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May 29, 2024

VIA ELECTRONIC FILING

Shonta Dunston, Chief Clerk
The North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-432

Re: DIRECT TESTIMONY OF EDWARD BURGESS ON BEHALF OF ATTORNEY GENERAL'S OFFICE
Docket No. E-100, Sub 190

Dear Ms. Dunston:

Yesterday in the above-reference docket, The North Carolina Attorney General's Office inadvertently filed an incorrectly redacted public version of the testimony and exhibits of Edward Burgess. The incorrectly redacted version of the testimony has been removed from the docket system. Attached please find the public corrected version of witness Burgess' testimony.

A copy of the public corrected redaction version is being forwarded to all parties of record by electronic delivery today. Confidential information is located on pages 2, 18, 32, 37, 38, 40, 54, 59, 63 – 65 and 83 of the testimony.

The confidential version has been provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Duke Energy Progress, LLC,	)	**EDWARD BURGESS**
and Duke Energy Carolinas,	)	**ON BEHALF OF**
LLC, 2023 Biennial	)	**ATTORNEY GENERAL'S**
Integrated Resource Plans	)	**OFFICE**
and Carbon Plan	)	

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Ed Burgess. I am the Founding Partner of Morpho Strategies, LLC. My business address is 3519 NE 15th Ave, #360 Portland, OR 97212.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have spent over 12 years working as a consultant in the energy and utilities industry. I specialize in various grid planning issues including the integration of renewable energy, energy storage, electric vehicles, and distributed energy resources. I have provided expert testimony on over 27 occasions before 12 state utility commissions on issues including utility resource planning, transmission planning, fuel and power purchase costs, rate design, and electric vehicle programs. Prior to co-founding Morpho Strategies in 2024, I was a Consulting Partner at Strategen, where I worked for over 8 years. While at Strategen, I directed the company's grid planning practice area. I also helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council and grew the organization to over 40 member companies. Prior to joining Strategen, I also worked as an independent consultant, providing technical support to clients before state utility commissions and legislatures. During that time, I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a bachelor's degree in Chemistry (A.B.) from

Princeton University. I also have master's degrees in Solar Energy Engineering and Commercialization (P.S.M.) and in Sustainability (M.S.) both from Arizona State University. My resume is attached as Burgess Direct Exhibit 1.

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

A. I am testifying on behalf of the North Carolina Attorney General's Office (AGO).

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified on behalf of the AGO in Docket Nos. E-100, Sub 179 (Duke Energy's 2022 Carbon Plan), Docket E-2 Sub 1300 (Duke Energy Progress' 2023 General Rate Case), and Docket E-7 Sub 1276 (Duke Energy Carolinas' 2023 General Rate Case).

Q. HAVE YOU EVER TESTIFIED BEFORE ANY OTHER STATE UTILITIES COMMISSIONS?

A. Yes. I have testified before utilities commissions in California, Colorado, Indiana, Louisiana, Massachusetts, Michigan, Nevada, Oregon, South Carolina, Virginia, and Washington. A full list of these proceedings is provided in Burgess Direct Exhibit 1. Additionally, I have represented numerous clients by conducting technical analyses, drafting formal comments, and participating in technical workshops on a wide range of proceedings at utilities commissions including in Arizona, District of Columbia, Maryland, Minnesota, Montana, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, and

Utah, as well as the Federal Energy Regulatory Commission, the Western Interstate Energy Board, and the California Independent System Operator.

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS CASE.

A. My findings and recommendations can be summarized as follows.

A. Findings

1. Duke Energy's (Duke or the Company) efforts to achieve 70% carbon dioxide emissions reductions (the Interim Target) by 2030 (or shortly thereafter) have been insufficient. Both the Company's recent actions and future planning activities have been inconsistent with this goal (detailed in Section III-A of my testimony).
2. In developing its plan, Duke overlooked practical, reasonable strategies for accelerating coal retirements (section III-B) and renewable additions (section III-C) that could assist with meeting the Interim Target while maintaining reliability.
3. Duke's proposed natural gas additions rely on unreasonable assumptions and present significant risks that are not adequately portrayed in the overall analysis (section IV).
4. Duke's underlying load forecast may not accurately capture declining usage per customer trends, leading to an inflated load forecast (section V-B).
5. Duke's plan also does not adequately consider customer-centric, demand-side solutions for mitigating overall load growth (section V-C).

6. Duke's plan did not sufficiently address a variety of reasonable, practical recommendations related to transmission that the AGO made in the Company's most recent general rate cases (section VI).

B. Recommendations

1. The Commission should set a clear directive for Duke to achieve the Interim Target by no later than 2032. This appropriately balances the statutory guidelines for a 2030 target versus the new challenges posed by recent load growth.
2. The Commission should direct Duke to pursue the multiple strategies outlined in this testimony for accelerating coal retirements and increasing renewable additions.
3. The Commission should give significant weight to two key factors when evaluating any future Carbon Plan Integrated Resource Plan (CPIRP) or certificate for public convenience and necessity (CPCN) for new natural gas resources: (1) the potential challenges in securing sufficient firm transportation capacity and (2) the potential impacts of the United States Environmental Protection Agency's (EPA) new Section 111 rule.
4. In future CPIRP proceedings, the Commission should conduct an independent load forecast analysis to validate Duke's forecast assumptions, including those for both large load additions and underlying usage per customer trends.
5. The Commission should direct Duke to supplement its resource plan with additional customer-centric demand-side options (including those highlighted

in my testimony) to mitigate forecasted load growth and related supply-side resource needs.

6. The Commission should require Duke to pursue the transmission-related recommendations outlined in section VI of my testimony.

Section VII of my testimony includes a more detailed and comprehensive list of recommendations.

III. <u>INTERIM TARGET FOR EMISSIONS REDUCTIONS AND SOLUTIONS FOR MEETING THE TARGET</u>

A. The Company's pathway analysis does not adhere to the letter and spirit of HB 951 and the associated 2030 emissions reductions timeline.

1. <u>Duke's proposal to delay the Interim Target to 2035 is not aligned with statutory guidelines or the Commission's previous orders.</u>

Q. WHAT IS YOUR UNDERSTANDING OF THE LEVEL OF CO_2 EMISSIONS REDUCTION ANY CARBON PLAN ADOPTED BY THE COMMISSION IS REQUIRED TO ACHIEVE, AND BY WHEN?

A. In order to evaluate Duke's proposal, I reviewed the relevant statutory language as well as the Commission's initial Carbon Plan order. My understanding is that, under N.C.G.S. § 62-110.9, the Commission was required to develop an initial plan for the Company to achieve an interim emissions reduction level of by 70% by 2030 and a final reduction level of 100% (i.e., "carbon neutrality") by 2050. This initial plan must then be updated every two years. The law appears to give some limited discretion to the Commission to determine the optimal timing for achieving these targets but does not permit a delay of more than 2 years unless very specific conditions have been met.

Q. WHAT IS YOUR UNDERSTANDING OF THE CONDITIONS NECESSARY TO DELAY COMPLIANCE BEYOND 2032?

A. My understanding is delay beyond 2032 is only permitted under two circumstances: (1) "in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility" or (2) "in the event necessary to maintain the adequacy and reliability of the existing grid."

Q. BASED ON YOUR REVIEW, HAS "THE COMMISSION AUTHORIZE[D] CONSTRUCTION OF A NUCLEAR FACILITY OR WIND ENERGY FACILITY THAT WOULD REQUIRE ADDITIONAL TIME FOR COMPLETION DUE TO TECHNICAL, LEGAL, LOGISTICAL, OR OTHER FACTORS BEYOND THE CONTROL OF THE ELECTRIC PUBLIC UTILITY"?

A. I am not aware of the Commission authorizing construction of any new nuclear or wind energy facilities. I am also not aware of any "technical, legal, logistical, or other factors beyond the control" of Duke that would impact the timing of any authorized construction.

Q. BASED ON YOUR REVIEW, DO YOU BELIEVE IT IS NECESSARY TO DELAY COMPLIANCE BEYOND 2032 "TO MAINTAIN THE ADEQUACY AND RELIABILITY OF THE EXISTING GRID"?

A. No. As described below, I believe there are sufficient reasonable steps that the Commission could take to ensure compliance by 2032 while maintaining the adequacy and reliability of the grid. In fact, the Company has put forward a portfolio that achieves the 2030 target while maintaining the adequacy and reliability of the existing grid, but this is neither its preferred portfolio nor sufficiently analyzed.

Q. BASED ON THE FOREGOING, WHAT DO YOU BELIEVE IS THE APPROPRIATE DATE FOR THE COMMISSION TO TARGET IN THIS PROCEEDING?

A. My understanding is that 2032 would still be the latest date for reaching the Interim Target absent further Commission action.

Q. DID THE COMMISSION AUTHORIZE A DELAY IN THE INTERIM COMPLIANCE DATE IN THE 2022 DUKE CARBON PLAN PROCEEDING BEYOND 2030?

A. No. In the 2022 Duke Carbon Plan proceeding, the Company and intervenors analyzed several resource plans with Interim Target dates ranging from 2030 to 2034. However, in its Order approving the 2022 Carbon Plan, the Commission declined to select a specific portfolio or approve a delay in the Interim Target date. Instead the Commission's Order focused on near-term actions while suggesting that it was too soon to say whether delaying the Interim Target was necessary, stating: "The Commission finds that, at this time, it is not appropriate to determine whether it is reasonable or necessary to extend the Interim Target compliance date beyond 2030."[1] My interpretation of this language is that, at the time of its 2022 Carbon Plan Order, the Commission viewed a 2030 Interim Target as an achievable target and expected Duke to pursue this Interim Target for future biennial Carbon Plans, and through other actions, absent further Commission guidance.

Q. FROM A PUBLIC INTEREST PERSPECTIVE, WOULD A DELAY IN MEETING THE INTERIM TARGET BE SIGNIFICANT IF THE FINAL 2050 TARGETS ARE ULTIMATELY ACHIEVED?

A. Yes, a delay in the Interim Target would be consequential to the public interest. From a global warming perspective, the primary factor that matters is the *cumulative tons* of CO_2 emissions placed into the atmosphere, not whether a final emissions rate of zero is achieved by 2050. A delay in the Interim Target would increase the cumulative tons of CO_2 emitted, which would remain in the atmosphere for hundreds to thousands of years. Thus, a delay in the Interim Target would exacerbate North Carolina's overall contribution to global warming for generations to come since it would increase the cumulative tons emitted. This increased harm from a delayed Interim Target would still occur even if the 2050 target is achieved on time. For example, comparing the results of Duke's modeled portfolios (P3 Fall Base versus P1 Fall Base), I estimated that a delay in the interim target from 2030 to 2035 would increase cumulative

[1] 2022 Carbon Plan Order, p 19: "Further, as noted above, N.C.G.S. § 62-110.9 creates an Interim Target and provides the Commission flexibility to delay compliance with that Interim Target. The Commission finds that, at this time, it is not appropriate to determine whether it is reasonable or necessary to extend the Interim Target compliance date beyond 2030. The Commission expects Duke to continue to pursue compliance with the Interim Target, including proposing portfolios that comply with the Interim Target in future Carbon Plan proceedings."

emissions by 24%. Additionally, a delay in the Interim Target would extend the public health consequences of criteria pollutants emitted from fossil resources.

Q. DOES DUKE'S 2024 CPIRP PROPOSE TO DELAY THE INTERIM TARGET PAST THE 2030-2032 TIMEFRAME SET FORTH IN THE STATUTE?

A. Yes. Duke's preferred plan in both its initial analysis (P3 Base) and its supplemental analysis (P3 Fall Base) only reach the Interim Target by 2035, which fails to meet the statutory expectations for at least three years, and which is not aligned with my understanding of the statutory guidelines.

Q. DID DUKE CONDUCT ANY SCENARIO ANALYSIS ON RESOURCE PLANS THAT ACHIEVED THE INTERIM TARGET CONSISTENT WITH THE TIMEFRAMES LAID OUT IN STATUTE?

A. Yes. However, the amount of analysis Duke performed on these compliant scenarios was very minimal and pales in comparison to the amount of analysis Duke performed on resource plans that it preferred: those which delayed the Interim Target to dates beyond 2032. More specifically, Duke's initial filing included analysis of 33 resource portfolios, but only 3 of those portfolios reflected an Interim Target prior to 2033. In its final supplemental analysis, only 1 of 7 portfolios evaluated reflects a target prior to 2033. In essence, Duke's overall approach to its CPIRP analysis seems to presume that the Commission will authorize a compliance delay even though this has not yet occurred. Yet the Commission's 2022 Order clearly stated: "The Commission expects Duke to continue to pursue compliance with the Interim Target, including proposing portfolios that comply with the Interim Target in future Carbon Plan proceedings." While it is true that Duke's final (supplemental) analysis included a single portfolio that met the 2030 Interim Target, that is certainly not where Duke has placed its overall emphasis for planning purposes, nor is it supported by any other actions the Company has taken since that Order. In short, it seems that Duke has already "stacked the deck" against selection of a portfolio that meets the Interim Target within the timeframes contemplated by the statute.

Q. ARE YOU AWARE OF ANY OTHER COMMISSION DIRECTIVES RELATED TO THE 2030 COMPLIANCE DEADLINE?

A. Yes. In its January 17, 2024 *Order Scheduling Public Headings, Establishing Interventions and Testimony Due Dates and Discovery Guidelines, Requiring Public Notice, and Providing Direction Regarding Duke's Supplemental Modeling* the Commission required Duke to "file a portfolio that meets the 70% reduction by 2030 along with its planned supplemental modeling."

Q. FOR THE SINGLE SUPPLEMENTAL PORTFOLIO DUKE ANALYZED WITH THE 2030 INTERIM TARGET, DO YOU BELIEVE THE ANALYSIS CONDUCTED WAS ROBUST?

A. No. For example, Duke explains that for its Pathway 1 portfolios (i.e., those with a 2030 Interim Target), it increased the assumed availability of certain resources in its modeling—namely by increasing the amount of solar, wind, and combined cycle gas that could be selected by 2030.[2] However, Duke also explains that "[b]attery and CT availabilities were not increased."[3] Duke's approach of increasing the availability of some resources and not others is inconsistent and inappropriate, and almost certainly skews the model results when comparing Pathways 1 to Pathways 2 and 3. Both batteries and simple-cycle natural gas combustion turbines (CTs) are relatively inexpensive, low-emitting capacity resources that would be ideal for replacing the capacity contribution of accelerated coal retirements under the 2030 Interim Target. Standalone wind and solar resources have relatively small contributions to winter peak demand. Thus, by excluding additional batteries and CTs from consideration, Duke's model becomes overly reliant on more expensive resources for meeting reliability needs during peak demand. This limitation on batteries and CTs would unnecessarily drive up the cost of the P1 portfolios relative to P2 and P3. The cost of over-relying on combined cycle resources in P1 is also exacerbated by the fact that Duke did not even model the availability of Appalachian gas as it did for P2 and P3. There are other deficiencies of Duke's overall analysis that I will elaborate on later.

[2] CPIRP, Chapter 3, p 8-9: "However, reaching the Interim Target by 2030 is not possible using the Companies' already aggressive base case assumptions for new resource availability as discussed in Chapter 2. To enable the capacity expansion model to solve, the Companies found it necessary to substantially increase assumed resource availability for modeling purposes, as explained in Chapter 2 and detailed in Appendix C."
[3] CPIRP, Appendix C, p 49

2. <u>Duke's recent actions have been inconsistent with the Commission's prior expectations for pursuing a 2030 Interim Target (or at least preserving that option)</u>

Q. DO YOU THINK DUKE'S ACTIONS SINCE THE 2022 CARBON PLAN ORDER ARE CONSISTENT WITH THOSE NECESSARY TO ACHIEVE THE 2030 INTERIM TARGET?

A. No. In its Order, the Commission explicitly stated: "The Commission expects Duke to continue to pursue compliance with the Interim Target, including proposing portfolios that comply with the [2030] Interim Target in future Carbon Plan proceedings." However, Duke's actions since this Order have not been consistent with what I would expect if the company were seriously pursuing the 2030 Interim Target (or at least preserving that as an achievable option).

As one example, in DEP and DEC's most recent general rate cases, Duke proposed multi-year rate plans (MYRPs) through the 2026/2027 timeframe. However, *none* of the proposed investments in these MYRPs included specific transmission investments that Duke previously claimed would be required to optimally retire certain coal facilities—investments which would likely be required to meet the 2030 Interim Target.[4] According to Duke, the optimal retirement of the Mayo plant would require the installation of a specific transmission-related piece of equipment known as static VAR compensator

[4] *See* Direct Testimony of Edward Burgess, Docket No. E-7, Sub 1276 at 41-42 (Jul 19, 2023); Direct Testimony of Edward Burgess, Docket No. E-2, Sub 1300 at 31-32 (Mar. 27, 2023).

(SVC), which has a lead time of up to 4 years.[5] Duke's own analysis suggests that this would need to occur before 2029 (i.e., the retirement date of the Mayo plant under the P1 scenario) if the Company were going to achieve a plan consistent with the 2030 target. The fact that no SVC-related investments were included in the MYRP suggests that the Company has not made a serious effort to achieve Mayo's retirement on a timeline aligned with the 2030 target.

Q. DID DUKE'S LACK OF INVESTMENT IN SVC TO RETIRE MAYO CONFLICT WITH THE 2022 ORDER?

A. Yes. The 2022 Carbon Plan Order required Duke Energy to "take appropriate steps to optimally retire its coal fleet on a schedule commensurate with its Carbon Plan proposal filed on May 16, 2022." During the 2022 Carbon Plan proceeding, Duke Energy acknowledged that 2026 was the optimal date for the retirement of the Mayo unit.[6] During the 2022 proceeding, the Company proposed delaying Mayo's retirement to the sub-optimal date of 2029, citing the need for transmission upgrades to be completed. However, as mentioned, these transmission upgrades have not been pursued in a timely manner. Thus, I do not believe Duke took appropriate steps to optimally retire the Mayo plant on the schedule required by the 2022 Order.

Q. COULD DUKE BE SEEKING REPLACEMENT GENERATION AT MAYO (AS AN ALTERNATIVE TO THE SVC TRANSMISSION INVESTMENT) TO ACHIEVE A 2029 RETIREMENT DATE?

[5] *See* Duke Response to AGO DRs 2-10 and 2-11.
[6] 2026 was the optimal retirement date for Mayo in nearly all of the scenarios that Duke analyzed (i.e., P1, P1-A, P2-A, P3, P3-A, P4, and P4-A) except for P2 which showed an optimal retirement in 2028.

A. I don't believe so. If that were the case, the process required to timely place into service that alternative also has not been pursued. As the table below shows, the Generator Replacement Request (GRR) submittal would have needed to occur in 2023 for Mayo to align with a 2029 retirement date. Notably, GRR submittals for Belews Creek 1 and 2 have also not yet occurred and would need to occur this year (2024) to align with a 2030 Interim Target. In summary, it doesn't appear that Duke's recent actions related to coal retirements are consistent with its own analysis on what is necessary to achieve the 2030 Interim Target.

Table AGO DR4-29 - Coal Unit Retirements and GRRs (effective by January 1 of year shown) - *Reference Table F-7 in CPIRP*

Unit	Utility	Winter Capacity (MW)	Effective Year (Jan 1)	
			Pathway 1	GRR Submittal
Belews Creek 1	DEC	1,110	2030	2024
Belews Creek 2	DEC	1,110	2030	2024
Marshall 3	DEC	658	2034	2028
Marshall 4	DEC	660	2034	2028
Mayo 1	DEP	713	2029	2023
Roxboro 3	DEP	698	2030	2024
Roxboro 4	DEP	711	2030	2024

Q. HAS DUKE TAKEN SUFFICIENT STEPS TO UNLOCK SOLAR RESOURCE DEVELOPMENT CONSISTENT WITH THE 2030 INTERIM TARGET?

A. No. While Duke has made some efforts on this front through its Red Zone Expansion Plan (RZEP) process, these efforts have not been sufficient. As shown below, the amount of solar unlocked via RZEP is lower than what is required under the P1 portfolio, and a significant gap still remains for DEC starting in 2029 and DEP starting in 2030. In fact, there is even a gap for meeting the solar additions required for Duke's preferred P3 portfolio, which has a 2035 Interim Target.

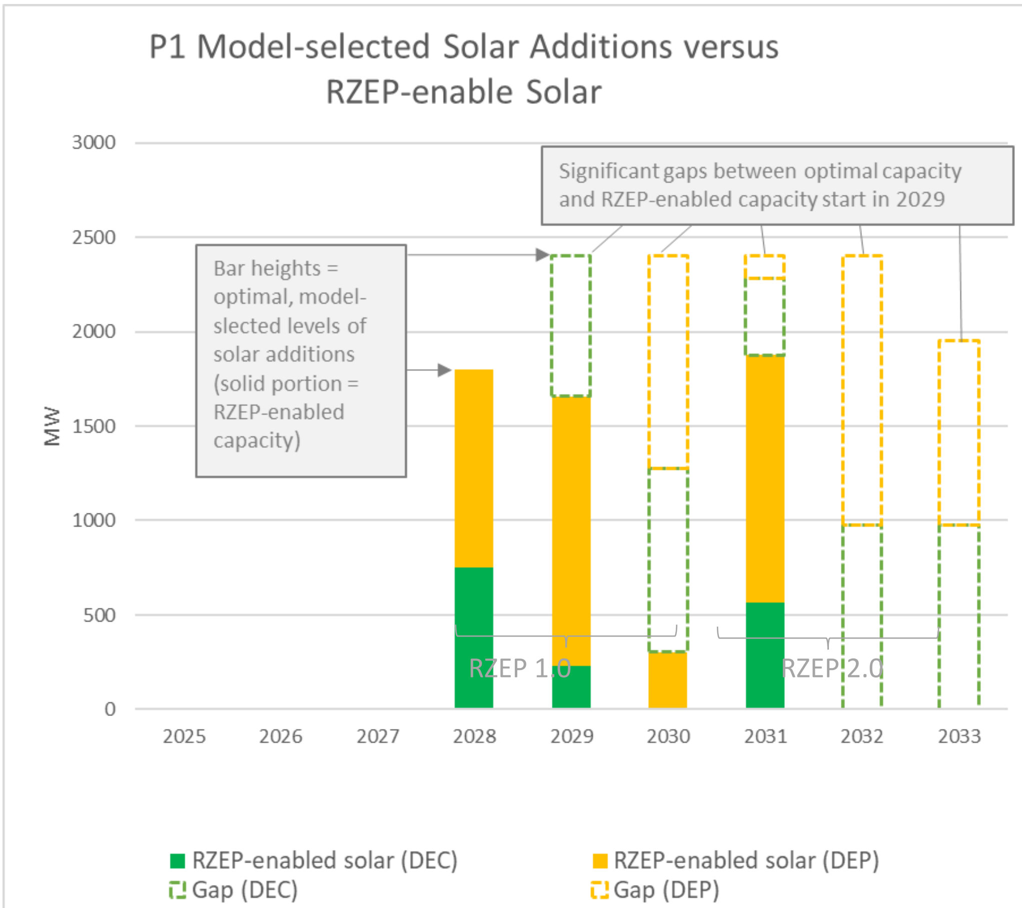

Figure 1. Comparison of Duke's model-selected solar resource capacity additions (in MW) to the amount of solar resources enabled by the RZEP 1.0 and 2.0 projects. The results show that Duke's previous and proposed RZEP projects are insufficient to meet P1, P2, and P3 solar resource additions. Data source is Duke's Response to AGO DR 4-10.

This suggests to me that Duke's RZEP study process, and subsequent investment activities, may not have been sufficiently geared towards identifying the transmission investments necessary to meet even a 2035 Interim Target—let alone the 2030 Interim Target.

Q. ARE THERE OTHER EXAMPLES OF RECENT ACTIONS (OR INACTION) ON DUKE'S PART THAT ARE INCONSISTENT WITH A CONSCIENTIOUS EFFORT TOWARDS PURSUING THE 2030 INTERIM TARGET?

A. Yes, there are several. For instance, in the 2022 Carbon Plan proceeding Duke's planning assumption for onshore wind availability was 2029, whereas it has now been delayed to 2031. In the 2022 Carbon Plan proceeding I presented modeling results on behalf of the AGO suggesting that it would be most cost effective for Duke to *accelerate* the development of onshore wind, ideally to achieve a 2027 online date, rather than delay this activity. The assumed slippage in the development timeframe (i.e., from 2029 to 2031) demonstrates that Duke has not taken a very proactive approach towards pursuing wind as a key component of reaching the 2030 Interim Target. The 2031 availability date for wind also seems contradicted by responses Duke received to its recent Wind RFI from developers suggesting a development timeline as short as [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] years in some cases.[7]

Similarly for solar, in the 2022 Carbon Plan proceeding the AGO presented modeling results (as did other intervenors) suggesting that to meet the 2030 Interim Target, it would be most beneficial to increase the amount of solar PV

[7] Duke Confidential Response to Public Staff (PS) DR 7-8b.

resources procured as part of a near-term action plan, relative to what Duke recommended in that case and has since pursued.[8]

Additionally, as I testified in the DEP and DEC general rate cases, Duke did not initially pursue time-limited federal financing opportunities made available through the Inflation Reduction Act (IRA) that could assist in reducing the cost of accelerating clean energy deployment. For example, reconductoring of transmission lines could allow for significantly greater renewable resource availability consistent with the P1 requirements. Meanwhile, this could be done much more cost-effectively with assistance from the Energy Infrastructure Reinvestment (EIR) program authorized through the IRA. However, the availability of this financing expires in 2026, which will be before the conclusion of Duke's present MYRP investment plan which extends only through 2026. If Duke were seriously pursuing the 2030 Interim Target as required by the 2022 Carbon Plan order, I would have expected the Company to be more diligent in its pursuit of opportunities like the EIR as part of its recently proposed (and Commission approved) MYRP investment plans. Action subsequent to those proceedings may well prove too little too late.

By failing to take obvious and reasonable steps like these over the last 2 years (i.e., steps that would have assisted with achieving the 2030 Interim Target in a

[8] Note that "Rebuttal Table 1" included in the Commission's 2022 Order included incorrect figures for the AGO's Alternative Proposal. In contrast to what the table showed, the AGO's modeling included recommended solar, wind, and battery resource additions that were greater than Duke's modeling.

least-cost manner) Duke has essentially created its own "self-fulfilling prophecy" whereby it has become increasingly more challenging and costly to meet the 2030 target due to Duke's own inaction. This underscores the importance of the Commission providing clear and firm guidance going forward on how Duke should proceed in order to meet the Interim Target.

3. Recent increases in forecasted load growth present new additional challenges but do not require the Interim Target to be delayed until 2035.

Q. ARE THERE FACTORS THAT HAVE EMERGED SINCE DUKE'S INITIAL 2024 CPIRP ANALYSIS THAT MAKE THE 2030 INTERIM TARGET MORE CHALLENGING TO MEET?

A. Yes. There has been a significant upward revision to Duke's load forecast since the initial analysis was performed, which is why Duke opted to conduct a supplemental analysis. This upward revision is attributed to an increase in the anticipated number of new large-load customers including "manufacturers, the electric transportation industry, data centers and advanced cloud computing and blockchain operations."[9] There is no doubt that there has been significant recent growth in these sectors across the US, and this may also be having a material impact on Duke's load forecast. I will discuss my observations and recommendations about how the Commission should evaluate Duke's load forecast below in Section V of my testimony. Setting aside that evaluation for now (i.e., assuming Duke's load forecast revisions are accurate), I acknowledge

[9] CPIRP, Supplemental Planning Analysis, p 3.

that this newly forecasted load growth would—all else being equal—make it more challenging to meet the 2030 Interim Target. However, this does not necessarily mean that a target in line with the statutory guidance is impossible, or that it necessitates a delay to as late as 2035. Instead, I believe a more modest delay (e.g. to 2032) would strike a balance between these increased compliance challenges and the statutory guidelines under HB 951. Further, as I will discuss below, there are various strategies that Duke should be pursuing (but is currently not pursuing) that could help to achieve an Interim Target as close to 2030 as possible.

Q. ARE THERE FINANCIAL INCENTIVES THAT MIGHT MOTIVATE DUKE TO PURSUE A DELAYED INTERIM TARGET, EVEN IF THAT IS NOT IN THE PUBLIC INTEREST OR CONSISTENT WITH STATUTORY GUIDELINES?

A. Yes. I think a very useful example to consider in this context is Duke's proposal, as part of its preferred 2024 Carbon Plan, to replace the Belews Creek coal plant with an advanced nuclear resource in the 2036 timeframe. Under rate-of-return regulation, there is an inherent tendency for investor-owned utilities (such as Duke) to increase the size of their capital investments in order to maximize profits (also known as "capital bias" or the Averch-Johnson Effect). Thus, all else being equal, the more capital-intensive a capacity resource is (i.e., in $/kW) the more attractive it should be to shareholders. In recent years, nuclear resources have tended to be one of the most capital-intensive resources available. The chart below shows some of Duke's assumptions for plant capital costs:

[redacted]

Figure 2. Capital Cost Comparison for resources with generally firm resource adequacy reliability contributions.

Thus, following the basic economic principles of profit maximization, it should come as no surprise if an investor-owned utility like Duke were biased towards the inclusion of a nuclear resource—such as the one planned at Belews Creek—in its resource plan. To be clear, as "clean firm" resources, nuclear units may have an important role to play in meeting the 2050 carbon neutrality target. However, due to the long development cycle of new nuclear technology (i.e., >10 years) it is not at all clear to me that nuclear should play any role at all in meeting the Interim Target. I am concerned that Duke's proposal to delay the

Interim Target to 2035 may be the result of an analysis skewed to "fit in" a nuclear resource at Belews Creek and to link this addition to the Interim Target. I'm even more concerned that Duke's delayed Interim Target comes with significant negative tradeoffs. In this specific example, the delay would mean:

a) deploying fewer cost-effective, clean resources in the near term, some of which may not have as much financial appeal to Duke's shareholders (e.g., demand-side resources, third-party owned solar, etc.),

b) a delay in retiring (or converting) the Belews Creek coal plant in accordance with the model-selected 2030 timeframe. Belews Creek is the largest coal plant in Duke's fleet and its operation alone has a significant influence on when the Interim Target will be met. Any plan that keeps the plant open longer for the sake of allowing a nuclear unit to be built there will almost necessarily push out the Interim Target date.

I also see a similar dynamic for other resources, such as Duke's plan to include a new natural gas combined cycle (CC) resource, with firm fuel supply, replacing coal units at the Roxboro plant. CC units—especially those with carbon capture and storage (CCS), which may be required by the EPA's recent rule—are significantly more capital intensive than other potential capacity resources such as CTs and batteries and are also likely to emit more CO_2 emissions in the near term. Thus, while Duke may have a company preference—and, again, additional capital bias—to add CC units in the 2029 timeframe (i.e., as soon as it would be practicable to do so), this is problematic for meeting a 2030 emissions target and likely contributes to the Company's proposal to delay in the Interim Target.

4. <u>Practical strategies exist for achieving a 2030-2032 Interim Target going forward but were not sufficiently considered by Duke.</u>

Q. IN ITS INITIAL SCENARIO ANALYSIS FOR THE 2024 CARBON PLAN, WHAT WAS DUKE'S RATIONALE FOR DELAYING THE INTERIM TARGET TO 2035 VERSUS PURSUING A PLAN WITH A 2030 INTERIM TARGET?

A. Duke claimed that the resource additions required under a 2030 Interim Target (i.e., "Pathway 1") "exceeds Duke Energy's expectations for what will be available and possible to connect without jeopardizing system reliability."[10] However, I am not persuaded that Duke's analysis fully explored all possible options or strategies that could have assisted with meeting a 2030-2032 Interim Target while maintaining reliability—even after considering some of the practical limitations that Duke describes. In other words, I believe that Duke left many stones unturned in its effort to identify a pathway that meets a 2030-2032 Interim Target, and there exists a set of practical strategies that could reasonably allow the Company to adhere to this timeline (or at least something close to it), many of which may also reduce costs for Duke customers.

[10] CPIRP, Chapter 3, p 9.

Q. WHAT OTHER STRATEGIES COULD DUKE HAVE EXPLORED IN ITS ANALYSIS TO ACCELERATE THE INTERIM TARGET IN A MANNER THAT IS REASONABLY ACHIEVABLE?

A. There are several practical strategies that Duke's CPIRP analysis could have explored in greater detail. In aggregate, these strategies may well be sufficient to accelerate the Interim Target closer to the statutory requirement of 2030 (rather than delaying it to 2035 as Duke has proposed). I elaborate on these strategies throughout the remainder of my testimony, however, I will briefly list a few of those practical strategies here now:

- **Accelerating coal retirements** towards 2030 by:
    1. Allowing greater availability of CTs and batteries as on-site capacity replacement options,
    2. Allowing off-site replacement (which can be competitively procured) in conjunction with any necessary transmission investments,
    3. Staggering individual unit retirements, and
    4. Conducting a more robust evaluation of gas conversion at Belews Creek prior to 2030.
- **Increasing generation output from renewable resources** in the near-term (i.e., solar and onshore wind prior to 2030) even under Duke's proposed interconnection constraints by:
    1. Pursuing additional transmission enhancements that can increase solar availability,

2. Pursuing additional hybrid resource configurations and/or pursuing flexible or “energy only” interconnection options,
3. Accelerating Carolinas onshore wind procurement,
4. Procuring imported onshore wind through the use of dynamic transfers,
5. Procuring offshore wind as soon as practicable.

- **Scaling up novel, customer-centric load management solutions** that leverage recent market developments and could minimize the need for new CO_2-emitting CC plants.
- **Prioritizing batteries and/or CT additions** in lieu of riskier CC additions for providing firm capacity.
- **Exploring additional Interim Target dates** (i.e., 2031 or 2032) that offer some additional flexibility, while remaining within statutory guidelines. Notably, none of Duke’s analyses explored Interim Targets with a 2031 or 2032 timeframe.

B. In the Company's preferred pathway (P3), significant coal retirements are delayed past 2030, thus precluding an Interim Target aligned with the statutory guidance. However, Duke's analysis did not consider practical strategies for achieving earlier retirement dates.

1. <u>Earlier retirements for Belews Creek and Roxboro may be a critical path for achieving an Interim Target in line with the statutory guidance.</u>

Q. HOW DO COAL PLANT RETIREMENT DATES DIFFER BETWEEN THE COMPANY'S FINAL PREFERRED PLAN, AND THOSE THAT THE MODEL SELECTED UNDER THE P1 SCENARIOS (I.E., THE SCENARIOS COMPATIBLE WITH THE 2030 INTERIM TARGET)?

A. The table below shows a comparison of the retirement dates ultimately included in Duke's preferred P3 portfolio[11] with the retirement dates selected by the model under the P1 portfolio.[12] Units with delayed retirement dates are **bolded**. It is important to note that Duke's preferred plan assumes significant delays in the retirements of several coal plants including Belews Creek 1 and 2, Cliffside 5, Mayo 1, and Roxboro 3 and 4. This almost certainly precludes the option for the Company to pursue an Interim Target in the 2030 timeframe.

[11] Notably the P3 Fall Base portfolio has nearly identical retirement dates to the P3 Base portfolio. As Duke notes on page 34 of its Supplemental Analysis, the only difference is that it switched the retirement dates of Roxboro units 2 and 4.

[12] Duke did not conduct a Supplemental Coal Retirement Analysis for the P1 or P2 portfolios. *See* Duke Response to AGO DR 8-4 (attached as Burgess Direct Exhibit 5).

Table 1. Comparison of optimal coal unit retirement dates under a 2030 Interim Target (P1) versus Duke's proposed 2035 Interim Target (P3 Fall Base).

Plant	Unit	Utility	MW	P1 Base - Model Selected	P3 Base/Fall Base – Final
Belews	1	DEC	1,110	2030	**2036**
Belews	2	DEC	1,110	2030	**2036**
Cliffside	5	DEC	546	2029	**2031**
Cliffssde	6	DEC	849	2049	2049
Marshall	1	DEC	380	2029	2029
Marshall	2	DEC	380	2029	2029
Marshall	3	DEC	658	2034	2032
Marshall	4	DEC	660	2034	2032
Mayo	1	DEP	713	2029	**2031**
Roxboro	1	DEP	380	2029	2029
Roxboro	2	DEP	673	2029	2029
Roxboro	3	DEP	698	2030	**2034**
Roxboro	4	DEP	711	2030	**2034**

While there are delays at Cliffside 5 and Mayo 1 (i.e., retirement by 2031), these still fall within the 2030-2032 timeframe, which is consistent with the statutory guidelines. The most consequential delays are those at the Belews Creek plant and two of the units at the Roxboro plant. Not only are these units large in terms of their CO_2 emissions contributions, but these delays would extend beyond 2032, which is the outer bound of the statutory guidance for achieving the Interim Target. The table below summarizes the annual CO_2 emissions from these two plants. Notably, the annual emissions from these plants are of a similar order of magnitude to the total emissions difference between P3 and P1 in 2030.[13] Thus, options that enable the retirement of Roxboro and Belews Creek by 2030 (or close to it) are likely part of the critical path for achieving an

[13] *See* Table C-69, which shows a roughly 15% difference between P1 and P3 in 2030.

Interim Target in the 2030-2032 timeframe. Instead, Duke's plan for these sites includes long lead-time projects (i.e., advanced nuclear and multiple CC units with firm pipeline supply) which will be in development well past 2032, and thereby preclude the earlier retirements needed to meet a 2030-2032 Interim Target.

Table 2. Comparison of CO_2 emissions from Roxboro and Belews Creek plants versus NC-required emissions reduction targets.

Emissions Source	**2022 Annual CO_2 Emissions, tons (Source: EIA)**	**% of Baseline Emissions**
Roxboro (all units)	6,107,413	7%
Belews Creek (coal)	3,159,148	4%
Belews Creek (gas)	3,532,888	4%
Total (Roxboro + Belews)	12,799,449	15%

2005 Baseline Emissions Level	83,028,677	100%
Reduction Required	58,120,074	70%
Interim 70% Emissions Target	24,908,603	30%

Table C-69: Annual Combined DEC and DEP NC CO_2 Emissions Reduction in 2030, Interim Target Year, and 2038 (Percent reduction relative to 2005)

	2030	Interim Target Year	2038
P1 Base	70.4%	70.4%	85.1%
P2 Base	55.9%	70.4%	81.1%
P3 Base	55.8%	70.6%	78.6%

Q. WOULD COAL RETIREMENTS IN THE 2030-2032 TIMEFRAME REDUCE DUKE'S RISK REGARDING FEDERAL REGULATIONS?

A. Yes. On May 9, 2024, the EPA finalized its Standards and Guidelines for Fossil Fuel-Fired Power Plants under Section 111. If these rules withstand pending legal challenges, they will require existing coal plants to significantly reduce emissions. However, coal plants that plan to cease operations by 2032 are exempt from these requirements.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF DUKE'S APPROACH TO SELECTING COAL RETIREMENT DATES IN THIS PROCEEDING?

A. Duke's approach appears geared towards ensuring that specific Duke-preferred—Company-owned, on-site, supply-side—replacement resources are included in the final resource plan (and the near-term action plan), some of which may have been more or less predetermined by Duke's actions or inaction. This includes CC plants at Roxboro, CT units at Marshall, and advanced nuclear at Belews Creek.

Q. ARE THERE SUPPLY-SIDE ALTERNATIVES TO THESE REPLACEMENT OPTIONS THAT YOU THINK WERE NOT SUFFICIENTLY CONSIDERED?

A. Yes. As described earlier, I don't think that there was sufficient consideration of CT and battery resource options as inexpensive capacity replacements for retiring coal, particularly in the P1 portfolios. Additionally, I don't think there was a sufficiently robust evaluation of off-site replacement generation, staggered unit retirements, or converting Belews Creek to natural gas.

2. <u>Practical strategies for accelerating retirement of coal units at Belews Creek and Roxboro (while maintaining resource adequacy) were not sufficiently considered.</u>

a) *Duke's analysis was inadequate in not considering additional batteries and/or CTs as on-site capacity replacement options for Belews Creek and Roxboro by 2030*

Q. DID DUKE CONDUCT ANY SPECIFIC ANALYSIS ON THE POTENTIAL FOR ACCELERATING COAL RETIREMENTS TO THE 2030 TIMEFRAME BY USING ADDITIONAL CTS AND/OR BATTERIES AS CAPACITY REPLACEMENTS?

A. Only in a very limited sense. As I described earlier, Duke's P1 analysis, which is aligned with the 2030 Interim Target, includes 2030 retirements at Roxboro and Belews Creek; however, the Company significantly (and unnecessarily) constrained the availability of batteries and CTs to serve as capacity replacement resources. It is not as if this type of replacement is unfeasible, in fact, Duke's own preferred plan includes CT replacement of coal resources at the Marshall plant in the 2029 timeframe and battery resources at the Allen plant retiring at the end of 2024.

Given this "pick-and-choose" manner of highlighting the availability of these resources for its preferred portfolio, but minimizing such for the P1 analysis, it is very concerning that Duke constrained the availability of batteries to serve in this replacement role for two reasons. First, Duke's modeling applies a blanket assumption that only [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of batteries receive the "energy communities" bonus tax credit, and weighs these resource costs accordingly.[14] However, in the case of coal plant replacements, 100% of these resources would almost certainly receive the bonus credit. If this more accurate 100% assumption were used at retiring coal locations, these battery projects would be more likely to be selected as replacement resources in Duke's modeling. Second, this may be the last CPIRP cycle where specific federal financing opportunities are available that could significantly reduce costs to customers. As I described earlier, the EIR program could be leveraged to reduce the costs of such a replacement, but only if specific commitments are made by 2026. Highlighting this very point, the director of this program details such a hypothetical replacement in the article linked in the footnote below.[15] By failing to examine this option, Duke may be missing out on a once-in-a-decade opportunity to save millions for its customers. Moreover, resources like batteries and CTs, which generally run for limited durations, are extremely well suited as capacity replacements for Duke's coal fleet. That is because, in recent years, many of Duke's coal plants have operated with relatively low capacity factors and are more akin to "peaker plants" than baseload units. Below are the percentages of time these units are expected operate in 2024 according to Duke's P3 Fall Base analysis:

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[14] Duke Confidential Response to AGO DR4-15; Duke Response to Public Staff DR 7-15.

[15] Jigar Shah, *Tapping into DOE's $250B of loan authority for projects that reinvest in US clean energy infrastructure* (July 6, 2023), https://www.utilitydive.com/news/department-of-energy-doe-250-billion-loan-authority-solar-wind-storage-nuclear-clean-energy/653530/.

Table 3. Model-estimated Capacity Factors for Duke's Coal Generation Units

Generation Unit	Capacity Factor
Belews Creek 1 (coal)	17.73
Belews Creek 1 Cofire (gas)	37.78
Belews Creek 2 (coal)	22.42
Belews Creek 2 Cofire (gas)	30.35
Cliffside 5 (coal)	1.64
Cliffside 5 Cofire (gas)	0.28
Cliffside 6 (coal)	8.05
Cliffside 6 Cofire (gas)	18.90
Marshall 1 (coal)	10.11
Marshall 2 (coal)	1.07
Marshall 3 (coal)	5.47
Marshall 3 Cofire (gas)	39.96
Marshall 4 (coal)	6.98
Marshall 4 Cofire (gas)	39.10
Mayo 1 (coal)	2.91
Roxboro 1 (coal)	20.51
Roxboro 2 (coal)	33.10
Roxboro 3 (coal)	26.37
Roxboro 4 (coal)	13.41

b) Duke's analysis did not sufficiently consider off-site replacement options for these resources.

Q. ARE THERE POTENTIAL ALTERNATIVES THAT COULD BE DEVELOPED ON A FASTER TIMELINE THAN THE ON-SITE REPLACEMENT GENERATION DUKE HAS PROPOSED FOR BELEWS CREEK AND ROXBORO?

A. Yes. Standalone storage, or solar plus storage, located anywhere on Duke's system could likely be developed well before any advanced nuclear unit. Even a simple cycle CT (at any location) would theoretically have a faster development timeframe than the CC with firm transportation fuel supply being contemplated at Roxboro (which may now be subject to new EPA rules that would also require CCS). However, as described further below, Duke did not consider these off-site alternatives in its CPIRP.

Q. COULD THERE BE OTHER ADVANTAGES TO OFF-SITE REPLACEMENT?

A. Yes. Such consideration would open up the options for resource replacement to a wider pool of resources and potentially allow for competitive procurement. In contrast, Duke's approach completely fails to consider allowing other entities to utilize the available interconnection space at the retiring facility.[16] In the case of Belews Creek, an off-site replacement strategy could allow Duke to retire Belews Creek on a timeline required to meet the Interim Target by 2030 to 2032, while still preserving the option of an advanced nuclear resource to be added at a later date.

Q. WOULD RETIREMENT OF COAL UNITS WITHOUT ON-SITE REPLACEMENT GENERATION LEAD TO THE NEED FOR TRANSMISSION UPGRADES?

A. According to Duke that is the case. This is the Company's proposal for the Mayo plant.

Q. WOULD OFF-SITE REPLACEMENT GENERATION SOLUTIONS BE COST EFFECTIVE, EVEN IF TRANSMISSION COSTS WERE INCLUDED?

[16] *See* Duke Responses to AGO DR 4-17 and AGO DR 4-22 (attached as Burgess Direct Exhibits 14 and 15).

A. Possibly. However, Duke did not even evaluate this possibility at any of its retiring coal plants except for Mayo.[17] Duke simply presumed its preferred on-site replacement was the most cost-effective option, and its modeling assumptions presumed on-site replacement at Marshall, Roxboro, and Belews Creek, even though off-site replacement (with transmission upgrades) is technically feasible.[18] In one case, Duke even went so far as to identify specific transmission projects that could allow for off-site generation replacement at Roxboro but made no attempt to estimate the cost of those transmission projects or further evaluate that possibility.[19]

c) Duke's analysis did not sufficiently consider staggering coal unit retirements more gradually over time.

Q. DID DUKE'S MODELING ALLOW FOR EACH COAL UNIT TO BE RETIRED INDEPENDENTLY, THEREBY ALLOWING A MORE FLEXIBLE, STAGGERED APPROACH?

A. No. Duke's modeling inappropriately tied certain units together, allowing them only to be retired as a group. This was the case at the Belews Creek, Marshall, and Roxboro plants. By definition any additional constraint added to the EnCompass model—including one like these unit groupings—will only increase the cost of the final result.

[17] *See* Duke Responses to AGO DRs 2-8 (attached as Burgess Direct Exhibit 6), 4-16, 4-18, 4-19, 4-21.
[18] Duke Response to AGO DR 2-8c.
[19] *See* Duke Response to AGO 4-23 (attached as Burgess Direct Exhibit 7).

In response to AGO DR 4-30, attached as Burgess Direct Exhibit 2, Duke attempted to provide a rationale for this modeling choice, explaining that the retirement of individual units would mean that staff and equipment would be "less efficiently optimized across stations." But that rationale is not compelling because the overall cost savings of retiring a single unit (including both capital and operating costs) may well exceed any localized efficiencies. Additionally, Duke's response admits that "The Companies have not performed quantitative cost analysis associated with select units retiring together compared to retiring independently." It is a common practice within the industry to consider the economics of coal units individually, and it is common practice in planning efforts to stagger individual unit retirements over time to allow more time and flexibility for replacement generation to come online. Individually staggered retirements would create more degrees of freedom, allowing for more practical and gradual replacement pathways (which could reduce overall costs), but also more options for meeting the Interim Target.

d) Duke's analysis of Belews Creek gas conversion includes some problematic assumptions. This option is worth further consideration.

Q. DID THE COMMISSION'S INITIAL CARBON PLAN ORDER ADDRESS THE CONVERSION OF BELEWS CREEK TO RUN ON NATURAL GAS?

A. Yes. The Commission's initial Carbon Plan order stated: "The Commission would benefit from additional review of such topics and others associated with the potential for fuel source conversion and directs Duke to re-study the potential costs and benefits of a further conversion of Belews Creek as part of its upcoming proposed biennial CPIRP."[20]

Q. WHAT ANALYSIS DID DUKE CONDUCT ON CONVERTING BELEWS CREEK TO GAS AND WHY DO YOU THINK IT WAS INSUFFICIENT?

A. Duke's analysis of this option was limited to a single variant of the initial P1 Base portfolio. However, even this limited analysis reveals information that warrants further consideration—particularly because of the outsized impact Belews Creek has on meeting the Interim Target. More specifically, the initial cost to convert the units is quite inexpensive compared to potential alternatives. The present value revenue requirement (PVRR) cost to convert the units is only [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] which compares favorably to investment in new gas generation capacity.[21] For example, Duke reports that the fixed costs of a new CC unit will be nearly [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in PVRR terms.[22] Under a scenario where the plant retires from coal in the 2030-32 timeframe, this would appear to be a viable option for securing approximately 1,110 MW of net firm capacity, and potentially displace the need to construct a similar amount of new CC resources.[23] However, Duke dismisses this option due to significant other costs the Company assumes will be incurred in conjunction with this conversion (which I will elaborate on below). Some of

[20] Initial Carbon Plan Order at 65.
[21] Duke Confidential Response to AGO DR 4-20 (attached as Burgess Direct Exhibit 8).
[22] Duke Confidential Response to AGO DR 8-1 (attached as Burgess Direct Exhibit 9).
[23] Notably 1,110 MW exceeds the deliverable capacity of the proposed CC plant at Roxboro.

the key assumptions Duke used in this analysis unfairly downplay gas conversion as a viable and cost-effective option. Duke may be motivated to provide analysis that is unfavorable for gas conversion since that solution might call into question Duke's preference of operating the plant on coal through 2036, even if gas conversion was better for its customers' costs and meeting the Interim Target sooner.

Q. WHAT ASSUMPTIONS DO YOU THINK WERE PROBLEMATIC IN DUKE'S ANALYSIS OF BELEWS CREEK GAS CONVERSION?

A. The table below summarizes some of the costs and benefits Duke identified in its analysis of the P1 Belews Creek conversion portfolio relative to the P1 Base portfolio. Notably, the cost to convert the unit is only [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] (in PVRR terms), compared to the fixed cost of a new CC plant which Duke reports would be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[24]

Table 4. Summary of Duke's Estimated Costs and Benefits for Belews Creek Gas Conversion

Cost Category	[redacted]
Production cost (benefit)	[redacted]
Cost to convert the unit	
Cost to maintain the capacity to 2041	
Cost to contract for firm fuel supply to 2045	
Economic Carrying Cost (benefit)	
Transmission Cost (benefit)	
PTC/ITC Changes	
Sum	

[24] Burgess Direct Exhibit 9.

Of particular concern are Duke's assumptions regarding the cost to maintain the capacity to 2041, and the cost to contract for firm fuel supply, both of which are problematic and make up the vast majority of the cost difference. First, regarding the cost to maintain capacity, this is largely a function of the 2040 ultimate retirement date selected by Duke. If an earlier retirement date were selected for the gas resource (e.g., 2035) these costs could be significantly reduced. This oversight is especially concerning given that the Commission's initial Carbon Plan order noted that Duke's evaluation in that case did not consider "whether Duke might justify the additional fuel source conversion at Belews Creek as an interim or bridge to a time when Duke could bring fully hydrogen-capable CT or CC generating units online, as an alternative to investing in new natural gas generating units now and then later incurring costs to convert those units to a zero-carbon fuel source."[25]

Second, regarding the cost to contract firm fuel supply, Duke selects a contract term through 2045, which is beyond the assumed life of the plant. A shorter contract term would have a lower cost. It is not clear to me why a contract term well beyond the useful life of the plant was used. Furthermore, Duke's assumption that firm fuel supply must be secured for Belews Creek is at odds with the Company's general practice towards the rest of its gas resource fleet. Notably, Duke's historical planning practices have not required the majority of its gas fleet to secure firm transportation. As such, the claim that FT is required

[25] Initial Carbon Plan Order at 65.

for the Belews Creek gas conversion is inconsistent with past practice. If Duke treated the Belews Creek conversion similarly to other gas resources in its current fleet (i.e., if it assumed FT was not required), then the PVRR of this scenario would be reduced by approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] (which is approximately equal to the entire cost differential identified in Table C-59).

Table C-59: Pathway 1 – Portfolio Variant Present Value 2038 and 2050 Relative to P1 Base ($B)

	PVRR Through 2038		
	DEC	DEP	CAR
P1 Belews Creek Gas	2.0	-0.1	1.9

Finally, the Economic Carrying Cost benefit may be undervalued. In comparing the P1 Base model run to the P1 Belews Creek 100% variant, it appears that the gas conversion only deferred about 425 MW of CT resources, and no CC resources were deferred. This may simply be an artefact of how certain model assumptions are calibrated (e.g. the size of CC resource assumed), when in reality conversion would be able to defer a similarly sized CC resource. This would also have the effect of reducing the FT costs of the deferred CC resource, which could yield significant additional benefits.

Given some of these observations, I recommend that the Commission require Duke to further evaluate and potentially implement a gas conversion option at Belews Creek that has a much more limited duration.

C. Duke's modeling assumptions for the availability of clean resources are incompatible with a 2030 Interim Target. These assumptions do not adequately reflect practical options for accelerating and increasing renewable energy output by the late 2020s.

1. <u>Duke's modeling assumptions severely limit "critical path" wind and solar resources.</u>

Q. IN ADDITION TO COAL RETIREMENTS, WHAT OTHER KEY STEPS DID DUKE FAIL TO TAKE THAT ARE NECESSARY TO MEET THE INTERIM TARGET IN THE STATUTORY TIMEFRAME?

A. To meet the interim target in the statutory timeframe, it will be necessary to procure significant amounts of already commercialized clean energy resources—particularly solar and onshore wind—between 2028 and 2032. I would characterize these as "critical path resources." Unfortunately, Duke's modeling includes assumptions that specifically disadvantage these critical-path resources (i.e., 2020s wind and solar) in terms of cost and availability. I'm concerned that the Company's approach is unreasonable and may be intended to portray a result suggesting that a 2030-2032 Interim Target as represented by P1 is infeasible or too costly.

Duke's modeling assumptions disadvantage these critical path resources in two key ways. First, Duke includes a 20% "cost risk premium" that is solely applied to resources in the P1 portfolio. Second, Duke assumes resource availability limits for wind, solar, and batteries that prevent the addition of those resource which would otherwise have been selected by the EnCompass model.

Q. DO YOU THINK DUKE'S 20% COST RISK PREMIUM ASSUMPTION IS A FAIR OR REASONABLE TO APPLY TO NEAR-TERM SOLAR AND WIND ADDITIONS?

A. No. While there have been some recent inflationary pressures due to supply chain issues for all resources, these are largely being worked through and should not persist into the late 2020s. Solar and wind equipment are globally manufactured, commoditized products whose prices are unlikely to be responsive to a modest increase in demand from a single utility (i.e., Duke). While there may be some range in project bid prices during any individual procurement cycle, it is unreasonable to apply a blanket 20% increase to all project costs, in all years in P1. Even if it were reasonable to include a cost risk premium for near-term resources, that cost risk premium should be applied to all portfolios.

Q. ARE THE COSTS OF P1 POTENTIALLY EXAGGERATED IN OTHER WAYS?

A. Yes. P1 contains larger and earlier deployments of renewable resources and battery storage. However, the assumed costs of these resources may be overstated. The Company used a variety of sources when determining the cost of renewable resources and energy storage, primarily using studies produced by Burns & McDonnell, Guidehouse, the Electric Power Research Institute, and internal company data.[26] The capital costs listed in Table E-2: Generic Unit Overnight Technology Capital Costs[27] and provided in discovery likely overstate the cost of renewable energy resources and energy storage.[28] The projected capital costs differ markedly from established and publicly available data sources, such as the National Renewable Energy Laboratory's (NREL) Advanced Technology Baseline (ATB).

Q. CAN YOU SUMMARIZE THE NEAR-TERM AVAILABILITY LIMITS DUKE HAS ASSUMED AND WHY YOU THINK THEY ARE UNREASONABLE?

A. Yes. The table below shows how the limits of new resources compare during this critical path period, under Duke's base modeling assumptions:

Table 5. Assumed Resource Availability Limits included in Duke's Model.

Annual Limits by year (MW)	Solar	Onshore Wind (Carolinas)	Onshore Wind (Imported)	Offshore Wind	CC	CT	Batteries
2027	0	0	0	0	0	0	200
2028	1,350	0	0	0	0	0	500
2029	1,350	0	0	0	1,360	4,250	500
2030	1,350	0	0	0	2,720	4,250	1,000
2031	1,575	300	0	0	2,720	4,250	1,000
2032	1,575	450	0	0	1,360	4,250	1,000
Cumulative Limit by 2032	7,200	750	-	-	8,160	17,000	4,200

[26] *See* CPIRP, Appendix E at Page 7.
[27] *See* CPIRP, Appendix E at Page 12.
[28] Duke Confidential Response to PS DR 26-1.

According to these assumed limits that Duke has specified, it is actually impossible for the model to select a resource plan that would meet a 2030-2032 Interim Target. This is partly because Duke has included relatively few energy generating resource options—except for carbon emitting resources such as CCs and CTs—in its model until after 2030. Based on the resource additions included in SPA T-8, I estimate that the total incremental clean energy needed to meet the Interim Target around the 2030 timeframe would be approximately 41,277 GWh.[29] Meanwhile, the most that could be achieved under the limits prescribed by Duke in its base assumptions would be 9,579 GWh by 2030 (and 18,803 by 2032). However, I don't believe that Duke's analysis, and the limitations therein, have appropriately accounted for several practical strategies that could increase the MWh output from wind and solar in the near term as a means to achieve the approximately 41,000 GWh needed to reach the Interim Target (under the revised load forecast).

2. <u>Practical strategies for increasing near-term solar and wind energy output by the 2030-2032 timeframe were not adequately represented in Duke's analysis.</u>

Q. WHAT ARE SOME OF THE PRACTICAL STRATEGIES DUKE'S ANALYSIS MAY NOT HAVE ACCOUNTED FOR?

A. There are several near-term actions that Duke could take to accelerate near-term, supply-side clean energy deployment in support of achieving an Interim

[29] Based on 12,825 MW of solar at 27% capacity factor, 1,050 MW onshore wind at 27% capacity factor, and 2,400 MW offshore wind at 40% capacity factor.

Target aligned with statutory guidance. I will briefly list a few of those actions here before elaborating on each of them further:

1) Increase solar MW availability through transmission enhancements,
2) Increase solar output (MWh) per MW of interconnection using a hybrid resource configuration and/or “energy only” interconnection,
3) Accelerate Carolinas onshore wind procurement by 1 to 2 years,
4) Procure imported onshore wind using “dynamic transfers” (i.e., non-firm transmission),
5) Procure offshore wind as soon as practicable,
6) Pursue incremental customer-side resources, above what was included in the initial filing.

Q. DO YOU THINK THAT THESE SIX ACTIONS, IN COMBINATION, COULD ALLOW DUKE TO ACHIEVE AN INTERIM TARGET IN THE 2030 TO 2032 TIMEFRAME, EVEN WITH THE COMPANY’S UPDATED LOAD FORECAST?

A. Yes. I believe if all of these actions were pursued, Duke could achieve a 2032 Interim Target, or at least be within striking distance. Below is an illustration of a potential pathway that reflects these actions and achieves a total amount of clean energy in line with Duke’s P1 Fall Base portfolio.

Table 6. AGO's Illustrative Compliance Pathway for the Interim Target compared to Duke's Estimated Needs for Clean Energy under P1 (in MWh).

P1 Fall Base (Supplemental)						
MW Total	**Solar**	**Onshore Wind (Carolinas)**	**Onshore Wind (Imported)**	**Offshore Wind**	**Incremental DSM/EE**	**Total Clean**
MW by 2030	12,825	1,050	0	2,400	0	
Capacity Factor	27%	27%	-	41%	N/A	
GWh	30,334	2,483	-	8,410	-	41,227
AGO Conceptual Illustration of an Interim Compliance Pathway						
MW by Year	**Solar**[30]	**Onshore Wind (Carolinas)**[31]	**Onshore Wind (Imported)**[32]	**Offshore Wind**[33]	**Incremental DSM/EE**	**Total Clean**
2027	0	0	0	0	0	
2028	1,350	0	0	0	100	
2029	1,800	300	150	0	100	
2030	1,800	450	150	0	100	
2031	2,100	450	150	0	100	
2032	2,100	450	150	1,600	100	
Sum by 2032 (MW)	9,150	1,650	600	1,600	500	
Capacity Factor	35%	27%	30%	41%	50%	
GWh	28,461	3,903	3,679	5,606	2,190	41,470

Q. COULD YOU PLEASE ELABORATE ON EACH OF THE SIX STRATEGIES YOU LISTED ABOVE?

A. Yes.

[30] *See* Strategies 1 & 2.
[31] *See* Strategy 3.
[32] *See* Strategy 4.
[33] *See* Strategy 5.

a) *Increase solar MW availability through transmission enhancements.*

One of the primary rationales the Company cites for limiting the amount of solar available in the near term is transmission interconnection availability. The main approach Duke has taken to date to address this limitation is to identify Red Zone Expansion Plan (RZEP) transmission upgrade projects, and to implement these in an iterative fashion. In this planning cycle, the RZEP 2.0 projects are introduced. While the RZEP projects are necessary and helpful to allow for increased availability of solar resources, there are additional enhancements to Duke's transmission system that the Company can and should be pursuing to unlock greater renewable resource availability. Some of these were outlined in my testimony in DEP and DECs last general rate cases (GRCs). I discuss these enhancements in greater detail below in Section VI of my testimony. If successfully implemented, I believe these can assist Duke in achieving solar resources closer to the "High Availability" scenario.

b) *Target solar procurement towards resources that can increase energy output (MWh) per MW of firm interconnection space by using an oversized hybrid resource configuration and/or "energy only" interconnection.*

As described above, Duke claims that one of the main barriers to increasing renewable energy in the near term is the limitation on transmission interconnection availability. In other words, there is a limited amount of solar capacity (i.e., MW-ac) that can be practically connected to the bulk transmission system in each year due to the need for additional transmission system upgrades.

Duke cites these interconnection limits to justify keeping annual solar additions to just 1,350 MW-ac per year in its preferred case. Given these limits and their impact on achieving the Interim Target, it is reasonable to consider strategies that can either increase the amount of solar energy generated per MW of firm interconnection space or avoid the need for transmission upgrades altogether. Indeed, it is technically possible to increase the total energy output (MWh) for each MW of firmly interconnected solar resource depending on the configuration or type of interconnection.

There are two potential ways this might be accomplished. Both approaches would go beyond what Duke's modeling assumes and would increase the overall MWh output of solar resources, even under the strict annual MW limits Duke uses. First, the amount of MWh delivered per MW of resources could be significantly enhanced by using an "oversized hybrid" configuration that significantly increases the MW-dc capacity of the solar panels behind the point of interconnection and uses storage to capture a significant amount of the energy that would otherwise be curtailed. Duke's standard assumption for solar plus storage resource output is a 27% capacity factor (per MW-ac), I have conducted analysis on a hypothetical NC-specific solar resource and found that an "oversized hybrid" configuration could increase this value to 35%. Targeting this type of resource in Duke's procurement activities could theoretically increase the portfolio total of solar energy delivered (in MWh) in 2032 by 30%, without changing the annual limits on MW-ac solar additions that Duke has assumed. An illustration is provided below:

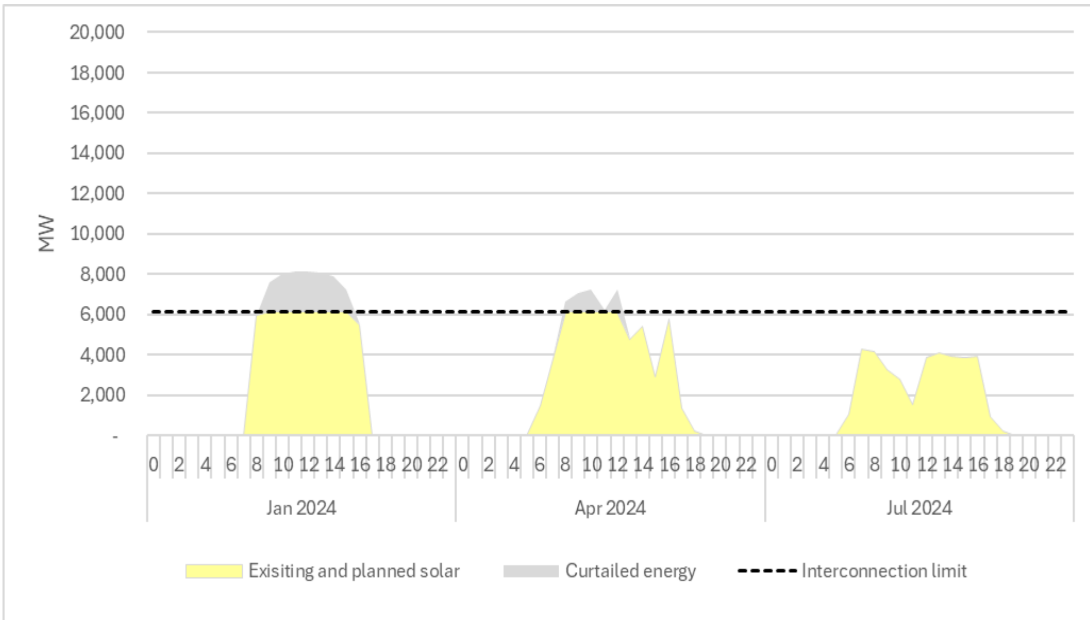

Figure 3. "Business As Usual" Approach to planning and procuring solar PV resources. Overall energy output is limited based on MW interconnection limit (black dashed line) unless transmission upgrades are timely achieved. In this illustration a 27% capacity factor is illustrated for a hypothetical NC solar resource.

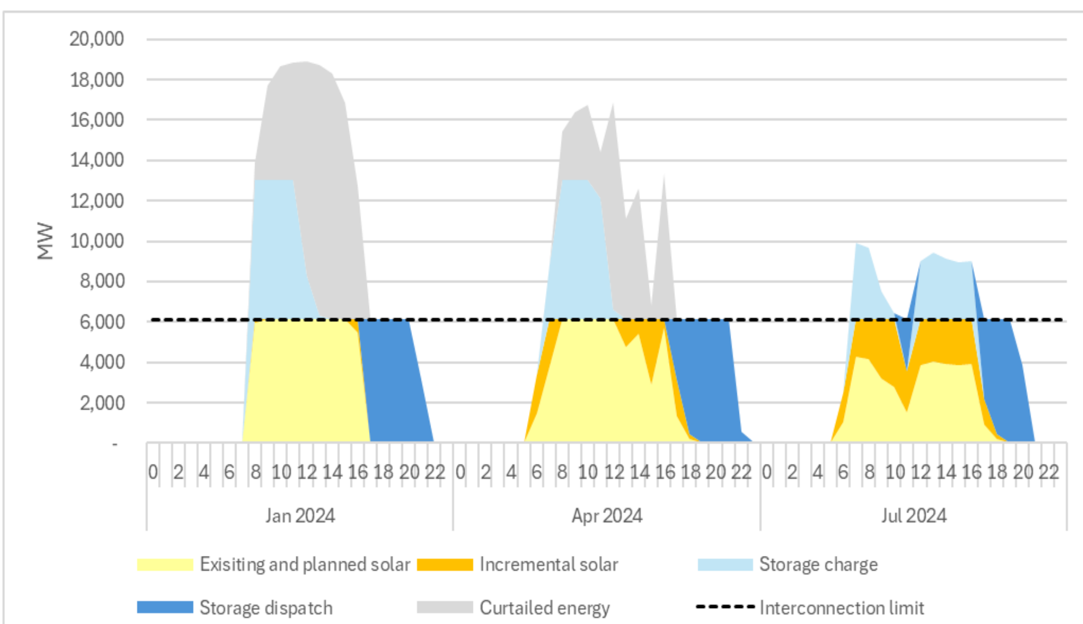

Figure 1. Novel approach to planning and procuring solar PV resources, targeting an "Oversized Hybrid" configuration. Overall energy output increases significantly. In this illustration a 35% capacity factor is illustrated

for a hypothetical NC solar resource, representing an 30% increase in MWh output relative to the "Business As Usual" approach, without needing to wait for lengthy transmission upgrades.

Q. WHAT IS YOUR SECOND PROPOSED METHOD FOR INCREASING OVERALL SOLAR ENERGY OUTPUT GIVEN DUKE'S ASSUMED INTERCONNECTION LIMITS?

A. Another method for increasing the output of solar resources given severe interconnection limits would be to require Duke to modify its general approach to interconnection to allow for a more flexible, or "energy only" interconnection process (sometimes referred to as "connect and manage," Energy Resource Interconnection Services, or "ERIS", or "provisional interconnection"). Under this approach, the connecting resource would not need to wait for substantial and costly grid upgrades that are normally required to accommodate the maximum potential output under the default Network Resource Interconnection Service (NRIS). Instead, the connecting resource would be required to accept a modest level of curtailment (or energy storage behind the point of interconnection) in order to connect.

I believe this "energy only" approach is especially sensible for standalone solar resources connecting in Duke's service territory because these resources are generally not providing any significant capacity contribution to grid reliability during winter peak hours, which Duke's reliability planning already assumes. That is, the ELCC value for solar calculated by Duke is very small and only decreasing. Therefore, there is little to be gained from continuing to require solar resources to use NRIS interconnection, since their deliverability will not be significant for resource adequacy reliability purposes. However, solar resources still have significant value in terms of the energy (MWh) they can provide to the system at a low cost, and their ability to assist in meeting the Interim Target. Reliability is paramount and must be met under any portfolio. Allowing for energy-only resources to connect does not detract from this goal while still providing valuable energy to the system.

To summarize, another important strategy for increasing renewable energy output is for Duke to seek procurement of "oversized hybrid" resources in the 2028-2032 timeframe and to allow resources to interconnect via ERIS. At a later date, grid upgrades might enable these resources to receive NRIS status and contribute more to resource adequacy if necessary.

Q. COULD THESE APPROACHES SPEED UP THE TIME NEEDED TO ADD SOLAR RESOURCES IN THE NEAR TERM?

A. Yes. Both approaches could minimize or eliminate the time needed for significant grid upgrades to be completed before solar resources are connected.

Q. HAS DUKE TAKEN THIS APPROACH OF OVERSIZING RESOURCES BEHIND THE POINT OF INTERCONNECTION ELSEWHERE?

A. Yes. Duke is planning to oversize the CT resource being contemplated to replace retiring Marshall coal units 1 and 2 by 140 MW relative to the size of the interconnection. It is also planning to oversize the CC unit being contemplated to replace retiring Roxboro coal units by 313 MW relative to the size of the interconnection. Duke may upgrade the interconnection for full deliverability at a later date, though the timing and cost of these upgrades is unclear. Thus, it would be reasonable to apply a similar strategy to future solar and solar plus storage resources.

Q. HAS DUKE STUDIED ALTERNATIVE CONFIGURATIONS OF SOLAR PLUS STORAGE LIKE THE ONE YOU ANALYZED?

A. No. Duke's modeling does include a few different configurations of solar plus storage but does not include any that would increase the overall capacity factor in the manner I described. It does not appear that Duke has studied this option. Indeed, when asked, Duke gave no answer regarding additional configurations that it had considered.[34]

Q. HAVE OTHER UTILITIES TAKEN AN APPROACH TO PLANNING SIMILAR TO WHAT YOU DESCRIBE FOR SOLAR PLUS STORAGE RESOURCES?

A. Yes. In PacifiCorp's most recent IRP, it allowed energy storage to be deployed in its model without interconnection limits, so long as any storage or hybrid resource was subject to an aggregate generation limit at the interconnection location.[35] The slide excerpted below provides an overview of this.

[34] *See* Duke Response to AGO DR 4-14.
[35] PacifiCorp 2023 Integrated Resource Plan, Oregon P.U.C. Docket L.C. 82 (May 31, 2023), https://edocs.puc.state.or.us/efdocs/HAS/lc82has14323.pdf.

Shared Interconnection and Energy Storage

- Resources can share a single interconnection: either as a hybrid (multiple technologies added at the same time), or as surplus (new technology added to an existing resource)
- On 12/30/22, PacifiCorp filed with FERC (docket ER23-754) to request that energy storage resources be allowed to interconnect and operate subject to pre-defined operating conditions, which may reduce transmission upgrades for these resources. This docket is pending. https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Energy_Storage_Resources_Study_Assumptions_ER23-754_Complete_File.pdf
- In light of the above, for the 2023 IRP:
  - New resources can be "hybrid", and combined subject to an aggregate hourly generation limit for their location.
  - Existing thermal resources are eligible for surplus interconnection, and can be combined with new resources subject to an hourly generation limit.
  - Energy storage is not subject to interconnection limits: this represents opportunities for surplus interconnection at existing facilities and the potential results of the pending energy storage study changes.

14 POWERING YOUR GREATNESS

Q. DO DUKE'S CPIRP PLANNING PROCESSES, RZEP STUDIES, OR INTERCONNECTION PROCESSES CONSIDER "ENERGY ONLY" RESOURCES (E.G., ERIS INTERCONNECTION)?

A. Not to my knowledge. They all appear to assume that NRIS interconnection is required for new resources. Duke confirmed this as its approach to its RZEP analysis.[36] The Company did mention that it recently started an investigation into offering provisional interconnection service, which I discuss further in section VI below.[37] In my opinion these processes should be reformed to consider this option.

c) *Accelerate Carolinas onshore wind procurement by 1-2 years.*

As explained earlier, in the 2022 Carbon Plan Duke assumed that onshore wind would have an online date of 2029. Duke now assumes that the earliest

[36] Duke Response to AGO DR 4-13.
[37] Duke Response to AGO DR 7-1(14).

practicable date is 2031. In many US regions, the lead time for wind project development is considerably less than 7 years (generally in the 2-to-4-year range). The Energy Information Administration assumes that the lead time for these projects is only 3 years.[38] In fact, Duke received responses to its recent Wind RFI from some suppliers identifying a development timeline as short as [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[39] Even assuming an additional 12-18 months for construction, this would put a 2029 online date within reach.

Due to the critical role that onshore wind can play in reaching the Interim Target, it is worth exploring whether Duke's assumed development timeline can be truncated, particularly for the lengthier items that Duke cites such as "Transmission Leadtime" and "State Regulatory Commission Approval." If additional diligence is applied, I believe it is feasible to consider a 2029 online date (as was assumed in the 2022 Carbon Plan) for Carolinas onshore wind. I recommend that the Commission authorize this procurement now, with the goal of bringing these resources online by 2029, since that is one of the factors that Duke cited for a potential delay.

d) *Procure imported wind through the use of dynamic transfers.*

Just as described above for solar, it may be technically possible to develop wind resources without firm transmission deliverability (akin to ERIS). This includes

[38] Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023, U.S. Energy Information Administration (March 2023), https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.
[39] Duke Confidential Response to PS DR 7-8b.

resources outside of Duke's balancing area which could then be "dynamically transferred" into Duke's service territory.[40] This could allow Duke to access superior wind resources, including those in places such as Ohio, Indiana, or Illinois which may have capacity factors in the 30-40% range, far exceeding that of the Carolinas. This dynamic, non-firm approach will likely lead to modest curtailment during hours when transmission is unavailable. However, there will still be a majority of hours when there is sufficient transmission available, and the wind resource can be delivered. According to one recent study by Brattle, non-firm resources may be >95% deliverable and, at least "[i]n PJM, curtailments on non-firm rights are rare (and small)."[41] This approach could also avoid the need to pay significant costs for firm transmission service from PJM, which may otherwise prevent wind imports from being cost effective. For example, PJM's non-firm transmission service is currently set at only $0.67/MWh[42] versus firm service which would be approximately $25/MWh.[43] To be clear, procuring imported wind in this manner cannot and should not be expected to contribute to Duke's resource adequacy reliability needs. However, such procurement also would not harm reliability. Just as explained above for solar, there is no downside for including incremental wind as an "energy only" resource in a portfolio if it is not expected to contribute to

[40] Dynamic Transfers, PJM, https://www.pjm.com/about-pjm/member-services/dynamic-transfers.
[41] Generation Interconnection and ELCC Values for Variable Resources, Brattle (Feb. 25, 2022), https://www.brattle.com/wp-content/uploads/2022/02/Generation-Interconnection-and-ELCC-Values-for-Variable-Resources.pdf
[42] Customer Guide to PJM Billing, (Oct. 3, 2022), https://www.pjm.com/-/media/markets-ops/settlements/custgd.ashx.
[43] Calculated based on PJM Border Charge of $66,231/MW-yr, and assuming a wind resource with a 30% capacity factor.

reliability in the first instance. From a modeling perspective, the ELCC value could be set to 0% and reasonable assumptions could be made about energy loss due to curtailment. While reliability needs must still be addressed in any portfolio, this concern should not preclude Duke from procuring low-cost "energy only" resources if it is economic to do so. This could be both a means of reducing operating costs as well as meeting the Interim Target. Unfortunately, Duke did not consider this approach in the development of its resource plan.[44]

e) *Procure offshore wind as soon as practicable.*

As Duke has acknowledged, offshore wind is an important resource in its preferred plan (P3 Fall Base), which includes 800 MW with an assumed online date of 2033. This accelerates the timeframe for offshore wind from the initial P3 Base plan which considered offshore wind as an optional resource in the 2035 timeframe. Meanwhile, Duke has begun evaluation of potential offshore wind projects and found that "[o]ne developer submitted scenarios with offshore wind available as early as 2030, while the remaining developers submitted scenarios with 2031-2032 availability."[45] These reported trends seem positive for offshore wind development in the Carolinas and, thus, it may be feasible to consider a slightly accelerated timeline for offshore wind (e.g., 2032 versus 2033).

f) Pursue more customer-sided resources.

[44] *See* Duke Response to AGO DR 1-12(c) (attached as Burgess Direct Exhibit 10) and AGO DR 2-5(d) (attached as Burgess Direct Exhibit 11).
[45] CPIRP, Appendix I, p 26.

In addition to supply-side resources, Duke can and should pursue additional demand-side or customer-sided resources to achieve the Interim Target. In fact, there are several factors that would suggest scaling up these resources is more achievable now than it was in the recent past. For example, the fact that Duke's load forecast has significantly increased suggests that the Company's year of first resource need has accelerated. This will have the effect of increasing the overall cost-effectiveness of traditional demand-side management and energy efficiency (DSM/EE) resources and should in turn warrant a larger overall program budgets and levels of effort for DSM/EE activities. The cost-effectiveness of DSM/EE measures should be further increased due to the fact that the marginal capacity resources Duke is considering (i.e., "avoided cost") now include new CCs with FT and advanced nuclear (instead of less costly proxy resources in the form of CTs). As such, any compliance pathway for the Interim Target should include incremental demand-side resources that reflect these realities. Some potential options in this regard are discussed further below in section V-C of my testimony, though this is by no means comprehensive. The options described therein are largely consistent with the illustrative compliance pathway I outlined earlier.

D. Recommendations

Q. WHAT ARE YOUR PRIMARY RECOMMENDATIONS BASED ON YOUR ASSESSMENT OF DUKE'S PROPOSED RESOURCE ADDITIONS IN ITS CPIRP?

- The Commission should set a clear directive for Duke to achieve the Interim Target at least by 2032. This appropriately balances the statutory guidelines for a 2030 target versus the new challenges posed by recent load growth.
- The Commission should direct Duke to pursue the multiple strategies outlined in my testimony above for accelerating coal retirements and increasing renewable energy delivery.

IV. NATURAL GAS ADDITIONS

A. Duke has over-emphasized CCs versus batteries/CTs for meeting reliability needs.

Q. PLEASE DESCRIBE DUKE'S CURRENT GAS FLEET AND PROPOSED GAS ADDITIONS.

A. The Company's natural gas asset fleet includes "55 CTs, nine CCs units, and one combined heat and power (CHP) unit, with a total capacity of 11,891 MW."[46] Additionally, Duke's preferred plan proposes to add nearly 7,000 MW of new CCs and over 2,000 MW of CTs by 2033.[47] As a result of these additions, the Company's forecast that gas will constitute 39% of their energy mix by 2033.[48]

Q. DO THESE PLANNED ADDITIONS PRESENT CHALLENGES FOR MEETING COMPLIANCE WITH BOTH STATE AND FEDERAL POLICIES?

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[46] CPIRP, Chapter 4, page 14.
[47] Supplemental Planning Analysis, Table 4-1.
[48] Supplemental Planning Analysis, Table 3-2.

A. Yes. In particular, I am concerned about the planned additions of CCs. These types of gas units are more capital intensive than simple cycle CTs, and thus are a more expensive capacity resource that will increase costs to customers. As Duke explained, it is planning 3 new CC additions by 2031, which will have a total fixed cost of over [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[49] Once built they are relatively efficient and cheaper to operate, but that also means they also tend to consume more fossil fuels (in total) and contribute more CO_2 emissions than CTs. This presents challenges for both state and federal policy. For North Carolina, the more frequent operation of CCs will make it more difficult to achieve and maintain the 70% and 100% carbon reduction targets under HB 951. Regarding federal regulations, on May 9, 2024, the EPA finalized new rules under Section 111 Clean Air Act which will set additional limits on the operations of new and existing fossil fuel power plants. These new requirements were not incorporated into Duke's analysis and may lead to the need for these plants to either operate less frequently (thus negating their advantage as efficient units) or install expensive CCS equipment.

Q. HOW MIGHT THE EPA'S FINAL SECTION 111 RULES AFFECT THE OPERATION OF DUKE'S PROPOSED NEW CC'S?

A. The EPA's final rules will require new gas plants operating as "base load" units (i.e., >40% capacity factor, which is typical for a CC plant) to capture 90% of CO_2 emissions by 2032. Alternatively, these plants could operate at lower

[49] Burgess Direct Exhibit 9.

capacity factors (<40%) after 2032, which may necessitate procurement of additional energy resources (ideally non-emitting resources).

Q. DOES THE COMPANY HAVE A CREDIBLE PLAN FOR CONVERTING NEW GAS RESOURCES TO HYDROGEN FUEL IN THE FUTURE?

A. No. The Company's assumed level of hydrogen blending is significantly short of what would be required to reach zero carbon emissions by 2050. In its modeling, Duke assumes 1% hydrogen blending in 2035, 2% in 2038, 3% in 2041, and "holding steady until significantly more hydrogen is required to meet carbon neutrality by 2050."[50] The Company does not provide a plan for increasing hydrogen levels from 3% in 2041 to a level sufficient to support 100% hydrogen operations. The Company admits that "line enhancements and/or new pipeline infrastructure will be required to handle increased hydrogen volumes" and that "it is currently unknown at what blend-level incremental costs for enhancements will be incurred."[51]

Q. ARE COMBINED CYCLE GAS PLANTS RELIABLE RESOURCES?

A. Gas resources, including CCs, are typically described as "firm" resources since they are dispatchable at most times. However, CCs are only truly firm, reliable resources insofar as they have a firm fuel supply. This proved not to be the case for many gas resources, including those Duke depended on, during recent winter reliability events such as Winter Storm Elliot.

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[50] *See* CPIRP, Appendix K at Page 8.
[51] *See* Duke Response to AGO DR 1-33(a).

Q. DO YOU THINK DUKE'S MODELING ASSUMPTIONS APPROPRIATELY REFLECT THE RELIABILITY CONTRIBUTION OF GAS RESOURCES?

A. No. Duke has inflated the reliability contributions and assumed a capacity value (i.e., ELCC value) for gas resources that is too high. This is mainly because Duke does not have firm fuel supply for a large share of its gas fleet. Duke can't have it both ways—it is inconsistent to assume a nearly 100% ELCC value for gas resources where only a fraction of the fleet has firm fuel supply. For comparison, PJM's most recent ELCC ratings only assigned a 79% ELCC value to CC resources and a 79% value to dual fuel CTs.[52]

Q. WHAT WOULD BE THE LIKELY OUTCOME IN DUKE ANALYSIS IF IT ADJUSTED THE ELCC VALUE OF ITS GAS FLEET TO ACCOUNT FOR THE LACK OF FIRM FUEL SUPPLY?

A. The model would likely select fewer gas resources since they would not provide as much reliability value to the system. Duke asserts that it plans to secure firm fuel supply for some new gas additions. However, as I mentioned earlier, this is somewhat meaningless if an overall deficiency remains for the gas fleet as a whole. Thus, until Duke can demonstrate that it has secured firm fuel supply for its entire fleet, I recommend that the ELCC value for new gas resources should be decreased. This adjustment should be performed prior to any analysis supporting a CPCN application and in any future CPIRP analysis.

[52] ELCC Class Ratings for the 2025/2026 Base Residual Auction, PJM, https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx.

Q. ARE THERE OTHER RESOURCES THAT COULD PROVIDE SIGNIFICANT RESOURCE ADEQUACY RELIABILITY VALUE TO DUKE'S SYSTEM?

A. Yes. In particular, Duke's ELCC analysis shows that battery resources provide a very significant contribution to resource adequacy, even though their duration is limited. In fact, Duke estimates they contribute over 90% of their nameplate rating in many scenarios. Additionally, CTs offer another form of firm capacity that can contribute to resource adequacy. While CTs face the same challenges as CCs in terms of securing firm fuel supply, they present less risk in terms of capital costs.

Q. DOES DUKE HAVE A FINANCIAL INTEREST IN NATURAL GAS BEYOND INVESTMENTS IN THE GENERATION PLANTS THEMSELVES?

A. Yes. Duke has a robust business in upstream gas infrastructure including intrastate and interstate pipelines. The siting and construction of these pipelines is often dependent on demonstrating a need for additional natural gas demand. Thus, beyond the return on capital that Duke earns from new gas generation resources, Duke may also have an interest in driving demand for gas fuel supply to support new pipeline investments.

B. Even with additional firm fuel transportation (FT) from the Mountain Valley Pipeline, Duke's preferred plan will have a deficiency in FT until [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. This risk factor is exacerbated by Duke's proposed new CC additions.

Q. DOES DUKE'S GAS FLEET PRESENTLY HAVE A DEFICIENCY IN TERMS OF FIRM PIPELINE TRANSPORT NEEDED TO RELIABLY PROVIDE FUEL SUPPLY?

A. Yes. Duke currently has secured only [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] through existing FT contracts, compared to its gas fleet's maximum potential requirement of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL], thus leaving a deficit of approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[53]

Q. DOES DUKE'S PREFERRED PLAN ANTICIPATE NEW FT CONTRACTS BEING SECURED IN THE FUTURE?

A. Yes. Duke assumes an additional [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of FT to be secured by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] associated with the Mountain Valley Pipeline (MVP), and an additional [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] with Gulf Coast pipelines.[54]

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[53] Duke Confidential Response to AGO DR 6-2 (attached as Burgess Direct Exhibit 12).
[54] Burgess Direct Exhibit 12.

Q. IS IT CERTAIN THAT DUKE WILL SECURE FUTURE FT CONTRACTS IN THE AMOUNTS THE COMPANY HAS ASSUMED?

A. No. There will be substantial competition for new pipeline capacity in the region and it is not certain who will be successful in securing firm delivery on these, let alone at what cost. This is exacerbated by the fact that many other utilities in the region have also announced plans to significantly expand their gas generation fleet.

Q. IF DUKE'S ASSUMED FUTURE FT ADDITIONS ARE CORRECT, WILL THAT BE ENOUGH TO MAKE UP FOR THE DEFICIT YOU MENTIONED EARLIER?

A. No. As illustrated in the chart below for the P3 Fall Base portfolio, there will continue to be a deficit in FT for gas fuel supply versus Duke's maximum gas fleet requirements through [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Table 7. Comparison of FT maximum requirement versus Duke's projected FT availability. Analysis based on data form Duke's Confidential response to AGO DR 6-2.

[redacted]

As the chart illustrates, Duke’s preferred portfolio (P3 Fall Base) does not provide firm fuel supply for its gas fleet until the year [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. While Duke does claim that it plans on securing FT in conjunction with the development of new CC resources, this claim is somewhat meaningless unless and until Duke is able to make up for the existing FT deficiency at gas units across its system.

Q. ARE YOU SUGGESTING THAT FT REQUIREMENTS SHOULD BE REMOVED FOR NEW GAS RESOURCES?

A. No. To the contrary, I believe FT should be required for all of Duke’s gas resources if these resources are to be considered “reliable” and therefore contribute to resource adequacy. Duke appears to agree with this as it implies that firm fuel supply is necessary to maintain reliability at Belews Creek under the gas conversion variant.[55] Instead, I am simply highlighting Duke's inconsistency in requiring FT for some gas resources, but not for others, and that this inconsistency may be leading to misleading results in Duke's analysis. Consequently, I think Duke's analysis should be modified for each of its portfolios to ensure FT is included for all gas resources (both new and existing) if these resources are assumed to be "firm, reliable" capacity resources. Alternatively, if FT is not secured, then the reliability contribution of all gas resources (new and existing) should be reduced accordingly until the year in which sufficient fleet-wide FT is expected to be secured.

Q. IN THE ALTERNATIVE CASE YOU MENTIONED ABOVE, HOW SHOULD DUKE ADJUST ITS MODELING OF GAS RESOURCES?

A. The ELCC value for all gas resources should be reduced according to the deficit. This reflects the fact that gas resources on Duke's system may not have sufficient fuel supply to generate at their full MW rating on peak winter days. This was the case for many gas generators in the region during Winter Storm Elliot.

Q. DO YOU THINK THE PROPOSED CC ADDITIONS IN DUKE'S PREFERRED PORTFOLIO PRESENT SIGNIFICANT EXECUTION RISKS?

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[55] CPIRP, Appendix C, p 87: "However, these benefits are offset by the cost to convert the unit, maintain the capacity to 2041, and <u>maintain the reliability of the resource through contracting for firm fuel supply</u>." (emphasis added).

A. Yes. While all resource types present a certain amount of execution risk, I believe this risk is significantly heightened in the case of the CC resources Duke has proposed due to both the scale of the proposed expansion and the two key risk factors I previously discussed. First, I expect it will be extremely challenging for Duke to secure sufficient FT to ensure that its gas resource fleet is reliable, particularly on the timeline proposed. Second, new gas resources may well be subject to the EPA's new 111 rules requiring additional pollution controls. Both of these risk factors can be minimized or eliminated through greater procurement of non-fossil resources in the late 2020s. I recommend the Commission give significant weight to these risk factors when evaluating any future CPIRP or CPCN for new gas resources.

C. Recommendations

- The Commission should give significant weight to two key execution risk factors when evaluating any future CPIRP or CPCN for new gas resources: (1) potential challenges securing sufficient FT and (2) the potential future impacts of the EPA's new Section 111 rule.
- All CPCN's for new gas should be required to include an analysis that reflects the impacts of the EPA's new Section 111 rule, with multiple compliance options evaluated including CCS, reduced operations (<40% capacity factor), and replacement with non-emitting resources.
- ELCC values for all gas resources should be discounted based on the firm fuel supply Duke has secured for its gas fleet as a whole. This adjustment should be performed prior to any analysis used to support a CPCN application for new

gas resources and for future CPIRP proceedings. This evaluation should also consider a scenario where incremental FT cannot be secured on the timeline Duke has forecasted.

V. LOAD FORECAST AND SOLUTIONS FOR MANAGING LOAD

A. Review of Load Forecast

Q. PLEASE SUMMARIZE DUKE'S LOAD FORECASTS UNDER THE SUPPLEMENTAL PLANNING ANALYSIS.

A. The load forecasts presented in the Supplemental Planning Analysis (SPA) include several additional large site developments when compared to the initial Plan. The Updated 2023 Fall Load Forecast includes 27 future economic development projects in both North Carolina and South Carolina, compared to only eight such projects in the original 2023 Spring Load Forecast.[56] These economic development projects total 1,742 MW in 2030 and 2,089 MW in 2035, driving Duke's claim that significant additional capacity investments are needed.[57]

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S LOAD FORECAST?

A. Yes. Since load forecasts drive the need for generation and transmission investments, establishing accurate load forecasts is crucial for utility resource plans. However, it is difficult to validate the accuracy of the Company's load forecast given the novelty of the sectors driving the load growth (i.e., EV and battery manufacturing, data centers for AI, etc.) as well as the proprietary nature

[56] CPIRP, Supplemental Planning Analysis, p. 15.
[57] CPIRP, Supplemental Planning Analysis, Table 2-2.

of the customer requests. Importantly, Duke does not track historical data on whether new large load customers have ultimately received service at the initially estimated MW demand or on the timeline initially predicted.[58] Thus, the Company's performance in accurately predicting large load additions is not well known. While I agree that some significant amount of load growth is occurring and will occur, I do have some concern that not all of the new, large site load Duke is projecting will materialize or may materialize at a later date than projected. Some large site customers expressed similar concerns during the most recent Georgia Power IRP.[59] As a monopoly company, Duke is in the sole and unique position for receiving information about new load requests but also has a natural capital bias towards over-including requests that are more speculative in nature given that these load requests are driving the justification for new, and potentially unnecessary, capital investment. This underscores the need, going forward, for a more independent analysis of the load forecast, especially one where the independent reviewer is permitted access to confidential information used to support new requests. Ideally this independent forecasting would also be coordinated across the region to address any potential "double counting" issues.

I am also concerned that while Duke has drawn much attention to the new large-site loads which are frequently "in the news," the Commission should not lose

[58] Duke Confidential Response to AGO DR 5-6(d).

[59] Microsoft Comments on Georgia Power's 2023 Integrated Resource Plan Update, Georgia P.S.C. Docket No. 55378 (Apr. 1, 2024), https://services.psc.ga.gov/api/v1/External/Public/Get/Document/DownloadFile/218199/99204.

sight of Duke's approach to forecasting changes in load from its existing customer base, before those new large sites are considered. Indeed, that underlying load still comprises the lion's share of Duke's sales, so small changes in the forecast methodology can have large effects on future demand—potentially even larger than the impact of new site loads. To this end, I performed an analysis on the Company's load forecast to understand how well it reflects long term trends in usage per customer. My analysis suggests that some effects of continuous end-use efficiency improvements are not being appropriately incorporated, which would lead to an inflated load forecast. I describe this analysis in Section V-B of my testimony.

Together, these factors underscore the need for (a) an independent approach to load forecasting and (b) a renewed focus on load management tools that can alleviate Duke's forecasted growth in peak demand (especially for winter peaks).

B. Duke's forecasted load in terms of "Usage Per Customer" is inconsistent with historical trends and expected future improvements in end-use efficiency.

Q. CAN YOU DESCRIBE THE PURPOSE OF THE ANALYSIS YOU PERFORMED ON THE COMPANY'S LOAD FORECAST REGARDING USAGE PER CUSTOMER?

A. Yes. Over the last several years, there have been significant improvements in the end-use efficiency of a wide range of electric appliances. These have been driven by technological improvements, as well as continual updates to numerous federal energy codes and standards. Below is a summary of some of the federal codes and standards that have recently gone into effect, or will go into effect soon, for residential and commercial appliances.[60] Each of these will produce incremental energy savings—thereby decreasing usage per customer—as customers purchase new appliances during the planning period.

Table 8. List of Residential and Commercial appliance standards affecting usage per customer in the CPIRP planning period.

Residential Appliances	**Last Standard Published**	**New Final Standard Due**
Air cleaners	2023	
Battery Chargers	2016	2024
Boilers	2016	2024
Ceiling Fans	2017	2025
Central Air Conditioners and Heat Pumps	2017	2025
Clothes Dryers	2011	2019
Clothes Washers	2012	2020
Cooking Products	2009	2017
Dehumidifiers	2016	2024
Direct Heating Equipment	2010	2021
Dishwashers	2012	2021
External Power Supplies	2014	2021
Furnace Fans	2014	2022
Furnaces	2007	2016
General Service Lamps	2016	2022
Metal Halide Lamp Fixtures	2014	2019
Microwave Ovens	2013	2021
Miscellaneous Refrigeration Products	2016	2024
Pool Heaters	2010	2018
Pool Pumps	2017	2025

[60] Information in these tables was sourced from the Appliance Standards Awareness Project's national database: https://appliance-standards.org/national.

Portable Air Conditioners	2020	2028
Room Air Conditioners	2011	2019
Water Heaters	2010	2018
Commercial Appliances	**Last Standard Published**	**New Final Standard Due**
Automatic Commercial Ice Makers	2015	2023
Commercial Boilers	2020	2028
Commercial CAC and HP (65,000 Btu/hr to 760,000 Btu/hr)	2016	2024
Commercial CAC and HP (<65,000 Btu/hr)	2015	2023
Commercial CAC and HP (Water- and Evaporatively-Cooled)	2012	2020
Commercial Clothes Washers	2014	2022
Commercial Refrigeration Equipment	2014	2020
Commercial Warm Air Furnaces	2016	2024
Commercial Water Heaters	2001	2018
Compressors	2020	2028
Computer Room Air Conditioners	2012	2018
Distribution Transformers	2013	2021
Electric Motors	2014	2022
Packaged Terminal AC and HP	2015	2023
Pre-Rinse Spray Valves	2016	2024
Pumps, Commercial and Industrial	2016	2024
Refrigerated Beverage Vending Machines	2016	2024
Single Package Vertical Air Conditioners and Heat Pumps	2015	2023
Small Electric Motors	2010	2018
Uninterruptible Power Supplies	2020	2028
Unit Heaters	2005	
Walk-In Coolers and Freezers	2014	2020
Water-Source Heat Pumps	2015	2023

As end-use efficiencies have improved, there has been a general trend of declining usage per customer over the years. This trend is expected to continue as more appliances are replaced over time and additional standards are adopted in the coming years. This general trend of declining usage per customer is sometimes described as "naturally occurring energy efficiency" since it occurs separate and apart from utility administered energy efficiency (UEE) programs. In essence, it reflects an overall improvement to the baseline consumption of appliances, whereas UEE reflects an incremental amount of energy savings above and beyond that baseline trend. The analysis I performed is intended to understand how well Duke's load forecast reflects the continuation of these baseline appliance efficiency trends, even before the incremental effects of UEE and other factors are considered.

Q. DOES DUKE AGREE WITH THE BASIC PREMISE THAT ITS LOAD FORECAST SHOULD REFLECT IMPROVEMENTS TO BASELINE EFFICIENCY OVER TIME?

A. Yes. In fact, this is Duke's primary rationale for "rolling off" a significant amount of the energy savings from UEE programs in its load forecast. As the Company explains:

> With the SAE model's framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from EE adoption. The impact of this interaction between naturally occurring EE and UEE is to recognize the earlier adoption of EE improvements, lowering energy usage earlier than would have otherwise been expected, and continuing the benefit of the EE over the forecasting period.[61]

[61] CPIRP, Appendix D, p 8.

Q. BASED ON THIS DESCRIPTION, WHAT PATTERN WOULD YOU EXPECT TO SEE FOR USAGE PER CUSTOMER IN DUKE'S LOAD FORECAST?

A. I would expect to see steadily declining usage per customer over time, in line with recent trends. I would expect this decline might be even more noticeable in later years (i.e., 2030 and beyond), when a significant amount of UEE is "rolled off" but, as Duke explains, the savings should continue in the underlying load forecast.

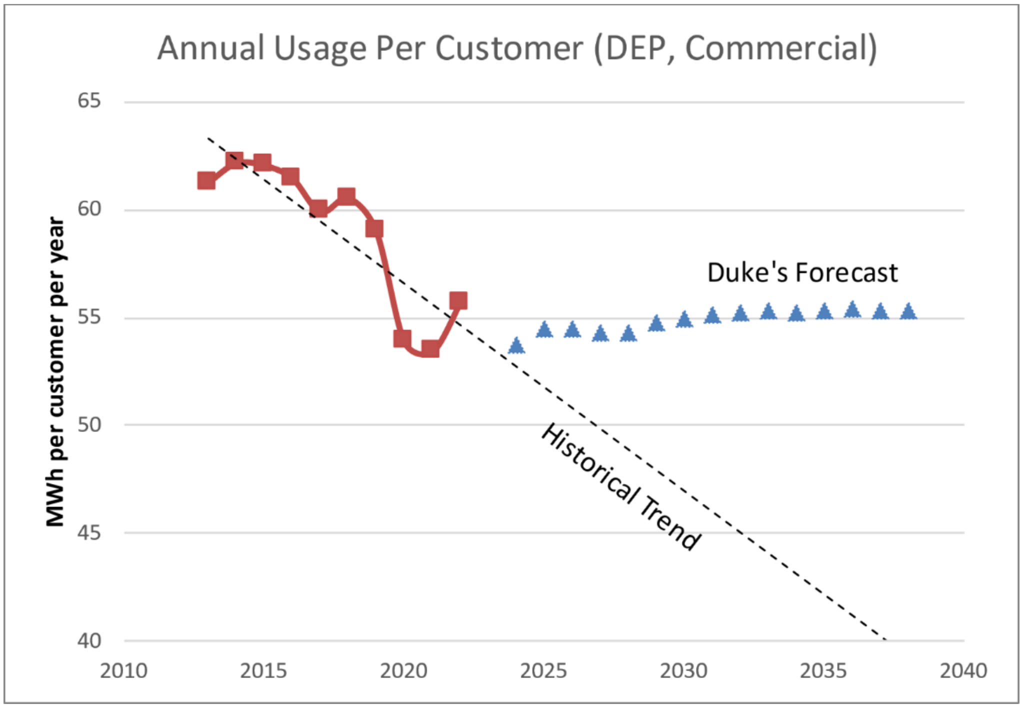
Q. IN YOUR ANALYSIS OF DUKE'S LOAD FORECAST, DID YOU OBSERVE THE PATTERN YOU EXPECTED—THAT IS, DID YOU OBSERVE A FUTURE TREND OF DECLINING USAGE PER CUSTOMER?

A. No. In several cases, the opposite trend is occurring. In other words, the usage per customer over time was generally flat, or even increasing in some cases. Below is an illustration of this for the commercial customer segment of DEP. The solid red line represents historical usage per customer (with the trendline shown in the black dashed).[62] The blue triangles represent future usage per customer based on Duke's load forecast. As you can see, Duke's forecast reflects an increase over time (rather than a decrease as the trendline would suggest). For some customer segments there was a very small decline, but usage per customer was still relatively flat and not in line with recent trends. Burgess Direct Exhibit 3 attached to my testimony provides a similar analysis of the

[62] Note that there may be year-to-year variation due to variations in weather patterns, but the overall trend is downward.

usage per customer for residential, commercial, and industrial customers in both DEP and DEC.

Table 9. Excerpt from Usage Per Customer analysis provided in Burgess Direct Exhibit 3.



Q. CAN YOU BRIEFLY DESCRIBE HOW YOU PERFORMED THIS ANALYSIS?

A. Yes. I used Duke's updated load forecast data as provided in PSDR 3-8 (Supplemental). I then removed the adjustments Duke made to its forecast to account for utility energy efficiency (UEE), electric vehicles (EVs), rooftop solar PV, and new large site loads. Notably, since the effects of EVs and large site loads are removed, they would not account for any of the observed trends on future usage per customer in this analysis.

Q. HAS DUKE PROVIDED ANY PERSUASIVE EXPLANATIONS FOR FORECASTING FLAT OR INCREASING USAGE PER CUSTOMER?

A. No. In the last CPIRP proceeding, Duke did briefly mention electrification and "the internet of things" as potential sources of new load included in the forecast. However, I do not find these to be persuasive explanations. As mentioned, the effects of EVs are removed from this analysis. Additionally, the vast majority of residential heating in the Carolinas is already electric, thus the installation of more efficient, modern electric heating appliances would likely reduce demand (rather than increase it). Meanwhile, there is no evidence that the "internet of things" will be a meaningful source of new demand sufficient enough to offset general trends in appliance efficiency.

Q. WHAT ARE THE POTENTIAL EFFECTS ON SYSTEM-WIDE DEMAND IF USAGE PER CUSTOMER DECLINES ALONG A SIMILAR TREND TO RECENT YEARS?

A. Using a linear regression technique, I calculated what the usage per customer could be in 2030 if it followed recent historical trends instead of Duke's forecast. If usage per customer followed these historical trends, then Duke's peak demand would be nearly 2,000 MW lower in 2030 than its SPA forecast. This suggests that the Commission should give additional credence to Duke's "low load" forecast sensitivities. It also suggests that the Commission should very carefully consider approval of new generation resources meant to service new load additions.

Q. WHAT DO YOU RECOMMEND BASED ON THIS ANALYSIS?

A. As mentioned above, I think an independent load forecast may be warranted and should be ordered by the Commission going forward to be available for and utilized in all future proceedings. I think this independent forecast should also include explicit modeling of usage per customer trends, not only for residential customers (as is Duke's current practice) but also for commercial and industrial customers.

C. Customer-Centric Programs that Alleviate Peak Load Growth Should Play a Larger Role in the Resource Plan

Q. DID THE COMPANY MODIFY ITS PROPOSED RESOURCE PORTFOLIO IN ITS SUPPLEMENTAL PORTFOLIO ANALYSIS?

A. Yes. In the Supplemental Portfolio Analysis ("SPA"), Duke proposed adding a significant amount of additional supply-side resources in order to account for the significant increase in forecasted load since the initial analysis was performed.

Q. DID THE NEW INCREMENTAL RESOURCES ADDED IN THE SPA INCLUDE ANY ADDITIONAL DEMAND-SIDE OR CUSTOMER-OWNED RESOURCES?

A. Duke included some incremental demand response (179 MW for DEC and 10 MW for DEP) that appear to reflect historical participation levels applied to the newly increased forecast for large customer loads. Beyond this, I'm not aware of any other incremental changes to demand-side or customer-owned resources.

Q. DOES THE COMPANY'S SPA ADEQUATELY CONSIDER DEMAND-SIDE RESOURCES?

A. No. The significant increase in the Company's load forecast suggests to me that there should have been a renewed emphasis on incremental customer-centric, demand-side solutions. Instead, Duke's response to growing demand in this case seems almost solely focused on growing capital-intensive, primarily natural gas fired, supply-side solutions.

Q. IN ADDITION TO ITS FOCUS ON MORE SUPPLY-SIDE RESOURCES, WHAT ADDITIONAL KINDS OF CUSTOMER-CENTRIC, DEMAND-SIDE RESOURCES SHOULD BE ADDED OR INCREASED IN THE COMPANY'S PORTFOLIO IN ORDER TO MEET GROWING PEAK DEMAND?

A. I recognize that Duke is already pursuing a wide range of customer-centric, demand-side solutions. However, if the SPA portfolio adds supplemental supply-side solutions to address growing demand, then it should also include additional supplemental demand-side solutions. These could be in the form of (a) developing novel programs to harness emerging markets and technologies, and/or (b) ramping up the level of effort in existing customer programs. While there are a wide range of options that could be considered, I suggest that, at a minimum, Duke undertake a concerted effort to develop (or enhance existing) customer programs to achieve load reductions in four key areas: (1) distributed solar and batteries, (2) EV load management, including bidirectional charging, (3) installing more efficient electric heating equipment, and (4) new large-site demand response and efficiency improvements. I expand on and provide a high-level scenario of the potential peak load contribution from each of these areas below.

1. Distributed Solar Plus Storage (Solar for All)

Q. HOW CAN DISTRIBUTED SOLAR AND BATTERIES CONTRIBUTE TO PEAK LOAD REDUCTION?

A. The Company's SPA load forecast includes reduced rooftop solar adoption rates, citing higher projected system costs, the implementation of new net metering tariffs in North Carolina, as well as economic headwinds such as higher borrowing costs and inflationary pressures.[63] However, the Company's forecast does not appear to include the impacts of funding from the Inflation Reduction Act, which can be expected to counteract the aforementioned factors. Specifically, the North Carolina Department of Environmental Quality (NC DEQ) recently received a $156 million grant from the EPA's Solar for All program to support solar deployment for low-income and disadvantaged communities across the state.[64] Scaling the awarded amount proportionally to the NC DEQ's initial application for $250 million to support at least 69.5 MW of residential solar over five years, the program can be expected to deliver about 44 MW of solar. The Commission should direct Duke to adopt an approach where these upcoming solar installations are leveraged to install co-located battery storage systems that could provide firm peak load reductions.

2. EV Load Management with V2X

Q. HOW CAN EV LOAD MANAGEMENT CONTRIBUTE TO PEAK LOAD REDUCTION?

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[63] Supplemental Planning Analysis, p. 16.
[64] North Carolina's Solar for All Program: EnergizeNC, N.C. Dept. of Envtl. Qual., https://www.deq.nc.gov/energy-climate/state-energy-office/inflation-reduction-act/solar-all.

A. EV charging is more flexible than traditional loads and can be controlled by the customer, the utility, or a third-party (e.g., a DER aggregator) to shift charging to off-peak periods as well as avoid charging and/or export power back to the grid during peak events. This load flexibility can be unlocked through time-varying rates, managed charging programs, and bidirectional charging programs (i.e., vehicle-to-grid "V2G" or vehicle-to-building "V2B" sometimes collectively referred to as "V2X"). There have been significant recent advances in V2X and V2G technologies that, if properly leveraged, could further mitigate the impact of EVs on Duke's peak demand. For example, Duke forecasts that there will be greater than 3 million EVs in operation by year 2037, many of which will be capable of bidirectional charging. Even if only 5% of these vehicles were able to discharge power to the customer's site (or to the grid) during peak hours, that would represent more than 1,000 MW in potential load reduction. Similar to telematics-based managed charging programs, V2X are also becoming more widely available. The Commission should direct to Duke to implement a similar program as soon as practicable and reflect its capacity value in future CPIRP modeling.

3. <u>More Efficient Winter Heating</u>

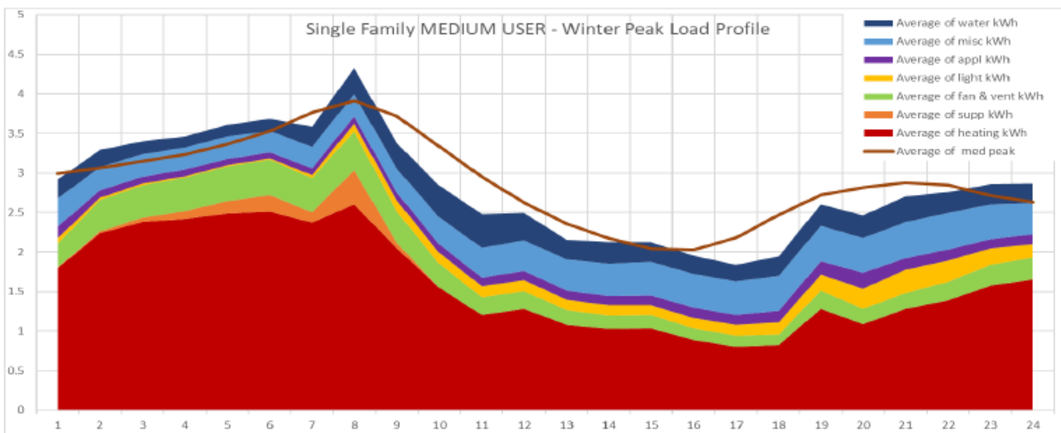
Q. HOW CAN MORE EFFICIENT ELECTRIC HEATING EQUIPMENT CONTRIBUTE TO PEAK LOAD REDUCTION?

A. Residential heating load is a significant contributor to Duke's winter peaks. According to data from the EIA, electricity is the main source of heat in 62-

64% of homes in the Carolinas, which is among the highest of any state.[65] According to the Company's 2030 Winter Peak Targeted DSM Plan, 40%, or about 1,600 MW in both North Carolina and South Carolina, of electric space heating load can be attributed to electric resistance heating.[66] This contributes significantly to the winter "needle peak" that Duke's system experiences, as illustrated below (heating load is shown in red/orange):

Table 10. Excerpt from Duke's 2020 Winter Peak Analysis and Solution Set

Figure 10. Single Family Peak Load Profile – Medium User



[67]

Electric resistance heating, including supplemental heat strips on older heat pumps, electric wall furnaces, electric baseboard heaters, and small supplemental plug-in heaters, are older technologies that are considerably less efficient than modern cold-climate heat pumps, which can deliver an equivalent

[65] Highlights for space heating fuel in U.S. homes by state, 2020, Energy Information Administration (Mar. 2023), https://www.eia.gov/consumption/residential/data/2020/state/pdf/State%20Space%20Heating%20Fuels.pdf.
[66] Duke Energy Winter Peak Targeted DSM Plan at 43 (Dec. 2020), https://cleanenergy.org/wp-content/uploads/Duke-Energy-Winter-Peak-Targeted-DSM-Plan-Final-Report.pdf.
[67] Duke Energy Winter Peak Analysis and Solution Set (Dec. 2020), https://cleanenergy.org/wp-content/uploads/Duke-Winter-Peak-Analysis-Solution-Set-Final-Report.pdf.

amount of heating using only a fraction of the demand.[68] If electric resistance heating in Duke's territory is replaced with more modern heat pumps that can operate efficiently in cold weather, the resulting peak load reduction can reach over 500 MW. Duke's 2020 Winter DSM study suggested a program to address winter heating, but I found the proposed budget and level of effort to be inadequate. Given its strong alignment with winter peaks, I believe this particular end use deserves an amplified level of effort in DSM programs going forward. This is especially true now since these programs may be able to leverage significant federal incentives for high-efficiency heat pump installation that were authorized as part of the Inflation Reduction Act.

4. <u>New Large Load Customer Programs</u>

Q. HOW CAN DEMAND RESPONSE AND EFFICIENCY IMPROVEMENTS FOR NEW LARGE SITE CUSTOMERS (E.G., MANUFACTURERS, DATA CENTERS) CONTRIBUTE TO PEAK LOAD REDUCTION?

A. New large-site customers, such as data centers, are generally modern facilities with sophisticated load management capabilities that can enable significant load reduction during peak events, while efficiency improvements can help reduce energy consumption 24/7. I recognize that some of these loads have generally high capacity factors and somewhat inflexible demand. However, at least one data center company has explained how it can help alleviate grid stress

[68] For example, some heat pumps on the market today can operate with coefficients of performance greater than 2.5 even at 5 degrees Fahrenheit. This means they would use only 40% of the equivalent electric heating energy.

by shifting non-urgent tasks to off-peak times and/or other locations.[69] In Virginia, Dominion Energy has also developed an energy efficiency program specifically targeted towards data centers.[70] Other types of large loads, such as manufacturing facilities, may have even more opportunities for load flexibility. Duke forecasts [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] MW of peak load from large customers in 2033.[71] A modest [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] reduction in these peak loads through peak load reduction from demand response or efficiency improvements would result in a substantial peak load reduction of over 200 MW.

Q. CAN YOU PROVIDE A SUMMARY OF THE TOTAL LOAD REDUCTION THAT THESE FOUR CUSTOMER PROGRAMS MIGHT ACCOMPLISH?

A. Yes. The table below provides a summary of the potential impacts of the efforts I described in my testimony above. While there are uncertainties about the exact peak savings that could be achieved, I believe this provides a credible roadmap for peak savings that could offset the need for a significant amount of supply-side generation.

[69] *Supporting power grids with demand response at Google data centers*, Google (Oct. 3, 2023), https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption.
[70] Virgina Electric and Power Company's 2023 Integrated Resource Plan, Case No. PUR-2023-00066 at p. 258 (May 1, 2023), https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/2023-va-integrated-resource-plan.pdf?la=en&rev=6b14e6ccd15342b480c8c7cc0d4e6593.
[71] Duke Confidential Response to PS DR 21-6(b).

Table 11. Summary of potential peak savings from four targeted load reduction areas recommended by the AGO.

New Customer-centric Load Reduction Program	Potential Peak Savings, by 2037 (MW)
Solar for All (rooftop solar + battery)	40
V2X	1,000
Winter Heating	500
Large Load efficiency/DR	200
Total	*1,740*

D. Findings and Recommendations

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission:

- Develop a process for an independent load forecast, ideally one that can also review confidential information provided to Duke regarding new economic development projects.
- Require Duke to accurately model usage per customer for all sectors, accounting for long-term improvements in end-use efficiency.
- Require Duke to develop meaningful load reductions through the four customer program areas identified and discussed above (among others).

VI. TRANSMISSION PLANNING ISSUES

A. Duke's CPIRP did not fully address several transmission planning issues the AGO raised in DEP and DEC's General Rate Cases (which were deferred to this proceeding).

Q. DID YOU PROVIDE TESTIMONY IN DEP AND DEC'S 2023 GENERAL RATE CASES?

A. Yes. I prepared written testimony in both DEP (E-2, Sub 1300) and DEC's (E-7, Sub 1276) most recent GRCs. My testimony addressed a variety of issues related to DEP and DEC's proposed transmission system investments.

Q. HOW DID THE COMMISSION'S ORDERS IN THOSE CASES ADDRESS YOUR FINDINGS AND RECOMMENDATIONS IN THAT CASE?

A. The Commission seemed to agree with Duke's assertion that all of the recommendations I raised were more related to "transmission planning" and thus more appropriately addressed in "the CPIRP or other proceedings."[72]

Q. DID DUKE TAKE ANY ACTION TO ADDRESS ANY OF THE TRANSMISSION RELATED ISSUES OR RECOMMENDATIONS THAT YOU MADE IN ITS CPIRP?

A. For some issues they did, but generally not in a detailed manner. However, Duke did provide a more comprehensive description of its approach to some of those issues and recommendations in its response to AGO DR 7-1, which is attached as Burgess Direct Exhibit 4.

Q. DID DUKE TAKE ANY ACTION TO ADDRESS YOUR RECOMMENDATION TO STUDY THE COST AND BENEFITS OF

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[72] "The Commission encourages DEC to continue evaluating and utilizing GETs as potential alternative solutions to identified transmission needs as appropriate, but the Commission agrees with DEC witness Maley's assertion that the recommendations of AGO witness Burgess and Sierra Club witness Goggin regarding transmission planning are designed to change DEC's decision-making regarding the types of transmission projects it undertakes. The Commission finds that the appropriate proceeding for consideration of GETs and other changes to transmission planning is the CPIRP or other proceedings." *Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions*, Docket No. E-7, Sub 1276 at 96 (Dec. 15, 2023).

DEPLOYING GRID ENHANCING TECHNOLOGIES (GETS) TO INTERCONNECT ADDITIONAL SOLAR GENERATION?

A: In its response to AGO DR 7-1, Duke identifies a few instances where it has employed technology solutions (to which it has applied the label "GETs") to address specific transmission needs.[73] However, Duke did not provide a comprehensive study on the potential benefits and costs of GETs as I recommended. Notably, Duke confirms that these technology solutions have been used as alternatives to reconductoring or constructing new transmission lines. This suggests that there may indeed be more expedient options for overcoming the interconnection limits Duke has applied to solar resources in its portfolio analysis beyond constructing new lines.

I recommend that Duke be required to perform a comprehensive study on the benefits and costs of GETs, including their ability to facilitate greater delivery of solar and wind energy. Duke's consideration of "GETs" technologies appears focused primarily on avoiding new transmission lines. However, GETs provide additional benefits beyond the ability to avoid new transmissions lines, including operational benefits such as the ability to integrate additional renewables and production cost savings. Any evaluation of GETs should include these operational benefits, which have been shown to be very substantial in some regions.

[73] It is not clear that the technologies Duke has evaluated in this context are comprehensive. For example, Duke does not mention any evaluation it has performed on Dynamic Line Ratings, which is one of the more commonly deployed GETs deployed in other jurisdictions.

Q. DID DUKE ADDRESS YOUR RECOMMENDATION TO ADOPT A FLEXIBLE APPROACH TO INTERCONNECTION?

A. Yes. In its response to AGO DR 7-1, Duke mentions that it is "making significant efforts to successfully manage the generator interconnection process to interconnect new generation including but not limited to investigating practices for offering provisional interconnection service to state-jurisdictional interconnection customers to allow resources to interconnect prior to NRIS required network upgrades being placed in-service." (emphasis added) This is noteworthy since provisional interconnection service (which is analogous to "energy only" interconnection service that I mentioned earlier), if structured correctly, could significantly accelerate renewable energy deployment and help facilitate faster achievement of a 2030-2032 interim target. However, Duke only just publicly announced its consideration of this option in an April 19, 2024 meeting.[74]

This delay in pursuing provisional interconnection is especially alarming since FERC authorized the practice as early as 2018 by way of its Order No. 845.[75] It is not clear why Duke did not pursue this option sooner consistent with HB 951's requirements. This delay suggests that—as stated in section III-C-2

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[74] DEC, DEP, & DEF Provisional Service Filings Update, Duke Energy (Apr. 19, 2024), https://t.co/ZcQSHjMGid.

[75] Peter Maloney, *FERC Order 845 opens door a little wider for energy storage*, UtilityDive (Apr. 23, 2018), https://www.utilitydive.com/news/ferc-order-845-opens-door-a-little-wider-for-energy-storage/521992/.

above—Duke has failed to pursue options that can facilitate the solar additions necessary to achieve a 2030-2032 interim target.

Finally, Duke's treatment of interconnection for third-party solar resources is inconsistent with its treatment of Company-owned gas resources. Specifically, Duke's plan includes gas resources as the Marshall and Roxboro plants whose nameplate rating exceeds the interconnection limit associated with retiring the coal resources. In other words, Duke is proposing to develop new gas resources in the 2029 timeframe that may not have full deliverability when they are constructed. That Duke does not and would not offer the same treatment to third-party solar resources is unreasonable. Specifically, solar resources should be procured even without full deliverability status in the 2028-2029 timeframe and then pursue additional deliverability at a later date if warranted.

Q: DID DUKE RESPOND TO YOUR RECOMMENDATION TO PURSUE INFLATION REDUCTION ACT (IRA) FINANCING, WHERE POSSIBLE, FOR RZEP PROJECTS?

A: Somewhat. In its response to AGO DR 7-1, Duke refers to the fact that it is providing informational updates to the Commission about the federal EIR program. This program could provide lower cost financing for a wide range of infrastructure projects, including those already included in the MYRPs, and yield cost savings to Duke customers. Duke was initially dismissive of this opportunity in its GRCs, but now seems to have more thoughtfully considered it. However, Duke's CPIRP does not contain any analysis of the potential cost savings that could be realized through this program. Notably, Duke's own evaluation confirms that the cost of the following activities could be reduced by utilizing the EIR program: replacing retired coal plant with carbon-free generation, uprating existing nuclear facilities, expanding pumped storage hydro, and reconductoring transmission lines. All of these are significant components of the proposed CPIRP. The Commission should require Duke to evaluate the potential cost savings of the federal EIR program and have those cost savings reflected in the PVRR of various portfolios.

Q: DID DUKE ADDRESS YOUR RECOMMENDATION TO, DURING COMPLETION OF EACH RZEP PROJECT, STUDY FOLLOW-ON UPGRADES TO UNLOCK ADDITIONAL RENEWABLE ENERGY INJECTION CAPABILITY?

A: Somewhat. In its response to AGO DR 7-1, Duke refers to the April 2024 release of a study regarding the "transmission impacts from integrating 12.5 GW of solar and solar paired with storage." This does not appear directly related to the recommendation at hand; however, it is noteworthy since the addition of 12.5 GW of solar is roughly in line with the requirement of the P1 scenario. Thus, this study may be helpful in identifying all transmission additions necessary to meet an Interim Target in line with P1. This is in contrast to Duke's RZEP study efforts to date, which the Company has admitted fall short of the solar additions necessary to meet P1, P2, and P3 requirements.

Q: DO YOU FIND DUKE'S RESPONSE CONCERNING?

A: Yes, the fact that this study has only just been released in April 2024 suggests that Duke was not actively pursuing a 2030 Interim Target as ordered by the Commission in its initial Carbon Plan order. Additionally, I still think it is worthwhile for the Commission to require Duke to study follow-on upgrades to RZEP projects. As I stated in my earlier testimony, other utilities have shown that small follow-on upgrades (i.e., <$1 million) to major new transmission projects can sometimes increase deliverability by several hundreds of MWs. These opportunities should be explored in Duke's case.

Q: DID DUKE ADDRESS YOUR RECOMMENDATION TO REPORT ON ITS PLANS FOR USING SURPLUS TRANSMISSION CAPACITY TO CONNECT NEW GENERATION AT UNDERUTILIZED COAL UNITS SUCH AS MARSHALL UNITS 1 AND 2?

A: Somewhat. In its response to AGO DR 7-1, Duke states that it already has plans for utilizing the transmission capacity at Marshall for other generation. However, this response does not fully address my concerns. My primary concern involved the fact that Duke's coal assets are underutilized even prior to their retirement dates. Thus, there may be opportunities to utilize the unused transmission capacity even before the official retirement date by simply using the headroom of the under-dispatched plant during most hours, particularly to accelerate battery storage deployment. I have seen no evidence that Duke has pursued this option. The Commission should order Duke to evaluate this option and incorporate any analysis into future CPIRP modeling.

Q: DID DUKE ADEQUATELY ADDRESS YOUR RECOMMENDATION TO IDENTIFY ANY NEAR-TERM TRANSMISSION UPGRADES THAT COULD FACILITATE ONSHORE WIND IN ITS CPIRP?

A: No. In its response to AGO DR 7-1, Duke does not provide any useful information about transmission upgrades that could facilitate onshore wind. This is notable since Duke's MYRPs also included no transmission upgrades related to onshore wind. Meanwhile, Duke claims that one of the primary reasons for delaying onshore wind deployment to 2031 in its CPIRP analysis is transmission lead time.[76] This suggests that Duke has not been seriously pursing a 2030 interim target, as required by the Commission's initial Carbon Plan order, since it has not pursued any transmission necessary to accommodate wind resource additions prior to 2030. If Duke were seriously pursuing onshore wind resources, as the Commission ordered, I would have expected some analysis to be performed to identify necessary transmission upgrades.

Q: DID DUKE ADEQUATELY ADDRESS YOUR RECOMMENDATION TO INCLUDE TRANSMISSION UPGRADES IN THE MYRP AS A MEANS TO TARGET THE MORE-OPTIMAL 2026 RETIREMENT DATE FOR THE MARSHALL PLANT?

A: No. In its response to AGO DR 7-1, Duke provides no rationale why it did not include transmission upgrades (or alternatively on-site battery storage) in its MYRP to facilitate a more optimal retirement date for Marshall Units 1 and 2. As I testified in the GRC, the optimal retirement date for these units as identified

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[76] *See* Burgess Direct Exhibit 11, and CPIRP, Appendix I, Figure I-4.

by Duke in the 2022 Carbon Plan was 2026.[77] In the case of DEP, the same issue is true for the Mayo plant as I describe earlier in my testimony. This lack of action in 2023 seems to contrast with the Commission's directive in the 2022 Carbon Plan Order stating: "That Duke shall take appropriate steps to optimally retire its coal fleet on a schedule commensurate with its Carbon Plan proposal filed on May 16, 2022."[78] I am concerned that the Company is not taking the appropriate steps to retire certain coal units according to the optimal schedule in the 2022 Plan.

Q: DID DUKE ADEQUATELY RESPOND TO YOUR RECOMMENDATION TO EVALUATE THE POTENTIAL FOR INCREASED INJECTION CAPABILITY FROM HIGHER VOLTAGE LEVELS OF RZEP PROJECTS AND PROVIDE A COMPARABLE METRIC FOR EVALUATING THESE OPTIONS IN THE FUTURE?

A: No. In its response to AGO DR 7-1, Duke simply stated that higher voltage levels "would incur a high cost for customers" but provided no analysis of what those "high costs" might be, whether potential benefits might exceed these costs, how those costs compared to other proposals in the CPIRP; nor did Duke consider the $/MW evaluation metric proposed in my prior testimony. This suggests that Duke is not considering the most cost-efficient transmission solutions for its long-term system needs. Instead, Duke's approach will require lines to be replaced repeatedly at a significant additional cost to customers. This approach is also not in line with FERC's most recent order, which specifically

[77] Direct Testimony of Edward Burgess, Docket No. E-7, Sub 1276 at 43 (July 19, 2023).
[78] Initial Carbon Plan Order at 132.

recognized the benefits of "right-sizing" as well as a greater focus on these long-term need analyses. The Commission should order Duke to perform this evaluation and reflect the results in future CPIRP analysis.

Q: DID DUKE ADEQUATELY ADDRESS YOUR RECOMMENDATION TO IDENTIFY ADDITIONAL RZEP PROJECTS IN THE EVENT THAT MORE SOLAR ADDITIONS ARE NEEDED IN THE 2028 TIMEFRAME?

A: No. In its response to AGO DR 7-1, Duke identified a single transmission project that could facilitate more solar additions by the 2028 timeframe. As I explained earlier, this is at odds with the amount of solar additions that Duke admits would be needed to achieve the P3 portfolio, let alone the P1 portfolio.[79] This suggests that Duke's transmission planning efforts have not been oriented towards meeting the 2030 Interim Target needs.

B. Recommendations

Q. CAN YOU SUMMARIZE YOUR TRANSMISSION PLANNING RECOMMENDATIONS BASED ON YOUR ASSESSMENT OF DUKE'S RESPONSES?

A. Yes. My recommendations remain largely the same as they did in the GRCs, and can be summarized as follows:

1. Require Duke to study RZEP additions that are actually sufficient to meet modeled renewable energy additions across a range of scenarios (and that do not leave a gap in availability as has been the case in recent years).

[79] Duke Response to AGO DR 4-10 (attached as Burgess Direct Exhibit 13).

2. Accelerate development of provisional interconnection service to state-jurisdictional interconnection customers to allow resources to interconnect prior to NRIS required network upgrades being placed in-service.
3. Require a study of the costs/benefits of Grid Enhancing Technologies (GETs) within six months, including the elements outlined in my GRC testimony.
4. Require Duke to continue pursuing Energy Infrastructure Reinvestment (EIR) program financing, and to provide an analysis of the potential reduction in revenue requirements from applying this to each of the relevant project categories (e.g., transmission reconductoring, retired coal plant replaced by carbon-free generation, etc.).
5. During completion of each RZEP project, require Duke to study follow-on upgrades to unlock additional renewable energy injection capability.
6. Require Duke, within six months, to identify any near-term transmission upgrades that could facilitate onshore wind.
7. Require Duke to provide an analysis of transmission upgrades as a means to facilitate retirement at each of its coal plants (i.e., not just Mayo) absent on-site generation.
8. When considering future RZEP projects, require Duke to evaluate higher voltage line replacement options and to utilize a MW/$ metric for evaluating the cost-efficiency of increasing injection capability.
9. Require additional actions to evaluate regional transmission projects, as described in my GRC testimony.

10. Require DEC to update its non-wires solutions methodology assess benefits and adjust costs to reflect the IRA tax credits for battery storage more precisely.

VII. RECOMMENDATIONS

Q. CAN YOU PROVIDE A FULL LIST OF THE RECOMMENDATIONS YOU'VE MADE THROUGHOUT YOUR TESTIMONY?

A. Yes. My recommendations include the following:

Interim Target:

- The Commission should set a clear directive for Duke to achieve the Interim Target no later than 2032. This appropriately balances the statutory guidelines for a 2030 target versus the new challenges posed by recent load growth.
- The Commission should direct Duke to pursue the multiple strategies outlined in my testimony above for accelerating coal retirements and increasing renewable energy delivery.

Coal Retirements:

- The Commission should direct Duke to further evaluate and potentially implement multiple strategies for accelerating coal retirements at Belews Creek and Roxboro to the 2030-32 timeframe, including:
  - On-site replacement with additional CTs and/or batteries (factoring in the full energy communities bonus tax credit),
  - Off-site replacement using CTs and/or batteries, combined with any transmission upgrades needed,
  - Staggered unit retirements,

- Gas conversion at Belews Creek with more limited duration (e.g. retires before 2035), shorter fuel contract, and CC deferral.

Renewable Resource Additions:

- In all near-term solar procurements, Duke should pursue development of higher-output hybrid solar + storage resources (capacity factors >30% AC) to better leverage limited interconnection space.
- The Commission should authorize procurement of at least 300 MW of onshore wind resources now, with a goal to bring the first tranche of wind resources online by 2029.
- Duke should further evaluate and potentially procure imported wind resources through dynamic transfers.
- Procure offshore wind as soon as practicable, with goal of 2032.

Natural Gas Resources:

- All CPCN's for new gas should be required to include an analysis that reflects the impacts of the EPA's new Section 111 rule, with multiple compliance options evaluated including CCS, reduced operations (<40% capacity factor), and replacement with non-emitting resources.
- ELCC values for all gas resources should be discounted based on the firm fuel supply Duke has secured for its gas fleet as a whole. This adjustment should be performed prior to any analysis used to support a CPCN application for new gas resources. This evaluation should also consider a scenario where incremental FT cannot be secured on the timeline Duke has forecasted.

Load Forecast:

- Develop a process for an independent load forecast, ideally one that can also review confidential information provided to Duke regarding new economic development projects.
- Require Duke to accurately model usage per customer for all sectors, accounting for long-term improvements in end-use efficiency.
- Require Duke to develop meaningful load reductions through the four customer program areas identified and discussed above (among others). These include:
- Require Duke to leverage expected future rooftop solar PV installations (e.g., through the Solar for All program) to include battery storage.
- Developing an EV V2X program with the goal of recruiting at least 5% of EV customers to participate during winter peak hours.
- Installing more efficient winter heating devices (e.g., cold climate heat pumps) with the goal of reducing peak demand by 500 MW.
- Developing new demand response and energy efficiency programs that are tailored to increase participation from new large-site customer loads.

<u>Transmission Planning:</u>

- Require Duke to study RZEP additions that are actually sufficient to meet modeled renewable energy additions across a range of scenarios (and that do not leave a gap in availability as has been the case in recent years).
- Accelerate development of provisional interconnection service to state-jurisdictional interconnection customers to allow resources to interconnect prior to NRIS required network upgrades being placed in-service.

- Require a study of the costs/benefits of Grid Enhancing Technologies (GETs) within six months, including the elements outlined in my GRC testimony.
- Require Duke to continue pursuing Energy Infrastructure Reinvestment (EIR) program financing, and to provide an analysis of the potential reduction in revenue requirements from applying this to each of the relevant project categories (e.g., transmission reconductoring, retired coal plant replaced by carbon-free generation, etc.)
- During completion of each RZEP project, require Duke to study follow-on upgrades to unlock additional renewable energy injection capability.
- Require Duke, within six months, to identify any near-term transmission upgrades that could facilitate onshore wind.
- Require Duke to provide an analysis of transmission upgrades as a means to facilitate retirement at each of its coal plants (i.e., not just Mayo) absent on-site generation.
- When considering future RZEP projects, require Duke to evaluate higher voltage line replacement options and to utilize a MW/$ metric for evaluating the cost-efficiency of increasing injection capability.
- Require additional actions to evaluate regional transmission projects, as described in my GRC testimony.
- Require DEC to update its non-wires solutions methodology assess benefits and adjust costs to reflect the IRA tax credits for battery storage more precisely.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Ed Burgess

Morpho Strategies LLC * (503) 862-8004 * eburgess@morphostrategies.com

Professional Summary

Ed has over 12 years of experience working as a consultant in the energy and utilities industry. He specializes in various grid planning issues including the integration of renewable energy, energy storage, electric vehicles, and distributed energy resources. He has provided expert testimony on over 27 occasions before 12 state utility commissions on issues including utility resource planning, transmission planning, fuel and power purchase costs, rate design, and electric vehicle programs. Prior to founding Morpho Strategies in 2024, he was a Consulting Partner at Strategen where he worked for over 8 years. While at Strategen, he directed the company's grid planning practice area, where he provided technical consulting services to a variety of public and private sector clients including state and federal government agencies, Fortune 500 companies, trade associations, and public interest organizations. He also helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council and grew the organization to over 40 member companies. He also worked for Arizona State University where he helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council.

Education

Professional Science Masters, Solar Energy Engineering and Commercialization
Arizona State University – Tempe, AZ (2012)

Master of Science, Sustainability
Arizona State University – Tempe, AZ (2011)

Bachelor of Arts, Chemistry
Princeton University – Princton, NJ (2007)

Work Experience

Founder, Morpho Strategies LLC, (March 2024 – Present)

Consulting Partner, Strategen Consulting, (August 2015 – March 2024)

- Joined in 2015 and helped grow the company's consulting practice team by more than 3 times.
- Directed the company's grid planning practice area, where he provided technical consulting services to a variety of public and private sector clients including state

and federal government agencies, Fortune 500 companies, trade associations, and public interest organizations.
- Helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council and grew the organization to over 40 member companies.

Independent Consultant (2012 – 2015)

- Worked as a technical consultant supporting various clients for attorney Kris Mayes (former Arizona Corporation Commission Chair and current Arizona Attorney General).
- Technical consultant for Schlegel & Associates, working with a coalition of Fortune 500 companies on energy efficiency and demand-side management policies across the US.

Research Associate, Arizona State University (2012-2015)

- Worked across disciplines as a researcher and program administrator for various efforts related to energy and sustainability.
- Assisted in launching the University's Utility of the Future initiative as well as the Energy Policy Innovation Council.
- Conducted a technical study in partnership with Arizona Department of Environmental Quality on the compliance pathways and impacts of the EPA's Clean Power Plan.

Research Fellow, Environmental Defense Fund (2007 – 2009)

Expert Testimony

California Public Utilities Commission

- Pacific Power 2020 Energy Cost Adjustment Clause (Docket No. A.19-08-002)
- Pacific Power 2021 Energy Cost Adjustment Clause (Docket No. A.20-08-002)
- Pacific Power 2022 Energy Cost Adjustment Clause (Docket No. A.21-08-004)
- Pacific Gas and Electric's Day-Ahead Real Time Rate and Pilot (Docket No. A.20-10-011)
- Pacific Gas and Electric's Electric Vehicle Charge 2 Application (Docket No. A.21-10-010)
- CPUC Rulemaking on Emergency Summer Reliability (Docket No. R.20-11-003)

Colorado Public Utilities Commission

- Tri-State Generation and Transmission Application for a CPCN (Docket No. 22A-0085E)

Indiana Utility Regulatory Commission

- Duke Energy Fuel Adjustment Clause (Cause No. 38707 FAC 125)

- Duke Energy Fuel Adjustment Clause –Sub-docket Investigation (Cause No. 38707 FAC 123 S1)

Louisiana Public Service Commission

Entergy Certification to Deploy Natural Gas Distributed Generation (Docket No. U-36105)

Massachusetts Department of Public Utilities

- National Grid General Rate Case (D.P.U. 18-150)
- Eversource, National Grid, and Until SMART Tariff (D.P.U. 17-140)

Michigan Public Service Commission

- Consumers Energy 2021 Integrated Resource Plan (Docket No. U-21090)

Nevada Public Utilities Commission

- NV Energy's Integrated Resource Plan in (Docket No. 20-07023)

North Carolina Utilities Commission

- Duke Energy Carbon Plan (Docket No. E-100, Sub 179)
- Duke Energy Progress 2023 General Rate Case
- Duke Energy Carolinas 2033 General Rate Case

Oregon Public Utilities Commission

- Pacific Power 2021 Transition Adjustment Mechanism (Docket No. UE-375)
- Pacific Power 2022 Transition Adjustment Mechanism (Docket No. UE-390)
- Northwest Natural 2022 General Rate Case (Docket No. UG-435)

South Carolina Public Service Commission

- Dominion Energy South Carolina 2019 Avoided Cost Methodologies (Docket No. 2019-184-E)
- Duke Energy Carolinas 2019 Avoided Cost Methodologies (Docket No. 2019-185-E)
- Dominion Energy Progress 2019 Avoided Cost Methodologies (Docket No. 2019-186-E)
- Dominion Energy South Carolina 2021 Avoided Cost Methodologies (Docket No. 2021-88-E)

Washington Utilities and Transportation Commission

- Avista Utilities 2020 General Rate Case (Docket No. UE-200900)
- Avista Utilities 2022 General Rate Case (Docket No. UE-220053/UG-220054)
- Puget Sound Energy 2022 General Rate Case (Docket No. UE-220066/UG-220067)

Selection of Relevant Experience

Western Resource Advocates
Nevada Energy IRP Analysis / 2018 -2019

- Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003).
- Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General
SMART Program / 2016 -2017

- Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years.
- Served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

Southwest Energy Efficiency Project
IRP Technical Analysis and Modeling / 2018 -2020

- Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
- Provided analysis on Salt River Project's resource plan as part of its 2035 planning process.
- Evaluated different levels of renewable energy and energy efficiency and identify any changes to the resources needed to meet these requirements and ensure reliability.
- Worked with Strategen technical team on utilizing a capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRPs.

California Energy Storage Alliance
California Hybridization Assessment / 2018 -2019

- Managed a special initiative of this leading industry trade group to conduct technical analysis and stakeholder outreach on the value of hybridizing existing gas peaker plants with energy storage

Portland General Electric
Energy Storage Strategy / 2016

- Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
- Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
- Supported development of a competitive solicitation process for storage technology solution providers.

Arizona Residential Utility Consumer Office (RUCO)

IRP Analysis and Impact Assessment / 2015 -2018

- Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
- Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
- Lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2020 -2021

- Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp'sIRP stakeholder input process.
- Prepared analysis, technical comments, discovery requests in advance of drafting formal comments to be submitted before the Oregon Public Utility Commission.

North Carolina, Office of the Attorney General

Duke Energy 2020 IRP Technical Support / 2020 -2021

- Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.
- Presented original analysis at multiple IRP-related technical workshops hosted by the NCUC

University of Minnesota

Energy Storage Stakeholder Workshops / 2016 -2017

- Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
- Conducted study on the use of storage as an alternative to natural gas peaker.
- Presented workshop and study findings before the Minnesota Public Utilities Commission.

New Hampshire Office of Consumer Advocate

NEM Successor Tariff Design / 2016

- Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Xcel Energy

Time-of-use Rates / 2017 -2018

- Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

Selected Recent Publications:

- New York BEST, 2020. Long Island Fossil Peaker Replacement Study.
- Ceres, 2020. Arizona Renewable Energy Standard and Tariff: 2020 Progress Report.
- Virginia Department of Mines and Minerals, 2020. Commonwealth of Virginia Energy Storage Study.
- Sierra Club, 2019. Arizona Coal Plant Valuation Study.
- Strategen, 2018. Evolving the RPS: Implementing a Clean Peak Standard."
- SunSpecAlliance for California Energy Commission.,2018.Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California.

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Refer to Appendix F, page 9 which states: "the Companies leveraged coal unit groupings to retire pairs of units where reduced costs of common operations and equipment are realized with retiring both units simultaneously compared to isolated retirements."

a. Please provide a detailed explanation for how including the additional modeling constraint of pairing unit retirements leads to lower overall costs.
b. Please provide any analysis Duke has performed to quantify the cost savings of paired unit retirements versus staggered unit retirements.

Response:

4-30(a): The pairing of units represents a realistic assumption of retiring coal units with common operations and equipment to realize saving associated with completely eliminating the shared resources or need to maintain shared components. Allowing units to retire independently would result in the retirement of individual units that would further require the operations and maintenance staff and equipment to be less efficiently optimized across stations.

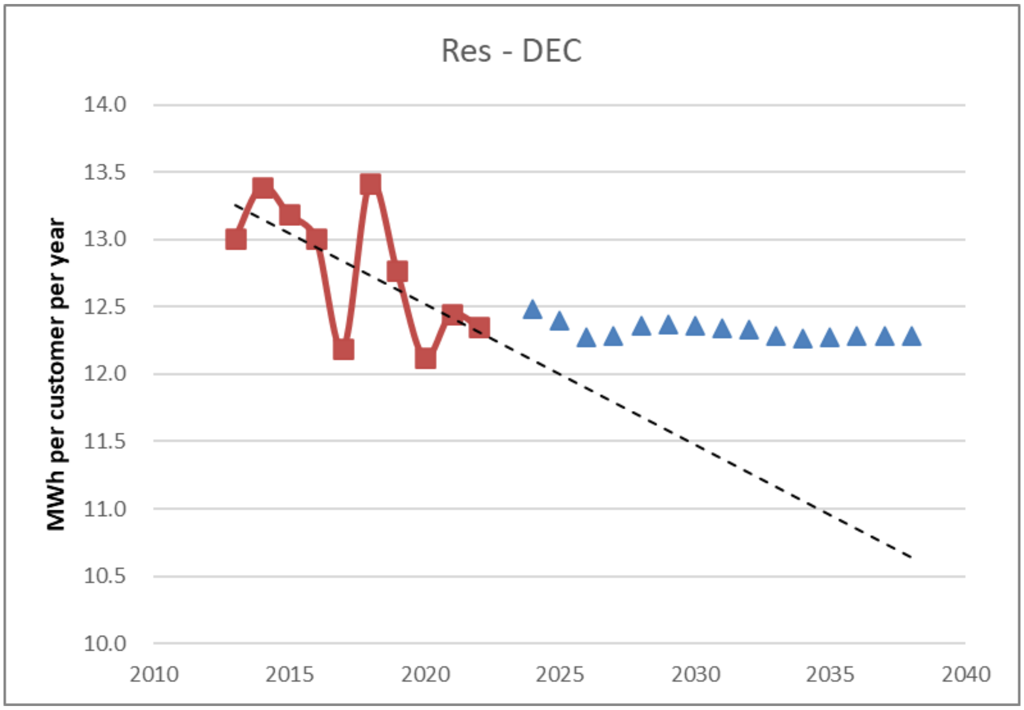
4-30(b): The Companies have not performed quantitative cost analysis associated with select units retiring together compared to retiring independently.

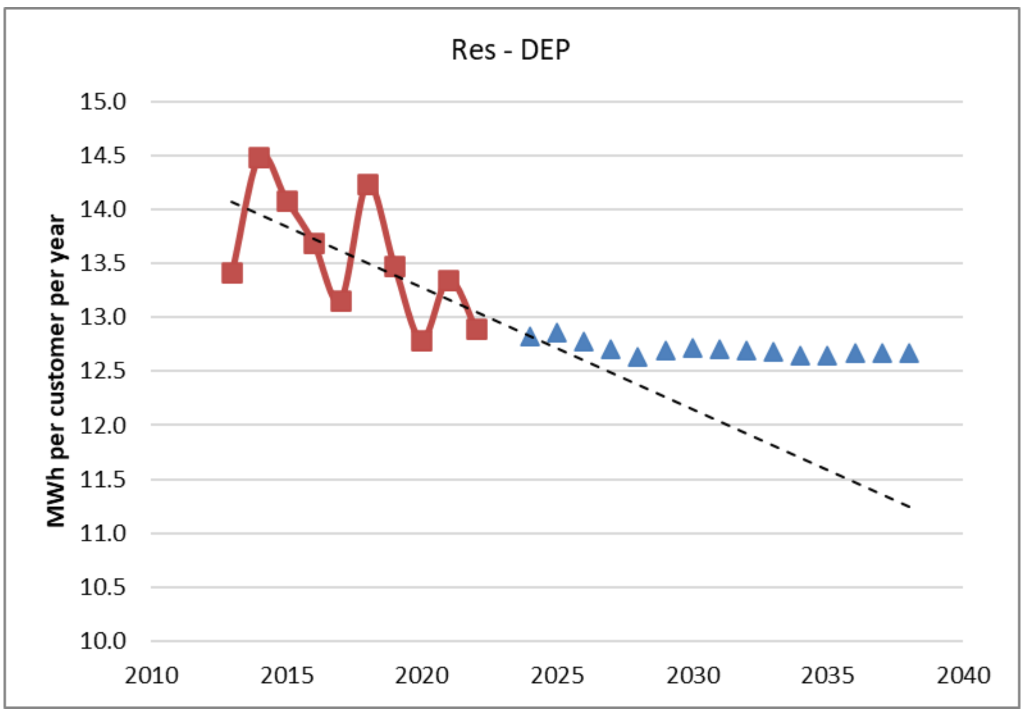
Responder: Michael T. Quinto, Director, IRP Advanced Analytics

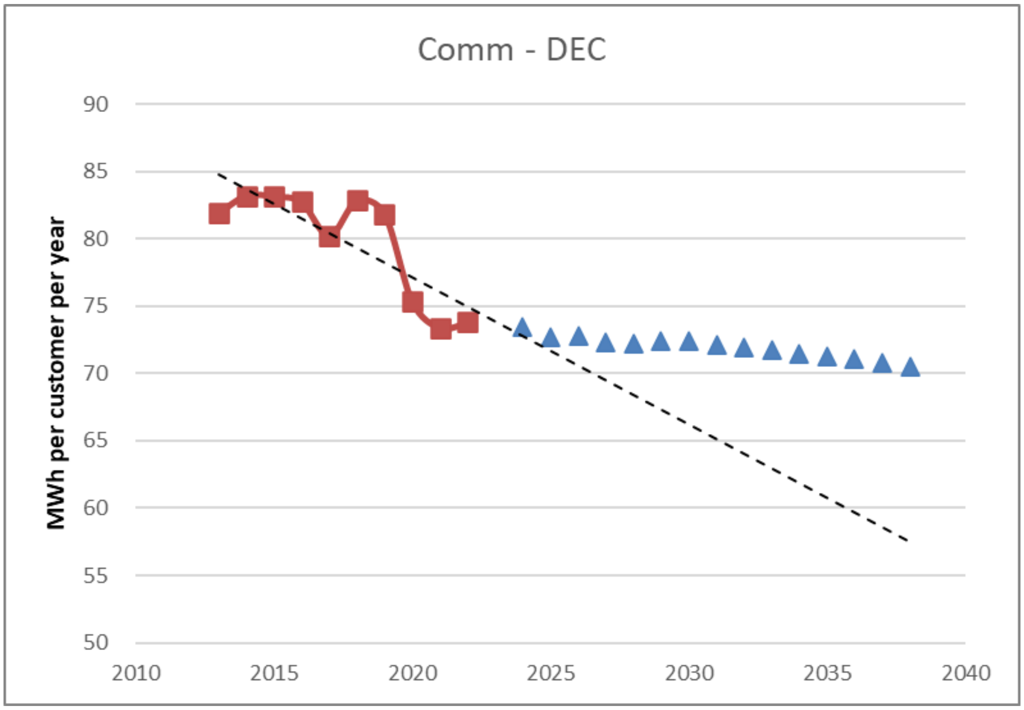
Usage Per Customer Analysis

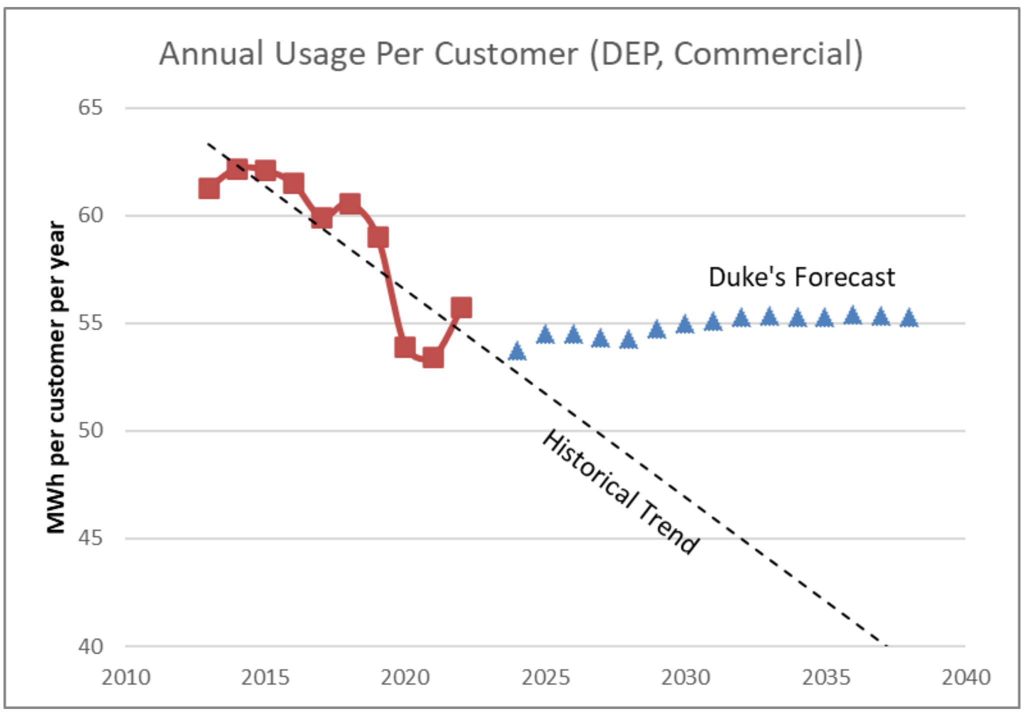
Overview:

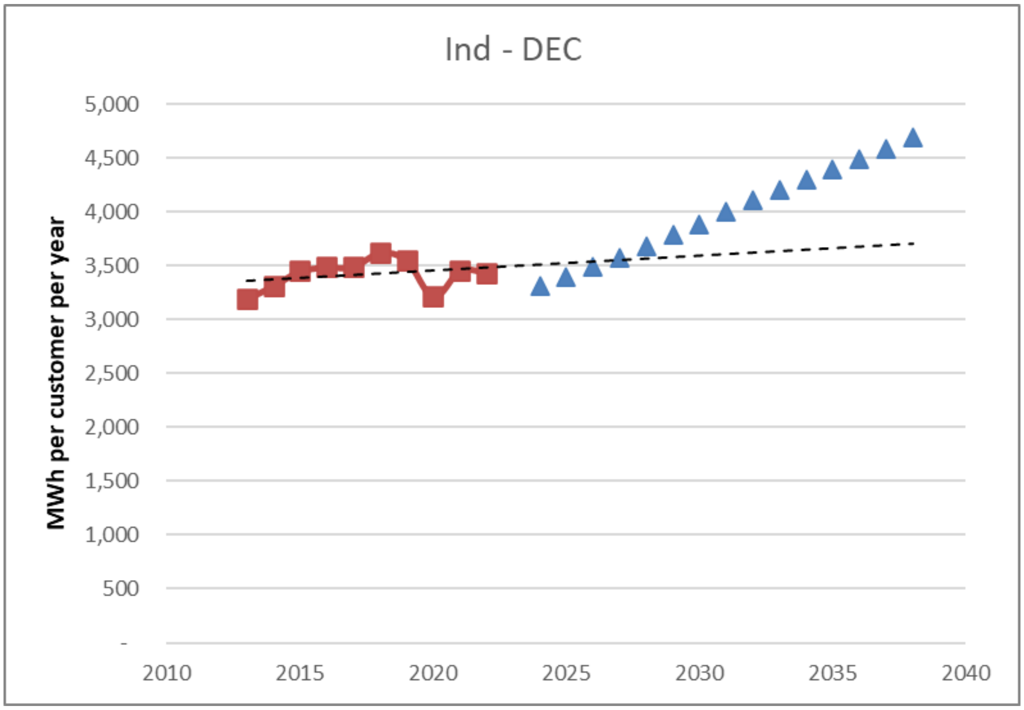
Duke's load forecasting approach explicitly models Usage Per Customer (UPC) for the residential sector, but not for the commercial or industrial sectors. Regardless, the implied UPC values can be calculated for any sector to observe how the forecasted values compare to historical trends. Duke also applies four separate adjustments to each of these sectors to account for: (1) rooftop solar PV, (2) electric vehicles (EVs), (3) utility energy efficiency programs (UEE), and (4) large site load additions. For this analysis, all four of these adjustments were removed from the sector-level load forecasts to determine the underlying UPC trends resulting from baseline efficiency improvements. The charts below show the observed UPC values (in MWh/customer/year), excluding the effects of UEE, EVs, rooftop solar PV, and large site loads. Sector-level load forecast data used to conduct this analysis was from Duke's Supplemental Response to PSDR 3-8 (per PSDR 21-11). Adjustments for PV, EVs, UEE, and large site loads were removed using data from Duke's Supplemental Response to AGO 1-8.

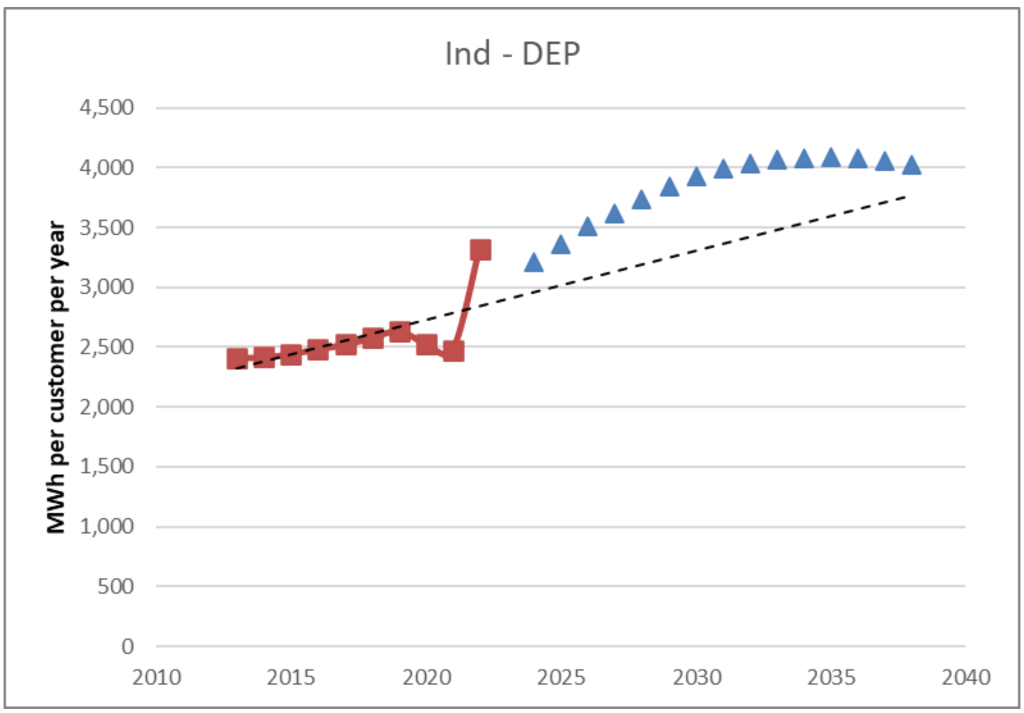

Res - DEC
MWh per customer per year
14.0
13.5
13.0
12.5
12.0
11.5
11.0
10.5
10.0
2010
2015
2020
2025
2030
2035
2040


Res - DEP
MWh per customer per year
15.0
14.5
14.0
13.5
13.0
12.5
12.0
11.5
11.0
10.5
10.0
2010
2015
2020
2025
2030
2035
2040


Comm - DEC
MWh per customer per year
90
85
80
75
70
65
60
55
50
2010
2015
2020
2025
2030
2035
2040


Annual Usage Per Customer (DEP, Commercial)
MWh per customer per year
65
60
55
50
45
40
Duke's Forecast
Historical Trend
2010
2015
2020
2025
2030
2035
2040


Ind - DEC
MWh per customer per year
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2010
2015
2020
2025
2030
2035
2040


Ind - DEP
MWh per customer per year
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2010
2015
2020
2025
2030
2035
2040

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please refer to the Rebuttal Testimony of DEC witness Daniel J. Maley in Docket No. E-7, Sub 1276, page 77 which states the following: "I disagree with several Witness Burgess' recommendations [sic]. Starting on page 6, line 13, Witness Burgess makes several transmission policy-related recommendations for activities already underway or that would be more appropriately considered in the Carbon Plan, NCTPC, or other avenues. I would like to address a few of his recommendations more specifically."

a. Please confirm that Witness Burgess' recommendations starting on page 6, line 13, as referenced above, include the following:

"My recommendations are as follows. The Commission should:

1. Approve DEC's proposed RZEP projects as part of the MYRP. However, the MYRP should also be revised to include *all* anticipated costs, even if some are included contingent on future approvals (e.g., CPCNs).

   Cost Related:

2. Require study of the costs/benefits of Grid Enhancing Technologies (GETs) within six months. The study should include the elements described in section V-A-1.

3. Require Duke to pursue Inflation Reduction Act (IRA) financing, where possible, for RZEP projects as described in section V-A-2. Energy Infrastructure Reinvestment (EIR) program financing should be pursued as part of this MYRP cycle (i.e., prior to the 2026 cutoff).

4. Require DEC, during completion of each RZEP project, to study follow-on upgrades to unlock additional renewable energy injection capability, as described in section V-A-3.

5. Require additional actions to evaluate regional transmission projects, as described in section V-A-4, including: (a) study of economic regional projects associated with DEC (i.e., through SERTP); (b) study greater transmission service requests (TSR) between DEP/DEC than 700 MW.

6. Require DEC to update its non-wires solutions methodology (as described in section V-A-5) to more precisely assess benefits and adjust costs to reflect the IRA tax credits for battery storage.

7. Require DEC to report on its plans for using surplus transmission capacity to connect new generation at underutilized coal units such as Marshall Units 1 and 2 (see section V-A-6)

   Carbon Plan Related:

8. Require Duke, as part of its first biennial Carbon Plan Integrated Resource Plan (CPIRP), to identify any near-term transmission upgrades that could facilitate onshore wind (see section V-B-1).

9. Require DEC to include transmission upgrades in the MYRP as a means to target the more-optimal 2026 retirement date for the Marshall plant (see section V-B-2). DEC should also seek DOE financing support for this (e.g., through the EIR program) as appropriate.

10. Require DEC to evaluate the potential for increased injection capability from higher voltage levels of RZEP projects and provide a comparable metric for evaluating these options in the future as described in section V-3 B-3.

11. Require DEC to identify additional RZEP projects in the event that more solar additions are needed in the 2028 timeframe according to the 2023/2024 Carbon Plan (see section V-B-4).

    Other Matters:

12. Require MYRP rates to be updated annually to reflect annual changes in FERC formula rates.

13. Require DEC to develop a plan to provide its System Intelligence information to neighboring utilities in real time and request similar information from them.

14. Require DEC to develop a plan to implement Flexible Interconnection across its transmission and distribution system."

Response:

The Company objects to the premise of this request to the extent it asks the Companies to provide a legal conclusion or otherwise determine what is "appropriate" for the Commission to consider in this proceeding. Notwithstanding the foregoing objection, the Companies' refer the AGO to the Companies response to DR 7-2 and respond as follows:

"My recommendations are as follows. The Commission should:
1. Approve DEC's proposed RZEP projects as part of the MYRP. However, the MYRP should also be revised to include all anticipated costs, even if some are included contingent on future approvals (e.g., CPCNs).

Response: A networked transmission project such as the RZEP projects has to be evaluated and included in an approved transmission plan that is the product of a FERC accepted transmission planning process such as NERC TPL-001 compliance, the LGIP DISIS Cluster Study process as specified in the DEC/DEP Joint Open Access Transmission Tariff (OATT), or the Carolinas Transmission Planning Collaborative Local Transmission Planning process. These processes are described in Appendix L of the Plan. All of the DEC RZEP 1.0 projects that are included in the MYRP are in an approved transmission plan. The status on cost and schedule for these projects is updated through a semi-annual report filed with the NCUC in Docket No. E-100, Sub 190T.

Cost Related:

2. Require study of the costs/benefits of Grid Enhancing Technologies (GETs) within six months. The study should include the elements described in section V-A-1.

Response: As discussed in Appendix L of the Plan, Duke Energy has utilized GETs as alternative solutions to identified transmission needs in the past and will continue to evaluate and utilize these potential alternative solutions where evaluated to be a sustainable and reliable solution for addressing identified transmission needs. Duke Energy has utilized phase shifting transformers, switchable reactors, and remedial action schemes as alternative solutions to reconductoring transmission lines or constructing new transmission lines. Duke Energy continues to consider different technologies for solutions to transmission needs as evidenced in the DEC and DEP 2022 Definitive Interconnection System Impact Study ("DISIS") Phase 2 Study Reports reflecting identified transmission network upgrade needs. These reports show five transmission line loading issues are being resolved through application of switchable reactors and eight transmission lines requiring reconductoring are utilizing High Temperature Low Sag Aluminum Conductor Steel Supported/ Trapezoidal Wire conductor. An overall assessment methodology and summary of analytical results evaluating non-wires alternatives such as battery storage being considered to defer or avoid traditional transmission upgrades is provided in Appendix G (Integrated System and Operations Planning).

Duke Energy will continue to consider GETs as potential alternative solutions to transmission needs. However, alternative solutions must not create conditions that are so complex that system operators are no longer able to maintain local and wide area situational awareness. Over-reliance on GETs can lead to circumstances where operators cannot successfully assess potential risks, hazards, or system events that might occur. Duke Energy will continue to use due diligence when considering application of GETs and non-wires alternatives to ensure any operational complexity is minimized and operator situational awareness of system configuration is not lost.

Furthermore, the Companies are implementing Ambient Adjusted Ratings in accordance with FERC Order 881 and the Companies will be implementing FERC Order 2023 requiring evaluation of alternative transmission technologies when studying generator interconnection requests.

3. Require Duke to pursue Inflation Reduction Act (IRA) financing, where possible, for RZEP projects as described in section V-A-2. Energy Infrastructure Reinvestment (EIR) program financing should be pursued as part of this MYRP cycle (i.e., prior to the 2026 cutoff).

Response: In reference the EIR program (the DOE loan guarantee program), Duke Energy is providing informational updates on the loan program to the Commission through the IIJA-related Docket No. M-100, Sub 164.

4. Require DEC, during completion of each RZEP project, to study follow-on upgrades to unlock additional renewable energy injection capability, as described in section V-A-3.

Response: The CTPC Local Transmission Planning process studies the entire DEC and DEP transmission systems comprehensively to identify constraints with high renewable scenarios. A 2023 study report reflecting resulting transmission impacts from integrating 12.5 GW of solar and solar paired with storage is planned to be published in April 2024. These study results are reflecting additional follow-on upgrades to enable more renewables integration.

5. Require additional actions to evaluate regional transmission projects, as described in section V-A-4, including: (a) study of economic regional projects associated with DEC (i.e., through SERTP); (b) study greater transmission service requests (TSR) between DEP/DEC than 700 MW.

Response (a) As stated in Appendix L, pages 15-17, the Companies have been and continue to be participants of SERTP and associated planning activities including studies of economic regional projects. Several economic studies for regional transfers have been conducted through SERTP over the last five years with DEC being the sink area, with the latest conducted in 2023.

Response (b) Appendix L - Transmission System Planning and Grid Transformation, pages 23-27, of the CPIRP identifies additional RZEP 2.0 projects in DEC including a Lilesville – Oakboro 230kV B/W line reconductor project that will enable more renewable integration as well as improve transfer capability between DEC and DEP. Furthermore, as reflected in the recent March 22 CTPC Transmission Advisory Group stakeholder meeting, in its 2024 Study Scope presentation, the CTPC plans to study a new 1000 MW DEC to DEP transfer.

6. Require DEC to update its non-wires solutions methodology (as described in section V-A-5) to more precisely assess benefits and adjust costs to reflect the IRA tax credits for battery storage.

Response: There is no need to introduce a requirement because the Company already regularly updates its Non-Traditional Solution ("NTS") screening methodology to reflect the value of generation capacity, energy, ancillaries, transmission, and distribution benefits to align with the latest studies. The screening process intentionally starts with generous benefits and lower costs (reduced by IRA tax credits) to screen in more potential projects. As projects progress through the screening process to a more detailed analysis, the precision increases for the NTS cost, the applicable tax credits, and the benefits that each NTS could provide.

7. Require DEC to report on its plans for using surplus transmission capacity to connect new generation at underutilized coal units such as Marshall Units 1 and 2 (see section V-A-6)

Response: DEC has already stated plans for utilization of the generation replacement process for utilizing transmission capacity at Marshall for units 1 and 2 for gas/hydrogen CTs and at Allen Plant for battery storage.

<u>**Carbon Plan Related:**</u>

8. Require Duke, as part of its first biennial Carbon Plan Integrated Resource Plan (CPIRP), to identify any near-term transmission upgrades that could facilitate onshore wind (see section V-B-1).

Response: Chapter 4 (Execution Plan) at 24-25 and Appendix I (Renewables and Energy Storage) at 18-24 provide significant detail regarding the need for and role of onshore wind as part of the Companies' proposed execution plan.

9. Require DEC to include transmission upgrades in the MYRP as a means to target the more-optimal 2026 retirement date for the Marshall plant (see section V-B-2). DEC should also seek DOE financing support for this (e.g., through the EIR program) as appropriate.

Response: See the Companies' response to subpart 3 above.

10. Require DEC to evaluate the potential for increased injection capability from higher voltage levels of RZEP projects and provide a comparable metric for evaluating these options in the future as described in section V-3 B-3.

Response: Converting DEC 100kV double circuit lines to 1-230kV circuit and 1-100kV circuit has been considered, but eliminates the use of auto-swapover schemes that would degrade reliability for customers. Converting DEC 100kV double circuit lines to 230kV double circuit lines would incur a high cost for customers having to replace 100kV high-side transformers with 230kV high-side transformers. With advanced conductors, significant capability can be achieved through upgrades of transmission lines without changing voltage class levels.

11. Require DEC to identify additional RZEP projects in the event that more solar additions are needed in the 2028 timeframe according to the 2023/2024 Carbon Plan (see section V-B-4).

Response: Appendix L - Transmission System Planning and Grid Transformation, pages 23-27, of the CPIRP identifies additional RZEP 2.0 projects in DEC including a Lilesville – Oakboro 230kV B/W line reconductor project that will enable more renewable integration as well as improve transfer capability between DEC and DEP.

Other Matters:

12. Require MYRP rates to be updated annually to reflect annual changes in FERC formula rates.

Response: This is not an appropriate issue for this proceeding.

13. Require DEC to develop a plan to provide its System Intelligence information to neighboring utilities in real time and request similar information from them.

Response: This asset health monitoring information would not be of any real-time operational benefit to neighboring utilities.

14. Require DEC to develop a plan to implement Flexible Interconnection across its transmission and distribution system."

Response: Utilizing a "connect and manage" approach for integration of a significant amount of renewable resources can lead to large curtailments of the resources and create reliability issues such as occurred with an ERCOT emergency event on September 2023 where ERCOT directed curtailment of 1,590 MW of generation (primarily wind resources) in the South region to address the potential for a reliability condition on a double-circuit 345 kilovolt (kV) transmission line south of San Antonio. Duke Energy is required through HB 951 and N.C.G.S. 62-110.9(a)(3) to: "Ensure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid." Duke Energy is making significant efforts to successfully manage the generator interconnection process to interconnect new generation including but not limited to investigating practices for offering provisional interconnection service to state-jurisdictional interconnection customers to allow resources to interconnect prior to NRIS required network upgrades being placed in-service.

Responder: Ami Patel, Associate Counsel

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please refer to Table SPA T-4 showing the results of the Supplemental Coal Retirement Analysis.

a. Please explain whether a similar Supplemental Coal Retirement Analysis was conducted for the P1 Fall Base and P2 Fall Base scenarios. If so, please provide the results of those analyses.
b. Please provide the model-selected coal retirement dates for the P1 Fall Base scenario and indicate whether they differ from the final portfolio retirement dates.

Response:

a.) Supplemental Coal Retirement Analysis was not conducted for the Pathway 1 or Pathway 2 for use in the P1 Fall Supplement or P2 Fall Supplemental Portfolios.

b.) As stated in part a.) the Companies did not conduct Supplemental Coal Retirement Analysis for the Pathway 1 or Pathway 2 in the Supplemental Planning Analysis. For P1 Fall Supplemental and P2 Fall Supplemental, the Companies utilized the coal retirement dates as determined in the initial filing as shown in Appendix F Tables F-4 and F-5 for the Pathway 1 and Pathway 2 portfolios respectively.

Responder: Michael Quinto, Director, IRP Advanced Analytics

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Refer to Appendix C, Table C-34 which shows Generic Transmission Network Upgrade Costs for the Mayo Retirement as $0.07/W.

a. Please explain what these costs reflect and whether they were avoidable under any scenario in Duke's modeling (e.g., due to on-site replacement generation).

b. Please explain whether Duke modeled transmission network upgrade costs associated with any other coal plant retirements. If yes, please provide those cost assumptions. If not, please explain why not.

c. For each coal plant in Duke's portfolio (including Marshall, Roxboro, and Belews Creek) please explain whether economic retirement without on-site generation replacement was a selectable option in EnCompass. For each plant, please explain whether Duke assumed incremental transmission costs associated with the retirement and provide the assumed costs.

Response:

2-8(a): Please refer to the Companies' response to AGO DR 2-11 for the basis of this assumption.

2-8(b): No, the Companies did not model transmission network upgrade costs associated with any other coal plant retirement. Please refer to the Companies' response to AGO DR 2-11 for the basis of these assumptions.

2-8(c): The Companies' coal retirement analysis assumed future utilization of all retiring coal sites with the exception of Mayo, as outlined in the Companies' response to AGO DR 2-11. The Companies assumed transmission network upgrades associated with applicable retiring coal sites were mitigated by future replacement of resources at those sites. The Companies did not conduct additional scenarios which evaluated the impact to coal retirements assuming the retiring coal units were not replaced with on-site generation. As stated in part b.) the Companies did not assume incremental transmission costs associated with retirements of coal units other than Mayo.

Responder: Michael T. Quinto, Director, IRP Advanced Analytics

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Refer to Appendix L, page 29 which states: "if the Roxboro/Mayo replacement generation is located in DEC and requires import into DEP, then additional upgrades would be required. Conceptual transmission projects that would likely be needed would be a Durham-Parkwood Tie 500 kV interconnection, a Bynum 500/230 kV Switching Station interconnection along with associated line upgrades, and potentially a Roxboro Plant-Sadler Tie 230 kV interconnection."

a. Please provide the estimated cost for each of these projects.
b. Please provide the amount of long-term firm import capability (e.g., in MW) each project, and the total of all the projects, would provide.
c. Please explain what steps Duke has undertaken within the last year to accelerate the completion of these projects.
d. Please explain what steps Duke could undertake to achieve a 2028 in- service date for these projects.
e. Please explain whether these projects were included in DEC or DEP's proposed Multi-Year Rate Plan. If not, why not?

Response:

4-23(a): As stated on page 29 of Appendix L, these projects are conceptual and thus not the result of any formal study. No cost estimates have been developed for these conceptual projects.

4-23(b): See response to AGO DR4-23(a).

4-23(c): See response to AGO DR4-23(a).

4-23(d): See response to AGO DR4-23(a).

4-23(e): These transmission projects are conceptual only and thus not included in the approved DEC and DEP MYRPs.

Responder: Sammy Roberts, GM, Transmission Planning and Operations Strategy

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DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Refer to Appendix L, page 33 which states “The request must be for firm transmission service to ensure the continued reliable operation and deliverability of energy from PJM to DEP.”

a. Please explain whether firm transmission service is required for the purchase or sale of economic energy (including non-firm energy) from PJM.
b. Please identify the current PJM border rate for non-firm transmission service.
c. Please explain whether non-firm energy and associated non-firm transmission service with PJM was considered as a resource option in the Carolinas Resource Plan. If not, please explain why.

Response:

1-12(a): The Companies were directed to perform further study of a long-term capacity purchase from PJM, which would require a class of transmission service of type Firm. The Companies did not consider the required transmission service class of an economic purchase while performing this further study.

Responder: Jack W. Armstrong, Lead Engineer

1-12(b): PJM does not have a border rate for non-firm transmission service. PJM publishes a Border Yearly Charge, on which the charges for non-firm transmission service are based. For additional information, please reference the PJM Billing, Settlements, & Credit website: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.
The PJM Open Access Sametime Information System (OASIS) also contains a "Guide to Billing" (available at https://www.pjm.com/-/media/markets-ops/settlements/custgd.ashx) to assist transmission customers in understanding the related Transmission Provider charges of PJM.

Responder: Jack W. Armstrong, Lead Engineer

1-12(c): The Companies did not consider non-firm energy and associated non-firm transmission service with PJM as a resource option in the Carolinas Resource Plan. The Companies do not believe long term resource planning should rely on non-firm energy and capacity to meet the needs of the system because there is no certainty that those energy and capacity needs would be available and may leave the Companies under-resourced for meeting the energy demands and reduction targets of the system.

Responder: Michael T. Quinto, Director, IRP Advanced Analytics

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please refer to Appendix C, Table C-28: Onshore Wind Modeling Assumptions

a. Please explain why the First Year of Eligible Selection is assumed to be 2031.

b. Please explain why this date is delayed from 2029 which was used in the 2022 Carolinas Carbon Plan.

c. Please explain why Duke did not include any wind resources located outside of the DEC and DEP service territories.

d. Please explain whether any non-firm wind resources were allowed to be selected in EnCompass.

Response:

2-5(a): As discussed in Appendix I (Renewables and Energy Storage) of the Resource Plan, the Companies believe 2031, meaning new onshore wind resources would be placed in service in 2030 is a reasonable assumption for the first year of availability. Figure I-4 (Appendix I), provides an Illustrative Onshore Wind Development and Execution Timeline and details the key assumptions that drive and support this timeline. The timeline accounts for key execution tasks such as project siting, site investigation activities, interconnection cluster studies and timeline for interconnection availability, permitting, and construction.

2-5(b): The assumption for the first year of availability shifted from 2029 to 2030 due to several key factors; (i) development for onshore wind was not approved in the 2022 Carolinas Carbon Plan, (ii) there are no active onshore wind projects within the Companies balancing authority under development, and (iii) based on the development and execution timeline that the Companies developed, which was informed by stakeholder engagement with third-party onshore wind developers, 2030 is a realistic first year of availability assumption.

2-5(c): As discussed in Appendix L (Transmission System Planning and Grid Transformation) of the Resource Plan, the Companies continue to explore import capabilities for alternative capacity resources. Specifically, an import capability analysis for a capacity purchase from PJM was performed by the Companies and a consultant. The import capability study revealed two key challenges: (i) significant annual cost for PJM transmission service (the Border Rate) and (ii) significant system reinforcement projects are needed on both PJM and DEP transmission systems.

The current PJM Border Rate is $66,231/MW-year, a 150 MW service request would cost approximately $9.9 million/year and the rate is subject to annual updates. It was estimated that at least $700 million of system reinforcement costs would be needed between the two systems. A 1,000 MW transmission service request ("TSR") is actively in the PJM interconnection queue, which is estimated to be studied sometime in 2026/2027 due to PJM's recently implemented queue reform process. Any transmission projects identified by the study to be needed to support this transmission service request would then need to be constructed and placed in service prior to firm transmission service being provided.

Furthermore, there are material risks associated with off-system capacity that include, but are not limited to: a delay in resource availability, loss of local ancillary benefits that are inherent with on-system resources, curtailment due to transmission constraints or system emergencies (such as those experienced in Winter Storm Elliott), transmission system stability issues, and changes to off-system grids (retirement and addition of resources).

The Companies preference is to locate generation within its balancing authority and connect directly to the Companies' transmission system. Off system resources introduce additional risk and complexity.

Responder: Justin C. LaRoche, Director Renewables Development

2-5(d): The Companies did not include in any of its Plan modeling the availability of non-firm wind resources to be selected in EnCompass.

Responder: Michael T. Quinto, Director, IRP Advanced Analytics

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DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please provide a breakdown of the following:

a. MW of solar-generating facilities already connected to DEC and DEP.
b. MW of new solar-generating facilities enabled by RZEP 1.0 projects.
c. MW of new solar-generating facilities enabled by RZEP 2.0 projects.
d. Total MW of solar-generating facilities required under each portfolio (P1, P2, P3).
e. MW of solar-generating facilities required under each portfolio (P1, P2, P3) for each year during the base planning period.
f. Any MW gap between the portfolios and the amount of solar enabled by the RZEP 1.0 and 2.0 projects.

Response:

a.) Please see attached file "AGO DR4-10a.xlsx."

AGO%20DR4-10a.xlsx

Responder: Bryan Dougherty, Principal Load Forecasting Analyst

b.) The RZEP 1.0 projects should enable the interconnection of at least 2,778 MW of solar-generating facilities in DEP and 981 MW of solar-generating facilities in DEC.

c.) The RZEP 2.0 projects should enable the interconnection of at least 1,309 MW of solar-generating facilities in DEP and 568 MW of solar-generating facilities in DEC.

Responder: Sammy Roberts, GM, Transmission Planning and Operations Strategy

d. and e.) See attached file: AGO DR4-10.d.e.f. - Portfolio Solar MW vs RZEP Solar Enabled.xlsx.

AGO%20DR4-10.d.e.f.%20-%20Portfolio%2

Please see Appendix C, Table C-57 on page 82 for cumulative resource additions by resource type through 2050. Note that the solar totals in Table C-57 are in addition to the 3,013 MW of solar already in advanced development and forecasted to be installed by 2031 (see Table C-21 on page 26).

Responder: Nathan Gagnon, Director IRP Regulatory and Policy Strategy

f.) The RZEP enabled Solar MW represents the results of transmission studies. The actual RZEP network upgrades create MVA capability in excess of what is needed to connect the RZEP enabled solar identified in the transmission studies. Thus the gaps identified in the attached file "AGO DR4-10.d.e.f. - Portfolio Solar MW vs RZEP Solar Enabled.xlsx" are conservative since additional MVA capability is created with these projects. More transmission studies would be needed to determine the additional solar enabled through using the full MVA capability created by the RZEP projects.

AGO%20DR4-10.d.e.f
.%20-%20Portfolio%2

Responder: Sammy Roberts, GM, Transmission Planning and Operations Strategy

AGO DR4-10.d.e.f. - Portfolio Solar MW vs RZEP Solar Enabled

Table C-49: P1 Base – Final DEC Annual Resource Additions and Coal Retirements (MW) (by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
Coal	-426	0	0	0	0	-1,306	-2,220	0	0	0	-1,318	0	0	0	0	
Solar	0	0	0	0	750	975	975	975	975	975	975	150	900	0	0	7650
Battery	0	0	0	0	0	740	980	0	780	240	0	0	0	0	0	
Onshore Wind	0	0	0	0	0	0	0	0	0	0	300	300	0	0	0	
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	300	300	900	
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1,680	0	0	0	0	
CC	0	0	0	0	0	0	1,360	0	0	0	0	0	0	0	0	
CT	0	0	0	0	0	1,700	0	0	0	850	0	0	0	0	0	

Table C-50: P1 Base – Final DEP Annual Resource Additions and Coal Retirements (MW) (by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
Coal	0	0	0	0	0	-1,766	-1,409	0	0	0	0	0	0	0	0	
Solar			0	0	1,050	1,425	1,425	1,425	1,425	975	375	0	0	0	0	8100
Battery	0	0	0	0	100	2,420	860	0	0	0	0	0	0	0	0	
Onshore Wind	0	0	0	0	0	0	300	300	450	450	150	0	0	0	0	
Offshore Wind	0	0	0	0	0	0	1,600	0	0	800	0	0	0	0	0	
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	300	600	0	
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
CC	0	0	0	0	0	1,360	0	0	0	0	0	0	0	0	0	
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Solar Enabled	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
DEC RZEP 1.0					750	231									
Gap					0	744	975								
DEP RZEP 1.0					1050	1425	303								
Gap					0	0	1122								
DEC RZEP 2.0								568							
Gap								407	975	975	975	150	900	0	0
DEP RZEP 2.0								1,309							
Gap								116	1,425	975	375	0	0	0	0
DEC/DEP	500**	766**	555**	819**	165**	69**	69**	69**							

** Annual breakdown for aggregated forecast shown in Appendix C - Table C-21 (page 26)

AGO DR4-10.d.e.f. - Portfolio Solar MW vs RZEP Solar Enabled

Table C-51: P2 Base – Final DEC Annual Resource Additions and Coal Retirements (MW) (by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
Coal	-426	0	0	0	0	-760	0	-546	-1,318	0	0	0	-2,220	0	0	
Solar	0	0	0	0	525	525	525	675	675	675	675	525	675	0	375	5850
Battery	0	0	0	0	140	140	0	180	300	540	180	0	0	0	300	
Onshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	300	0	150	
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	0	900	300	
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1,680	0	0	0	0	
CC	0	0	0	0	0	0	0	1,360	1,360	0	0	0	0	0	0	
CT	0	0	0	0	0	1,275	0	0	0	0	0	0	0	0	0	

Table C-52: P2 Base – Final DEP Annual Resource Additions and Coal Retirements (MW) (by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
Coal	0	0	0	0	0	-1,053	0	-713	0	-1,409	0	0	0	0	0	
Solar	0	0	0	0	825	825	825	900	900	900	900	900	900	0	375	8250
Battery	0	0	0	0	220	220	160	700	640	2,820	420	0	0	0	0	
Onshore Wind	0	0	0	0	0	0	0	300	450	450	450	0	0	0	0	
Offshore Wind	0	0	0	0	0	0	0	0	800	800	0	0	0	0	0	
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	300	0	300	
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
CC	0	0	0	0	0	1,360	0	0	0	0	0	0	0	0	0	
CT	0	0	0	0	0	850	0	0	0	0	0	0	0	0	0	

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Solar Enabled															
DEC RZEP 1.0					525	456									
Gap					0	69	525								
DEP RZEP 1.0					825	825	825								
Gap					0	0	0								
DEC RZEP 2.0								568							
Gap								107	675	675	675	525	675	0	375
DEP RZEP 2.0								900	712						
Gap								0	188	900	900	900	900	0	375
DEC/DEP	500**	766**	555**	819**	165**	69**	69**	69**							

** Annual breakdown for aggregated forecast shown in Appendix C - Table C-21 (page 26)

AGO DR4-10.d.e.f. - Portfolio Solar MW vs RZEP Solar Enabled

Table C-53: P3 Base – Final DEC Annual Resource Additions and Coal Retirements (MW) (by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
Coal	-426	0	0	0	0	-760	0	-546	-1,318	0	0	0	-2,220	0	0	
Solar	0	0	0	0	525	525	525	675	675	675	675	675	675	525	600	6750
Battery	0	0	0	0	140	140	20	840	540	460	0	0	740	0	420	
Onshore Wind	0	0	0	0	0	0	0	0	0	0	0	450	150	0	0	
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	300	600	600	
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1,680	0	0	0	0	
CC	0	0	0	0	0	0	0	0	1,360	0	0	0	0	0	0	
CT	0	0	0	0	0	1,275	0	0	0	0	0	0	0	0	850	

Table C-54: P3 Base – Final DEP Annual Resource Additions and Coal Retirements (MW) (by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
Coal	0	0	0	0	0	-1,053	0	-713	0	0	-1,409	0	0	0	0	
Solar	0	0	0	0	825	825	825	900	900	900	900	900	900	0	0	7875
Battery	0	0	0	0	220	220	0	860	0	0	820	0	600	0	0	
Onshore Wind	0	0	0	0	0	0	0	300	450	450	450	0	0	0	0	
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	300	0	
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
CC	0	0	0	0	0	1,360	0	0	0	1,360	0	0	0	0	0	
CT	0	0	0	0	0	850	0	0	0	0	0	0	0	0	0	

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Solar Enabled															
DEC RZEP 1.0					525	456									
Gap					0	69	525								
DEP RZEP 1.0					825	825	825								
Gap					0	0	0								
DEC RZEP 2.0								568							
Gap								107	675	675	675	675	675	525	600
DEP RZEP 2.0								900	712						
Gap								0	188	900	900	900	900	0	0
DEC/DEP	500**	766**	555**	819**	165**	69**	69**	69**							

** Annual breakdown for aggregated forecast shown in Appendix C - Table C-21 (page 26)

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Refer to Appendix L, page 28 which states: "A Generation Replacement Request for Marshall Plant Units 1 and 2 replacement generation (780 MW of advanced CT generation) has been submitted to the Generation Replacement Coordinator for study in accordance with the Generation Replacement queue process approved by FERC and provided in the OATT."

a. Please explain what firm or entity serves as the Generation Replacement Coordinator.
b. Please explain whether Duke conducted a competitive solicitation for the 780 MW of replacement generation prior to submitting the Generation Replacement Request. If not, why not?
c. Please provide the date when the Generation Replacement Request was submitted.

Response:

4-17(a): Excel Engineering.

4-17(b): No. The Companies did not conduct a competitive solicitation. Generator Replacement Requests are specific to Duke Energy interconnection rights at existing sites. N.C.G.S. 62-110.9(2) mandates that 100% of all new generation selected in the Carbon Plan for execution is utility owned, except for solar and solar plus storage, which is 55% utility owned. Building new generation at existing sites and leveraging existing infrastructure, permits, staffing, security, land, interconnection rights, etc. is the best value for customers for this dispatchable generation need. For the reasons listed above, and as stated in Chapter 4 Execution plan (pages 12 and 13 "Retiring Existing Coal," page 17, "Self-Development," and page 19, "Table 4-6: Procurement / Development Approach by Resource") a competitive solicitation for this on-site replacement generation was not pursued. The Companies have substantial self-development experience with internal processes to competitively bid major equipment and EPC services to ensure the best value for customers considering project-specific costs and risks.

4-17(c): March 2023.

Responder: Ben Smith, Generation & Regulatory Strategy Director

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Refer to Appendix L, page 29 which states: "A Generation Replacement Request for A Generation Replacement Request for Roxboro Plant Units 1 and 2 replacement generation (1,053 MW of gas fired CC generation) has been submitted to the Generation Replacement Coordinator for study in accordance with the Generation Replacement queue process approved by FERC and provided in the OATT."

a. Please explain what firm or entity serves as the Generation Replacement Coordinator.
b. Please explain whether Duke conducted a competitive solicitation for the 1,053 MW of replacement generation prior to submitting the Generation Replacement Request. If not, why not?
c. Please provide the date when the Generation Replacement Request was submitted.

Response:

4-22(a): Excel Engineering.

4-22(b): No. The Companies did not conduct a competitive solicitation. Generator Replacement Requests are specific to Duke Energy interconnection rights at existing sites. N.C.G.S. 62-110.9(2) mandates that 100% of all new generation selected in the Carbon Plan for execution is utility owned, except for solar and solar plus storage, which is 55% utility owned. Building new generation at existing sites and leveraging existing infrastructure, permits, staffing, security, land, interconnection rights, etc. is the best value for customers for this dispatchable generation need. For the reasons listed above, and as stated in Chapter 4 Execution plan (pages 12 and 13 "Retiring Existing Coal," page 17, "Self-Development," and page 19, "Table 4-6: Procurement / Development Approach by Resource") a competitive solicitation for this on-site replacement generation was not pursued. The Companies have substantial self-development experience with internal processes to competitively bid major equipment and EPC services to ensure the best value for customers considering project-specific costs and risks.

4-22(c): March 2023.

Responder: Ben Smith, Generation & Regulatory Strategy Director