STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

In the Matter of 2025 Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-2(a)(3a), 62-110.1, 62-110.9, and Commission Rule R8-60A	)))))))	Docket No. E-100, Sub 207

DIRECT TESTIMONY OF
JOHN MICHAEL HAGERTY

ON BEHALF OF
CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION

MARCH 30, 2026

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Q: PLEASE STATE YOUR NAME, JOB TITLE, EMPLOYER AND BUSINESS ADDRESS.

A: My name is John Michael Hagerty. I am a Principal at The Brattle Group. My business address is 1800 M Street Northwest, Washington, DC 20036.

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A: I earned an M.S. in Technology and Policy from the Massachusetts Institute of Technology and a B.S. in Chemical Engineering from the University of Notre Dame. I have 13 years of experience at The Brattle Group in utility and electric power industry planning and regulatory analysis, including utility resource planning, transmission planning, valuation of renewable energy, storage, and transmission assets, wholesale market design to achieve resource adequacy requirements, and optimized approaches to economy-wide deep decarbonization.

Since 2021, I have analyzed and reviewed the future resource needs in the Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") service territories (collectively referred to as “Duke”) as an intervenor in the resource planning dockets before the Commission. I have also actively participated since 2023 in the Carolinas Transmission Planning Collaborative (“CTPC”) transmission planning studies, including the 2023 Public Policy Study and the 2025 Multi-Value Strategic Transmission (“MVST”) planning process.

In addition to my experience in North Carolina, I have experience supporting generation developers, transmission developers, electric utilities, state regulators and agencies, and regional transmission operators with transmission planning processes and benefits analyses in all of the planning regions across the country, including CAISO, ERCOT, SPP, MISO, NYISO, PJM and ISO-NE. I authored a report on the regional transmission planning completed by the Southeastern Regional Transmission Planning (“SERTP”) process, in which Duke participates, and opportunities to improve its regional planning approach through FERC Order No. 1920. I am also currently involved in the Florida Reliability Coordinating Council stakeholder process for compliance of Order No. 1920.

I have participated in generation resource planning across the country and submitted testimony, reports, or stakeholder comments to the respective state-level commissions or applicable boards in California, Maine, Wisconsin, Tennessee, and Kentucky. My work in generation resource planning includes work for electric utilities completing the resource planning studies as well as renewable energy trade groups and generation developers intervening in the planning process and related dockets.

Recently, I have worked with both generation developers and hyperscalers in seeking opportunities for interconnecting new data centers to the power system as efficiently as possible while meeting the resource adequacy and transmission security needs of the system.

A copy of my CV is attached as **Exhibit 1**.

Q: WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A: I provide economic and financial analysis for a broad set of clients in the electric utility industry that are mostly focused on the drivers for new generation and transmission infrastructure investments, including renewable energy and gas-fired generation resources as well as transmission assets. As noted above, my clients include electric utilities, renewable energy and storage developers, transmission developers, system operators, environmental organizations, and state agencies.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A: Yes, I testified before the North Carolina Utility Commission in the 2022 and 2024 Duke resource planning dockets, specifically Docket No. E-100, Sub 179 and Docket No. E-100, Sub 190. I also presented on behalf of the Carolinas Clean Energy Business Association in the Large Load Technical Conference on October 14, 2025 in Docket No. E-100, Sub 208.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: The Carolinas Clean Energy Business Association (CCEBA).

Q: ARE YOU SUBMITTING ANY EXHIBITS WITH YOUR TESTIMONY?

A: Yes, I am submitting the following exhibits:

- **Exhibit 1**: CV of John Michael Hagerty.
- **Exhibit 2:** Astrape Consulting, Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study, November 1, 2023;
- **Exhibit 3**: Affidavit of Aaron Melda and Lonnie Bellar (Overview Affidavit), Attachment B to the SEEM Transmittal Letter;
- **Exhibit 4**: Potomac Economics, Annual Audit Report on the Southeast Energy Exchange Market, June 2, 2025;
- **Exhibit 5**: CAISO, Western Energy Imbalance Market Benefits Report, Fourth Quarter 2025, February 13, 2026;
- **Exhibit 6:** GDS Associates, Inc., Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC: December 2022 Winter Storm Outages and Blackouts, Docket No. ND-2023-1-E, August 25, 2023;
- **Exhibit 7**: CTPC, 2024 Multi-Value Strategic Transmission (MVST) Study, January 17, 2025.
- **Exhibit 8**: Hagerty, et al., Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy, April 2, 2025.

Q: WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A: The purpose of my testimony is to: (1) review Duke's IRP modeling assumptions and approach as it relates to solar resources, (2) review the results of the IRP modeling and the value of solar to the Duke system, (3) summarize recent transmission planning studies completed by Duke to reduce costs, increase the ability to serve future demand, and support new generation resources, and (4) discuss ways of addressing large customers with clean energy goals and requirements.

Q: PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS.

A: My testimony reaches the following conclusions:

- Solar resources continue to be a prudent, cost-effective addition to the Duke system, with Duke's modeling showing the need to add 4 GW of new solar by 2034 and over 10 GW by 2040 in the Near-Term Action Plan.
- Duke's assumptions for the costs and operating characteristics of solar resources are generally reasonable and comprehensive, with no hidden costs unaccounted for in the modeling.
- However, two assumptions in Duke's modeling tend to underestimate the value of solar, including: (1) the failure to capture the full value of battery storage as an operating asset in conjunction with solar; and (2) the inability to export excess solar to neighboring systems.
- Other markets in the U.S. already generate more from solar and wind resources than Duke's forecasts for 2035; for example, the 2025 generation mix of the ERCOT market in Texas included 14% of total generation from solar and an additional 23% from wind resources;
- Solar provides critical value to Duke ratepayers by serving as a hedge against natural gas price volatility and supply infrastructure risks, a significant factor as Duke's reliance on gas generation is projected to [redacted] through 2035.

- Duke's modeling demonstrates across a wide range of future system conditions that more solar capacity is cost-effective to the future Duke system than identified in the Preliminary Base scenario.
- Duke has a limited set of resource options in the near-term for meeting a significantly higher projection of load growth both in terms of total annual energy demand and peak demand requirements.
- Solar and storage are essential resources for meeting higher load growth scenarios, as Duke's modeling shows these resources are the primary additions needed when load growth exceeds the limits of building new gas combined cycle plants.
- Proactive transmission planning through the CTPC's MVST process will reduce ratepayer costs, streamline the interconnection process, and provide more accurate inputs for resource planning.
- By contrast, relying primarily on the interconnection process to identify transmission upgrades results in higher costs to customers; proactive planning should identify least-regrets upgrades that provide cost effective reliability benefits across a range of future scenarios.
- The clean customer tariff proposed by witnesses Levitas and Barua for the Clean Energy Buyers Association ("CEBA") is persuasive and their proposal would enhance the ability to meet large customer demand for clean energy resources while limiting risk to other ratepayers.

Q: CAN YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION?

A: Yes, I have the following recommendations for the Commission to consider:

1. The Commission should increase the solar procurement targets in the Duke Near-Term Action Plan from an average of 770 MW per year for the 2026-2028 RFPs to at least 1,000 MW per year to ensure it has sufficient resources to serve the High Load case.
2. Duke should update its modeling to reflect the full value of battery storage. Duke can do so by either better capturing volatility in the marginal costs of energy and the reliability services value of storage within its model, or by calculating the estimated incremental value of storage not captured by the EnCompass software and incorporating those results into the model.
3. Duke should improve its representation of transactions with its neighboring systems in its model to better account for the availability and value of non-firm transactions in the most cost-effective resource portfolio.
4. The Commission should require Duke to study the effectiveness of the Southeast Energy Exchange Market ("SEEM") in enabling cost-saving transactions with neighboring systems and identify improvements such as an energy imbalance market that could unlock additional savings based on experience in the non-RTO portions of the western U.S.
5. I recommend the following for the next MVST study:
    a. Given the uncertainty in load projections identified in the current resource planning study, the next MVST scenarios should include at least two future load growth scenarios rather than one;

b. The CTPC should summarize constraints identified in the base case production cost model, similar to the results shared for the reliability models, and present the costs incurred by those binding constraints during the needs assessment phase;

c. The CTPC should validate its production cost model using a recent historical year's load, generation resource mix, renewable energy generation, and natural gas prices to calibrate how well the model replicates the results of the real-world system, including generation mix, renewable curtailments, and total production costs; and,

d. The CTPC should present more detail of its analysis of each of the benefits of transmission solutions, so that stakeholders can understand the impact of each solution to the system compared to alternatives.

6. The Commission should continue to review Duke's transmission planning and interconnection processes to identify opportunities for improving the processes and reducing costs to ratepayers while maintaining system reliability.

7. The Commission should actively participate in the development of the SERTP Order No. 1920 compliance filing and urge Duke to leverage its experience with the MVST process to support a proactive, multi-value, scenario-based planning process at SERTP that exceeds the requirements of Order No. 1920 and supports cost-saving regional transmission upgrades across the Southeast.

8. The Commission should find that the existing GSA Choice program does not provide the additionality that large customers need, and has therefore largely failed to serve its intended purpose. I recommend that the Commission direct

Duke to file an application for approval of a new clean customer tariff for commercial and industrial customers consistent with the six elements described in CEBA's testimony and endorsed in my testimony.

I. REVIEW OF DUKE IRP MODELING APPROACH AND ASSUMPTIONS

Q: DID YOU REVIEW DUKE'S MODELING FOR ITS 2025 IRP, INCLUDING THE ASSUMPTIONS FOR NEW SOLAR RESOURCES?

A: Yes, I reviewed Duke's approach and assumptions for modeling its future power system for the 2025 IRP including the appendices and several responses to data requests with a particular focus on the assumptions for new solar photovoltaic resources (which I will refer to as "solar" in the rest of my testimony).

Q: WHAT INPUT ASSUMPTIONS ARE NEEDED TO ACCURATELY CAPTURE THE COST AND VALUE OF SOLAR RESOURCES IN DUKE'S IRP MODELING?

A: There are several modeling inputs that are important for accurately capturing the cost and value of solar to the Duke system. The key input assumptions for modeling the cost of solar to the system include: (1) the costs of installing new solar resources (often referred to as the "capital costs"), (2) the costs of building necessary transmission network upgrades for interconnecting the solar resources, (3) the operations and maintenance costs ("O&M") once the resource has been built, (4) federal tax credits applicable to the solar resource, (5) the hourly generation profile of the solar resource, (6) the contribution of the solar resource to meeting Duke's planning reserve requirements (which is quantified based on the resource's Effective Load Carrying Capability, or "ELCC"), and (7) annual build limits. In addition, Duke assumes that the addition of renewable energy resources, including solar and wind resources, will increase its need for operating reserves.

In addition to the assumptions specific to solar resources, the value of solar to the Duke system is dependent on the growth and shape of system load; the cost, availability and operating characteristics of alternative sources of generation and storage; commodity fuel prices; natural gas infrastructure costs and availability; and compliance with regulatory and statutory emissions requirements.

Q: ARE THE INPUT ASSUMPTIONS SPECIFIC TO THE SOLAR RESOURCES GENERALLY REASONABLE?

A: Yes, at a high level the Duke modeling of solar resources reflects reasonable assumptions concerning the costs and operating characteristics of solar. Several assumptions have changed significantly since the last Duke resource planning study including higher capital costs, the end of federal tax credits for renewable energy resources that start construction after July 2026, and the removal of the North Carolina interim GHG emissions target for the early 2030s. The solar build limits of 1,200 MW per year in the early 2030s, while lower than the 1,800 MW per year recommended by CCEBA in the past, are reasonable given recent macroeconomic and system level changes impacting the Duke portfolio selections and the impact of proactive transmission planning to reduce interconnection challenges in the future.[1]

Importantly, the assumptions are comprehensive in terms of solar costs, generation profiles, and uncertainty in analyzing the impacts and value of solar on the system. There are no "hidden" costs of solar that the Duke modeling does not capture. Instead, several assumptions within the modeling completed for the IRP tend to underrepresent the value of solar.

Q: YOU MENTIONED THAT SOME COSTS ARE HIGHER THAN IN THE PAST IRP STUDIES. WHAT IS DRIVING THOSE HIGHER COSTS AND HOW DO THE COST INCREASES FOR SOLAR COMPARE TO OTHER RESOURCES?

A: The costs of **<u>all</u>** generation resources have increased over the past several years due to general escalation of costs across the economy, higher labor costs, interest rates, the effect of tariffs, and tighter supply chains for meeting the growing demand for new generation and electrical equipment across the country to serve significant load growth. The costs of other resources, including gas CC, gas CT, and battery storage, have also increased for many of the same reasons. Overall the assumed capital costs for solar and other generation resources in the Duke IRP modeling are in a reasonable range based on my experience modeling power system across the country and input from current solar developers.

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1 Verified Petition for Approval of 2025 Carbon Plan and Integrated Resource Plan of Duke Energy Carolinas LLC and Duke Energy Progress LLC, Docket E-100, Sub 207, October 1, 2025, ("Duke IRP") Appendix C: Quantitative Analysis, p. 27.

Importantly, the future costs of solar projects may not be the same as assumed in Duke's resource planning study. Duke's sensitivity cases for higher and lower costs of new solar resources are thus important for understanding the impacts of higher and lower capital costs on optimal solar resource volumes. The results of those cases show that 30% higher solar costs have limited impact on solar additions, reducing 2040 solar by just 225 MW from the Preliminary Base scenario. On the other hand, the scenario with 30% lower solar costs identifies a need for significantly more solar, increasing solar additions by 4,000 MW over the Preliminary Base scenario.[2]

Q: DOES DUKE ACCOUNT FOR THE COST OF TRANSMISSION NETWORK UPGRADES FOR INTERCONNECTING SOLAR AND OTHER RESOURCES?

A: Yes, Duke includes a transmission network upgrade cost for each resource type in its modeling, and that value is added to the installed cost of the generation resource itself. As Duke notes, "[t]his cost adder is a proxy for upgrading the transmission network for reliable power transmission from the resource into the networked transmission system."[3] For solar, Duke assumed the cost for network upgrades is $190-200/kW, depending on the utility operating company territory.[4] Notably, the network upgrade costs for solar are lower than the network upgrade cost for new gas CC, gas CT, and nuclear resources, as shown in Figure 1 below. Thus, not only does Duke account for transmission upgrades for new solar

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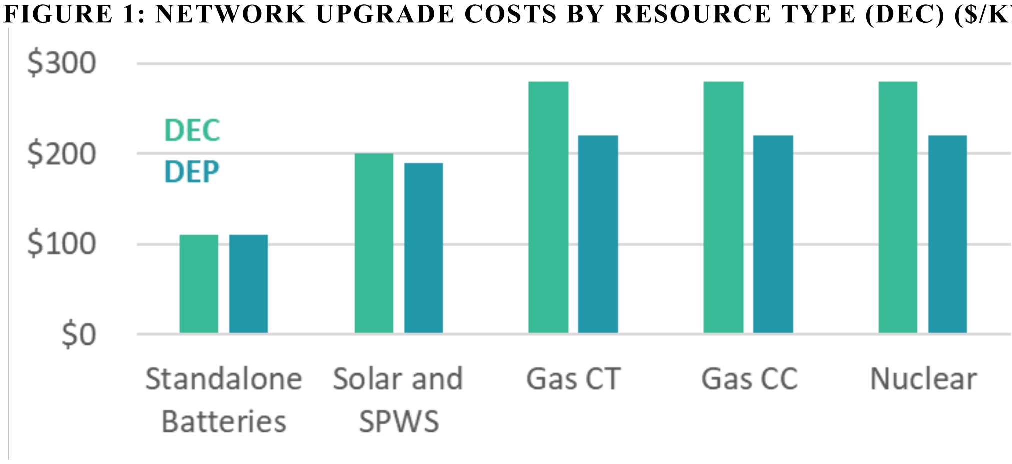
2 Duke IRP, Chapter 3: Portfolio Development & Evaluation, Table 3-5, p. 6.

3 Duke IRP, Appendix C: Quantitative Analysis, p. 37.

4 Duke IRP, Appendix C: Quantitative Analysis, p. 37.

generation and other resources in its modeling, the network upgrade costs for Gas CC and CT are higher than for Solar and Solar Paired With Storage ("SPWS").

FIGURE 1: NETWORK UPGRADE COSTS BY RESOURCE TYPE (DEC) ($/KW)



Source: Duke IRP, Appendix C: Quantitative Analysis, p. 37.

Q: WHAT IS THE BASIS FOR THE NETWORK UPGRADE COSTS ASSUMED IN THE DUKE IRP MODELING?

A: Duke estimates the network upgrade costs based on recently completed generator interconnection studies and results from the ongoing 2024 Definitive Interconnection System Impact Study ("DISIS") Phase II Cluster study.[5]

Q: IS THERE ANY REASON TO BELIEVE THAT THERE ARE MISSING CATEGORIES OF NETWORK UPGRADE COSTS NOT ASSUMED IN DUKE'S MODELING?

A: No.

Q: WHY NOT?

A: Duke has relied on the most recent market data for projects currently in development for estimating the costs of network upgrades.

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[5] Duke IRP, Appendix C: Quantitative Analysis, p. 37.

Q: DO YOU HAVE ANY REASON TO BELIEVE THAT FUTURE NETWORK UPGRADE COSTS FOR INTERCONNECTING SOLAR WILL BE LOWER THAN THE RECENT COST DATA INDICATES?

A: Yes.

Q: WHY?

A: The network upgrade costs are based on recent information from interconnection costs of each resource type. I expect future network upgrades costs likely will decrease in future years as Duke, through the CTPC, implements proactive approaches to planning its future system, including the Red Zone Economic Projects ("RZEP") and MVST projects. These projects are being pursued for a variety of economic and reliability reasons, but one benefit of these forward-looking planning approaches will be reduced network upgrade costs and reduced delays for new generation. As I noted above, this is important because lower solar capital costs have a significant impact on solar additions.

I explain in more detail later in my testimony the approaches that Duke is taking to reduce the costs and increase the value of transmission additions for serving new load and accessing lower cost resources.

Q: EARLIER YOU MENTIONED THAT THE SOLAR GENERATION PROFILE IS AN IMPORTANT ASSUMPTION FOR MODELING SOLAR RESOURCES. PLEASE EXPLAIN.

A: The solar generation profile provides the IRP models an input of the hourly amount of electricity that will be generated by each solar resource. The amount of solar output differs by the hour of day and throughout the year, but also from hour-to-hour and day-to-day based on projected weather conditions.

Q: DOES THE DUKE IRP MODELING ACCOUNT FOR THE NATURAL VARIATION IN SOLAR GENERATION?

A: Yes. I reviewed the assumed solar generation profiles that Duke includes in its IRP modeling for new solar resources and found that they accurately account for variations in solar output.[6] Duke completes an extensive analysis of historical solar generator production across North Carolina and South Carolina to develop these profiles.[7] The solar generation profiles incorporate variations in: (1) hourly generation due to the daily cycle of sunlight, (2) daily generation due to day-to-day variations in cloud cover, and (3) monthly generation due to seasonal shifts in solar irradiance. These hourly, daily, and monthly variations in generation are mostly predictable at the portfolio level, such that Duke is able to forecast solar production accurately and integrate that production with the efficient dispatch of other generation resources. Duke assumes the same profiles for each future year, which does not capture annual variations in total solar irradiance, but annual variation tends to be relatively low with most years within 2-3% of the average.

I created several figures to demonstrate the variation in solar generation across different timescales assumed in Duke's resource planning models. [redacted]

6 I reviewed the solar generation profiles provided by Duke in response to PS DR 7-2 in the file 1.7.5.1_PS DR 7-2 Solar Capacity Fa_F_workpapers (confidential).xlsm, specifically the sheet labeled as 'Future Solar'. ("Duke Response to PS DR 7-2")

7 "Actual solar output is variable and dependent on natural irradiance (daylight) and cloud cover. Solar profiles modeled in the Resource Plan are based on a "typical meteorological year," ("TMY"), using 25 years of historical irradiance data from 22 sites across the Carolinas." Duke IRP, Appendix C: Quantitative Analysis, p. 25.

shows the hourly variation of solar generation that Duke assumes for July 1 – 5 following the expected daily pattern of solar irradiance and variations in the amount of solar output day-to-day. Duke is able to handle the hourly variation of solar by dispatching other generation and storage down during solar generation hours and up during non-solar generation hours, as discussed in more detail below.

[redacted]

Source: Duke Confidential Response to PS DR 7-2.

[redacted] below shows the daily difference in total solar generation output. This figure counts the number of days per year that solar capacity factor is within the range shown on the bottom of the figure and differentiates days in each of the four seasons. For example, most days in the summer have solar output in the [redacted] range with several higher in the [redacted] range and some lower in the [redacted] range. In the winter though, the average output per day tends to be lower with the most in [redacted] range.

[redacted]

[redacted]

[redacted]

[redacted]

Source: Duke Confidential Response to PS DR 7-2.

These figures demonstrate that the natural variation in solar generation by the hour, day, and season is accounted for in the IRP modeling.

Q: CAN THE DUKE SYSTEM EFFICIENTLY RESPOND TO VARIATIONS IN SOLAR GENERATION?

A: Yes. Duke responds to variations in solar generation in two important ways. First, in operating its system, Duke forecasts solar generation patterns for the next day based on weather forecasting and plant availability and plans its dispatch of system resources in conjunction with that projected output to serve load while also taking into account the availability and operating parameters of other resources. Second, Duke maintains operating reserves to respond to moment-to-moment changes in solar generation. This is similar to how Duke dispatches its generation resources to serve the daily cycles of its projected *load* and maintains operating reserves in case of generator outages as well as sudden changes in electricity demand.

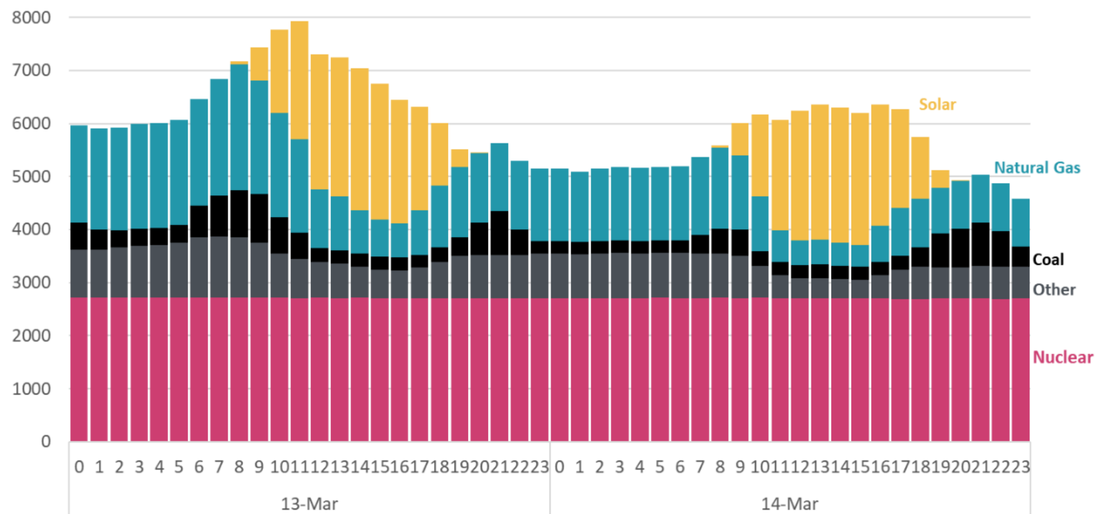
Q: HOW DOES DUKE DISPATCH ITS RESOURCES IN RESPONSE TO VARIATIONS IN SOLAR GENERATION?

A: Yes. Duke has always had to plan for the dispatch of its resources to meet hourly changes in load and has installed "load-following" resources to do so, including natural gas CCs, storage, and certain types of hydroelectric generation. With increasing solar generation on its system, Duke now dispatches its resources to serve the amount of load that is not served by solar, often referred to as the "net load." Duke dispatches its generation resources to serve load while accounting for the hourly solar generation as shown in Figure 5 below. [8] The figure shows

[8] Hourly generation by resource type is not available based on Duke's IRP modeling due to data limitations.

hourly generation by resource type in the Duke Energy Progress East balancing area for March 13 and 14, 2026 when solar is particularly high and load is generally low. In fact, solar served about 50% of the hourly load from 1 – 3 pm on March 14!

FIGURE 5: DUKE ENERGY PROGRESS EAST GENERATION FOR MARCH 13-14, 2026



Source: U.S. Energy Information Administration ("EIA"), Hourly Electric Grid Monitor, https://www.eia.gov/electricity/gridmonitor/dashboard/custom/pending, accessed March 25, 2026.

In this high solar case, total generation is low in overnight hours (around 6,000 MW on March 13) and then starts to climb in the morning, resulting in several resources increasing their output to serve the higher load. When solar generation begins around 9 am, the other resources are dispatched down reducing their total output by about 3,000 MW, primarily from reducing the output of flexible gas generation. Resources then increase their output during the afternoon hours to serve evening and overnight load. As Duke notes in its IRP report about gas CCs, "[g]iven the flexibility of these resources to quickly ramp up and down output, they are well equipped to operate dynamically within the fleet to integrate variable energy resources, like solar and wind, while meeting fluctuating load requirements."[9] Gas CTs and storage are also well equipped to efficiently respond to the changes in load and renewable energy throughout the day.

Coal plants are generally less flexible, but the figure above shows coal output adjusting to changes in load and solar output. Due to low natural gas prices since around 2010, coal power plants have been less cost effective to run than Gas CCs and have had to operate more flexible over that timeframe. The costs of operating and maintaining coal plants while operating in this way is reflected in Duke's assumptions for its variable and fixed operations and maintenance ("O&M") cost assumptions. By 2032, Duke forecasts that the remaining 6.3 GW of coal plants will have a capacity factor of [redacted] when running on coal, such that their ramping costs, if any, are likely to be quite low.

Q: YOU NOTED THAT DUKE WILL INCREASE ITS OPERATING RESERVES WITH INCREASING SOLAR CAPACITY. DOES DUKE INCLUDE THE NEED FOR ADDITIONAL OPERATING RESERVES IN ITS MODELING?

A: Yes. In addition to the hourly variation in its solar generation profiles, Duke also accounts for the hourly uncertainty in solar generation by adjusting the amount of operating reserves that are on standby to generate in case of a sudden decrease in solar output. As noted in Appendix L, "the Plan accounts for these realities by updating the balancing and regulating reserve requirements used within the

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9 Duke IRP, Appendix C: Quantitative Analysis, p. 31.

modeling process to capture the increased flexibility needs from variable renewable output."[10]

Q: DOES THE REQUIREMENT OF ADDITIONAL OPERATING RESERVES DUE TO MORE SOLAR CAPACITY INCREASE COSTS FOR DUKE?

A: Yes, the increased operating reserves add costs to portfolios with greater solar generation because gas plants are operating at lower output and start up more frequently, which are accounted for in Duke's IRP production cost modeling.

Q: DOES DUKE CALCULATE THE MAGNITUDE OF THESE ADDITIONAL COSTS?

A: Yes, Duke regularly calculates the incremental costs of the additional operating reserves due to increasing solar resources on the Duke system when setting the Solar Integration System Charge ("SISC"). As noted in the 2023 SISC report:

> "unexpected changes in solar output can be cost effectively accommodated by increasing upward ancillary service targets within the existing conventional fleet. Increasing ancillary service targets forces the system to commit more generating resources which allows generators to dispatch at lower levels giving them more capability to ramp up. There is a cost to this increase in ancillary services because generators are operated less efficiently when they are dispatched at lower levels. Generators may also start more frequently, which also increases costs… This 2023 Study analyzes multiple solar penetration levels and quantifies the cost of utilizing the

[10] Duke IRP, Appendix L, Reliability and System Resilience, p. 10.

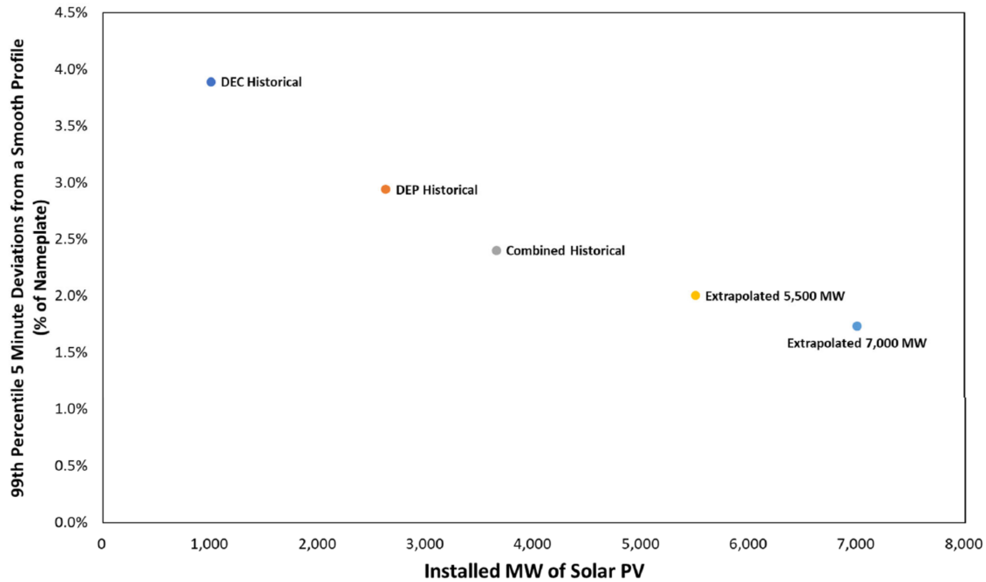
existing fleet to reliably integrate the additional solar generation."[11]

Duke calculates the SISC based on the incremental costs of the additional operating reserves and the additional unit start costs divided by the megawatt-hour ("MWh") of solar generation. The most recent analysis of the SISC in 2023 calculated the SISC to be $0.89/MWh to $1.62/MWh across two tranches of solar resources and the two service territories.[12] Based on recent solar costs, the SISC adds only about 1% to the total costs of solar, which is immaterial to the amount of solar generation selected by resource planning tools like EnCompass. As noted by CCEBA in the 2025 Avoided Cost docket, E-100, Sub 211, the 2023 SISC study may not account for the effects of greater BESS deployment in Duke's territory, which would further reduce the costs.

Importantly, the 2023 SISC report finds that the volatility of generation from installed solar resources decreases with increasing solar penetration, as shown in Figure 6 below. Specifically, the figure shows that the amount of deviations from a normalized profile decreases from nearly 4% at 1,000 MW of installed solar capacity (blue dot labelled "DEC Historical") to less than 2% at 7,000 MW (light blue dot labelled "Extrapolated 7,000 MW").[13]

[11] Exhibit 2, 2023 SISC report, pp. 3-4.
[12] Exhibit 2, 2023 SISC report, Table ES-4, p. 8.
[13] Exhibit 2, 2023 SISC report, Figure 13, p. 32.

FIGURE 6: SOLAR GENERATION VOLATILITY BY INSTALLED CAPACITY



Source: Astrape Consulting, Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study, November 1, 2023 (**Exhibit 2**), p. 32.

This trend occurs because the addition of new solar resources diversifies the location of the solar plants and the volatility in generation across solar resources. The volatility of solar generation resources will continue to decrease as additional solar is added well beyond 7,000 MW to nearly 12,000 MW in the NTAP case based on the 2025 IRP.

Q: DO OTHER CANDIDATE GENERATION RESOURCES HAVE UNIQUE OPERATING PROFILES THAT DUKE MUST CONSIDER AND ACCOUNT FOR IN ITS MODELING?

A: Absolutely. Resource planning requires extensive analysis of the system needs as well as the unique cost, capabilities. and limitations of each resource type. For example, coal and nuclear generation facilities have long been key resources in the Duke system but both resources are generally inflexible in their ability to respond to changes in system conditions and so other resources need to be available to provide those services and account for the lack of flexibility of coal and nuclear power plants. Duke specifically notes that utilities are moving away from coal plants towards resources that are "more efficient, flexible, and cost-effective."[14]

In addition, thermal generation resources including coal, gas and nuclear resources, experience unexpected outages that create challenges for operating the system. Duke evaluates the amount of additional resources it must add to the system "to maintain reliability through *unplanned outages* or higher than expected loads due to extreme weather events."[15] The uncertainty created by thermal outages directly translates to higher costs for reliably serving load by increasing the amount of resources that have to be procured to meet planning reserve requirements. [16]

Q: WHAT DOES DUKE ASSUME FOR THE CONTRIBUTIONS OF SOLAR TO MEETING ITS RESOURCE ADEQUACY NEEDS AND SPECIFICALLY THE PLANNING RESERVE REQUIREMENTS?

A: Duke assumes that solar resources have a relatively low contribution to meeting the planning reserve requirements. Duke estimates the contribution of solar, wind and storage based on its ELCC, which it estimates through a separate study. The ELCC of solar is 10% or less.[17] The values are low because Duke's modeling

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[14] Duke IRP, Appendix F: Coal, p. 1.

[15] Duke IRP, Appendix C: Quantitative Analysis, p. 69.

[16] See, e.g., Winter Storm Elliot, as discussed in **Exhibit 6.**

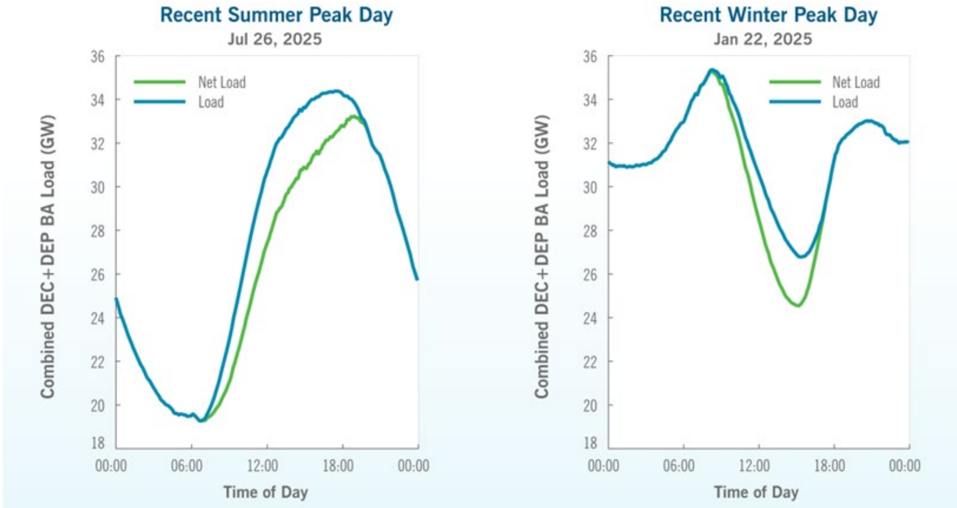
[17] Duke IRP, Appendix C: Quantitative Analysis, p. 25.

identifies winter mornings as the primary driver of reliability events throughout the year before solar resources start generating or are generating very little.

Q: DOES THAT MEAN SOLAR HAS NO VALUE AT ALL TO MAINTAINING A RELIABLE SYSTEM?

A: No, the way Duke calculates ELCC does not mean that the solar resources on the Duke system are not valuable to maintaining a reliable system. On the contrary, some of the highest load throughout the year occurs in the summer during daylight hours when solar is generating. Solar output during this period is critical to maintaining a reliable power system. Increased solar reduces the likelihood of reliability events during the periods when it is producing. And without solar resources, the frequency of reliability events during peak load periods would otherwise be higher. The more solar enters the system, the more it reduces the "net load" during the middle of the day and the chance of a reliability event during those times, shifting reliability events to other non-solar hours. Figure 7 below demonstrate that in the summer of 2025 solar played a key role in meeting peak demand and significantly lowering net peak demand. Solar will continue to do so in the future with additional resources. While the incremental reliability need will likely get pushed to later in the evening when solar does not produce, the advent of battery storage at scale should enable stored solar energy to assist in meeting this later peak.

FIGURE 7: SUMMER AND WINTER 2025 PEAK DAY LOAD AND NET LOAD



Source: Duke IRP, Appendix L: Reliability & Operational Resilience, p. 10.

Q: ARE THERE ANY ASSUMPTIONS IN DUKE'S MODELING THAT RESULT IN UNDERESTIMATING THE FUTURE CAPACITY OF SOLAR?

A: Yes, there are two assumptions in particular that tend to underestimate the value of solar in Duke's modeling: the full value of storage is not captured and they do not account for opportunities to export excess solar.

Q: HOW DOES THE DUKE IRP MODELING NOT FULLY ACCOUNT FOR THE VALUE OF STORAGE?

A: Resource planning modeling performed by Duke and other resource planners across the country relies primarily on normalized inputs for hourly demand, hourly renewable energy generation, daily natural gas prices, transmission outages, and fossil resource outages. These normalized assumptions underestimate the volatility that occurs in the real-world power system. As Duke notes in its IRP documents, the EnCompass capacity expansion model normalizes system conditions by using "a simplified, average representation of hourly system demand to screen for the optimal resource portfolio for a given set of input assumptions."[18] Battery storage resources provide significant value to the power system by taking advantage of the expected and unexpected volatility of the market, absorbing the output of low-cost generation during certain hours and injecting power back into the system during high-cost hours, as well as providing operating reserves and regulation services. By not accounting for the actual market conditions of its system, Duke will underestimate costs of serving load during especially high cost hours. By missing that value, models like EnCompass will significantly underestimate the amount of cost-effective storage capacity.

This is a common issue across resource planning models because fully accounting for real-world market conditions over a multi-decade period requires new approaches and assumptions. But there are ways to better capture storage value in resource planning models. Two approaches that my colleagues and I at The Brattle Group have implemented to account for this common shortcoming are to: (1) calculate the missing value for battery storage in a separate analysis based on historical volatility in market conditions and then add that value into the capacity expansion model as an offset to annual fixed battery storage costs; and, (2) develop more representative assumptions for the load profiles, renewable energy generation, and natural gas prices that account for non-normalized conditions and include them in the capacity expansion model. I have recently supported an electric utility in making similar refinements to their modeling capability to account for the full value of storage following the first option noted

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[18] Duke IRP, Chapter 2: Methodology, p. 22.

above. I highly recommend that Duke pursue improvements in its modeling capability to better value storage resources in its resource planning models in future IRP planning studies.

Q: DOES UNDERESTIMATING THE VALUE OF STORAGE AFFECT SOLAR RESOURCES?

A: Yes. More storage resources on the Duke system will tend to increase the value of solar by providing low-cost supply for charging the storage resources. This relationship between storage capacity and solar resource additions can be clearly seen in the Duke sensitivity cases. Specifically, Duke ran a sensitivity case with lower cost storage, which can also represent a case in which additional storage value is included in the model. The low storage cost case results in an additional 2,800 MW of storage *and* 1,875 MW of additional solar on the system compared to the preliminary base case, displacing about 1,800 MW of gas resources.[19] This demonstrates that by not fully capturing the value of storage, Duke's modeling skews the results away from solar and storage.

Q: HOW DOES DUKE MODEL ITS INTERACTIONS WITH NEIGHBORING UTILITIES AND MARKETS?

A: Duke models its system as an island without opportunities to sell excess power to its neighboring system or purchase imports for cost-effectively serving load on a non-firm basis. Duke specifically notes that it does not include the ability to transact with its neighboring system through the existing bilateral trading market in the Southeast known as SEEM, explaining that "because these potential, 15-

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[19] Duke IRP, Appendix C: Quantitative Analysis, Table C-30, p. 56.

minute economic energy purchases and sales are as-available, non-firm, and completely dependent on neighboring utilities' load and resource availability, as well as the availability of non-firm transmission to deliver the energy, the Companies do not include the potential economic benefit of SEEM in their resource planning modeling."[20] Similarly, Duke does not include transactions with the PJM electricity market.

This modeling approach does not reflect the real world. Duke transacts with neighboring systems and can offer its generation or purchase generation via SEEM. However, SEEM transaction volumes have been relatively small to date.[21] The use of the existing non-firm transfer capability with neighboring systems for cost-effective transactions – through bilateral transactions or via SEEM – is less than would occur if Duke were to participate in an energy imbalance market or a day-ahead energy market.

Q: WHY DOES MODELING THE DUKE SYSTEM WITHOUT ACCESS TO IMPORTS OR EXPORTS RESULT IN LESS SOLAR CAPACITY ADDITIONS?

A: The "islanded" utility assumption has an impact on solar resource additions in the Duke modeling because, without accounting for and including transactions with neighboring systems, solar resources will be curtailed more frequently to avoid periods of overgeneration. As Duke notes in Appendix L, "On the lowest-load days (such as mild and sunny spring days), solar energy and other non-solar

[20] Duke IRP, Appendix C: Quantitative Analysis, p. 11.

[21] https://southeastenergymarket.com/wp-content/uploads/SEEM-Audit-Report-Annual-2024-F.pdf.

generation may need to be curtailed to maintain system reliability at the LROL [Lowest Reasonable Operating Level] if other management options are not available."[22]

If instead Duke included in its modeling the ability to *export* energy from solar to neighboring systems, Duke would increase off-system sales revenue, which would reduce the net costs to Duke's customers and increase the value of the solar resources compared to simply curtailing its output. In the near-term, solar curtailment is most likely to occur in the spring and fall when load is lower and output of solar is still fairly high (as shown above), but with increasing solar penetration it can also occur in other months.

Q: ARE THERE MODELING APPROACHES THAT DUKE CAN IMPLEMENT TO BETTER CAPTURE THE VALUE OF ADDITIONAL NON-FIRM TRANSACTIONS WITH ITS NEIGHBORING SYSTEMS?

A: Yes. Including interactions with neighboring systems is a common modeling practice in the industry. To better capture the value of off-system sales, utilities often follow one of two approaches. Some resource planners include in their models a larger geographic footprint than their own system that includes neighboring systems and allows for transactions between systems on a non-firm basis up to the limits of the transmission system. Alternatively, utilities will allow the model to schedule imports and exports up to transmission limits based on an hourly estimate of the marginal costs of resources in neighboring systems. When Duke's marginal costs are lower than its neighboring systems, such as during

[22] Duke IRP, Appendix L, p. 10.

excess generation periods, the model will choose to export to their neighbors and earn revenues from doing so. Either of these approaches would increase the value of solar during periods of excess generation, reduce curtailments, and increase the volume of cost-effective solar selected by the capacity expansion model.

Q: WILL DUKE BE ABLE TO SCHEDULE IMPORT AND EXPORT TRANSACTIONS WITH ITS NEIGHBORING SYSTEMS AS EFFICIENTLY AS A MODEL WOULD ALLOW?

A: SEEM is a step in that direction by enabling participating utilities to efficiently schedule transactions on a 15-minute basis between neighboring systems and across the region. With solar growing across the Southeast, scheduling transactions to efficiently utilize resources during periods of excess generation will become a more common driver for transactions across the SEEM region. The FERC filing for SEEM specifically noted this benefit, stating that SEEM will "allow for better integration of diverse generation resources, including rapidly growing renewables, and is expected to reduce renewable curtailments."[23]

However, SEEM's ability to produce those benefits using its current market structure is likely to be limited. The Annual Audit Report on the Southeast Energy Exchange Market by the SEEM Independent Market Auditor Potomac Economics notes that total trading volume in 2024 across the full SEEM footprint (not just DEC and DEP) was just 1,055 GWh.[24] However, the report highlights

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23 Affidavit of Aaron Melda and Lonnie Bellar (Overview Affidavit), Attachment B to the Transmittal Letter, P 26. (**Exhibit 3**).

24 https://southeastenergymarket.com/wp-content/uploads/SEEM-Audit-Report-Annual-2024-F.pdf, p. 2. (**Exhibit 4**).

that transactions are increasing, indicating "increased interest and confidence in the market."[25]

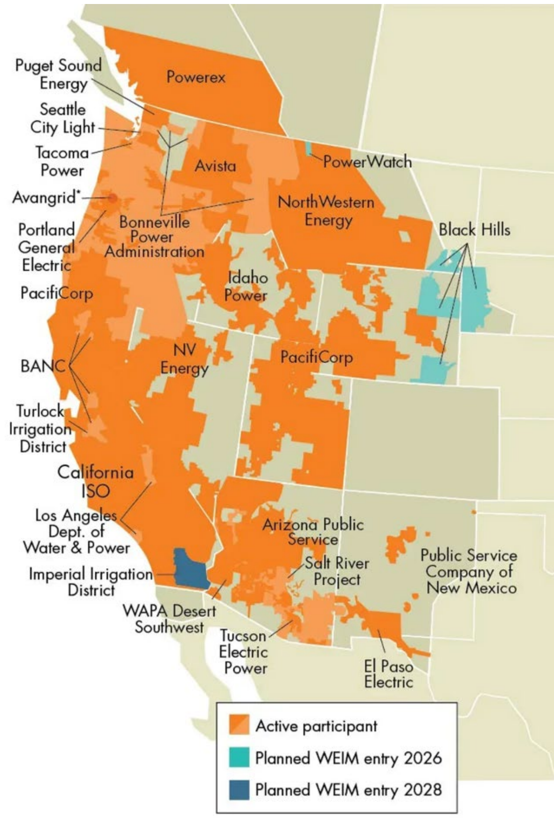
Based on these findings, SEEM transactions currently are limited but may be able to enable an increasing volume of efficient market transactions in the real-time operation of the Duke system by the mid-2030s. Assuming in the IRP modeling that these transactions are not available for efficiently operating their market all the way through 2050 is not reasonable and reduces the value of solar on Duke's system and overlooks potential cost savings for ratepayers.

Q: ARE THERE OTHER MARKET DESIGNS COULD MORE EFFICIENTLY SCHEDULE TRANSACTIONS WITH NEIGHBORING SYSTEMS, LOWER SYSTEM COSTS, AND INCREASE THE VALUE OF SOLAR IN DUKE'S SYSTEM?

A: Yes. Alternative approaches to scheduling transactions and utilizing available non-firm transmission are available, and they have proven better able to cost-effectively utilize excess generation from solar. For example, reducing curtailments of (and monetizing the benefits of) renewable energy is a chief benefit of the Western Energy Imbalance Market ("WEIM"). WEIM has been in operation across most of the Western U.S. for over 12 years and includes regions *without* a regional transmission operator ("RTO"). A map of the WEIM service territory is shown below.

[25] *Id.*, p. 6.

FIGURE 8: WESTERN ENERGY IMBALANCE MARKET PARTICIPANTS



Source: https://www.westernenergymarkets.com/western-energy-imbalance-market-weim

Compared to the limited transactions enabled by SEEM, WEIM more efficiently utilizes available non-firm transmission capacity in the real-time energy market compared and reduced renewable energy curtailments by 258 GWh in 2025.[26] Greater utilization of low-cost generation that would otherwise have been curtailed is one of the reasons that WEIM provided $416 million of benefits in the fourth quarter of 2025 to its participants, with $408 million of the benefits going to non-RTO participants.[27] In fact, since its inception, WEIM has provided

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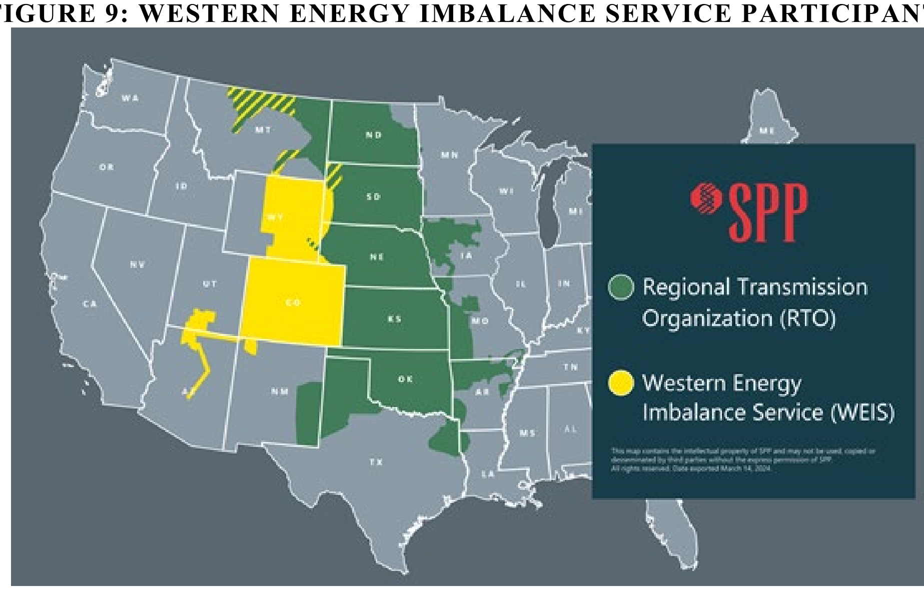
[26] https://www.westernenergymarkets.com/documents/iso-western-energy-imbalance-market-benefits-report-q4-2025.pdf, p. 15. (**Exhibit 5**).

[27] *Id,* p. 3.

$8.2 billion in benefits, again with the majority of those benefits to non-RTO participants ($7.1 billion).[28]

The Western Energy Imbalance Service operated by the Southeast Power Pool ("SPP") provides similar services to non-RTO service territories in several states, including Wyoming, Colorado, and New Mexico, as shown in Figure 9.

FIGURE 9: WESTERN ENERGY IMBALANCE SERVICE PARTICIPANTS



Source: https://spp.org/western-services/weis/

Q: WOULD PARTICIPATING IN AN ENERGY IMBALANCE MARKET REQUIRE DUKE TO JOIN AN RTO?

A: No. The Western Energy Imbalance Market and the Western Energy Imbalance Service both operate in non-RTO portions of the western U.S. and do not require participants to join an RTO. The participants in these energy imbalance market include vertically integrated utilities similar to Duke, including PacifiCorp, NV Energy, Arizona Public Service, and Xcel Energy Colorado.

[28] https://www.westernenergymarkets.com/western-energy-imbalance-market-weim/benefits

Q: DO OTHER MARKETS IN THE U.S. INCLUDE MORE SOLAR THAN THE DUKE SYSTEM?

A: Yes. Solar generation is currently [redacted] of the total generation in the Duke system and is projected to reach [redacted] of its generation mix in 2035 in the NTAP scenario. Two markets have much more solar today. The 2025 generation mix of the ERCOT market in Texas included 14% of total generation from solar and an additional 23% from wind resources, amounting to 37% of generation from renewable energy resources.[29] The most recent generation data from California is from 2024 and shows that 23% of its generation came from solar resources and an additional 7% from wind, totaling up to 31% from wind and solar energy.[30]

In the past month, ERCOT reached nearly 80% of its load being met by a combination of solar and wind. From 9 am to 6 pm on March 14, total renewable energy generation served at least 70% of its load, as shown in Figure 10 below.

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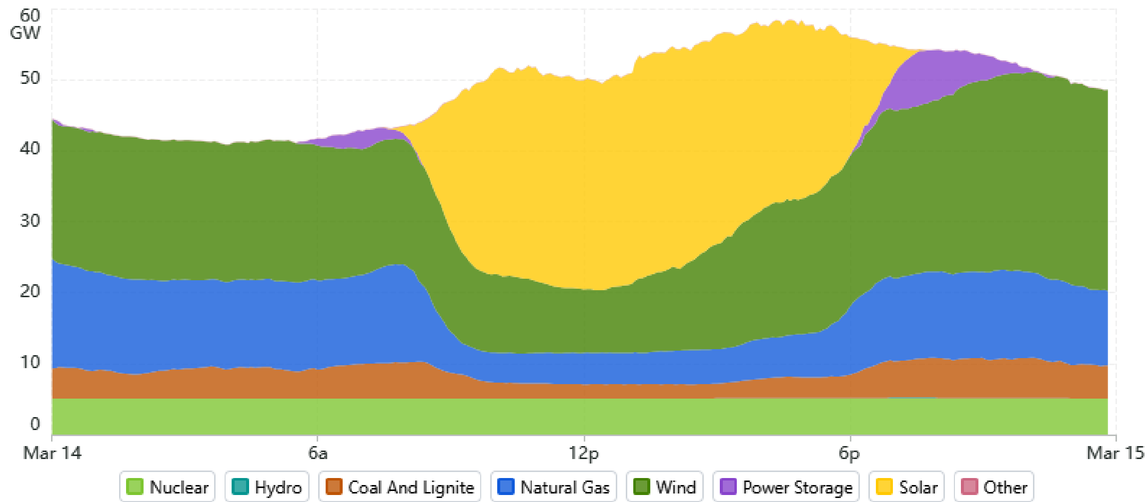
[29] ERCOT, Interval Generation by Fuel Report, March 9, 2026.

[30] California Energy Commission, In-State Electric Generation by Fuel Type (GWh), accessed March 24, 2026.

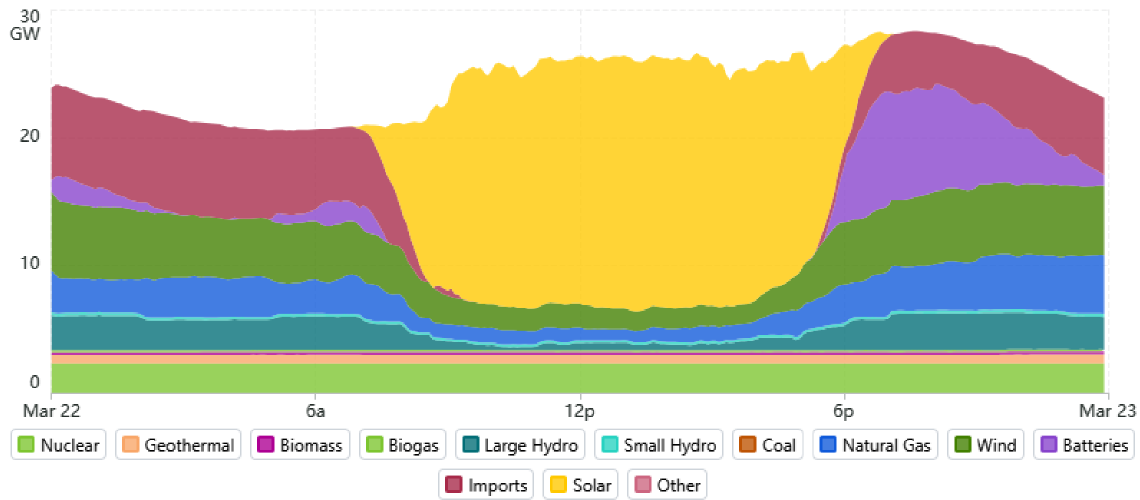
FIGURE 10: ERCOT GENERATION MIX ON MARCH 14, 2026



Source: GridStatus, accessed March 28, 2026, https://www.gridstatus.io/live/ercot?date=2026-03-14

In California, the renewable energy generation in CAISO on March 22, 2026 served over 90% of its demand for most of the daylight hours and exceeded its total demand for an hour, resulting in about 5 GW of exports into the surrounding power system. The CAISO generation mix on that day is shown in Figure 11 below.

FIGURE 11: CAISO GENERATION MIX ON MARCH 22, 2026



Source: GridStatus, accessed March 28, 2026, https://www.gridstatus.io/live/caiso?date=2026-03-22.

Q: HAS THE ADDITION OF SOLAR MADE THOSE SYSTEM LESS RELIABLE?

A: No. Even at much higher penetrations of solar and wind, these markets remain highly reliable. Market rules have been adjusted to account for the variability in output of renewable energy generation by increasing operating reserves and in CAISO a flexible reserve. However, the incremental costs of these reserves are relatively small and efficiently met by existing resources, including flexible gas resources and increasing penetration of battery storage.

Q: ARE THERE ANY DIFFERENCES IN MARKET DESIGN THAT IMPACT HOW WELL THESE OTHER MARKETS CAN INTEGRATE HIGHER SOLAR CAPACITY?

A: Yes, both ERCOT and the California market, as noted above, include regional real-time and day-ahead energy markets that allow for efficient use of resources, including solar.

Q: CAN YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION BASED ON YOUR REVIEW OF THE IRP MODELING?

A: I have three recommendations. First, Duke should improve its modeling to better capture the value of battery storage. Second, Duke should improve its representation of transactions with its neighboring systems in its model to better account for the availability and value of non-firm transactions on the most cost-effective resource portfolio. Third, the Commission should require Duke to study the effectiveness of SEEM for enabling efficient transactions with neighboring systems, including the current limitations to the market framework and improvements that can be made to SEEM to increase its effectiveness, and compare the effectiveness of SEEM to a regional Southeast energy imbalance market similar to the markets currently in place in the non-RTO portions of the western U.S.

II. REVIEW OF DUKE IRP MODELING RESULTS

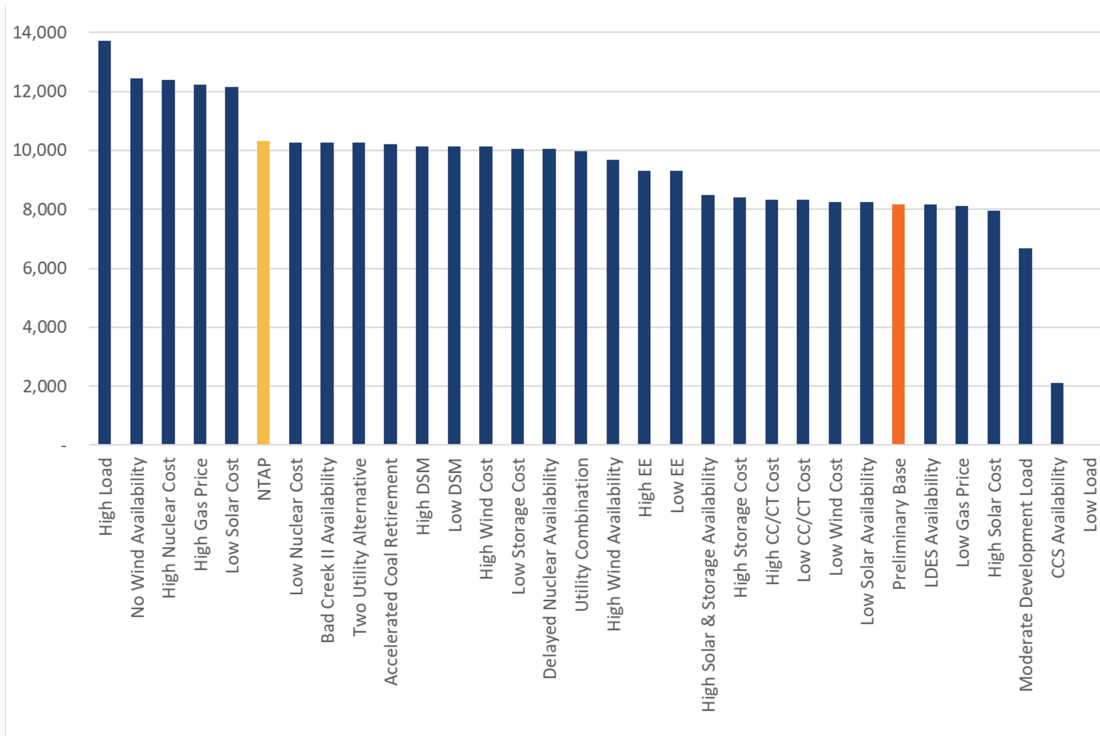
Q: DID DUKE FIND ADDITIONAL SOLAR RESOURCES TO BE COST-EFFECTIVE IN ITS MODELING AND IN ITS NEAR-TERM ACTION PLAN (NTAP)?

A: Yes, Duke identified a need for ongoing solar capacity additions to its system through 2040. In its Preliminary Base case, Duke expects to add about 8,175 MW of new solar resources by 2040.[31] Across an additional 30 scenarios, Duke

[31] Duke IRP, Appendix C: Quantitative Analysis, p. 51.

identified a wide of range of outcomes for future solar additions by 2040, ranging from no additional solar in the Low Load scenario to nearly 14 GW in the High Load scenario.[32] As shown in Figure 12, most of the scenarios add more solar than the Base Preliminary case (orange bar). Reflecting the range of additional solar capacity Duke identified across the scenarios, Duke included 10.3 GW of solar by 2040 in the Near-Term Action Plan scenario ("NTAP") (yellow bar).

FIGURE 12: 2040 SOLAR CAPACITY BY SCENARIO



Source: Duke IRP, Appendix C: Quantitative Analysis, pp. 51-62.

Q: WHICH SCENARIOS RESULT IN THE HIGHEST SOLAR ADDITIONS?

A: In addition to the High Load scenario, Duke added at least 12 GW of new solar resources in four additional scenarios: No Wind Availability, High Nuclear Costs, High Gas Prices, and Low Solar Costs.

[32] Duke IRP, Appendix C: Quantitative Analysis, pp. 51-62

Q: DO OTHER SCENARIOS RESULT IN SOLAR CAPACITY ADDITIONS SIMILAR TO THE NTAP SCENARIO?

A: Yes, there are ten additional scenarios where Duke finds a need for approximately 10 GW of solar resources, including the Utility Combination (DEC-DEP merger) scenario.

Q: IS IT REASONABLE FOR DUKE TO INCLUDE MORE SOLAR IN ITS NTAP THAN IDENTIFIED IN ITS PRELIMINARY BASE PORTFOLIO?

A: Yes, absolutely. The results of the scenarios demonstrate across a wide range of future system conditions that more solar capacity is cost-effective to the future Duke system than identified in the specific assumptions in the Preliminary Base scenario. Specifically, the High Load, High Nuclear Cost, and High Gas Price cases demonstrate that solar resources are needed today to be prepared for future system conditions that can materialize.

Q: WHY DOES SOLAR PROVIDE A COST-EFFECTIVE RESOURCE TO THE DUKE SYSTEM IN THE CAROLINAS?

A: As noted earlier in my testimony, solar resources generate during high load periods during the middle of the day, displacing the need for operating resources that have significant operating costs primarily through the consumption of fuel, including natural gas and coal. During these periods, Duke will need to dispatch less efficient, higher cost resources to meet that demand. More solar resources reduces the need to incur those costs. In addition, solar provides the additional generation needed to charge the increasing capacity of storage resources on the system. The storage resources are able to shift dispatch of energy from solar hours to evening and morning hours when load is high but the sun is not shining. This is especially the case when natural gas prices are higher, increasing the costs of running all natural gas-fueled power plants, particularly the least efficient plants.

Solar also produces electricity without generating any carbon dioxide emissions. While the interim target for reducing emissions was removed recently, Duke still must meet the long-term decarbonization objectives by 2050, as set by legislation in North Carolina, and many of Duke's largest customers have their own carbon dioxide-reduction requirements and seek cleaner forms of generation. Meeting those long-term objectives requires making steady progress to avoid the risks and costs of attempting a sudden, very large change in Duke's resource mix in the late 2040s.

In addition, solar resources are currently in development across the Duke service territory and provide a known resource that is relatively low-risk to develop and is not dependent on additional fuel infrastructure for adding new capacity and serving future load. While transmission improvements are needed to connect solar to load centers, Duke is actively pursuing transmission projects that support the future generation and load needs of the system, providing multiple system benefits such as reduced production costs, increased reliability, and access to new cost-effective generation resources.

Q: WHAT DOES DUKE IDENTIFY AS THE PRIMARY VALUE DRIVERS OF SOLAR ADDITIONS IN ITS SYSTEM?

A: In their testimony, Duke's Solar and Energy Storage Panel summarizes four drivers of the value of solar, including (1) hedging against fuel price volatility, (2) hedging against delayed additions from other resources, (3) ensuring energy adequacy throughout the year, and (4) reducing system production costs.[33] Similarly, the IRP and Near-Term Actions Panel notes that "[a]s a fuel-free resource, additional solar in these sensitivities provides a commodity price risk hedge by reducing natural gas consumption on the system" and "several portfolios increase near term solar deployments to offset risk in other planning considerations, such as high natural gas price or not relying on wind resources over the long term."[34]

Q: WHAT RESOURCES DOES SOLAR DISPLACE WHEN IT IS ADDED TO THE DUKE SYSTEM?

A: Based on Duke's modeling, the addition of more solar on the Duke system in the mid-2030s primarily reduces [redacted]. Later in the 2030s, the solar additions start to displace output from [redacted] as well. To identify the impact of additional solar resources on the generation mix, I specifically compared the annual generation by resource type from Duke's production cost modeling of the Preliminary Base scenario and the NTAP scenario.[35] The NTAP scenario includes about [redacted] more solar in 2035. [redacted] below shows from 2034 to 2036 that the additional solar adds [redacted]

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[33] Direct Testimony of Maura Farver, Gray Tompson, and Ben Smith, p. 18.

[34] Direct Testimony of Glen Snyder, et al., p. 57 and 61.

[35] I analyzed the EnCompass production cost model results for the Preliminary Base and NTAP scenarios provided by Duke in the files " 2.20_2025 IRP - Base Portfolio - PC.xlsx" and "2.101_2025 IRP - NTAP - PC.xlsx", specifically the sheets labeled 'Resource Annual'. ("Duke Preliminary Base and NTAP PC Results")

[redacted]

[redacted]

Source: Duke Preliminary Base and NTAP PC Results

Q: DO THESE RESULTS SUPPORT THE VALUE OF SOLAR YOU NOTED ABOVE AND DUKE WITNESSES NOTED IN THEIR TESTIMONY?

A: Yes, these results support the view that solar provides value to the Duke system by avoiding high-cost generation while also reducing emissions from both coal and gas generation.

Q: PLEASE EXPLAIN THE VALUE OF REDUCING GAS BURN.

A: While gas generators are a key part of the portfolio of resources to cost-effectively serve future load, they also expose Duke customers to greater cost risks from fluctuations in the commodity prices of natural gas. The monthly average prices of natural gas at the Henry Hub trading hub since 2020 have fluctuated from just under $2/MMBtu to nearly $9/MMBtu, as shown in Figure 14 below.[36] The price of natural gas has significant impacts on the cost of running natural gas CC and CT resources to serve electricity customers. The graph shows that there were periods of relatively low gas prices in the $2-4/MMBtu range, but there were also sustained periods of higher prices in 2022 (averaging $6.42/MMBtu throughout the year) and a recent spike in prices in January 2026 to $7.70/MMBtu (reaching over $25/MMBtu for two days).

FIGURE 14: HISTORICAL HENRY HUB NATURAL GAS PRICES ($/MMBTU)

Source: EIA, Henry Hub Natural Gas Spot Price, accessed March 24, 2026

Duke accounted for uncertain natural gas prices by creating three projections of future natural gas prices and modeling scenarios based on each projection. The natural gas prices in each case remain below $5/MMBtu in all cases through 2030.[37] Gas prices increase in the 2030s in the base case to about $6/MMBtu in 2040, stay below $5/MMBtu in the low case, and climb to $13/MMBtu in 2040 in the high case. Importantly, Duke's modeling does not

[36] EIA, Henry Hub Natural Gas Spot Price, accessed March 24, 2026.

[37] Duke IRP, Appendix C: Quantitative Analysis, Figure C-7, p. 40.

consider in any of those cases the spikes in prices shown in the figure above throughout 2022 or in January 2026.

Q: IS DUKE'S EXPOSURE TO NATURAL GAS COMMODITY PRICE RISK INCREASING IN THE FUTURE?

A: Yes, by quite a lot. Duke is proposing in its NTAP to build about 10 GW of new gas CC and Gas CT plants by 2035. Duke's modeling of the NTAP scenario shows that its reliance on gas generation will [redacted] by 2035, climbing from [redacted] GWh in 2025 to [redacted] GWh in 2035, as shown in the figure below. This will result in generation from natural gas resources increasing from [redacted] of the total generation in 2025 to [redacted] from 2032 to 2035, an increase of [redacted] By comparison, the projected solar additions in the NTAP will reach [redacted] of total generation in 2035.

[redacted]

Source: Duke Preliminary Base and NTAP PC Results.

Q: WILL SOLAR REDUCE EXPOSURE TO GAS COMMODITY PRICE RISK?

A: Yes, increasing the amount of generation from other resources onto the system, especially resources that require no fuel to generate, provides a defensive hedge against commodity price spikes and sustained periods of elevated prices. Solar resources fill that role well.

Q: DOES DUKE'S MODELING DEMONSTRATE THE VALUE OF SOLAR RESOURCES WITH HIGHER NATURAL GAS PRICES?

A: Yes, in the High Gas scenario Duke's IRP modeling builds an additional 4 GW of solar compared to the Preliminary Base scenario and an additional 2 GW compared to the NTAP scenario, as shown in Figure 12 above.[38]

Q: ARE THERE ANY OTHER RISKS ASSOCIATED WITH RELIANCE ON NATURAL GAS?

A: Yes. Bringing 10 GW of new natural gas capacity on to the system will require significant new natural gas supply infrastructure. The NTAP includes building new gas pipelines and liquified natural gas ("LNG") storage capacity.[39] The first three new Gas CCs (Person County CC1 and CC2 and Anderson County CC3) will rely on existing firm transportation service and additional firm transportation provided by two projects that are currently in development: the Transco Southeast Supply Enhancement and Mountain Valley Pipeline Southgate. The additional 3 CCs identified to be needed will rely on either enhanced liquified natural gas ("ELNG") or additional firm transportation from the Gulf Coast.

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[38] Duke IRP, Appendix C: Quantitative Analysis, Table C-29, p. 55.

[39] Duke IRP, Chapter 2: Table 2-5, p. 18.

There are significant execution risks associated with building this infrastructure, especially natural gas pipelines. For example, the Mountain Valley Pipeline that provides Duke access to natural gas production from the Marcellus shale region was delayed by six years from 2018 to 2024. Earlier, the Atlantic Coast Pipeline developed by Duke and Dominion to serve new natural gas plants was cancelled. Similar delays in building natural gas pipelines to serve Duke's new gas resources will limit Duke's ability to serve its growing load.

Duke acknowledges these risks, identifying insufficient fuel supply due to litigation of pipeline infrastructure as a primary execution risk for its buildout of its natural gas-fired generation resources: "[t]he increase in natural gas generating capacity, however, has led to adequate natural gas supply being the largest risk."[40] Duke further notes that "the Transco SSE and Southgate projects are both required for the Companies to be able to successfully execute their planned least-cost fleet transformation while supporting load growth."[41]

This amount of natural gas also increases the reliability risk of correlated outages of natural gas plants during winter storms. During Winter Storm Elliot, Duke had over 5,000 MW of generation capacity that was unable to operate due to planned and forced outages.[42] The outages included several natural gas plants that were unable to generate due to frozen instrumentation and natural gas

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[40] Duke IRP, Appendix I: Natural Gas & Low-Carbon Fuels, p. 22.

[41] Duke IRP, Appendix I: Natural Gas & Low-Carbon Fuels, p. 22.

[42] GDS Associates, Inc., Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC: December 2022 Winter Storm Outages and Blackouts, Prepared for the South Carolina Office of Regulatory Staff, Docket No. ND-2023-1-E, August 25, 2023. (**Exhibit 6).**

deliverability issues due to insufficient pressure in the natural gas pipeline system.[43]

Q: WILL ADDING SOLAR AT THE LEVEL PROPOSED IN THE NTAP REDUCE RISKS ASSOCIATED WITH INCREASING RELIANCE ON GAS RESOURCES?

A: Yes, by adding more solar generation to the system through the annual procurement processes, Duke will add new non-gas generation resources to the system ahead of the need and be ready to serve larger loads on its system even if there are delays to permitting and construction of new natural gas infrastructure. To provide the capacity to maintain reliability during both peak periods and during winter storms that impact the availability of gas to the Duke system, Duke will also need to continue to add more battery storage resources along with the solar additions.

Q: WHY DOES THE HIGH LOAD CASE RESULT IN THE MOST SOLAR ADDITIONS?

A: As noted above, the High Load case results in the most solar additions, reaching 14 GW by 2040.[44] This outcome is not surprising because with higher load growth Duke will need more generation resources to serve that load. But what stands out about the High Load scenario in particular is that even with an additional 1.5 GW of peak demand and 20 TWh of load compared to the Preliminary Base scenario Duke finds *no* increase in gas CC or gas CT capacity,

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43 *Id.*

44 Duke IRP, Appendix C: Quantitative Analysis, Table C-27, p. 53.

coal plant capacity, or nuclear capacity. Zero! Instead, in the High Load case, Duke adds another 5.6 GW of solar, 1.8 GW of battery storage, and 300 MW of onshore wind.

Duke adds no new gas resources in the High Load scenario because it projected that it can only add six new combined cycles plants by 2035 and it builds up to that limit under the base case load growth. Duke limits new gas CC builds based on its experience developing large gas plants, site availability, fuel supply infrastructure limits, and permitting challenges. [45]

Therefore, when additional load materializes, Duke will need to rely on other resources. Solar and storage are the primary resources available to serve the additional load. If North Carolina wishes to attract all of the demand in the High Load case, Duke will need to add more energy to its system to serve that load through increased adoption of solar and storage.

Q: WHY ARE OTHER RESOURCES NOT SELECTED IN THE HIGH LOAD CASE?

A: Duke has a limited set of resource options in the near-term for meeting a significantly higher projection of load growth both in terms of total annual energy demand (in gigawatt-hours) and peak demand requirements (in terms of gigawatts). I will touch on each of the resources that is being considered by Duke to be added through 2035:

[45] See Duke IRP, Chapter 2, Table 2-5 ("Beginning with CC4, additional Enhanced Firm Transportation ("EFT") natural gas supply delivered from the Gulf Coast." And, "Cumulative limit of three additional CCs with EFT supply.")

- Natural Gas: As noted above, Duke has set limits on new Gas CC builds by 2035 based on its experience developing large gas plants, site availability, fuel supply infrastructure limits, and permitting challenges. All of the available new Gas CC capacity is selected in nearly every scenario Duke modeled, including the Preliminary Base scenario, such that Duke is unable to build additional Gas CCs to serve the load in the High Load scenario.
- Coal: Duke explains that there are four key factors that make it costly and risky to continue to operate existing coal generation fleet: (1) risks to coal supplier viability in a market with declining domestic demand; (2) coal supply chain risks and transportation constraints that limit flexibility to respond to rapid changes in demand; (3) coal fleet operational constraints; and (4) uncertainty surrounding environmental requirements impacting the coal generation fleet.[46] For these reasons, Duke is continuing to pursue 6 GW of coal plant retirements by 2035, while primarily running the remaining plants on natural gas.
- Onshore and Offshore Wind: Duke is limited in the amount it can develop within its territory with no new onshore or offshore wind in its base plan or NTAP due to the lack of resources in development.[47]
- Nuclear: Duke reviewed the available nuclear technologies and their development timelines and determined they will not be available until 2037.[48]

46 Duke IRP, Appendix F: Coal.
47 Duke IRP, Appendix C: Quantitative Analysis, pp. 32-35.
48 Duke IRP, Appendix C: Quantitative Analysis, pp. 35-36.

Q: WHAT ARE YOUR TAKEAWAYS BASED ON THESE LIMITATIONS IN THE RESOURCES THAT DUKE CAN ACCESS?

A: In addition to solar being a hedge against higher natural gas commodity prices (as noted by Duke witnesses), solar is also the resource that Duke can continue to add in parallel to new Gas CCs to reduce the risk that it will have insufficient energy generation available to serve future load and support economic development in the State. Delays in natural gas infrastructure development and other challenges to development both cap how much Duke can rely on new gas CCs builds and also highlight the risks of relying on such a large deployment of new resources. In order to get ahead of those limits, Duke should be pursuing as much solar capacity as it can currently interconnect to reduce its risks of having insufficient resources to serve the higher end load forecasts.

Q: WILL SOLAR RESOURCES BE UTILIZED IF THE PROJECTED DEMAND DOES NOT MATERIALIZE?

A: Yes, because solar costs primarily are upfront capital costs, once the resources are built, they will produce as projected (or close to it, given the variations noted above) with effectively zero marginal production costs. Because solar resources do not incur additional costs to generate, they will produce whether demand is high or low.[49] By comparison, the output of fossil fuel-fired resources, especially higher cost resources like new CTs and existing coal plants, will vary depending on year-to-year variations in total electricity demand and the total load growth.

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[49] Duke contractually pays solar resources for their output on a per-MWh basis at a pre-set rate and can only curtail so much of its output. In this way, the contractual cost of solar is a sunk cost and does not factor into real-time generation dispatch decisions.

For that reason, the risk of solar resources not supporting future energy demands is near-zero.

In addition, if Duke determines in the next several years that the High Load scenario is unlikely to materialize, Duke can pivot its procurements in future years and reduce solar capacity targets for future procurements if updated load forecasts demonstrate that the expected future load level is unlikely to reach the High Load scenario. This "no regrets" approach will also provide a more stable market for the development of multi-year solar projects – increasing execution certainty and reducing costs – while avoiding the inefficiency of having to procure very large amounts of solar in a short period in the out years to make up for lower procurements in earlier ones.

Q: WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION BASED ON YOUR REVIEW OF THE RESULTS OF DUKE'S IRP MODELING?

A: To best prepare to serve the High Load Case as well as hedging against the cost factors discussed above, I recommend procurement of more solar in the 2026 to 2028 procurement processes then set forth in the NTAP.[50] I view the NTAP as the minimum necessary procurement and believe an additional 230 MW to 430 MW per year up to the 1,200 MW build limit would be prudent. If Duke determines at a later date that the High Load scenario is unlikely to materialize, Duke can then reassess its future procurement levels of solar.

[50] Duke IRP, Chapter 4, Table 4-2, p. 10.

III. REVIEW OF DUKE'S TRANSMISSION PLANNING PROCESS

Q: WHAT APPROACHES IS DUKE TAKING TO COST-EFFECTIVELY INTERCONNECT NEW RESOURCES, INCLUDING SOLAR, INTO ITS TRANSMISSION SYSTEM?

A: Duke has made several significant improvements to its transmission planning and interconnection processes over the past several years, many at the urging of the Commission. The improvements include implementation of cluster studies in the interconnection process (including a separate cluster for its solar solicitations), the identification and construction of RZEP projects, and the completion of the first MVST planning process through the CTPC. Building on these improvements, Duke should continue to implement these processes effectively and make additional changes to its processes to improve its ability to incorporate cost-effective resources into its system and reduce ratepayer costs.

Q: WHAT ARE THE BENEFITS OF THE RZEP PROJECTS?

A: The RZEP projects build out the transmission system in regions of the Duke system with significant low-cost solar resources and as a result will reduce the costs and time required for interconnecting those resources. The projects were identified as needed through several rounds of interconnection studies and verified to be necessary for interconnecting future solar resources in the 2023 Public Policy Study. However, due to the nature of the interconnection study process, the RZEP projects had not yet been selected for construction as network upgrades since their costs would have been borne by the first few generators seeking interconnection --

even though those upgrades would provide transmission capacity that would serve a much larger set of resources that benefit the Duke system.

Due to the system-wide benefits they provide for cost-effectively meeting the future resource needs of the system and reducing the risk of outages, Duke added the RZEP upgrades to the CTPC transmission plan. By doing so, the upgrades are built on a coordinated basis in anticipation of need, reducing the costs of building future network upgrades and reducing the time required for future economic resources to be studied and interconnected. The RZEP projects also have reliability benefits by replacing existing facilities with higher capacity ones, which will reduce risk of loss of load. As Duke notes in Appendix K, "[t]he RZEP projects eliminate barriers to interconnecting resources in both South Carolina and North Carolina and have stand-alone value based on the merits of replacing aging equipment and the associated reduction in the probability of customer service interruptions."[51]

This approach of identifying backbone-type upgrades identified frequently in the interconnection study process and pulling them into the transmission planning process is a good one. It debottlenecks future interconnection studies, avoids the same upgrades continually limiting new resource additions, reduces costs, and reduces the time needed for constructing network upgrades. But, it only considers the next set of resources seeking interconnection and does not account for system-wide needs over a longer timeframe. The addition of the MVST process helps fill that gap.

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[51] Duke IRP, Appendix K: Transmission, p. 10.

Q: WHAT IS THE MVST PLANNING PROCESS?

A: The MVST planning process is a newly-implemented proactive transmission planning study completed by the CTPC for identifying cost-effective transmission upgrades. The MVST process starts by identifying several future scenarios to model, including the future load and generation mix over a ten-year timeframe. The CTPC then identifies the future transmission needs in each scenario, prioritizes those needs into clusters, develops solutions to cost-effectively meet those needs, and analyzes the benefits and costs of several solutions and eventually the full portfolio of MVST solutions. This approach differs from existing reliability studies that look only at the reliability-driven needs of the system (i.e., resolving transmission element overloads), do not incorporate all of the future generation additions planned to serve future load, and do not include a cost-benefit analysis of the candidate solutions to evaluate whether new transmission enable delivery of lower cost generation to customers.

The primary advantages of the MVST compared to the prior transmission planning processes include:

- A scenario-based approach to analyzing system needs that accounts for key uncertainties in the Duke power system and evaluates common upgrades required across multiple futures;
- Coordinated planning of both load and generation that leverages the recent results of Duke's resource planning studies;

- Multi-value benefits analysis of transmission identifies which upgrades provide the most bang-for-the-buck and demonstrates that transmission investments can reduce total costs for serving load;
- Increased transparency about planning assumptions, needs, and solutions and opportunities for stakeholders to provide input on the study approach and results; and,
- Development of new tools for evaluating the impacts of transmission investments and the needs of the future Duke system.

The MVST process draws from significant experience with multi-value, scenario-based transmission planning at the regional level across the country. What makes the MVST process unique is that it is occurring within the local transmission planning process for the Duke service territory in North Carolina and South Carolina and that it is being completed in a region without a centralized energy market.

Q: WHICH FUTURE SCENARIOS DID THE MVST STUDY?

A: The CTPC requested input from stakeholders on which futures to study and received input from several stakeholders that resulted in the first MVST studying three scenarios based on the P1 Fall Supplemental Portfolio and P3 Fall Supplemental Portfolio generation resource portfolios from the 2023 Carolinas Resource Plan approved by the Commission.[52] The scenarios include a single outlook for load growth and two different resource mixes: the P1 Fall Supplemental Portfolio included a higher level of solar (21 GW) and offshore wind (2.4 GW) and

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[52] **Exhibit 7.**

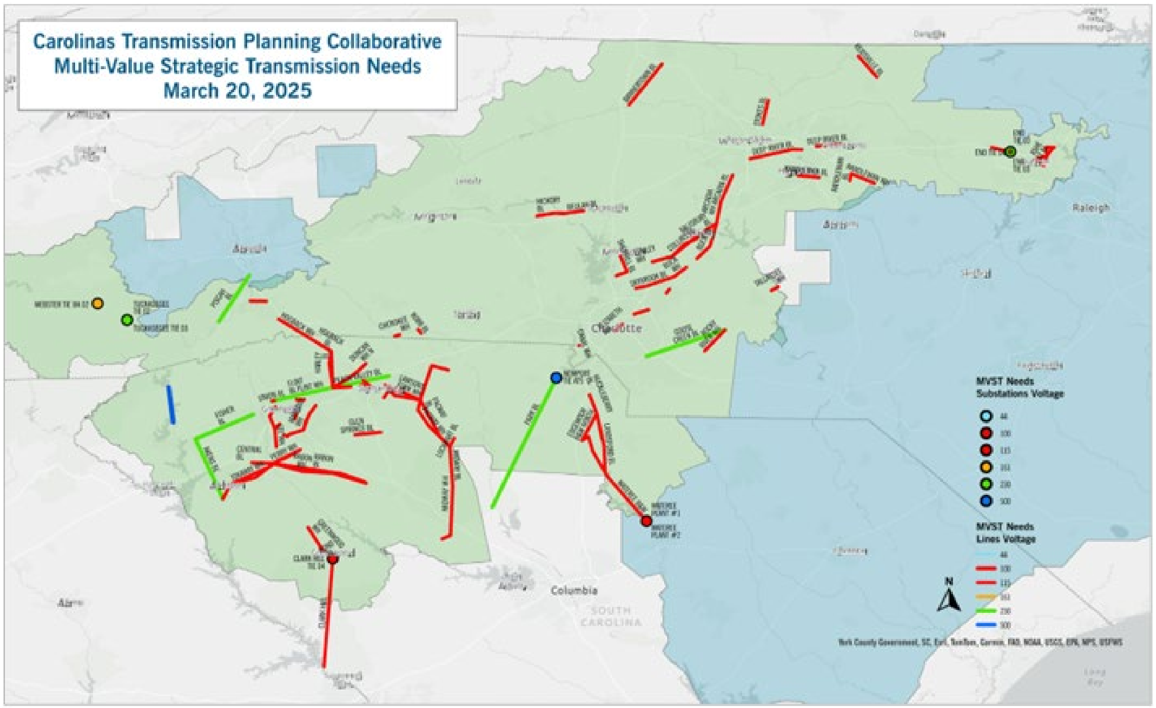
the P3 Fall Supplemental Portfolio included less (13 GW of solar and 1.7 GW of offshore wind). The third scenario shifted the location of the new solar resources between DEC and DEP. Utilizing these scenarios the MVST study analyzed two key uncertainties about the future system coming out of the 2023 resource planning process: the amount and location of future solar resources. While the future locations of new resources are unknown, the CTPC utilized the generator interconnection queue as an indication of future resource development and requested input from solar developers to ensure that the locations aligned with their expectations.

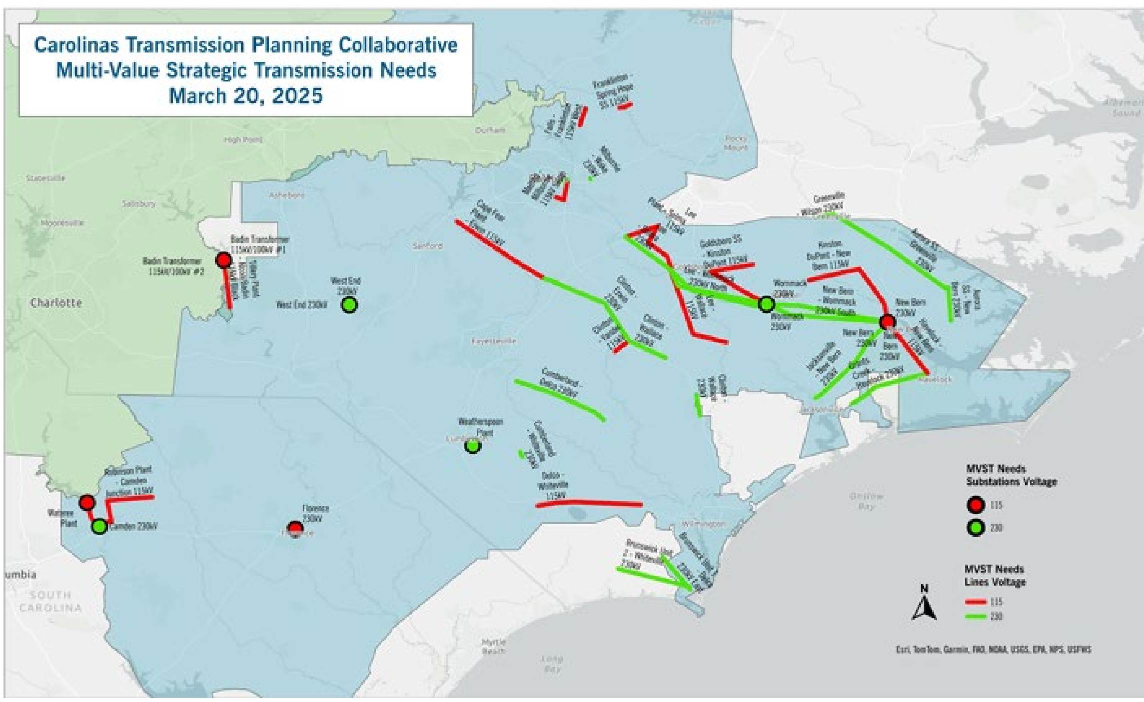
In addition to the scenarios, the CTPC also studied multiple sensitivities for each scenario to test whether needs persisted with incremental changes in load and additional offshore wind.

Q: DID THE MVST STUDY IDENTIFY A NEED FOR TRANSMISSION UPGRADES?

A: Yes, the CTPC implemented the future scenarios into its local reliability planning models to identify future reliability-driven needs. The CTPC identified significant reliability violations on both the DEC and DEP systems, as shown in the maps below. The CTPC prioritized the reliability needs based on a number of factors to identify those that occur in the most scenarios and sensitivities and provide capacity for interconnecting the most new resources. At the request of stakeholders, the CTPC then identified specific clusters of violations to evaluate during the solutions development step of the MVST study.

FIGURE 16: MVST RELIABILITY-DRIVEN NEEDS





Source: Duke IRP, Appendix K: Transmission System Planning & Grid Transformation, p. 12.

Q: DID THE MVST STUDY IDENTIFY NEEDS BASED ON UNECONOMIC DISPATCH AND OTHER DRIVERS IN ADDITION TO RELIABILITY?

A: No, the first MVST solely focused on reliability-driven needs utilizing powerflow models and did not evaluate constraints on the system that result in higher dispatch costs for serving load throughout the year, which are commonly referred to as "economic" drivers of transmission needs. Reliability-driven needs focus on studying challenging periods for operating the system and serving load, such as summer peak and winter peak conditions, and which constraints arise during contingency events that coincide with peak demand, such as transmission outages and generation outages. These studies are necessary to ensure reliable service to the Duke system.

In addition to maintaining system reliability, transmission upgrades can also reduce the costs of serving load by accessing lower cost generation resources, both in terms of reducing the costs of building new resources and the cost of operating generation resources, which is the basis for the "multi-value" focus of the MVST process. Economic drivers are most often identified utilizing production cost models that evaluate system needs throughout the year on an hourly basis and identify when transmission constraints result in an uneconomic dispatch. An uneconomic dispatch arises when Duke must operate a higher-cost resource instead of a lower-cost resource because the lower-cost resource is limited by a transmission element. Uneconomic dispatch results in higher generation costs to serving load than otherwise would occur if more transfer capability were available. Compared to reliability models, production cost models look at a wider range of system load and generation dispatch conditions that occur throughout the year and evaluate the cost impacts of transmission constraints.

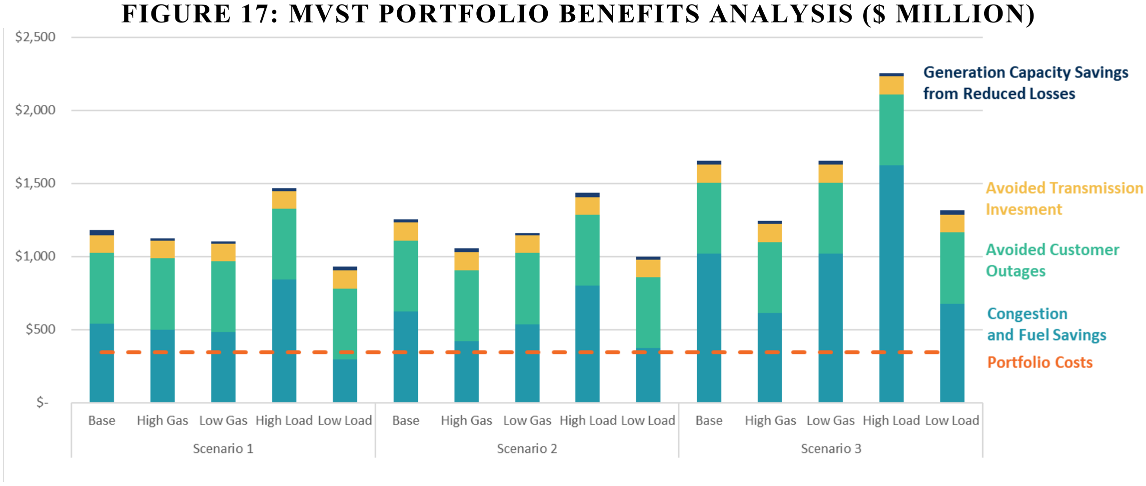
In the case of the MVST, the CTPC did not yet have an operational production cost model of its system with sufficient granularity to perform the economic needs assessment of the transmission system at the beginning of its study. Several stakeholders raised the need for the development of a production cost model that includes a detailed representation of Duke's transmission lines, substations, generation resources, and load, which is often referred to as a "nodal" model, for performing the needs assessment as well as the benefits analysis. Duke regularly performs production cost modeling within the IRP, but at a zonal level rather than a nodal level. Zonal production cost modeling aggregates the demand and generation resources in portions of its system into zones without detailed representation of the transmission system. This level of detail is sufficient for resource planning and evaluation of generation needs, but is insufficient for evaluating the future needs of the transmission system. By the end of the MVST study, the CTPC had developed such a nodal production cost model and utilized it for the benefits analysis.

I recommend that in future iterations of the MVST the CTPC perform both a reliability-driven needs assessment as well as an economic-driven needs assessment for identifying transmission constraints on its system that results in uneconomic dispatch and higher costs for serving load. This additional needs assessment will help the CTPC and its stakeholders identify transmission solutions that maximize the benefits of transmission investments for Duke's customers.

Q: HAS THE MVST STUDY IDENTIFIED COST-EFFECTIVE TRANSMISSION UPGRADES?

A: Yes, after studying multiple solutions to the identified reliability-driven needs, the CTPC released its benefits analysis for a portfolio of transmission upgrades. The analysis demonstrates that there are significant benefits to the portfolio of upgrades being proposed across all three scenarios and sensitivities related to natural gas prices and load growth. **FIGURE 17** below shows the benefits of the MVST portfolio as stacked bars with each section showing the source of the benefits, including congestion and fuel savings (due to reductions in uneconomic dispatch), avoided customer outages (from replacing aging transmission lines), avoided transmission investments (due to reducing loading on constraints that triggered an upgrade in the CTPC Base Reliability plan), and generation capacity savings from reduced losses (reducing total capacity needs to serve peak loads).

FIGURE 17: MVST PORTFOLIO BENEFITS ANALYSIS ($ MILLION)



Source: CTPC, MVST 2024 - Multi-Value Analysis - Portfolio - Draft - 2026 03 10, March 20, 2026. https://carolinastpc.org/media/reference/2026/03/20/MVST_2024_-_Multi-Value_Analysis_-_Portfolio_-_Draft_-_2026_03_10.xlsx

The benefits analysis demonstrates that the MVST portfolio cost savings and reliability benefits of $0.9 billion to $2.3 billion greatly exceed the costs of $0.3 billion. The benefits are highest in Scenario 3, in which more solar is located in DEP, and in the high load sensitivities when the system will be the most stressed. The large congestion and fuel savings in the high load case in particular demonstrate how transmission investments provide a hedge against the higher costs of serving load when demand is particularly high in a given year or if the system load grows faster than expected (as it is now doing).

Q: WHAT ARE YOUR PRIMARY TAKEAWAYS FROM THE FIRST MVST STUDY?

A: I have several takeaways from the MVST process but want to note that the complete benefits analysis of the proposed MVST portfolio was recently released and requires additional review through the CTPC stakeholder process. At this stage, my takeaways on the outcomes of the MVST include:

- The MVST successfully developed a set of future scenarios for the CTPC to study that is integrated with the Duke resource planning study, providing an important link between resource planning and transmission planning that did not previously exist for the Duke service territory;
- The needs assessment in particular demonstrated the large scale of transmission upgrades required for serving future load and interconnecting new generation resources and required the CTPC transmission planners to prioritize the highest value needs on the system;

- The MVST required the CTPC to look differently at their system by prioritizing areas of needs and addressing the highest value projects first, as well as developing new tools for identifying transmission needs and assessing alternative solutions;
- The MVST study demonstrates the multi-value nature of transmission in the Duke system and provided transparency about the costs and cost savings of incremental transmission investments beyond the standard reliability-driven studies;
- The CTPC provided significant information throughout the process in terms of its modeling approach, results, solutions development, and benefits analysis for stakeholders to consider and provide feedback, and the CTPC has been timely and comprehensive in providing responses; and,
- The MVST successfully identified several upgrades that provide significant benefits to the system and would not have been built otherwise, reducing costs to ratepayers and supporting future generation additions and load growth.

Q: DO YOU HAVE ANY RECOMMENDATIONS FOR THE NEXT MVST STUDY?

A: Yes, while I am still reviewing the final results from the MVST study recently posted by the CTPC, at this time I would recommend the following for the next MVST study:

- Given the uncertainty in load identified in the current resource planning study, the next MVST scenarios should include at least two projections of future load growth;

- The CTPC should summarize constraints in the base case production cost model that result in uneconomic dispatch and the costs of the binding constraints during the needs assessment phase, similar to the results shared for the reliability models, and provide a summary to stakeholders for their review;
- The CTPC should validate its production cost model by replicating the load, generation resource mix, renewable energy generation profiles, and natural gas prices of a recent historical year and comparing key outputs from the model, including generation mix, renewable curtailments, and total production costs, against their actual system in order to identify how well the model reflects the real-world system; and,
- The CTPC should present in more detail its analysis of each of the benefits so that stakeholders can understand the impacts of each proposed solution to the system and the drivers of benefits.

Q: HOW DOES PROACTIVE TRANSMISSION PLANNING IMPROVE THE GENERATION INTERCONNECTION PROCESS?

A: Proactive transmission planning will improve the generation interconnection process in three ways. First, generation developers will have better information earlier in the development cycle about where there is headroom on the system that will result in lower interconnection costs and less schedule risks. Second, the interconnection studies will be less complex and require less time as interconnection studies will identify fewer incremental upgrades and the upgrades will primarily be upgrades at or near the point of interconnection. Third, fewer incremental network upgrades will mitigate the schedule risks to developers of interconnecting new resources and reduce outage coordination challenges for Duke.

Q: SHOULD DUKE CONTINUE TO IDENTIFY AREAS OF NEED FOR DEVELOPING PROACTIVE PROJECTS BASED ON THE INTERCONNECTION STUDIES?

A: Yes, interconnection queues and interconnection study results should continue to be an important source of information for the types, amount, and location of resources that are currently in development and the transmission system upgrades necessary to integrate those resources. Ideally, those needs and the associated upgrades would be considered in the MVST process and either validated, like they have been in the 2023 public policy study and the first MVST study, or replaced by larger and more cost-effective upgrades that can support interconnection of new resources and provide other benefits to the Duke system. To do so, Duke must allow recently identified upgrades in the interconnection studies as well as reliability studies to be replaced by holistic upgrades identified through the MVST study process.

Q: DOES DUKE PARTICIPATE IN REGIONAL TRANSMISSION PLANNING?

A: Yes, through SERTP.

Q: DOES SERTP'S PLANNING APPROACH IDENTIFY COST-EFFECTIVE REGIONAL UPGRADES?

A: No, the current SERTP process is quite limited and has not identified a single regional transmission project since its inception in 2007. The Southeast region that SERTP covers is going through a period of rising transmission costs, significant load growth and generation resource additions, and increasing severity and frequency of winter storms, all of which can be aided by improved regional transmission. However, the SERTP process is not currently designed to identify regional transmission solutions that will increase the transfer capability between utility service territories and provide significant benefits to the region. In 2025 I completed a study that summarized the current SERTP transmission planning process, identified shortcomings of its process, and recommended changes to its regional planning process.[53]

Q: WHAT ARE THE PRIMARY ISSUES WITH THE SERTP REGIONAL TRANSMISSION PLANNING PROCESS THAT YOU IDENTIFIED IN YOUR STUDY?

A: The regional planning process that SERTP completes is an annual "bottom-up" process that primarily combines the updated load and generation assumptions and local transmission upgrades from each of its sponsor utilities and confirms that the system meets its reliability requirements. The regional study is limited in scope as it only considers a single future scenario based on the base assumptions included in each of the sponsor utility's local planning process and does not utilize the multiple scenarios developed in the resource planning studies, such as the current 2025 Carolinas Resource Plan study. Similarly, the regional planning study only includes a subset (about 12%) of the new generation resources identified in the most recent resource planning studies. Specifically, as of 2025, the SERTP regional planning studies only included 10 GW of new resources by 2035 across its region, even

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[53] **Exhibit 8**.

though the resource planning studies across the region identified a need for *80 GW* of new resources in the same timeframe. As noted above, this approach reflects the reliability-only approach previously employed by the CTPC in its reliability study and does not reflect the coordinated generation and transmission planning the CTPC completed through the MVST study. Finally, the SERTP process lacks transparency as limited information is provided on the costs of transmission in the regional plan, reliability violations identified in its planning studies, and alternative approaches studied to meet regional needs. This approach will not identify and approve the most cost-effective transmission infrastructure to reliably serve future load across the Southeast.

Q: DID YOU EVALUATE WHETHER REGIONAL TRANSMISSON UPGRADES WOULD PROVIDE BENEFITS TO THE CUSTOMERS ACROSS THE SOUTHEAST?

A: Yes, based on an economic request to study 10 GW of transfers from MISO to Southern Company, SERTP identified three 500 kV upgrades that cost about $5 billion and increase transfer capability between the Duke, Southern Company, and TVA service territories. To demonstrate the value of Southeast regional transmission, my colleagues and I performed a high-level analysis of the benefits and costs of these three 500 kV upgrades. While SERTP evaluates regional projects only based on their ability to avoid local upgrades, our analysis evaluated the potential cost savings and other benefits of the regional projects utilizing recent historical market data and based on an expanded set of benefits, including production cost savings, load diversity benefits, and resilience benefits during extreme weather conditions.

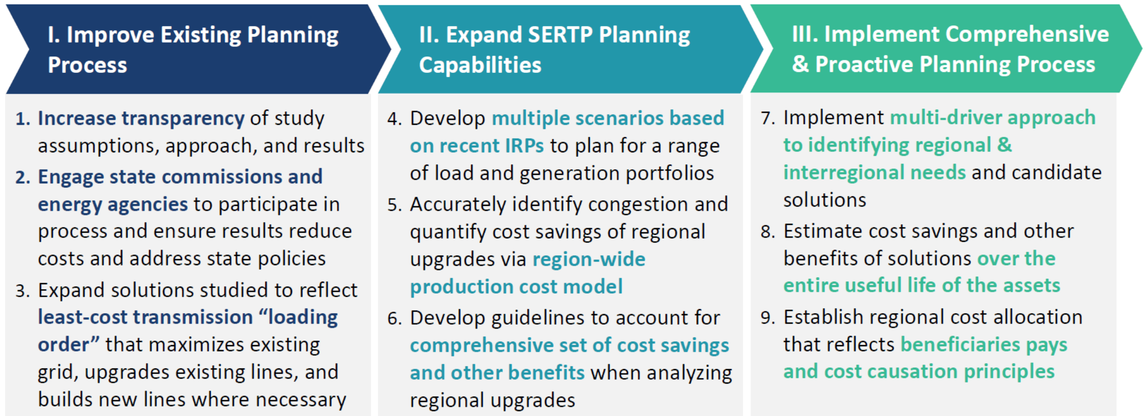
Q: WHAT DID YOUR ANALYSIS OF REGIONAL UPGRADES IN SERTP FIND?

A: Using an expanded set of benefits, we estimated that the three 500 kV projects would provide about $8 billion of cost savings and other benefits to the region, resulting in $3 billion of net benefits for customers across the Southeast, including Duke's service territory, over the life of the assets. The benefits included: production cost savings of $2.0 billion to $3.6 billion; load diversity-related cost savings of $0.9 billion to $6.0 billion; and resilience benefits of $0.7 billion to $2.3 billion. By contrast, SERTP's narrow view of benefits identified **no** cost savings from the addition of three major 500 kV lines to the Southeast system. This analysis demonstrates that regional transmission upgrades can reduce system costs when a broader scope of cost savings and other benefits are analyzed.

Q: WHAT WERE THE RECOMMENDATIONS OF YOUR STUDY FOR IMPROVING SERTP'S REGIONAL TRANSMISSION PLANNING PROCESS?

A: I recommended that the SERTP leverage the significant experience across the industry over the past 20 years with improved transmission planning approaches to improve its process and reduce long-term system costs and risks. I specifically noted that SERTP should learn from the experience gained from the Midcontinent Independent System Operator's Long-Range Transmission Planning Process and the CTPC's MVST local transmission planning process within SERTP's footprint. I recommended nine specific changes to the SERTP process, as shown in **FIGURE 18** below.

FIGURE 18: RECOMMENDATIONS FOR IMPROVING SERTP REGIONAL PLANNING



Source: Hagerty, et al., Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy, April 2, 2025, p. 5. (**Exhibit 8**).

Compliance with FERC Order No. 1920 provides SERTP and its sponsor utilities, including Duke, an opportunity to enhance its regional transmission planning process. Order No. 1920 requires SERTP to implement a proactive, long-term, multi-value regional planning process, similar to MVST at the regional level, presenting a pivotal opportunity for the Southeast to align its regional transmission planning with industry best practices developed over the past 10–20 years. The Southeast should embrace this opportunity to modernize its regional transmission planning to build a stronger, more efficient grid that supports economic growth, energy affordability, and long-term resilience.

Q: WHAT IS THE ROLE OF THE COMMISSION IN IMPROVING TRANSMISSION PLANNING AND INTERCONNECTION PROCESS TO ACHIEVE LEAST-COST OUTCOMES FOR RATEPAYERS?

A: The Commission should continue to review Duke's transmission planning and interconnection processes to identify opportunities for improving the processes and reducing costs to ratepayers while maintaining or improving system reliability. The Commission's recommendations in the 2022 Carbon Plan proceeding played an important role in Duke recently reforming these processes and the Commission should continue to track those reforms to ensure they are implemented effectively. In particular for the large-scale of upgrades required to transform the transmission network, the Commission should ensure that Duke provides a clear and transparent justification for the scenarios and contingencies tested in interconnection and transmission planning studies and the alternative solutions considered for maintaining reliability at least cost to ratepayers.

In addition, the Commission should actively participate in the development of the SERTP Order No. 1920 compliance filing and urge Duke to leverage its experience with the MVST process to support a proactive, multi-value, scenario-based planning process at SERTP that exceeds the requirements of Order No. 1920 and supports cost-effective regional transmission upgrades across the Southeast.

IV. <u>SUPPORT FOR CEBA'S PROPOSED CLEAN CUSTOMER TARIFF</u>

Q: ARE YOU FAMILIAR WITH THE DIRECT TESTIMONY SUBMITTED BY PRIYA BARUA AND STEVEN LEVITAS ON BEHALF OF CEBA IN THIS PROCEEDING?

A: Yes. I have spoken with Mr. Levitas and reviewed a draft of the Direct Testimony of Ms. Barua and Mr. Levitas in its entirety. Their testimony proposes a new clean customer tariff structured around six core elements, and explains in detail why Duke's existing Green Source Advantage Choice program has failed to meet the needs of large customers with clean energy goals.

Q: DO YOU AGREE WITH CEBA'S CONCLUSION THAT THE EXISTING GSA CHOICE PROGRAM IS NOT MEETING THE NEEDS OF LARGE C&I CUSTOMERS?

A: Yes, I do, in my experience large customers generally are actively seeking opportunities to procure clean energy. However, as I understand it, the GSA Choice program does not offer the one feature that most large customers with serious clean energy commitments require: additionality.

Q: CAN YOU EXPLAIN WHAT ADDITIONALITY MEANS AND WHY IT MATTERS TO A SUCCESSFUL CLEAN CUSTOMER TARIFF?

A: Additionality, as used in CEBA's testimony and as I understand it, means that a customer's financial commitment to a clean energy resource is the reason that resource was built, and that it would not have been constructed absent the customer's participation. This is not an abstract or aspirational concept. It is a practical requirement imposed by corporate sustainability frameworks, investor disclosure standards, science-based emissions reduction targets, and third-party verification protocols. When a customer subscribes to a resource that would have been built regardless of their participation, they receive no attributable incremental environmental benefit. They may be simply paying more for electricity without advancing their clean energy goals in any meaningful or verifiable way. Under those circumstances, a rational customer could decline to participate, and that is what appears to have happened with the GSA Standard option and the Resource Acceleration Option.

Q: DO YOU AGREE WITH CEBA'S CHARACTERIZATION OF WHY THE GSA STANDARD OPTION AND THE RESOURCE ACCELERATION OPTION HAVE ATTRACTED NO SUBSCRIBERS?

A: Yes. CEBA's testimony explains why each option falls short and I agree with their characterization of the problems. Under the GSA Standard option, resources that a customer brings to Duke are counted toward Duke's own procurement targets to meet Duke's system needs, meaning the customer's participation causes no net increase in clean energy on the system. The customer bears the cost and effort of selecting a project but may produce no attributable incremental clean energy generation or incremental reduction of greenhouse gas emissions. Under the Resource Acceleration Option, the available resources for procurement are limited to projects that participated and lost in the prior Duke RFP, and additionality is limited to only a few years - the period by which the customer's participation accelerates a resource that Duke was already planning to eventually procure. Customers seeking to count resources toward long-term clean energy goals cannot credibly do so on the basis of a few years of accelerated deployment. Neither option meets the basic cost-benefit test that a large customer would likely apply before committing capital to a voluntary clean energy program.

Q: PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE SIX ELEMENTS OF CEBA'S PROPOSED CLEAN CUSTOMER TARIFF.

A: CEBA proposes a tariff built around the following six elements.

First, participating customers would be permitted to bring new dedicated carbon-free resources to Duke's system, including not only traditional utility-scale generation but also energy efficiency programs, aggregated behind-the-meter resources, and demand-side management measures, and would receive the environmental attributes associated with those resources.

Second, customers would be free to work directly with developers of their choosing to identify the preferred size, technology type, and location of their resource, without being limited to projects that were unsuccessful in Duke's competitive solicitations.

Third, participating customers would pay the full cost of their dedicated resource plus a reasonable administrative fee, ensuring that non-participating customers bear no additional costs.

Fourth, participating customers would receive bill credits reflecting the full avoided energy, avoided capacity, and system value that their resource provides to Duke's system.

Fifth, and most critically, the resources customers bring to the system would be incremental to the resources Duke would otherwise procure pursuant to its Commission-approved Near-Term Action Plan, establishing genuine additionality.

Sixth, multiple customers would be permitted to pool their demand and jointly subscribe to a single clean energy resource, extending the program's benefits to customers whose load alone may not justify a dedicated utility-scale project.

Q: DO YOU SUPPORT EACH OF THESE SIX ELEMENTS?

A: Yes. Each element addresses a specific limitation of the existing GSA Choice program or a specific need expressed by large customers seeking to meet their clean energy commitments. Taken together, the six elements form a coherent and well-designed program that to my understanding is responsive to the actual needs of the large customers it is designed to serve.

Q: IS THE FIFTH ELEMENT, ADDITIONALITY TO DUKE'S NEAR-TERM ACTION PLAN, THE MOST IMPORTANT FEATURE OF CEBA'S PROPOSAL?

A: Based on my understanding of the goals of the members of CEBA, yes, it is the most important feature in terms of distinguishing CEBA's proposal from the existing GSA Choice program and making the proposed tariff attractive to large customers. Without it, the program would offer little meaningful improvement over what already exists and would likely attract similarly low participation. However, I would emphasize that the other elements are also essential. A program that offers genuine additionality but does not allow customers to select their preferred resources, or that does not fully compensate customers for the value their resources provide to the system, would still fail to attract the level of participation needed to achieve the program's broader goals.

Q: DO YOU SUPPORT THE INCLUSION OF DEMAND-SIDE RESOURCES SUCH AS ENERGY EFFICIENCY, BEHIND-THE-METER CLEAN ENERGY, AND DSM MEASURES IN THE PROPOSED TARIFF?

A: Yes. The inclusion of demand-side resources is an innovative and pragmatic feature of CEBA's proposal. These measures can typically be deployed more quickly than utility-scale generation resources, reducing near-term pressure on Duke's system while longer lead-time resources are developed. They also provide direct benefits to the households and small businesses that participate in efficiency and behind-the-meter programs funded by large customers. Given the pace of load growth Duke is projecting and the potential for supply chain and interconnection constraints to delay new generation, the Commission should welcome any mechanism that allows large customers to deploy their capital quickly and effectively toward measurable system benefits and increase the economic well-being of the State.

Q: DOES CEBA'S PROPOSAL ADEQUATELY PROTECT NON-PARTICIPATING CUSTOMERS FROM COST SHIFTS?

A: Yes, if done properly. CEBA has been explicit that the proposed tariff must be revenue neutral for non-participants. Participating customers would pay the full cost of their dedicated resources and a reasonable administrative fee. Non-participating customers would pay for the output of the new dedicated carbon-free resources based on the avoided cost of those resources, meaning they pay no more than they would have paid for the equivalent energy and capacity in the absence of the program. This is a sound and fair approach that the Commission should find consistent with its obligation to ensure just and reasonable rates for all customers.

Q: CEBA'S TESTIMONY NOTES THAT NORTH CAROLINA SENATE BILL 266 REMOVED THE 2030 INTERIM CARBON EMISSIONS REDUCTION TARGET. DOES THAT CHANGE AFFECT YOUR VIEW

OF WHETHER THE COMMISSION SHOULD APPROVE THE PROPOSED TARIFF?

A: Yes, it is a significant development. The removal of the 2030 interim target gives the Commission and Duke considerably more flexibility in how they structure voluntary customer programs and in some ways makes those programs more important than before. Previously, the near-term emissions reduction mandate created pressure to count every clean resource toward Duke's own compliance obligations, making it more difficult to designate customer-subscribed resources as genuinely additional. With that constraint removed, the Commission has a clear opportunity to approve a program in which customer resources are demonstrably incremental to Duke's own procurement plans, advancing the clean energy goals of participating customers without disrupting Duke's core planning obligations. Duke’s own reduced forecast procurements shows there is room for interconnecting such customer projects, which would benefit the paying customer and the system at large.

Q: ARE THERE PRECEDENTS IN OTHER STATES FOR A PROGRAM SIMILAR TO WHAT CEBA PROPOSES?

A: Yes. CEBA's testimony highlights the Customer Identified Resource option recently approved by the Georgia Public Service Commission within Georgia Power's Clean and Renewable Energy Subscription program. That program allows large customers to subscribe to specific clean energy resources procured by Georgia Power on their behalf through power purchase agreements, with subscribing customers paying the incremental cost and receiving bill credits based on avoided cost value. Multiple customers may also collaborate to subscribe to a single resource. The Georgia experience demonstrates that a program of similar design can be approved and implemented within a traditionally regulated utility framework, and provides a useful model for the Commission's consideration in this proceeding.

Q: WHAT IS THE BROADER SYSTEM BENEFIT OF DIRECTING DUKE TO DEVELOP THE PROPOSED CLEAN CUSTOMER TARIFF?

A: The broader benefit is that the proposed tariff harnesses private capital from large customers to expand clean energy deployment beyond what Duke would otherwise plan, reducing the system's long-term dependence on gas-fired generation and the fuel price risks that accompany it. Duke is currently projecting load growth of more than 6,000 MW over its 15-year planning horizon and is proposing to meet a substantial portion of that growth with nearly 10 GW of new gas-fired combined-cycle and combustion turbine capacity. As discussed in my testimony above, dependence on gas-fired generation leaves end customers exposed to gas price risk. If large customers, many of whom are the very source of the forecast load growth, can instead bring incremental clean resources to the system through CEBA's proposed tariff, the need for some of that gas capacity may be reduced or deferred. That outcome benefits all of Duke's customers, not just those that participate in the program.

Q: WHAT DO YOU RECOMMEND THAT THE COMMISSION DO IN THIS PROCEEDING?

A: I join CEBA in recommending the Commission find that the existing GSA Choice program does not provide the additionality that large customers need and has therefore largely failed to serve its intended purpose. I further recommend the Commission to direct Duke to file an application for approval of a new clean customer tariff for commercial and industrial customers consistent with the six elements described in CEBA's testimony and endorsed in my testimony. The large customers that CEBA represents are ready to deploy their capital to bring additional clean energy resources to Duke's system. The Commission should give them the program they need to do so.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.