low irradiance, resulting in extremely low capacity factors for solar output. These low capacity factors would result in insufficient energy to reliably serve customer demand especially if this solar output is the energy also being depended on for charging battery storage resources to provide dispatchable capacity. The capacity factor of the solar fleets interconnected in DEP for the seven consecutive days in February 2021 represented in Figure 5 (Feb. 9 – Feb 15) was only 6.06% and only 3.44% for five consecutive days (Feb. 11 – Feb 15).

Figure 15: DEP Low Solar Capacity Factor 7-Day Period

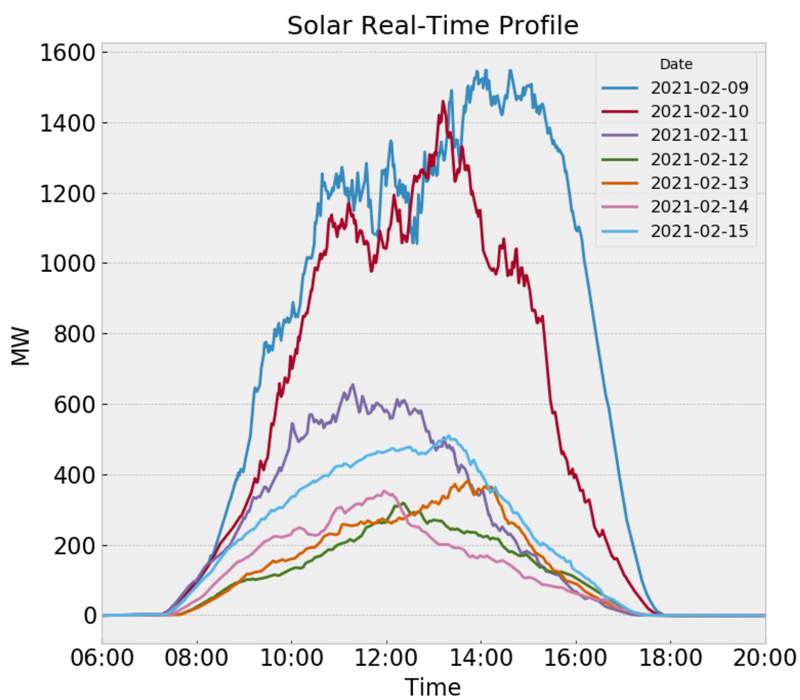
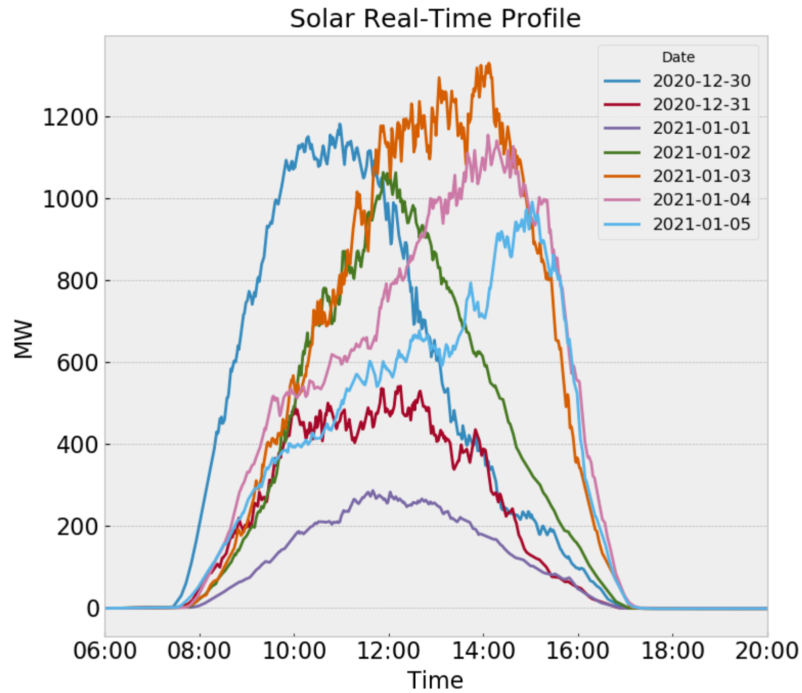


Figure 16: DEP Low Solar Capacity Factor 7-Day Period

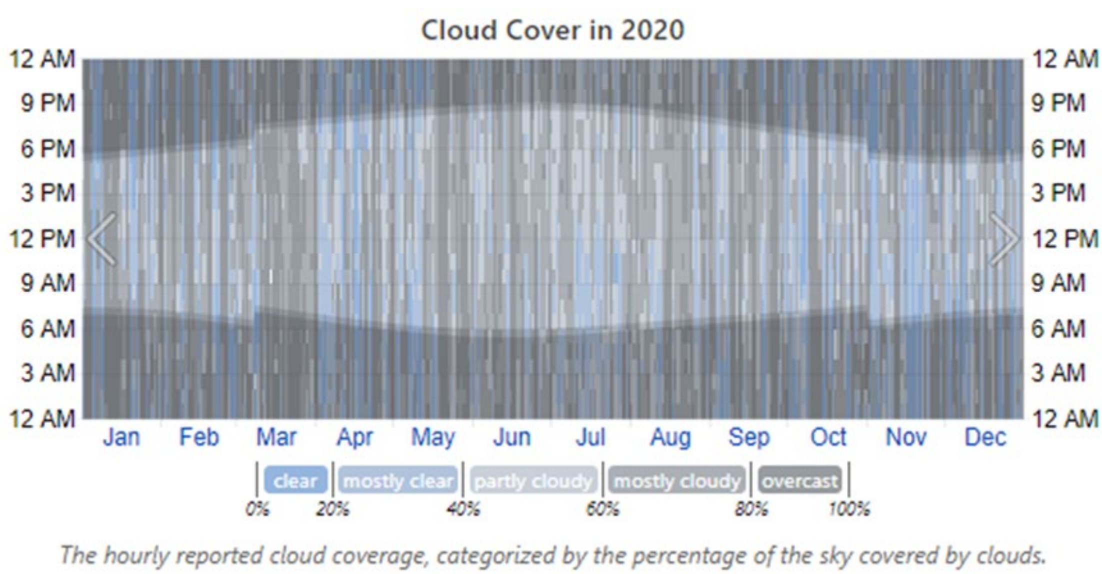


These figures highlight the real world uncertainty of solar production from day to day and week to week. Without adequate time to study, plan for, and develop effective solutions to the challenges, counting on solar production for serving customers' electric demand and for charging battery storage should be approached with caution and overreliance on these technologies could jeopardize DEC's and DEP's ability to provide reliable electric service to its customers. Similarly, overreliance on solar plus battery storage, such as suggested in the Synapse Report addressed in Section XVI. of these Reply Comments, would present reliability challenges in the Carolinas for serving winter peak demand.

Another operational reality in the Carolinas is cloud cover. The AGO emphasizes that assumptions around whether solar can serve peak demand should be revisited and that lessons learned through operational experience in other regions, such as ERCOT, should be evaluated and applied in North Carolina.[247] The Companies agree that this makes sense; however, it is also important to focus on DEC's and DEP's real world operational experience integrating solar on cloudy days in the Carolinas in evaluating whether solar can serve peak demand.

Cloud cover data, which is directly correlated with the amount of solar irradiance available as the fuel for solar panels to generate output, reflects the day-to-day, week-to-week variability, and the unreliable nature of solar output in the Carolinas. Figure 17 and Figure 18 reflect the 2020 cloud cover for Raleigh, North Carolina and Columbia, South Carolina. These cloud cover charts reflect the volatile nature of irradiance in the Carolinas. In contrast, Figure 19 presents the cloud cover in Las Vegas, Nevada where realized solar capacity factors are much higher and solar output is more predictable and dependable from day-to-day, week-to-week.

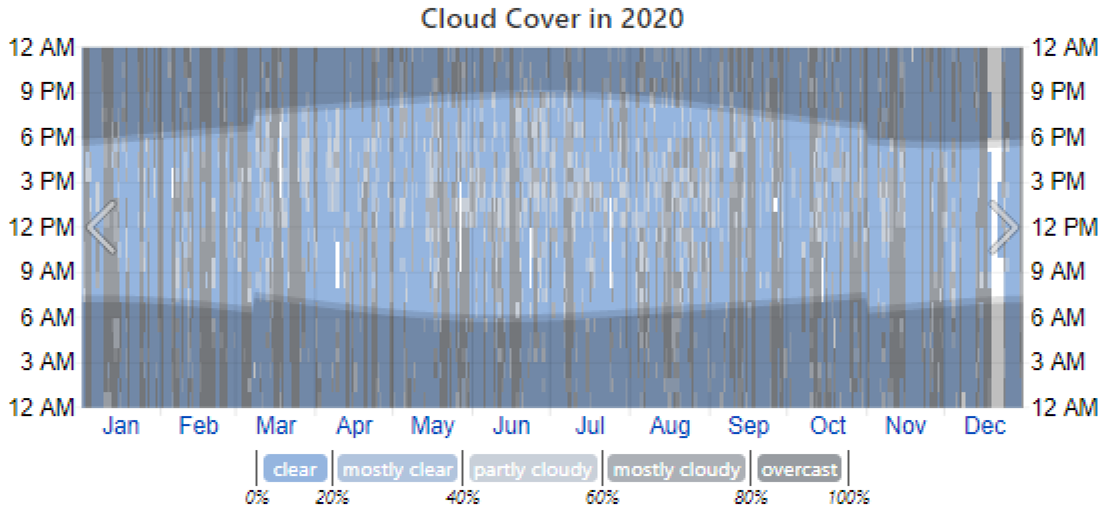
Figure 17: Raleigh, NC 2020 Cloud Cover[248]



[247] AGO Initial Comments, at 23-24.

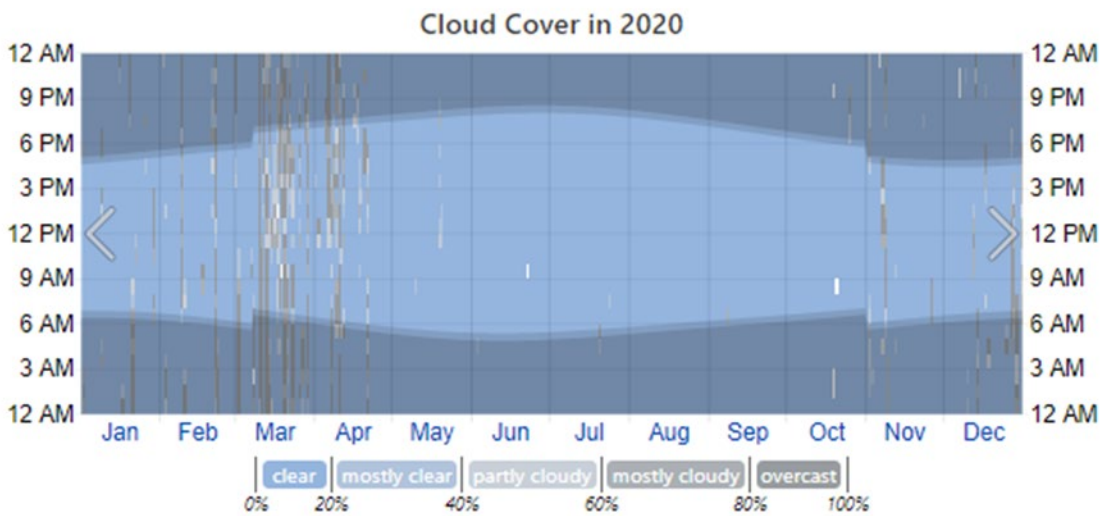
[248] Historical Weather during 2020 at Raleigh-Durham International Airport, North Carolina, United States - Weather Spark, https://weatherspark.com/h/y/146992/2020/Historical-Weather-during-2020-at-Raleigh-Durham-International-Airport-North-Carolina-United-States.

Figure 18: Columbia, SC 2020 Cloud Cover[249]



The hourly reported cloud coverage, categorized by the percentage of the sky covered by clouds.

Figure 19: Las Vegas, NV 2020 Cloud Cover[250]



The hourly reported cloud coverage, categorized by the percentage of the sky covered by clouds.

[249] Historical Weather during 2020 at Columbia Owens Downtown Airport, South Carolina, United States - Weather Spark, https://weatherspark.com/h/y/146892/2020/Historical-Weather-during-2020-at-Columbia-Owens-Downtown-Airport-South-Carolina-United-States.

[250] Historical Weather during 2020 at North Las Vegas Air Terminal, Nevada, United States - Weather Spark, https://weatherspark.com/h/y/145434/2020/Historical-Weather-during-2020-at-North-Las-Vegas-Air-Terminal-Nevada-United-States.

The key point is that DEC's and DEP's real world operational experience in the Carolinas should be given greater weight than studies based on national assumptions and operational experience in other parts of the Country.

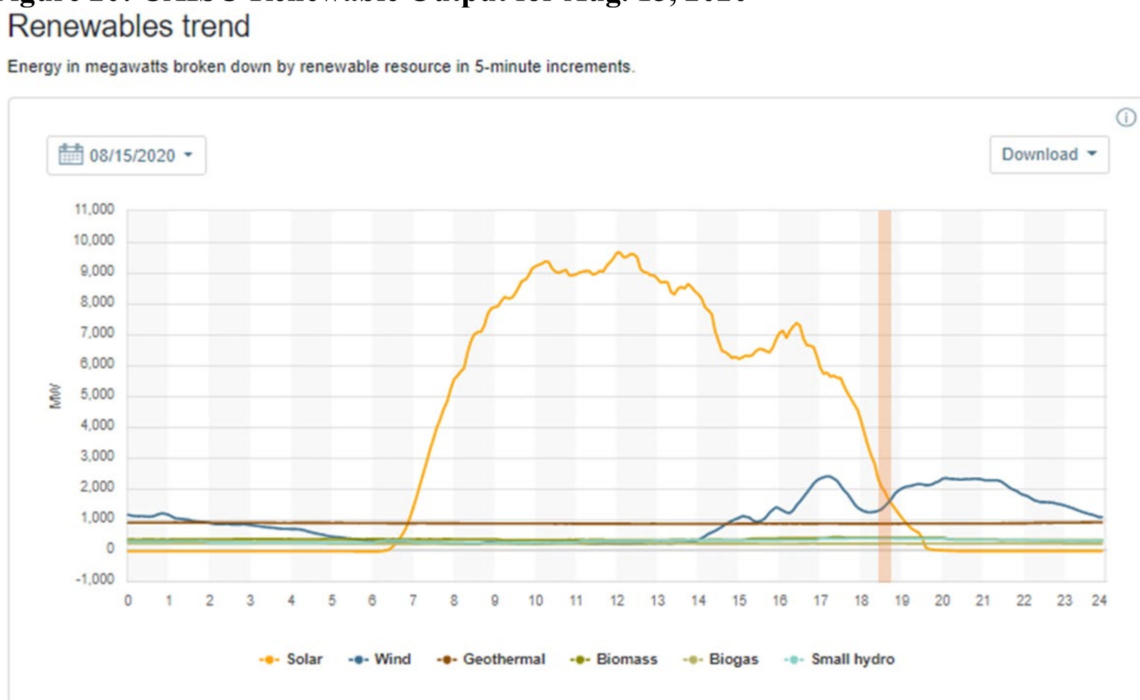
This is not to say that operational experience in other parts of the Country is not valuable to provide lessons learned as the AGO points out. Even in areas of California that experience some of the highest irradiance in the U.S., afternoon cloud cover and its impacts on solar production were mentioned in the root cause analysis report as a contributing cause of the August 15, 2020 rotating blackouts that occurred between 6:28 and 6:48 PM PST.

> In addition, solar generation was reduced by high clouds from a storm covering large parts of California on August 15 and smoke from active fires on both days. Wind generation was impacted by storm patterns through the peak and net demand peak period on August 15, which caused a decline in actual production of 1,200 MW between 5:12 p.m. and 6:12 p.m. before increasing again closer to 7:00 p.m.[251]

Figure 20 shows the variability of solar and wind resources in the CAISO on August 15, 2020.

[251] *See* California ISO, Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave, at 50 (Jan. 13, 2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

Figure 20: CAISO Renewable Output for Aug. 15, 2020[252]



Again, the key point is that the Commission must undertake a technically objective and holistic approach to assessing the capacity value of solar, as well as all other resource options identified in the 2020 IRPs, and results-oriented analyses and assumptions—like the Synapse Report discussed in Section XVI. of these Reply Comments—will create power system reliability risk for customers.

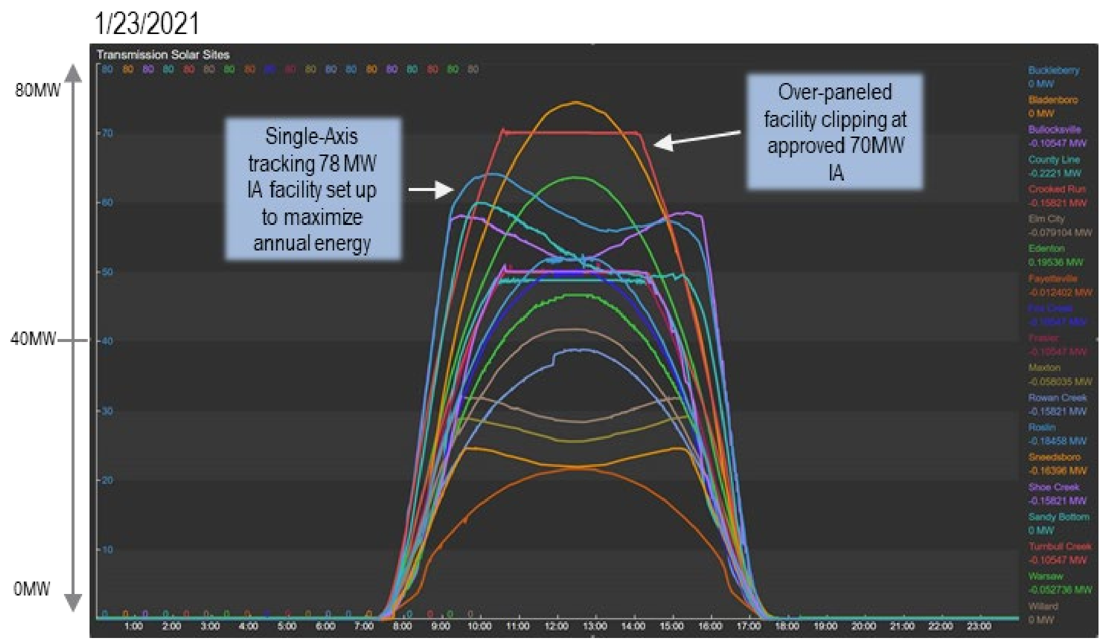
A third consideration in placing greater weight on the Companies' real world operational experience in the resource planning process can be demonstrated by considering design specifications for solar facilities in the Carolinas. For example NCSEA/CCEBA's SEIA Lucas Report, states that "[f]or larger [solar] systems that are being built to meet Duke's "designated" and "mandated" programs, Duke should assume that 100% of future builds will be single-axis trackers. The cost premium of tracking

[252] *See* California ISO, Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave, at 50 (Jan. 13, 2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf. CONFIRM WITH SAMMY

systems has declined over time, and as shown by the market evolution, the additional energy and capacity benefits that come from trackers more than compensates for the price premium." What is notable about this statement from a resource planning and system operations-perspective is that the "additional energy and capacity benefits" to the project owner justifying the investment decision to install a single axis tracking system may not translate into significant incremental capacity value for customers during the winter morning periods when the Companies have the greatest loss of load risk and capacity need. As noted above in Section XI. C., solar's contribution to winter peak demand increases from 1% for fixed tilt solar to 3% for single-axis tracking solar due to the ability of north-south axis tracking solar which tilts easterly during the winter peak hour to catch the early morning rising sun.

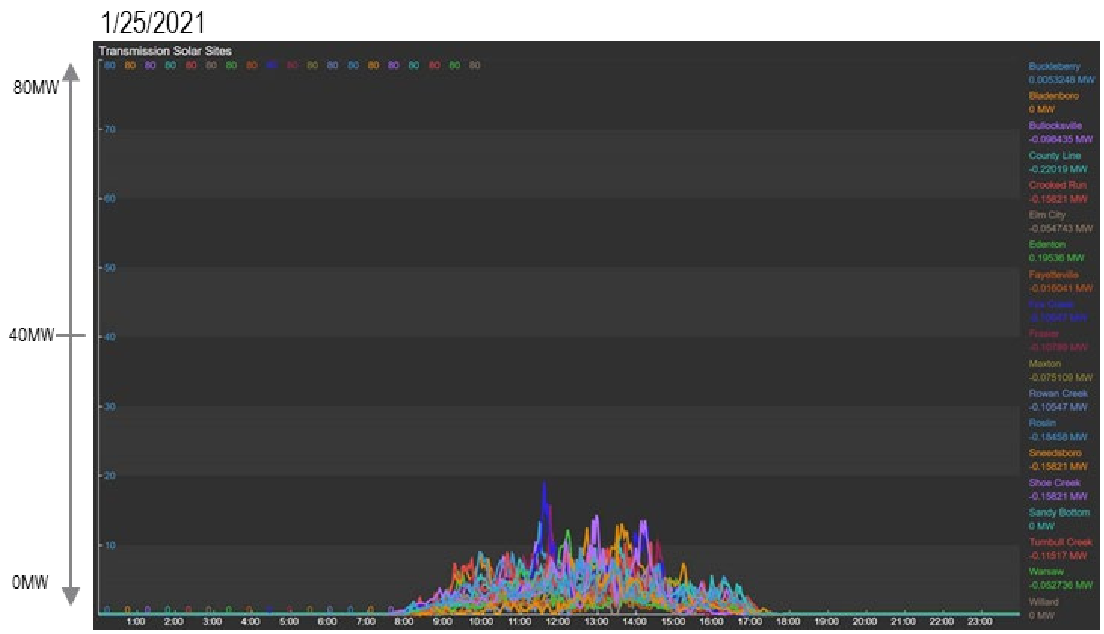
Based on the Companies' experience with transmission connected fixed tilt and single axis tracking solar facilities, the SEIA Lucas Report is correct that the annual energy from north-south oriented single-axis tracking facilities is greater on average as compared to fixed tilt facilities. However, if comparing these types of solar facilities for winter peak capacity value in combination with battery storage, the less expensive fixed tilt solar facilities provide just as much winter peaking capacity value in combination with battery storage. Figure 21 reflects the output curves of the transmission connected solar facilities on the DEP system for a blue-sky day. The average capacity factor data for these fixed tilt solar and single axis tracking solar facilities in the DEP area is 16% and 15%-16%, respectively, for the winter months of January and February as compared with 25%-29% and 28% - 31%, respectively, for the summer months of June through August. Thus, in the winter months of January and February when DEP has the greatest need for incremental capacity, from a solar capacity factor consideration for charging battery storage, fixed tilt is just as good an option as single axis tracking. This result is due to installing a solar facility with a north-south axis tracking system designed to maximize annual energy while providing a similar capacity factor (soufflé-shaped output) as compared with fixed tilt solar facilities during the winter months.

Figure 21: DEP Transmission-connected Solar Facility Output Curves for Blue-sky Day (Jan 23, 2021)



It also must be noted that solar facilities in the Carolinas, whether fixed tilt or single axis tracking, have substantial risks if being relied upon for winter capacity and energy with or without complementary battery storage. Figure 22 below shows the same group of transmission connected solar facilities on the DEP system on a cloudy, rainy winter day.

Figure 22: DEP Transmission-connected Solar Facility Output Curves for Cloudy, Rainy Winter Day (Jan 25, 2021)



As these figures demonstrate, the Companies' real world operating experience integrating solar in the Carolinas must inform a technically objective assessment of a resource that provides substantial energy value during the summer but has limited, variable and intermittent fuel and, as a result, has limited capacity value during the winter. As a zero carbon resource, solar can help the Companies achieve carbon reduction goals and when complemented with storage, solar plus storage does have capacity value for serving peak demand periods. However, as demonstrated in Figures 15, 16, and 22, there are days, consecutive days, and even 7-day periods during the winter when solar capacity factors are low. This risk needs to be objectively and adequately considered in resource planning if solar is the energy source being depended on for charging battery storage. Furthermore, if taken to an extreme, as is the case with the results-oriented Synapse Report, over-reliance on solar plus battery storage as a capacity resource will lead to unnecessary reliability challenges and a higher loss of load risk for DEC and DEP customers.

XII. Battery Storage as a Resource in the 2020 IRPs

A. Battery Storage System Cost Assumptions

1. Battery Storage Capital Costs

The Public Staff did not dispute or specifically address the Companies' battery storage cost assumptions in their initial comments. However, the SEIA Lucas Report sponsored by NCSEA/CCEBA claims that the Companies' "storage cost and operational assumptions are inappropriate," and recommends the Companies base its battery costs on NREL's ATB Advanced scenario.[253] With further analysis into NREL's ATB's cost projection, and reviewing additional industry sources, it is clear that this is not the case.

The SEIA Lucas Report primarily focuses NREL's ATB storage costs in an attempt to invalidate the Companies' battery storage cost assumptions. NREL's 2020 Battery Report Figure 4,[254] which is included as Figure 23 below, shows the variety of starting points for battery storage costs from industry sources that NREL considered in developing the NREL ATB cost estimates, represented in 2019 $/kWh costs. The solid blue line has been added to represent the Companies' 2020 IRP battery cost starting point, but increased to a 2019 starting point consistent with NREL's methodology.[255]

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[253] NCSEA/CCEBA Initial Comments, Exhibit 3 SEIA Lucas Report at 24.
[254] NREL Battery Storage 2020 Update at 8.
[255] The NREL Battery Storage 2020 Update states that "If a publication began its projections after 2019, the 2019 value was estimated using linear extrapolation from the nearest value. For example, if the 2020 price was $500/kWh and the 2021 price was $480/kWh, then the 2019 price was assumed to be $520/kWh." Similarly, to come up with a comparable number, the Companies linearly extrapolated the represented 2019 battery cost using the 2020 IRP assumptions for battery costs in 2020 and 2021.

Figure 23: Comparison of DEC/DEP 2020 IRP Battery Costs to Published Resources Using NREL Methodology

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The green triangle in the figure represents NREL's starting point for its cost projections. As shown in the figure, the Companies' starting point for battery storage costs is squarely within the range of published resources such as Wood Mackenzie and NIPSCO and at the very top end of the EPRI range.

It is also important to highlight that NREL developed its starting point battery cost and "assess[ed] the quality of [their] starting point,"[256] by comparing their costs to published resources as shown above. As utilities look for opportunities to maximize the benefits of batteries, costs are becoming more use-case specific, and it is becoming increasingly difficult to rely on published resources to justify battery costs for long-term planning purposes. The NREL 2020 Battery Report highlights this very point, stating:

256 NREL 2020 Battery Storage 2020 Update, at 7.

> There are a number of challenges inherent in developing cost and performance projections based on published values. First among those is that the definition of the published values is not always clear. For example, dollar year, duration, depth-of-discharge, lifetime, and O&M are not always defined in the same way (or even defined at all) for a given set of values. As such, some of the values presented here required interpretation from the sources specified. Second, many of the published values compare their published projection against projections produced by others, and it is unclear how much the projections rely upon one-another. Thus, if one projection is used to inform another, that projection might artificially bias our results (toward that particular projection) more than others. Third, because of the relatively limited dataset for actual battery systems and the rapidly changing costs, it is not clear how different battery projections should be weighted. with something here. [257]

This helpful explanation emphasizes precisely why one cannot simply compare the Companies' battery storage costs to the NREL ATB or any other generic industry publication and accurately conclude that the Companies' battery costs are high.

It is also important to understand that the battery the Companies include in the IRP is designed to meet both the current and potential operating requirements that may be placed on battery storage. For this reason, the battery is designed to be flexible, reliable and safe to operate. It is likely that at least some of the batteries for which public costs are provided meet the Companies' requirements, while some of the batteries for which public cost are provided would not be robust enough to meet the needs of the Companies' system, and some may not even meet the basic requirements to interconnect to the system. Furthermore, some published resources may not properly include the cost impacts of Depth of Discharge (DoD) limitations that are required of some battery technologies to meet manufacturer warranty requirements. This point is further emphasized in the NREL 2020

[257] *Id. a*t 2

Battery Report, which states that the chart "demonstrate[s] that there is considerable uncertainty (+/- $100/kWh) in the current price of battery storage systems."[258]

To demonstrate the impact that design assumptions can have on battery costs, the Companies' used their third-party supplied battery cost model to adjust design requirements and develop cost projections based on those new design assumptions. Confidential Figure 24 below shows the impact of making the following adjustments to the design of the battery:

- Moving from controls that require real time optimization to controls that are based on pre-programmed commands.
- Moving from high quality HVAC and fire suppressions systems including back up power sourced from reputable vendors to standard systems that just meet the minimum necessary codes and standards.
- Moving from greenfield siting requiring new transmission or distribution interconnections to a brownfield site that does not require any interconnection.
- Removing costs associated with a DoD requirement.

[258] *Id. a*t 7

Figure 24: Redesigned DEC/DEP Battery Illustration

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[redacted]

[END CONFIDENTIAL]

As shown by the blue dashed line in Confidential Figure 25 below, if these adjustments were made to the design of the battery, it would align much closer to the starting cost of the NREL battery.

Figure 25: Comparison of DEC/DEP 2020 IRP Battery Costs, "Redesigned DEC/DEP Battery Costs," and Published Resources Using NREL Methodology

[BEGIN CONFIDENTIAL]

[redacted]

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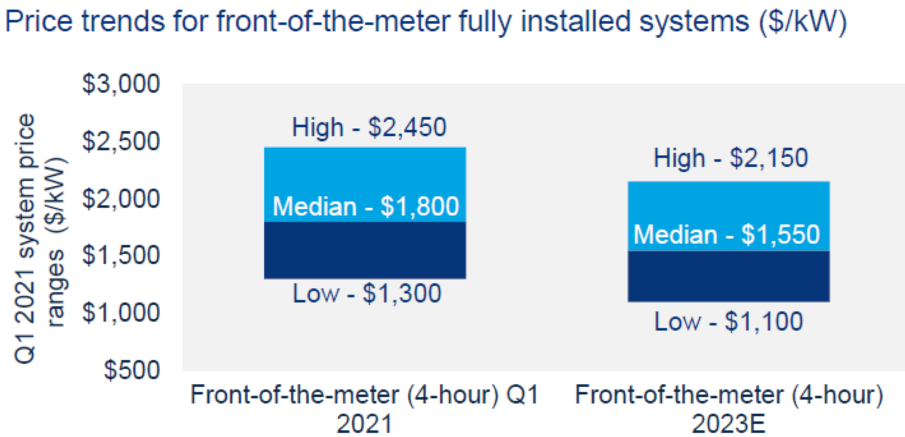
It is also worthwhile noting that the "Wood Mack" cost assumptions shown in the charts above were recently updated in Wood Mackenzie's "U.S. Energy Storage Monitor 2020 Year in Review." That report, which was co-authored with the U.S. Energy Storage Association ("ESA") includes the following Figure 26, which shows battery storage costs in Q1 2021 and estimated storage costs in 2023 that compare very favorably with the Companies 2021 assumption of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and the 2023 assumption, in real 2021 dollars, of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Figure 26: Wood Mackenzie Power & Renewables / ESA U.S. Energy Storage Monitor 2020 Year in Review: Front-of-the-meter Battery Storage Costs[259]



SEIA suggests that NREL's methodology for estimating battery storage cost projections limits the Companies' concern that part of the discrepancy between the Companies' figures and other benchmarks is due to the Companies battery degradation and depth of discharge assumptions.[260] SEIA then suggests that the Companies "erred in interpreting NREL's ATB battery cost methodology."[261] However, the SEIA Lucas Report is not correct in this assertion. While the SEIA Lucas Report correctly points out that NREL does normalize the published storage costs, NREL only normalizes those costs "to develop cost *projections*" as noted on page 2 of the NREL report. NREL *does not* normalize costs for the starting point of those cost projections.

Aside from the comparison to NREL's starting point assumptions, the Companies' cost declines are very similar to the NREL ATB Advanced case. From 2020 to 2029, the Companies' battery costs decline 34% while the ATB Advanced case declines 37%. The Companies' battery cost decline exceeds the NREL ATB Moderate case which only

[259] Wood Mackenzie Power & Renewables / ESA U.S. Energy Storage Monitor 2020 Year in Review: Front-of-the-meter Battery Storage Costs at 22
[260] NCSEA/CCEBA Initial Comments, Exhibit 3 SEIA Lucas Report at 21-22.
[261] *Id.* at 24.

declines 27%. As shown in Figure 27 below, which is Figure ES-1 in NREL's 2020 Battery Report, the mid or Moderate projections align with the median projections of the publications evaluated by NREL, while the low or Advanced projections track the most aggressive cost declines in those publications. Significantly, the Companies' cost projections are very well aligned with NREL's most aggressive cost projections through 2035.

Figure 27: Figure ES-1 from NREL's 2020 Battery Report Showing High, Mid, Low Battery Normalized Battery Costs Compared to Normalized Published Values and DEC/DEP's Normalized 2020 IRP Values

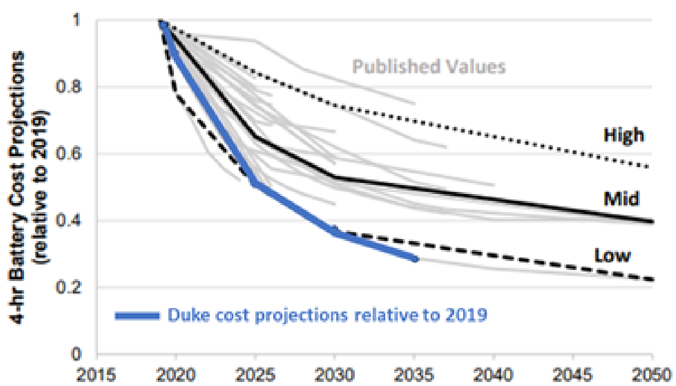


Figure ES-1. Battery cost projections for 4-hour lithium-ion systems, with values relative to 2019.
The high, mid, and low cost projections developed in this work are shown as the bolded lines.

NC WARN also presents a critique of the Companies battery storage costs that should be rejected. The Powers Report sponsored by NC WARN/CBD attempts to compare the cost of the Companies' batteries to that of a "survey of leading battery manufacturers" to show that battery storage costs today are already lower than the Companies' projections for battery storage costs in the 2027-2028 timeframe. However, NC WARN deceptively compares the cost assumptions of a fully installed battery storage system in 2027-2028 to just the battery pack and battery cell portion of a battery storage system today. This is an "apples-to-oranges" comparison and they neglect to include other significant costs such as power electronics, software and controls, systems integration, site installation costs, project development fees, owner's costs, and interconnection fees, all of which are included in the Companies' battery cost projections.

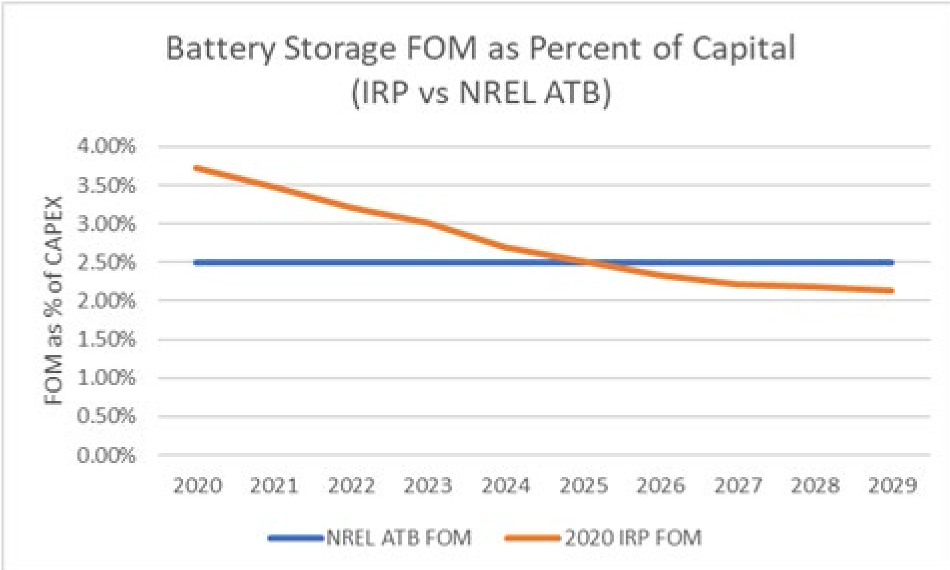
In sum, while the Companies firmly believe the battery energy storage capital cost assumptions used in the 2020 IRPs are appropriate for planning purposes at this time, the Companies are committed to continuing to evaluate these costs as battery storage technologies evolve.

2. The Companies plan to continue to review and refine their Battery Energy Storage fixed O&M Costs in future IRPs.

The SEIA Lucas Report also takes issue with the Companies' fixed O&M assumptions regarding standalone battery storage.[262] The Companies have identified a non-material issue with their standalone battery storage fixed O&M assumptions. Upon investigation, the Companies discovered that some aspects of regular fixed O&M unrelated to replenishment, were in fact included in the replenishment fixed O&M, thereby inflating the fixed O&M associated with standalone battery storage. The Companies will correct their fixed O&M assumptions in the upcoming 2021 IRP Update. Regardless, the discrepancy did not impact the analysis. While the fixed O&M assumptions were high early in the planning period, by 2030, those prices dropped by over 60%. In fact, NREL's assumptions, (across the advanced, moderate, and conservative cases) show that fixed O&M cost ($/kw-year) is 2.5% of the battery capital cost ($/kW). As shown in Figure 28 below, even with this discrepancy, the Companies' fixed O&M assumptions are lower than NREL's assumptions by 2026.

[262] NCSEA/CCEBA Initial Comments, Exhibit 3 SEIA Lucas Report at 22-23.

Figure 28: Comparison of DEC/DEP IRP Fixed O&M Cost to NREL ATB Fixed O&M Cost



In future IRPs, the Companies will adjust their FOM cost assumptions to ensure costs for replenishment are not "double counted" with normal FOM costs associated with day-to-day operation of the battery storage facilities.

3. The Companies solar plus storage capital and operating expenses are reasonable and will continue to be updated in future IRPs.

The SEIA Lucas Report raises several concerns with the Companies' assumptions of storage that is paired with solar.[263] The author takes issue with the Companies' assumption that standalone battery storage utilizes a replenishment strategy to manage battery degradation while the storage paired with solar utilizes an overbuild strategy. He also claims that the Companies "erroneously assume[s] that 100% of the battery pack must be replaced" midway through the life cycle of the solar asset. Finally, he falsely claims

[263] NCSEA/CCEBA Initial Comments, Exhibit 2 at 23-24.

that the Company uses different battery pack costs for standalone storage than for storage paired with solar.

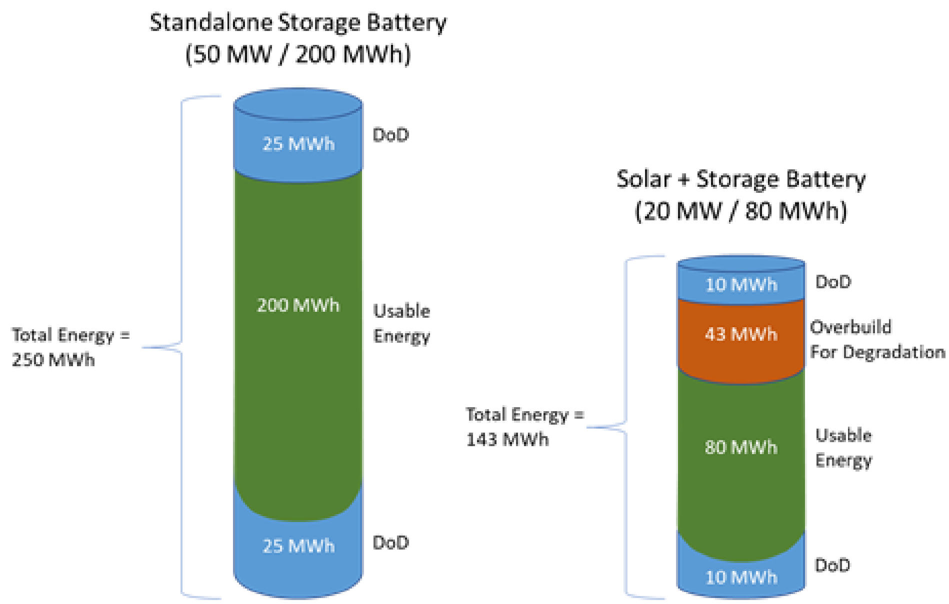
First, it is appropriate to assume two different methodologies for managing degradation of the battery asset under these use cases. In the IRP, the Companies assume solar assets have 30-year lives, while battery storage assets have 15-year lives. Over the life of a battery, the energy capacity of the battery cells degrade, and if nothing is done to account for that degradation, the battery will hold significantly less usable energy at year 15 than it did during year one. For standalone storage, the Companies account for degradation by "augmenting" the battery with additional battery cells at regular intervals to maintain the usable energy of the battery.

The alternative approach is to "overbuild" the battery so that as the battery cells degrade, the amount of usable energy in year 15 is the same as in year one. Because the life of a storage asset does not align with the life of the solar asset it is paired with, at some point during the life of the solar asset, certain components of the battery system, including the battery cells, must be replaced. While it may be appropriate to augment a battery over the 15-year life, there is risk that as battery technologies rapidly evolve, the ability to cost-effectively and reliably augment the battery may be challenged due to factors such as supply chain risk for equipment obsolescence, difficulty balancing the system state of health, and cell integration challenges. These risks would only increase if augmentation were assumed for maintaining a battery's energy capacity over a 30-year period. For this reason, the Companies elected to model the storage plus solar asset by initially overbuilding the battery at year one to achieve a 15-year operation, then replacing the battery cells and other battery components that are likely to be at or near end of life with another overbuilt battery to achieve another 15-years of operation.

Further, the Companies did not err in assuming the battery pack must be replaced midway through the life of the solar asset. Battery technology is still maturing relative to traditional grid infrastructure, and the Companies are not aware of any sufficiently reliable data that validates precisely how a utility scale battery energy storage system that is designed to match the life of a 30-year solar asset will operate when the battery is 15-years into its life cycle. But it is common for lithium-ion battery cells to require replacement after 10 to 15 years of operation depending on several factors including cycles per day, temperature conditions, and available energy requirements. The Companies' assumption that the battery pack must be replaced is a reasonable assumption given the still maturing state of utility scale battery technology.

Next, the Companies are not inconsistent in battery pack assumptions, and in fact, the SEIA Lucas Report makes a common mistake of comparing different battery energy capacities when comparing $/MWh costs of energy storage. Before explaining this error, the following simplistic graphic shows the difference between the standalone storage assumption and the solar + storage assumption for the battery asset.

Figure 29: Comparison of Standalone Storage and Solar + Storage Batteries in the 2020 IRP



The battery on the left in the figure is the Companies' assumption for standalone storage which is a 50 MW / 200 MWh asset. The battery on the right is the assumption for the storage asset that is paired with solar in a solar plus storage configuration. The standalone battery is larger and does not include overbuild, while the storage paired with solar does include overbuild.

The SEIA Lucas Report attempts to compare the battery pack prices between these two batteries in order to claim the Companies are using different battery pack prices. However, this analysis is flawed because the author did not conduct the comparison on an "apples to apples" basis. Figure 30 below summarizes the numbers presented in the Lucas Report[264], except the report did not calculate the standalone storage Usable Energy + DoD number in the analysis. The report simply stopped at the Usable Energy Basis for the standalone storage asset.

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[264] NCSEA/CCEBA Initial Comments, Exhibit 3 at 24.

Figure 30: SEIA Lucas Report Comparison of DEC/DEP Battery Pack Costs

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Without knowing anything else about the batteries, the only numbers that are truly comparable in the table are the Usable Energy + DoD number for the Standalone Storage asset and the Usable Energy + DoD + Overbuild number for the Solar + Storage Battery Pack because those numbers represent the battery pack cost based on the "Total Energy" of the battery, and as shown, those numbers are the same across the battery use cases. However, when comparing battery prices across literature, or between utilities, it is often not clear which cost is being represented. The Companies' represent their numbers on a Usable Energy Basis by dividing the total cost of the battery by the usable energy of the battery. Most publications do the same, but as shown above, that number does not tell the complete story. The SEIA Lucas Report's position on this issue provides a perfect example of this point when it states on page 24,

> Considering that Duke plans to initially install the 143 MWh battery for this [solar plus storage] project, it appears the lowest cost estimate is the most appropriate. However, that begs the question as to why the battery pack cost would be so much lower in this configuration than for a standalone storage project…

Had the author compared the two batteries on the same basis, then he would have realized that the Companies are in fact using the same battery pack prices across the battery use cases.

4. The IRPs' identified concerns about limited battery storage operating experience & supply chain risks are reasonable for planning purposes.

On page 2 of NC WARN/CBD's Powers' Report, NCWARN claims that because Wood Mackenzie estimates that US energy storage deployments will reach almost 7.5 GW annually in 2025 that the Companies' concerns with supply issues of battery storage and the fact that the electric utility industry has little meaningful experience with batteries is "unsupported." However, NC WARN fails to point out several factors in Figure 1 of the Powers report:

1) Of the 1,275 MW of storage estimated to be installed in 2020, only approximately 1,000 MW is front of the meter (FTM) or utility scale storage. Later in that same Wood Mackenzie report on page 48, Wood Mackenzie shows that the vast majority of those MW are installed in California.

2) The average duration of storage estimated to be installed in 2020 in that report is around 2.4 hours, which is much less than the 4 hours required in the Carolinas. By 2025, that average duration is up to 3.6 hours.

Based on those numbers, and the fact that the Companies have less than 10 MW of battery storage operating in DEC and DEP today, the concern that there is little experience with operating utility scale battery storage is valid. Supply chain concerns are also very real given the expected surge in Electric Vehicle and Utility Scale Storage demand.

Wood Mackenzie highlights these issues in their brief "Surging Demand for Batteries: Will the Supply Keep Up?."[265] This policy paper highlights potential issues with much of the supply concentrated in China today and how a potential supply crunch could not only effect prices but the quality of batteries may be impacted as Tier II and Tier III battery suppliers are relied on more to meet surging demand.

B. Battery Energy Storage Operating Assumptions

1. Capacity Value of Storage.

The Public Staff suggests that future Storage ELCC Study updates should consider the fact that PURPA facilities larger than 5 MW will have their rates and rate schedules renewed every five years, which should mitigate this reduced capacity value effect.[266] The Companies disagree with this recommendation for two reasons. First, rather than making assumptions of which facilities would have utility control and which facilities would not, the Companies assumed all solar plus storage assets in the 2020 IRP would operate under "economic arbitrage" mode to the benefit of those resources. Second, in order to apply the Public Staff's suggestion, the Companies would have to calculate new rate schedules for increasing increments of solar plus storage additions to determine the new fixed dispatch schedule for incremental resources. This would be a complex and highly debated assumption that may not significantly change the results as the model would still be completely limited in its flexibility to dispatch these resources.

The E3 Report sponsored by NCSEA/CCEBA also critiques the Companies' study of the capacity value of storage. The E3 Report recommends that the Companies "Model

[265] Mitalee Gupta, Shijie Liu, *Surging Demand For Batteries: Will the supply keep up?* Power and Renewable Insight, Wood Mackenzie.
[266] Public Staff Initial Comments at 79.

storage resources in "preserve reliability" mode rather than "economic arbitrage" mode in SERVM" and claims that "Duke's modeling of storage in "economic arbitrage" mode rather than "preserve reliability" mode diminishes the reliability value of both storage and solar."[267]

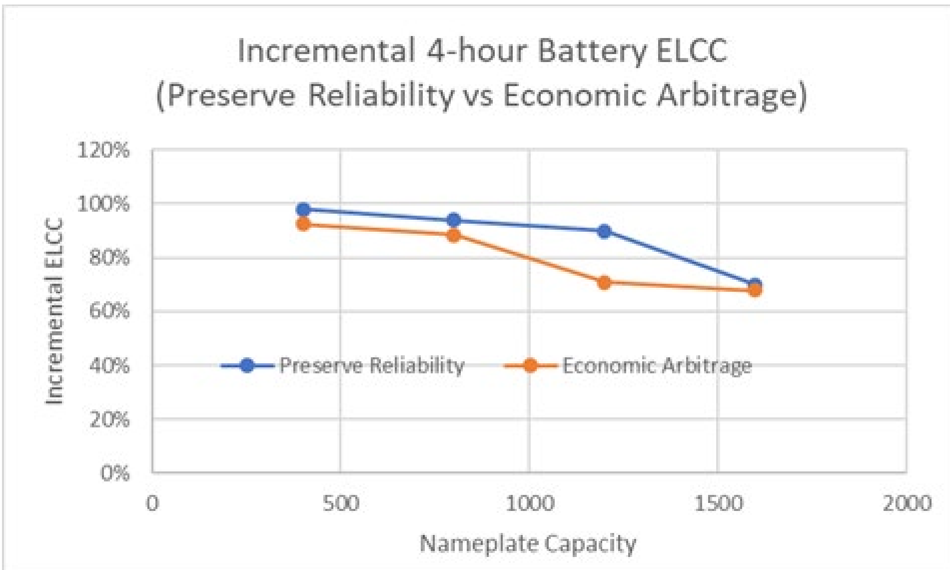
In reply to these intervenor comments, the Companies note that the Storage ELCC Study conducted by Astrapé produced results for both preserve reliability and economic arbitrage modes to understand the impact of the different operational modes of storage. As discussed within the Storage ELCC Study, the preserve reliability mode assumes the battery will remain fully charged at all times and will only be discharged during reliability events. In contrast, the economic arbitrage mode assumes the battery will, on a daily basis, operate to maximize economic value and be charged during low-cost hours and discharged when system energy costs are high. As discussed in the Storage ELCC Study report, the difference in capacity value represents the imperfect knowledge that exists in real time commitment and dispatch of batteries.

The Companies disagree with E3's recommendation. Using the "preserve reliability" results from the Capacity Value of Storage Study would not be an appropriate assumption given the way in which batteries are expected to be dispatched on the Companies' systems in the future. The economics of battery storage are not based on a single value stream. In generation space, battery storage can provide both capacity and energy arbitrage value, as well as, some support to ancillary requirements. If battery storage is going to be valuable to the DEC and DEP systems, it will need to provide all of these value streams. If the Companies were to assume energy storage capacity value based

[267] NCSEA/CCEBA Initial Comments, Exhibit 2 at 5.

on "preserve reliability" mode, then its economic arbitrage value would be reduced. While an "economic arbitrage" basis does reduce capacity value, as shown in Figure 31, the drop off in value is initially relatively minor, 5 to 6% for the first 800 MW and the incremental value is essentially the same for the two modes at 1,600 MW of storage.

Figure 31: Comparison of "Preserve Reliability" Mode to "Economic Arbitrage" Mode in DEC



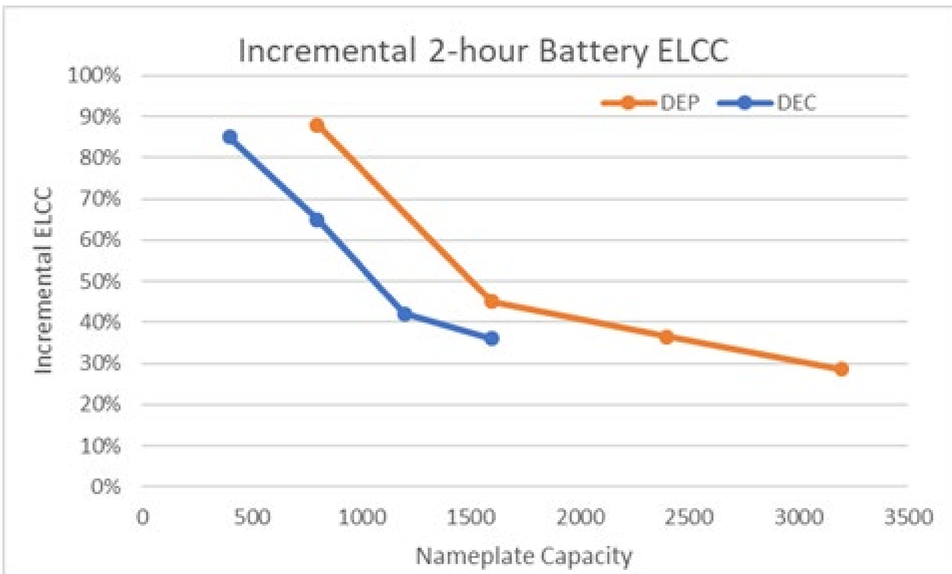
The "economic arbitrage" mode maximizes the energy value of the battery while still providing significant capacity value, and therefore the "economic arbitrage" assumption in the IRP is appropriate for valuing capacity value of storage.

2. The Companies do not support modifying 2020 IRPs to model 2-hour battery storage as recommended by NCSEA/CCEBA.

The SEIA Lucas Report contends that the Companies should update their models "to select up to 1,500 MW and up to 1,000 MW of two-hour batteries in DEP and DEC, respectively."[268] As evidence for this statement, the author claims that "two-hour batteries provide useful capacity during winter and summer peak load hours."[269]

While it is true that the Storage ELCC Study did identify that two-hour battery storage could potentially provide nearly 90% capacity value for the first increments of storage, that value quickly drops as incremental storage is added as evidenced in the Figure 32 below.

Figure 32: Incremental 2-hour Battery Storage ELCC

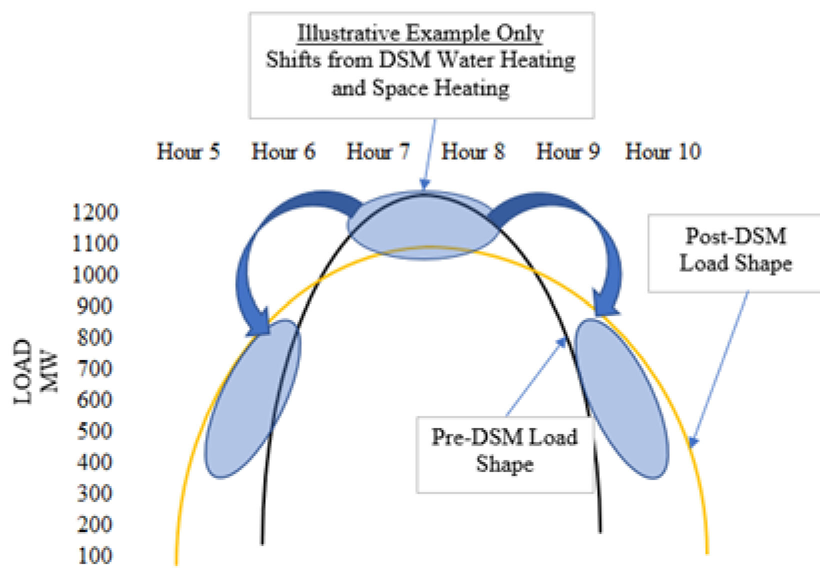


Additionally, the SEIA Lucas Report relies on its Figure 6, which represents the average value of 2-hour storage on the DEP and DEC systems. However, the incremental 2-hour battery ELCC is necessary for evaluating the value of incremental 2-hour battery additions to the system.

[268] NCSEA/CCEBA Initial Comments, Exhibit 3 SEIA Lucas Report at 26.
[269] NCSEA/CCEBA Initial Comments, Exhibit 3 SEIA Lucas Report at 25.

The SEIA Lucas Report also disputes the Companies' assertion that two-hour batteries generally perform the same function as DSM programs.[270] While it is true that some DSM programs have limits to how often they can be activated, and participant fatigue is a valid concern, DSM programs receive 100% contribution to winter peak capacity in the IRP. Any additional demand response programs, as shown in Figure 33, will have the impact of flattening winter peak demand thereby increasing the need for longer duration resources.

Figure 33: Illustrative Example of Impact of DSM Programs on Winter Peak Demand



This highlights the fact that there is only so much need on the system for narrow limited-hour load shifting resources before longer duration storage is needed.

Similar to NCSEA/CCEBA, the AGO disputes the Companies exclusion of 2-hour battery storage in the IRPs suggesting that "2-hour storage is well suited to meet Duke's

[270] NCSEA/CCEBA Initial Comments, Exhibit 3 SEIA Lucas Report at 25.

reliability needs, which are characterized by acute winter peaking conditions during the 7 to 9 morning hours in the month of January" and noting that "expanded winter DSM was not evaluated in the 2020 IRP base cases."[271] While the AGO notes here that increasing DSM should not be considered when evaluating 2-hour storage, they seemingly contradict themselves when they argue on the next page of their comments that "Duke should reassess the capacity value for solar given its potential synergies with winter DSM."[272]

Further, the risk facing the Companies and our customers from too much reliance on short duration load shifting resources is both a reliability issue and an economic issue. Several recent reliability events across the nation highlight the potential for longer duration peak events that require resources with sustainable output over longer durations of time. From an economic perspective if it turns out longer duration storage is required to reliably serve load then customers effectively end up paying for capacity twice as they would need to buy multiple MWs of short duration storage to equal a single MW of a reliable longer duration resource. While the Companies support and stand behind their ELCC modeling, it should be recognized that all operational considerations cannot be fully captured in an ELCC modeling framework and the Companies are ultimately responsible for the reliable provision of electric service. Given the potential for demand side resources to satisfy the incremental demand over shorter periods of time, the 2020 IRPs approach of only considering four-hour storage, or longer, for capacity value is reasonable and appropriate for planning purposes at this time.

Further, as discussed in Section XII. C. below, this assumption is particularly appropriate in light of the recent extended extreme cold weather event in Texas where 2-

[271] AGO Initial Comments, at 26.
[272] AGO Initial Comments, at 27.

hour battery storage would have likely been of little use to the system as outages to a variety of resources limited both capacity and energy to serve customer needs.

C. More Study of Storage Capacity Value and Future Role in System Operations is Needed in Light of Recent ERCOT Reliability Events

The SEIA Lucas Report opines that the incremental natural gas generation as shown in the Companies' 2020 IRPs base planning scenarios is inconsistent with the Companies' net-zero goals and implies that solar plus 2-hour storage is an adequate substitute.[273] The Companies question the technical objectivity of SEIA's and NCSEA/CCEBA's solar-centric advocacy on this issue and reiterate the importance of allowing the Companies time to study, plan for, and develop effective solutions to the challenges of integrating significant variable solar generation into their systems and, at the same time, to also better understand the operational characteristics of battery storage as a capacity resource on the DEC and DEP systems.

As discussed in Section XI. C. above, the operational realities in the Carolinas, such as cloud cover, must be assessed when considering the capacity value of solar and solar plus storage. As shown in Figures 15 and 16 of these reply comments, weather in the Companies' BAs can lead to several consecutive days of low irradiance resulting in low capacity factors for solar output. These low capacity factors could result in insufficient energy to reliably serve customer demand especially if this solar output is the energy that is then being depended on for charging battery storage resources to provide dispatchable capacity.

[273] NCSEA/CCEBA Initial Comments, Exhibit 3 SEIA Lucas Report at 25, 26..

The recent extreme cold weather events in ERCOT provide some preliminary insights into the ability of solar and storage to replace more fuel-secure and dispatchable resources like natural gas-fired generation in the Carolinas.

To be clear, the Companies are planning to add significant storage resources over the 15-year planning period as part of a balanced and diverse portfolio of resources needed to reliably meet customers' capacity and energy needs. As shown in the DEC and DEP IRP summary tables, between 1,050 and 7,400 MW of incremental storage is planned across the six portfolios. However, storage requires energy produced from other resources to store to be useful. Additionally, for each MWh of energy stored, only 0.75 to 0.85 MWh is returned to the system. As discussed in Section XI. C. above, solar output in the Carolinas is not dependable as an energy source for charging battery storage during winter months when the Companies experience their greatest loss of load and reliability risks. To remedy this shortfall, solar would need to be constructed in extreme excess which would be costly and result in more challenges for the system operator due to excess energy produced during months of low customer demand and thus, necessitate more curtailments of solar during shoulder month periods.

At the opposite end of the spectrum of the need for longer duration storage, the SEIA Lucas Report suggests the Companies should evaluate up to 2,500 MW of two-hour duration storage in their resource plans. Short duration storage has limited capabilities for providing dependable capacity needs to the system. To reflect these limited capabilities associated with 2-hour battery storage, a 50 MW, 2-hour duration battery can discharge 100 MWh of electrical energy into the system. Once the 100 MWh is discharged, the battery storage has to be recharged with 118 MWh of electrical energy prior to being useful as a 50 MW, 2-hour duration capacity resource again. This charge/discharge cycle is vastly different as compared with a 100 MW gas-fired combustion turbine that once started, can produce electricity anywhere in between its minimum and maximum capabilities for as long as needed. This type of reliable, dependable, and dispatchable resource is critical to being able to serve extended high customer demand and to regulate around the variability and intermittency of solar output. This extended high customer demand is demonstrated in Figure 40 that shows an actual 2018 winter load shape as well as the similar IRP 2030 load shape. Considering the impacts of DSM further flattening the peak demand, 2-hour duration storage at the levels suggested by the SEIA Lucas Report would not be sufficient for providing reliable winter peaking capacity in the Carolinas. [274]

Battery storage, if under system operator control, is beneficial where excess energy from solar is available to store for use in assisting the system operator with lessening the burden on load following /regulating resources meeting steep ramps created by solar's non-conforming output and thus providing resource assurance to help meet NERC Reliability Standard requirements. However, there would be scenarios such as periods of consecutive days with low solar output and high winter customer demand where storage, if being heavily relied upon as a capacity resource, could be unreliable. Indeed, looking at the recent ERCOT extreme cold weather event, as reflected in Figure 34, there were approximately 72 hours where ERCOT was shedding firm load and there would have been no energy available to store.[275]

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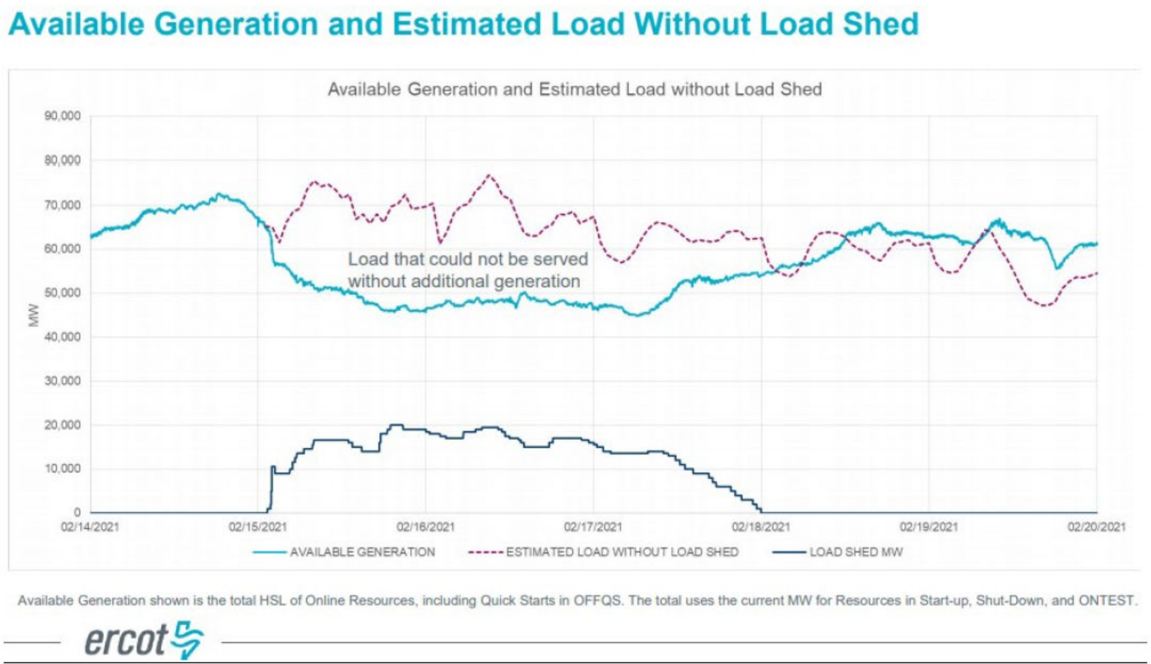
[274] *See* Figure 40: Comparison of DEC and DEP's Combined Peak Winter Load, January 2018 and January 2030 to Synapse assumed 2030 Winter Peak Load Shape

[275] Texas Legislative Hearings: Senate Business and Commerce Committee House Joint Committee on State Affairs and Energy Resources Presentation by Bill Magness, President & Chief Executive Officer ERCOT, February 25, 2021, at slide 15, http://www.ercot.com/content/wcm/lists/226521/Texas_Legislature_Hearings_2-25-2021.pdf (last visited March 17, 2021).

Figure 34: ERCOT 72-Hour Available Generation and Firm Load Shed



Without the energy from solar or other resources, the availability to charge any amount of battery storage would have been limited or even non-existent. Closer to home, in January 2018, the Carolinas experienced a prolonged cold weather event that fortunately did not result in the inability of the Companies to serve their customers, but the system was strained, nonetheless. The Jocassee and Bad Creek Pumped Hydro Storage resources that provide approximately 12-hours of energy were nearly exhausted during that event. It is unlikely that 2-hour storage would have provided much capacity value during that week.

Similar to the recent experience in ERCOT, if the Company's portfolio of resources are not planned appropriately and are not adequate to ensure needed dependable and dispatchable capacity is available every second, minute, hour and day of the year to meet this energy need, the resulting resource/demand imbalance can cause unscheduled power flows and impact system frequency, causing NERC reliability risks for our customers.

XIII. Energy Efficiency and Demand Side Management

The Companies first acknowledge the Public Staff's determination that DEC & DEP complied with the requirements of Rule R8-60 and previous Commission orders regarding forecasting of DSM/EE program savings and have appropriately addressed changes in their respective forecasts of DSM/EE resources and the peak demand and energy savings from those programs.[276] The Companies also agree with the Public Staff that continued success in planning and implementing cost-effective EE programs has led to a lower sales growth rate than would have occurred in the absence of these programs.[277]

The Companies' long-term, ongoing, and consistent efforts, particularly as compared to other Southeastern utilities, have garnered praise from environmental advocates for years. For example, in 2017, SACE published an article titled "Duke Energy Leads the Southeast on Energy Efficiency," in which it congratulated the Companies for their EE successes and counted DEC and DEP as "first in the Southeast" for energy efficiency.[278] In 2018, SACE published its first annual "Energy Efficiency in the Southeast" report in which it again concluded that DEC and DEP were leaders in energy efficiency among over 500 utilities in the Southeast.[279] SACE came to the same conclusion in each of its two more recent reports, in which DEC and DEP were first—by a healthy margin—among 500 other Southeastern utilities for energy efficiency, finding that "Duke's utilities in the

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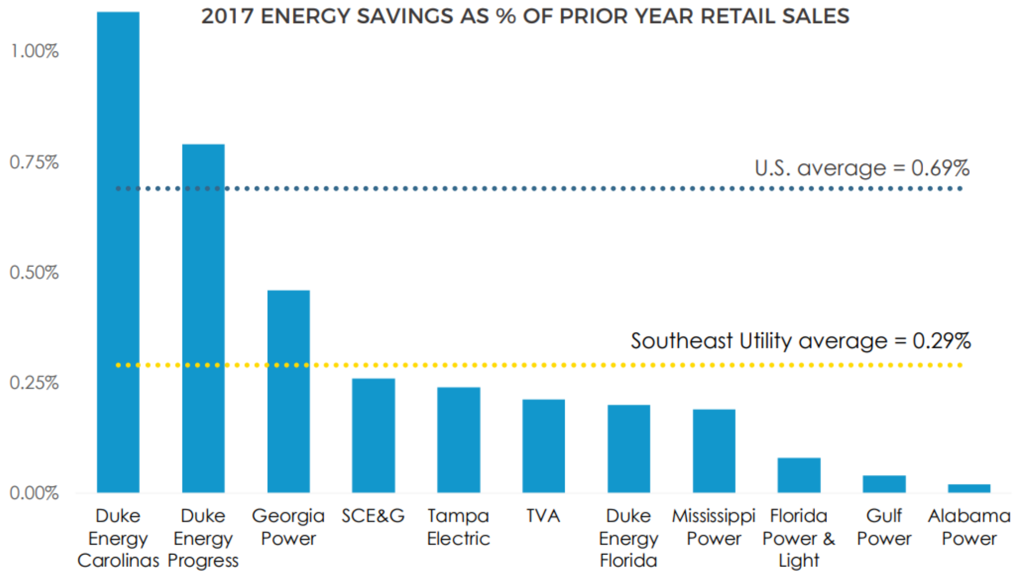
[276] Public Staff Initial Comments at 50.
[277] *Id.* at 52.
[278] Duke Energy Leads the Southeast on Energy Efficiency, SOUTHERN ALLIANCE FOR CLEAN ENERGY (Oct. 12, 2017), *available at* https://cleanenergy.org/blog/southeast-energy-efficiency-2017.
[279] Energy Efficiency in the Southeast: 2018 Annual Report at 4, SOUTHERN ALLIANCE FOR CLEAN ENERGY, *available at* https://cleanenergy.org/wp-content/uploads/2018-Energy-Efficiency-in-the-Southeast-SACE-2.pdf.

Carolinas continue to lead the region in annual efficiency savings".[280] Figures 35, 36 and 37 below illustrate the DEC and DEP EE savings performance relative to the U.S. average and other Southeastern utilities.

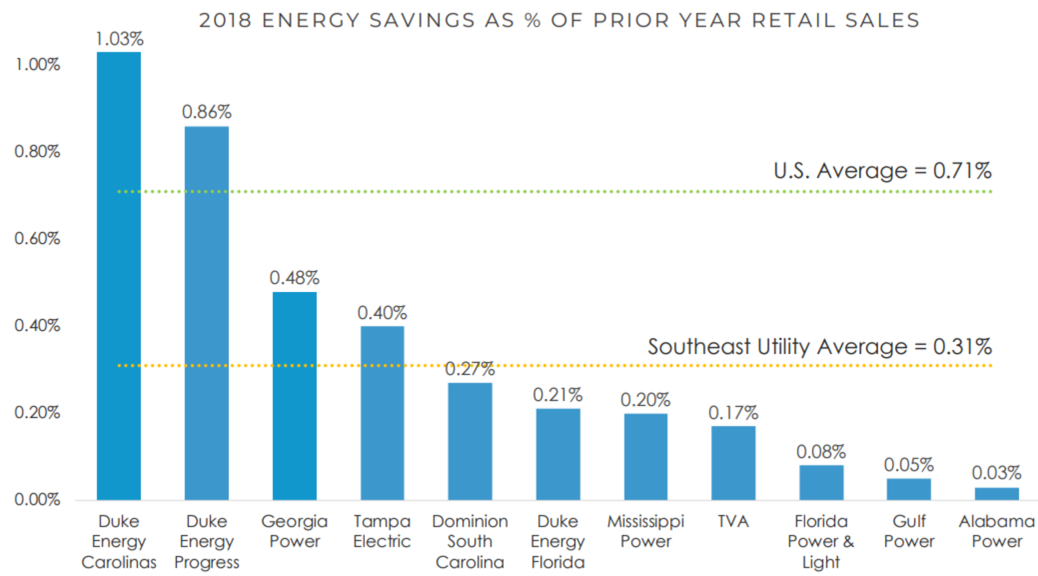
Figure 35: SACE's depiction of 2017 year-on-year energy savings by utility.[281]



[280] Energy Efficiency in the Southeast: 2019 Annual Report at 7, SOUTHERN ALLIANCE FOR CLEAN ENERGY, *available at* https://cleanenergy.org/news-and-resources/energy-efficiency-in-the-southeast-2019-annual-report/; Energy Efficiency in the Southeast: Third Annual Report at 6, SOUTHERN ALLIANCE FOR CLEAN ENERGY (Jan. 26, 2021), *available at* https://cleanenergy.org/wp-content/uploads/22Energy-Efficiency-in-the-Southeast22-third-annual-report-2021.pdf.

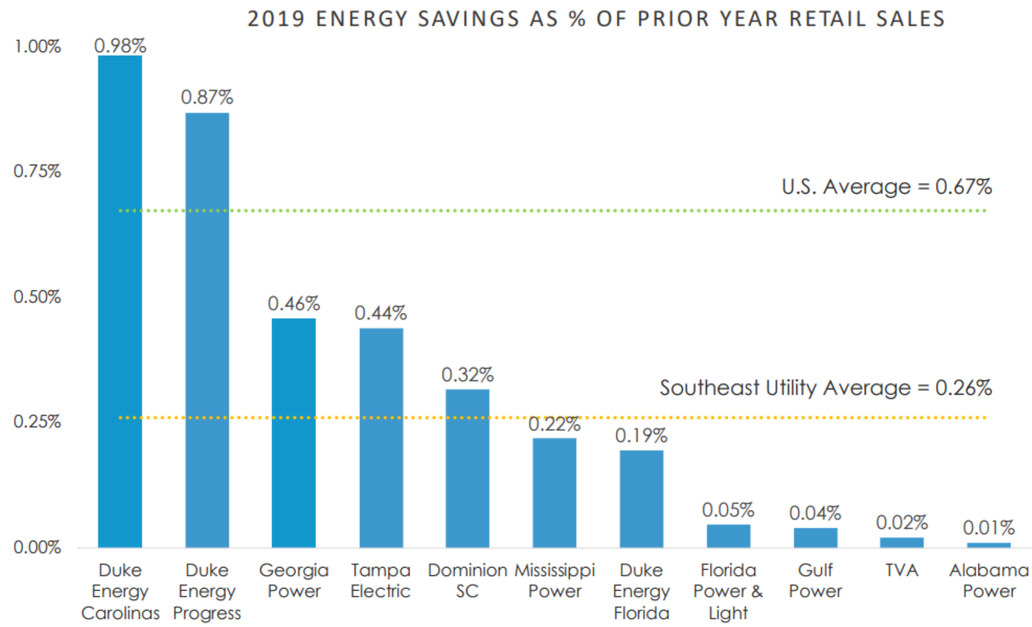
[281] Energy Efficiency in the Southeast: 2018 Annual Report at 4, SOUTHERN ALLIANCE FOR CLEAN ENERGY, *available* https://cleanenergy.org/wp-content/uploads/2018-Energy-Efficiency-in-the-Southeast-SACE-2.pdf.

Figure 36: SACE's depiction of 2018 year-on-year energy savings by utility.[282]



[282] Energy Efficiency in the Southeast: 2019 Annual Report at 5, SOUTHERN ALLIANCE FOR CLEAN ENERGY, *available* https://cleanenergy.org/news-and-resources/energy-efficiency-in-the-southeast-2019-annual-report/.

Figure 37: SACE's depiction of 2019 year-on-year energy savings by utility.[283]



A. DSM/EE Initiatives Generally

As recommended by the Public Staff, the Companies' modeling processes use the DSM resource forecast that represents the reasonably expected load reductions that are available at the time the Companies call upon the resource as capacity.[284] The Public Staff also commented that the utilities should utilize DSM to reduce fuel costs when marginal costs of energy are high in IRP modeling. The Companies currently set the marginal DSM cost to correspond with higher cost peaking units to limit use of DSM to periods of high marginal energy cost, as well as to ensure reliability. This is done in accordance with prudent dispatch practices around traditional DSM programs where frequent utilization will excessively impact customers and lead to loss of participants. However, as newer DSM technologies become available, future program designs may enable more frequent

[283] Energy Efficiency in the Southeast: Third Annual Report at 6, SOUTHERN ALLIANCE FOR CLEAN ENERGY (Jan. 26, 2021), *available at* https://cleanenergy.org/wp-content/uploads/22Energy-Efficiency-in-the-Southeast22-third-annual-report-2021.pdf.
[284] Public Staff Initial Comments at 18.

DSM employment with less impact to customers, particularly when combined with innovative rate designs. As these prospective programs are approved and implemented, optimal use of these technologies may enable fuel and other operational cost savings as the Companies integrate them into system operations and gain experience with customer acceptance, adoption and retention.

The Public Staff also recommended that the Companies identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold required by the Commission.[285] While it is impossible to accurately predict—and impractical to attempt to—discuss the full range of drivers that may affect future EE potential, the Companies agree that it would be beneficial to stakeholders to discuss macro trends and drivers likely to impact future EE projections. Accordingly, the Companies will add additional narrative discussion to the EE/DSM chapter of future IRPs, regardless of the 10% threshold, discussing key trends observed and emerging technology or program developments that we anticipate may meaningfully impact future EE/DSM forecasts.

With respect to intervenors' comments on the Companies' DSM/EE initiatives, the Environmental Parties argue in their comments that the Companies limited DSM/EE to just two blocks of predetermined levels and do not evaluate whether proposed supply additions are less expensive than adding more DSM/EE.[286] The Companies disagree that the proposed methodology regarding supply additions would generate an outcome with higher levels of DSM/EE than the Companies' models. The current modeling methodology provides maximum inclusion of achievable potential based on the detailed analysis

[285] *Id.*

[286] Environmental Parties Partial Initial Comments at 7-8.

represented in the Market Potential Study ("MPS") and, going forward, additional innovative programs identified in the Winter Peak Study ("WPS"). If the maximum achievable potential were broken into "bundles" of selectable resources, the model could only select less, not more, DSM/EE. This criticism demonstrates a lack of understanding on the part of the Environmental Parties that customer adoption of DSM/EE measures is not something that can be forced. The purpose of developing the Achievable Potential estimates in multiple scenarios in the MPS is to identify the amount of DSM/EE that can be reasonably included in system planning where reliability is a fundamental requirement. The only explanation for the intervenors' desire to model DSM/EE as a supply-side resource is that they would seek to add additional, selectable DSM/EE above and beyond the Achievable Potential, presumably at an understated cost, in the hopes that the model would select this additional DSM/EE rather than other supply side resources. This methodology would completely disregard the fact that modelings outcomes do not affect customer adoption decisions and could result in a plan that artificially overstates the potential future of DSM/EE savings, and thereby understates the net load forecast and amount of traditional supply side resources required to reliably serve customer load.

B. Market Potential Study ("MPS")

In 2019, the Companies retained Nexant, Inc to conduct a comprehensive assessment of EE/DSM potential for DEC and DEP. Nexant's methods are industry-leading and its analysis relies on the best data available at the time to support the study, and its results were *specific to the DEC and DEP service territories*. The MPS includes currently known technologies, estimated costs, and energy and demand reduction impacts for these EE and DSM measures and determines the Technical, Economic, and Achievable Potential of EE/DSM programs applicable to DEC and DEP customers.

Unsurprisingly, the Public Staff found that the list of measures included in the MPS appears to be reasonable and that the Technical Potential savings appear reasonable relative to other MPS conducted across the country.[287] Public Staff also noted, however, that Economic Potential savings are lower than some other studies with an average Economic Potential of 25% of forecasted sales and stated that this is likely due to a lack of a comprehensive measure list.[288] The Companies do not agree that the Economic Potential savings number being lower than some other studies is due to lack of comprehensive measure list as the MPS used a comprehensive list of measures including many that are not a part of DEC or DEP programs resulting in a comparable Technical Potential as noted above. Instead, the apparently lower Economic Potential is a function of cost-effectiveness screening which the additional measures not currently offered by the Companies did not pass. Any observed disconnect with other potential studies is likely driven by differences in avoided costs between the studies utilities, or, the specific cost effectiveness test, used for the economic screening step of the MPS.

The Public Staff also noted that Achievable Program Potential savings appeared to be lower than the average of other MPS across the country.[289] However, this is once again a function of specifics of the Companies' service territory and customer base. Direct comparisons of EE savings as a percentage of load is of limited value across disparate service territories due to significant differences in factors influencing the cost effectiveness and adoption of EE programs including climate, age and type of housing stock, fuel types for space and water heat as well as other energy end uses, retail energy prices, avoided

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[287] Public Staff Initial Comments at 56, 57.
[288] *Id.* at 57, 58.
[289] *Id.* at 58-59.

energy costs, EE program maturity, opt-out rules, and average usage per retail customer. Additionally, the Companies' exceptional EE achievements in recent years have exceeded the national average, thereby eroding the remaining achievable potential of existing technologies by "pulling forward" adoption from future years.

The Public Staff stated that the Companies' EE savings forecasts continue to shift away from lighting and toward behavioral measures like "My Home Energy Report" in keeping with the Achievable Potential projections of the MPS. This is an outcome of the Companies' noted success in implementing lighting and other equipment-based measures in the past which now result in fewer remaining opportunities for further adoption of equipment-based measures such as lighting. This is another reason why it is imperative to consider program maturity and past successes when comparing future potential projections across disparate utilities. Additionally, rising baseline efficiencies applicable to lighting programs reduce the opportunity for incremental savings driven by utility-sponsored programs. This shift toward behavioral measures is a natural progression for well run and successful EE programs. Moreover, the Companies do not see this shift as an area of concern as behavioral programs are deployed as an "opt-out" design across nearly 1.2 million residential customers in the DEC and DEP territories. Behavioral programs are innovative, comprehensive, effectively free for customers, and they yield reliable savings across all end uses.

1. DEC/DEP Reasonably Considered Spectrum of DSM Options.

In their comments, the Environmental Parties assert, without valid justification, that Duke failed to use the entire spectrum of EE/DSM options and under-estimated the economic and achievable potential of these resources.[290] These intervenors claim that their consultant, Mr. Jim Grevatt, found that the MPS failed to account for potential savings from emerging technologies, failed to evaluate a variety of measures used in other jurisdictions, failed to consider new/enhanced customer engagement strategies or program designs, and significantly underestimates potential EE and DSM savings due to omissions, unreasonable assumptions, and arbitrary limitations in study design which, he argues, is particularly important with respect to DSM during the winter peak.[291]

The Companies strongly disagree with these unfounded and unsupported positions. The MPS is a systematic, evidence-based analysis of known and quantifiable energy and demand savings achievable by DEC and DEP. These comments include suggestions and critiques that appear to misunderstand Nexant's methodology applied in the study and offer a speculative and incomplete perspective that would not provide the Companies with a technically sound and reliable estimate of future EE and DSM program opportunities.

One of Nexant's primary objectives in developing the MPS was to avoid introducing bias in its evaluation of the Companies' market potential within their geographic service territories. As such, Nexant develops measure impacts on the basis of currently available data and information. This includes using observed data from the service territory and data concerning energy efficiency measures that are commercially available at the time of the study.

Additionally, the concept of changes to baseline and efficient technologies over the 25-year study period is, in fact, incorporated in the study methodology in two ways. First, the Companies' baseline sales forecasts include trends in energy consumption over time,

[290] Environmental Parties Partial Initial Comments at 1, 2.
[291] *Id.* at 9, 10.

which is determined based on the historic effects of changes to various technologies' efficiency. The baseline forecast therefore accounts for future changes in energy consumption, which would almost certainly include the influence of "emerging technologies" to the extent that they have affected historic consumption trends that are projected into future periods. Second, while the study includes a finite set of existing measures with known impacts and costs, Nexant applies measure savings to the baseline sales forecast on a percentage basis (i.e., the efficient technology is applied to the baseline forecast as a percent reduction in consumption). Therefore, the study assumes that, over the 25-year time horizon, the opportunities for efficient technologies relative to the baseline will continue to exist at a similar savings level regardless of changes to baseline efficiencies, which almost certainly will include new technologies.

Regarding the claims that the MPS uses an incomplete measure list, of the nineteen "omitted measures" suggested by Mr. Grevatt,[292] eighteen were actually accounted for in the MPS; the one measure that was not accounted for is a gas measure, as explained below.

Figure 38: Measures Implemented by the Companies

Class	Measures	Applicable Program
Residential	LED decorative and directional lamps	Implemented through retail, online store, and direct install programs
	CEE tier 2 refrigerators	Included as part of Energy Star Refrigerator program
Commercial	Networked lighting controls	Implemented through Prescriptive/Custom
	LED parking lot lighting	Implemented through Prescriptive/Custom
	LED directional lamps	Implemented through Prescriptive/Custom
	Evaporator fan motor controls	Implemented through Prescriptive/Custom
	Variable refrigerant flow (VRF)	Implemented through Prescriptive/Custom

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292 *Id.* at Attachment 1 at 7, 8.

	Dedicated outdoor air system (DOAS)	Implemented through Prescriptive/Custom
	Air-source heat pumps	Implemented through Prescriptive/Custom
	Variable speed air compressor	Implemented through Prescriptive/Custom
	Dual enthalpy economizer for existing buildings	Implemented through Custom
	Data center hot/cold aisle configuration	Implemented through Prescriptive/Custom, but is industry standard so would likely be a baseline
Industrial	Strategic energy management	Implemented through Custom for Retro-Commissioning ("RCx") and monitoring-based commissioning
	Process improvement	Implemented through Custom
	Compressed air leak survey & repair	Implemented through Prescriptive
	Compressed air no-loss drains	Implemented through Prescriptive
	Chiller plant optimization	Implemented through Custom
	Advanced rooftop control	Implemented through Prescriptive / Custom

As for pool covers—the one measure that was omitted from the MPS—the Companies' research indicates that this measure would hold very little potential for electric savings and would likely be a far more effective natural gas efficiency measure. The Company's 2019 Residential Appliance Saturation Study indicates that only 2% of pool owners in North Carolina, and not even 1% of South Carolina pool owners, utilize electric pool heaters. This makes it challenging to design a cost effective program around pool covers and next to impossible to reduce the Companies' load forecasts in a significant, meaningful way by offering it to customers.

Finally, regarding the claim that the MPS does not fully capture the entire winter DSM capability, as the Companies stated in the IRPs:

> [I]t is premature to include such findings in the Base Case forecast . . . . Over time, as new programs/rate designs are approved and

> become established, the Company will gain additional insights into customer participation rates and peak savings potential and will reflect such findings in future forecasts.[293]

Assuming a particular amount of savings resulting from these potential future programs and rate designs—before they are developed by the Companies and stakeholders and approved by the Commission—would be irresponsible from a system planning perspective. Additionally, the non-dispatchable DSM measures based on rate design would not be included in the IRPs DSM forecast as the impacts on customer load shape and peak demand from such programs would instead be represented in the load forecast. Moreover, the majority of incremental peak demand reduction identified in the WPS above and beyond the MPS result from rate design programs and therefore would be reflected within the load forecast rather than as part of EE/DSM savings.

2. Environmental Parties Comments about Potential Omissions/Design Flaws in MPS Should be Rejected.

The Environmental Parties also claim that Mr. Grevatt identified "four major issues with the MPS study design.": (1) unreasonable assumptions on commercial/residential end-uses that result in underestimation; (2) failure to account for increased measure savings due to technology improvement and decreasing measure and program costs driven by economies of scale, and unreasonable constraint in calculation of achievable potential, due to limiting it to measures already included in Duke's EE portfolio;[294] (3) achievable potential is based on historic participation rates; and (4) Total Resource Cost test instead

[293] DEC IRP at 36; DEP IRP at 36.

[294] *See supra* at Section XI.B.1. addressing this "design flaw."

of the Utility Cost Test to screen for cost-effectiveness, which depressed the estimates of economic DSM and EE potential.[295]

The Companies disagree with all four of the supposed MPS "design flaws" and ascribe these criticisms to a lack of understanding of Nexant's methodology and lack of appreciation for the reliability impacts of overstating EE/DSM savings potential in the course of system planning and IRP analysis.

First, regarding residential and commercial load allocated to the miscellaneous end-use category during forecast disaggregation, the MPS primarily relied on DEC's and DEP's end-use consumption data, with secondary data from EIA to supplement and further disaggregate the forecast data. To maximize applicability and relevance to a particular utility, Nexant's preference is to primarily align study parameters with utility-specific data, particularly when the study findings are inputs for future resource planning. The Environmental Parties' recommendation here that the Companies recalculate the MPS based on EIA end uses would lessen the correlation of the study inputs and findings to the Companies' customer characteristics and consumption patterns, as the EIA survey information is applicable to the entire South Atlantic region rather than data specific to DEC and DEP. The South Atlantic regional data in the EIA report encompasses eight states from the Mason-Dixon line all the way to the Florida Keys, which includes five different climatic zones. This recommendation would only reduce the validity and relevance of the MPS and reduce, rather than improve its value as an input to the IRP EE/DSM forecasts.

[295] Environmental Parties Partial Initial Comments at 10.

The third "design flaw" reveals yet another misinterpretation or mischaracterization that the MPS uses historic program data as an upper bound for assessing achievable potential when, in reality, this data was used as a calibration step in developing the achievable potential. Nexant's longstanding experience is that actual results from historic program offerings in the Companies' service territories are a reliable indicator of expected program performance in the future for comparable programs and spending levels. The Companies have actively managed the EE and DSM program cycle in the Carolinas for over ten years, and the Companies have conducted multiple market potential studies and engaged in continuous program planning, management, and evaluation. The Environmental Parties have also been active participants in the Companies' DSM Collaborative for years and have had ample opportunity to recommend strategies to increase customer adoption.

The MPS included interviews with the Companies' program staff as well as a review of evaluation reports that have been conducted for the Companies' programs and associated recommendations and best practices, making the historic participation rates a data point to inform future market adoption rather than an "upper bound". Additionally, the MPS' Enhanced scenario was initially envisioned to include additional measures that are not part of the Companies' current programs. However, because all cost-effective measures were already included in the Companies' programs, the Enhanced scenario was revised during the study to include consideration of additional program investment and the resulting impact on participation rates and savings. Higher incentive rates for the measures included in the study was used as the proxy mechanism to reflect additional program spending, resulting in increased participation rates.

The final “design flaw”, according to the intervenors here, is the use of the Total Resource Cost (“TRC”) test for cost effectiveness screening rather than the intervenors’ preferred Utility Cost Test (“UCT”). There are several standard industry tests for cost-effectiveness screening, which provide different perspectives relevant for utility EE and DSM program planning. While the intervenors criticize the use of the TRC for economic screening, they ignore the fact that the UCT test only provides the perspective of the utility’s costs and benefits. Accordingly, it does not consider customer economics which is necessary in assessing market potential and rates of measure adoption by customers. The intervenors solely focus on the higher Economic Potential resulting from using UCT as opposed to TRC in the economic screening stage of the MPS but do not then acknowledge that little of the resulting increased economic potential would translate into increased Achievable Potential.

An example of this phenomenon is high efficiency HVAC programs where, due to the very high consumer cost of the overall system, the measure may fail cost effectiveness screening under the TRC test. However, from a UCT perspective where the utility rebate or incentive and administrative costs are the only items on the cost side, the cost benefit ratio appears more favorable and the measure passes the economic screening stage. This does *not* mean that the measure will now be widely adopted because, from the customer perspective, the cost benefit ratio is small or even unfavorable (which is why the measure did not pass the TRC test). The intervenors argue that there are other “customer benefits” including non-financial benefits that are not captured by the TRC and thus, some customers will still adopt measures that fail TRC but pass UCT. The Companies agree that a small number of customers may make that decision regardless of the economics. In response, and in discussion with the Collaborative, the Companies agreed to increase the achievable potential used in EE forecast development for the IRP by 10% to account for any potential increase that might be driven by using UCT versus TRC in the economic screening stage of the MPS.

The recommendation that the Companies revise the IRPs after they "[r]ecalculate levelized costs from the UCT perspective, as the sum of program incentives and administrative costs divided by the discounted sum of lifetime energy savings" and the "MPS is revised to address potential savings more fully"[296] is illogical because levelized MPS costs based on TRC or UCT are not used in IRP modeling. The annual program incentive and administrative costs associated with all measures represented in the EE Forecast are fully accounted for in the IRP models as part of the total portfolio PVRR.

3. Winter Peak Study Reasonably Plans for Meeting Winter Peak Needs with DSM/EE.

In mid-2020, the Companies engaged Tierra Resource Consultants ("Tierra") to perform a deeper analysis into the winter peak loads which are driving system capacity planning for DEC and DEP. Following the initial winter peak analysis, Tierra collaborated with Dunsky Energy Consulting to identify a range of potential winter peak focused DSM solutions for the DEC and DEP service territories. As the Public Staff recognized in its comments, "these reports incorporate traditional DSM/EE measures, non-traditional measures, and rate schedule and tariff-based DSM opportunities to provide increased winter peak reduction opportunities."[297] Further, the Companies agree with the Public Staff's assessment that the Companies have "already started tackling the 'low hanging

[296] Environmental Parties Partial Initial Comments at 12.
[297] Public Staff Initial Comments at 61.

fruit'" for residential winter DSM potential through the winter-focused smart thermostat programs that were recently approved by this Commission in Docket Nos. E-2, Sub 927, and E-7, Sub 1032.[298] The Companies will continue to study the recommendation of the WPS to develop new and enhanced DSM programs in conjunction with the Collaborative and other stakeholders.

As discussed earlier,[299] the Environmental Parties claim that Nexant significantly underestimated winter DSM potential in the MPS in comparison to the WPS.[300] What these intervenors failed to recognize is the broader range of program types which generated that higher DSM potential: in particular, rate schedule and tariff-based DSM opportunities. The incremental savings identified in the WPS based on rate or tariff design are not classified as traditional DSM programs and, thus, would not be reflected in the DSM forecast but would instead be reflected in the load forecast. The Environmental Parties further state that the Companies have failed to adequately explore DSM options for extreme winter weather events and that the Companies should engage with customers and stakeholders on this.[301] The Companies strongly disagree with this assertion as the entire purpose of conducting the WPS is to continue exploring these potential future opportunities and collaborating with stakeholders on new programs and rate designs for the purpose of addressing winter peak concerns.

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[298] *Id.* at 62.
[299] *See infra* at Section XI.B.1.
[300] Environmental Parties Partial Initial Comments at 11.
[301] *Id.* at 16.

XIV. The Companies are Planning for Electric Vehicles

City of Charlotte requests the Commission to "[e]ncourage Duke Energy to incorporate recent automakers' EV rollouts and reforecast EV penetration and improve utility planning."[302] The Companies' adoption forecast is a current best estimate based on market data available today and industry trends. The Companies are in the process of developing a new forecasting tool that will enable greater flexibility to create additional EV forecast scenarios based on announced industry goals, government policies, and EV charger infrastructure investments. Additionally, the Companies will begin incorporating Medium Duty (MD) and Heavy Duty (HD) adoption and energy forecasts in the load forecast for the first time in the 2022 Comprehensive IRP.

The City of Charlotte also requests the Commission to "[r]ecommend that Duke Energy plan a robust suite of EV offerings and analyze how a more ambitious, proactive approach to increasing EV penetration in the state will impact future load growth."[303] In March 2019, the Companies proposed a robust suite of EV pilot programs. The Commission approved a limited selection of these pilot programs in November, 2020 ("Phase I Pilots"). In addition to these approved Phase I Pilots, the Company has worked through a stakeholder process, which started in December 2020, to propose: (i) a Make-Ready Credit program that will reduce the upfront cost of upgrading electrical systems to install charging infrastructure for homeowners and businesses and (ii) a second phase of the EV pilots (Phase II Pilots) that is designed to expand DC fast charging on state highways and EV charging at multi-family dwellings and to provide financial support to school systems to purchase electric school buses. Approval of these proposals is currently

[302] City of Charlotte Initial Comments at 11-12.
[303] City of Charlotte Initial Comments at 11-12.

pending before the Commission in Docket Nos. E-2, Sub 1197 and E-7, Sub 1195. Through the development of the new EV forecasting model, the Company expects to be able to more readily estimate the impacts of different programs and offerings on future EV adoption.

XV. Economic Evaluation of Portfolios and Sensitivities

The Companies performed industry-standard present value revenue requirement analysis in their 2020 IRPs. The Public Staff recognizes that PVRR is a common tool in IRP to compare the costs of portfolios.[304] The Companies presented most PVRR results excluding the explicit cost of carbon from the PVRR analysis, with the use of a carbon tax in the analysis simply as a proxy price (or shadow price) to show the potential impacts carbon policy could have on resource selection and on system dispatch. Uncertainty exists on exactly how energy policy will develop to incentivize new technologies and drive carbon emissions out of the electric sector is unknown, so excluding this explicit carbon cost is appropriate for a clearer comparison of portfolio performance from one portfolio to the next. However, in certain instances the inclusion of an explicit carbon tax in the PVRR analysis can be insightful, to show the potential impacts to customers if carbon policy did result in a direct carbon cost that gets passed on to customers, as noted by the Public Staff. To show this possible policy outcome, the IRPs do in limited instances include an explicit carbon tax in the PVRR analysis and clearly note when such costs are included.

Finally, the Public Staff acknowledges that because portfolios C-F are highly prescribed, they are not appropriate for planning.[305] Of note these portfolios were designed to achieve specific outcomes on restricting carbon generating resource types and meeting

[304] Public Staff Initial Comments, at 150.
[305] Public Staff Initial Comments, at 154.

carbon reduction targets, and therefore were not specifically optimized by least cost constraints. However, the Companies maintain that the cost and carbon reduction tradeoffs are informative for regulatory and energy policy discussions.

A. Risk Analysis – DEC/DEP Agree to Perform Minimax Regret Analysis to Assess Relative Portfolio Risk in 2022 IRP

The Companies reviewed the Public Staff and other intervenors risk analysis around the PVRR analysis performed by the Companies in the 2020 IRPs. The Public Staff showed the breakdown of costs incorporated in the IRPs, which reflects, not the total cost to be collected from customers, but rather the total cost that is quantified and may vary from portfolio to portfolio and scenario to scenario in the IRPs. [306] This means that while production cost and capital costs for new projects will vary from portfolio to portfolio and scenario to scenario are included in the PVRR, other costs expected to be collected as part of the revenue requirements, such Grid Improvement Plan Investments, that are constant among portfolios and scenarios or not contemplated by the IRP at all, are not included the cost analysis. The Public Staff also presented a cost premium analysis comparing portfolio cost results to the Base Case portfolios in the IRP to highlight the tradeoffs between carbon reduction and production cost certainty. [307] The Public Staff performed the analysis in both an including explicit carbon tax costs and excluding carbon tax costs to highlight the potential of how carbon policy such as a tax could be passed on to the rate payer.

NCSEA/CCEBA's proffered SEIA Lucas Report presented a portfolio risk quantification through a Minimax Regret Analysis. This analysis shows how a certain portfolio's cost performance across a range of scenarios results in potential cost regret for

[306] Public Staff Initial Comments, at 153.
[307] Public Staff Initial Comments, at 153-154.

selecting that pathway. Regret Analysis is designed to quantify the amount by which a given portfolio exceeds the least-cost portfolio. It is a means to understand the risks associated with each portfolio given the uncertainty in future fuel and carbon prices. A portfolio with a small amount of regret across a variety of pricing scenarios is robust to a variety of futures. The SEIA Lucas Report specifies Max Regret as the "difference between a portfolio's highest PVRR and the lowest PVRR of ***all*** the scenarios."[308]

SEIA's regret analysis points to the cost effectiveness of Earliest Practicable Coal Retirement Portfolio, compared to the economic coal retirement scenarios in its Regret Analysis.[309] SEIA's analysis results in the Earliest Practicable Coal Retirements Portfolio being a close second in terms of minimizing the maximum regret and highlighting a lower cost range compared to the Base Case Portfolios.

The Companies generally agree that a regret analysis can be informative. However, the Companies disagree with approach taken by SEIA in performing the analysis. While this is a nuanced difference, the Companies believe the approach representing regret as the PVRR amount by which each portfolio exceeds the lowest cost portfolio in each fuel and CO2 price case with the maximum regret being the most a portfolio varies from the lowest cost option would be more applicable to scenario planning as only one future can happen, while several portfolios could be applied in that one scenario. Correcting the approach also causes a different outcome in terms of the least regret portfolio. On a combined system basis, the Companies approach results in the Base Planning Case without Carbon Policy being the portfolio that minimized Maximum Regret, followed by Base Planning Case with Carbon Policy. These plans also represent lower mean regret and lower regret standard

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[308] NCSEA/CCEBA Exhibit 3 SEIA Lucas Report, at 13.
[309] *Id.*

deviation compared to Earliest Practicable Coal Retirements Portfolio. Tables 11 and 12 show the results of the combined system Regret Analysis and Minimax Regret Analysis.

Table 11: DEC and DEP combined PVRR Regret Analysis for the IRP Portfolio Scenario Analysis (including the explicit cost on carbon)

	Base Planning without Carbon Policy	Base Planning with Carbon Policy	Earliest Practicable Coal Retirements	70% CO2 Reduction: High Wind	70% CO2 Reduction: High SMR	No New Gas Generation
High CO2-High Fuel	$2.8	$0.0	$0.8	$8.8	$3.6	$16.0
High CO2-Base Fuel	$1.5	$0.0	$0.8	$11.1	$5.9	$18.6
High CO2-Low Fuel	$0.8	$0.0	$0.8	$12.4	$7.2	$20.0
Base CO2-High Fuel	$1.7	$0.0	$1.1	$10.7	$5.5	$17.9
Base CO2-Base Fuel	$0.5	$0.0	$1.0	$12.9	$7.8	$20.5
Base CO2-Low Fuel	$0.0	$0.3	$1.3	$14.5	$9.4	$22.2
No CO2-High Fuel	$0.0	$1.2	$4.1	$18.2	$13.1	$25.0
No CO2-Base Fuel	$0.0	$2.4	$4.3	$20.8	$15.7	$28.3
No CO2-Low Fuel	$0.0	$3.1	$4.8	$22.5	$17.5	$30.3

Table 12: DEC and DEP combined PVRR Minimax Regret Analysis for the IRP Portfolio Scenario Analysis (including the explicit cost on carbon)

	Base Planning without Carbon Policy	Base Planning with Carbon Policy	Earliest Practicable Coal Retirements	70% CO2 Reduction: High Wind	70% CO2 Reduction: High SMR	No New Gas Generation
Max Regret	$2.8	$3.1	$4.8	$22.5	$17.5	$30.3
Mean Regret	$0.8	$0.8	$2.1	$14.7	$9.5	$22.1
Regret Standard Deviation	$1.0	$1.2	$1.7	$4.8	$4.8	$4.9

The Companies agree with NCSEA/CCEBA and SEIA that Minimax Regret Analysis can be useful risk quantification analysis; however they disagree with the specific approach taken by SEIA. However, the Companies developed the Maximum Regret analysis for the 2020 IRP consistent with the approach presented by South Carolina ORS's 3rd part consultant in the SC 2021 IRP proceeding. Importantly, Minimax Regret analysis, as all other components in an IRP should be reviewed holistically. The analysis puts no weight on how likely (or unlikely) a portfolio and scenario may be. For example, if the Companies were to find themselves in a high gas and high CO2 price scenario, it is very unlikely the Companies would pursue and execute on a portfolio such as Base Case without Carbon Policy. The Regret analysis is expected to provide additional perspective and context, but should not be wholly relied upon for make determinations of what portfolio is best suit across the board.

B. Analysis of Customer Rate Impacts: The Companies Accept Public Staff's Recommendation and will Continue to Refine their Analysis in Future IRPs

The Companies for the first time in their IRPs included Customer Bill Impacts for each of the portfolios. The Public Staff pointed out in their comments that Dominion has included rate impacts in last several IRP cycles. The Public Staff commented that this metric is insightful and compelling[310] recommending DEC and DEP adopt this metric. In the 2018 proceeding the Public Staff renewed its recommendation to include rates analysis for each portfolio and was supported by the AGO, who went further to recommend customer bill impacts for all three rate classes, not just residential.

While the Commission did not require the Companies to include the Customer Bill Impacts in their 2018 or 2019 IRP orders, the Companies, through continued collaboration with the Public Staff decided to include the metric in the 2020 IRPs. The Customer Bill Impacts represent those impacts from incremental costs identified in the IRP. While it is a useful tool, it is directional in nature and not a comprehensive analysis of future changes

[310] Comments of the Public Staff, at 81 Docket No. E-100, Sub 147, (filed February 17, 2017.)

to the existing rate base, changes to cost of service or potential benefits or costs in other parts of the business, not evaluated in the IRP.

The Public Staff does not take issue with the Companies calculation of the portfolios customer bill impacts. While the residential bill impact is shown in the IRPs, the Public Staff recognizes that the Companies could similarly calculate commercial and industrials bill impacts, but additional challenges with summarizing parameters for these two additional classes make it much more difficult to include a specific bill impact for each. The 1,000 kWh residential bill is a much more commonly used measure of residential class usage and more easily applied.

The Companies agree with the Public Staff's apt observation that the customer bill impacts should be considered on relative terms to each other rather than on absolute terms.[311] As discussed, the IRP only captures certain costs that vary across portfolios and scenarios, and that capturing absolute changes in customer bills would require much more holistic and comprehensive analysis outside the scope of an IRP, such as those performed in Rate Cases. Instead comparing the bill impact for one portfolio compared to another is a more appropriate comparison. For example if two plans have similar PVRRs, but one has a customer bill impact of 2x, this could be a meaningful consideration in evaluating that pathway. The Companies agree the metric, in combination with Present Value Revenue Requirement analysis, is a helpful tool in understanding nearer and longer term cost impacts to customers, and plans on including comparable analysis in the future, as the Companies work with stakeholders to most accurately reflect the impact of plans on customer affordability.

[311] Public Staff Initial Comments, at 160.

XVI. Preliminary Response to First Corrected Synapse Report

NCSEA/CCEBA and the Environmental Parties ("Joint Synapse Sponsors") jointly filed partial initial comments and an alternative resource planning proposal developed by Synapse Energy Economics, Inc. ("Synapse") dated March 1, 2021.[312] This alternative resource plan was initially corrected and refiled on March 22, 2021 due to errors made in Synapse's "Reasonable Assumptions" scenario ("Synapse Report").[313] On May 4, 2021, during the 2021 South Carolina evidentiary hearing on the 2020 IRPs, the Companies pointed out significant flaws in the Synapse Report, which were admitted by the Synapse witness during cross-examination. In response, on May 27, 2021, counsel for the Joint Synapse Sponsors filed yet another corrected version of the Synapse Report to address additional substantial flaws in its analysis. ("Second Corrected Synapse Report"). The Companies did not receive the Second Corrected Synapse Report until served by counsel for the Joint Synapse Sponsors after 4:00 p.m. on the day before these reply comments were due and had already been preparing to respond to the first corrected Synapse Report. Accordingly, the Companies provide these comments to the first corrected Synapse Report and reserve the right to file comments on the Second Corrected Synapse Report after the Companies have had a reasonable period of time for review and to seek additional discovery as may be warranted.

The Companies initially highlight for the Commission that this Synapse Report is the second alternative resource plan developed by Synapse and filed by certain of the Joint Synapse Sponsors that would—based on a cursory summary analysis and little supporting

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[312] *See Report of Synapse Energy Economic, Inc.*, Docket No. E-100, Sub 165 (Mar. 22, 2021).
[313] According to the March 22, 2021 filing letter, the error was due to Synapse' paired solar-plus-storage projects within the EnCompass model.

documentation—fundamentally alter the Companies' IRPs to retire operating coal generation facilities sooner and establish a future "clean" resource portfolio that relies almost exclusively on solar, battery storage, and DSM/EE and excludes new, dispatchable natural gas capacity.[314] In 2018, Synapse argued that this alternative clean resource portfolio was fully capable of meeting the Companies' reserve requirements and reliably serving customers future capacity and energy needs. However, the Companies' reply comments in the 2018 IRP proceeding strongly disproved the Synapse claims, emphasizing for the Commission that the 2018 Synapse report was not technically objective nor analytically sound and, instead, was "the product of a special interest group that appears to make assumptions in their model with a predetermined outcome in mind."[315] Accordingly, after identifying the more material flaws for the Commission, the Companies concluded that that the 2018 Synapse report should be dismissed because it would not conform to DEC's and DEP's obligations as regulated public utilities to plan for and to provide adequate and reliable service at least cost over the planning period.[316] The 2018 Synapse Report also touted that adopting its alternative clean energy-only resource portfolio would also save DEC and DEP customers billions of dollars over the 15-year planning period.[317]

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[314] *See* North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Synapse Energy Economics, Inc., Attachment 1 to NCSEA's Initial Comments on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans, Docket No. E-100, Sub 157 (Mar. 7, 2019).
[315] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Reply Comments, at 32, Docket No. E-100 Sub 157 (May 20, 2019).
[316] *Id.*; *see also Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, at 71, Docket No. E-100, Sub 157 (Aug. 27, 2019) ("2018 IRP Order") (acknowledging Duke's reply comments that "the [Synapse] report's cost savings are based on multiple assumptions that, if implemented, would cripple the reliability of the DEC and DEP systems.
[317] 2018 IRP Order at 71-73 (summarizing Duke's reply comments stating that Synapse's cost assumptions are invalid because they fail to, among other things, (1) include transmission implications associated with must-run designations; (2) meet the minimum reserve margin of 17% for DEC and DEP and instead use a 15% reserve margin, and (3) recognize that over-reliance on energy imports from neighboring utilities is inconsistent with the reality that there is not enough firm transmission available to reliably import this level of energy.)

However, the Companies' reply comments highlighted that these purported cost savings were premised on unreasonable cost and operating assumptions and flawed modeling that did not reflect the Companies' real world operations or accurately project the expected costs of serving customers in North Carolina in the future. In its 2018 IRP Order, the Commission summarized the comments surrounding the 2018 Synapse report but did not discuss the Synapse report or give the report any weight and in its analysis, findings, or conclusions.[318]

The Synapse Report filed in this 2020 IRP proceeding generally tracks the prior 2018 Synapse report. The Synapse Report presents a fundamentally-different resource planning future for the Carolinas that—if feasible—would further accelerate DEC's and DEP's planned coal fleet retirements as well as—again, if feasible—reliably meet both new load growth and replace approximately 10,000 MW of coal-fired capacity with a new "clean" resource portfolio that relies almost exclusively on solar, battery storage and DSM/EE and excludes new dispatchable natural gas capacity. The Synapse Report also tells a very similar story to the 2018 Synapse study, touting that its clean "Reasonable Alternative" portfolio can reliably serve customers, while also saving DEC's and DEP's customers billions over the 2020-2035 15-year planning period and, at the same time, significantly reducing carbon emissions.

The Joint Synapse Sponsors go all-in supporting these claims, commenting:

> Synapse's analysis demonstrates that when the inaccurate assumptions in Duke's evaluation of resource options are corrected, modeling will produce portfolios that, in comparison to Duke's lowest-cost portfolio, reduce overall system cost by $7.2 billion while reducing carbon dioxide emissions by tens of millions of tons per year, deploying large volumes of solar and energy storage, and avoiding natural gas capacity additions, all while maintaining resource adequacy.

[318] *See* 2018 IRP Order at 71-74.

They also repeatedly suggest that Synapse's alternative analysis "demonstrates" that the Companies have "presented this Commission with deeply flawed IRPs" and suggest that "Synapse's modeling corrects significantly flawed and inaccurate assumptions and inputs in Duke's modeling and demonstrates that a very different resource plan than those developed by Duke is in the best interest of Duke ratepayers."[319]

In response to repeated criticisms by the Joint Synapse Sponsors as well as recognizing the Companies' customers' significant interest in many of the policy objectives advanced by the Synapse Report, the Companies have undertaken a detailed review of whether this alternative, purported "Reasonable Assumptions" resource plan is actually reasonable and achievable to reliably serve the Companies' customers future capacity and energy needs. Put another way, if the Synapse Report's analysis credibly did what the Joint Synapse Sponsors say it does—"outlines a cleaner and cheaper energy future than Duke's IRPs"— then it should be give substantial weight by the Commission. However, based on the Companies' review—and consistent with the Companies' findings of their review of the 2018 Synapse study—the Companies have determined that the Synapse Report is grossly inaccurate in its modeling, extremely unrealistic in many of its assumptions, and lacks the regulatory rigor that the Companies' Carolinas IRP organization proudly employs to ensure IRPs filed with this Commission are capable of adequately, reliably and affordably providing increasingly clean electric service to customers over the next 15 years.

[319] Joint Synapse Sponsors Initial Comments at 2-4.

A. Synapse's "Mimic Duke" Portfolio Fails to Actually Mimic Duke's IRPs as it Does not Recreate the Companies' Base Case with Carbon Portfolio and Sets an Inflated Baseline Cost

The foundation of the Synapse Report is its "Mimic Duke" portfolio, which Synapse explains is a reference case that "uses Duke's input values to create a resource portfolio . . . that results in a similar, but not identical, portfolio to that put forth in Duke's Base Case with Carbon Policy."[320] The Joint Synapse Sponsors comment that the Report "attempts to model a similar portfolio to Duke's Base Case with Carbon Policy, in order to provide a basis for comparison."[321]

The Mimic Duke portfolio is critical to the report's primary objective of showing that planning even for a combined DEC and DEP "joint Duke" system can maintain reliability while accelerating coal retirements, reducing load through EE and DSM, and replacing the remaining needed capacity and energy with renewable generation and energy storage. However, the Synapse Report fails to get this first step even reasonably correct in recreating a reasonable economic selection to mimic the Companies' Base Case with Carbon Policy. This failure to appropriately recreate the Companies' Base Case with Carbon Policy portfolio results in an inflated baseline cost delta between the Base Case with Carbon Policy and the Mimic Duke portfolio to the point of invalidating the entire comparison.

As an initial point of difference, the Synapse Report admits that it makes three fairly material "updates" to increase the cost of new natural gas-fired generation in the Mimic Duke portfolio.[322] These adjustments significantly change the relative costs of natural gas

[320] Synapse Report, at 3.
[321] Joint Synapse Sponsors Initial Comments at 9.
[322] Synapse Report, at 12.

resources in the model compared to other resources. Among others modeling input difference that will be discussed in this section, some of the more noteworthy input assumption changes are summarized in table 13, below.

Table 13: Comparison of Base Case with Carbon Policy Modeling Inputs/Assumptions

	Duke Base Case with Carbon Policy	Synapse Mimic Duke
New Gas Resource Planning Lives	35 years	Indexed to 2050, assumed retirement year
New CC Firm Transportation Cost	Fixed Cost, Does not impact dispatch	Variable Cost, Impacts dispatch
New CC Gas Basis Pricing	Dominion Southpoint (DSP)	Transco Zone 5
Existing Gas Basis Pricing	Transco Zone 4 and 5, adding DSP in 2026	Exclusively Transco Zone 5
Jointly Owned Units	Joint Ownership, Correctly Incorporated	No Joint Ownership, Overstates Capacity
Coal Must Runs	Indexed to load	Year-round
Regional Set up	3 Balancing Authorities	1 Balancing Authority
Monthly Peak Load Forecast	Duke IRP	Duke IRP
Monthly Total Energy Forecast	Duke IRP	Duke IRP
Production Cost Modeling Load Shape	Hourly 8760 per year	Encompass Typical Peak/Off-Peak Days
Federal ITCs	Effective as of filing	December 2020 Legislative

These differences, among other modeling inputs and assumptions not discussed drive a discernable difference between the Companies' Base Case with Carbon Policy portfolio and the Synapse Report's Mimic Duke portfolio as highlighted below in Table 14 by total and incremental resource selections in the two portfolios.

Table 14: Comparison of the Companies resulting Base Case with Carbon Policy portfolio and Synapse's Mimic Duke portfolio

	Duke Base Case with Carbon Policy	Synapse Mimic Duke
Total Incremental Solar	**8,395**	**3,375**
Economically Selected Solar	3,675	3,375
Total Incremental Wind	**750**	**0**
Economically Selected Wind	750	0
Total Incremental Storage	**2,188**	**0**
Economically Selected Storage	1,889	0
Total Economically Selected Gas	**7,328**	**8,751**
Economically Selected CT	3,656	7,347
Economically Selected CC	3,672	1,404

As Table 14 shows, on its face the Synapse Report's "Mimic Duke" portfolio is clearly inappropriately named. Synapse claims in a discovery response that it successfully mimicked Duke's Base Case with Carbon Policy because it "adds additional gas-fired capacity to meet projected demand in a case where existing coal retires over the duration of the analysis period." [323] While it is true that the Companies' Base Case with Carbon Policy replaces the lost capacity from some of the projected coal facility retirements with gas-fired capacity, Synapse's "Mimic Duke" portfolio is a far cry from a reasonable benchmarking of the Companies' Base Case with Carbon Policy portfolio as the changes to the resources plans are significant and drastically impact the system operations and cost of the Base Case with Carbon Policy portfolio. It is also true that the Companies include forecasted and projected penetrations of additional renewables and storage, past the forecasted additions the portfolio development continues to demonstrate the economics of standalone storage, standalone solar, solar paired with storage, and wind starting in the late 2020's and through the end of the planning horizon. Simply put, the Synapse's Mimic

[323] DEC/DEP Second Data Request to NCSEA, CCEBA, and SACE et al., Item No. 2-30.

Duke portfolio is not an accurate representation of the Companies' Base Case with Carbon Policy portfolio, or any reasonable portfolio developed with a carbon price that rises to over $50 per ton by the end of the study period and therefore should be afforded little weight in this proceeding.

The Synapse Report takes other liberties that further diverges the Mimic Duke portfolio from the Companies' Base Case with Carbon Policy portfolio. Many of these changes are subjective modeling inputs and some of the changes are objectively wrong, but all of these changes continue to raise the baseline cost of the Mimic Duke portfolio in an effort to make Synapse's alternative no new gas Reasonable Assumptions portfolio appear more reasonable. These changes include (1) inflating the levelized recovery cost of gas units by forcing them to be fully recovered and retired by 2050; (2) including a variable fuel charge on new combined cycle units that impacts dispatch instead of incorporating that cost as a fixed cost that does not impact dispatch; and (3) and improperly including a fixed fuel charge that would be expected to deliver lower cost gas on new combined cycles while assigning these units a more expensive gas price.[324]

In sum, despite the absolute and false claim of using "all modeling assumptions" from the Companies' IRPs,[325] the Synapse Report's flawed "Mimic Duke" portfolio fails to provide a credible benchmark to Duke's Base Case with Carbon policy given the stark difference in portfolio components and selective modeling liberties taken to inflate the price of the portfolio before comparing it to Synapse's Reasonable Assumptions portfolio.

[324] Synapse Report, at 12.
[325] Synapse Report, at 11.

B. The Synapse Report is also Founded on Significantly Flawed Modeling Assumptions of Duke's Existing System Operations

While the Joint Synapse Sponsors unabashedly allege that the Companies' modeling was "significantly flawed," the corrected Synapse Report, which was just corrected again, is itself founded on numerous modeling errors and significantly flawed modeling assumptions of Duke's existing system operations.

Before addressing the flaws the Companies identified in Synapse's modeling, it is initially important to identify the simplifying assumption that Synapse applied to DEC's and DEP's system operations in its modeling. As identified in Table 4 in the Synapse Report, Synapse did not analyze DEC's and DEP's operations independently, with transmission ties and limits between BAs as Duke does to model real world operations, but, instead, "merged" the three DEC and DEP-E and DEP-W Balancing Authorities.[326] As further discussed in Section XV.B of these Reply Comments, DEC and DEP do not currently undertake joint capacity planning or share capacity or transmission assets between the two utilities, and it is prohibited by Commission regulatory conditions, so this simplifying assumption is flawed and inconsistent with real world operations. Combining the Balancing Authorities produces many factors that favor a no new gas scenario such as Synapse's "Reasonable Assumptions" portfolio. For example, the alleviation of this constraint allows for load in any part of the combined service area to be served by any generator. This becomes especially important when variable energy resource penetration and generation are high. The more combined a modeled system, the greater the number of renewables that can be added to meet load, as there are no requirements on where the load is geographically located or where the resources need to be sited within the system.

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[326] Synapse Report, at 14.

Turning now to the Companies more detailed review of the Synapse Report, Synapse's use of the Horizon Energy's National Database[327] and lack of detailed review and understanding of DEC's and DEP's systems also caused a significant error in Synapse's representation of operational and planning constraints.

First, and most significantly, the Synapse Report fails to appropriately model joint ownership of units on DEC's system which leads to significantly overstated available capacity available to the system. As identified in the 2020 DEC IRP, DEC's ownership of the Catawba Nuclear Station and W.S. Lee Combined Cycle Station is less than 100 percent with entities such as NCEMC, NCMPA 1, and PMPA all holding stakes in these stations' capacities.[328] To accurately reflect the operation of the stations, the Companies first include the entire stations' capacity in its model and then model an off-system sale of capacity that is not included in the Companies' load forecast. This method provides an accurate representation of capacity and energy going to customer load, while also accurately reflecting the operations and costs of the stations on the system. The Synapse Report, using Horizon Energy's database, included the full capacity amounts for these stations *without* an off-system sale. This inaccurate modeling assumption results in the Synapse Report inappropriately including an additional 1,700 MW of nuclear capacity and 100 MW of the most efficient natural gas combined cycle capacity on the DEC system as "available" to serve the combined DEC and DEP systems. The inaccurate nuclear capacity assumption can easily be identified in Figure 1 of the Synapse Report, which identifies approximately 11,100 MW of nuclear capacity (pink shading at bottom of resource stack) as available between DEC and DEP versus the approximately 9,400 MW that DEC and

[327] DEC/DEP Second Data Request to NCSEA, CCEBA, and SACE et al., Item No. 2-16.
[328] DEC 2020 IRP at 215.

DEP actually can rely upon to serve customers. Figures 2, 3, 4 and 5 of the Synapse Report highlight the continuing role of DEC's and DEP's nuclear fleets (pink shading) as a baseload resource in both its modeling portfolios, providing a significant portion of the capacity and energy assumed to be available to meet DEC's and DEP's energy and capacity needs. The amount of excess energy included in Synapse's "Mimic Duke" scenario from these two low dispatch and low energy cost resources produce throughout the year equates to about 10% of the systems total energy needs in the Companies' base cases.

This is a significant error in Synapse's modeling that would have real-world implications for DEC's and DEP's ability to reliably serve customers in the future and fundamentally undermines the credibility of the study. For example, from a capacity perspective, this overstated nuclear capacity equates to 2.2 time the MW of DEC's Robinson Nuclear Station or the equivalent of other 6,800 MW of solar plus storage capacity. [329] From an energy perspective, this overstatement of energy equates to approximately 14,892,000 MWh per year and could ***power the homes of 68% of DEC's NC residential customers or 99% of DEP's NC residential customers*****, respectively.**[330]

The second major issue uncovered in Synapse's modeling is the modeling of must run designations for certain of the Companies' coal units. The Companies' coal units provide voltage and frequency support to the transmission system during high load periods. During these high load times, it is necessary for the units to run regardless of pure economics to support the transmission system and provide reliable energy. However, the

[329] Assumes solar plus 4-hour duration storage, 25% storage to solar ratio and 25% effective load carrying capability (ELCC).

[330] 1700 MW of Nuclear Capacity at 95% capacity factor and 100 MW of CC Capacity at 85% Capacity factor equates to 14,892,000 MWh. DEC has 1,812,239 residential customers as of March 2021. DEP has 1,254,159 residential customers as of March 2021. Assuming 1000 kWh per month usage for residential customers, this overstated energy equates to 68% or 99% of the total DEC NC or DEP NC residential customer energy usage.

coal units are not required to run outside of these high load periods. In the Synapse Report, the coal units were incorrectly modeled to be required to *run year around*; a significant departure from how these units actually are required to run and very different from how the Companies actually operate them. The following tables (Tables 15-17) compare the number of service hours per year that the Mayo, Marshall 1, and Belews 1 units ran historically from 2017-2020 and how they are modeled to run in Duke's Base Case with Carbon Policy and Synapse's Mimic Duke.

Table 15: Mayo Annual Service Hours, Actuals, IRP Modeling, and Synapse Modeling

	Mayo Annual Service Hours			
	Historicals	**Duke IRP Base Case with Carbon Policy**	**Synapse Mimic Duke**	**Delta**
2017	4,012			
2018	6,352			
2019	4,415			
2020	2,399			
2021		4,120	6,328	2,208
2022		3,517	6,328	2,811
2023		3,561	6,328	2,767
2024		3,237	6,345	3,108
2025		3,690	6,328	2,638
2026		3,726	6,328	2,602
2027		3,491	6,328	2,837
2028		4,533	6,345	1,812

Table 16: Marshall 1 Annual Service Hours, Actuals, IRP Modeling, and Synapse Modeling

	Marshall 1 Annual Service Hours			
	Historicals	Duke IRP Base Case with Carbon Policy	Synapse Mimic Duke	Delta
2017	3,948			
2018	3,657			
2019	3,531			
2020	3,391			
2021		4,228	6,116	1,888
2022		3,035	6,116	3,081
2023		2,359	6,116	3,757
2024		2,280	6,131	3,851
2025		1,593	6,116	4,523
2026		1,539	6,116	4,577
2027		1,377	6,116	4,739
2028		1,310	6,131	4,821
2029		847	6,116	5,269
2030		745	6,116	5,371
2031		474	6,116	5,642
2032		552	6,131	5,579
2033		895	6,116	5,221
2034		729	6,116	5,387

Table 17: Belews Creek 1 Annual Service Hours, Actuals, IRP Modeling, and Synapse Modeling

	Belews Creek 1 Annual Service Hours			
	Historicals	Duke IRP Base Case with Carbon Policy	Synapse Mimic Duke	Delta
2017	4,319			
2018	5,836			
2019	3,804			
2020	4,000			
2021		5,349	6,187	838
2022		6,172	6,187	15
2023		6,146	6,187	41
2024		6,439	6,200	-239
2025		4,774	6,187	1,413
2026		4,659	6,187	1,528
2027		4,255	6,187	1,932
2028		4,055	6,200	2,145
2029		3,727	6,187	2,460
2030		3,356	6,187	2,831
2031		3,266	6,187	2,921
2032		3,279	6,200	2,921
2033		3,600	6,187	2,587
2034		3,773	6,187	2,414
2035		4,264	6,187	1,923

As can be seen above, the impact of this modeling error forces some coal units to run as much as 5,642 hours more than it otherwise should, or 60% of an entire year. These tables show the drastic difference between modeling only the absolutely necessary must run requirements of the Companies' coal units compared to the blanket assumption—which the Synapse Report makes in its Mimic Duke portfolio—that the coal units are required to run year-round. Not only does the Synapse model imposing unnecessary must run requirements for the coal units result in higher cost system, it also erroneously raises the projected carbon emissions of the system, which in turn increases the cost of the system due to the inclusion of the explicit cost of carbon discussed later. Furthermore, Synapse's error may disincentivizes the addition of efficient, base load natural gas to offset erroneous carbon emissions and provide less expensive and capital intense energy. This error of forcing much of the Companies' coal fleet to operate at least minimum load the majority of the year in the Mimic Duke scenario may also crowd out the system's appetite for renewables.

In contrast, Synapse's Reasonable Assumptions scenario relieves any must run constraints imposed on the coal units. In IRP scenarios when the Companies retired the affected coal units with must run designations, the portfolio either designated replacement of capacity at site to fill the transmission needs or incorporated estimated costs to relieve the constraint. The complete removal of these must run designations without any cost or transmission impact studies or estimated costs further dilutes the validity of the analysis, and the comparison of the Mimic Duke and Reasonable Assumptions scenario.[331]

C. Synapse Presents Modeling Assumptions that do not Reflect Real World Operations

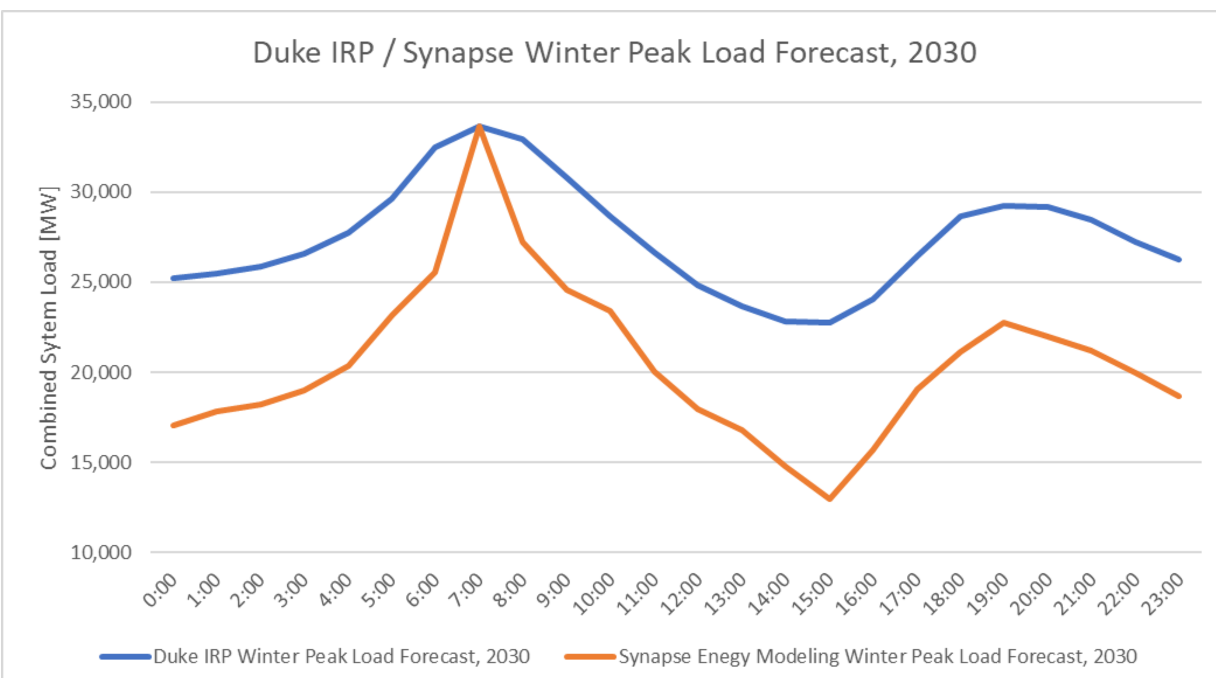
The Synapse Report presents results that are based on modeling assumptions that are not consistent with how the Companies' systems actually operate. First, as discussed above, the Synapse Report combines the balancing authorities of DEP-W, DEC, and DEP-E into a single balancing authority for modeling purposes. Second, the Synapse report, possibly in its effort to more easily incorporate their EE assumptions, significantly distorts the Companies' load shape. Similar to its inaccurate modeling of jointly-owned stations,

[331] Further investigation into this topic revealed Synapse failed to model the earliest practicable coal retirements schedule in their Reasonable Assumptions scenario. From the date Mayo is observed to continue to operate in 2026 through 2028. In the most economic retirement analysis Mayo is retired at the end of 2028, but in the earliest practicable coal retirements schedule, Mayo is retired in 2025. This is another error and inconsistency with what is stated in their report, compared to what is actually modeled.

this assumption favors Synapse's goal of exaggerating the cost of Duke's Base Case with Carbon Policy relative to Synapse's Reasonable Assumptions portfolio.

With regard to the prevailing load shape used in the Synapse modeling, the Companies understanding is that the modeled load shape was developed endogenously in Encompass to create load profiles for the system to meet, rather than using the specific hourly forecast. This process, as specified in the model set up, will capture the monthly peak demand and total monthly energy, but due to simplifying assumptions, it distorts the load into a "needle peak" with a deep, mid-day valley. Figure 39 compares the resulting Synapse 2030 winter peak day load shape compared to the Companies' 2030 winter peak day load shape. The blue line demonstrates the Companies' 2030 load shape on a winter peak day, while the orange line is the load shape that Synapse's modeling is planning to meet.

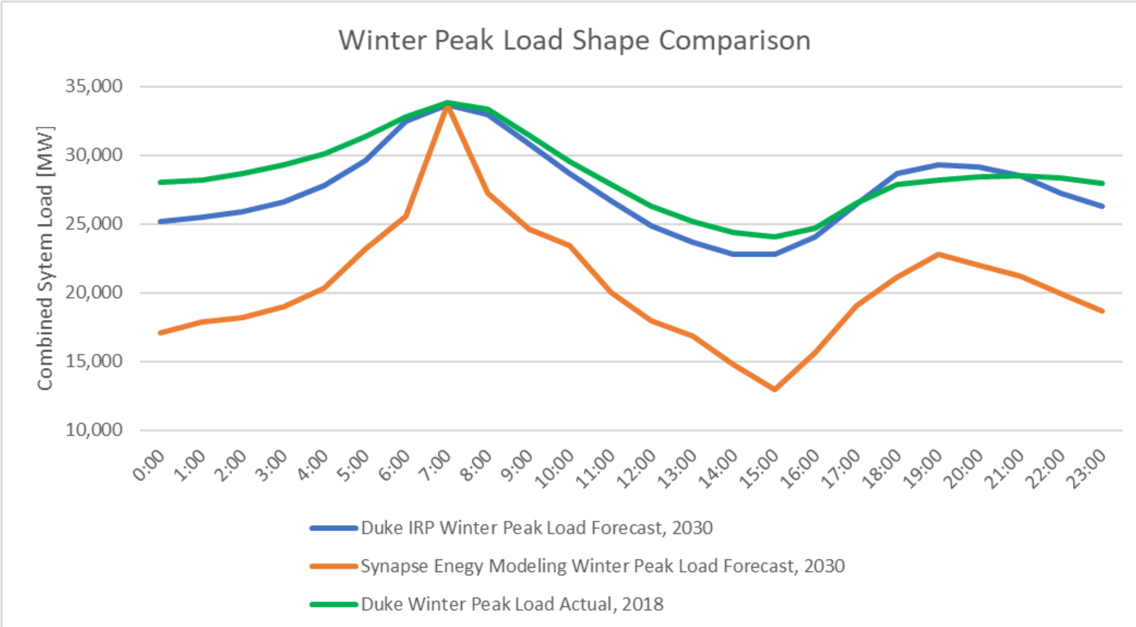
Figure 39: Comparison of DEC and DEP's Combined Peak Winter Load, 2030



In testimony in the Companies' 2020 IRP proceeding before the Public Service Commission of South Carolina, the Companies' Transmission Planning and System Operations expert witness testified in March 2021 that in his "two-plus decades of system operations experience" he has "never seen a peak load shape like [the one presented in the Synapse Report]" occur on the DEC or DEP system."[332] The witness presented a comparison of the actual combined system load from January 5th 2018 highlighting the difference between the companies actual, experienced load shape on a peak winter day, compared to Synapse's 2030 peak day load shape. That 2018 winter peak day load shape has been overlayed on the previous graph to further illustrate the stark differences among the Companies' and Synapses load shapes.

[332] *In re South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Dkt. Nos. 2019-224-E & 2019-225-E, Live Rebuttal Testimony of D. S. Roberts, Hearing Tr. Vol. 4, p. 1063 (Apr. 29, 2021).

Figure 40: Comparison of DEC and DEP's Combined Peak Winter Load, January 2018 and January 2030 to Synapse assumed 2030 Winter Peak Load Shape[333]



While this process of averaging and shaping does capture the system's peak load, to retain the appropriate total energy for the month the model is forced to distort the shape of load profile so drastically that it fails to resemble any such real world shape. In fact, the winter peak load forecast represented by Synapse *serves 25% less energy* over the course of the day compared to the Companies' winter peak load forecast. This is important because the driver for severe winter peak is based on the persistence of cold weather for an extended duration as experienced in the Carolinas in January 2018 or in ERCOT in February 2021.

333 The January 2018 actual combined system load was driven by an extended cold weather event resulting in "above normal weather load." The IRP load forecast uses strictly "weather normal load." The fact that the peak loads are similar between the 2018 actual and the 2030 projected is the difference between weather normal load growth over time compared to an isolated cold weather event, which greatly reduce available operating reserves on that day. Importantly, the IRPs' combined load shape is very similar in shape throughout the peak day, whereas the Synapse modeling load shape with needle peak and deep, mid-day valley is inconsistent with historical real world operations, and the companies' view of the future load profile of the jurisdiction.

It is also important to note that the distorted load shape Synapse based its model on results in a sharp and narrow peak and deep valley that significantly favors shorter-duration capacity resources like battery storage and increases costs for traditional resources. The narrow peak allows for large amounts of battery storage to clip the peak by discharging during these hours of high demand, and then recharging the battery during the deep valley, when solar energy is contributing during daylight hours. This artificially increases the value and selection of the battery storage resources selected in Synapse's Reasonable Assumptions portfolio.

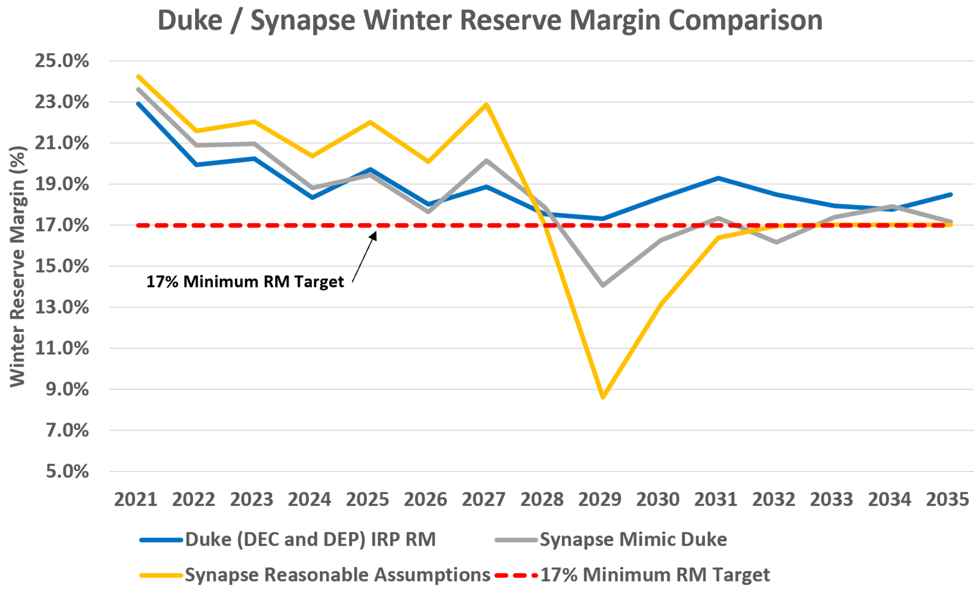
In sum, the Synapse report is flawed because it modeling is not actually planning to meet the needs of DEC's and DEP's real world operations in the future, and, therefore, is selecting resources that may not reliably be able to meet that need.

D. The Synapse Report Fails to Meet the Target 17% Reserve Margin in all Years

The Synapse Report highlights in its core findings, and the Joint Synapse Sponsors tout repeatedly in their comments, that "Synapse's model generates these [carbon emissions reduction and cost savings] results while maintaining Duke's full 17 percent planning reserve margin" and "reliably meets load in every hour of the 15-year planning period. [334] However, after investigating the details of the Synapses modeling, the Companies were able to determine that these statements about maintaining reliability are simply not true. Both the Mimic Duke and the Synapse Reasonable Assumptions scenarios fail to meet the required 17% resource margin in multiple years of the 15-year planning period. Figure 41 depicts the planning reserve margin for the Companies' IRP Base Case with Carbon Policy, and Synapse's Mimic Duke and Reasonable Assumptions portfolios.

[334] Synapse Report, at 1.

Figure 41: Planning Reserve Margin comparison of the Companies Base Case with Carbon Policy and Synapse's Mimic Duke and Reasonable Assumptions portfolios



As shown in Figure 42, the yellow (Reasonable Assumptions) and grey (Mimic Duke) lines dip below the 17% minimum planning reserve margin for multiple years, while the Companies' IRP reserve margin maintains the 17% reserve margin throughout the planning horizon. The industry standard for physical reliability of the system is a loss of load expectation ("LOLE") of one day every ten years. The inadequate planning reserve margin achieved in Synapse's portfolios equates to, in the Reasonable Assumptions scenario, a one day in every four years of LOLE.

While the Joint Synapse Sponsors are quick to sing the praises of the Synapse Report for meeting energy in every hour of the year over the planning period, it fails to meet the required reserve margin multiple years throughout the planning horizon. Because load forecasts are developed on a weather normalized basis, and reliability reserve margins ensure a reasonable level of extra capacity for non-weather normal events, failing to achieve the target planning reserve margin means that system may not have adequate capacity to maintain a reliable system. Synapse's standard of reliability of meeting load in every hour, for a weather normal peak load forecast, with a severely distorted load shape, is a low bar to make such lofty claims and does not reflect the modeling rigor that the Companies adhere to when making claims about meeting their planning reserve margin.

It should also be noted that as dispatchable resources, such as coal are removed from the portfolio and replaced exclusively with intermittent renewable resources and energy limited energy storage, the potential availability, variability, and uncertainty would likely require a higher reserve margin. The Reasonable Assumptions alternative portfolio proposed in the Synapse Report—including accelerated coal retirements and the lack of dispatchable, long run replacement resources such as natural gas—would require the Companies to hold more firm capacity to ensure a reasonably reliable system. Furthermore, as batteries fill a larger role in the system, serving peak demand, energy in more hours throughout the day, and ancillary requirements of responding to variations in generator availability, renewables output, and load changes, the incremental value of each additional MW is diminished. Due to the limited energy batteries can store, their effective load carrying capability ("ELCC") or the likelihood that they are available at the peak hour, decreases as more are incrementally added to the system. This presents a compounding challenge of remaining economic by needing more nameplate capacity per MW for every increment of firm capacity with less opportunity to serve other benefits to the system. In effect, as more energy-limited resources are added to the system, especially those that need to be recharged, such as batteries, more are needed and the less valuable they are.

E. Synapse Report's Assumptions Surrounding Energy Efficiency Inputs are Unreasonable and Largely Depend on Events Outside of Duke's Control

The Synapse Report assumes significantly more DSM/EE is achievable during the planning period than the Companies' 2020 IRPs. However, the assumptions driving the DSM/EE inputs in the Synapse Report are flawed in a number of respects and this over-reliance on unrealistic levels of EE achievement during the planning period undermines the credibility of the report as a whole.

For starters, the Synapse Report selectively relies on the American Council for an Energy-Efficient Economy's September 2020 research report ("ACEEE Report")[335] as a justification for using a high EE savings projection, but fails to acknowledge that the ACEEE Report specifically commends the Companies as leaders in EE programs in the Southeast region.[336] The ACEEE Report also identifies the primary barrier to achieving higher levels of EE savings in the future to be legislative or procedural and, thus, introduce risks that are outside the control of the Companies' resource planning capabilities.[337] Put differently, an overstatement of EE resources that is dependent on factors such as EE-favorable legislation in an IRP will *directly* result in an understatement of the load forecast should these aggressively optimistic assumptions fail to come to fruition. Similarly, an overstatement of a utility's DSM resources depending on factors outside of Duke's control will directly result in an overstatement of a utility's available generation. Overstating EE

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[335] American Council for an Energy Efficiency Economy. September 2020. *How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy, Cost, and Greenhouse Gas Impacts*. Available at: https://www.aceee.org/sites/default/files/pdfs/u2007.pdf.
[336] ACEEE Report at vi.
[337] ACEEE Report at 3-5.

and DSM in the resource planning process like the Synapse Report does, especially in the near term, will result in a compromised ability for the Companies to meet customer load.

It is critical that the Companies only include reasonable, dependable DSM/EE projections in its resource planning rather than very high projections such as those proposed by Synapse that rely on significant legislative and policy developments out of the Companies' control. Consistent with a utility's unique responsibility to reliably meet load —a burden that is not shared by the Joint Synapse Sponsors and other intervenors—the Companies and the Commission must ensure that the inputs and assumptions driving assumed EE potential are well grounded in a market potential study or other credible analysis that appropriately support the IRP as a system planning document. These inputs must be accurate, evidence-based, and specific to the utility's system and customer base. Proposals or suggestions that fail to meet these fundamental requirements—such as aggressive legislative assumptions or comparisons to states wholly different than North Carolina—should not and cannot be relied upon to inform the IRP.

Regarding EE specifically, the Synapse Report makes unreasonable assumptions regarding the amount of EE that the Companies should include in its planning process. For example, the Synapse Report's Reasonable Assumptions scenario assumes that DEC and DEP can increase its EE programs from its 5-year EE plans levels in 2020 of 0.9% by 0.15% per year to ultimately reach 1.5% of retail sales annually. Even more concerning, in response to discovery requests, the workpapers produced by Synapse showed they built up to a level of 2% of retail sales annually rather than the 1.5% stated in the report. The Companies are uncertain which value was ultimately applied to the Encompass modeling but, in any case, either level of savings is unrealistically high. The Synapse Report then maintains this extremely aggressive 1.5% level throughout the study period.[338] This assumed increase is unreasonable for DEC's and DEP's systems and operations, however, because it is based on cherry picking data from small, northeastern states (Massachusetts and Rhode Island) whose EE savings are among the highest in the nation and such extremely aggressive assumptions are not properly adjusted for the vastly different load and customer characteristics in North Carolina.

The Synapse report never states why selectively using a top line target from these non-analogous states is a more "reasonable" approach to EE forecast development than using the primary research conducted as part of a detailed market potential study and relying on Duke's 5-year program plan specific to the DEC and DEP systems. On the contrary, there are many reasons why the states Synapse chose are completely inappropriate for setting North Carolina EE targets. There is a litany of differences between these states and North Carolina which directly impact the cost effectiveness and applicability of EE programs and measures including: (1) climate; (2) age and type of housing stock; (3) fuel types for space and water heat as well as other energy end uses; (4) retail energy price; (5) avoided energy costs, and; (6) average usage per retail customer. One very clear example of the unreasonableness of these assumptions is the Synapse Report's simplistic use of "percentage of retail sales" as a comparison metric between these states and North Carolina, yet readily available EIA data shows that the average residential customer in Massachusetts and Rhode Island uses in the range of 600 kWh per month whereas in North and South Carolinas, the average is 1100 kWh per month. As a result, identical levels of residential EE kWh savings that would constitute 2% in Massachusetts

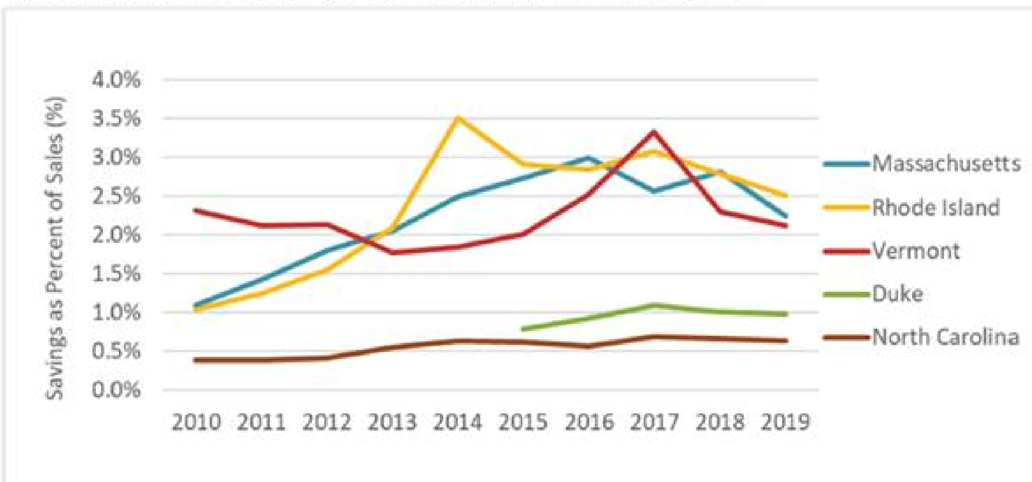
[338] *See* DEC/DEP First Data Request to NCSEA, CCEBA, and SACE et al., Item No. 1-1, "Duke IRP EE&DSM Review.xlsx."

or Rhode Island would only be 1.1% in North Carolina or South Carolina. The Synapse Report ignores and makes no effort to account for these very significant differences.

Not only are the comparisons inappropriate in basic analytical terms, but the research report Synapse chose as the basis for this assumption even shows that such high levels of EE savings are not sustainable over time even within these states. As seen in Figure 8 of the Synapse Report (replicated in Figure 42 below), EE savings for these small, northeastern states begin to decline in 2017/2018 and continue to trend in that direction.

Figure 42: Synapse Report, Figure 8

Figure 8. Historical First Year Savings: Duke and North Carolina vs. Leading States



Source: ACEEE's State Energy Efficiency Scorecard reports; data files "NCSEA DR7-48 DEP Projection and True up Filings 2015-2019.xlsx" and "NCSEA DR7-48 DEC Projection and True up Filings 2015-2019.xlsx" obtained from Duke.

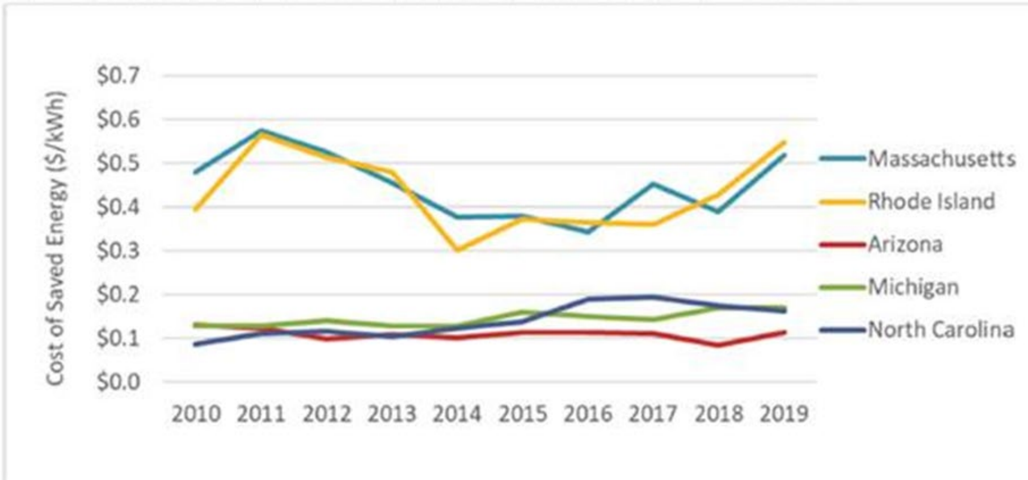
The most impactful area of energy efficiency in recent years has been the transition from incandescent to CFL to LED lighting which provides a very high level of kWh savings at a low cost. Over time, the baseline efficiency levels against which utility EE savings are measured are raised to account for the new technologies becoming widely installed or even required by codes and standards.

The Synapse report also presents a number of issues relating to the cost of EE initiatives. For example, Synapse's "Reasonable Assumption" scenario holds costs per kWh saved consistent through 2035. Synapse justifies this by arguing that historical evidence shows consistent program costs over time. This analysis fails, however, to account for the differences between historical periods and future EE potential costs. As explained above, the success of EE/DSM over the last 10 years in particular has been significantly driven by advancements in EE lighting that have provided high savings at a low cost. Due to rising baseline efficiency standards and LEDs already accounting for a far greater percentage of the lighting market and current installed fixtures, savings from these measures will make up a much lower percentage of future utility EE portfolios. The known EE opportunities available to replace this lost lighting savings are likely to come at a much higher cost due to higher technology costs for measures that can achieve similar savings levels compared to the equipment they replace.

Simultaneously, EE/DSM portfolios are shifting to more complex solutions that provide both energy savings and flexibility to incorporate greater integration of variable renewable generation. Combined, these factors point to increased future costs per kWh for savings for EE/DSM portfolios as compared to the past decade. Synapse's Figure 11 (replicated in Figure 43 below), copied below, shows the start of this trend by looking at the costs of saved energy in Massachusetts and Rhode Island. Moreover, Figure 11 is an illustration of the marked differences in avoided energy costs between unrelated jurisdictions, which means that EE measures and programs that are deemed cost effective in one region has no bearing on their cost effectiveness or applicability to other regions of the country.

Figure 43: Synapse Report, Figure 11

Figure 11. Costs of Saved Energy for Selected States from 2010 to 2019 ($ per kWh first year)



Source: ACEEE's State Energy Efficiency Scorecard reports

The Synapse Report conveniently overlooks select data in the ACEEE Report that undermines its argument that 9.6% of projected system load by 2035 is a reasonable assumption for a cumulative EE savings target. Either Synapse's analysts misunderstand, or are grossly overstating, the data in the ACEEE Report to meet their desired outcome without identifying the risk and potential real world impact on reliability.[339] The conclusions of the ACEEE Report referenced by Synapse clearly show that the Investor Owned Utility EE savings grow *minimally* in the absence of significant changes in legislation and policy and reach only **<u>3.6%</u>** of the total load by 2040 compared to Synapse's "reasonable assumption" of 9.6% of total load by 2035.[340]

[339] Synapse Report, at 13.
[340] ACEEE Report at 16-17, Table 1.

Figure 44: ACEEE Report, Table 2

Total annual electricity savings by policy/program	GWh savings 2030	GWh savings 2040	Total savings in 2040 (% of overall load)
IOU EERS	5,259	5,573	3.6%
Co-ops and municipal utilities	950	1,030	0.66%
Building code stringency and compliance	1,071	2,027	1.30%
Weatherization	43	46	0.03%
Agricultural energy audits	21	23	0.01%
Industrial assessments	79	108	0.07%
Strategic energy management	616	666	0.43%
Total savings	8,043	9,473	6.09%
Remaining electricity needs (GWh)	135,177	146,031	

We present total savings in 2040 as a percentage of forecasted electricity sales in 2040 from the reference case. We do not include savings from USI because our measure life assumptions resulted in savings that do not extend to 2030.

The ACEEE Report provides a lengthy list of legislative and policy changes assumed in its aggressive "Energy Efficiency Policy" scenario that Synapse relied upon in making its "Reasonable Assumption" of achieving 9.6% of total load in EE by 2035.[341] However, even in the most optimistic and unlikely scenario that all of these policy changes are quickly adopted (which is inherently *un*reasonable), the ACEEE Report shows that Investor Owned Utility EE program savings only reach 7.6% by 2040.[342] This is, again, well below the 9.6% "reasonable" assumption put forth in the Synapse Report. The 18.5% of total EE savings potential that Synapse refers to is misleading, at best, because it represents the *sum* of EE savings from a variety of sectors and includes a wide range of impacts from programs that go far beyond utility sponsored energy efficiency programs.[343]

The incremental savings identified in ACEEE's "Energy Efficiency Policy" Scenario—which Synapse relies upon in its report—are largely dependent on uncertain legislative and policy changes well beyond the Companies' control and would almost

[341] ACEEE Report at 18-19, Table 2.
[342] ACEEE Report at 19-20, Table 3.
[343] Synapse Report at 13; ACEEE Report at 19-20, Table 3.

certainly entail much higher costs than have been demonstrated in historical programs. It is not reasonable for the Companies to assume and include a markedly higher level of EE savings at costs comparable to current and historical programs. For example, the proposed expansion of low income and weatherization programs listed in Table 2 of the ACEEE Report are undoubtedly helpful to these customers, and effective at reducing energy use, however, these programs rarely pass required cost effectiveness screening and must be subsidized though bundling with other lower cost programs in order for the overall portfolio of utility EE programs to comply with cost effectiveness requirements. Including a major expansion of such programs and the other proposed policy changes makes it highly unlikely that future EE program costs would remain in line with current and historical cost per kWh trends. A "reasonable" assumption is that these additional savings would come at a significantly higher cost per kWh and thus would likely result in a more costly IRP plan which is not in keeping with the least cost integrated resource planning required by Commission Rule R8-60(a).

The Companies, as public utilities, must be prudent in planning their systems. When a portion of the assumptions supporting its load or generation forecasts are speculative—such as EE load savings or DSM generation support—the IRP ceases to be a well-supported planning document and moves into the realm of wishful thinking. For these reasons, the EE and DSM inputs and assumptions used in the Synapse Report further demonstrate that the analysis is not reasonable and should not be relied upon.

F. The Assumed Reasonable Assumptions Portfolio Cost Savings are Grossly Inaccurate

The "lead headline" of the Synapse Report is that its Reasonable Assumptions alternative "produces an alternate clean energy resource portfolio that reduces total system cost by $7.2 billion and CO_2 emissions by 78 percent compared to a scenario similar to Duke's modeled Base Case with Carbon Policy." Setting aside the numerous inaccurate assumptions and errors made in Synapse's modeling that artificially inflate the cost of the Mimic Duke portfolio and favor Synapse's preferred Reasonable Assumptions scenario, the bulk of these touted "savings" are completely illusory. In the IRPs, the Companies' provide explicit discussion in the Executive Summary[344], and in Appendix A[345], about the use of carbon pricing as proxy for energy policy broadly and the exclusion of these costs from the majority of the companies PVRR analyses[346] and from the Executive Summary Results Tables.[347] The Companies are transparent in their use of the carbon tax as a proxy for carbon policy, and the exclusion of that cost from the companies cost analyses. On the other hand, the Synapse report is silent on the issue. Reviewing the work papers of the report, approximately two thirds of the delta ($4.8 billion) between the two Synapse modeling cases is due to inappropriately including the explicit cost of an assumed carbon tax modeled in the scenarios, contrary to how the companies have presented results. While this is a choice of the authors and analysts, the lack of discussion is misleading, overselling the results, and misrepresenting the comparability to the IRPs. Assuming that the incentive to reduce carbon is an explicit tax, of which the cost is passed directly onto customers, is a policy approach that has not gotten much traction, with few signals pointing to a direct carbon tax, which Synapse relies on to inflate the cost delta between the two scenarios.

The remaining delta between the Mimic Duke and Reasonable Assumptions scenarios is based on aggressive and speculative technology cost declines, unrealistic

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[344] DEC IRP and DEP IRP at18-19.
[345] DEC IRP and DEP IRP at 152.
[346] DEC IRP at 186; DEP IRP at 185.
[347] DEC IRP at 16, note 2; DEP IRP at 17, note 3.

energy efficiency growth, admittedly failing to account for the cost of network upgrades associated with interconnecting these facilities, relieving reliability must runs and retiring coal without appropriate transmission system costs reflected, and erroneously increasing the effective cost of natural gas assets in the Mimic Duke by forcing their retirement by 2050. The skewed economic results, built on a foundation of unrealistic operational modeling assumptions should be given no weight especially when compared to the robust modeling and planning included in the Companies' IRPs.

In summary, as the Companies emphasized in responding to the 2018 Synapse report, any party can claim that their plan is lower cost than the Companies' plans, but to achieve those costs savings in the manner that Synapse did, while still claiming to meet the reliability standards that the Commission, the Companies, and their customers demand, is completely unrealistic and lacks regulatory rigor. DEC and DEP, as the regulated utilities in North Carolina, have the sole obligation to meet its customers' energy needs at all times throughout the year, and the Companies are steadfast in their belief that the DEC and DEP IRPs achieve that standard by doing so at the lowest reasonable cost while meeting and exceeding environmental regulations at the state and federal levels. Simply put, other parties to this docket do not have the obligation to serve, nor do they have an obligation to maintain a reliable electric system. Their use of overly simplistic modeling approaches to reach a predetermined ideological outcome would not be compliant with reliability standards and as such should be rejected.

G. Plans for Additional Comments on Second Corrected Synapse Report

As discussed above, Counsel for the Joint Synapse Sponsors filed the Second Corrected Synapse Report after 4:00 p.m. on the day before these reply comments were due to be filed with the Commission. Accordingly, the Companies' comments in this section only apply to the first corrected version of the report, filed in this docket on March 22nd, as the Companies have not yet been able to review the Second Corrected Synapse Report. The Companies plan to conduct additional discovery on the Second Corrected Synapse Report as needed and will seek leave of the Commission to file additional comments in the near future.

XVII. Future Modeling Methodologies

A. The Companies will file the 2021 IRP with EnCompass Model from Anchor Power Solutions

The Companies have selected the EnCompass from Anchor Power Solutions for future resource planning modeling. This will be the model of record for the 2021 IRP Update and future regulatory filings. EnCompass uses a mathematical solver to find the optimal solution to the capacity expansion and the production cost problems. The mathematical solver is expected provide a more optimal solution that the older methods used by System Optimizer and Prosym.

For production cost, in Prosym, unit commitment was determined by calculating a commitment cost based on anticipated run time and was not reevaluated to see if the commitment schedule was optimal. Energy storage was solved in two passes. The first pass created a marginal cost curve that a second pass used to schedule energy storage and generation before making the final commit and dispatch decisions.

EnCompass determines the commit and dispatch, and energy storage and generation solutions simultaneously to yield an overall optimal solution within a user specified tolerance. However, the capacity expansion problem is still determined by simulating a subset of hours and extrapolating the result to cover the entire time period. This is necessary to evaluate thousands of portfolio compositions to reach solution within a reasonable time. Energy storage expansion options require hourly chronologic detail to be accurately evaluated. So, energy storage expansion options selected by EnCompass still need to be verified by the more rigorous production cost simulation.

B. The Companies Disagree with the Public Staff's Recommendation to Present a Portfolio Allowing the Model to Economically Select Resources Based on an Imposed Carbon Limit

The Companies disagree with the Public Staff's recommendation to evaluate carbon reduction on carbon limit models.[348] In general, energy policy has not gravitated to strictly policy solutions such as mass cap scenarios, but in part to market-based solutions such as clean energy standards, carbon tax, cap with allowance and trading programs, or investment and production tax credits. Modeling a mass cap scenario is often iterative (expansion planning and carbon budgeting throughout the year) and time-consuming approach. Carbon price as a shadow price as proxy for energy policy is appropriate for planning.

EnCompass can be used to evaluate mass cap scenarios. However, as alluded to above, mass cap evaluation rely on segmenting an annual cap into smaller optimization blocks such as hourly, daily, or weekly. This severely limits economic optimization of the portfolio, both the selection of resources in the capacity expansion set, and dispatch of resources in the production cost modeling step by prescribing carbon budgets, when not knowing the best (most economic) time to allocate allowable emissions. The CO_2 shadow price, as deployed in the Companies' 2020 IRPs, gives an economic signal that the model uses to determine the best allocation of allowable emissions. The shadow price can be varied to give the desired solution.

[348] Public Staff Initial Comments, at 155.

C. The Companies will evaluate whether the EnCompass Model can Determine the Economically Optimal Retirement Dates Endogenously and Plan to Discuss this Issue with the Public Staff

As discussed above in the Companies' response to intervenor comments on the coal retirement analyses, the Companies performed an in-depth, detailed, and rigorous economic coal retirement analysis. The Companies have agreed they will evaluate EnCompass's ability to more completely and accurately model coal retirements.

Like System Optimizer, the capacity expansion model used in the 2020 IRP, EnCompass can evaluate retirement options during the capacity expansion solution. Ongoing fixed costs can be entered based on an estimate of unit operations. This methodology presents, however, similar issues the Companies identified with optimization in capacity expansion models, in general, where the ongoing costs of coal units may change as the operation and retirement date vary. The model cannot change these inputs dynamically during the solution, such as the Companies approach in the economic coal retirement analysis. While the Companies are continuing to evaluate the economics of retiring 10,000 MWs of coal, the Companies will continue to investigate how a model can help determine the retirement dates with the appropriate level of cost detail and will discuss this issue with the Public Staff prior to the next comprehensive IRP in 2020.

D. The Companies Disagree with Public Staff's Recommendation to Consider Implementing Stochastic Optimization in its Capacity Expansion Model

The Public Staff recommends that "Duke should consider implementing stochastic optimization in its capacity expansion model."[349] The Companies disagree with this recommendation. Stochastics are generally more appropriate for single variable, short-

[349] Public Staff Initial Comments, at 16, 168.

term volatility. While stochastics can produce an array of results, and can be informative, the median and bounds of the analysis typically resemble a base case and high and low sensitivities as performed in scenario analysis. It is the Companies belief that long range modeling of uncertainties is better addressed and captured in scenario analyses, rather than volatility and randomness of stochastics modeling.

XVIII. Fundamental Regulatory and Market Reforms Beyond Scope of IRP Proceeding

A. Recommendations to Incorporate "Benefits of Regionalization" Through Study of RTO or EIM are FERC Jurisdictional Issues Subject to Future Legislative Consideration and are Beyond the Scope of IRP Proceedings

NCSEA/CCEBA argue that "Duke should incorporate into its IRPs the potential benefits of broader regionalization through structures such as energy imbalance markets ("EIM"), independent system operators ("ISO"), or regional transmission organizations ("RTO")" and suggest somewhat critically that the Southeast is the last region of the Country without an EIM, ISO, or RTO.[350] Vote Solar similarly alleges that the Companies' 2020 IRPs failed to assess the benefits of regional coordination, suggesting that formation of "an [EIM] or creation of a [RTO] in the Southeast could drive even more economic and carbon emissions benefits."[351] Tech Customers comments go further advocating that the Commission should direct DEC to submit an alternative IRP scenario assuming DEC is "participat[ing] in a reorganized market, such as an RTO . . ."[352]

In making these recommendations, these advocacy groups ask the Commission to extend IRP proceedings well beyond their statutorily prescribed purposes. IRP

[350] NCSEA/CCEBA Initial Comments at 42.
[351] Vote Solar Initial Comments at 9.
[352] Tech Customers Initial Comments at 18.

proceedings are appropriately focused on "analy[zing] . . . the long-range needs for expansion of facilities for the generation of electricity in North Carolina . . . ." *See* N.C. Gen. Stat. § 62-110.1(c); *State ex. rel. Utilities Comm. v. N.C. Electric Membership Corp.*, 105 N.C. App. 136, 142 (1992) ("N.C. EMC"). Wholesale power market constructs, like RTOs, EIMs, or the Southeast Energy Exchange Market now before FERC, are overseen and regulated by FERC under the Federal Power Act and such alternative market structures are well beyond the scope of IRP planning under the Public Utilities Act. *N.C. EMC.*, 105 N.C. App. at 144 (recognizing that "exclusive jurisdiction over interstate wholesale electric power transactions is conferred upon FERC" and affirming that issues affecting wholesale rates were appropriately not addressed in IRP proceeding as "such an issue is more appropriately addressed to FERC") *see also Nat'l Ass'n of Regulatory Util. Comm'Rs v. FERC*, 964 F.3d 1177, 1181 (2020). As the Commission is aware from its consideration and ultimate February 5, 20201 *Order Dismissing Protest*[353], SEEM is an automated energy-only exchange market and merely creates "a more efficient platform for conducting bilateral wholesale transmission transactions that are already permissible and transpiring" and does not otherwise change the Companies' operations or legal obligations.[354] The Companies did not consider SEEM, nor was it relied upon in any way, in developing the 2020 IRPs.

Moreover, to the extent that North Carolina has an interest in evaluating whether to fundamentally change the wholesale power market construct that exists in North Carolina, this complex policy decision is appropriately for the General Assembly to consider and not before the Commission in these IRP proceedings. While the Commission would

[353] *Order Dismissing Protest,* Docket Nos. E-2, Sub 1268 and E-7, Sub 1245 (Feb. 5, 2021) ("SEEM Order").
[354] SEEM Order at 5.

undoubtedly have much work to do if the State of North Carolina made the decision to introduce a different market structure, that involvement would only occur if state legislators make a decision to move in that direction.

NCSEA/CCEBA, Vote Solar, and Tech Customers also suggest that numerous studies have demonstrated that power system reliability will be improved and customer costs will be reduced if the Southeast region were to form an RTO.[355] However, this conclusory assertion is based on unreviewed policy papers that have not been subject to regulatory scrutiny. Furthermore, the cited studies only present one view of this complex issue while other recent studies have reached substantially different conclusions.[356] Both sides of this policy debate should be subjected to significant scrutiny in the legislative arena before any meaningful conclusions are reached.

It is also important to highlight from a more practical perspective that "studying" such fundamental market reforms in an IRP would not be a straightforward exercise. It would necessarily require the Companies' to make numerous, likely controversial, assumptions about what form of RTO and wholesale market would exist in the Carolinas and when. Furthermore, such an undertaking would require an immense amount of the Companies' resources to develop a credible and thorough analysis, as well as Public Staff resources and Commission resources to assess its reasonableness. The Companies' view therefore is that such a complex and costly undertaking is not appropriate in the context of

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[355] NCSEA/CCEBA Initial Comments at 42; Exhibit 3 SEIA Lucas Report at 71-72; Vote Solar Fitch Report at 9.

[356] *See e.g.,* Clark, Gifford, and Larson, *The Vertically Integrated Utility: A Time-Tested Approach for Delivering Customer Benefits and Ensuring State Flexibility in Achieving Energy Policy Goals* (Oct. 2020), accessible at: https://www.wbklaw.com/news/white-paper-the-vertically-integrated-utility/.

an IRP, particularly given that such a study, by itself, will likely have no direct, meaningful impact on the Companies' long-term planning process.

In sum, the Commission should reject these recommendations and, in doing so, make clear that fundamental wholesale market reforms that are subject to FERC's jurisdiction and future legislative consideration are well beyond the scope of IRP proceedings.

B. Recommendations to Study Merging DEC and DEP are Beyond the Scope of IRP Proceedings

The SEIA Lucas Report also recommends that the Companies should proactively seek changes that would allow the Companies to file joint IRPs between DEC and DEP and plan and operate its two companies as a single utility suggesting that this would "minimize[] costs for all its customers."[357] Vote Solar similarly argues that the Commission should require the Companies to "prepare an action plan for implementing joint capacity planning between the Companies," including evaluating any required changes to the joint dispatch agreement, any anticipated required regulatory approvals, and a projection of a realistic timeline for implementation.[358]

As the Commission is aware, pursuant to the Commission's regulatory approvals of the Duke-Progress Merger,[359] DEP and DEC continue to operate as separate BAs and utilities, and each is responsible for its own independent resource planning and operations. Indeed, Section 4.1 of the regulatory conditions, as approved by the Commission, clarified that the Commission's approval of the merger was conditioned upon the Joint Dispatch

[357] NCSEA/CCEBA Initial Comments, Exhibit 3 SEIA Lucas Report at 68.
[358] Vote Solar Attachment 1 Fitch Direct at 59.
[359] *See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, N.C.U.C. Docket Nos. E-2, Sub 998 and E-7, Sub 986 (June 29, 2012).

Agreement not being interpreted as providing for or requiring a single integrated electric system, a single Balancing Authority Area or joint planning of generation.[360] Likewise, Section 4.2 of the regulatory conditions requires that DEC and DEP file advance notice with the Commission prior to engaging in any of the activities listed in Section 4.[361] However, the Companies have consistently included a joint planning scenario in their IRPs. As part of their review of the 2020 IRPs, the Public Staff concluded that "there are potential operational benefits associated with treating the DEC and DEP systems as a combined system for the purposes of sharing reserves and firm capacity, notwithstanding the legal barriers that exist to such operation."[362] The Companies will continue to include a joint planning scenario in future IRPs and, if and when a combination of the DEP and DEC balancing authorities or utilities would be in the public interest, the Companies will seek such regulatory approvals.

However, similar to these advocacy groups' improper recommendation to study wholesale market reforms in future IRPs, addressed above, mandating a formal study of merging DEC's and DEP's operations would be a complex and costly undertaking that is also well beyond the scope of IRP proceedings. Even if the Companies or the Commission

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[360] Regulatory Condition No. 4.1, which provides that "DEC and DEP acknowledge that the Commission's approval of the merger and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA never being interpreted as providing for:

(a) A single integrated electric system
(b) A single BAA, control area, or transmission system
(c) Joint planning or joint development of generation or transmission
(d) DEC or DEP to construct generation or transmission facilities for the benefit of the other
(e) The transfer of any rights to generation or transmission facilities from DEC to DEP to the other, or
(f) Any equalization of DEC's and DEP' production costs or rates."

[361] Regulatory Condition No. 4.2 which provides that "To the extent that DEC and DEP desire to engage in any of items (a) through (f) listed in Regulatory Condition 4.1, above, DEC and DEP shall file advance notice with the Commission at least 30 days prior to taking any action to amend the JDA or a successor document or to enter into a separate agreement. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition."

[362] Public Staff Initial Comments at 75.

were to initiate a review of the Companies' operations under the JDA or to consider the significant regulatory complexities and implications of combining the DEC and DEP Balancing Authorities, the IRP proceeding would not be the appropriate forum for considering such issues. Accordingly, the Commission should reject the NCSEA/CCEBA and Vote Solar requests for the Companies to undertake such comprehensive, time consuming and expensive regulatory and analytical studies of fundamental market reforms that are beyond the scope of integrated resource planning.

XIX. Proposals for Future Regulatory Action

A. The Companies do not Oppose the Public Staff's Recommendation for a Commission Rulemaking Proceeding to Assess the Need for Commission Approval Prior to Construction of a Battery Energy Storage Facility

The Public Staff highlights that "[battery] storage is increasingly impacting the utility reserve margin planning as it is relied upon to provide electricity during peak load hours, similar to a traditional generation resource or pumped hydro storage facility" and suggests that "battery storage acts as electric load while charging and acts as electric generation while discharging and should be accounted for in the regulatory planning and construction processes."[363] In order to better ensure that the Commission and the Public Staff are "aware of the replacement capacity needed, alternative solutions, and other aspects of Duke's operations to ensure efficiency, minimize costs, and evaluate reliability, including impacts on individual Duke balancing areas as well as neighboring balancing areas," the Public Staff recommends that the Commission initiate a rule making proceeding that would evaluate whether, and under what circumstances, an electric supplier should be

[363] Public Staff Initial Comments, at 108-109.

required to receive Commission approval prior to construction of a battery energy storage facility.[364]

The Public Staff correctly recognizes the growing role of battery storage in the Companies' future resource plans to reliably and cost effectively serve customers, and the Companies agree that the Commission should be informed of the Companies' plans to install battery storage on their systems to provide peaking capacity and/or to operate as a load to reliably serve customers. The Companies do not oppose the Public Staff's recommendation for a rulemaking to evaluate *whether, and under what circumstances*, an electric supplier should be required to receive Commission approval prior to construction of a battery energy storage facility. If the Commission elects to undertake such a rulemaking, the Companies recommend the Commission consider the following:

1) *Whether such a rule is needed?* The Companies agree with Public Staff that a threshold question should be whether such a rule is needed to keep the Commission and the Public Staff informed of the Companies and other electric suppliers' plans to construct battery storage systems in North Carolina. The Companies addressed their plans for new generation, demand-side resources as well as battery storage in their 2020 IRPs and will continue to refine their deployment plans in future IRPs. To the extent that the Commission seeks more detail on these nearer-term deployment plans, the IRP seems to be the most reasonable and efficient regulatory vehicle to keep the Commission informed of the Companies' plans. Consideration of any new process should be careful to assess the potential drawbacks of over-regulation that might have the

[364] Public Staff Initial Comments, at 15-16, 109.

potential to stifle or slow innovation or impede timely investments needed for reliability.

2) *What "electric suppliers" should be subject to such a rule*? "Electric supplier" is a defined term within the territorial assignment provisions of the Public Utilities Act and means "any public utility furnishing electric service or any electric membership corporation." *See* N.C. Gen. Stat. § 62-110.2(a)(3). It is unclear whether this is the meaning intended by the Public Staff. If the Commission believes that a new certificate-like approval process is needed prior to construction of certain types of battery storage assets, this requirement should align with the certificate requirements for new generating facilities and exclude only classes of storage facilities that would not be subject to obtaining a certificate under the Public Utilities Act under N.C. Gen. Stat. § 62-110.1(g).

3) *What operational considerations would be meaningful for the Commission to be aware if a rule is established?* As the Public Staff recognizes, storage can be utilized both as an electric load while charging and acts as electric generation while discharging. A key question is whether battery storage will be "helping" grid operations and improve reliability or be operated in an economic arbitrage mode, as described above in Section XII. B. 1., that may introduce greater complexity for the system operator. Storage needs to be studied for network load service unless under control of a system operator. If under system operator SCADA control, the storage system output or load can be quickly adjusted to mitigate any threat to NERC Reliability Standard compliance. In addition, the 2020 IRP shows 4-hour battery storage to have a higher capacity value if under

utility control due to factors such as the system operator monitoring and controlling state of charge and ensuring the battery storage is ready and optimized when needed for peaking capacity.[365] Accordingly, if the Commission finds that initiating a rulemaking on this topic is appropriate, then the Companies recommend the Commission include operational considerations in the draft rule so that the Commission can be informed of the planned operation of the battery storage.

B. Environmental Parties' All-Source Procurement Proposal is a Solution in Search of a Problem that Would Require Enabling Legislation, not Regulatory Approval in an IRP Docket, and Therefore Should be Rejected

Environmental Parties submit an expert report by John D. Wilson of Resource Insight, Inc. entitled "Implementing All-Source Procurement in the Carolinas" ("All-Source Procurement Proposal").[366] Relying on the All-Source Procurement Proposal, the Environmental Parties argue that Commission should "require Duke to implement all-source procurement starting in 2026 as part of the Commission's annual plan to meet electricity resource needs . . ." and assert that this approach will ensure the Companies "upcoming need [for new capacity] is met with least-cost and clean resources."[367] The crux of the All-Source Procurement Proposal is that allowing DEC and DEP to follow "traditional procurement practices" is purportedly biased to promote fossil-fueled, self-built generation and against selecting renewables and energy efficiency resources.[368] The All-Source Procurement Proposal points to Colorado's regulatory framework as model

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[365] See DEC 2020 IRP at 344-349; DEP 2020 IRP at 338-343.
[366] Environmental Parties Attachment 6, J. Wilson ASP Report.
[367] Environmental Parties' Initial Comments, at 23.
[368] Environmental Parties' Initial Comments, at 22.

where this "unified resource acquisition process" has been utilized by another vertically integrated utility to procure new generation—primarily new solar and battery storage.[369] Environmental Parties conclude that the Commission has the authority to, and should, force the Companies to fundamentally modify the resource planning and generation certification process in North Carolina to an integrated all-source procurement framework.[370]

As an initial matter, the one-size-fits-all approach recommended by the Environmental Parties is a solution in search of a problem, as the existing regulatory construct has served customers well. The Commission has a well-established and effective process under its existing rules to stay informed of the Companies' evolving resource planning process and provide guidance on those plans under Rule R8-60. The IRP process then informs how DEC and DEP plan to serve customers future capacity and energy needs, subject to Commission oversight, through either approval of a CPCN to construct a new generating facility under Rule R8-61, approval of a new DSM/EE program under Rule R8-68, or expedited approval of a new renewable energy facility selected in the CPRE Program under Rule R8-71. Similar to the Public Utilities Act itself, the Commission's existing regulations provide an "integrated plan" for overseeing the Companies operations and effectively ensure DEC's and DEP's resource decision-making aligns with the State's energy policy.[371] In the recent past, the Companies have made various types of resource decisions to ensure continued reliability of customers at affordable rates all under the existing regulatory construct with appropriate Commission oversight. Imposing further

[369] Environmental Parties Attachment 6, J. Wilson ASP Report at 12.
[370] Environmental Parties' Initial Comments, at 20.
[371] *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 495 (2012)("Chapter 62 is a single, integrated plan. Its several provisions must be construed together so as to accomplish its primary purpose.")(internal citations omitted).

complex regulatory processes onto such decisions is not in the best interests of customers, particularly where unique facts and circumstances do not lend themselves to one-size-fits-all approach. For example, the Companies Western Area Modernization Project is a unique, multi-faceted project approved by that Commission that has clearly benefitted customers but for which an All Source Procurement would not have been appropriate. Because the Companies have the responsibility to manage the business and ensure reliability for customers, it is imperative that they have the flexibility needed to adapt to emerging issues, technical considerations and market conditions in order to identify the most cost-effective resources available to meet customer needs. All such decisions are subject to regulatory scrutiny, but imposing a one-size-fits-all regulatory process is not needed at this time, particularly where no fundamental flaw has been identified in the current regulatory construct.

In addition, the Environmental Parties' All-Source Procurement Proposal is inconsistent with North Carolina's regulatory construct and the statutory framework for planning and seeking approval to construct new generation under the Public Utilities Act. First, the only legislative authority that Environmental Parties identify as supporting their recommended process is N.C. Gen. Stat. § 62-110.1(c) mandating the Commission undertake least cost resource planning. While it is true that long-range integrated resource planning is mandated by the General Assembly to reliably meet future capacity needs at least cost, Environmental Parties generalized assertion that "all-source procurement is more likely to lead to least-cost procurement than the status quo" is neither accurate nor a sufficient basis on which to fundamentally change the regulatory process in North Carolina.

In North Carolina, the integrated resource planning process is a fact-gathering legislative hearing-type process intended to inform future decisions by utility management regarding resource planning decisions to made at a later date; "[n]owhere is it suggested in section 62-110.1(c) that the purpose of the proceeding is to issue directives which fundamentally alter a given utility's operations." *N.C. EMC*. 105 N.C. App. at 143-144. Public Utilities are then responsible for filing for applications for certificates of public convenience and necessity ("CPCN") under N.C. Gen. Stat. § 62-110.1(a) for approval to construct new generation to provide adequate and reliable service to their customers. The Companies' IRPs are "consider[ed by the Commission] . . . in acting on any petition by any utility for construction" to ensure that "construction will be consistent with the Commission's plan for expansion of electric generating capacity." N.C. Gen. Stat. § 62-110.1(c), (e). However, the Commission has recognized that "[a]t the end of the day, . . . it is the utilities' responsibility to balance the sometimes complex and competing issues so that their customers are assured a reliable electricity supply at reasonable cost." *Order Holding Docket in Abeyance*, Docket No. E-100, Sub 112 (Aug. 11, 2009).

Mandating an all-source procurement process to "unify" the IRP and new generation CPCN process into single multi-step proceeding managed by the Commission and an independent entity on behalf of the utility is simply not supported by the current statutory framework and further would substantially impede the utility management's role in selecting new resources on which it will then rely to ensure reliability. As the Commission is well aware, the IRP is not static and evolves over time as load, generation resources, policy and myriad other factors change. Requiring all source procurement at the IRP stage could lead to some unintended consequence and run directly contrary to the purpose of the CPCN process to "prevent costly overbuilding." *State ex rel. Utilities Com. v. High Rock Lake Asso*., 37 N.C. App. 138, 141 (1978).

Despite Environmental Parties' creative arguments that support for this new integrated all-source procurement framework can be found in the IRP statute's general mandate for least cost planning, the All-Source Procurement Proposal cited by the Environmental Parties itself implicitly recognizes that adopting this new "Colorado model" procurement framework would require legislative action. The All-Source Procurement Proposal suggests that its recommendation to adopt the "Colorado model" is built on the recommendations of the North Carolina Energy Regulatory Process' ("NERP") competitive procurement study group. The NERP process report recommended that a threshold step for adopting a procurement model would be for "the General Assembly [to] expand existing procurement practices to utilize competitive procurement as a tool for electric utilities to meet energy and capacity needs defined in utility Integrated Resource Plans (IRPs) . . ."[372] The Companies' similarly view action by the General Assembly as necessary to implement the All-Source Procurement Proposal.

It is also notable that the General Assembly has provided for an independently-administered CPRE Program somewhat similar to the Colorado model recommended in the All-Source Procurement Proposal but *only* for the limited purpose of procuring renewable energy facilities up to 80 MW under N.C. Gen. Stat. § 62-110.8(a). In approving rules to implement the CPRE Program, the Commission recognized and attempted to balance the legislative direction in N.C. Gen. Stat. § 62-2(3) to promote "adequate, reliable, and economical utility service" to Duke's customers with the new CPRE Program statutory

[372] North Carolina Energy Regulatory Process, Summary Report and Compilation of Outputs (Dec. 22, 2020).

framework, and identified that a "process that forces proposals selections on the utility could be viewed as undermining the Commission's ability to look solely to the utility in meeting the directive in G.S. 62-2(3), while a proposal process that grants the utility unilateral authority to select proposals could be viewed as undermining the 'independence' of the administration of the CPRE Program."[373] The Commission was able to "strike[] an appropriate balance between retaining traditional utility authority for the provision of adequate and reliable service and fostering the independence in the CPRE Program that the General Assembly intended."[374] Importantly, the General Assembly prescriptively established this alternative independently-administered procurement framework solely for the purpose of procuring renewable energy facilities under the CPRE Program and has not established an all-source procurement framework as recommended by Environmental Parties and in the All-Source Procurement Report.

In sum, the All-Source Procurement Proposal is a solution in search of a problem, as the existing regulatory construct has served customers well. At this time, and absent legislative action finding this significant restructuring of the regulatory framework to be in the public interest in North Carolina, the Commission should reject the All-Source Procurement Proposal.

XX. Requests for Evidentiary Hearing Should be Denied

Some intervenors, as well as many of the consumer statements of interest filed with the Commission, have asked for an evidentiary hearing. The Companies respectfully assert that an evidentiary hearing is not necessary, because the Commission has a voluminous record before it, including numerous studies and reports from various technical witnesses,

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[373] *Order Adopting and Amending* Rules, at 16 Docket No. E-100, Sub 150 (Nov. 6, 2017).
[374] *Id.* at 17.

which is adequate to review and rule on the adequacy of the Companies' 2020 IRPs. Furthermore, as discussed at the outset of these reply comments, the IRPs are a "snapshot in time," and the 2021 IRP Updates are due to be filed on September 1, 2021 – approximately three months from now. The Companies therefore respectfully assert that an evidentiary hearing at this point of the proceeding would leave little, if any, time to complete the record on the 2020 IRPs prior to the filing of the 2021 IRP Updates and would therefore be of limited value, especially when all intervenors have had the opportunity to make legal, factual, and technical arguments to the Commission in their filed comments. Finally, some comments—particularly those contained in some consumer statements—appear to reflect an incorrect assumption that Commission acceptance of an IRP constitutes the Companies' request for, or Commission approval of, specific generation resources contained therein. As the Commission noted in its June 26, 2015 *Order Approving Integrated Resource Plans and REPS Compliance Plans,* in Docket No. E-100, Sub 141, at page 11:

> General Statute 62-110.1(c), in pertinent part, requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." In *State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation*, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that
>
> [t]he Duke and CP&L plans were "reasonable for the purposes of [the] proceeding" before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of "analy[zing]…the long-range needs for expansion of facilities for the generation of electricity in North Carolina…" See N.C. Gen. Stat. § 62-110.1(c).
>
> The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific

> projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing "directives which fundamentally alter a given utility's operations." With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

As such, by statute, decisions on the need, cost and timing of a specific generation resource would only be made after a CPCN application was filed and considered by the Commission in a public and transparent CPCN proceeding conducted pursuant to N.C. Gen. Stat. §§62-110.1 and 62-82. Accordingly, Duke Energy respectfully asserts that the requests for an evidentiary hearing on the 2020 IRPs should be denied.

CONCLUSION

In conclusion, the Companies submit that their 2020 IRPs, REPS Compliance Plans, and CPRE Plans meet the requirements of all applicable statutes, Commission Rules, and Commission orders and should be approved. Furthermore, DEC and DEP assert that there is no compelling reason to hold an evidentiary hearing when all parties have had adequate opportunity to present their comments and alternatives before the Commission, and the requests for same should be denied.

This the 28th day of May, 2021.

/s/E. Brett Breitschwerdt

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DEC/DEP Attachment 1

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Duke Energy Progress, LLC

ICF Report on 2020 IRP Stakeholder Engagement

Duke Energy 2020 Integrated Resource Planning (IRP) Stakeholder Engagement Summary Report

1. Executive Summary

This report provides an overview of the stakeholder engagement activities undertaken by Duke Energy (Duke) to support development of the 2020 IRPs for Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC). Duke organized these activities for its North Carolina and South Carolina stakeholders with the objectives of educating participants on the IRP regulatory requirements and development process, soliciting upfront input to inform the foundational inputs to the 2020 IRP and to simplify the post-filing adjudicated process.

These engagement activities, which spanned six distinct efforts/events and included North Carolina and South Carolina stakeholders, are described in greater detail later in the report:

1. Community-level IRP listening sessions in North Carolina and South Carolina to solicit stakeholder input about priority IRP focus areas and suggestions for how to structure later engagement activities (January to April 2020).
2. Duke and ICF co-facilitated an IRP 101 webinar to provide stakeholders with an overview of national trends, existing North Carolina and South Carolina regulatory requirements, and current Duke practices (March 2020).
3. A pre-engagement survey, conducted by ICF prior to two virtual stakeholder forums, to solicit input on priority focus areas and suggestions for how to structure forthcoming IRP engagement activities (March 2020).
4. An initial IRP virtual forum with focus areas based on stakeholder-indicated priorities from the ICF survey, designed to allow ample engagement by stakeholders through moderated Q&A (March 2020).
5. A second IRP virtual forum that largely covered the same focus areas as the first forum, but advanced the conversation by providing new types of information sought after by stakeholders and allowed for greater dialogue between stakeholders and Duke (April 2020).
6. A pre-filing webinar to review various comments and questions from stakeholders and to provide an overview of how Duke decided which input to incorporate into this year's IRPs (June 2020).

Additionally, Duke created a web site, www.duke-energy.com/irp, to provide stakeholders with access to materials from these IRP sessions and related reference materials, including all of the presentation materials from the webinars and virtual forums, and a document capturing Q&As raised by participants during these sessions. Duke also followed up directly with stakeholders whose questions were not able to be addressed during the allotted timeframes of each session.

These engagement activities allowed Duke to solicit valuable input from stakeholders and ensure the process was informative for stakeholders. For example, while ICF's pre-engagement survey highlighted that less than half of respondents were familiar with Duke's IRP modeling process, a survey following the last webinar demonstrated that stakeholders had enhanced their understanding of Duke's IRP process throughout these engagement efforts (i.e. an average score of 7.8 out of 10). The feedback received during these stakeholder engagement activities allowed Duke to more effectively design subsequent engagement activities around stakeholder priority areas and actively explore opportunities to reflect stakeholder input in the development of the 2020 IRP, all with the goal of simplifying the post-filing adjudicated process.

Stakeholder feedback generally converged on five key areas: (1) resource evaluation; (2) carbon reduction in the IRP; (3) energy efficiency (EE) and demand response (DR); (4) transparency of the IRP process; and (5) opportunities for stakeholder participation.

- **Resource Evaluation:** Stakeholder feedback in this area centered on how Duke models different resources to meet system needs and which data inputs, methodological assumptions and outputs it uses as part of the IRP. Stakeholders expressed interest in further understanding how Duke is evaluating the long-term role of existing supply resources, including nuclear, gas, and coal, and how it would expand efforts to incorporate newer resources, such as solar, storage, and wind. Some stakeholders expressed support for Duke's transition to the EnCompass modeling tool, which they indicated will help create improved functionality and greater transparency for modeling non-traditional resources to meet system needs. Additionally, stakeholders provided Duke with suggestions on specific datasets to use as inputs for the IRP modeling and the types of outputs that would be most valuable.
- **Carbon reduction in the IRP:** This focus area includes the pathways Duke could take to achieve carbon reduction goals, including fossil fuel power plant retirements and clean energy modeling. Some of the key areas of alignment in stakeholder feedback for this area include ensuring Duke explicitly states how the 2020 IRP differs from prior IRPs given the company's new climate goal, understanding how Duke reconciles differences in the time horizons for its IRP and climate goals, and identifying potential rate impacts associated with various carbon reduction pathways. Stakeholders also expressed interest in learning more about the role expanded transmission would play (e.g., to transmit electricity generated by offshore wind) and how Duke considers fugitive emissions as part of the modeling process. Stakeholders noted overlap between this topic and resource evaluation given the importance of identifying clean energy resources to replace retired coal assets and decrease the reliance on natural gas resources.
- **EE and DR:** Stakeholders expressed support for expanding opportunities for EE and DR (or demand-side management, or DSM, more broadly) to contribute to meeting system peaking needs. Given increasing winter peaking system needs, stakeholders suggested that DSM could play an important role in meeting those needs and should therefore be analyzed alongside other supply resources. In response, Duke proposed to conduct a winter peak reduction study to further evaluate the potential for innovative program designs and rate designs to help address

these needs, particularly in future IRPs. Stakeholders indicated strong support for undertaking this study and reinforced support for the development of innovative rate designs (e.g., time-of-use rates) to more accurately reflect the varying nature of system costs. One key area of emphasis from stakeholders was that all these contemplated options should ensure low- and moderate-income customers have opportunities to participate.

- **Transparency of the IRP process:** Related to the first three areas, stakeholders emphasized the importance of improving transparency of the IRP process. Given the technical rigor of the IRP modeling, stakeholders expressed an interest in having greater insights into the inputs and key methodological assumptions Duke uses as part of the process. Stakeholders also provided feedback on the types of outputs that would be most valuable, which can help streamline the post-filing data request process.
- **Opportunities for stakeholder engagement:** Stakeholders commended Duke for creating multiple opportunities and avenues for stakeholders to engage proactively on the 2020 IRP. Stakeholders appreciated Duke's efforts to design engagement sessions that allowed for informative two-way dialogue and supported the use of an independent facilitator to moderate the discussions. Additionally, stakeholders found it helpful for Duke to clearly articulate areas of feedback it sought from stakeholders and appreciated the opportunity to provide additional input to Duke outside of the engagement sessions themselves.

Following each of the virtual forums, ICF administered a survey of participants to solicit input on areas of interest and suggestions for future engagement activities. In total, 52 participants responded to the two surveys – 13 for the first forum and 39 for the second forum. Table 1 provides a summary of the average scores based on participants' responses to each of the questions (each forum had five rating-scale questions). Additionally, participants expressed appreciation for the opportunity to engage in dialogue with Duke and suggested a continued focus on the five areas mentioned above.

Table 1: Summary of Virtual Forum Survey Responses to Rating-Scale Questions

Survey Question	First forum average score (scale of 0-10)	Second forum average score (scale of 0-10)
How helpful was this forum in enhancing your understanding of Duke Energy's Integrated Resource Plan process? (0 = not at all helpful, 10 = extremely helpful)	7.4	7.6
How satisfied are you with the opportunity to provide feedback to and engage in dialogue with Duke Energy? (0 = not at all satisfied, 10 = extremely satisfied)	7.2	7.1
How helpful was this workshop in enhancing your understanding about other stakeholders' point of view? (0 = not at all helpful, 10 = extremely helpful)	5.5	6.7

Survey Question	First forum average score (scale of 0-10)	Second forum average score (scale of 0-10)
How willing are you to engage in follow-up conversations with Duke Energy around the IRP initiative? (0 = not at all willing, 10 = extremely willing)	9.5	N/A
How effective was this workshop in providing a foundation for new kinds of conversation and collaboration going forward? (0 = not at all effective, 10 = extremely effective)	6.9	6.8
How likely are you to provide Duke Energy with additional feedback before the May 1st deadline? (0 = not likely at all, 10 = extremely likely)	N/A	7.2

In addition to the surveys, 18 entities provided feedback on the following topics that Duke specifically requested input on during the second forum:

- **Resource Evaluation:** Additional data sources or evaluation methodologies to be considered
- **Carbon Reduction:** Additional scenarios and sensitivities and technology assumptions
- **Energy Efficiency/Demand Response:** Potential for Duke to undertake a winter peak demand reduction analysis

As the final planned stakeholder engagement session prior to the filing of the 2020 IRP, Duke hosted a webinar on June 18 to share the feedback stakeholders submitted that had generated the most stakeholder support and interest and address the company's ability to incorporate this feedback into the 2020 IRP. Following the webinar, 23 stakeholders completed a survey and expressed strong support and appreciation for Duke's IRP engagement process. Table 2 provides a summary of the average scores based on participants' responses to each of the five rating-scale questions.

Table 2: Summary of Final Planned Webinar Survey Responses to Rating-Scale Questions

Survey Question	Average score (scale of 0-10)
How helpful was this forum in enhancing your understanding of Duke Energy's Integrated Resource Plan process? (0 = not at all helpful, 10 = extremely helpful)	7.8
How satisfied have you been with the opportunity to provide feedback to and engage in dialogue with Duke Energy? (0 = not at all satisfied, 10 = extremely satisfied)	7.4

Survey Question	Average score (scale of 0-10)
Do you feel the key themes of today's webinar were reflective of stakeholder feedback? (0 = not at all reflective, 10 = extremely reflective)	7.6
How effective have these stakeholder engagement efforts been for you? (0 = not at all effective, 10 = extremely effective)	7.5
How likely would you be to engage in future IRP discussions? (0 = not likely at all, 10 = extremely likely)	9.0

Duke's six stakeholder engagement efforts/events—plus an additional opportunity for stakeholders to provide feedback on specific high-priority areas Duke identified—allowed Duke to amass a significant amount of stakeholder input aimed at further improving the 2020 IRP. While the feedback covered an array of topics, it generally aligned with one of three focus areas: (1) resource evaluation, (2) carbon reduction, or (3) energy efficiency, demand response, and winter peaking study. Duke provided guidance during its final pre-IRP filing stakeholder webinar on June 18 on how it is responding to this stakeholder feedback (Table 3).

Table 3: Summary of Duke Actions in Response to Stakeholder Feedback

Stakeholder Feedback: Areas with Most Stakeholder Support and/or Interest	Duke Action Taken
Resource Evaluation	
Desire by some for earlier insight on key data inputs and methodological assumptions	• Expedited response for intervenors under a non-disclosure agreement (NDA) • Duke moved up the timing of a Duke-hosted technical review with stakeholders from November to September
Consideration should be given to additional data sources	• Duke will use the EIA's 2020 Annual Energy Outlook (AEO) high and low oil and gas supply natural gas price curves as a benchmark to develop price curves • Vendor-supplied data uses market-based project data and Duke will benchmark with public sources to determine reasonableness
Duke should utilize EnCompass for the 2020 IRP and describe more about the integration of Duke's Integrated System & Operations Planning (ISOP) effort	• Duke will transition to EnCompass model in 2021 given delays in required training and implementation due to COVID response • The 2020 IRP will provide an update on ISOP and the 2022 IRP will reflect basic ISOP elements by assessing opportunities to defer or avoid traditional investments with non-traditional solutions

Stakeholder Feedback: Areas with Most Stakeholder Support and/or Interest	Duke Action Taken
Further clarity sought on coal retirement analysis	• Duke is conducting a transparent, detailed analysis of each remaining unit • Duke is conducting analysis that considers the most economic retirement pathway and earliest practicable retirement pathway
Interest in learning more about the potential for competitive solicitations	• Duke actively supports competitive procurement of renewables, which was part of comprehensive, collaborative legislation (HB 589) • When selecting resources to replace retiring coal units, Duke will consider alternative resources through a competitive procurement process • Duke envisions alternate technologies bidding into future RFPs
Duke should explain what the customer bill impacts are of various pathways forward	• IRP will present high-level system costs and average bill impacts of varying resource portfolios and carbon reduction glide paths
Carbon Reduction	

Diversity in carbon scenarios, with specific interest in CEP scenarios and relationship to climate goals	• IRP will rely on CO_2 prices to drive reductions in emissions and prices will align with previous or currently proposed carbon regulations
	• The IRP will reflect CO_2 prices with two separate views
	  ○ As a driver to commit resources to achieve a “carbon mass cap”
	  ○ As an explicit tax that is collected through utility bills as a carbon tax
	• Portfolios will reflect multiple glide paths to achieving Duke’s 2050 net-zero carbon goals, including considerations for the Clean Energy Plan

Role of expanded transmission	• The Transmission Planning Collaborative is studying opportunities to bring offshore wind into DEC and DEP, and the ISOP developmental effort will also explore potential benefits of strategic transmission investments
Considerations & assumptions for new technologies, especially solar, storage, wind, and solar plus storage	• Forecasts will include ~50% of incremental additions as solar plus storage • The model is eligible to select additional solar and solar plus storage above the forecast
EE, DR, and Winter Peaking Study	
Strong support for pursuing the Winter Peaking Study	• Proceeding with the study and will incorporate into the IRP’s high EE/DR scenario (when available) • Will continue engaging stakeholders via the EE collaborative and ISOP stakeholder sessions

Stakeholder Feedback: Areas with Most Stakeholder Support and/or Interest	Duke Action Taken
Study should evaluate customer programs that help address clean energy goals	• Use of 8760 hourly load shapes will help facilitate carbon impact modeling
Consideration needed for customer cost impacts, especially non-participants	• Will consider both participant and non-participant impacts with a focus on rate designs and innovative DER approaches that minimize program costs while driving targeted impacts
Study should evaluate differences between DEC and DEP	• The analysis will incorporate this distinction
Evaluate DEP West water heater and heat pump measures	• The study will analyze cold climate heat pumps and water heater controls
Study should account for winter peak length and continuation of summer peak hours	• Duke program designs will account for the length, frequency, and other characteristics of winter peak needs • Since the IRP accounts for all hours of the year, many of these winter-peak solutions can also help drive summer peak savings

Duke will consider stakeholder input in the development of the 2020 IRPs for DEC and DEP and will work with intervenors to provide access to key inputs in an expedited fashion shortly after filing. Duke also plans to hold a post-filing Technical Briefing in September and share additional details on IRP inputs as well as key takeaways from the expanded analysis in the 2020 IRPs, which will reflect alternate resource portfolios as part of a broader range of scenarios and sensitivities compared to past IRPs. Since one of the objectives of this IRP stakeholder process is to simplify the post-filing adjudicated process, Duke will assess the effectiveness of this formal stakeholder engagement effort and make adjustments as appropriate to enable greater transparency of the evaluation processes and understanding of IRP results to hopefully provide for streamlined proceedings before the NCUC and PSCSC.

2. Overview of Duke Energy Stakeholder Engagement Activities

2.1. Intervenor Comments

To help inform potential focus areas in the Duke engagement activities, ICF evaluated recent comments from relevant South Carolina and North Carolina dockets. For South Carolina, ICF reviewed from Docket 2019-224-E and 2019-225-E where intervenors filed comments related to Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP), respectively. Intervenors who submitted comments (all since January 2020) in these South Carolina PSC dockets include South Carolina Solar Business Alliance, Inc. and Johnson Development Associates, Inc. (SCSBA/JDA), Southern Environmental Law Center, South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Upstate Forever.

For North Carolina, ICF reviewed comments from the Commission-issued Order (August 2019) on the 2018 IRP, along with comments from a public meeting held in January 2020 where Duke, NRDC, Southern Alliance for Clean Energy, the Sierra Club, and North Carolina Public staff shared comments on IRP issues.

2.2. Community-Level IRP Listening Sessions

Duke hosted a total of seven community-level listening sessions – three in South Carolina and four in North Carolina – to engage a variety of stakeholder audiences (e.g., customers; environmental; renewables/DER; etc.) and solicit input on their priorities related to the 2020 IRP. Due to COVID-19, some of the earlier sessions that Duke had planned to hold in person were moved to virtual sessions.

Table 4: Summary of Duke Community IRP Listening Sessions

Date	Location	Number of Participants
February 26, 2020	NC	12
March 2, 2020	SC	4
March 4, 2020	NC	5
March 5, 2020	NC	7
March 5, 2020	SC	3
March 9, 2020	SC	2
April 8, 2020	NC	23

Table 5 provides a summary of key comments and questions stakeholders raised over the course of these listening sessions. These questions helped inform the topics ICF and Duke selected to focus on during the two forums, which are further described in Sections 2.5 and 2.6.

Table 5: Summary of Stakeholder Comments and Questions During IRP Listening Sessions

Category	Comments
Resource Evaluation	How does the modeling effort take into consideration existing resources considering that they may or may not become un-economic over time?
	Would small modular nuclear be considered as part of the future resource mix?
	How is Duke approaching nuclear relicensing?
	How long will the requested relicensing for Oconee last for?
	How is the potential impact of merchant gas development factored into the IRP?
	What will happen to gas resources after 2030? How does the company's carbon goal impact this?
	What policies and replacement resources are needed to retire coal? What role do existing resources and imports play?
	How does Duke model EE? How does the Market Potential Study inform the IRP?
	What role does Duke assume microgrids will play in meeting peaking needs?
	What benefits might arise if Duke combined the Carolinas into a single balancing authority?
	How does Duke compare rate impacts of various scenarios?
IRP Basics	What is the difference between IRP and ISOP?
	What is the role of IRP?

Category	Comments
	What is the time horizon Duke is considering in the IRP?
	What are the impacts of adding the transmission and distribution components to the IRP? How does this impact large customers?
Stakeholder Involvement	What is the Commission's involvement in ISOP?
	What is the involvement of the PUC in the IRP?
	How can stakeholders provide feedback in this process?
Transparency	Stakeholders identified the need for greater transparency around RECs in the IRP and suggested tying it with e-grid data.
	What steps is Duke taking to increase transparency in the modeling process?
	How can stakeholders request access to modeling documentation?
Clean Energy	What is Duke's vision in terms of ownership of new renewables and availability of future programs available to promote REC ownership?
	Duke should be explicit about how the company's climate strategy is changing the approach in the 2020 IRP relative to prior IRPs.
	How does the IRP incorporate Duke's net-zero by 2050 goal? What changes is Duke making if achieving this goal is inconsistent with a least-cost model?
	Does Duke use a carbon price when conducting its IRP?
	What transmission upgrades are needed to capture the potential of offshore wind?
	What assumption does Duke make about fugitive emission on the gas system? Does it consider other scope emissions or the carbon footprint of its supply chain?
Load Forecast	How does Duke determine the load forecast? How can Duke provide greater transparency into data sources and assumptions?
	Does Duke analyze how climate change may change heating/cooling degree day estimates?
	Is Duke considering vehicle electrification, including the potential for managed EV charging?
Input Data	How does Duke determine technology cost curves for renewables?
DSM	What is Duke's projected growth in EE and demand response (DR)?
	What opportunities do low-income customers have to participate in DSM programs?
Transmission	How does Duke focus on transmission reliability (e.g., how Duke locates failures)?
Specific Model Questions	What optimization software is Duke using for both production cost modeling and capacity expansion?
	Duke should consider the full value of renewables, including resilience

2.3. IRP 101 Webinar

Duke and ICF co-facilitated a one-hour webinar on March 10, 2020 to provide an overview on IRP and set the stage for further engagement as part of the two forums. The webinar focused on the following components:

- What an IRP is and why it's an important tool
- Defining characteristics of an IRP
- Components and factors considered within an IRP
- IRP results and outputs
- Duke Energy IRP overview

34 stakeholders attended the webinar. Duke also posted and distributed the webinar slides and recording to all stakeholders, ensuring those who could not make the webinar had a chance to review them prior to the virtual forums.

2.4. ICF Survey

ICF conducted a survey of North Carolina and South Carolina Duke stakeholders prior to the March 17 forum to further solicit input to inform the structure of the two forums. The survey, which ICF sent to Duke stakeholders on March 4, included seven questions and 16 stakeholders participated. The following provides a high-level summary of survey questions and responses:

- **Q1 – How familiar are you with North and South Carolina IRP filing requirements.**
  - The majority of respondents are somewhat familiar (44%) or very familiar (31%) with the IRP filing requirements.
  - No respondent indicated they were not familiar with the IRP process.
- **Q2 – Please rank topics below in order of importance to you for discussion at the IRP forum.**
  - Participants ranked options on a scale of 1 to 5. Options included:
    - State filing requirements
    - Input data assumptions
    - Modeling methodology
    - "Big picture" scenario outlooks
    - Types of modeling outputs/results/metrics.
  - In order of importance, the top three topics (based on the total score) were (1) "big picture" scenario, (2) input data assumptions, and (3) modeling methodology. Eight respondents ranked "big picture" scenario as their top choice, while 13 ranked state filing requirements as their lowest choice.
- **Q3 – Please indicate any topics areas of interest not identified in Question 2.**
  - Most respondents focused on resource evaluation and carbon reduction metrics and goals.
  - Other topics respondents mentioned included: differences between North and South Carolina, treatment of stranded asset risk for new natural gas, use of non-wires alternatives and demand-side management (DSM), ancillary services from storage, and how to get IRP outputs for use in spreadsheets.
- **Q4 – How familiar are you with Duke's IRP modeling process?**
  - 44% of respondents are not familiar with Duke's IRP modeling process, 25% of respondents are somewhat familiar, and 19% are very familiar.
- **Q5 – Please rank data input assumption areas you would be interested in discussing.**
  - Respondents chose between seven options:
    - Commodity price forecast (e.g., natural gas prices)
    - Capital equipment cost and performance
    - Load forecast
    - Energy efficiency/demand side management

    - Environmental policy and compliance options
    - Distributed energy resources
    - Reserve requirements
  - While results were relatively evenly distributed amongst all seven options, the top three were (1) energy efficiency/demand side management, (2) distributed energy resources, and (3) environmental policy and compliance options.
- **Q6 – Please indicate if there are any additional data topics not identified in Question 5 that you would be interested in discussing.**
  - Like question 3, the topics of greatest interest for respondents were resource evaluation and carbon reduction. Respondents provided other topics, including considerations around making the Carolinas a single balancing authority, how real-time pricing could affect peak demand, and how to model other environmental costs
- **Q7 – Do you have any preferred dataset/sources you can provide? Please list sources and/or include links in the comment box.**
  - Respondents provided two studies:
    - "Natural Gas: A Bridge to Climate Breakdown." Linked here: https://energyinnovation.org/wp-content/uploads/2020/03/Natural-Gas_A-Bridge-to-Climate-Breakdown.pdf
    - Alqahtani, B. and Patiño-Echeverri, D., Combined effects of policies to increase energy efficiency and distributed solar generation: A case study of the Carolinas. Energy Policy. Volume 134, November 2019, 110936. https://doi.org/10.1016/j.enpol.2019.110936 Alqahtani, B. and Patiño-Echeverri, D., “Integrated Solar Combined Cycle Power Plants: Paving the Way for Thermal Solar” Applied Energy 2016 (169), 927–936, doi:10.1016/j.apenergy.2016.02.083

2.5. First IRP Forum

Duke hosted its first IRP forum on March 17, 2020 via webinar. Although initially scheduled as an in-person session in Columbia, South Carolina, Duke converted the session to be entirely virtual due to the COVID-19 pandemic. ICF facilitated the stakeholder workshop on Duke’s behalf. Duke shared the agenda, slides, and recordings[1] from the session. Duke also created an IRP engagement e-mail at IRP-engagement@duke-energy.com that it shared during the forum where stakeholders could submit additional ideas and feedback. To encourage open dialogue, Duke did not record portions of the workshop that entailed verbal participation by stakeholders.

Excluding Duke and ICF staff, the stakeholder workshop featured a total of 72 attendees representing 48 entities (Table 6).

[1] There are five separate recordings, one for each agenda item covered during the forum.

Table 6: Breakdown of Stakeholder Attendees from 3/17 Forum

Stakeholder Category	Total Attendees
Academic/Research	7
Environmental	19
Government	14
Customers	12
Renewable/DER	10
Other	10

2.5.1. Overview of Forum Agenda and Breakout Sessions

Duke and ICF structured the first forum to focus on the topics that were most important to stakeholders based on feedback from listening sessions, intervenor comments filed in previous IRP dockets, and the survey sent by ICF on March 4. The forum began with an overview from ICF of the national landscape for utility IRP processes, including forecasting and planning requirements and recent national trends. Duke then provided an overview of the IRP process in the Carolinas and how that aligns with national best practices and trends. These presentations set the stage for four breakout sessions that were chosen based on stakeholders' greatest areas of interest: (1) resource evaluation; (2) carbon reduction in the IRP; (3) energy efficiency; and (4) load forecasting. Each session featured a short introduction from Duke subject-matter experts and concluded with ICF moderating a Q&A session between participants and Duke.

Resource Evaluation

Duke provided a short overview of the key considerations it takes when determining cost-effective resource mixes, which sources it uses for various data inputs, and key factors impacting evaluation for the 2020 IRP. During the ICF-moderated Q&A session, Duke answered stakeholder questions focusing on topics including fuel price and discount rate assumptions, analysis of ancillary services from storage, updates on Duke's renewable integration analysis with NREL, and the role of DSM resources in capacity expansion modeling.

Carbon Reduction in the IRP

Duke provided a short overview of how the IRP will consider Duke Energy's climate strategy and the North Carolina Department of Environmental Quality (DEQ) Clean Energy Plan, including how this builds off Duke's current process for evaluating carbon reductions and relates to its coal plant retirement analysis. During the ICF-moderated Q&A session, Duke answered stakeholder questions focusing on topics including how carbon pricing impacts decisions around coal plant retirement, whether Duke uses discrete values for carbon price assumptions, if Duke considers carbon impacts for imports, and if Duke's carbon reduction plans account for fugitive emissions from natural gas production and distribution.

Energy Efficiency and Demand Response

Duke started by describing the full range of existing EE and DSM programs available to its customers in the Carolinas and provided an overview of its 2020 Market Potential Study (MPS) and methodologies for forecasting EE and demand response growth. During the ICF-moderated Q&A session, Duke answered stakeholder questions focusing on topics including which programs are directed to low-income customers, how EE and DSM could be leveraged to lower the system peak, what role there may be for more dynamic pricing at the retail level, and how Duke differentiates between organic growth of EE versus that driven by the company's programs.

Load Forecasting

Duke opened the breakout session by reviewing its load forecasting economic assumptions, projections for weather, renewables, EE, net metering (NEM), and electric vehicles (EVs), and the overall load forecasting methodology spanning from retail to wholesale to system level. Duke also described emerging trends in its system that could shift it from summer peaking to winter peaking. During the ICF-moderated Q&A session, Duke answered stakeholder questions focusing on topics including how COVID-19 is affecting load forecasts, what potential benefits would result by forecasting system needs based on a single balancing authority for the Carolinas, and how Duke considers potential overlap in customers who are on NEM and also adopt EVs.

2.5.2. Overview of Stakeholder Survey Results

Duke developed a survey to capture stakeholder feedback about the value of the forum and opportunities to improve future engagement activities. The survey included five rating scale questions and four short-answer questions. The survey was available to stakeholders through the webinar platform immediately following the forum and Duke sent a follow-up email on March 19 to stakeholders with a reminder to complete the survey. In total, 18% of attendees participated in the survey.

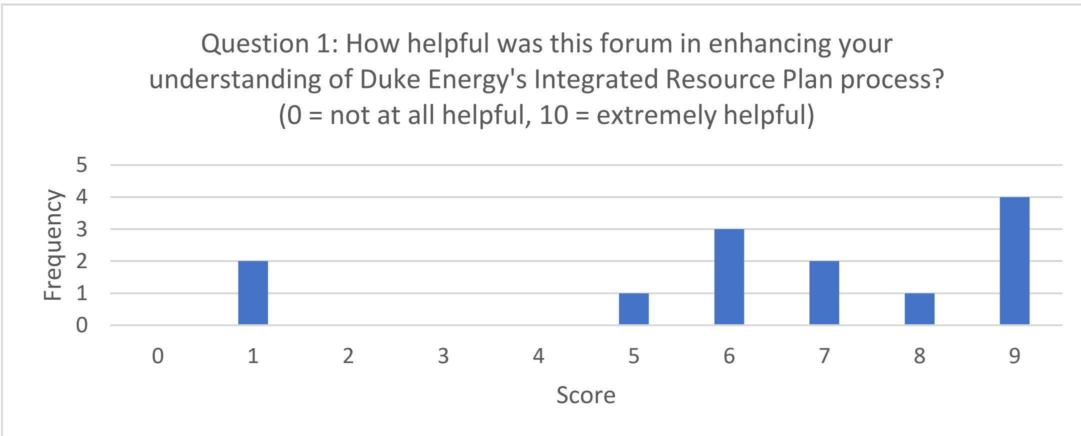
Figure 1 provides the distribution of all survey responses for each of the five rating-scale (i.e. on a scale of 0 to 10) questions. Average scores are as follows:

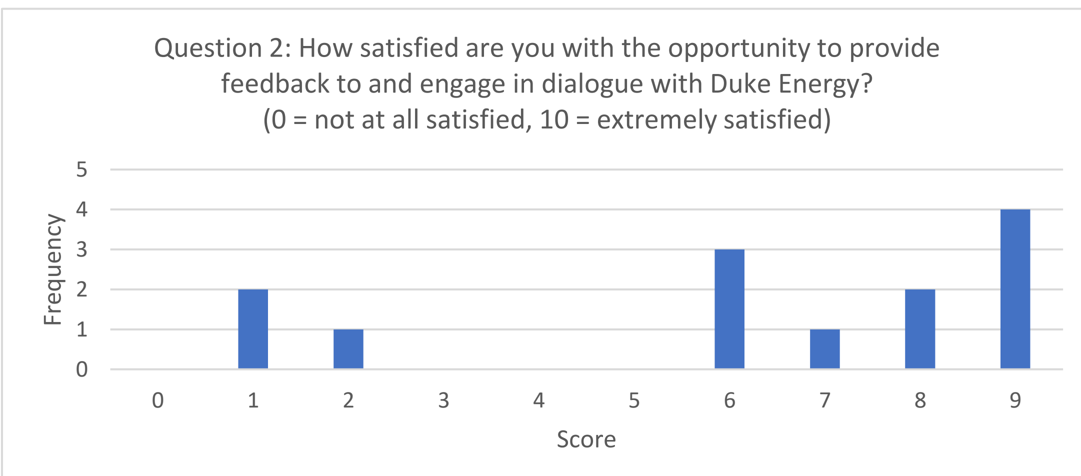
- Question 1: How helpful was this forum in enhancing your understanding of Duke Energy's Integrated Resource Plan process? (0 = not at all helpful, 10 = extremely helpful)
  - **Average score: 7.5**
- Question 2: How satisfied are you with the opportunity to provide feedback to and engage in dialogue with Duke Energy? (0 = not at all satisfied, 10 = extremely satisfied)
  - **Average score: 7.3**
- Question 3: How helpful was this workshop in enhancing your understanding about other stakeholders' point of view? (0 = not at all helpful, 10 = extremely helpful)
  - **Average score: 5.7**
- Question 4: How willing are you to engage in follow-up conversations with Duke Energy around the IRP initiative? (0 = not at all willing, 10 = extremely willing)

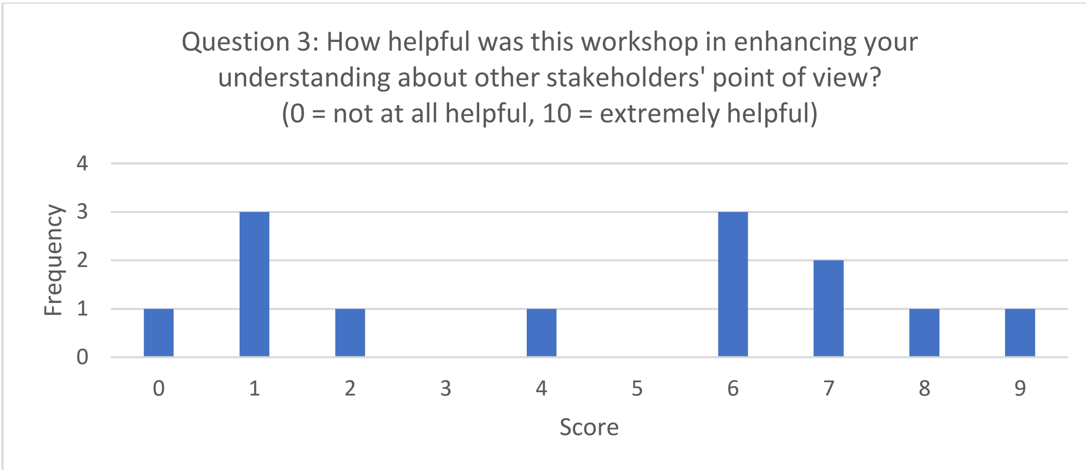
- **Average score: 9.5**

- Question 5: How effective was this workshop in providing a foundation for new kinds of conversation and collaboration going forward? (0 = not at all effective, 10 = extremely effective)
  - **Average score: 7.2**

Figure 1: Summary of Survey Responses to Rating-Scale Questions from 3/17 Forum






Question 3: How helpful was this workshop in enhancing your understanding about other stakeholders' point of view?
(0 = not at all helpful, 10 = extremely helpful)
Frequency
Score
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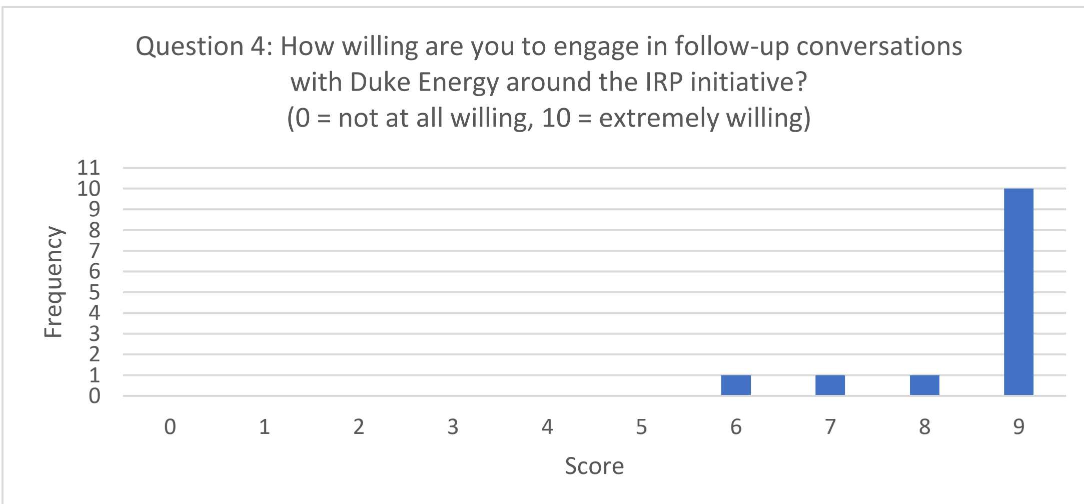
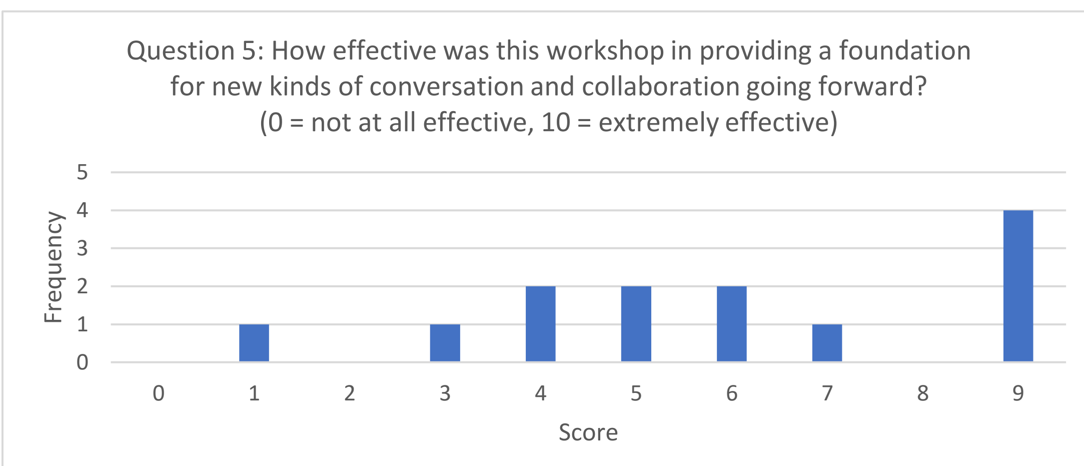

Question 4: How willing are you to engage in follow-up conversations with Duke Energy around the IRP initiative?
(0 = not at all willing, 10 = extremely willing)
Frequency
Score
0 1 2 3 4 5 6 7 8 9


Question 5: How effective was this workshop in providing a foundation for new kinds of conversation and collaboration going forward?
(0 = not at all effective, 10 = extremely effective)
Frequency
Score
0 1 2 3 4 5 6 7 8 9

In addition to the rating-scale questions, stakeholders provided written responses to four short-answer questions. Key themes of stakeholder responses for each question are summarized in Table 7.

Table 7: Key Themes of Stakeholder Responses to Short-Answer Survey Questions from 3/17 Forum

Question	Key Themes
What specific topics from today's session would you like to see covered in greater depth at subsequent webinars or meetings?	• Pathways for greater integration of solar, storage, and non-wires alternatives • Inputs used for the IRP analysis • Incorporation of carbon reduction scenarios • Effects on IRP due to changing winter and summer load curves
What did you like best about today's workshop?	• It was an effective format to begin each breakout session with a short overview of the topic followed by stakeholder Q&A • The PowerPoint presentations were informative, and the Duke panelists were knowledgeable and responsive • The webinar format allowed for high levels of stakeholder interaction in terms of submitting questions • The moderator was helpful for keeping the conversation flowing
Do you have suggestions for improving the next workshop or other ideas for the stakeholder engagement process?	• More time for the Q&A sessions • Focus more on providing details about the generation mix and data inputs rather than explaining what an IRP is and how the individual components work • Explain more effectively how stakeholder input will inform the 2020 IRP since Duke has already determined its initial assumptions • Use a better backdrop for Duke speakers using webcams • Allow for a longer break around lunch time
Is there anything else you'd like to tell us that we haven't asked about?	• IRP modeling ○ How Duke will address IRP scenarios proposed by stakeholders or report on them to the North Carolina Utilities Commission and South Carolina Public Service Commission ○ Potential for Duke to (1) plan for firm capacity between its utilities in the IRP modeling and (2) allow for options like real-time or critical-period pricing • Logistics ○ How Duke will respond to questions it did not have time to answer ○ Allow participants the option to use the computer for audio

Following the forum, Duke followed up directly with individual stakeholders who asked questions during the forum but whose questions were unable to be addressed within the allotted timeframe. Prior to Duke's second IRP Forum, Duke created an IRP stakeholder web page at https://www.duke-energy.com/our-company/irp and posted materials from the IRP 101 webinar, March 17 forum and the agenda and slides for its April 16 forum.

2.6. Second IRP Forum

Duke hosted its second IRP forum on April 16, 2020 via webinar. Although initially scheduled as an in-person session in Raleigh, North Carolina, Duke converted the session to be entirely virtual due to the COVID-19 pandemic. ICF facilitated the stakeholder workshop on Duke's behalf. Duke posted the agenda and slides from the session, but did not record the workshop in order to avoid attribution of stakeholder comments and questions given the significant level of verbal dialogue between stakeholders and Duke presenters throughout the webinar.

Excluding Duke and ICF staff, the stakeholder workshop featured a total of 113 attendees (81 of which did not attend the South Carolina forum) representing 70 entities (Table 8). In addition to these external stakeholders, Duke subject matter experts and other leaders also engaged in the workshop.

Table 8: Breakdown of Stakeholder Attendees from 3/17 Forum

Stakeholder Category	Total Attendees
Academic/Research	17
Environmental	27
Government	38
Customers	7
Renewable/DER	8
Other	16

2.6.1. Overview of Forum Agenda and Breakout Sessions

Similar to the first forum, this forum began with an overview from ICF of the national landscape for utility IRP processes, including forecasting and planning requirements and recent national trends. Duke then provided an overview of the IRP process in the Carolinas and how that aligns with national best practices and trends.

Following the introductory presentations, ICF provided an overview of the first forum and explained how today's forum fit within the context of Duke's broader stakeholder engagement efforts for the 2020 IRP. Duke then provided an overview of how it designed the forum directly in response to feedback it had received from stakeholders across all the previous engagement efforts. First, Duke specifically designed this forum to be responsive to stakeholder desires to increase opportunities for dialogue, minimize the upfront level-setting presentations, and avoid having the webinar run through lunch. Second, Duke focused the three breakout sessions around three key areas of stakeholder interest: (1) data inputs; (2) generation trajectories; and (3) customer programs and pricing. Finally, Duke provided clear asks of stakeholder to provide the types of input that would be most valuable to Duke as it advanced its 2020 IRP.

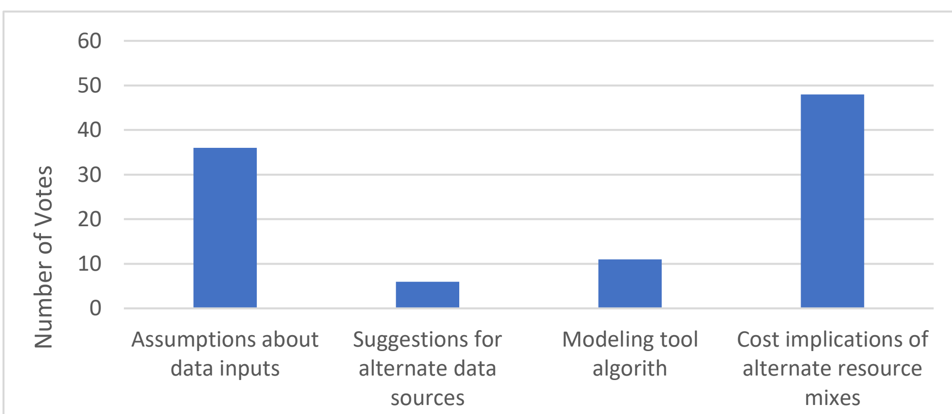
Similar to the first forum, Duke provided breakout sessions to enable an opportunity for further discussion on topics of greatest interest to stakeholders. The three breakout session topics – resource evaluation, carbon reduction in the IRP, and energy efficiency and demand response – were also in the first forum, but Duke adjusted presentation materials to more specifically focus on the three areas mentioned in the prior paragraph based on feedback from stakeholders. Additionally, Duke removed the fourth breakout session from the first forum (load forecasting) in order to allow greater time in each of the three breakout sessions for stakeholder dialogue.

Each session featured a short introduction from Duke subject-matter experts and concluded with ICF moderating a Q&A session between participants and Duke. To help shape the Q&A session, stakeholders were asked to vote through the webinar for which topics they wanted to discuss further out of a set of topics Duke had listed based on previously identified stakeholder priority topics. Given the magnitude of participation in the forum, attendees were instructed to "raise their hand" through the webinar so ICF could prompt stakeholders to ask questions in the order in which they raised their hand. Since there was not enough time to address all stakeholder questions, Duke committed to follow up individually with those stakeholders who had an outstanding question.

Resource Evaluation

Duke provided a short overview of the key considerations it takes when determining cost-effective resource mixes, which sources it uses for various data inputs, and key factors impacting evaluation for the 2020 IRP. In response to stakeholder feedback after the first forum, Duke expanded the list of data inputs and sources it shared with stakeholders and explicitly asked stakeholders to provide suggestions on any additional data sources. Additionally, to be responsive to stakeholder requests for further opportunities to engage during the forum, Duke had participants vote on their top two choices for discussion topics based on a set of four choices. Given the vote totals, the open dialogue portion of this breakout session focused on further exploring cost implications of alternate resource mixes and data input assumptions (Figure 2).

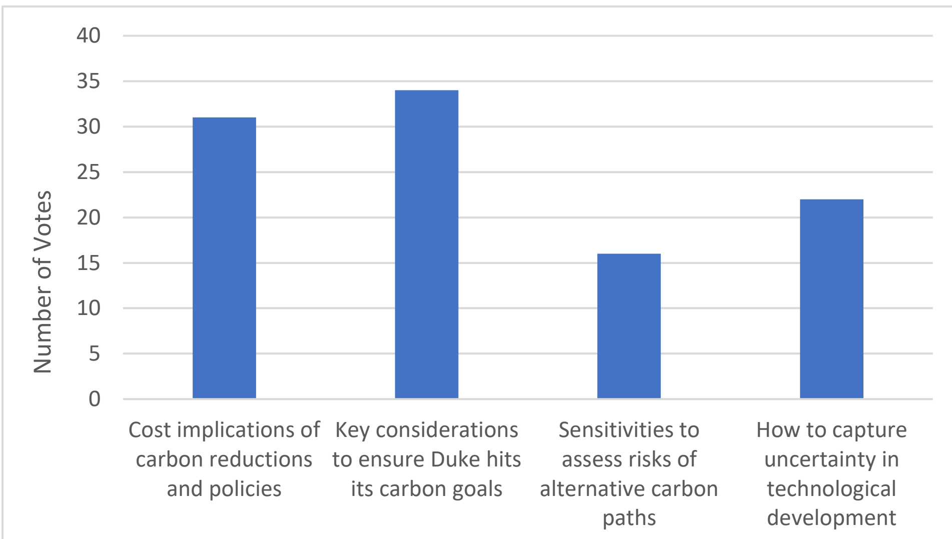
Figure 2: Priority Resource Evaluation Topics for Attendees



Carbon Reduction in the IRP

Duke provided a short overview of how the IRP will consider Duke Energy's climate strategy and the North Carolina Department of Environmental Quality (DEQ) Clean Energy Plan, including how this builds off Duke's current process for evaluating carbon reductions and what types of technological development will help achieve net-zero carbon emissions by 2050. Like the Resource Evaluation breakout session, attendees voted for their top two priority topics for further discussion with Duke. Based on the votes, Duke and stakeholders engaged in discussions around key considerations to ensure Duke hits its carbon goals and the cost implications of carbon reduction pathways and policies (Figure 3).

Figure 3: Priority Carbon Reduction in the IRP Topics for Attendees



Energy Efficiency and Demand Response

Duke began the breakout by explaining its EE forecast methodology, 2020 Market Potential Study, and the emerging trend that may shift the Carolinas to a winter peaking system from a summer peaking system. Given this potential for a winter peaking system and having heard stakeholder interest in exploring the potential role of DSM to help address this need, Duke unveiled the scope of a potential winter peaking study it could conduct to further evaluate how new rate designs and innovative program designs could drive winter peak load reductions. Unlike the other two breakout sessions, this one did not include a poll given Duke's interest in soliciting feedback specifically on the winter peaking study. During the ICF-moderated dialogue, stakeholders communicated wide support for undertaking the study and expressed interest in maintaining involvement as Duke further develops the study's scope.

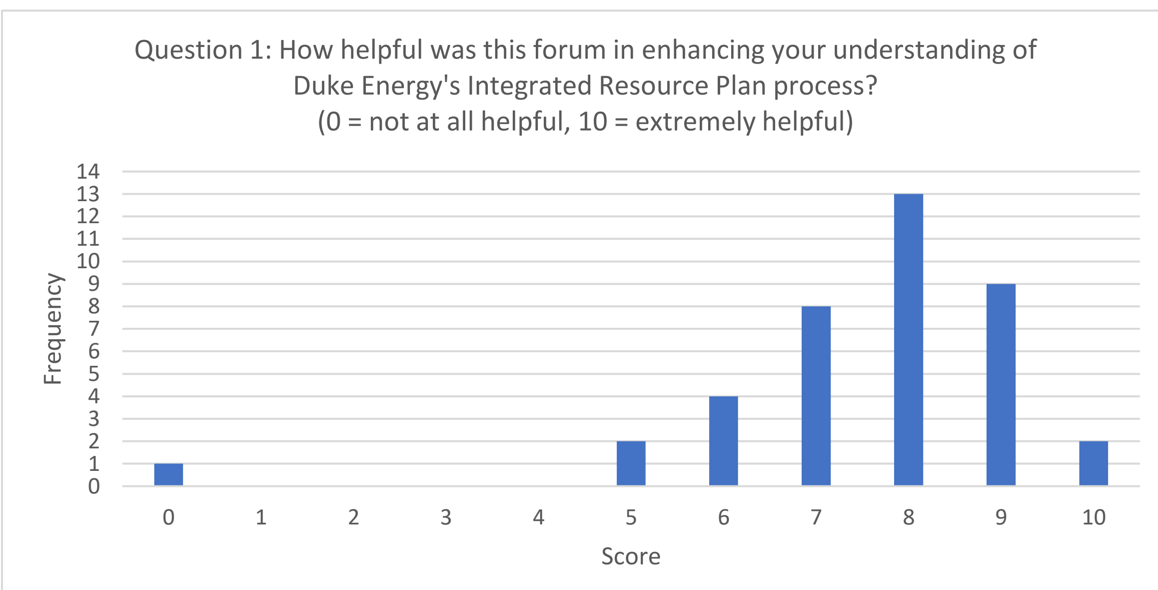
2.6.2. Overview of Stakeholder Survey Results

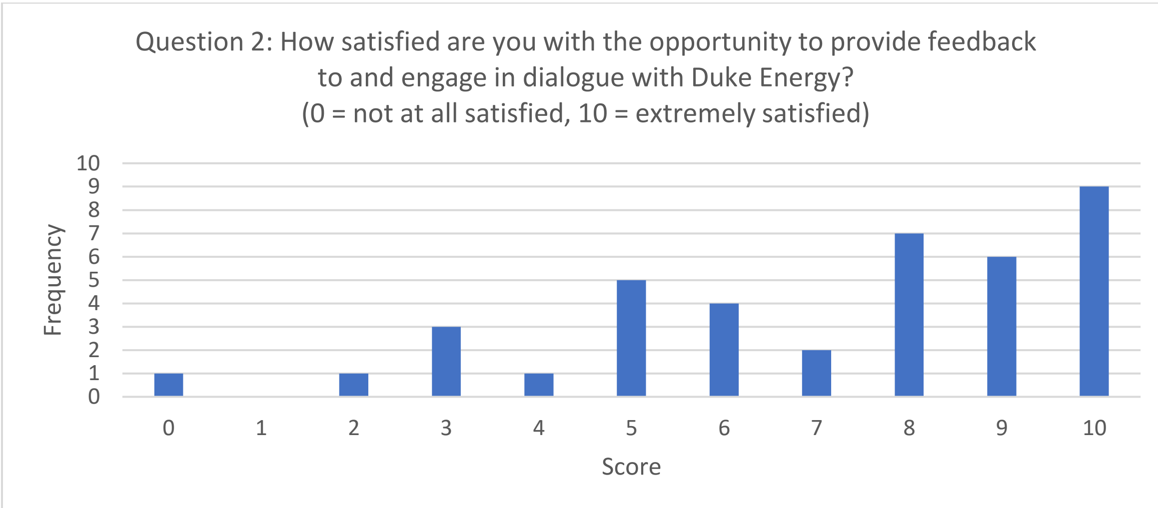
Duke developed a survey to capture stakeholder feedback about the value of the forum and opportunities to further improve future engagement activities. The survey included five rating scale questions and three short-answer questions. The survey was available to stakeholders through the webinar platform immediately following the forum and Duke sent a follow-up email on March 18 to stakeholders with a reminder to complete the survey. In total, 35% of attendees participated in the survey, nearly twice the participation rate of the survey from the first forum.

Figure 4 provides the distribution of all survey responses for each of the five rating-scale (i.e. on a scale of 0 to 10) questions. Average scores are as follows:

- Question 1: How helpful was this forum in enhancing your understanding of Duke Energy's Integrated Resource Plan process? (0 = not at all helpful, 10 = extremely helpful)
  - **Average score: 7.6**
- Question 2: How satisfied are you with the opportunity to provide feedback to and engage in dialogue with Duke Energy? (0 = not at all satisfied, 10 = extremely satisfied)
  - **Average score: 7.1**
- Question 3: How helpful was this workshop in enhancing your understanding about other stakeholders' point of view? (0 = not at all helpful, 10 = extremely helpful)
  - **Average score: 6.7**
- Question 4: How likely are you to provide Duke Energy with additional feedback before the May 1st deadline? (0 = not likely at all, 10 = extremely likely)
  - **Average score: 7.2**
- Question 5: How effective was this workshop in providing a foundation for new kinds of conversation and collaboration going forward? (0 = not at all effective, 10 = extremely effective)
  - **Average score: 6.8**

Figure 4: Summary of Survey Responses to Rating-Scale Questions from 4/16 Forum




Question 2: How satisfied are you with the opportunity to provide feedback to and engage in dialogue with Duke Energy?
(0 = not at all satisfied, 10 = extremely satisfied)
Frequency
Score
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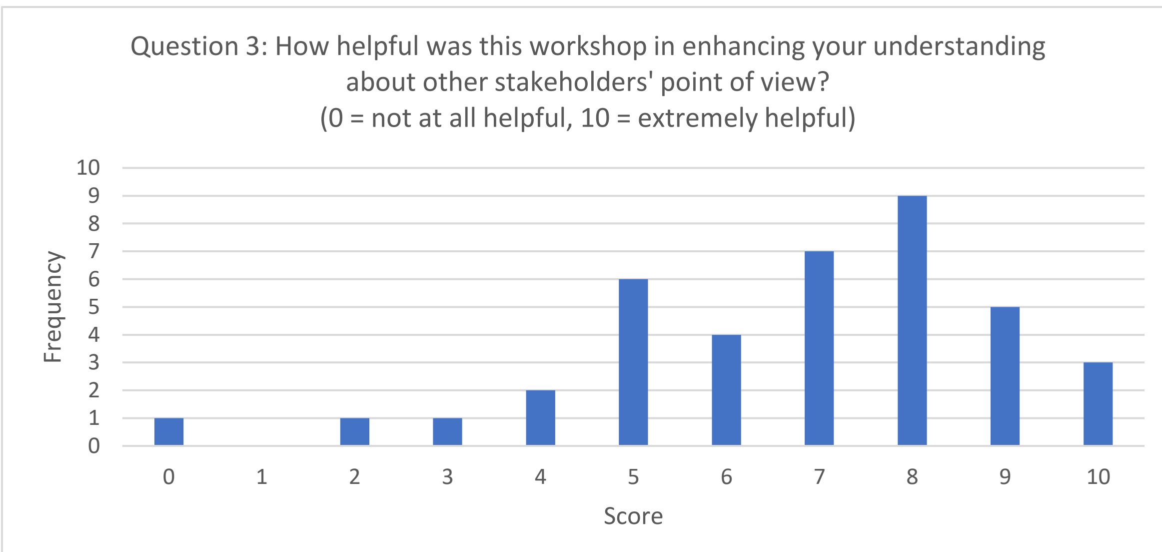
Question 3: How helpful was this workshop in enhancing your understanding about other stakeholders' point of view?
(0 = not at all helpful, 10 = extremely helpful)
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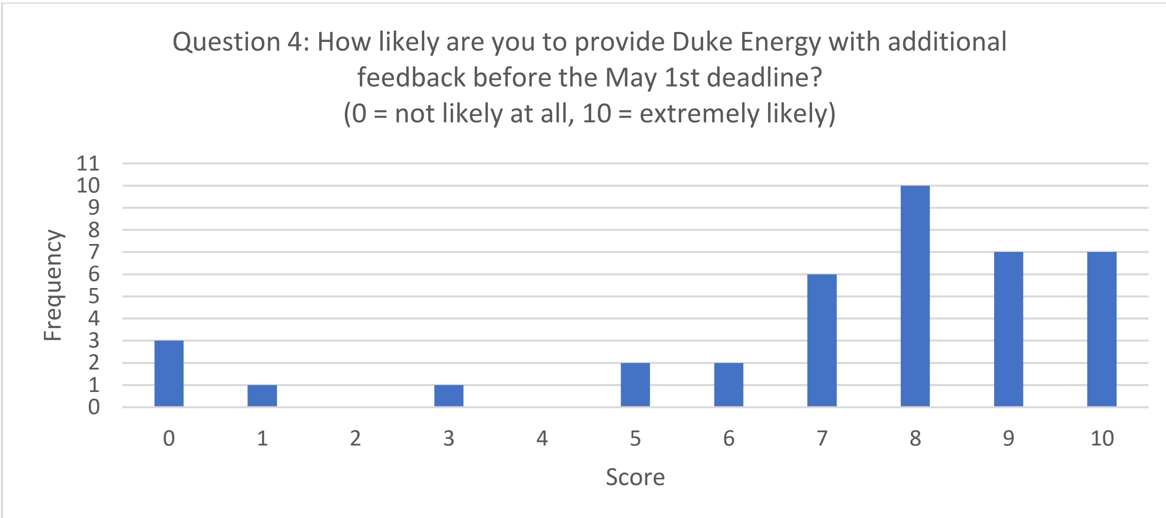
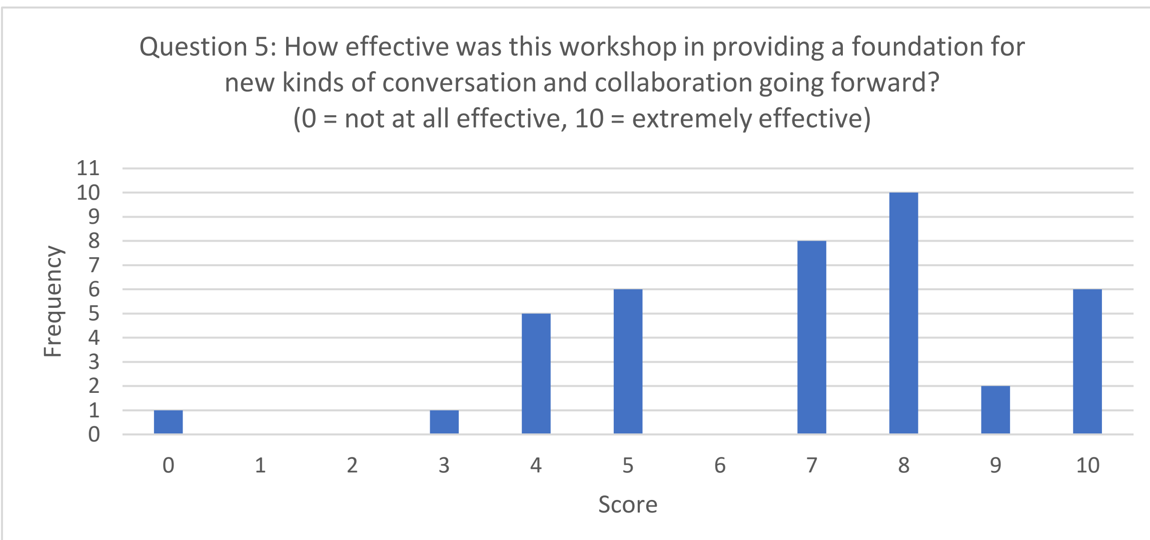




In addition to the rating-scale questions, stakeholders provided written responses to three short-answer questions. Key themes of stakeholder responses for each question are summarized in Table 9.

Table 9: Key Themes of Stakeholder Responses to Short-Answer Survey Questions from 4/16 Forum

Question	Key Themes
Do you have suggestions for the early June stakeholder update?	• Continue to share sought after information, as available, with stakeholders to ensure a productive conversation • Share slides further in advance to allow stakeholders to more sufficiently digest discussion topics • Allow additional time to enable more of a two-way dialogue with stakeholders

Question	Key Themes
	• Explore creation of a sub-committee to further evaluate the potential scope of a winter peaking study, and allow for an update on progress during the June update
What did you like best about today's forum?	• Ample opportunities to ask questions and vote on priority topics • Speakers were knowledgeable and clear • Appreciation for Duke's clear request of what kinds of additional input it would deem valuable
Is there anything else you'd like to tell us that we haven't asked about?	• Further consideration needed about the time difference between the IRP (15 years) and Duke Energy's carbon reduction goals (50% reduction by 2030; net-zero by 2050) • Stakeholders appreciated making this a webinar format given the COVID-19 crisis • Appreciation for using an independent facilitator for the engagement process

Following the forum, Duke followed up directly with individual stakeholders who asked questions during the forum but whose questions were unable to be addressed within the allotted timeframe.

2.7. Final Pre-IRP Filing Webinar

Duke hosted its final pre-IRP filing webinar on June 18, 2020, with ICF facilitating the stakeholder webinar on Duke's behalf. Duke shared the slides from the session. To encourage open dialogue, Duke did not record the webinar or attribute questions asked during the webinar to specific attendees. Excluding Duke and ICF staff, the stakeholder workshop featured a total of 97 attendees representing 61 entities (Table 10).

Table 10: Breakdown of Stakeholder Attendees from Final Pre-IRP Filing Webinar

Stakeholder Category	Total Attendees
Academic/Research	8
Environmental	28
Government	26
Customers	4
Renewable/DER	15
Other	16

2.7.1. Overview of Webinar Agenda and Breakout Sessions

Duke and ICF structured the webinar to provide stakeholders with clear guidance on how Duke was responding to stakeholder feedback it had received over the course of its formal engagement process. ICF began the webinar with an overview of the 2020 IRP stakeholder engagement timeline and a high-level description of the key themes of stakeholder feedback that had generated the most interest and/or support. Duke then provided an overview of how the 2020 IRP will differ from prior IRPs, which in large part was driven by the feedback Duke received throughout this process from stakeholders.

The stakeholder webinar then centered on three breakout sessions focused on the three areas of greatest interest/support among stakeholders: (1) resource evaluation, data access and inputs; (2) carbon reduction; and (3) EE, DR, and winter peaking. Like the two prior forums, ICF facilitated Q&A sessions to close each of the breakout sessions.

Resource Evaluation, Data Access and Inputs

Duke provided an overview of the key areas of stakeholder feedback—such as requests for expanded data sources and availability and suggestions for how to structure Duke's modeling—and what actions it would take in response. During the ICF-moderated Q&A session, Duke answered stakeholder questions focusing on topics including how the IRP will account for COVID-related impacts, assumptions made around solar plus storage growth and costs, if the IRP would include sensitivities around whether the Atlantic Coast Pipeline would be completed, and the role of competitive solicitations in determining the future resource mix.

Carbon Reduction

Building off of the first breakout session, Duke provided further information about how the IRP would address stakeholder feedback in terms of its incorporation of the Clean Energy Plan and Duke corporate climate goals, relationship to the coal retirement analysis, and assumptions around new technologies including solar, storage, solar plus storage, and wind. During the ICF-moderated Q&A session, Duke answered stakeholder questions focusing on topics including the carbon price Duke uses for the IRP, the role of zero-emitting load-following resources (ZELFRs) in achieving carbon reductions, the methodology for calculating rate impacts of alternative pathways, and how the IRP would consider scenarios that achieve CO_2 emissions reductions beyond 50% by 2030.

EE, DR and Winter Peaking

Duke began by providing updates on its EE market potential study and how that would factor into the 2020 IRP. Additionally, Duke provided further details around its plans for conducting a winter peak reduction study given the significant stakeholder support for conducting the study. During the ICF-moderated Q&A session, Duke answered stakeholder questions focusing on topics including how transportation electrification factors into the study to reduce winter peak loads, what the historical contribution of hot water heaters has been to winter peaks, and what the role of advanced metering infrastructure (AMI) would be for leveraging the capabilities of smart thermostats.

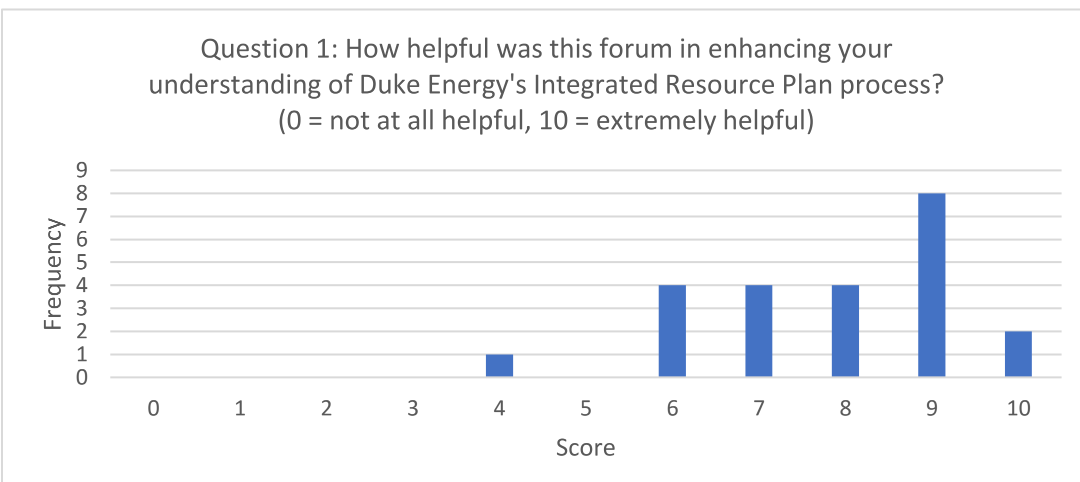
2.7.2. Overview of Stakeholder Survey Results

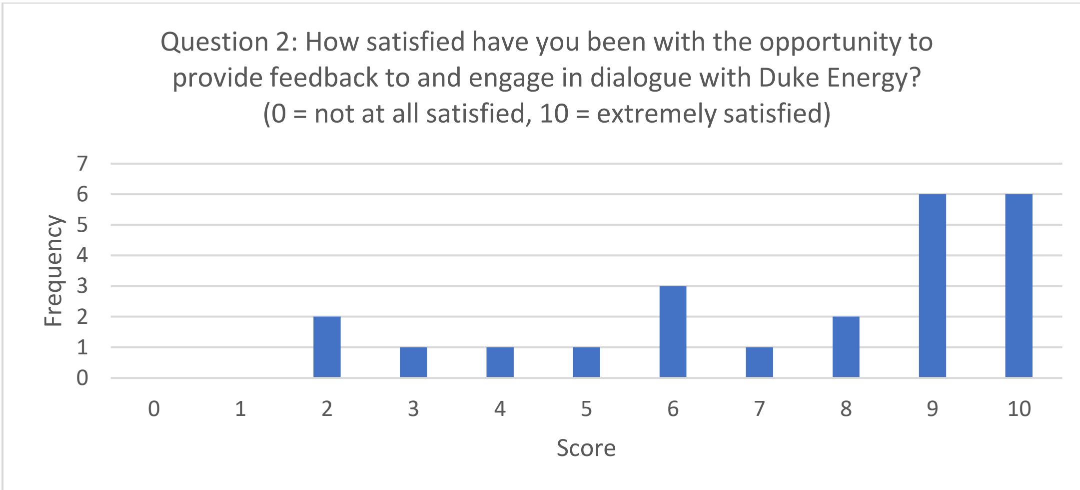
Duke developed a survey to capture stakeholder feedback about the value of the webinar and the overall stakeholder process. The survey included five rating-scale questions and two short-answer questions. The survey was available to stakeholders through the webinar platform immediately following the webinar and Duke sent a follow-up email to stakeholders with a reminder to complete the survey. In total, 24% of attendees participated in the survey.

Figure 5 provides the distribution of all survey responses for each of the five rating-scale (i.e. on a scale of 0 to 10) questions. Average scores are as follows:

- Question 1: How helpful was this forum in enhancing your understanding of Duke Energy's Integrated Resource Plan process? (0 = not at all helpful, 10 = extremely helpful)
    - **Average score: 7.8**
- Question 2: How satisfied have you been with the opportunity to provide feedback to and engage in dialogue with Duke Energy? (0 = not at all satisfied, 10 = extremely satisfied)
    - **Average score: 7.4**
- Question 3: Do you feel the key themes of today's webinar were reflective of stakeholder feedback? (0 = not at all reflective, 10 = extremely reflective)
    - **Average score: 7.6**
- Question 4: **How effective have these stakeholder engagement efforts been for you?** (0 = not at all effective, 10 = extremely effective)
    - **Average score: 7.5**
- Question 5: **How likely would you be to engage in future IRP discussions?** (0 = not likely at all, 10 = extremely likely)
    - **Average score: 9.0**

Figure 5: Summary of Survey Responses to Rating-Scale Questions from 6/18 Webinar




Question 2: How satisfied have you been with the opportunity to provide feedback to and engage in dialogue with Duke Energy?
(0 = not at all satisfied, 10 = extremely satisfied)
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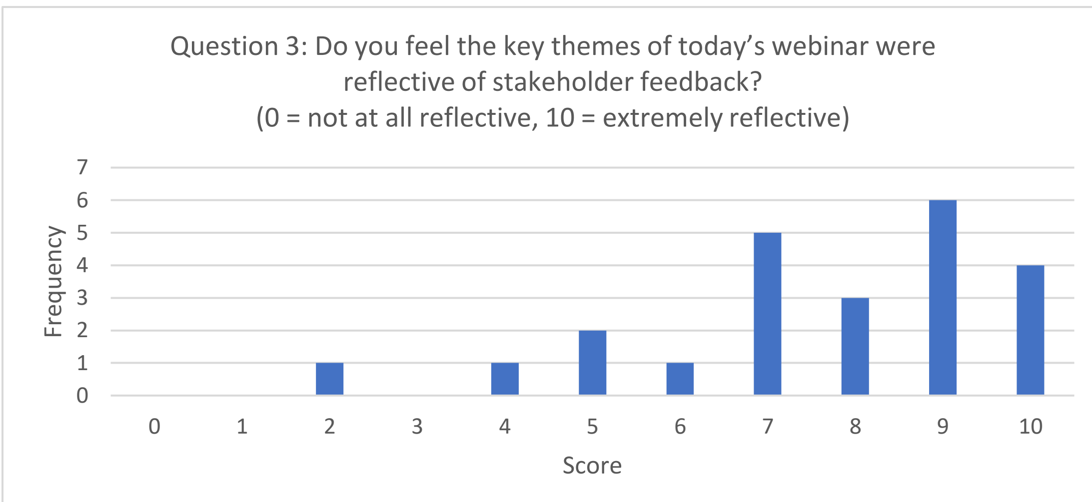
Question 3: Do you feel the key themes of today's webinar were reflective of stakeholder feedback?
(0 = not at all reflective, 10 = extremely reflective)
Frequency
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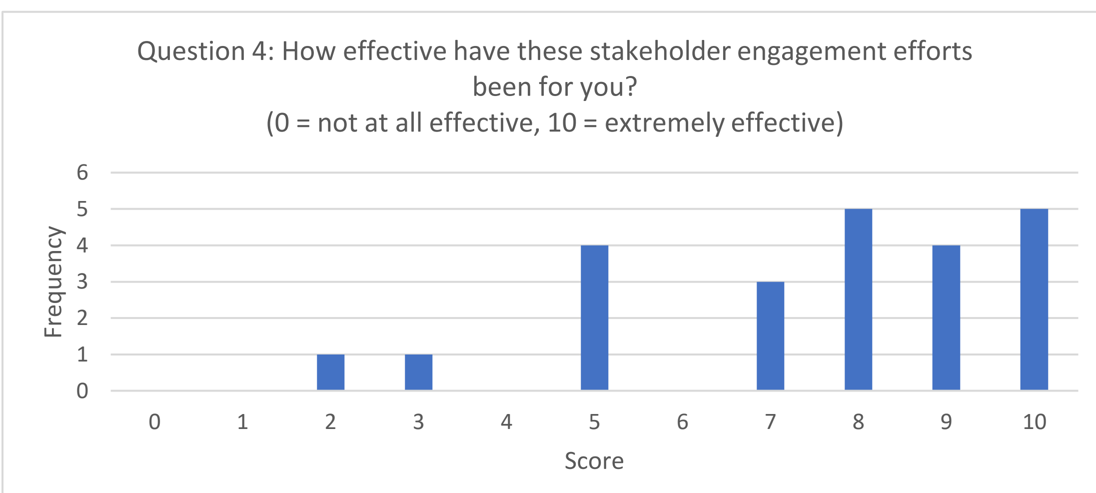
Question 4: How effective have these stakeholder engagement efforts been for you?
(0 = not at all effective, 10 = extremely effective)
Frequency
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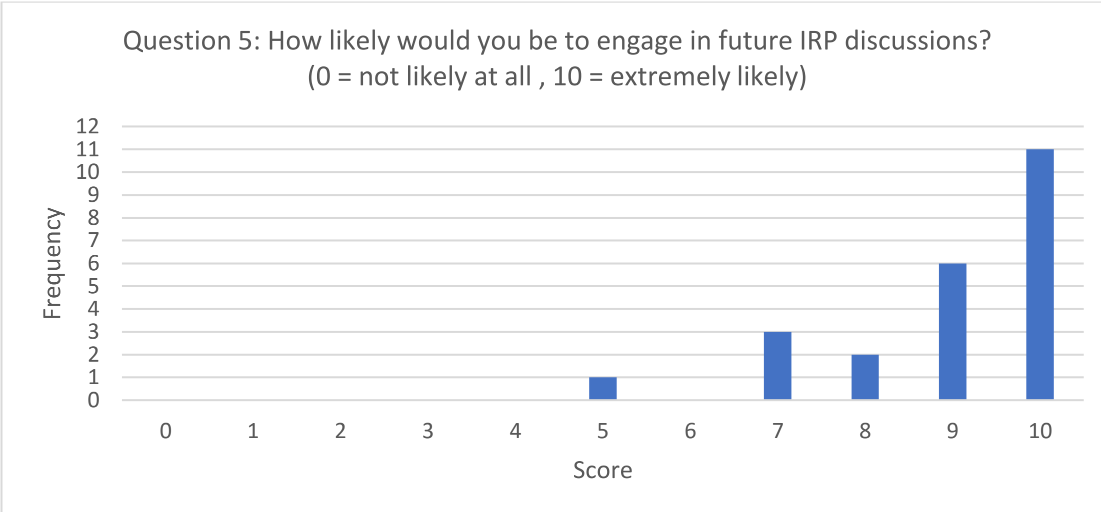


In addition to the rating-scale questions, stakeholders provided written responses to two short-answer questions. Key themes of stakeholder responses for each question are summarized in Table 11.

Table 11: Key Themes of Stakeholder Responses to Short-Answer Survey Questions from 6/18 Webinar

Question	Key Themes
What did you like best about today's workshop?	• The Duke subject matter experts were able to provide targeted and informed updates on stakeholder feedback • Duke's transparency around what stakeholder feedback will be incorporated into the 2020 IRP • Significant time allocated to allow Duke to answer stakeholder questions submitted during the webinar
Is there anything else you'd like to tell us that we haven't asked about?	• If possible, it would be preferred to allow stakeholders to verbally ask questions rather than submit them in typed form • More time could have been spent on the breakout sessions rather than providing another round of background information • Interest in having greater transparency into the assumptions underlying the various scenarios

Following the forum, Duke followed up directly with individual stakeholders who asked questions during the forum but whose questions were unable to be addressed within the allotted timeframe.

3. Next Steps

Duke is incorporating the stakeholder input into the development of the 2020 IRPs for DEC and DEP and will work with intervenors to provide access to key inputs in an expedited fashion shortly after filing. Duke also plans to hold a post-filing Technical Briefing in September and share additional details on IRP inputs as well as key takeaways from the expanded analysis in the 2020 IRPs, which will reflect alternate resource portfolios as part of a broader range of scenarios and sensitivities compared to past IRPs.

DEC/DEP Attachment 2

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

James R. Robb, North American Electric Reliability Corporation, March 11, 2021 Testimony Before United States Senate Committee on Energy and Natural Resources, Full Committee Hearing On The Reliability, Resiliency, And Affordability Of Electric Service

"Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events"

March 11, 2021

Before the Committee on Energy and Natural Resources
United States Senate
Washington, DC

Testimony of James B. Robb
President and Chief Executive Officer
North American Electric Reliability Corporation

The bulk power system is undergoing major transformation that must be understood and planned for to preserve reliability. A rapidly changing generation resource mix is driving this transformation. Traditional baseload generation plants are retiring, while significant amounts of new natural gas and variable generation resources are being developed. During this transition, natural gas-fired generation is becoming more critical to provide both "bulk energy" and "balancing energy" to support the integration of variable resources. Extreme weather exacerbates the challenges of the transforming grid while also stressing the system in unique ways. This transition requires the electric industry to reconsider how the system is planned and operated.

With a highly reliable and secure bulk power system (BPS) at the core of NERC's mission, NERC is focused on proactively addressing the reliability risks of the transforming grid. This testimony examines BPS reliability through the lens of recent extreme weather events. Through this examination, we discern key observations and steps for consideration to further assure reliability and resilience during this transformation.

About NERC

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority with a mission to assure the effective and efficient reduction of risks to the reliability and security of the grid. Designated by the Federal Energy Regulatory Commission (FERC) as the Electric Reliability Organization (ERO) for the United States, NERC develops and enforces reliability and security standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC performs a critical role in situational awareness and information sharing to protect the electricity industry's critical infrastructure against cyber and physical threats to the BPS. Through delegation agreements and with oversight from FERC, NERC works with six

Regional Entities on compliance monitoring and enforcement activities. Collectively, NERC and the Regional Entities comprise the ERO Enterprise. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves nearly 400 million people in the continental United States, Canada, and Mexico.[1]

Central United States Cold Weather Event of February 2021

Extreme, record-breaking arctic weather descended upon the central part of the nation during the second week of February, forcing power outages throughout the region. States in the middle south were especially hard hit, particularly Texas where the extreme cold forced generators offline, resulting in a massive deficit of energy to serve customers during record winter demand conditions. The system operator for the majority of Texas – the Electric Reliability Council of Texas (ERCOT) – was forced to order unprecedented load shedding as a last resort measure to restore frequency and protect system stability. At its peak, 52,277 MW of generation across *all* fuel types within ERCOT were unavailable, or 48.6% of total installed capacity.[2] The crisis lasted more than a week, ultimately subjecting more than 4 million Texans to localized blackouts and millions more to a range of compounding impacts. Many municipal water systems failed with 14 million under boil-water notices. Natural gas deliveries were curtailed due to frozen infrastructure and little to no dual-fuel capability was available in Texas. This serves as a sobering reminder of the essentiality of electric service to support all other critical infrastructures. And, most tragically, lives were lost in the crisis.

While the scale in Texas was especially dramatic, extreme winter weather also caused significant forced outages and load shedding in states throughout the central part of the country from North Dakota to Louisiana. To maintain system stability, the Midcontinent Independent System Operator (MISO) ordered 1,430 MW of load shedding on February 16, affecting citizens from southern Louisiana, Arkansas, Mississippi, east Texas, and Illinois. MISO reported a peak of 59,322 MW of generation was unavailable throughout the entire balancing authority area on February 14. This includes 8,081 MW that was weather related. The Southwest Power Pool service area experienced 3,443 MW of load shedding and the loss of 25,000 MW of generation across a range of resources. Outages occurred in Arkansas, Louisiana, Texas, Oklahoma, Kansas, Missouri, Nebraska, North Dakota and South Dakota. This crisis shows the increased vulnerability of the electric supply system to an extreme common condition that spans electric systems.

The human toll – suffering, death, and economic loss – makes the 2021 extreme cold weather event highly significant. To be clear, load shedding is an unwelcome last resort measure to avoid uncontrolled cascading outages across an entire interconnection. Faced with untenable choices during an emergency event when decisions must be made within minutes, actions taken by grid operators helped prevent even more widespread suffering. Data presented by

[1] See appendix for a map depicting the footprints of NERC and the Regional Entities.

[2] Presentation to ERCOT Board of Directors, "Review of February 2021 Extreme Cold Weather Event," ERCOT, February 24, 2021.

ERCOT show the entire electric system was within minutes of frequency and voltage collapse, necessitating the dramatic action they took.

To promote learning and risk reduction, NERC and the Regional Entities study reliability events and take appropriate and positive actions. On February 16, FERC and NERC announced a joint inquiry into the Midwest and South-Central states cold weather event. The joint inquiry will examine how the extreme weather impacted operations of the bulk power system in the affected regions of the country. The joint inquiry team includes Regional Entities from the impacted areas[3] and the Department of Energy (DOE). The FERC/NERC/Regional Entity Joint Staff Inquiry (Joint Inquiry) will cover three general themes:

1. Comprehensive, detailed analysis of the event and root causes
2. Commonalities with other cold weather events, including the 2011 winter event that also impacted Texas
3. Findings and recommendations for further action

Prior to the next winter preparation season, the inquiry team expects to issue a preliminary summary with the final report to follow. Working with FERC, NERC will move forward expeditiously on action items within our authority, including any necessary enhancements to mandatory reliability standards. As recently stated by FERC Chairman Glick, actions calling for further attention must not languish on the shelf.

Cold Weather Preparation – Reliability Guidelines and Mandatory Standards

February 2011 was the first well-studied cold snap to hit Texas and the southwest region since NERC was certified as the ERO. Temperature lows were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and in New Mexico. In 2011, between February 1-4, 210 individual generating units within ERCOT's footprint experienced either an outage, a derate, or a failure to start.[4] At the peak of the crisis, a controlled load shed of 4,000 MW affected 3.2 million customers in Texas. During the course of the event, power losses also occurred in parts of New Mexico and Arizona.

The extreme low temperatures also affected natural gas production and service. From February 1 through February 5, an estimated 14.8 Bcf of production was lost. These declines propagated downstream through the rest of the gas delivery chain, ultimately resulting in natural gas curtailments to more than 50,000 customers in New Mexico, Arizona, and Texas.[5]

[3] Texas RE, Midwest Reliability Organization, and SERC Reliability Corporation.
[4] FERC/NERC report, "Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations."
[5] FERC/NERC staff report, *"Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011,"* 9 .

Following the 2011 event, FERC and NERC produced a joint inquiry report, "Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations." Key recommendations included:

- Generation owners and operators should ensure adequate construction, maintenance and inspection of freeze protection elements such as insulation, heat tracing and wind breaks.
- Reliability coordinators and balancing authorities should require generators to provide accurate data about the temperature limits of units so they know whether they can rely on those units during extreme weather.
- Balancing authorities should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.
- Finding that natural gas service was also impacted by the event, state lawmakers and regulators in Texas and New Mexico, working with industry, should determine if weather-related production shortages can be mitigated through the adoption of minimum winterization standards for natural gas production and processing facilities.

After significant consideration, NERC and the electric industry pursued and published a Reliability Guideline in 2012 to help industry develop their own readiness program for generating units throughout North America. NERC holds a "Winter Preparation for Severe Cold Weather" webinar every year before the winter season to reinforce the guideline's recommendations. Regional Entities conduct similar outreach to industry within their respective footprints.

The guideline provides a framework for developing an effective winter weather readiness program for generating units. The focus is on maintaining individual unit reliability and preventing future cold weather-related events. A collection of best industry practices, the guideline calls for an evaluation of potential problem areas with critical equipment, systems testing, training, and event communications. The guideline has been updated based on industry experience and learnings from subsequent cold weather events. These events include the 2014 Polar Vortex and the cold weather event of January 17, 2018 that impacted the south-central area of the country.[6] Version three of the winter readiness guideline was published in June 2020.[7]

Reliability Guidelines have the advantage of addressing certain risks where quick action is desirable or those risks categorized as high impact, low frequency or rare. However, the extremes of 2011, 2014, and 2018 demonstrated that these events could no longer be treated

[6] FERC/NERC staff reports, "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011" and "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018."

[7] "Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3," NERC.

as rare. Further, in the past decade, the generation fleet has transformed to one that is more sensitive to weather with extreme temperatures.

Accordingly, to address the risk of extreme cold weather, NERC concluded that mandatory standards addressing cold weather risks were warranted. In September 2019, NERC initiated development of new cold weather requirements through enhancements to existing mandatory reliability standards.[8] After considering stakeholder comments, NERC expects to submit the proposed standards to NERC's Board of Trustees (BOT) in June. The final winterization requirements will be filed with FERC following BOT approval. The standards will support reliability of the BPS by helping to ensure that generator units are prepared for cold weather and enhancing situational awareness in the operational planning and operations timeframes. A set of draft standards are posted for comment through March 12 and include draft requirements for the following:

- Cold weather preparedness plans developed, maintained, and implemented by generators for each unit, incorporating freeze protection measures based on geographic location and plant configuration
- Annual maintenance and inspection of generation unit freeze protection measures
- Adoption of cold temperature operating parameters, including minimum design temperature and historical performance during cold weather in the previous five years
- Awareness training on the roles and responsibilities of site personnel
- Communication of specific unit limitations to Reliability Coordinator and Balancing Authorities for use in setting operating processes, determining contingency reserves, and performing operational planning analysis

Until a cold weather standard is approved and enforceable, NERC is also considering use of additional reliability tools, such as our alert system, to understand winter preparation status and incorporate plant preparation status into our annual seasonal assessment.

Western Heatwave Event of August 2020

During the middle of August, a massive heat wave developed across the West, forcing high temperatures 15 to 30 degrees above normal, breaking many daily highs. The California Independent System Operator (CAISO) reported that the August extreme heat was a 1-in-30 year weather event. On August 18, the Western Interconnection hit a new peak demand of 162,000 MW.[9] CAISO implemented numerous operational actions to balance resources with customer demand. In terms of energy supply, the extreme heat reduced electricity output from thermal resources, which typically operate less efficiently during temperature extremes. In addition to below normal hydro conditions, utility-scale and behind-the-meter solar generation output was reduced due to wildfire smoke and cloud cover.[10] High electricity demand across

[8] Project 2019-06 Cold Weather, NERC.
[9] Presentation, "Western Interconnection August Heat Wave Event," WECC, October 20, 2020.
[10] "Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave," CAISO, CPUC, CEA joint report, January 13, 2021, 21-22.

the West limited CAISO's ability to import energy from neighboring areas. During the early evening hours of August 14-15 when solar energy production naturally declines, CAISO was forced to resort to controlled load shedding of approximately 1,800 MW to maintain system stability. Power outages lasting between 8-to-150 minutes, impacting approximately 800,000 customers served by utilities regulated by the California Public Utilities Commission.[11]

This heatwave event occurred across the entire Western Interconnection. The widespread nature of this heatwave reduced options to mitigate impacts as exports to California dried up due to the need for organizations to serve their native loads. Though not as dramatic as the recent cold weather event, it is another example of an extreme common condition that overwhelmed the electric system. It demonstrates that these conditions can occur in summer or winter and for which industry needs to plan.

NERC and the Western Electricity Coordinating Council, the Regional Entity serving the Western Interconnection, are conducting a review of the Western heatwave event through our Event Analysis program. This review is nearing completion. We will provide the committee with the final report. A separate joint analysis by CAISO and California energy regulators was published on January 13, 2021. The report finds that issues with calculating resource planning targets and market practices contributed to the supply deficits during the extreme heat contradictions.

Identifying and Communicating Reliability Risk

Section 215(g) of the Federal Power Act requires NERC to assess the reliability and adequacy of the BPS. Through our reliability assessments, NERC evaluates the performance of the BPS, identifies reliability trends, anticipates challenges, and provides a technical platform for important policy discussions. The breadth and fidelity of NERC assessments evolve with our understanding of risk and improved tools. As the resource mix has shifted to be increasingly reliant on variable generation, wind and solar, and "just in time" natural gas deliveries, we began introducing fuel risks into our seasonal assessments and developed more probabilistic analysis of reliability.

By identifying and quantifying emerging reliability and security issues, NERC provides risk-informed recommendations and supports a learning environment for industry to pursue improved reliability performance. These recommendations, along with the associated technical analysis, provide the basis for actionable enhancements to resource and transmission planning methods, planning and operating guidelines, security, as well as NERC reliability and security standards. In short, NERC's independent assessments provide critical insights necessary for assuring reliability and security of a rapidly changing electricity sector.

Applying peak demand scenarios, the *2020/2021 Winter Reliability Assessment* includes the below map depicting regions in North America where there is heightened reliability risk due to potential extreme weather or fuel supply disruptions. In this assessment, NERC warns of the

[11] Ibid, 35.

potential for extreme generation resource outages due to severe weather in winter and summer, and the potential need for grid operators to employ operating mitigations or Energy Emergency Alerts (EEA) to meet peak demand.[12] The assessment highlights that during extreme and prolonged winter conditions, vital natural-gas fuel supplies for electricity generation can be at risk in New England, California and the southwestern United States. High reliance on natural gas-fired generation and limited natural gas infrastructure elevates reliability risk in these areas.

For this assessment, NERC analyzed severe weather scenarios that incorporated generation outages under peak load conditions. NERC noted particular reliability risk in areas within MISO, the Canadian Maritimes, Texas, the Rocky Mountain Reserve Group and the Northwest Power Pool.

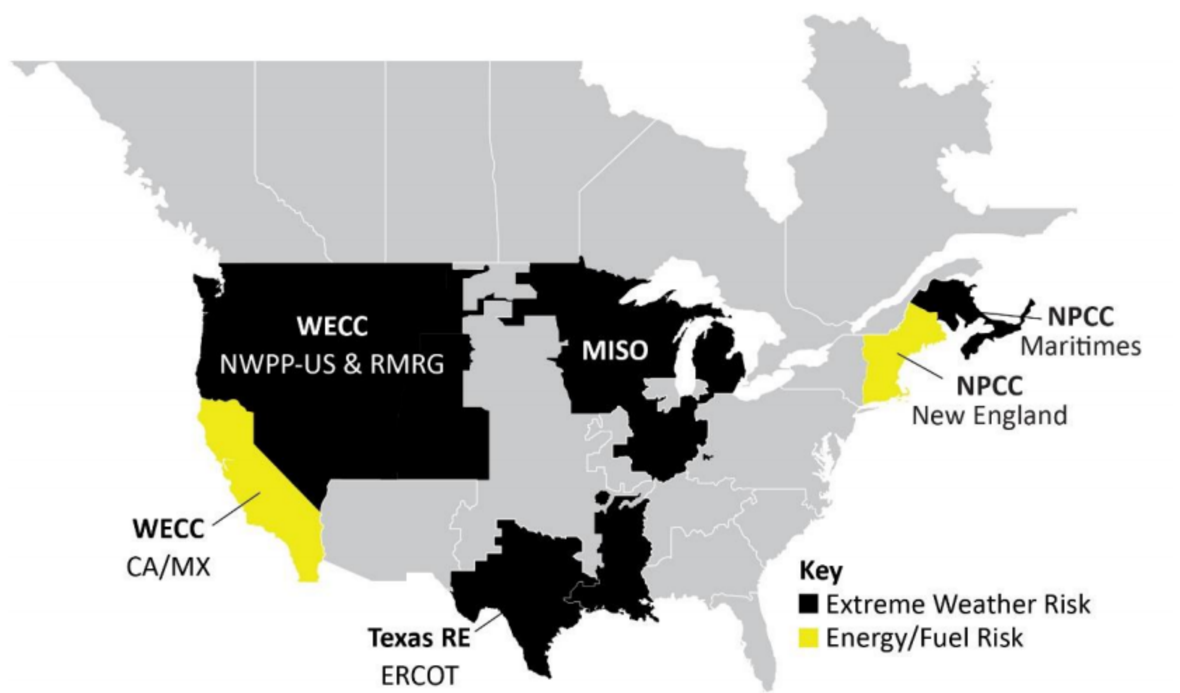


Figure 1: Areas with Reliability Risks during Extreme Weather Events and/or Fuel Supply Disruptions

Source: *2020/2021 Winter Reliability Assessment*, NERC.

Over the years, NERC's assessments have continued to identify three areas of primary concern: California, Texas, and New England. While recent events in the central-south and western parts of the country have attracted national attention, New England is another region that NERC has identified as particularly vulnerable to extreme cold weather.

[12] *2020/2021 Winter Reliability Assessment*, NERC, 6, 27.

New England

New England's exposure to extreme weather is exacerbated by its limited pipeline capacity to import gas and its dependence on a handful of critical fuel assets. NERC has continually identified fuel supply risk in New England, noting, "A standing concern is whether there will be sufficient electrical energy available to satisfy electricity demand while satisfying operating reserves during an extended cold spell given the existing resource mix and seasonally-constrained, fuel delivery infrastructure."[13] New England secures fuel reliability through dual-fuel capability in its natural gas fleet. A cold snap in December 2017/January 2018 led to natural gas shortages and fuel oil was burned to preserve reliability. If the cold front had not dissipated after January 8, several more hours of freezing weather would have exhausted the fuel oil in inventory and ISO-New England would have been forced into load shedding to preserve reliability. It was a near-miss event.

ERCOT/Texas

NERC's assessments have consistently highlighted reliability risk in Texas. As far back as nine years ago, the *2012 Long-Term Reliability Assessment* expressed this warning about ERCOT:

> Starting as early as next year, the [ERCOT] Planning Reserve Margin is projected to be below the NERC Reference Margin Level. Specifically, for 2013 the Anticipated Reserve Margin of 13.4 percent is below the ERCOT planning target (NERC Reference Margin Level) of 13.75 percent. At these levels, the risk of insufficient generation resources to meet peak demand increases beyond the accepted target. Throughout the 10-year assessment period, the Planning Reserve Margin continues to degrade and is projected to fall below five percent by 2017 and approximately zero by 2020 if more resources are not acquired.[14]

Concern for ERCOT's reserve margins has been a standing concern in NERC's assessments. In the most recent *2020/2021 Winter Reliability Assessment*, NERC warns of the potential for extreme generation resource outages in ERCOT due to severe weather in winter and summer, and the potential need for grid operators to employ operating mitigations or energy emergency alerts to meet peak demand.[15] *2020 State of Reliability* finds that Texas continues to have insufficient resources to meet the reference margin level but still successfully met demand throughout the 2019 summer season.[16] NERC's *2020 Long-Term Reliability Assessment* points to low operating reserves during the summer and during the months of March and October of the study years (2022 and 2024).[17]

[13] *2020/2021 Winter Reliability Assessment*, NERC, 18.
[14] *2012 Long-Term Reliability Assessment*, NERC, 11.
[15] *2020/2021 Winter Reliability Assessment*, NERC, 6, 27.
[16] *2020 State of Reliability*, NERC, ix.
[17] *2020 Long-Term Reliability Assessment*, NERC, 6.

California

NERC assessments have also identified energy sufficiency issues in California before the 2020 summer event. The *2019 Long-Term Reliability Assessment* discusses a need for flexible resources to meet increasing ramping and variability requirements, noting, ". . . as solar generation increases in California and various parts of North America, system planners will need to ensure that sufficient flexibility is available to operators to offset variability and fuel uncertainty."[18] In discussing the California region, NERC's *2019 Summer Reliability Assessment* concludes, "Extreme outages may result in insufficient resources at peak load."[19] The high-risk scenario in the *2020 Summer Reliability Assessment* predicted, "Operating mitigations and EEAs [Energy Emergency Alerts] may be needed under extreme demand and extreme resource derated conditions."[20]

Findings and Recommendations

Managing the pace of change is the central challenge for reliability. The rapid evolution of the generation resource mix is altering the operational characteristics of the grid. We highlighted this issue most visibly in our 2018 special assessment of baseload generation retirements and it has been a recurring theme of our outreach to federal and state regulators.[21] It is imperative to understand and plan for the different operating characteristics of variable, inverter-based resources. This includes time to study, plan for, and develop effective solutions to the challenges. Variable energy resources can provide ramping and other essential reliability services, yet existing regulatory models and contracts do not always value these capabilities. Sound policies, both public and market-based, should support a reliable energy transition.

More transmission and natural gas infrastructure is required to improve the resilience of the electric grid. Electric transmission investment must keep pace with the increase in utility scale wind and solar resources, which are generally located outside of major load centers. Transmission investments can also strengthen the ability to wheel power to different load centers improving resilience through redundancy. Additional pipeline infrastructure (including gas storage) is needed to reliably serve load and enable natural gas as a balancing resource. Many are discussing the merits of a national transmission system similar to the interstate highway system, point-to-point DC lines, and other interconnections. Whatever approaches may ultimately be pursued, few long-haul transmission lines and pipelines are actually being planned and built.

Natural gas is essential to a reliable transition. As variable resources continue to replace other generation sources, natural gas will remain essential to reliability. In many areas, natural gas-fueled generation is needed to meet energy demand during shoulder periods between times of high and low renewable energy availability. And on a daily basis in areas with significant solar

[18] *2019 Long-Term Reliability Assessment*, NERC, 8.
[19] *2019 Summer Reliability Assessment*, NERC, 29.
[20] *2020 Summer Reliability Assessment*, NERC, 33.
[21] *Generation Retirement Scenario*, NERC, December 2018.

generation, the mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap. Natural gas generation is best positioned to play that role. The criticality of natural gas as the "fuel that keeps the lights on" will remain unless or until very large-scale battery deployments are feasible or an alternative flexible fuel such as hydrogen can be developed. Growing reliance on natural gas for electric generation is driving a variety of actions within the industry and across interdependent infrastructure sectors to manage risks to natural gas fuel supply. Most areas are reliant on natural gas to meet on-peak electricity demand. Unlike generation with on-site fuel storage, natural-gas-fired generators depend on the natural gas pipeline system to deliver just-in-time fuel for electricity production. Unless they are dual-fuel units with onsite fuel oil, they can be particularly sensitive to extreme cold temperature, and should be winterized to reduce the risk to their ability to operate. Further, growth in the use of natural gas as a fuel for electric generation and other applications can stress the natural gas supply infrastructure when necessary expansions do not keep pace. The problem is particularly acute during extremes.

<u>Regulation and oversight of natural gas supply for electric generation needs to be rethought</u>**.** – While natural gas is key to supporting a reliable transformation of the grid, the natural gas system is not built and regulated to serve the needs of an electric power sector that is increasingly dependent upon reliable natural gas service. As it relates to BPS reliability, clear regulatory authority is needed over natural gas when used for electric generation.

<u>Planning for extreme weather.</u> The BPS must remain reliable and resilient during all operating conditions. As the recent extreme weather events show, industry should proactively plan for and recover from rare events. NERC reliability assessments and reliability standards are identifying and attempting to address these risks within our authorities. Regulatory and market structures need to support this planning, prioritize reliability, and support necessary investments.

<u>Resource adequacy does not guarantee energy sufficiency.</u> A diverse generation portfolio strengthens reliability and resilience, yet the benefits of diversity are lost when all resources underperform or fail. All generation sources have energy limits and physical constraints, and these limits and constraints need to be accurately accounted for in seasonal and long-term planning assessments. While it is premature to draw hard conclusions before the joint inquiry is complete, thermal and variable resources in ERCOT, MISO, and SPP were forced offline or failed to perform as expected during the extreme cold weather event. The event is not a debate about one resource or another. The joint inquiry will look at all generation failures and their root causes.

<u>Energy storage can and will be a game changer.</u> As the technology continues to develop and economics continue to support the growing penetration of energy storage, these resources will become a game changer. However, we have to appreciate the gap that currently exists and the

scale that we need to obtain. NERC recently completed a battery storage study.[22] The assessment emphasizes the reliability benefits that battery energy storage systems can offer, such as providing peaking capacity; minimizing the need for new generation and transmission infrastructure; and providing essential reliability services such as frequency response. The assessment stresses the need to plan for a significant increase in the critical mass of battery storage or other balancing resource (such as hydrogen) *at scale* before natural gas reduces its role as the critical fuel for electric reliability that it is today. Investment in energy storage technologies and/or a hydrogen production and delivery system will be required if the vision of a largely/completely decarbonized electric system can be realized.

Market Issues. While electricity market issues are outside of NERC's direct purview, policymakers, planners, and market operators need to understand how electricity market policies value reliability and incentivize investments in hardening energy infrastructure.

Conclusion

Managing extreme weather impacts and a transforming grid is highly complex, requiring significant coordination among widely diverse policymakers and stakeholders. North America has four distinct interconnections. The owners, operators, and users of the BPS number in the thousands and have varied corporate structures. Some entities are vertically integrated, while others operate as unbundled entities in regional wholesale markets. These entities are overseen by a diversity of regulators at the local, state, provincial, and federal levels. Energy is being supplied from new sources that create new opportunities as well as challenges for the grid. All these factors must be well coordinated during the transformation in order to preserve reliability.

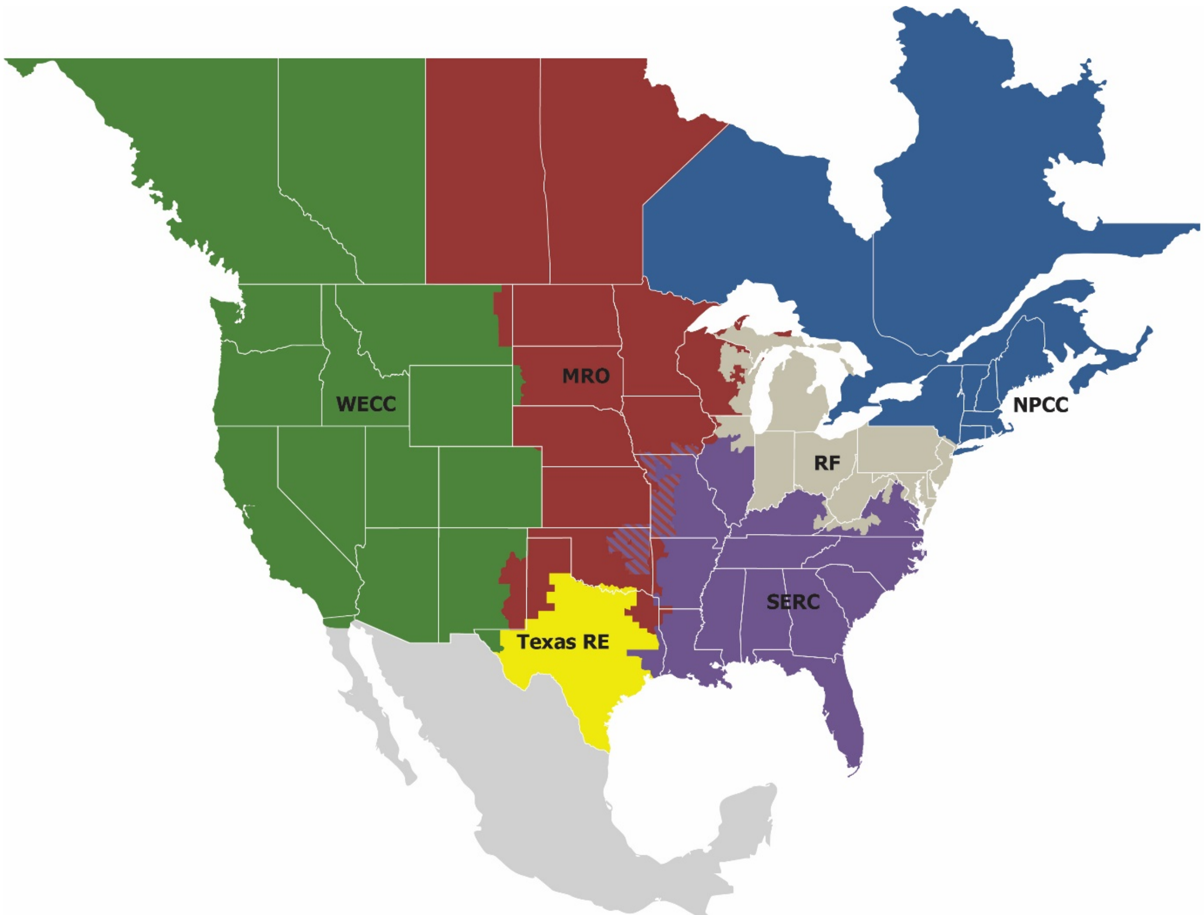
While reliability of the BPS incorporates certain standing principles, there is no one-size-fits-all approach. Rather, states and regions adopt solutions that work for them based on the availability of energy resources, energy infrastructure, and policy preferences. Reliability and resilience to extreme events must be a key factor of all discussions as we move forward. We have seen what happens when reliability is not planned for or fully incorporated into the planning and development of the changing resource mix.

Thank you for the opportunity to participate in this hearing. NERC greatly appreciates the committee's interest in our independent work. Working with FERC, industry, policymakers, and all stakeholders, NERC is uniquely situated to assure reliability for the nearly 400 million people in North America who depend on our work. Given myriad challenges, NERC's mission has never been more important.

[22] "Impacts of Electrochemical Utility-Scale Battery Energy Storage Systems on the Bulk Power System," NERC, February 2021.

APPENDIX

Footprints of NERC and the Regional Entities



DEC/DEP Attachment 3

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Vote Solar Response to DEC and DEP Interrogatory Request 1-9

**DEC's and DEP's First Set of Requests
For Production of Documents and Interrogatories
To Vote Solar
Docket Nos. 201-224-E & 2019-225-E**

Request:

1-9. Please explain whether and how Mr. Fitch considered reliability risks of not meeting customer load in his evaluation of the climate risks facing DEC and DEP.

Response:

Answer: Testimony submitted by Mr. Fitch identifies climate-related risks to the Companies' assets and operations, and assesses how the Companies characterize and manage those risks. Mr. Fitch expects that the Companies will manage reliability risks just as they manage all relevant business risks, in line with prudent business management. Mr. Fitch's testimony does not provide an analysis or conclusion on the Companies' management of reliability risks.

DEC/DEP Attachment 4

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Response to Public Staff Data Request 17-10

NC Public Staff
Docket No. E-100, Sub 165
2020 IRP
NC Public Staff Data Request No. 17
Item No. 17-10
Page 1 of 3

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC (DEP)

Request:

[**DEC only**] Page 287 states in part, "Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 300 MW per year over the planning horizon in DEC."

a. Please provide a summary of the total amount of solar (third party and utility-owned) interconnected in each year for the past five years.

b. Please explain the factors that limit interconnection of solar capacity for DEC.

Response:

a. Please see attached file "PSDR 17-10_DEC Solar Interconnect.xls" for a summary of historic solar interconnections in DEC and DEP.

b. From the time a solar facility enters the transmission or distribution queue to when the facility is connected and given permission to put power to the grid, there are several areas where constraints can occur in the process. First, regardless of the generator's capacity, facilities have historically been studied to determine if any transmission system or network upgrades are required in the order that they entered the queue. Completing a study can take months or years depending on the type of interconnection request (FERC vs State projects) and the number of projects already in the queue to be processed at the time of the request. The study must then be accepted by the requesting facility which can also add further delays. Because the studies are conducted in sequential order, in some instances, the transmission planners must evaluate the interdependency of one project on the next project in the queue. For State requests, until the first study is complete and accepted by the requesting facility, the interdependency of that project on the next project cannot be studied. For FERC requests, the studies move forward, but Contingent upgrades can remain an open uncertainty for years. Once the studies are finally completed and accepted, the construction work must be planned. Planning to interconnect any facility to the transmission system is complex. Scheduling new interconnection work is dependent on other work taking place on the transmission system (i.e., customer connections, maintenance, other interconnection construction and general transmission projects), generator outages which can change power flows on the system, and projected energy demand on the system. Generally, over the course of the year there are only about 24 weeks (shoulder months) where transmission outages take place. In some instances, temporary transmission lines can be constructed to allow for extended project work, but that adds cost to the projects. When the projects are planned, Duke must communicate the upcoming construction plans to the communities around the construction sites and establish the resources (both the people and the materials) to construct the projects. Some equipment has long lead times, but to date finding skilled labor has not been a major limiting factor to interconnecting solar. However, Duke project planners compete with other utilities in the region for resources. To the extent states, such as Virginia, progress on their paths towards a zero carbon future, there will be increased competition for resources as Duke and NC embark on similar efforts. Finally, once the projects are connected to the system, the facilities must be granted permission to operate by the ECC. Testing and commissioning of the newly interconnected facility can take additional time, particularly if issues arise that cause a delay in the utility issuing the permission to operate.

It is also important to note that over the last 5 to 6 years, many of the projects that have interconnected have been small (<5 MW) projects on the distribution system. These projects, while low in capacity, can still be complex projects that can have impacts on the transmission system that require complex solutions. The efficiency of interconnecting these smaller projects is low (i.e., high effort for low MW). As is occurring presently, the economies of scale of larger projects are leading to larger projects entering the queue, which in theory should improve the efficiency of the interconnection process.

Additionally, the recently developed queue reform process that will allow for “cluster studies” of groups of projects should improve the efficiency of transmission impact studies by eliminating the sequential method that projects are currently studied under and spreading the costs of larger upgrades across projects. However, that will not change the fact that larger projects can lead to more complex interconnection solutions on the system with more network upgrades required; and, as smaller projects have been sited closer to existing transmission infrastructure, future projects will be sited further from that infrastructure, potentially requiring more time consuming right-of-way acquisition and more complex projects just to reach the existing transmission infrastructure.

While the above represents physical constraints, the Company did not include certain economic constraints such as an escalating SISC charge on increasing penetrations of solar or solar + storage, nor did the Company include any system upgrade costs for interconnecting increasing levels of solar or solar + storage as penalties in the capacity expansion planning process. Finally, while not an issue through 2030, the same resources that are required for interconnecting this solar generation will also be needed for interconnecting up to 300 MW/year of onshore Carolinas wind between DEC and DEP in the later portion of the planning horizon.

In summary, certain real-world physical constraints and economic constraints such as increasing ancillary service costs and project specific system upgrade costs are difficult to precisely model in an IRP modelling framework. As such, reasonable estimates of such constraints were applied in the IRP base case.

Person responding: Matt Kalemba, Director, DET Planning & Forecasting

Universal Solar Connections - Including Utility Owned	2014	2015	2016	2017	2018	2019
Counts						
DEC Transmission	0	1	2	2	1	0
DEC Distribution	32	51	39	16	10	12
Total DEC Connections	32	52	41	18	11	12
DEP Transmission	9	9	6	23	8	4
DEP Distribution	51	84	51	41	57	40
Total DEP Connections	60	93	57	64	65	44
Capacity						
DEC Transmission	0	18	90	79	75	0
DEC Distribution	64	132	100	32	25	29
Total DEC Capacity	64	150	190	112	100	29
DEP Transmission	43	167	170	470	248	78
DEP Distribution	198	401	210	163	208	160
Total DEP Capacity	241	569	380	633	456	238

Universal Solar Connections - Third Party Only	2014	2015	2016	2017	2018	2019
Counts						
DEC Transmission	0	1	1	1	1	0
DEC Distribution	32	51	39	16	10	11
Total DEC Connections	32	52	40	17	11	11
DEP Transmission	9	6	5	23	8	4
DEP Distribution	51	84	51	41	57	40
Total DEP Connections	60	90	56	64	65	44
Capacity						
DEC Transmission	0	18	75	19	75	0
DEC Distribution	64	132	100	32	25	23
Total DEC Capacity	64	150	175	52	100	23
DEP Transmission	43	67	130	470	248	78
DEP Distribution	198	401	210	163	208	160
Total DEP Capacity	241	468	340	633	456	238

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing _Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Reply Comments_, as filed in Docket No. E-100, Sub 165, was served via electronic delivery or mailed, first-class, postage prepaid, upon all parties of record.

This, the 28th day of May, 2021.

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