PUBLIC / REDACTED

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and§ 62-110.l(c)	))))	Docket No. E-100, Sub 190

DIRECT TESTIMONY OF

JOHN MICHAEL HAGERTY

ON BEHALF OF

CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION

MAY 28, 2024

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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 11 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 the future resource needs in the Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") service territories (collectively referred to as "Duke") to reliably serve load and achieve the policy objectives included in House Bill 951 ("HB 951") of reducing carbon dioxide emissions from generation resources located in North Carolina by 70% relative to 2005 emissions. I have also actively participated in the 2023 and 2024 North Carolina Transmission Planning Collaborate ("NCTPC") transmission planning studies.

In addition to my experience in North Carolina, I have experience supporting transmission developers, generation developers, utilities, state regulators and agencies, and regional transmission operators with transmission planning processes and benefits analyses in CAISO, ERCOT, SPP, MISO, NYISO, PJM and ISO-NE. I have recently also evaluated interconnection processes across the country.

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 infrastructure investment in a decarbonizing world, including renewable energy and gas-fired generation resources as well as transmission assets. 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 previously before the North Carolina Utility Commission in Docket No. E-100, Sub 179, concerning the 2022 Biennial Integrated Resource Plan and Carbon Plan on behalf of the Clean Power Suppliers Association.

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: I have attached my CV as Exhibit A. All other references are cited in text with hyperlinks.

Q: WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A: The purpose of my testimony is to: (1) demonstrate based on Duke's resource planning analysis, that large-scale additions of solar photovoltaic ("PV") generation and battery storage resources currently are and are projected to remain an essential resource in least-cost portfolios that achieve the requirements of HB 951 in the best interest of Duke's ratepayers; and (2) identify opportunities for Duke to improve its transmission planning and interconnection processes that will lower customer costs by proactively identifying transmission upgrades, shortening and de-risking the generation interconnection, and increasing access to cost-effective resources.

Q: PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS.

A: My testimony reaches the following conclusions:

- Solar PV and battery storage are cost effective resources in the Duke system now and through 2035;

- Additional solar PV beyond the amount in Duke's portfolios will further reduce ratepayer costs if Duke can increase the rate at which those resources are added to its system;
- Duke limits solar PV interconnection rate due to its analysis of constraints on the existing transmission system and the pace at which it can upgrade its system to interconnect new resources;
- With the Commission's support, Duke has improved its transmission planning and interconnection processes to enable more rapid and lower cost additions of solar PV and battery storage, including through the development of Red Zone Expansion Plan ("RZEP") projects and the addition of the Multi-Value Strategic Transmission ("MVST") planning process;
- Duke has not coordinated the future resource mix identified in its resource planning modeling with the transmission planning studies to identify cost-effective upgrades in advance of need, which results in the Duke system being perpetually constrained when new resources request interconnection;
- Duke can further improve its transmission planning and interconnection processes by proactively identifying transmission investments that result in lower total costs to ratepayers, leveraging best practices from the Midcontinent Independent System Operator ("MISO") and the Southwest Power Pool ("SPP") and others;
- Effective implementation of the MVST planning processes will be critical to meeting the future system needs at least cost to ratepayers, for the following reasons;

- Improved transmission planning that adds proactive transmission upgrades to Duke's annual transmission plan will create needed headroom on Duke's system;
- Additional headroom built in advance of interconnection requests will reduce schedule and costs risks of interconnecting solar PV up to Duke's solar PV interconnection limits, and ultimately allow for the interconnection of higher volumes of cost-effective solar PV;
- Implementing the MVST effectively should shift the identification of cost-effective transmission upgrades, like the RZEP projects and future proactive upgrades, from the near-term, just-in-time interconnection process to a more efficient long-term proactive planning process;

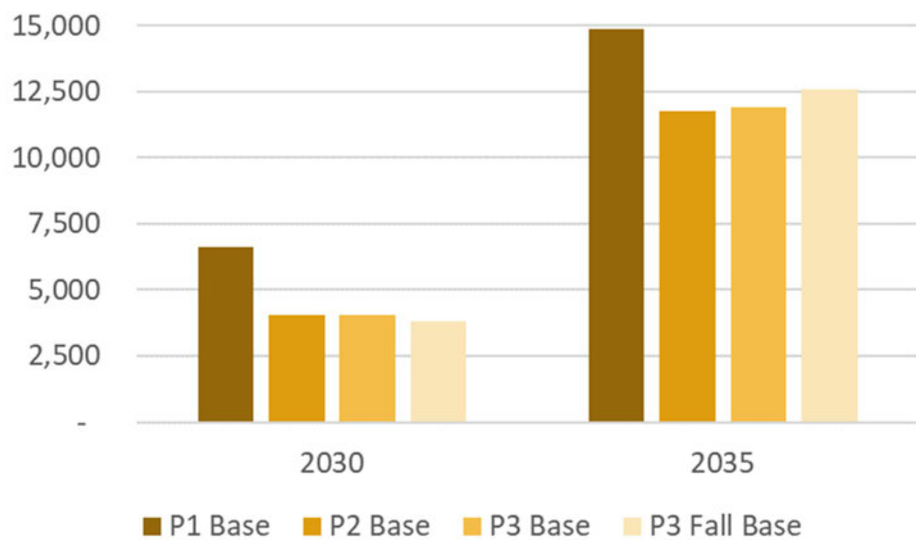
▸ The Commission has already played a key role in identifying the need for Duke to improve its transmission planning and interconnection processes and should continue to oversee and as needed scrutinize the implementation phase to ensure that cost effective upgrades are identified and constructed to reduce ratepayer costs.

I. <u>DUKE'S FILING DEMONSTRATES THAT SOLAR PV AND STORAGE ARE COST EFFECTIVE COMPONENTS OF ALL LEAST COST RESOURCE PORTFOLIOS</u>

Q: PLEASE SUMMARIZE THE NEW SOLAR PV AND BATTERY STORAGE CAPACITY THAT DUKE INCLUDES IN ITS 2023 CAROLINAS RESOURCE PLAN PORTFOLIOS.

A: In the 2023 Carolinas Resource Plan, Duke projects several future resource portfolios that most cost effectively meet customers' electricity needs, subject to carbon dioxide emission requirements and transmission-related constraints. All of the portfolios in the base analysis (P1 Base, P2 Base, and P3 Base) and supplemental analysis (P3 Fall Base) include large amounts of new solar PV and battery storage. By 2035, the total solar PV additions range from 11,800 MW in P2 Base to 14,900 MW in P1 Base, as shown in Figure 1 below. The P3 Fall Base portfolio developed in Duke's supplemental analysis includes 12,600 MW of solar PV by 2035.

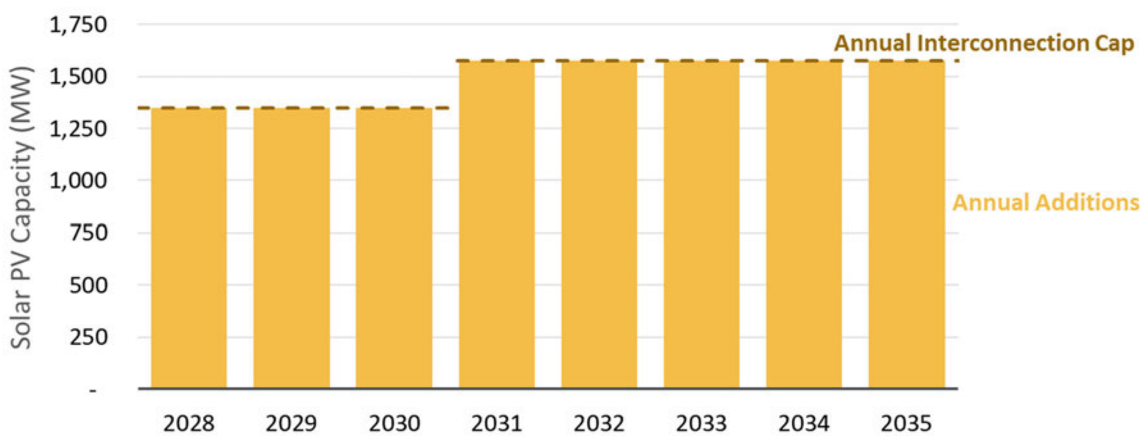
FIGURE 1: SOLAR PV CAPACITY ADDITIONS BY PORTFOLIO (MW)



The difference in the total solar PV additions across the scenarios is driven by two factors: (1) the target date for achieving 70% reductions; and (2) the annual limit Duke sets on new solar PV additions. The most solar PV is built in P1 Base with the earliest date for achieving the policy objective and the highest annual build limit. However, in all of these portfolios, Duke's economic modeling selects large capacity of solar PV additions over an eight-year period from 2028 to 2035 with annual additions ranging from [redacted] to [redacted] per year up to the target HB 951 compliance date.

Duke's modeling caps the annual addition of new solar PV additions based on Duke's consideration of its ability to interconnect solar capacity each year, and not based on its analysis of whether additional solar is cost-effective to build. For example, the figure below shows that in the P3 Base case, the annual solar additions (yellow bars) were equal to the interconnection cap (brown dashed line) in each year: 1,350 MW per year in 2028 to 2030 and 1,575 MW per year in 2031 to 2035. Duke's modeling economically chooses solar volumes right up to the assumed interconnection limit indicating that solar PV is cost effective and that the model would economically select more solar PV if allowed.

FIGURE 2: P3 BASE SOLAR PV ADDITIONS VERSUS ANNUAL INTERCONNECTION CAP



Duke's modeling also shows that battery storage is an essential component of least-cost portfolios for the future Duke system. By 2035, Duke's modeling projects 4,300 MW of battery storage in P3 Base, 6,700 MW in P2 Base, and

5,100 MW in P3 Fall Base. Because battery storage is added as a cost-effective resource to achieve Duke's reserve requirements, annual battery storage additions vary more year-to-year than solar and appear to depend on annual coal plant retirements, natural gas additions and load growth.

Q: DOES DUKE'S ANALYSIS ACCOUNT FOR THE COST INCREASES IN GENERATING RESOURCES, INCLUDING SOLAR PV AND BATTERY STORAGE, OVER THE PAST SEVERAL YEARS?

A: Yes, Duke included updated cost assumptions for all of the resources included in its analysis. For solar PV, Duke updated its 2023 capital cost estimate based on recent cost analysis by Burns & McDonnell that was cross-checked with costs for solar PV projects in Duke's territory submitted into the 2022 solar procurement process.[1] For projecting future costs, Duke developed a cost trend forecast based on several sources, including the 2023 Energy Information Administration Annual Energy Outlook (EIA AEO) cost projections, and cost decline curves developed by Guidehouse and EPRI. Duke further updated solar capital costs for the supplemental analysis to reflect the most recent market trends based on cost information from the 2023 Solar Request for Proposal submissions.[2]

Based on these considerations, the projected capital costs in the 2023 Carolinas Resource Plan for new solar PV entering in 2028 to 2035 are [redacted]

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[1] Duke, 2023 Carolinas Resource Plan, Appendix E: Screening of Generation Alternatives, 2023, pp. 7-8.

[2] Duke, 2023 Carolinas Resource Plan, Supplemental Planning Analysis, 2024, p. 23

higher than solar PV capital costs in the 2022 Carbon Plan analysis.[3] Battery storage costs are projected to be [redacted] higher, all in nominal terms.

The projected 2024 costs of gas-fired combined-cycle, gas-fired combustion turbines, offshore wind, and onshore wind have all increased from the 2022 Carbon Plan analysis. Duke assumes that the cost of these resources returns to previously projected costs by 2026 but assumes that solar and storage remain elevated relative to the earlier projections. This treatment is inconsistent about the common cost drivers amongst technologies including materials, electrical equipment, labor, and general inflation. It is also inconsistent with PJM's latest Cost of New Entry study conducted by The Brattle Group and Sargent & Lundy, which projects gas-fired generation resource costs to continue to increase with inflation at least through the 2026-2027 delivery year (and the indexes for materials, equipment, and labor the studies identified for updating the costs over time have also continued to increase).[4] In my view, Duke's assumptions result in an overly optimistic outlook for the costs of resources other than solar PV and battery storage.

Q: HAVE THESE COST INCREASES CHANGED THE OUTLOOK THAT LARGE VOLUMES OF SOLAR PV AND BATTERY STORAGE ARE ECONOMICALLY SELECTED AS MAJOR COMPONENTS OF ALL COMPLIANT PORTFOLIOS?

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3 For example, the projected capital costs for Solar PV bifacial single axis tracking entering in 2032 in the 2023 Carolinas Resource Plan is [redacted] compared to [redacted] in the 2022 Carbon Plan.

4 Newell, Samuel, et al., PJM CONE 2026/2027 Report, April 21 2022.

A: No. Accounting for the recent costs for solar PV and battery storage reflected in the 2022 and 2023 procurements, solar PV and battery storage remain cost-effective resources in the Duke system and essential components to least-cost compliance portfolios. In fact, solar resources are selected and built up to the maximum annual interconnection limit that Duke sets on new solar additions in every year and every portfolio up to that portfolios HB 951 compliance date, with the exception of 2030 in the P3 Fall Base when [redacted] is added, [redacted] less than the limit. Duke's modeling selects this scale of solar PV and other resources for the portfolios because those resources are critical components of meeting the reliability requirements and emissions requirements at least cost to ratepayers.

Further, by selecting the maximum amount of solar PV up to the annual interconnection, Duke's modeling demonstrates not only that the amount of solar PV included in the portfolios is cost effective but that even more would be cost effective, if it were possible for Duke to add more to its system (and Duke's model were to allow it). That is, in the absence of a limit on solar builds or in the case with a higher limit, Duke's modeling would select an even higher amount of solar PV to enter and avoid the need for higher cost resources.

Q: WHY DOES DUKE'S MODELING SELECT LARGE VOLUMES OF SOLAR PV AS A COST-EFFECTIVE RESOURCE IN ALL OF THE LEAST-COST COMPLIANCE PORTFOLIOS?

A: Duke's modeling selects the large volumes of solar PV I noted above because solar PV is one of the least cost sources of generation overall and the least cost source of zero carbon generation resources. [redacted] below shows the levelized costs of generation and transmission of solar PV, onshore wind, offshore wind, and nuclear SMRs based on Duke's assumed capital costs.[5,6] The levelized costs shown here are an indication of the relative cost effectiveness of alternative resource types, but it does not account for operational characteristics of each resource other than its annual projected output and each resource's contribution to reserve requirements. However, as clean energy resources are entering to provide low-cost, low-carbon generation to the Duke system to meet carbon dioxide emissions limits, solar PV's low levelized costs supports the Duke system reduce emissions at least cost to ratepayers.

[redacted]

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5 **Confidential** Data Response to PSDR2-11 and PSDR6-9.

6 Duke, 2023 Carolinas Resource Plan, Appendix C: Quantitative Analysis, 2023, Figure C-34

Solar PV is also the only zero-carbon clean energy resource currently deployed at scale in the Duke service territory. The 2023 interconnection studies (Resource Solicitation Cluster and DISIS) in DEC and DEP include about 3,000 MW of solar PV capacity and no capacity for onshore wind, offshore wind, or nuclear SMR.[7] Less than 20 MW of biomass and hydro are included in the latest interconnection studies.

Q: ARE YOU SAYING THAT DUKE CAN MEET THE REQUIREMENTS OF HB 951 IN A LEAST-COST MANNER WITH SOLAR PV ALONE?

A: No. Certainly not. It is clear that other resources provide benefits that solar PV cannot on its own provide. However, solar PV is the cheapest source of carbon-free electrons on the grid now and for the foreseeable future. All things being equal, the more generation (in kWhs) that Duke can get from solar PV instead of other resources, the cheaper it will be for Duke to comply with carbon reduction targets.

Q: DID YOU REVIEW THE RESULTS OF THE PORTFOLIOS WITH NO CARBON CONSTRAINTS?

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[7] Interconnection study reports accessed via OASIS websites for DEC (http://www.oasis.oati.com/duk/) and DEP (http://www.oasis.oati.com/cpl/). Specific reports can be accessed: http://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DEC_2023_Resource_Solicitation_Cluster_(Phase_1)_Report.pdf; https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2023_DEP_Resource_Solicitation_Cluster_(Phase_1)_Study_Report.pdf; http://www.oasis.oati.com/woa/docs/CPL/CPLdocs/DEP_DISIS_2023_Phase_2_Study_Report.pdf; http://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2023_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report.pdf.

A: Yes, I reviewed the results of the No Carbon Constraints Supplemental Portfolio and the SP SC No CO2 Constraints Fall Supplemental Portfolio. At the request of the South Carolina Public Service Commission, Duke simulated its future power system without the limit on carbon dioxide emissions generation facilities in North Carolina required by H591. Both portfolios are very different from the portfolios discussed above that meet the goals of HB 951, with 12 to 13 GW less solar, no nuclear SMRs, and 5 to 7 GW more gas-fired capacity compared to portfolios with the carbon constraint, and higher emissions than what is allowed by HB 951.[8,9]

Q: DOES REMOVING CARBON CONSTRAINTS FROM THE MODEL RESULT IN SIGNIFICANT COST SAVINGS TO RATEPAYERS?

A: No, it does not. Replacing solar PV and other clean energy resources primarily with gas-fired capacity, as Duke's modeling does in the No Carbon Constraints Supplemental Portfolio, results in an estimated 1.5% reduction in costs to ratepayers compared to the P3 Base case, as shown in Figure 4 below.[10] However, the No Carbon Constraints Supplemental Portfolio exposes Duke's ratepayers to the significant risk of higher costs. For example, Duke's sensitivity analysis for P3 Base demonstrates that natural gas commodity price risk in the P3 Base portfolio greatly exceeds the relatively minor base case cost savings shown in the

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[8] Duke, 2023 Carolinas Resource Plan, Supplemental Planning Analysis Technical Appendix, 2024.

[9] Duke, 2023 Carolinas Resource Plan, Appendix C: Quantitative Analysis, 2023, p. 101

[10] Duke, 2023 Carolinas Resource Plan, Appendix C: Quantitative Analysis, 2023, p. 101. The No Carbon Constraints Supplemental Portfolio present value of revenue requirements ("PVRR") are about $65 billion through 2038, which is 1.5% lower than the P3 Base PVRR of $66 billion.

No Carbon Constraints Supplemental Portfolio.[11] The P3 Base Capital/High Fuel sensitivity case assumes higher gas costs [redacted] from 2028 to 2040 exposing ratepayers to [redacted] in higher costs than the case with base case with gas costs [redacted] an [redacted] increase in ratepayer costs (compared to the [redacted] cost savings without a carbon constraint).[12] But, this is an underestimate of the natural gas cost risks to ratepayers of the No Carbon Constraints Supplemental Portfolio. The No Carbon Constraints Supplemental Portfolio has much higher natural gas demand than the P3 Base portfolio ([redacted]) which makes it even more sensitive to gas price spikes.[13] Indeed, such spikes in natural gas commodity prices have happened in recent years, with Henry Hub natural gas prices in 2022 remaining on average over $6/MMBtu for the full year.[14]

By contrast, portfolios *with* the carbon constraints in line with HB 951 include more renewable and nuclear resources that provide ratepayers a valuable hedge against volatility in their electricity bills with fluctuations in natural gas commodity prices, in addition to lowering carbon dioxide emissions and local air pollutants.

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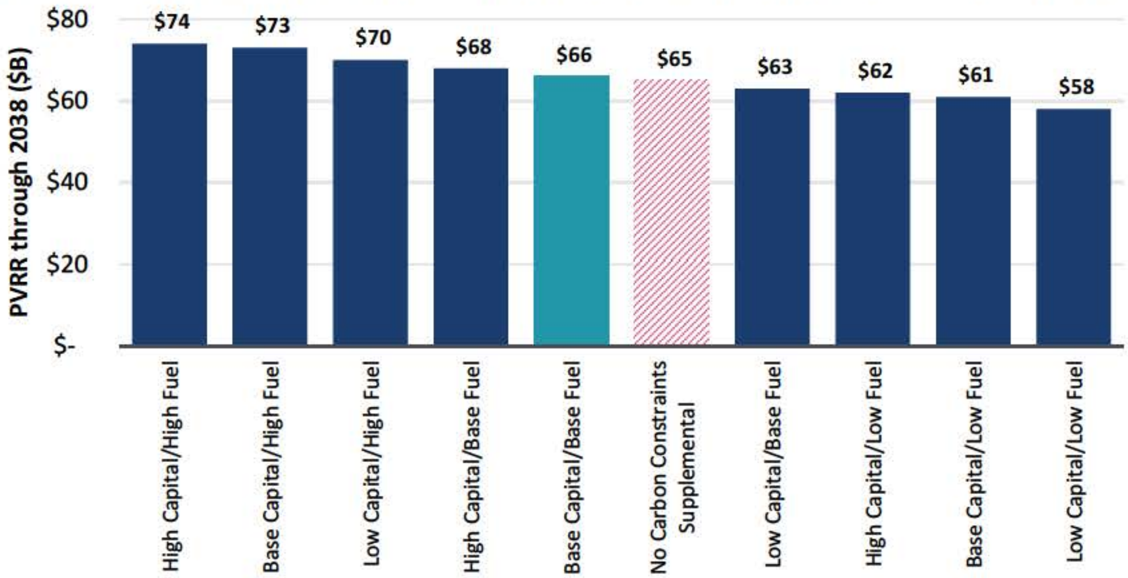
[11] Duke, 2023 Carolinas Resource Plan, Appendix C: Quantitative Analysis, 2023, p. 91.

[12] Modeled natural gas prices are calculated from the EnCompass output files.

[13] Natural gas demand is calculated from the EnCompass output files.

[14] U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price, May 22, 2024.

FIGURE 4: PVRR THROUGH 2038 OF P3 BASE SENSITIVITY CASES ($ BILLION)



Source: Duke, 2023 Carolinas Resource Plan Appendix C Quantitative Analysis, 2023, p. 91.

The SP SC No CO2 Constraints Fall Supplemental Portfolio results in slightly higher cost savings relative to the P3 Fall Base Portfolio of about 5%.[15] But the increased demand for national gas will further expose Duke ratepayers to the gas price risk noted above. Duke did not complete similar sensitivity analysis of the P3 Fall Base portfolio at higher and lower national gas prices to demonstrate the scale of the natural gas cost risks to ratepayers.

[15] Duke, 2023 Carolinas Resource Plan, Supplemental Planning Analysis Technical Appendix, 2024, pp. 8, 16.

II. PROACTIVE TRANSMISSION PLANNING IS KEY TO KEEPING RATEPAYER COSTS LOW

Q: WHAT ARE THE INTERCONNECTION AND TRANSMISSION BARRIERS TO ADDING MORE ECONOMIC SOLAR TO DUKE'S SYSTEM?

A: As noted above, Duke's models would select even higher volumes of solar if allowed to do so, but Duke caps the annual solar PV interconnection rate based on its assessment of the limitations it faces in interconnecting new solar PV capacity. Duke identifies the number of transmission outages required for interconnecting new solar PV during the spring and fall seasons as the key limiting factor.[16] However, Duke cites two factors in its supplemental analysis that will increase the maximum interconnection rate of solar additions. First, Duke increases the interconnection rate in the supplemental analysis from 1,350 MW to 1,575 MW in 2031 based on "continued success in proactively achieving transmission additions through the Red Zone Expansion Project 2.0 projects."[17] Second, Duke supports increasing the interconnection rate further to 1,800 MW per year in 2032 if developers can increase the size of new renewable energy capacity to limit the number of interconnections required.[18]

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[16] Duke, 2023 Carolinas Resource Plan, Appendix L Transmission System Planning and Grid Transformation, 2023, pp. 20-21. Duke provides limited information to assess the validity of this claim, including the basis for the amount of line outages that would be required for interconnecting solar resources, the amount of time needed for those outages, and the amount of time they have available for additional interconnection-related outages.

[17] Duke, 2023 Carolinas Resource Plan, Supplemental Planning Analysis, 2024, p. 25.

[18] Duke, 2023 Carolinas Resource Plan, Supplemental Planning Analysis, 2024, p. 25.

Q: WHAT APPROACHES CAN DUKE TAKE TO EASE THE CHALLENGES OF INTERCONNECTING COST-EFFECTIVE NEW RESOURCES, INCLUDING SOLAR PV?

A: Duke has recently made several significant improvements to its transmission planning and interconnection processes, many at the urging of the Commission, including the development of RZEP projects, implementation of cluster studies in the interconnection process (including a separate cluster for its solar PV solicitations), and the introduction of the MVST planning process. Changes to its interconnection study process have reduced the amount of time required to complete interconnection studies from four years to two years.[19] 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 while achieving the carbon dioxide emissions reductions goals.

In particular, Duke needs to proactively plan its transmission system for the future market conditions identified in the 2023 Carolinas Resource Plan portfolios, incorporating both the projected changes in demand and the resource mix into its planning studies. Up to now, Duke has not coordinated the future resource mix identified in its resource planning modeling with the transmission planning studies to identify cost effective upgrades in advance of need. This approach results in a perpetually constrained system that has to play "catch-up"

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19 Direct Testimony of Dewey S. Roberts and Jing Shi on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Roberts & Shi"), Docket No. E-100, Sub 190, September 1, 2023, p. 23.

when new resources are studied in the interconnection process, particularly in the areas of the system with the most development opportunities. As discussed below, a proactive approach should enable higher volumes of interconnection at lower costs to ratepayers. In addition, as discussed in CCEBA witness Miller's testimony, solar PV QFs with expiring PPAs offer an opportunity for using existing interconnections to expand grid resources at lower cost and with shorter timelines. Duke should also continue to seek ways to improve its interconnection process to identify only the upgrades needed to deliver output to the system, rely on lower-cost approaches to providing reliable delivery than building transmission upgrades, and improve its approach to outage coordination.

Q: HOW DOES DUKE CURRENTLY IDENTIFY THE NECESSARY TRANSMISSION UPGRADES TO ACCOMMODATE NEW RESOURCES?

A: Duke currently does not study in its transmission planning process how to cost effectively build out its system to accommodate new resources in the 2023 Carolinas Resource Plan portfolios, but instead identifies necessary upgrades for new resources through the interconnection process. When resources seek interconnection into a system with limited available headroom, interconnection studies become more complicated and take more time, creating schedule and cost uncertainty for developers and delaying the addition of cost-effective resources. I agree with Duke witnesses Roberts and Shi on this point.[20] Once the necessary

20 "[T]he Companies also anticipate that the pace, scope, and scale of the significant resource additions identified as needed in the CPIRP will drive increasingly complex interconnections and the need for significant transmission upgrades to enable these generator interconnections." Roberts & Shi, p. 22.

upgrades are identified in the interconnection studies, Duke must then build those upgrades prior to the new resources coming online, adding the potential for additional delays in interconnecting cost-effective resources.

Recently, Duke has identified two portfolios of RZEP projects based on the upgrades that have been repeatedly identified in interconnection studies as necessary upgrades to integrate new resources. The RZEP projects are near-term proactive projects that reflect system needs for the scale and location of resources included in recent cluster studies and will ease the interconnection of those resources and potentially more in the future. I fully support the use of interconnection studies to identify RZEP network upgrades that provide broader benefits to the system. However, relying solely on this "bottom-up" process is inherently reactive and will not identify the longer-term needs of the transmission system and opportunities to improve it at scale. Using the interconnection process alone to identify network upgrades also slows down the interconnection process and increase the development timeframe for solar PV projects substantially.

By contrast, the NCTPC 2023 Public Policy Study identified upgrades necessary to interconnect over 14 GW of new solar PV, onshore wind, and offshore wind resources.[21] Duke used the 2023 Public Policy study to validate the projects included in both the RZEP 1.0 portfolio and the RZEP 2.0 portfolio, but

[21] North Carolina Transmission Planning Collaborative, Report on the NCTPC 2023 Public Policy Study, Draft Report, May 17, 2024 (http://www.nctpc.org/nctpc/document/REF/2024-05-17/NCTPC_2023_Public_Policy_Study_Draft%20Report%2005172024.pdf).

did not identify additional long-term proactive upgrades based solely on the 2023 Public Policy study.[22]

Q: SHOULD INTERCONNECTION STUDIES BE THE PRIMARY SOURCE OF IDENTIFYING THE TRANSMISSION UPGRADES NEEDED FOR NEW RESOURCE ADDITIONS?

A: No. Relying primarily on the interconnection process to identify transmission upgrades will result in higher costs to customers because it builds the system out in a piecemeal fashion, studying the system needs only for the deliverability of a specific set of resources. Instead, areas that are constantly constrained and specific upgrades repeatedly identified as necessary in the interconnection study process should be incorporated into and evaluated in the long-term proactive planning process along with other driver of long-term transmission expansion value.

Q: CAN YOU PLEASE EXPLAIN A MORE COST-EFFECTIVE APPROACH TO PLANNING THE FUTURE TRANSMISSION SYSTEM?

A: Duke should instead identify and build cost effective, least-regrets transmission upgrades through a longer-term, proactive transmission planning process that: (1) incorporates the full set of resources needed to achieve future reliability and policy requirements rather than just the next set of resources that are seeking interconnection to the system; (2) considers a broader range of benefits of transmission upgrades, such as reducing system congestion and other cost savings

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[22] Following the 2023 Public Policy study, the NCTPC added a project to the RZEP 2.0 portfolio that had previously been identified as needed in interconnection studies.

for ratepayers; and (3) creates headroom on the system in advance of the resources seeking interconnection. The transmission planning process should focus on identifying system-level, least-regrets upgrades that are beneficial across a range of future scenarios and support the delivery of multiple future resource additions.

Proactively planning and building upgrades will have several benefits to Duke ratepayers. First, proactive planning reduces the total costs of upgrades by finding larger scale, more cost-effective upgrades that support wider set of new resources. Second, it streamlines the interconnection process by creating headroom on the system prior to interconnection requests, so that interconnection studies are simpler and resources can utilize the newly created headroom on the system that has been built (or in the process of being built). Interconnection studies would then primarily identify local interconnection facilities at the point of interconnection. Third, by implementing proactive transmission planning, Duke can foresee the upgrades needed to meet future goals and build out the facilities in advance of need, instead of having to build the facilities "just in time" to interconnect new resources.

By planning ahead and reducing the total amount of required upgrades, proactive planning will require fewer outages. Duke witnesses Roberts and Shi came to the same conclusions on the benefits of proactive planning for improving the interconnection process: "The real-world limitations on generator interconnections required to execute the resource additions identified in the Plan can be reduced through interconnecting larger facilities and through strategic identification and proactive construction of transmission network upgrades that enable a more efficient interconnection process."[23]

Q: HAS PROACTIVE TRANSMISSION PLANNING PROVIDED RATEPAYER BENEFITS AND SAVINGS ELSEWHERE?

A: Yes. The benefits of proactive transmission planning have been demonstrated across multiple transmission planning studies and planning regions. MISO has been studying the long-term benefits of proactive upgrades on its system since 2010 and approved an initial set of Multi-Value Projects ("MVP") in 2011 that provide a broad range of benefits to its system. Importantly, MISO has continued to confirm net benefits of the MVP projects to its system since they were initially approved through triennial reviews. MISO recently re-started its proactive planning through its Long-Range Transmission Planning ("LRTP") process and identified portfolio of Tranche 1 upgrades that provide benefits that are 2.6 – 4.1 times the costs across the northern portion of its system.[24] That means for every dollar ratepayers will spend on Tranche 1 transmission upgrades will result in $2.60 - $4.10 of ratepayer cost savings from lower production costs, lower capital costs for new generation, avoided reliability outages, and avoided future transmission project costs.

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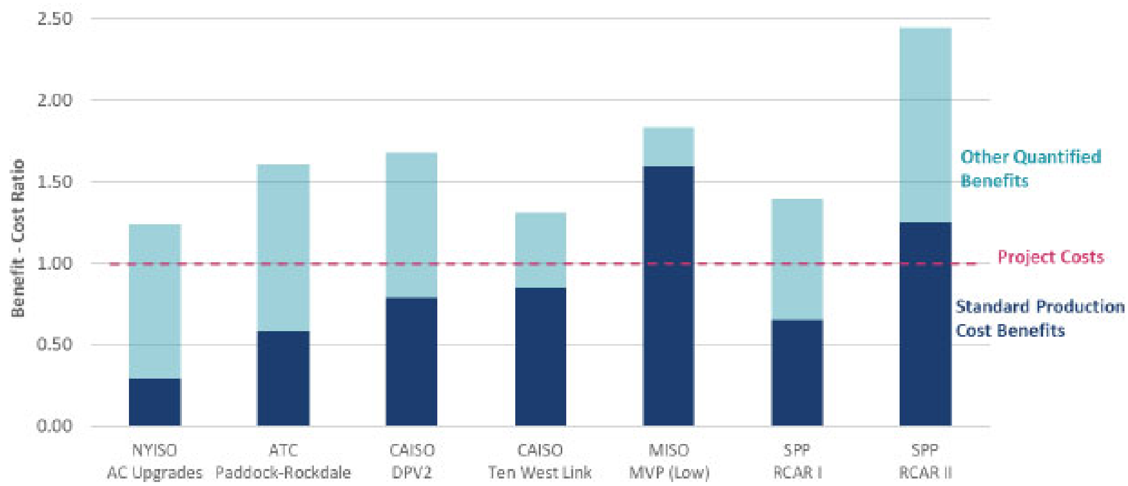
[23] Roberts & Shi, p. 21.

[24] MISO, MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1: Executive Summary, 2022, p. 3 (https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf).

The figure below highlights seven cases across a broad set of planning regions, including MISO, SPP, NYISO, CAISO, and ATC in Wisconsin, in which proactive transmission planning have identified beneficial transmission projects or portfolios of projects through a multi-value framework. My colleagues and I documented the industry's experience in proactive transmission planning in the report *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* that is included as an exhibit to my testimony.

FIGURE 5: EXAMPLES OF BENEFICIAL PROACTIVE TRANSMISSION PLANNING



Source: Pfeifenberger, Johannes, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021, p. 33.

Q: HOW CAN DUKE ENSURE THAT LONG-TERM PLANNING PROCESSES RESULT IN COST-EFFECTIVE UPGRADES WITHOUT KNOWING AT THE TIME EXACTLY WHICH RESOURCES WILL BE INTERCONNECTING TO THE SYSTEM?

A: One of the primary challenges that transmission planners face with proactive planning is specifying the type and locations of the future resource mix that will be necessary to meet its future system needs. In this case, Duke has already developed several portfolios that can be studied in the transmission planning process and identified high likelihood regions for development in previous studies. Additional analysis will be necessary for identifying the future location of resources and Duke can learn from the best practices utilized by other transmission planning regions. Each of the planning entities noted above have developed an approach to do so that resulted in sufficient buy in from its stakeholders and regulators for approving the projects. Similar to its approach for identifying near-term proactive RZEP projects, Duke will need to develop an effective long-term planning process for identifying cost-effective, least-regrets upgrades that will provide benefits to the system across a range of future scenarios.

III. EFFECTIVE IMPLEMENTATION OF MVST WILL SUPPORT IDENTIFICATION OF PROACTIVE TRANSMISSION UPGRADES

Q: CAN DUKE IMPLEMENT A PROACTIVE PLANNING PROCESS THROUGH THE MVST PROCESS?

A: Yes, Duke developed the MVST process over the past two years with the support of the Commission and had its tariff revisions for the MVST process approved by the Federal Energy Regulatory Commission ("FERC") earlier this year.[25] The key aspects of the MVST include: an updated stakeholder meeting process to

[25] *Order Adopting Initial Carbon Plan and Providing Direction for Future Planning*, Docket No. E-100, Sub 179, December 30, 2022, at 134.

review assumptions, needs, and solutions; a forward-looking, proactive approach to planning; the use of scenarios to account for different possible futures; and the consideration of multiple benefits of transmission. Duke has a great opportunity over the next year to improve its transmission planning process through the development and completion of the first MVST planning process. In my experience, the details of the implementation of the transmission planning process are very important and will ultimately determine whether the MVST assists Duke in the necessary transformation of its transmission system over the next 10-15 years.

Q: DO YOU HAVE RECOMMENDATIONS FOR HOW DUKE CAN MAKE THE MVST PROCESS AS EFFECTIVE AS POSSIBLE?

A: Yes. Implementing an efficient and effective MVST process that identifies proactive, multi-value transmission upgrades will be critical to cost effectively transforming Duke's system for the projected changes in demand and resource mix. Planning the transmission system to meet the future resource needs and including cost-effective transmission upgrades into the annual transmission plan will (1) reduce the total costs of the future power system to ratepayers, (2) create headroom on the network to reduce the complexity and uncertainty of the interconnection process, and (3) provide more accurate inputs into the resource planning process.

There are several key elements for Duke, stakeholders, and the Commission to focus on to make the MVST process as effective as possible. These elements are based on recommendations in the report I co-authored titled

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs.[26]

- **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, load levels, and load profiles over the lifespan of the transmission investment. Developing a stakeholder-vetted process for selecting the locations of new resources on the Duke system will be important to building confidence that the identified transmission upgrades are needed.
- **Account for the full range of transmission projects' benefits** and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits. As reported by the CTPC to the Transmission Advisory Group in its May meeting, the first step of identifying which benefit metrics to quantify in the MVST is underway, including production cost savings, avoided energy losses, reliability benefits, avoided generation capacity due to a reduction in peak losses, avoided transmission upgrades, and avoided upgrades of end-of-life assets. In addition to these benefit metrics, Duke should consider the benefits of providing access to portions of its system that will reduce the costs of resources identified as necessary in its resource planning process. The approaches that Duke uses for

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[26] Pfeifenberger, Johannes, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021 (https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf).

analyzing each of these metrics will be important for accurately quantifying the benefits of transmission projects.

- **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events. Incorporating the market events that tend to stretch the capability of the system, including generation and transmission outages and heat waves, will be a key input into quantification of benefits. Duke should review recent challenging market conditions, such as Winter Storm Elliot, and real-time uncertainty in demand or renewable generation to capture the benefits of transmission under these circumstances.
- **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently than a project-by-project approach. The MVST should focus on identifying systemwide needs and developing a portfolio of projects that can more cost effectively integrate new resources, instead of focusing on the benefits of each upgrade separately.
- **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits. While this point is less relevant to the Duke local transmission planning process, it does emphasize the importance of Duke using its MVST process as an example for improving regional and interregional planning through SERTP.

Q: DO YOU HAVE ANY TAKEAWAYS FROM THE RESULTS OF THE 2023 PUBLIC POLICY STUDY THAT SHOULD BE ADDRESSED IN DEVELOPING AND IMPLEMENTING THE MVST PROCESS?

A: Yes. At a high-level, the results are very promising. NCTPC identified that the addition of 14.5 GW of renewable energy resources (12.5 GW of solar and 2 GW of onshore/offshore wind) will require $2.5 billion in transmission upgrades, or $170/kW.[27] All of the identified upgrades are either reconductoring or upsizing existing transmission facilities on existing rights-of-ways, though the NCTPC suggested that a greenfield 230 kV network in DEC may be a long-term potential solution to consider in future studies. The costs that NCTPC included are below the current assumption for solar transmission cost adders in the CPIRP modeling based on recent interconnection study results, and demonstrate that proactive planning can identify cost-effective upgrades for a much larger amount of renewable energy capacity.

Three additional aspects of the 2023 Public Policy study are worth considering while developing and implementing the MVST process. First, completing the additional analyses for a multi-value, scenario-based planning process will require Duke to devote significant resources to the MVST study. In the 2023 NCTPC Public Policy study, stakeholders requested the NCTPC to complete reliability studies for six scenarios. The stakeholders requested six

[27] North Carolina Transmission Planning Collaborative, Report on the NCTPC 2023 Public Policy Study, Draft Report, May 17, 2024. The cost estimates do not include upgrades required at the point of interconnection for the additional resources.

scenarios to account for two levels of solar capacity (5.5 GW and 12.6 GW) and three alternative sets of locations so that the NCTPC could identify least-regrets near-term and long-term upgrades. Initially, the NCTPC planned to model two levels of solar capacity with a single set of locations scenarios, but ultimately only modeled a single scenario due to staff and time constraints. I am providing this as an example of the amount of work that will be required for completing the MVST process that will include reliability studies for more than one scenario and the additional analyses required for capturing a broad range of benefits of transmission upgrades. Duke will need to devote additional staff and other resources to the MVST for it to be successful.

Second, the results of the 2023 Public Policy study provided limited details for stakeholders to review and provide feedback. The study summarized the high-level results in terms of the network upgrades identified and their costs, but no information on the specific reliability violations that required network upgrades, the alternative upgrades or other solutions considered to resolve the violations, and the rationale for including the identified transmission upgrades in the RZEP 2.0 portfolio or not. Instead, the study concluded with several vague findings that (1) the results are driven by the assumptions, (2) the results provide no commitment to building identified upgrades, (3) developers should submit interconnection requests to identify required upgrades, and (4) Duke will continue to study the impacts of a changing resource mix and load additions. Duke should focus on increasing its transparency of its planning process in the MVST to ensure that the most cost-effective solutions can be identified for meeting future system needs and clearly articulate the basis by which they will decide on whether to build upgrades identified in the MVST study from the beginning.

Third, the 2023 reliability study and public policy studies identified two separate portfolios of upgrades without an explanation of whether the portfolios include the same upgrades, whether the policy upgrades are incremental to the reliability studies, or the policy study portfolio avoids upgrades identified as necessary in the reliability study portfolio. This is very important for understanding the costs for interconnecting future resources, as well as determining if upgrades included in the reliability-driven portfolio may be unnecessary in a future with the additional resources modeled in this study. If the upgrades are unnecessary in a future with the CPIRP modeling resource mix, Duke should complete additional analysis to ensure those upgrades need to be built for reliability purposes accounting for both load growth and the future resources.

Q: ARE THERE PROACTIVE TRANSMISSION PLANNING PROCESSES THAT DUKE AND THE COMMISSION SHOULD REVIEW WHILE DEVELOPING ITS MVST PROCESS?

A: Yes. I would recommend that Duke consider the Southwest Power Pool (SPP)[28] and Midcontinent Independent System Operator (MISO)[29] planning processes in

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[28] *See* Southwest Power Pool, 2021 Integrated Transmission Planning Assessment: Report & Addendum, Version 2.0, December 9, 2022 (https://www.spp.org/documents/66812/2021%20itp%20report%20&%20addendum%20v2.0.pdf).

[29] *See* Midcontinent Independent System Operator, MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report: Executive Summary, 2022

particular. Both regions develop long-term scenarios for the future demand and resource mix assumptions and then convert those scenarios into details for running detailed reliability and economic planning studies. They then review several potential drivers of transmission needs including reliability, economic, and policy drivers for developing a portfolio of upgrades to consider. Finally, they evaluate several portfolios of projects based using a multi-value framework to identify the most beneficial portfolio of projects to approve and include in their regional transmission plan. For developing detailed assumptions for the locations of future resources, I would also recommend that Duke review the approach the California Public Utilities Commission and California Energy Commission to mapping the resource portfolios approved by the California Public Utilities Commission to specific locations on the CAISO system.[30] They consider several important considerations, including access to transmission, land use impacts, community impacts, and commercial interest. I include representative reports from each of these entities as exhibits to my testimony.

Q: DOES THE RECENTLY RELEASED FERC ORDER NO. 1920 IMPACT THIS PROCESS?

(https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf).

[30] *See* California Public Utilities Commission, Integrated Resource Planning (IRP) Proposed Portfolios for the 24-25 Transmission Planning Process (TPP) and Preliminary Busbar Mapping: Workshop, October 20, 2023 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/tpp-psp_10-20-23_workshop_tppbusbarslides.pdf).

A: FERC's new Order No. 1920 requires regional transmission providers to include a 20-year long-term regional planning study using many of the elements discussed above. While Order No. 1920 that will not directly impact Duke's local transmission planning process, it will have an impact on the Southeast Regional Transmission Planning ("SERTP") regional planning process, of which Duke is a member. Duke will need to work with the other members of SERTP to prepare a plan for compliance with Order No. 1920. In many ways, Duke's MVST can be example of an approach to comply with many of the requirements included in Order No. 1920. Duke may also wish to review Order No. 1920 to determine whether any additional modifications to the MVST process would be worth implementing.

One especially important consideration in Order No. 1920 is on the role of states to participate in and contribute to transmission planning processes. FERC closely considered the role for states in the long-term regional planning process and concluded that states play an important role throughout the process, including in identifying which state policies to include in the planning studies, which benefits to analyze and how to do so, and determining the cost allocation approach for approved transmission projects. The Commission should better understand this role for participating in the SERTP process, but also for continuing to identify opportunities for Duke to improve its local transmission planning process.

IV. PROACTIVE TRANSMISSION PLANNING WILL IMPROVE GENEARTION INTERCONNECTION AND RESOURCE PLANNING

Q: HOW WILL 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: ARE THERE ADDITIONAL IMPROVEMENTS TO GENERATION INTERCONNECTION THAT DUKE SHOULD IMPLEMENT?

A: Yes. Proactive transmission planning is an important aspect of improving generation interconnection, but there is more Duke can do to improve the process and continue to maintain the same level of reliability at lower costs to ratepayers. Additional improvements to the interconnection process include: (1) consideration of lower cost solutions than network upgrades, such as economic re-dispatch, simple Remedial Action Schemes ("RAS"), and grid-enhancing technologies, to maintain system reliability especially during lower probability system conditions, such as TPL-001 P3 contingencies; (2) providing developers a sufficiently differentiated interconnection service option through Energy Resource Interconnection Service ("ERIS") in which developers can choose to take on the higher risks of curtailment and lower resource adequacy value while reducing the costs and schedule risks of Network Resource Interconnection Service ("NRIS"); (3) reduce the challenges of transmission outages during the construction of network upgrades through the use of grid-enhancing technologies and transmission shoo-flies;[31] and (4) expand the use of provisional interconnection service to allow resources to come online prior to the completion of all identified network upgrades.

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 recent 2023 public policy study, or replaced by larger and

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[31] "GETs can minimize impact during construction by avoiding an outage altogether, or preventing congestion caused by transmission outages that occur while interconnecting the new projects. Topology Control software could also be used to identify the least impactful outage options." Tsuchida, et al., Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts, April 20, 2023, p. 15.

more cost-effective upgrades that can support interconnection of new resources and provide other benefits to the Duke system.

Q: HOW WOULD IMPROVED TRANSMISSION PLANNING IMPACT THE RESOURCE PLANNING PROCESS?

A: In its CPIRP process, Duke develops portfolios of the future resources needed to serve load using a power market model, EnCompass, that simulates resource additions and retirements and resource operations to meet future hourly demand and reserve requirements. Duke generates resource portfolios that consider a range of important assumptions, including two assumptions related to the transmission system: (1) the capital costs of new resources include projected network upgrade costs required for interconnecting each resource type to the system; and (2) as noted above, annual solar additions are limited based on assumed challenges implementing network upgrades for each new project and coordinating outages on the existing system.

Currently, neither of these assumptions are informed by the long-term transmission planning process. Network upgrade cost adders in the 2023 CPIRP simulations of $0.21/Watt in DEP and $0.35/Watt in DEC (2023 dollars) are based on near-term network upgrades costs identified in recent interconnection studies.[32] Similarly, Duke relied on its recent experience coordinating transmission outages for setting the annual build limit of 1,575 MW per year on

[32] Duke develops estimates from other sources for resources that have not recently completed interconnection studies.

solar PV through 2031, rising to 1,800 MW per year due to the impacts of proactive RZEP projects and rising solar capacity per project, as described above.

In its next iteration of CPIRP modeling, Duke could instead rely on the results from the 2023 Public Policy study and future transmission planning studies for estimating network upgrade cost adders in resource planning studies. The 2023 Public Policy study identified upgrade costs of about $0.17/W, based on $2,531 million (2023 dollars) for 14.5 GW of incremental solar and wind capacity, lower than the costs recently modeled for solar and other resources in the CPIRP. For setting solar addition limits, Duke should review the findings of the 2023 Public Policy study to identify how the number of upgrades and related outages will change if these projects are included in future transmission plans and how that impacts the rate of solar additions.

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 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 that 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.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.