STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

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, 2022 Biennial	)	**ATTORNEY GENERAL'S**
Integrated Resource Plans and	)	**OFFICE**
Carbon Plan	)	

Contents

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Edward Burgess. My business address is Strategen Consulting ("Strategen"), 10265 Rockingham Dr., Suite #100-4061, Sacramento, CA 95827.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Senior Director of Integrated Resource Planning with Strategen.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am a leader on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric and gas utility sectors on issues relating to resource planning, transmission planning, renewable energy, energy storage, rate design, cost of service, program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. 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 Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Arts degree in Chemistry from Princeton University. A full resume is attached as Exhibit 1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No. However, I have provided technical support to the Attorney General's Office on several recent proceedings including Duke's 2018 and 2020 Integrated Resource Plans. I have also presented at the October 2021 Technical Workshop on Duke's 2020 Integrated Resource Plan.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY OTHER STATE REGULATORY BODY?

A. Yes. I have testified before the California Public Utilities Commission (Docket Nos. A.19-08-002, A.20-08-002, R.20-11-003, A.21-08-004, A.21-10-010, and A.21-10-011), the Oregon Public Utilities Commission (Docket Nos. UE-375, UE-390, and UG-435), the Indiana Utility Regulatory Commission (Cause Nos. 38707 FAC 123 S1 and 38707 FAC 125), the Louisiana Public Service Commission (Docket No. U-36105), the Massachusetts Department of Public Utilities (D.P.U. 18-150 and D.P.U. 17-140), the Michigan Public Service Commission (Docket No. U-21090), the Nevada Public Utilities Commission (Docket No. 20-07023), the South Carolina Public Service Commission (Docket Nos. 2019-186-E, 2019-185-E, 2019-184-E, and 2021-88-E), and the

Washington Utilities and Transportation Commission (Docket Nos. UE-200900 and in UE-220053/UG-220054, UE-220066/UG-220067). Additionally, I have represented numerous clients by drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at utilities commissions in Arizona, California, District of Columbia, Maryland, Minnesota, Nevada, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, at the Federal Energy Regulatory Commission, and at the California Independent System Operator.

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

A. The purpose of my Direct Testimony is to address the proposed Carbon Plan Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC," together with DEP, "Duke").

Q. WERE YOU INVOLVED IN THE PREPARATION OF THE STRATEGEN REPORT THAT WAS INCLUDED AS PART OF THE AGO'S JULY 15TH FILING?

A. Yes. I was the principal author of the Strategen report. I affirm the accuracy and truthfulness of that report and incorporate its contents by reference as part of my testimony.

II. TESTIMONY SUMMARY

A. The AGO's proposed Carbon Plan portfolio ("SP-AGO") represents a balanced approach, that minimizes risks and uncertainties.

Q. GIVEN THE COMPLEXITY OF THIS CASE, HOW SHOULD THE COMMISSION APPROACH ITS DECISION TO ADOPTING A CARBON PLAN?

A. At the outset, it should be acknowledged that the Commission's task of adopting a Carbon Plan is not a simple one. I have had extensive experience in resource planning cases at utility commissions around the country and have seldom seen such a large volume of complex technical analysis conducted by numerous parties. Even in similarly complex cases, the timeframe for rendering a decision was never as compressed as it is here. Given these circumstances, the Commission may be tempted to select one of Duke's Supplemental Portfolios as a sort of "off the shelf" plan representing a "middle ground" between what Duke originally proposed, and some of the concerns raised by Public Staff. However, it is important for the Commission to recognize that the Supplemental Portfolios are not exactly a middle ground since they fail to address important concerns raised by other parties, including the AGO. In particular, the Supplemental Portfolios do not attempt to achieve a seventy percent (70%) reduction in emissions of carbon dioxide from Duke's North Carolina power plants from 2005 levels by 2030. Moreover, they are not reflective of the new reality under the Inflation Reduction Act. As such, while the Supplemental Portfolios contain some improvements over Duke's initial portfolios, the Commission should still make further improvements in its final decision.

Q. DOES THE AGO'S PROPOSED CARBON PLAN PORTFOLIO REFLECT AN IMPROVEMENT OVER THE SUPPLEMENTAL PORTFOLIOS (I.E., SP5 AND SP6)?

A. Yes. At the AGO's request, Strategen conducted modeling in EnCompass to develop an additional Supplemental Portfolio ("SP-AGO"). The starting point for this analysis was Duke's SP5 portfolio. SP-AGO builds upon SP5 by making improvements to a limited number of input assumptions. These improvements reflect several of the outstanding concerns raised by AGO and other parties, but which were not addressed by Duke or Public Staff in the SP5 and SP6 portfolios.

Q. WAS THE SP-AGO PORTFOLIO DESCRIBED IN THE AGO'S INITIAL COMMENTS OR THE STRATEGEN REPORT WHICH WERE BOTH FILED ON JULY 15, 2022?

A. No. The analysis supporting the SP-AGO portfolio was conducted after those comments and report were filed and after Duke's testimony was filed on August 19, 2022. Below is a timeline of the events leading up to the development of the SP-AGO portfolio:

- May 16, 2022: Duke filed its proposed Carbon Plan with four Initial Portfolios, (P1-P4) and four Alternate Fuel Portfolios (P1A-P4A)
- July 15, 2022: Intervenor comments filed. AGO/Strategen provides numerous recommendations to improve inputs and assumptions used in Duke's Initial Portfolios. Modeling/analysis of alternative portfolios

provided by CPSA/Brattle, NCSEA/Synapse, and Tech Customers/Gabel.

- Late July – Early August: Duke worked with Public Staff to identify modified input assumptions for four Supplemental Portfolios (SP5, SP6, SP5A and SP6A). Some of AGO's recommended improvements were reflected in these Supplemental Portfolios, but many were not. Table 3 provides an overview of which recommended improvements were omitted.
- August 19, 2022: Duke filed testimony with findings from Supplemental Portfolios.
- August 22 – September 2: AGO/Strategen conducted additional modeling of Supplemental Portfolios (using inputs from SP5 as starting point).
- September 3, 2022: AGO filed testimony (this document) with results of modified Supplemental Portfolio (SP-AGO), containing the remainder of AGO's recommended improvements.

Section IV-F and Exhibit 2 of this testimony provide more details on the SP-AGO modeling.

Q. DO YOU BELIEVE THE SP-AGO PORTFOLIO REPRESENTS A SENSIBLE AND BALANCED APPROACH?

A. Yes. As mentioned above, the SP-AGO portfolio builds upon the SP5 Supplemental Portfolio, which contains a few improvements over P1-P4. SP-AGO further develops SP5 by addressing some of the other key concerns the

AGO had raised. It also balances many of the interests and concerns raised by other parties in this case, not just Public Staff. Some of the key features of the SP-AGO portfolio include the following:

- Continues to pursue solar, onshore wind, and battery storage as "no regrets" near-term additions.
- Includes an ambitious—but achievable—level of near-term solar deployment (i.e., midpoint between high and low cases).
- Avoids a "rush to judgment" on the need for new gas units in light of uncertainties around fuel supply and competitiveness under the IRA.
- Maximizes competition by allowing selection of valuable resource options that were initially overlooked (e.g., 100% gas conversion at Belews Creek, alternative solar plus storage configurations, alternative wind import options).
- Maintains a "safety valve" or fallback option for meeting House Bill 951 ("HB951") compliance if there are unforeseen delays (i.e., 2030 set as initial deadline, with option to postpone at a later date).

Given these advantages, I recommend the Commission adopt the SP-AGO portfolio as its selected Carbon Plan. Furthermore, I recommend the Commission only approve the near-term actions associated with this plan that can be considered "no regrets," recognizing that more analysis is needed in light of the IRA.

B. Key Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows:

1. The passage of the Inflation Reduction Act ("IRA") is a significant and material change to key planning assumptions which are likely to affect the results of any Carbon Plan portfolio analysis, as well as certain near-term actions. While near-term procurement of solar, wind, and battery storage will be further cemented as "no regrets" options, the reasonableness of procuring new gas resources (especially CC additions) should be re-evaluated in the context of the IRA. This re-evaluation needs to be performed prior to consideration of an application for a Certificate of Public Convenience and Necessity ("CPCN") to construct such facilities.
2. While recognizing that analysis of the IRA is still needed, the Commission should adopt the AGO's SP-AGO portfolio as an interim measure. At a minimum, the Commission should reject any portfolio that does not incorporate specific modeling changes recommended in the AGO's initial comments, which are included in the SP-AGO portfolio such as:
   - Eliminate or significantly relax the constraints identified below in Section IV-A, including modeling constraints for solar, solar plus storage, onshore wind, and natural gas;
   - Use the alternative approaches described in Section IV-B in order to minimize out-of-model adjustment steps;

- Adjust assumptions for new natural gas resources as discussed in Section IV-C, including those related to plant book life, uncertainties around lack of firm transport for gas supply, and the uncertain feasibility of hydrogen conversion.

3. The Commission should approve the "no regrets" procurement of solar, onshore wind, and battery resources as proposed in Duke's near-term action plan.
4. The Commission should defer approval of new natural gas additions (especially CC additions) until an updated Carbon Plan can be developed that include the changes described above (items 1 and 2). The Commission should require Duke to include the resulting portfolio as supporting analysis in any CPCN applications for near-term resource additions.
5. The Commission should defer a decision on cost recovery of long-lead time resources until a future proceeding. In doing so, the Commission should allow Duke to pursue development of these resource additions. However, additional caution should be applied to SMRs.
6. The Commission should require Duke to develop additional contingency plan scenarios that meet HB951's requirements under a high natural gas price forecast.
7. The Commission should direct Duke to include high capacity factor solar plus storage resources in its near-term solicitations as a means to more efficiently use limited transmission interconnection space.

8. The Commission should direct Duke to conduct a near-term solicitation for onshore wind to test market readiness with a target in-service date in the 2026-2027 timeframe. This solicitation should allow for wind imports with non-firm transmission. Both the wind and solar procurements mentioned above should seek to maximize competition through third party providers.
9. The Commission should direct Duke to pursue deployment of battery storage at the Marshall and Mayo plants as a means to achieve more economic early retirement dates in the 2027-2028 timeframe, while avoiding the need for additional transmission upgrades. These deployments should seek to leverage new DOE financing options under the IRA.
10. The Commission should require Duke to employ strategies that minimize execution risk of renewable resources including:
    a. Pursuing additional solar plus storage configurations with higher capacity factors that can reduce needed interconnection space.
    b. Pursuing additional wind options including imports with non-firm transmission.
    c. Increasing opportunities for distributed resources.
    d. Siting facilities at or near retiring coal plants to minimize transmission constraints.
    e. Investing in grid-enhancing technologies to increase interconnection limits.

f. Identifying low-cost, incremental transmission improvements following larger upgrades that can unlock greater interconnection potential.

11. Prior to any future Carbon Plan filings, the Commission should order Duke to provide information on the feasibility and cost of retiring Belews Creek from coal by 2030 and operating the plant on 100% natural gas.

12. In future Carbon Plan filings, the Commission should order Duke to:

- Minimize the number of out-of-model adjustments in future iterations of the Carbon Plan and to provide full transparency on specific resource additions made through any out-of-model adjustments and the reason for those adjustments (e.g., reliability-based adjustments);
- Minimize the number of resource-specific model constraints;
- Include the Belews Creek 100% gas conversion option for the model to select;
- Include Energy Efficiency ("EE")/Demand-Side Management ("DSM") and distributed solar as a selectable resources;
- Evaluate the costs and benefits of different levels of EE/DSM and rooftop solar deployment by varying the level of incentives provided;
- Ensure that the forecast is not overly inflated by revising the method for including Utility Energy Efficiency ("UEE") roll-off in its load forecast relative to "naturally occurring" efficiency.

13. In a future proceeding, the Commission should re-evaluate the current cost-benefit analysis for EE/DSM (*i.e.*, the Utility Cost Test) to reflect currently

proposed carbon-free resources (*e.g.*, Small Modular Reactors ["SMRs"], Offshore Wind ["OSW"]) as the alternative to the traditionally used proxy resources (*e.g.*, Combustion Turbines ["CTs"]).

14. The Commission should reject Duke's proposal to move to an "as-found" EE/DSM baseline and instead maintain the current approach to counting EE savings, using the minimum federal efficiency and performance requirements as the baseline.

III. THE INFLATION REDUCTION ACT

A. The Inflation Reduction Act materially changes many key planning assumptions used by Duke and other parties.

Q. HAVE THERE BEEN ANY SIGNIFICANT FEDERAL POLICY CHANGES SINCE STRATEGEN'S REPORT WAS SUBMITTED TO THE COMMISSION ON JULY 15TH?

A. Yes. On August 16th, 2022, the Inflation Reduction Act ("IRA") was signed into law by President Biden. At the time of Strategen's July 15th report, it was not clear if any federal energy legislation would pass through Congress any time soon, let alone what provisions would be included. However, the recently enacted IRA is one of the most significant pieces of federal energy legislation in recent decades and will likely have transformational effects on energy investments made over the next decade.

Q. WOULD THE CHANGES MADE UNDER THE IRA HAVE A SIGNIFICANT IMPACT ON THE INPUTS AND ASSUMPTIONS USED

BY DUKE AND OTHER PARTIES IN THEIR ANALYSIS OF THE CARBON PLAN?

A. Yes. To put it bluntly, the previous analysis was performed using assumptions that are now obsolete and do not reflect the current reality. As such, the previously proposed portfolios likely differ in meaningful ways from the optimal path forward under the IRA. In an ideal world, a major federal policy change like this would be a moment to "hit pause" and give parties additional time to reevaluate what resources the preferred Carbon Plan portfolio should include. A complete reevaluation may not be feasible given the short timeframe the Commission has to render a decision on this matter under HB951 and the significant amount of time and effort already put into this proceeding by many parties. But given the significance of the IRA, the Commission should make every effort to take it into account.

Q. DID DUKE'S SUPPLEMENTAL PORTFOLIO ANALYSIS (I.E., SP5 AND SP6) FILED IN ITS AUGUST 19, 2022 TESTIMONY INCORPORATE THE EFFECTS OF THE IRA?

A. No. To my knowledge, no comprehensive analysis of a Carbon Plan portfolio has been completed by Duke or any other stakeholder that includes the effects of the IRA.

Q. EVEN THOUGH NO UPDATED PORTFOLIO MODELING HAS BEEN PERFORMED YET, HOW DO YOU EXPECT THE IRA WILL INFLUENCE THE OPTIMAL CARBON PLAN PORTFOLIO IN THE

NEAR TERM (I.E., THROUGH 2030), INCLUDING DUKE'S PROPOSED NEAR-TERM ACTIONS?

A. I expect that if the IRA assumptions were incorporated, it would very likely increase the economic selection of wind, solar, and (especially) battery storage resources. Meanwhile, it would likely decrease the economic selection of natural gas due to reduced competitiveness. The IRA might cause nuclear and hydrogen to become more cost-effective over the long-term, but as Duke and other parties have acknowledged, these technologies are still being developed and aren't expected to be available until the 2030s. The IRA could also accelerate replacement of coal plants with new generation through the availability of low-cost financing offered through the DOE's Loan Program Office.[1]

B. The Carbon Plan will not be informative in future CPCN proceedings if it is developed without analysis of the IRA.

Q. WOULD YOU HAVE ANY CONCERNS IF THE COMMISSION WERE TO APPROVE A CARBON PLAN THAT DID NOT FULLY ANALYZE THE EFFECTS OF THE IRA?

A. Yes. I am particularly concerned about the possibility that the Commission might approve a Carbon Plan based on analysis without the effects of the IRA, and that this approval would later be used to inform a determination of need in future CPCN proceedings. This is especially true if Duke succeeds in its

---

[1] Also known as Section 1706, see: https://crsreports.congress.gov/product/pdf/IN/IN11984.

position that the Carbon Plan should provide *a de facto* determination of need as is suggested in Duke's statement that, "to the extent the Commission selects a resource as part of an approved Carbon Plan, the Commission's Carbon Plan ruling should be controlling in a CPCN proceeding absent a material change in the facts and circumstances from the Carbon Plan assumptions."[2]

Q. DOES THE IRA CONSTITUTE A "MATERIAL CHANGE IN THE FACTS AND CIRCUMSTANCES FROM THE CARBON PLAN ASSUMPTIONS" THAT DUKE USED IN BOTH ITS INITIAL MAY 2022 AND SUPPLEMENTAL AUGUST 2022 ANALYSIS?

A. Yes, it is a material change. Thus, even under Duke's position, approval of a Carbon Plan without addressing these material changes should *not* be controlling in a CPCN proceeding.

IV. MODELING—METHODOLOGY

Q. WHAT ARE YOUR KEY RECOMMENDATIONS REGARDING DUKE'S MODELING METHODOLOGY?

A. Duke's use of EnCompass, an objective modeling software, represents an improvement over past resource planning efforts. However, I have two key concerns with Duke's modeling efforts. First, Duke placed a large number of unnecessary constraints on certain resource types. Second, Duke performed a number of "out-of-model" steps rather than relying on EnCompass's capabilities. Combined, these concerns have the potential to inject subjectivity into the modeling and may not have resulted in the least-cost mix of resources.

[2] Duke Energy Response to PS Data Request ("DR") 11-2(a).

Therefore, I recommend that the Commission reject any portfolio that contains these flaws. This section of my testimony focuses primarily on Duke's initially proposed Carbon Plan portfolios (i.e., P1-P4). However, I also address the changes made in Duke's Supplemental Portfolios (SP5 and SP6).

Q. WHAT ARE SOME OF THE KEY MODELING INPUTS AND ASSUMPTIONS THAT WOULD BE AFFECTED BY THE IRA?

A. Below is a table summarizing a partial set of the key model inputs that would need to be changed in the analysis presented by Duke and other parties to accurately reflect current law under the Inflation Reduction Act:

Table 1

Model Assumptions	IRA Changes	Carbon Plan Implications
Cost of wind and solar	• Extends Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") for 10 years. • Manufacturing production credits may help reduce costs and/or alleviate supply chain issues.	• Significantly reduces cost of wind and solar from 2023-2032 from previous assumptions (i.e., on the order of 20% or more).
Cost of battery storage	• Allows standalone storage to claim ITC without pairing with solar (extends for 10 years). • Manufacturing production credits may help reduce costs and/or alleviate supply chain issues.	• Significantly reduces cost of battery storage from previous assumptions (i.e., on the order of 30% or more). • Eliminates dispatch limits for hybrid resources.
Cost of other clean electricity resources	• Electricity generated from nuclear and green hydrogen ("H2") power plants can also claim an ITC/PTC (starting 2025).	• Significantly reduces cost of nuclear and green hydrogen resources.

Cost of green hydrogen fuel	• Facilities that produce clean H2 are eligible for tax credits.	• Significantly reduces cost of green hydrogen fuel.
Load forecast and demand side resources	• Tax credits for electric vehicles ("EVs"). • Tax credits for EV chargers. • Tax credits for residential solar and batteries. • Tax credits for energy efficiency improvements and home energy audits. • Rebates for home retrofits, efficient electric appliances. • Local aid for advanced building codes.	• Decrease in load forecast due to accelerated efficiency improvements and distributed solar. • Increase in load forecast due to accelerated adoption of EVs and electric appliances.
Long lead-time resources (*e.g.*, SMR, OSW)	• Department of Energy (DOE) Loan Program Office lending option.	• Could reduce the financing cost of new SMR and OSW projects.
Coal/Gas Retirements	• DOE funding to support projects that invest in retired generation[3]	• Could reduce the cost of projects replacing retired coal plants.

Q. ARE THERE ANY RESOURCES IN DUKE'S PROPOSED CARBON PLAN FOR WHICH THE IRA DOES NOT PROVIDE A MEANINGFUL CHANGE?

A. Yes. New natural gas plants and related pipeline projects won't receive any direct financial benefits. It is possible that new gas plants could receive a tax credit if they include carbon capture and sequestration ("CCS"). However, I am

[3] Michael O'Boyle, Inflation Reduction Act Benefits: Billions In Just Transition Funding For Coal Communities (Aug. 24, 2022), https://www.forbes.com/sites/energyinnovation/2022/08/24/inflation-reduction-act-benefits-billions-in-just-transition-funding-for-coal-communities/?sh=688779156ebd.

skeptical that CCS investments will be economic for new gas plants, even with the provisions included in the IRA. Additionally, the IRA introduces a new charge on methane emissions in the upstream oil and gas industry which could potentially increase costs for gas suppliers who are unable to control methane leaks and flaring.[4] Thus, the passage of the IRA appears to have significantly reduced the competitiveness of new natural gas resources relative to nearly all other resources being considered in the Carbon Plan.

A. Duke's Initial Portfolio modeling (i.e., P1-P4) included several arbitrary and unreasonable constraints on potential resource options. Some, but not all, of these constraints were addressed in the Supplemental Portfolios (i.e., SP5 and SP6).

Q. WHAT CONSTRAINTS DID YOU IDENTIFY IN DUKE'S INITIAL MODELING?

A. Duke's modeling included an extensive number of resource-specific planning constraints for certain resource types. While it is typical to have some constraints, I am concerned that some of these resource-specific limits appear to be somewhat arbitrary and overly restrictive.

Q. WHAT MODELING CONSTRAINTS DO YOU BELIEVE ARE ARBITRARY AND UNREASONABLE?

[4] Inflation Reduction Act Methane Emissions Charge: In Brief, Congressional Research Service (Aug. 29, 2022), https://crsreports.congress.gov/product/pdf/R/R47206.

A. While more details are provided in the Strategen Report,[5] Duke's Initial Portfolios (P1-P4) included the following:

- First, Duke set limits on the amount of annual solar interconnection. For example, Portfolio 1 included a limit of 1,800 MW after 2028, whereas the remaining portfolios included a limit of 1,350 MW after 2028.
- Second, Duke set cumulative limits for certain solar plus storage additions. The limit was set for 50% Battery Ratio solar plus storage resources at 450 MW in the DEC territory and 750 MW in the DEP territory.[6]
- Third, Duke limited the configurations of solar plus storage that the model could select.
- Fourth, Duke set an annual limit for additions of onshore wind. This limit was set at combined 300 MW for both DEC and DEP.[7]
- Fifth, Duke set cumulative limits for onshore wind additions. The limit was set at 600 MW for DEC and 1,200 MW for DEP.
- Sixth, Duke delayed the first year that the model could select both solar and onshore wind additions. For solar, the model was constrained from adding solar until 2027. For wind, the model was constrained from adding wind until 2029.
- Finally, Duke set constraints on the types of natural gas combined cycle units that the model could select. When conducting its base fuel supply

---

[5] *See* Strategen Report, p. 6-7.
[6] *See* Strategen Report, p. 19-20.
[7] *See* Strategen Report, p. 20-22.

case analysis, Duke restricted EnCompass such that "only 1200 MW CC resources were allowed to be selected."[8]

Q. WERE ANY OF THESE CONSTRAINTS RELAXED OR REMOVED IN DUKE'S SUPPLEMENTAL PORTFOLIOS?

A. Yes, but only for two of those mentioned above. Specifically, Duke included one additional solar plus storage configuration and also allowed multiple types of combined cycle units to be selected. Table 2 below describes these changes in more detail.

Q. WHAT IMPACT DID THESE ARBITRARY CONSTRAINTS HAVE ON THE MODELING RESULTS?

A. Taken together, these limits likely play a significant role in shaping the final portfolio results, especially in the near-term. By definition, when constraints become limiting factors in the model's resource selections (*i.e.*, they are "binding constraints"), the portfolio results will be higher in cost than if the constraints were relaxed or removed. This is because the binding constraints prevent the model from selecting the least-cost resources, and instead force the model to select more expensive resources in order to stay within the constraints.

Q. WHICH OF THE CONSTRAINTS THAT YOU IDENTIFIED WERE BINDING IN DUKE'S MODELING?

A. All of the constraints that I have identified above were binding in Duke's modeling. This means that the model likely would have selected more of each if it were allowed to do so. When a modeling constraint is binding, it is even

[8] Duke Energy Response to Public Staff DR 10-2.

more important to examine that constraint to ensure that the model is not being forced to make uneconomic decisions.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH FOR ANNUAL SOLAR INTERCONNECTION LIMITS?

A. Duke is grappling with real technical limitations on how much solar can realistically be interconnected each year. However, Duke has not provided sufficient justification for its assumed solar interconnection limit. In fact, Duke acknowledged that the Companies "do not have specific underlying calculations for the annual selection constraints" and that the constraints "are based on engineering judgement and transmission planning experience."[9]

According to the Clean Power Suppliers Association ("CPSA"), Duke's annual solar interconnection limit of 750 MW for 2022-2026 is approximately the same as the amount of solar that Duke reports having interconnected in 2015 and 2017, meaning that Duke assumes it will not make any improvements in its ability to interconnect new solar projects until 2027.[10] However, as CPSA also notes, there are several reasons to expect interconnection rates to improve in the near term.[11] Given this, I recommend increasing the limitations on solar additions above what Duke initially proposed. Specifically, I recommend the limit be set at the midpoint of Duke's Initial P1 portfolio and "High Solar

[9] Duke Energy Response to NCSEA-SACE DR 3-30.
[10] CPSA Comments, p. 15
[11] CPSA Comments, p 15-19.

Interconnection" sensitivity of the Supplemental Portfolios and advanced by one year. The specific levels are shown in the table below:

Table 2

Year[12]	MW
2027	1125
2028	1275
2029	1800
2030	1800
2031	1800
2032	1800

In addition, prior to future Carbon Plan filings additional studies should be performed to inform what levels of annual interconnection are possible.

Q. DO YOU SHARE CLEAN POWER SUPPLY ASSOCIATION'S CONCERNS OVER THE SOLAR INTERCONNECTION CAP?

A. Yes. I agree that the exact MW cap values Duke proposed appear to be somewhat arbitrary and are a significant limitation on the solar resources selected by the model. I also agree with the notion of setting an ambitious goal, which can be adjusted later if found to be unachievable. At the same time, I also appreciate Public Staff's concerns regarding potential execution risks if the limit is set too high (while recognizing that execution risks exist for all of Duke's proposed portfolios). Considering each of these concerns, I initially concluded that it was reasonable to increase the cap from what Duke proposed, particularly in the early years, but not quite to the full level proposed by CPSA.

[12] The dates used in the table above reflect a beginning of year basis, meaning resources are selected at the end of the previous year, for the full calendar year listed.

While I think this approach is still valid, I also recognize that the IRA has some features that may assist in generator interconnection, such as expanding the federal ITC to include qualified interconnection costs for facilities less than 5 MW. Additionally, the potential limitations on interconnection for solar are a primary reason why Strategen recommended exploring procurement of a more diverse set of renewable resources including: (1) additional solar plus storage configurations, including those with higher capacity factors than what Duke modeled in its Initial and Supplemental Portfolios, (2) additional wind options including non-firm "energy only" imports, and (3) increased distributed resources. In addition, Strategen recommended other low-cost methods for alleviating interconnection limits, such as (1) siting facilities at or near retiring coal plants and (2) pursuing grid-enhancing technologies. As such, I recommend that the Commission direct Duke to pursue all five of these strategies, and where possible, include them in any near-term solicitations. Finally, regardless of any MW limits the Commission ultimately considers, perhaps the most important feature of any Carbon Plan will be a concerted effort to accelerate the process for generation interconnection and identify appropriate transmission upgrades.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH FOR CUMULATIVE LIMITS ON SOLAR PLUS STORAGE RESOURCES?

A. Cumulative limits on solar plus storage resources should be removed. As discussed in the Strategen Report, the reliability issue cited by Duke to support the limit does not appear to be based on a real concern.[13] If there are reliability concerns about over-selection of short duration batteries, these should be evaluated through supporting technical analysis.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH FOR SOLAR PLUS STORAGE CONFIGURATIONS?

A. Rather than modeling only two solar plus storage configurations, Duke should have modeled additional configurations, including those with larger sized Direct Current ("DC") components, such as batteries. Duke's Initial Portfolios included only two possible configurations of solar plus storage, which represents a very limited set of choices and does not reflect the range of potential options available. Oversizing the DC components (including the battery) of a solar plus storage system can actually allow solar plus storage resources to operate more similarly to resources that typically have higher capacity factors (like combined cycle units) as well as provide "more bang for the MW buck" of AC interconnection space.[14] While there are limits to the total number of resource types that can reasonably be modeled, the two solar plus storage resource options Duke included are not necessarily representative of the configurations that would maximize value into the future as the Carbon Plan evolves.

Q. DID DUKE'S SUPPLEMENTAL PORTFOLIOS INCLUDE ADDITIONAL SOLAR PLUS STORAGE CONFIGURATIONS?

---

[13] *See* Strategen Report, p. 20.
[14] *See* Strategen Report, p. 15-19.

A. The Supplemental Portfolios included one additional configuration, which I support.[15] Notably, this new configuration was preferred by the model. However, Duke should enable even more solar plus storage configurations in subsequent versions of the Carbon Plan, including those with larger DC components.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH FOR SETTING ANNUAL LIMITS FOR ADDITIONS OF ONSHORE WIND?

A. Onshore wind is a mature, low-cost, zero carbon, supply-side generation resource with a recent track record in the U.S. Even though the Carolinas have a relatively modest opportunity for onshore wind resource development, onshore wind should play an important role in the Carbon Plan, whether developed in the Carolinas or imported from neighboring regions. Notably, the 300 MW annual limit is significantly less than that assumed for solar. It is concerning that the wind limit is less than half of that of solar without any further justification from Duke.[16] It is premature to presume both that no more than 300 MW can be procured and that a 2029 in-service date is required prior to testing the market through a true competitive solicitation. While it is true that significant wind resource development has not yet occurred in the Carolinas, such development has occurred already in PJM and there continues to be a substantial amount of wind projects in development there. Thus, the specific limit on onshore wind imports to DEC (*i.e.*, 150 MW of the 300 MW total) is

---

[15] Direct Testimony of Snider, et al. for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, NCUC Docket No. E-100, Sub 179 (Aug. 19, 2022) p. 57.
[16] *See* Strategen Report, p. 20-21.

of particular concern. Moreover, it is not clear that Duke even considered imports for DEP. It is worth noting that the transmission costs Duke assumes associated with onshore wind imported from PJM are based upon a Firm Point-to-Point transmission service, which may be overly limiting. Duke should explore the potential for non-firm or "energy only" type of transmission service for these wind imports.[17]

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO CUMULATIVE LIMITS ON ONSHORE WIND RESOURCES?

A. Similar to the cumulative limits on solar plus storage, cumulative limits on onshore wind resources should be relaxed or removed.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO SELECTING A FIRST YEAR FOR SOLAR AND ONSHORE WIND ADDITIONS?

A. Delaying procurement of these resources is not justified. Typical solar and wind project development timelines are often 2-3 years. This is especially true for wind projects imported from PJM that may already be in advanced stages of development. Currently the PJM queue has over 70 onshore wind projects totaling more than 2,400 MW of capacity with targeted in-service dates of 2026 or sooner. Instead of assuming delayed timing is inevitable, the Commission should consider a near-term solicitation to test market readiness with a target in-service date in the 2026-2027 timeframe. This is especially feasible if opportunities for "energy only" wind resource imports are explored.

[17] *See* Strategen Report, p. 22.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO SELECTING NATURAL GAS RESOURCES?

A. I am concerned that Duke's decision to allow the model to select only 1,200 MW Combined Cycle ("CC") units in the base fuel case of its Initial Portfolios unnecessarily limits the model's flexibility and ability to select a smaller sized CC unit. Thus, I support the option for the model to select both F-Class and J-Class CCs and CTs in the Supplemental Portfolios assuming there is sufficient natural gas fuel supply.[18] However, in cases with constrained supply (i.e., No Appalachian Gas), I believe Duke's original approach of limiting CC additions to a single 800 MW F-Class facility makes sense. I am concerned that Duke seems to have abandoned this sensible limitation in its Supplemental Portfolio analysis, which I will address in more detail below (see Section IV-C).

B. Duke's Initial and Supplemental Portfolios were substantially adjusted through non-transparent "out of model" steps. Most of these adjustments can and should have been addressed within the EnCompass model, rather than through a separate analysis.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "OUT OF MODEL" STEPS.

---

[18] Direct Testimony of Snider, et al., p. 58.

A. In developing its proposed Carbon Plan, Duke took several consequential steps to modify the resource portfolios that all occurred outside of the core EnCompass optimization algorithm.

Q. PLEASE EXPLAIN WHY "OUT OF MODEL" STEPS ARE CONCERNING TO YOU.

A. I do not believe all out-of-model adjustments are necessarily unwarranted. However, in my experience, these kinds of additional steps can introduce a new potential "black box" that is non-transparent and can be difficult for stakeholders to independently assess. These types of adjustments run the risk of allowing the utility to "put their thumb on the scale" in favor of certain outcomes. Thus it is generally preferable that these additional steps be minimized.

Additionally, in EnCompass, the simultaneous equations of the optimization algorithm are solved as a set, not in isolation from each other. In practice, this means that if changes to certain variables are made after the optimization is completed, they may no longer represent the optimal solution without additional re-optimization. As a hypothetical example, if the model selected 1,000 MW of battery storage (among other resource selections), which were then manually replaced with 1,000 MW of CTs through an "out of model" adjustment, then it is possible that the other resources previously selected for the portfolio no longer reflect the optimal mix. Since the CTs have different attributes than the battery storage (*i.e.*, longer duration), it is possible that forcing in 1,000 MW of CTs would have led the model to select a smaller quantity of other resources or a different economic retirement schedule. In such cases, the secondary "out of model" step leads to a sub-optimal result unless the portfolio is re-optimized after the 1,000 MW of CTs are forced in.

Q. WHAT "OUT OF MODEL" STEPS DID YOU IDENTIFY IN DUKE'S MODELING?

A. While more details are provided in the Strategen Report, these steps include the following:

- First, Duke delayed the retirement dates beyond the economic dates selected by the EnCompass model for Mayo 1, Marshall 1 & 2, and Belews Creek 1 & 2 (P1 Scenario). Duke explained that this was done to accommodate required transmission upgrades, however I am skeptical of this as explained in Section V below.
- Second, Duke replaced between 1,600 and 2,000 MWs of standalone battery storage selected by the model with between 1,500 and 1,900 MWs of natural gas CTs. Duke explained that this adjustment (referred to as the Battery-CT Optimization) was made because the "typical day" load profile used by the EnCompass included a steeper transition between the daily peak and minimum system load levels. According to Duke, this profile tended to overvalue short duration storage at the expense other resources. The Supplemental Portfolios (SP5 and SP6) included a similar replacement of solar plus storage resources that were initially selected by EnCompass.

- Third, Duke pre-determined the dispatch profile of solar plus storage resources rather than allowing the model to flexibly dispatch the storage component. Under this approach, EnCompass was not allowed to make modifications to the dispatch schedule even if the modeled grid conditions would suggest otherwise.
- Fourth, Duke fixed the level of demand-side resources available by including them in the load forecast.
- Finally, Duke conducted a "Final Reliability Adjustment," which added two additional CTs in a subset of portfolios.

Q. WERE THESE "OUT OF MODEL" STEPS REASONABLE?

A. No, with the possible exception of the Reliability Adjustment. A primary functionality and reason to use a model like EnCompass, is its ability to co-optimize across multiple resource choices and constraints over a set time horizon. Any "out-of-model" adjustments therefore run the risk of distorting the model results and leading to non-optimal results that increase the portfolio's overall costs.

Q. **WHAT WOULD BE A MORE REASONABLE APPROACH TO MODELING THE RETIREMENT OF COAL GENERATING FACILITIES?**

A. Per the Commission's 29 July 2022 order, my suggested approach to coal unit retirements is described below in Section V.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO ADDRESSING THE MODEL'S ALLEGED OVERVALUATION OF STANDALONE STORAGE?

A. Instead of including the Battery-CT Optimization step, the "typical day" profile should have been adjusted within EnCompass to more closely reflect real world conditions. As described above, replacing a single variable without additional re-optimization means that the resulting portfolio may no longer represent the optimal solution.

Q. DID DUKE ATTEMPT TO IMPROVE THE "TYPICAL DAY" PROFILE WITHIN ENCOMPASS, AS YOU HAVE SUGGESTED (AND WAS RECOMMENDED IN STRATEGEN'S JULY 2022 REPORT), IN ITS SUPPLEMENTAL PORTFOLIO MODELING?

A. No. In fact, Duke did not even respond to this recommendation in its August 19 testimony. Duke has yet to provide a justification for why it resorted to an out-of-model adjustment rather than seeking to make this improvement within EnCompass and thereby ensuring the integrity of the optimization results.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO MODELING SOLAR PLUS STORAGE?

A. Rather than assume a fixed dispatch profile, a more reasonable approach would have been for Duke to have permitted EnCompass to dispatch the storage resources. The fixed dispatch approach significantly devalues additional solar plus storage resources that are added to the system.[19] While there may be

---

[19] *See* Strategen Report, p. 14-15.

concerns regarding how dispatch decisions affect ITC eligibility, these concerns can still be addressed within the model. Moreover, these concerns are largely irrelevant now due to the IRA which extends ITC eligibility to storage regardless of its generation source and therefore renders previous dispatch limitations as moot. Overall, I support the approach employed in the Supplemental Portfolios, which allowed the model to optimize the battery dispatch profile.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO MODEL DEMAND-SIDE RESOURCES?

A. Rather than including demand-side resources as a fixed input into the load forecast, EnCompass should have been allowed to select demand-side resources. In addition, the load forecast should have been adjusted to include a corresponding amount of naturally occurring efficiency to the amount of UEE roll-off. I discuss these issues in more detail in Section X.

Q. DO YOU HAVE ANY RECOMMENDATIONS RELATED TO DUKE'S "FINAL RELIABILITY ADJUSTMENT"?

A. Yes. It is essential that reliability be evaluated comprehensively, to ensure that any simplifications in models like EnCompass do not overlook any potential gaps. Therefore, a step similar to Duke's "final reliability adjustment" may be necessary. However, this modeling step can be difficult to assess. This may allow Duke to "hand select" additional resources when it is often unclear what underlying reliability issues need to be addressed or whether the selected resources are a good fit.

For this Carbon Plan cycle, I do not recommend removing this reliability adjustment step because the adjustments made by Duke appear to be relatively limited and well into the next decade (at least in the case of the Initial Portfolios). As such, I am not too concerned by these changes in this proceeding. However, in future iterations of the Carbon Plan, it will be important to make sure that transparent information is provided about these types of reliability adjustments, including (1) the size and type of adjustment made, (2) the reason for the change, including any 8760 hourly model data that showed reliability deficiencies, and (3) alternatives that were considered. This will allow the Commission and stakeholders to ensure that additions are truly needed to address reliability gaps.

Q. WHAT IMPACT WOULD REMOVING THESE "OUT OF MODEL" STEPS HAVE ON THE OUTCOME OF THE MODELING?

A. Conducting the portfolio analysis without these additional steps (with the exception of the reliability adjustment) would lead to a more internally consistent and more optimal result. This would include greater assurance that the least cost choices are being made in terms of retirement dates and resource additions.

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS FOR THE ABOVE MODELING PROBLEMS (I.E., UNREASONABLE RESOURCE CONSTRAINTS, AND "OUT OF MODEL" ADJUSTMENTS)?

A. I recommend that the Commission reject Carbon Plan portfolios that do not eliminate or significantly relax the constraints identified above. Portfolio model runs with these relaxed constraints should also be included in the supporting analysis provided as part of any application made by Duke for a certificate of public convenience and necessity ("CPCN applications") for near-term resources selected in the Carbon Plan.

In future iterations of its Carbon Plan, the Commission should also require Duke to minimize the number of out-of-model adjustments made. Finally, the Commission should also require Duke to provide full transparency on what specific resource additions were made through reliability adjustments, or other out-of-model changes, and the reasons for those changes.

C. Some of Duke's assumptions for new gas resource are questionable and warrant further scrutiny

Q. DO YOU HAVE ANY CONCERNS REGARDING THE MODELING ASSUMPTIONS RELATED TO NATURAL GAS GENERATION?

A. Yes. I have concerns about both the natural gas price and natural gas supply assumptions used by Duke, the effective load carrying capacity ("ELCC") values used by Duke, and Duke's assumptions about switching natural gas generators to operate on hydrogen.

i. Current natural gas prices are significantly higher than the "worst case scenario" that Duke modeled in its Carbon Plan.

Q. WHAT CONCERNS DO YOU HAVE ABOUT THE NATURAL GAS PRICE ASSUMPTIONS USED BY DUKE IN ITS MODELING?

A. Duke's plan was developed before the recent and significant increase in natural gas prices driven in part by Russia's invasion of Ukraine. This means that current gas prices are significantly higher than the "worst case scenario" that Duke assumed in its Carbon Plan.[20]

Q. DO YOU SHARE ANY OF PUBLIC STAFF'S CONCERNS REGARDING NATURAL GAS COMMODITY PRICING AND DELIVERABILITY?

A. Yes. However, I have some additional concerns that I do not think Public Staff has fully addressed. For example, Public Staff is somewhat dismissive of the recent surge in natural gas prices, stating that "the natural gas forecasts contained in the Proposed Carbon Plan affect capacity expansion starting around year 2026, well beyond the current price volatility."[21] This implies that current prices will eventually subside and return to where they have been in the recent past. However, it is not clear when or if that will be the case. For example, due to the development of LNG export terminals in recent years, the U.S. gas market is now much more exposed to global commodity prices than it was in

---

[20] *See* Strategen Report, p. 23-24.
[21] Public Staff Comments, p. 71.

the previous decade.[22] These global prices are in turn more affected by unpredictable dynamics such as the war in Ukraine. Public Staff has not provided evidence to suggest when/if a "return to normalcy" will occur. Even Duke conceded that the long-term market price for natural gas, delivered in 2027, has increased by $0.71/MMBtu or nearly 20% relative to the Company's original assumptions.[23] As a result, I believe it is essential to err on the side of caution when considering future natural gas prices. In practice this means the Commission should seriously examine the high gas price sensitivity. It also suggests that the Commission should seek to limit customers' exposure to natural gas prices by minimizing or delaying addition of new gas plants where possible.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO THE NATURAL GAS PRICE ASSUMPTIONS USED BY DUKE IN ITS MODELING?

A. Although Duke may not have been able to foresee the recent run-up in gas prices and adjust its plan accordingly, it is instructive to consider the implications of this recent development by examining the "High Gas Price Forecast" sensitivity cases that Duke provided. However, because Duke did not re-optimize resource selections for this sensitivity case, the results are of limited value in considering potential changes to the underlying resource portfolio. If Duke had re-optimized the portfolio under higher gas prices, then it is probable

[22] The United States became the world's largest LNG exporter in the first half of 2022, U.S. Energy Information Administration (July 25, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53159.
[23] Snider, et al., page 176

that fewer gas units (and CC units in particular) would have been selected. Since fuel costs are directly passed to Duke's customers through the annual fuel clause proceeding, this price risk is borne primarily by Duke's customers rather than by Duke itself. Given the potential magnitude of this price risk, I recommend that the Commission consider all options available to reduce exposure to gas fuel prices, including alternatives that could reduce new CC buildouts. Finally, the presumption that new CTs will operate on ULSD at least some of the time will add to their operating cost and emissions contribution. These impacts should be reflected in future modeling.

ii. There are significant uncertainties regarding the feasibility and cost of securing firm transportation of natural gas sufficient to fuel new CC plants. It is not clear that these costs were correctly modeled by Duke in its resource selection process.

Q. WHAT CONCERNS DO YOU HAVE ABOUT THE NATURAL GAS SUPPLY ASSUMPTIONS USED BY DUKE IN ITS MODELING?

A. Duke's base fuel supply assumption in both its Initial Portfolios (P1-P4) and Supplemental Portfolios (SP5 and SP6) is that the Companies will be able to obtain incremental firm transportation ("FT") service to supply Duke's existing CC fleet as well as a limited number of new CC units. For P1-P4, Duke assumed that it could secure incremental FT service to access Appalachian gas (e.g., via the Mountain Valley Pipeline), whereas SP5 and SP6 assumed incremental access to Transco Zone 4.[24] In both cases, new gas pipeline capacity would be required. Absent new gas pipeline capacity, Duke's CC fleet does not have access to a firm fuel supply. This deficiency in firm fuel does not only apply to new CC units being considered, but it also applies to Duke's existing fleet. In light of this lack of firm fuel, I am concerned that Duke may be overstating the reliability contribution of its CC units (both new and existing). If the CCs cannot obtain firm fuel supplies, then they are subject to disruptions during peak load hours. The lack of firm natural gas delivery was one factor that led to the near collapse of the power grid in Texas during the winter storm of February 2021.[25] Given the limited available pipeline capacity in the region to support firm delivery of gas to both existing and new CC units, reliance on natural gas introduces a significant reliability risk in the event of severe cold weather when gas demand is high throughout the region and CC units have to compete with retail natural gas customers for fuel supply. Expanding Duke's gas CC fleet will only exacerbate this risk, potentially negating any effort to mitigate the current risk to Duke's existing fleet.

Moreover, the incremental FT service Duke assumes in its base case is significant. According to the Company, the incremental FT service assumed in

[24] See Duke Carbon Plan, Appendix E, p. 42, which states: "This incremental firm supply allows for the Companies' existing CC fleet to be fully supported by interstate firm transportation and with the potential for capacity for a limited amount of new CC units to also operate at this gas price."; Direct Testimony of Snider, et. al, Exh. 1, p. 3, which states: "Existing CC fleet fueled Transco Zone 4, FT for two new CCs with Transco Zone 4"
[25] *See* Strategen Report, p 26.

the base case suggests that the Company [BEGIN CONFIDENTIAL] [redacted].[26] [END CONFIDENTIAL]

Q. WERE THE COSTS OF SECURING INCREMENTAL FT SERVICE CORRECTLY INCLUDED AS PART OF THE COST OF NEW CC RESOURCES WHEN DUKE PERFORMED ITS ENCOMPASS MODELING?

A. I don't believe so. It is not obvious that the costs of this additional pipeline capacity are fully accounted for in Duke's EnCompass analysis for resource selection.[27] Strategen is concerned that Duke's analysis may have underestimated the fixed costs necessary to secure firm fuel transportation for new CC resources.

Q. DID DUKE MODEL ANY PORTFOLIOS WITH MORE CONSERVATIVE INCREMENTAL FT ASSUMPTIONS?

A. Yes. To account for the likelihood that Duke is unable to secure access to Appalachian gas, Duke's Initial Portfolios also included an "Alternate Fuel Supply Sensitivity," under which new CC units will have to rely on delivered gas from the higher-cost Transco Zone 5 and dual-fuel capability. Additionally, the remaining portion of Duke's existing CC fleet will also not have firm interstate capacity. The limited firm transportation under the Alternate Fuel Supply Sensitivity results in fewer CC units in all four portfolios (i.e., $P1_A$-$P4_A$),

---

[26] *See* Strategen Report, p. 25 and Duke Energy Confidential Response to AGO DR 8-9 (attached as Exhibit 3).
[27] *See* Strategen Report, p. 25-26.

reducing the amount of new CC from 2,400 MW to 800 MW. In contrast, none of the Supplemental Portfolios (SP5, SP6, $SP5_A$, and $SP6_A$) included these more conservative assumptions for FT service, and each assumed gas supply would be sufficient to support both the existing CC deficiency and 2,400 MW of new CC capacity.

Q. DO YOU HAVE CONCERNS WITH PUBLIC STAFF'S APPROACH TO NATURAL GAS DELIVERABILITY?

A. Yes. First, as discussed above and addressed in the Strategen report,[28] there appears to be some discrepancies in Duke's cost assumptions for firm transport of gas to new CC units and what was included in the EnCompass model. It does not appear that Public Staff has addressed this issue, despite an otherwise thorough discussion in their July 15th comments. Second, I am very concerned about Public Staff's apparent recommendation to Duke that the No Appalachian gas portfolios in the Supplemental Portfolio analysis (i.e., SP5 and SP6) would be able to support "up to 2,400 CC, supported with Transco Zone 4 interstate FT for this capacity."[29] Public Staff's comments provided no evidence that securing incremental FT supply of this magnitude from Transco Zone 4 would be feasible or cost effective. Bear in mind, Public Staff's recommendation (and Duke's subsequent modeling) for SP5 and SP6 suggested that incremental FT from Zone 4 would be available to support not only 2,400 MW of new CC capacity, but also Duke's current deficiency. [BEGIN CONFIDENTIAL] [redacted]

---

[28] Strategen Report, page 26.
[29] Duke Energy Response to AGO DR 8-10.

[redacted][30] [END CONFIDENTIAL] Public Staff's Comments mention "recent proposals for Williams Transco upgrade projects" which I interpret to mean the proposed Southside Reliability Project. However, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Moreover, as discussed in the Strategen Report, none of this additional FT capacity for this project is currently earmarked for electricity.[31] Given these concerns, I don't believe Public Staff's recommended FT assumptions, which underpin Duke's analysis for SP5 and SP6, are reasonable.

Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE NATURAL GAS SUPPLY ASSUMPTIONS USED BY DUKE IN ITS MODELING?

A. Given the potential risk of gas deliverability to the proposed new CC projects, and the reliability risks this may impose, I strongly recommend that the Commission consider Duke's Alternate Fuel Supply Sensitivity (i.e., "No Appalachian Gas") as modeled in $P1_A$-$P4_A$ as a better primary assumption for the Carbon Plan instead of the Base Fuel Supply case of the Initial Portfolios (i.e., P1-P4) or the Supplemental Portfolios (i.e., SP5, SP6, $SP5_A$, and $SP6_A$).

---

[30] Exhibit 3.
[31] Strategen Report, p 27.

iii. Clean hydrogen fuel is an emerging technology, and it is premature to include it in the Carbon Plan at this time.

Q. WHAT CONCERNS DO YOU HAVE ABOUT DUKE'S ASSUMPTIONS REGARDING THE CONVERSION OF ITS NATURAL GAS GENERATION TO OPERATE ON HYDROGEN?

A. Duke modeled natural gas plants with a 35-year lifetime. Therefore, any new CC or CT would operate past the 2050 deadline under HB951 for achieving net zero carbon emissions. Duke attempts to address this concern by assuming that any new gas plant built in the 2040s will operate on 100% hydrogen and those added before 2040 will be converted to 100% hydrogen by 2050. There are two key problems with this approach: (1) many of the cost assumptions used to model these resources are speculative,[32] and (2) the feasibility of this plan is questionable.

Additionally, the assumed conversion to hydrogen fuel in the 2050 timeframe may underestimate the portfolio costs of any new gas resource from a present value of revenue requirement ("PVRR") perspective. This is because all PVRR calculations performed by Duke are done only through 2050,[33] including any necessary fixed cost investments.[34] This means that the potentially significant future cost of hydrogen conversion of gas resources is largely absent from Duke's Carbon Plan simply due to the time horizon selected for the analysis.

---

[32] *See* Strategen Report, p. 29.
[33] Duke Energy Response to AGO DR 4-3.
[34] Duke Energy Response to AGO DR 4-4.

Regarding hydrogen supply, Duke calculated that curtailed or unutilized carbon-free energy could be used to produce enough hydrogen to meet all hydrogen needs on Duke's system through 2049 and nearly half of hydrogen needs in 2050.[35] However, these calculations did not address the costs to produce the hydrogen through electrolysis or the availability of the remaining hydrogen need in 2050 and beyond. Duke also did not attempt to account for the increased carbon-free generation capacity necessary to produce this hydrogen in the Carbon Plan.[36]

There are also key concerns about the feasibility of Duke's plan to operate all natural gas generation on 100% hydrogen by 2050. The ability of gas units to operate on hydrogen by 2050 depends on overcoming many uncertainties and challenges related to the cost-effective production, transportation, storage, and combustion of green hydrogen fuel and related equipment.[37] Despite such uncertainties, Duke relies heavily on the assumption that a robust hydrogen market will develop by 2050 to justify a significant buildout of natural gas units in the near term. While hydrogen combustion may ultimately become feasible in the 2030s, planning based on today's technologies suggests that new natural gas plants would likely need to retire early and impose significant additional stranded costs on Duke's customers.

[35] Duke Carbon Plan, Appendix E, p. 102.
[36] Duke Energy Response to AGO DR 4-13.
[37] *See* Strategen Report, p. 29-30.

Q. WHAT WOULD BE A MORE REASONABLE WAY TO MODEL THE POTENTIAL THAT NATURAL GAS GENERATION BE RUN ON 100% HYDROGEN BY 2050?

A. Given the significant uncertainty around the potential costs of hydrogen conversion, as well as around whether a robust hydrogen market will materialize, it appears to be premature to assume that new gas plants added in the near term will convert to hydrogen. The approach taken in the Supplemental Portfolios addresses these concerns by removing hydrogen fuel. Additionally, it may also be prudent to assume that all new natural gas plants have lifetimes that do not exceed the 2050 timeframe, due to the zero emission target. Practically speaking, this means that the CC and CT additions contemplated as part of the near-term action plan (*i.e.*, with in-service dates in the 2029 timeframe) should be modeled assuming 20-year lifetimes, rather than the 35-year lifetimes that Duke has assumed, at least until there is more clarity on the future of the hydrogen market. It may also make sense to delay a decision on new CC and CT additions as long as possible in order to monitor the development of green hydrogen technologies, gain further clarity on costs, and avoid stranded asset risks for consumers.

Q. PUBLIC STAFF RAISES CONCERNS ABOUT DUKE'S ASSUMPTIONS REGARDING HYDROGEN BLENDING. DO YOU SHARE THESE CONCERNS?

A. Yes. In fact, when energy density of the fuel is considered, the carbon reduction benefit of hydrogen blending is actually fairly small relative to the volume of natural gas fuel replaced.

D. Public Staff's comparison of portfolio CO2 abatement costs is incomplete and outdated given the impact of the IRA.

Q. DO YOU AGREE WITH THE METHODOLOGY USED IN PUBLIC STAFF'S ANALYSIS COMPARING CO_2 ABATEMENT COSTS OF THE FOUR PORTFOLIOS PROPOSED BY DUKE AND THEIR RESULTING CONCLUSION THAT THE P1 PORTFOLIO IS NOT JUSTIFIED EVEN WHEN CONSIDERING THE SOCIAL COST OF CARBON ("SCC")?

A. No. While I appreciate the analysis that Public Staff has conducted, it does not appear definitive to me that P1 should be eliminated based on CO_2 abatement costs. More specifically, Public Staff relies upon the 2021 Interagency Working Group on Social Cost of Greenhouse Gases[38] which includes multiple potential scenarios for the SCC values. Public Staff apparently selected the 3% discount rate scenario for its analysis; however, it is not clear why this scenario was selected over others. For example, the same report also includes SCC values ranging from \$22/ton to \$206/ton in 2035 depending on the scenario selected. Under the 3% (95th percentile) scenario, Portfolio 1 would be the most cost effective. Under the 2.5% discount rate scenario, P1 would perform better than

[38] Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interagency Working Group (Feb. 2021), https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

P2, and roughly equal to P4 in 2035. Furthermore, Public Staff appears to have inappropriately applied the 2035 SCC values for its 2050 evaluation. Finally, the IRA likely changes the cost-benefit analysis that Public Staff performed – especially the cost of solar and storage which are higher in P1. Thus, the analysis should be revisited, and I would expect that P1 would perform much more favorably.

E. Duke's Supplemental Portfolios (SP5 and SP6) do not fully address the AGO's concerns. The Commission should not adopt a Carbon Plan that does not resolve these issues.

Q. DID DUKE'S SUPPLEMENTAL PORTFOLIOS ADDRESS ALL OF THE CONCERNS THAT THE AGO/STRATEGEN HAD PREVIOUSLY RAISED IN ITS JULY 2022 REPORT?

A. No. While it did address some of these concerns, it did not address all of them. The Table below provides a summary of which concerns were addressed and which were not. This table is comparable to Table SPA-1 in Duke's testimony.

Table 3

Modeling Issue Identified by AGO/Strategen	Approach Used in Initial Portfolios P1-P4	Approach Used in Supplemental Portfolios SP5-SP6	Do SP5 & SP6 Address AGO's Concerns?
SPS Battery Dispatch Optimization	Fixed battery dispatch profile	Model optimized battery dispatch	Yes
Available SPS Battery Configurations	• 4-hr, 25% battery to solar ratio • 2-hr, 50% battery to solar ratio	• 4-hr, 25% battery to solar ratio • 2-hr, 50% battery to solar ratio • 4-hr, 50% battery to solar ratio	Partially (additional configurations would have been helpful)
Cumulative Battery Limits	4-hr battery capped at 1,500 MW in DEC and 1,800 MW in DEP;	4-hr and 6-hr battery not capped, but continue to decline in capacity value at higher penetrations	Yes

	6- hr battery at 3,200 MW in DEC and 2,000 MW in DEP		
Cumulative SPS Limits	50% battery to solar ratio capped at 450 MW in DEC and 750 MW in DEP	Limit remains for original solar plus storage configuration	No
Inclusion of Hydrogen Fuel	H2 Fuel Included	H2 Fuel <u>Not</u> Included	Yes
Availability of incremental FT Under "No Appalachian Fuel" Supply Case	No incremental FT for new CCs	FT for existing CCs plus two new CCs with Transco Zone 4	No; unclear if 400,000 dkt/day of FT is available at Transco Zone 4; insufficient for both existing and new CCs.
Cost of incremental FT	EnCompass inputs were too low	EnCompass inputs more reasonable, but may still be too low	Possibly
Availability of F-Class and J-Class CCs and CTs	Smaller F-Class CC available in no Appalachian fuel supply case. Larger J-Class CC available in limited Appalachian supply case. Only J-Class CTs available.	Both J-Class and F-Class CCs and CTs available in both fuel supply scenarios.	Partially; Strategen recommended that both sizes be available in the Base case, but not in the "No Appalachian Gas" case due to gas availability.
Useful Life of New Gas	35 years	35 years	No; Strategen recommended 20 years
Coal Retirements Dates	Predetermined outside of core model (i.e., Not Economically Selected in Core Model)	Predetermined, (i.e., Not Economically Selected in Core Model)	No; Strategen recommended economically selected dates
Belews Creek conversion to 100% NG	Not modeled	Not modeled	No; allow prior to 2030
Battery/CT Replacement	Conducted as an "out of model" step	Conducted as an "out of model" step	No. In-model adjustments should have been made.
Solar Limits	See Table SPA-1	Same as P2-4; (high solar sensitivity modeled)	No; recommended increase in early years to >1000 MW
Wind Limits	See Table E-41	Unchanged	No; recommended increase annual limit & first year deployment; allow non-firm transmission

Load Forecast	UEE Base Case	UEE Base Case (low UEE modeled)	No; recommend high UEE, and/or load forecast adjustment
Compliance Date	P1: 2030 P2: 2032 P3: 2034 P4: 2034	P5: 2032 P6: 2034	No; AGO/Strategen recommended 2030

Q. DID THE RESULTS OF DUKE'S SUPPLEMENTAL PORTFOLIO MODELING VALIDATE ANY OF THE ORIGINAL CONCERNS RAISED BY AGO/STRATEGEN?

A. Yes. As Duke explained in its testimony, the inclusion of an additional solar plus storage ("SPS") configuration with a larger battery, along with revised SPS modeling (both of which the AGO/Strategen recommended) led to more SPS being selected. Moreover, the results suggest that there may be merit to exploring additional SPS configurations going forward. This also demonstrates more broadly that AGO/Strategen's concerns are legitimately focused on issues that could have a material impact on the Carbon Plan and should not be casually dismissed. Yet, Duke did dismiss several of these concerns.

Q. WERE YOU CONSULTED BY DUKE OR THE PUBLIC STAFF IN THE DEVELOPMENT OF DUKE'S SUPPLEMENTAL PORTFOLIO MODELING?

A. No.

Q. SEVERAL OF AGO/STRATEGEN'S CONCERNS WERE NOT ADDRESSED IN DUKE'S SUPPLEMENTAL PORTFOLIO MODELING. DID THE AGO SEEK TO HAVE THESE CONCERNS

ADDRESSED BY DUKE IN ITS SUPPLEMENTAL PORTFOLIO MODELING EFFORTS?

A. Yes. However, Duke did not agree to several of the additional changes that the AGO requested. Moreover, Duke did not provide satisfactory reasons for why several of the requested changes should not be included.

Q. BEYOND THOSE INITIAL CONCERNS, DID DUKE'S SUPPLEMENTAL PORTFOLIO MODELING INTRODUCE NEW ASSUMPTIONS THAT YOU ARE CONCERNED ABOUT?

A. Yes. Most notably, I am concerned about the new assumptions relating to natural gas fuel supply under the "No Appalachian Gas" case. Specifically, SP5 and SP6 assumed that Duke would be able to secure 400,000 dekatherms/day of incremental firm transport from Transco Zone 4. Duke explains that this would be sufficient for "enough firm supply for two large, or three small, CC units" or about 2,400 MW of new CC units in total. This contrasts with Duke's previous approach in its Initial Portfolios which limited new CC additions to 800 MW under the "No Appalachian Gas" scenario. Duke's testimony did not address the feasibility or cost of securing 400,000 dekatherms/day of incremental firm transport. This is a critical input underpinning the viability of Duke's proposed CC additions in the Supplemental Portfolios and needs significant scrutiny.

Q. HAS THE AGO/STRATEGEN PERFORMED ANY FURTHER MODELING TO ADDRESS THESE OUTSTANDING CONCERNS?

A. Yes. This is described in Section IV-F below.

F. AGO Supplemental Portfolio Modeling

Q. DID DUKE'S SUPPLEMENTAL PORTFOLIOS ADDRESS ALL OF THE CONCERNS THAT AGO RAISED IN ITS JULY COMMENTS?

A. No. As summarized in Table 3 above, Duke's Supplemental Portfolios did address some concerns shared between AGO and Public Staff but left many of AGO's concerns unaddressed.

Q. DID THE AGO MAKE A REQUEST TO DUKE THAT THESE ISSUES BE ADDRESSED IN ITS SUPPLEMENTAL PORTFOLIO ANALYSIS?

A. Yes. However, after some initial discussions with Duke, the Company indicated that it was not able to complete the AGO's request within the timeframe allotted. This in turn led the AGO to file its motion to require Duke to conduct the additional modeling.

Q. GIVEN DUKE'S REFUSAL TO COMPLETE THE AGO'S REQUESTS, HAS THE AGO SOUGHT OTHER MEANS TO CONDUCT THIS ANALYSIS?

A. Yes. While not part of its initial scope of work, the AGO has engaged Strategen to conduct supplemental portfolio analysis in EnCompass. This scenario analysis builds upon SP5 but includes several key modifications. A more complete description of this analysis and its findings is attached to my testimony as Exhibit 2.

Q. WHAT ARE SOME OF THE KEY MODIFICATIONS INCLUDED IN THE AGO'S SUPPLEMENTAL PORTFOLIO ANALYSIS?

A. As explained above, there were several modeling issues identified by AGO/Strategen in the July comments/report which were described in Table 3 above. Table 4 below explains how these same issues were addressed in the SP-AGO scenario.

Table 4

Modeling Issue Identified by AGO/Strategen	**Do SP5 & SP6 Address AGO's Concerns?**	**Approach Used in SP-AGO**
SPS Battery Dispatch Optimization	Yes	Same as SP5
Available SPS Battery Configurations	Partially (additional configurations would have been helpful)	Same as SP5
Cumulative Battery Limits	Yes	Same as SP5
Cumulative SPS Limits	No	Cumulative limits removed
Availability of incremental FT Under "No Appalachian Fuel" Supply Case	No; unclear if 400,000 dkt/day of FT is available at Transco Zone 4; insufficient for both existing and new CCs.	Gas expansion assumptions consistent with $P1_A$ -$P4_A$
Cost of incremental FT	Possibly	Same as SP5
Availability of F-Class and J-Class CCs and CTs	Partially; Strategen recommended that both sizes be available in the Base case, but not in the "No Appalachian Gas" case due to gas availability.	Gas expansion assumptions consistent with $P1_A$ -$P4_A$
Useful Life of New Gas	No; Strategen recommended 20 years	20-year life
Coal Retirements Dates	No; Strategen recommended economically selected dates	Economically selected

Belews Creek conversion to 100% NG	No; allow prior to 2030	Conversion by 2028
Battery/CT Replacement	No. In-model adjustments should have been made.	Same as SP5 (no in-model adjustments made due to time constraints)
Solar Limits	No; recommended increase early years to >1000 MW	Midpoint of High Solar Case and P1 (see Table 2 above);
Wind Limits	No; recommended increase annual limit & first year deployment; allow non-firm transmission	Increased annual import limit allowing for non-firm transmission (0% ELCC); First addition in 2027
Load Forecast	No; recommend high UEE, and/or load forecast adjustment	Same as SP5 (no adjustments made due to time constraints)
HB 951 Compliance Date	No; AGO/Strategen recommended 2030	2030 compliance date

Q. WHAT ARE SOME OF THE KEY FINDINGS FROM THIS ANALYSIS?

A. The results of the EnCompass analysis using the SP-AGO inputs listed above show that a feasible portfolio is achievable with a 2030 compliance date at a substantially lower cost than the P1 and $P1_A$ portfolios. Some of the key features of the SP-AGO portfolio include the following:

- Meets 2030 compliance with HB 951, and achieves lower cumulative emissions than any Duke-modeled portfolio.
- Significant investments in solar plus storage, including over 3,100 MW added in the 2027-2028 timeframe. As much as 1,200 MW of the newly added configuration (50% battery ratio with 4-hr storage) is selected in the following two years.

- Over 500 MW of battery storage added in 2027, increasing to 2,000 MW in 2028. This roughly coincides with retirements at the Mayo 1 and Marshall 1 and 2 plants.
- Despite having zero assumed capacity contribution, significant additions of onshore wind imports with non-firm transmission were selected. These additions were selected as soon as the model would allow (i.e., 2027).
- New gas CT units were selected at the end of 2028 for DEP (462 MW). No new gas CC units were added.
- Economic retirement of the Mayo coal plant occurs in 2027 and Marshall 1 and 2 in 2028. Belews Creek is converted to gas prior to 2030.
- Present Value Revenue Requirement (PVRR) through 2050 (DEP/DEC Combined System) of $100 billion is lower in cost than other 2030-compliant portfolios (e.g., P1 and $P1_A$) and also lower than SP5.

Q. WERE THERE ANY LIMITATIONS IN THE ANALYSIS SUPPORTING AGO'S SUPPLEMENTAL PORTFOLIO?

A. Yes. An analysis like this normally would be conducted over several months. However, due to the circumstances (including Duke's refusal to consider AGO's inputs) it had to be conducted in under 2 weeks. Given more time a more complete analysis could have been pursued, however, this was not possible due to time constraints. Nonetheless, I believe the model results are robust enough for the Commission's consideration. In full transparency there are certain limitations that should be acknowledged and which I believe can be improved upon given ample time to do so.

First, due to the complexities of modeling the Belews Creek gas conversion, this resource was simply included in the 2028 timeframe rather than being a result of the model's resource selection process. While this is less than ideal, I am confident that this is a reasonable approximation of the optimal outcome due to the considerably favorable economics of this conversion over a new gas plant addition.

Second, although Strategen identified serious concerns with Duke's underlying load forecast (including the long-term effects of UEE), there was insufficient time to develop an alternative load forecast and as such Duke's forecast was used. Ideally, this would have been adjusted to better reflect naturally occurring EE, which would have led to a reduced overall resource need.

Third, there was insufficient time to model additional solar plus storage configurations, including those with higher capacity factors. I believe this could be a highly consequential change and should be considered in future modeling efforts.

Finally, AGO/Strategen's intention was to exclude H2 from the SP-AGO model run, consistent with SP5. However, an inadvertent modeling error allowed H2 resources to be selected in the 2040-2050 timeframe. This error was discovered less than 24 hours before the deadline for this testimony and caused some H2 resources to be included in that timeframe. Given the substantial time for new model runs to be completed and interpreted (typically more than 24 hours), there was insufficient opportunity to correct this. Strategen is currently working to do so. I expect that the effect of this change will be relatively small, and do not anticipate it to impact any near-term actions. Any impact would be in the 2040-2050 timeframe.

V. COAL UNIT RETIREMENT SCHEDULE

A. Duke's modeled portfolios include adjusted coal retirement dates that were inconsistent with the economically optimal results.

Q. HOW DID DUKE ADDRESS COAL UNIT RETIREMENTS?

A. In its proposed Carbon Plan, Duke claims to have initially run its model using the most economic retirement dates of its coal plants ("endogenous retirements"). However, Duke then made subjective changes to these dates without further explanation of each change being made in its filing. Duke claimed that these "minor adjustments"[39] were made by applying "limited professional engineering judgments,"[40] but did not elaborate. This is concerning because it may mean that Duke is not aligning its coal retirement schedule with

---

[39] Duke Carbon Plan, Appendix E, p. 49.
[40] Duke Carbon Plan, Appendix E, p. 45.

the dates that are most optimal for reducing customer costs under HB951's requirements.

Q. DID DUKE GIVE A REASON FOR ADJUSTING THE ENDOGENOUS RETIREMENT DATES?

A. Not in its initial Carbon Plan filing. In response to a data request, Duke provided high level explanations for some of the changes that were made.[41]

Q. WHAT WAS THE IMPACT OF THESE CHANGES?

A. Despite referring to these changes as "minor adjustments,"[42] a substantial number of the retirement dates were altered. Some of these changes were quite significant. For the P1 portfolio, the economic retirement dates for Belews Creek 1 & 2, Marshall 1 & 2, and Mayo 1 occur much sooner than what Duke has proposed. These changes are noteworthy since they overlap substantially with the timing of in-service dates for resources procured as part of Duke's proposed near-term action plan. Thus, they could have a significant effect on resource decisions made in the 2026- 2030 timeframe.

For Mayo 1, Duke revealed that the economic date was 2026 in all scenarios, rather than the 2029 date it ultimately selected.[43] Duke selected the 2029 date even though the Company confirmed that the earliest retirement date could be as soon as 2027 and that battery technology could be a replacement option.[44]

---

[41] Duke Energy Second Supplemental Response to AGO DR 4-7 (attached as Exhibit 4).
[42] Duke Carbon Plan, Appendix E, p. 49.
[43] Exhibit 4.
[44] Id.

Meanwhile, Duke's assumption for the earliest possible deployment of battery storage is 2025, which is much sooner than the 2027 earliest retirement date.

Similarly, Duke delayed the retirement date for Marshall 1 and 2 from the economic date of 2026 to a later date of 2029. Duke explained that the economic 2026 retirement date was not selected due to transmission needs at the site. Specifically in Appendix P of the Carbon Plan, Duke states the following: "If any Marshall coal units are retired and not replaced with new generation on-site, then significant transmission projects will be needed." However, this suggests that on-site resources (like the battery storage mentioned above, or CTs), could potentially avoid these transmission upgrades and allow for the more economical 2026 retirement date to be pursued.

For Belews Creek 1 & 2, the economic retirement date was as early as 2030, yet the Company selected 2036 as the retirement date. Duke explained that the adjustment was made "based on a number of considerations including the units' flexibility to co-fire natural gas, the sheer size of the replacement generation, reliability benefits, providing additional time for development of SMR technology and supporting the corporate goal to be out of coal generation by the end of 2035."[45] This explanation is not sufficiently precise to support delaying the retirement dates to such a degree. The response also suggests that

[45] Exhibit 4.

Duke may be targeting the Belews Creek site for a potential SMR deployment in the mid-2030s rather than considering more economic alternatives.

B. Earlier retirement of coal generation at the Marshall, Mayo, and Belews Creek plants may be both economic and feasible. Duke's rationale for delaying these is insufficient.

Q. WHAT ALTERNATIVE APPROACH TO COAL RETIREMENTS WOULD YOU RECOMMEND?

A. Contrary to Duke's proposal, the least cost solution may be to accelerate procurement of about 1,473 MW of new resources to the 2025-2026 timeframe to replace uneconomic coal operations at Marshall 1 and 2, and at Mayo 1. By keeping these plants online longer than is optimal, they are effectively "crowding out" other more economic resources that could be considered earlier in the action plan. Meanwhile, given the relatively short timeframe, it may make sense to target replacement resources that can be deployed quickly at these facilities such as battery storage (or possibly solar plus storage, space permitting).

In Appendix P, Duke cited transmission upgrades as being necessary for retirement of certain coal plants, including Belews Creek. There should be ample opportunity to complete any necessary transmission upgrades prior to 2030, rather than waiting until 2036. During the 2020 IRP process, Strategen raised significant concerns about Duke's assessment of the need for these retirement-related transmission upgrades.[46]

Q. WHAT RECOMMENDATIONS WOULD YOU MAKE REGARDING COAL UNIT RETIREMENTS?

A. EnCompass' economic retirement dates should be considered feasible if: (1) onsite generation is installed earlier (*e.g.*, battery storage before 2026 at Mayo or Marshall), or (2) transmission upgrades are installed earlier (*e.g.*, by 2030 for Belews Creek). The Commission should also explore whether it would be feasible to modify Belews Creek to operate on 100% natural gas as an alternative to retirement and direct Duke to include this gas conversion as an option in all future scenarios.

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS REGARDING DUKE'S PROPOSED COAL RETIREMENT DATES?

A. Yes. One additional area of concern is the relationship between coal retirement dates and the high gas price forecast discussed above.

I am concerned that all of the high gas price sensitivity runs result in portfolios that do not comply with the HB951 emission reduction requirements. At a basic level, this is simply due to the fact that, under high gas price conditions, Duke dispatches its coal fleet more frequently, which leads to greater emissions. As discussed in Section IV, there is a distinct possibility that we will be headed

---

[46] These concerns included duplicative projects, shifting explanations of the deficiencies to be addressed, inaccurate planning assumptions, and inconsistencies with recent operations, among others. These concerns were presented at the October 2021 Technical Workshop.

towards a scenario closer to the high gas price sensitivity. However, it is not clear that Duke has developed a portfolio under these conditions that would actually meet the requirements of HB951 due to the coal redispatch issues described above. For example, Tables E-96 and E-97 in Appendix E of Duke's Carbon Plan show carbon reductions fail to reach the 70% statutory target. This is also indicative of the fact that Duke did not re-optimize the coal retirement schedule under the high gas price sensitivity cases as a means to identify a workable solution.

Q. HOW WOULD YOU ADDRESS THIS CONCERN?

A. As discussed above in Section IV, it is especially important to give weight to the high gas price sensitivity cases, including both the Base Portfolios (*e.g.*, P1-P4) and Alternative Fuel Supply Portfolios (*e.g.*, $P1_A$-$P4_A$). In addition, Duke should develop a contingency plan in case gas prices remain high.

One potential solution to meeting the 70% statutory target under this environment would be to accelerate certain coal retirements such that they occur before the statutory deadline (*e.g.*, 2030) while allowing other cleaner resources to take their place. This is especially relevant for the Belews Creek plant, which showed an economic retirement date as soon as 2030 in some cases. Removing Belews Creek from Duke's system by 2030 would not only match the economic retirement date identified in Duke's endogenous runs, but it may also be able to close the gap towards HB951 compliance across multiple sensitivity cases. In fact, based on Table A-3, if Belews Creek's 2021 coal emissions were removed from Duke's system, this would account for a 10% incremental carbon reduction versus the 2005 baseline.

Q. DO YOU AGREE WITH PUBLIC STAFF'S CONCERN ABOUT RETIRING BELEWS CREEK FROM COAL PRIOR TO 2036?

A. No. Public Staff states that they are "concerned that the decision to retire the Belews Creek units in 2035 was based on an arbitrary target set by Duke Energy Corporation to cease coal generation by 2035, and not on economics." However, this ignores the fact that EnCompass found 2030 to be the economic retirement date for the plant in the P1 scenario. I recognize the heartburn associated with retiring a plant that has received a significant recent capital investment in the form of its partial gas conversion. However, it is important that the Commission not succumb to the "sunk cost fallacy" in this instance. Furthermore, it appears that Duke did not evaluate all of the options for this plant since it failed to include full gas conversion as an option in its modeling, which could enable a later retirement date while also reducing emissions and costs. Based on the information Duke provided thus far, this appears to be a relatively economic option that should be available as an economic selection in the modeling.[47]

Additionally, Public's Staff's suggestion that Duke should ignore the model-selected retirement date and run Belews Creek to 2037 is just as arbitrary as Duke's assumption. In my opinion, it is better to let the model select the

[47] Strategen Report, p 39.

retirement date. Any transmission deficiencies should be easily addressed ahead of 2030.

Q. REGARDING DUKE'S PROPOSED RETIREMENT DATES FOR MARSHALL 1 AND 2, AND MAYO DO YOU AGREE THAT STRATEGEN'S CRITIQUE "REFLECT[S] A MISUNDERSTANDING OF THE ANALYSIS AND IGNORE[D] THE NEED FOR SUPPORTING INFRASTRUCTURE"?[48]

A. No. Strategen's report clearly considered the Company's purported needs for supporting infrastructure. However, there are many elements of the Strategen report's critique on this issue that Duke's testimony ignored.

Q. DUKE CLAIMS THAT AVOIDING LENGTHY TRANSMISSION UPGRADES AT MARSHALL 1 AND 2 REQUIRES REPLACEMENT GENERATION RESOURCES TO BE ON SITE. HOWEVER, THE COMPANY'S AUGUST 19TH TESTIMONY DISCOUNTS BATTERY STORAGE AS AN OPTION STATING THAT THE REPLACEMENT "MUST BE DISPATCHABLE RESOURCES CAPABLE OF LONGER RUN TIMES TO SATISFY GRID RELIABILITY REQUIREMENTS."[49] DOES THIS MAKE SENSE TO YOU?

A. No. Throughout this proceeding and the 2020 IRP, I have found Duke's responses on this issue to be unpersuasive, and insufficient justification for delaying retirements beyond the economical timeframe. In the 2020 IRP

[48] Snider et al. p 136.
[49] Snider, et al., p 137.

proceeding, Duke explained that transmission upgrades at its retiring coal plants were primarily needed for frequency regulation and voltage support. However, neither of these functions requires a dispatchable resource with a long duration on site. In fact, frequency regulation does not even require that the resource be located on site at all. Duke's testimony was also somewhat evasive regarding the Mayo plant's retirement. Ultimately, however, the Company did not dispute the notion that a 2027 retirement date was achievable, even if challenging to accomplish. One of the reasons Duke provided for delaying retirement was to "take advantage of continued cost declines for declining cost resources, such as batteries."[50] However, this cost decline advantage has been realized now that the IRA will provide a significant reduction in the cost of battery storage virtually overnight via the ITC starting in 2023.

Q. STRATEGEN'S REPORT NOTED THAT CONVERSION OF BELEWS CREEK TO RUN ON 100% GAS AND RETIRING IT FROM COAL PRIOR TO 2035 MAY BE A VIABLE AND RELATIVELY ECONOMIC OPTION. HOWEVER, THIS WAS NOT MODELED AS AN OPTION IN DUKE'S CARBON PLAN ANALYSIS. DID DUKE ADDRESS THIS CRITIQUE IN ITS TESTIMONY?

A. No, the Company did not explain why this option was not modeled. Duke discussed gas conversions more generally stating that such a conversion was "potentially feasible" and that its initial evaluations "did not show favorable

[50] Snider, et al., p 136.

economics."[51] However, I disagree with this characterization. First, these evaluations were not performed as part of the EnCompass modeling which would have more definitively determined whether the economics were favorable. Second as the Strategen report pointed out,[52] the economics of this conversion do appear to be quite favorable compared to other resources additions Duke considered in the Carbon Plan.

VI. NEAR-TERM PROCUREMENT ACTIVITY: SOLAR, SOLAR PLUS STORAGE, STANDALONE STORAGE, ONSHORE WIND, AND NATURAL GAS GENERATION

A. The IRA bolsters the rationale for near-term solar, wind, and battery storage resources, but calls into question near-term procurements of natural gas.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR THE COMMISSION REGARDING DUKE'S NEAR-TERM PROCUREMENT ACTIVITIES BASED ON THE PASSAGE OF THE IRA?

A. Yes. I believe the IRA further cements the notion that near-term procurement of solar, wind, and battery storage in the 2023-2030 timeframe is a "no regrets" strategy for any Carbon Plan. In contrast, the Commission should not use any approved Carbon Plan to inform any future CPCN proceeding for new gas

[51] Snider, et al., p 140.
[52] Strategen Report, p 39.

resources unless and until the IRA can be fully incorporated into the portfolio modeling process.

In considering Duke's Proposed Near-Term Actions, the procurement of 3,100 MW of solar, 1,600 MW of battery storage, and 600 MW of onshore wind are likely to be under-estimates, if anything, of the optimal quantity for these resource types. Meanwhile, the passage of the IRA calls into question whether procurement of new natural gas – particularly new CC units – is part of the economically optimal portfolio and whether a CPCN should still be pursued in 2023, if at all.

Q. WILL THE COMMISSION BE ABLE TO ADDRESS THE CPCN ISSUE BY SIMPLY INCORPORATING THE IRA INTO IN ITS ANALYSIS IN THE NEXT CARBON PLAN CYCLE?

A. Not if the Carbon Plan will be relied on to inform CPCN determinations regarding gas resources. In its August 19, 2022 testimony, Duke continued to express its intent to pursue CPCN applications for new gas plants in 2023. This was based on its Supplemental Carbon Plan analysis which does not reflect the IRA. If the Commission accepts the analysis without fully considering the IRA, then it would lock in a potentially sub-optimal resource investment and increase costs and risks to customers for decades to come.

B. Near-term procurement of solar, battery storage, and onshore wind should proceed as "no regrets" options.

Q. WHAT ARE YOUR KEY RECOMMENDATIONS REGARDING DUKE'S NEAR-TERM PROCUREMENT ACTIVITIES?

A. Given the modeling concerns described above, it is premature for the Commission to adopt any of the Initial Portfolios proposed by Duke as is, and premature to approve all of the near-term actions Duke has proposed. This is also true for the Supplemental Portfolios (SP5 and SP6). Instead, I recommend that the Commission consider the SP-AGO portfolio, which addresses the remainder of issues described in this testimony and in the AGO's initial comments, and which were not addressed in SP5 or SP6.

However, even if the Commission adopts a Carbon Plan without considering any further modeling, the Commission should, at a minimum, consider certain actions for each resource type as part of any near-term action plan adopted.

Q. DO YOU SUPPORT ANY OF DUKE'S NEAR-TERM PROCUREMENT ACTITIVITES?

A. Yes. I believe there is a sufficient basis to move forward with a minimum amount of solar, storage, and onshore wind procurements, and that these resources are still likely to be selected in any revised model run. This is especially true in light of the recent passage of the IRA, which has extended the federal ITC and PTC for renewable resources through 2032 rather than phasing them down as was the case prior to the legislation. Moreover, the ITC now applies to standalone battery storage, rather than being limited to storage co-located with renewable resources. Thus, the solar, storage, and wind procurements that Duke has identified in its proposed near-term action plan should still be pursued as part of a "no regrets" strategy. In fact, greater quantities of these resources may be warranted due to the IRA. Meanwhile, any solicitation for solar plus storage resources should consider configurations beyond those modeled by Duke in its plan, as a means to maximize limited interconnection space.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS REGARDING DUKE'S NEAR-TERM PROCUREMENT OF BATTERY STORAGE RESOURCES?

A. Yes. As discussed in Section V, Duke should seek to site battery storage at retiring coal facilities (e.g., Marshall 1 and 2, Mayo) as replacement generation by 2025 to avoid transmission upgrade requirements and advance economic retirements in the 2026 timeframe. Furthermore, Duke should explore opportunities to take advantage of new DOE financing opportunities under the IRA designated for infrastructure investments at retiring generation sites.

B. It is premature to pursue near-term procurement of new natural gas generation and the role of new natural gas units as part of the Carbon Plan should be further examined in 2023 or 2024 (i.e., the next Carbon Plan cycle).

Q. DO YOU HAVE ANY CONCERNS WITH DUKE'S NEAR-TERM PROCUREMENT OF NATURAL GAS GENERATION?

A. Yes. As described in Section IV, Duke's modeling (both initial and Supplemental) had several limitations that likely led to additional natural gas generation at the expense of other resources. As demonstrated in the SP-AGO portfolio, once those problems were corrected, less natural gas generation was selected and therefore procurement could be minimized or delayed. All four of Duke's initial portfolios (P1-P4) as well as both Supplemental Portfolios (SP5 and SP6) included 2,400 MW of new natural gas CC additions in the 2029 timeframe. Given this lack of variation, and the magnitude of this investment, it is important to understand what the underlying drivers are, and whether potential alternatives were sufficiently represented and allowed to compete in the model selection process. Perhaps even more importantly, the Commission should determine whether the magnitude of proposed gas investments is reasonable to pursue in the face of scarce fuel supplies and uncertainties around the cost and availability of firm transport on existing pipelines.

CC units are more capital intensive than other types of gas units like CTs and are therefore less suitable for strictly meeting peak capacity needs; however, they are more operationally efficient and thus more suitable for meeting energy needs. Due to this efficiency, CC units are designed to operate with higher capacity factors relative to CTs, and thus will contribute more significantly to carbon emissions, potentially making HB951 compliance more challenging. Based on Duke's modeling, it appears that some amount of new gas may be needed in the Carbon Plan portfolio. However, the question of "how much," "what type," and "when" these additions will be needed is less clear. This uncertainty is further magnified by the passage of the IRA as I explained in Section III above. At this point in time, I believe it is premature to determine what role natural gas generation should play in the Carbon Plan and premature for Duke to pursue a new CPCN in 2023, especially for new CCs, and that such considerations should be deferred until a later date. If the Commission chooses to adopt a plan with new CCs, this plan should be limited in this cycle to no more than one 800 MW facility, consistent with Duke's initial No App Gas case.

Q. DO YOU AGREE WITH PUBLIC STAFF'S FINAL RECOMMENDATION TO APPROVE 1,200 MW OF NEW NATURAL GAS COMBINED CYCLE UNITS AS PART OF DUKE'S NEAR-TERM ACTIONS?[53]

A. No. In fact, I am surprised that Public Staff ultimately recommended this given the significant concerns raised about new gas throughout their comments. These include concerns regarding future natural gas fuel supply, proposed hydrogen conversion, arbitrarily constrained options for new gas resources in the model selection (*i.e.*, only 1,200 MW resources can be selected, versus 1,200 or 800 MW resources), and so on. Furthermore, any preference Public Staff may have had for new gas resources needs to be thoroughly reconsidered in light of the IRA.

Q. DO YOU AGREE WITH TECH CUSTOMERS' OBSERVATION THAT A GREATER SHARE OF POWER PURCHASE AGREEMENTS

[53] Public Staff Comments, p 153.

("PPAS") VERSUS UTILITY-OWNED GENERATION COULD INCREASE PLANNING FLEXIBILITY AND REDUCE COSTS?

A. Yes. In my experience, it is typical for PPA projects procured through a competitive bidding process to be lower in cost than utility-owned generation. In fact, it is my understanding that Duke's analysis includes a reduction in solar resources costs of about [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to account for the share of solar resources that are procured from PPAs (*i.e.*, 45% of the total).[54]

Thus, to the extent the Commission has the flexibility to authorize or even require PPAs for a share of solar resource greater than 45%, this could produce substantial cost savings to Duke customers. The same is true for all other resources that could be procured as PPAs through a competitive process, including wind, battery storage, and even natural gas. As such, I recommend the Commission pursue all avenues to seek competitive procurements, beyond 45% of solar resources.

Q. DO THE RESULTS OF THE SP-AGO ANALYSIS SUPPORT THE CONCLUSIONS YOU DESCRIBED ABOVE?

A. Yes. The results indicate that new gas CT resources are not needed until the end of 2028 and can therefore be considered at a later date when the full effects of the IRA can be analyzed. Furthermore, the results indicate that new gas CC resources may not be needed at all. Finally, the results indicate that addition of

[54] Duke Energy Response to Public Staff DR 16-4.

additional solar plus storage configurations and wind imports are beneficial – both of which could be facilitated through competitive PPA solicitations.

<u>VII. NEAR-TERM DEVELOPMENT ACTIVITIES: LONG-LEAD TIME RESOURCES</u>

A. The Commission should consider the varying levels of technology readiness when evaluating each of Duke's proposed long-lead time resources.

Q. PLEASE SUMMARIZE YOUR KEY RECOMMENDATIONS RELATED TO DUKE'S PROPOSED NEAR-TERM DEVELOPMENT ACTIVITIES FOR LONG-LEAD TIME RESOURCES.

A. If completed, each of the long-lead time resources proposed by Duke would provide unique value to Duke's system and could contribute significantly to achieving the carbon reduction policy. However, they are all very costly resources, and should not be approved lightly by the Commission. As described below, these resources also all carry significant execution risk due to lengthy and complex siting and permitting challenges. As such, there should be some awareness about the varying uncertainties that these resources bring which could cause them to be delayed or cancelled.

Q. DO YOU SUPPORT ANY OF THE PROPOSED NEAR-TERM DEVELOPMENT ACTIVITIES FOR LONG-LEAD TIME RESOURCES?

A. Yes. In my view, the one of these resources with the most certainty is pumped hydro. Pumped hydro is a mature technology with a well proven track record and is widely deployed across the U.S. Thus, from an execution risk standpoint, it may make sense to approve further development activities for this resource.

Similarly, offshore wind has a proven track record in Europe, but not yet in the U.S. I recommend that the Commission apply more caution in approving development activities for this resource but I recognize it may make sense to move forward due to the significant amount of carbon-free energy that offshore wind can generate, and its ability to complement solar in terms of the timing of when energy is produced.

Q. WHAT DO YOU RECOMMEND REGARDING THE NEAR-TERM DEVELOPMENT ACTIVITIES FOR SMALL MODULAR REACTORS?

A. Small modular reactors ("SMRs") are an unproven technology and could carry significant risk to Duke's customers in the event of cost overruns, which have been common among recent nuclear projects in the U.S.[55] Given the lack of commercial SMR deployments to date, and the recent history of cost overruns which have more than doubled the cost in some cases, I believe that some of Duke's capital cost assumptions may be overly optimistic.

The Commission should use extreme caution in approving any development activities for new nuclear and ensure that all other options have been explored

---

[55] See for example: Jeff Amy, Georgia nuclear plant's cost now forecast to top $30 billion (May 8, 2022), https://apnews.com/article/business-environment-united-states-georgia-atlanta7555f8d73c46f0e5513c15d391409aa3.

first. Further, the AGO has recommended that cost recovery issues be addressed in a different proceeding. I also recommend that the Commission order Duke to model a contingency plan in the event that new SMR resources are not able to be developed within Duke's proposed timeframe.

B. Preliminary development activities can proceed, but the Commission should not address cost recovery issues in this proceeding.

Q. PUBLIC STAFF APPEARS TO BE SUPPORTIVE OF NEW NUCLEAR SMR RESOURCES AS A KEY COMPONENT OF THE CARBON PLAN. DO YOU HAVE ANY CONCERNS ABOUT THIS?

A. Yes. Most of these concerns were already expressed in the Strategen Report. However, it is worth noting that Public Staff points to PacifiCorp's demonstration project in Wyoming as an example of where else SMR projects are being developed. It is worth a degree of caution in referring to this project as a near-term example of SMR deployment. The Oregon PUC specifically chose not to include this project in its acknowledgement of PacifiCorp's most recent IRP.[56] This was in part due to concerns raised by intervenors about the cost, risk, and aggressive timeline of the proposed project.

VIII. WORK ON EXISTING RESOURCES

[56] OPUC Order No. 22-178, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=22-178.

A. Duke's proposed work to expand flexibility of the existing gas fleet and pursue SLRs is reasonable.

Q. AT A HIGH LEVEL, DO YOU SUPPORT DUKE'S PROPOSAL TO PURSUE "EXPANDING FLEXIBILITY OF THE EXISTING GAS FLEET AND CONTINUED DISCIPLINED PURSUIT OF SLRS"?

A. Yes. Enhancing the flexibility of existing gas units could be an effective method of aiding renewable resource integration without needing to invest in new generation. Similarly, extending the life of existing nuclear plants will significantly minimize the challenge of meeting the Carbon Plan's requirements.

IX. TRANSMISSION PLANNING, PROACTIVE TRANSMISSION, AND RZEP

A. Consolidation of Balancing Areas ("BAs") is beneficial for a variety of reasons.

Q. DO YOU AGREE WITH PUBLIC STAFF'S SUGGESTION THAT DUKE SHOULD BEGIN STEPS TO CONSOLIDATE ITS BAS?

A. Yes. Consolidation of BAs is important for a variety of reasons, including the fact that this will aid in the integration of variable resources, improve operational efficiency and reduce related operating costs, and enhance reliability. This is affirmed by NCSEA, et. al, who explain that combining the DEP and DEC balancing areas could dramatically affect the resources required in Duke's Carbon Plan.

B. Several of Public Staff's suggestions related to transmission planning are reasonable, however, hurdle rates should not persist over the long run.

Q. DO YOU AGREE WITH PUBLIC STAFF'S RECOMMENDATION THAT RZTEP COSTS SHOULD BE INCLUDED IN THE PVRR CALCULATIONS GOING FORWARD?

A. Yes. It is important to evaluate Carbon Plan options wholistically, including both generation and transmission costs. In addition to RZTEP, it is important that capital costs associated with other resources are fully accounted for in the same manner. For example, existing coal plants are subject to ongoing incremental capital expenditures that can be on par with new generation facilities. Similarly, existing and new gas plants are subject to incremental fixed costs associated with firm transportation of fuel supply. Thus any attempt to include RZTEP costs in the PVRR calculations should ensure the same treatment is applied to these other fixed cost categories.

Q. DO YOU AGREE WITH PUBLIC STAFF'S SUGGESTION THAT A 20-YEAR TRANSMISSION PLAN SHOULD BE CONSIDERED GOING FORWARD?

A. Yes. This is consistent with emerging practices of many other large system operators around the US.

Q. DO YOU HAVE ANY GENERAL THOUGHTS ON PUBLIC STAFF'S RECOMMENDATIONS REGARDING TRANSMISSION PLANNING AND RELATED COSTS?

A. Yes. I believe Public Staff has many good recommendations regarding transmission planning that the Commission should consider. However, as a general matter, I believe that Public Staff and Duke are too focused on transmission upgrades within Duke's own footprint rather than considering how the regional transmission network can be improved to better integrate regional resources into Duke's system. As discussed in Strategen's report, nearly all of the recent studies on cost-effective integration of high levels of clean energy conclude that such regional coordination is essential.

Q. DO YOU AGREE WITH PUBLIC STAFF'S SUGGESTION THAT INTERTIES BETWEEN DEC AND DEP "CANNOT BE MODELED FOR FIRM CAPACITY TRANSFERS TO SATISFY EACH COMPANY'S RESERVE MARGIN"?

A. Not exactly. While this may reflect current reality, this does not mean firm transfers cannot be modeled. Moreover, limitations on firm transfer is a condition that the Commission should seek to remedy going forward. Consolidation of BAs brings many benefits, not the least of which is the ability to share resources over a wider region, which can enhance reliability and lower overall costs. As Duke has testified, the 2026-2027 timeframe could be a reasonable target date for this consolidation which would align with the near-term resource additions being considered in the Carbon Plan.

Q. DO YOU HAVE ANY THOUGHTS ON PUBLIC STAFF'S RECOMMENDATION REGARDING APPLYING A HURDLE RATE TO ENERGY TRANSFERS BETWEEN DEC AND DEP?

A. Similar to my comments above, I believe it is possible to envision a near-term future where the BAs are consolidated and such a hurdle rate would no longer apply, and therefore does not need to be modeled. However, I believe Public Staff's suggestion is useful for considering potential resources outside of the DEC and DEP BAs. More specifically, resources located outside of Duke's service territory could be delivered to Duke via the current FERC-approved non-Firm service annual $/kWh as found in the publicly available OATT for each utility. This is consistent with my earlier recommendation for consideration of wind imports.

C. The Commission should require Duke to identify "low hanging fruit" opportunities to increase the resource injection capability of any major transmission upgrade.

Q. BEYOND PROACTIVE TRANSMISSION PLANNING FOR MAJOR GRID UPGRADES, ARE THERE LOW-COST WAYS TO INCREASE INJECTION CAPABILITY OF THE GRID?

A. Yes. As one recent example I am familiar with, Tri-State Generation and Transmission in Colorado recently sought several major new additions to its transmission system costing over $400 million to accommodate 400 MW of new renewable energy resources to be connected as part of its Responsible Energy Plan.[57] As part of a settlement agreement approving the new transmission lines, Tri-State agreed to conduct a follow-on study to identify

[57] Colorado PUC Proceeding No. 22A-0085E.

incremental transmission improvements that could increase the injection capabilities of the new lines and thus allow even more renewable resources to be connected. The results of the study showed that a modest incremental investment of approximately $270,000 could allow up to an additional 430 MW to be injected. Thus, the study revealed significant low-cost "low hanging fruit" in incremental improvements that could be made to maximize the injection capability of the new lines. While every transmission system is different, it is certainly possible similar circumstances could arise on Duke's system through its proactive transmission planning process. Thus, I recommend that the Commission require Duke to follow a similar practice in its transmission planning whenever major new upgrades are identified and pursued. This will help minimize the execution risk of adding significant amounts of new solar to the Duke system.

X. EE/DSM ISSUES/GRID EDGE

A. Duke selected an ambitious but reasonable level of UEE in its Carbon Plan.

Q. HOW DID DUKE ADDRESS EE/DSM IN ITS PROPOSED CARBON PLAN?

A. In its proposed Carbon Plan, Duke stated that it intends to pursue utility-implemented EE/DSM measures ("UEE") that collectively achieve savings of 1% of eligible retail load annually. After this 1% level of UEE was selected, it was embedded in the load forecast that Duke subsequently used to conduct its analysis in EnCompass for selecting supply-side resources. While Duke did evaluate a Low Load sensitivity that contemplates a higher level of UEE achievement equivalent to annual savings equal to 1% of all retail load (rather than "eligible" retail load), the Company did not conduct any calculations on the cost or performance of this sensitivity case.

Q. WHAT ARE YOUR CONCERNS WITH HOW DUKE ADDRESSED EE/DSM IN ITS PROPOSED CARBON PLAN?

A. I have several concerns with how Duke addresses UEE in its proposed Carbon Plan. First, Duke's target is not as ambitious as it could be, even for eligible load. Notably, several states have consistently achieved annual EE/DSM savings of 1% or higher, with 14 states doing so in 2019 and some states even exceeding 2% savings.[58] Second, by incorporating UEE savings as part of its load forecast, the amount of UEE resource Duke has proposed is essentially fixed or "forced-in" prior to the model. As such, there is no way to assess whether a different amount of utility investment in these UEE measures would have been warranted and could have led to a lower cost portfolio. Third, Duke's approach to UEE Roll Off is concerning to me and suggests that there may be underlying problems with Duke's initial load forecast. Finally, Duke's proposal to use an "as-found" baseline does not accurately reflect incremental UEE savings and has potential unintended consequences.

Q. WHAT WOULD BE A MORE REASONABLE UEE TARGET?

A. I believe a scenario consistent with Duke's Low Load sensitivity may be a more reasonable target. This is especially true in light of the passage of the IRA which

[58] See ACEEE 2020 State Energy Efficiency Scorecard, https://www.aceee.org/research-report/u2011.

includes a plethora of new tax incentives and rebates. Some estimates have suggested that this could amount to $14,000 in efficiency upgrades for each individual homeowner. While some of these might be pursued absent UEE programs, they will have the same effect, and UEE programs can leverage these opportunities to make EE/DSM measures even more compelling to prospective participants.

Q. DO YOU HAVE ANY RESPONSE TO PUBLIC STAFF'S CONCERNS ABOUT DUKE'S ASSUMPTION OF ACHIEVING 1% EE AND RELATED LEGISLATIVE CHANGES THAT MAY BE REQUIRED?

A. Yes. First, as a preliminary matter, I believe the main concern with the potential for EE/DSM underperformance is due to the fact that North Carolina allows commercial and industrial ("C&I") customers to opt-out of both funding and participating in EE programs, even though they continue to benefit from residential customers' participation in these programs. However, it is worth noting that opting out of these programs is a choice, not a requirement, for larger customers. If Duke were to offer EE/DSM programs that were actually attractive to C&I customers, then there is the possibility that these customers would opt back in as a means to reduce their energy bills over the long run. In my experience, many utilities are not always highly motivated to offer comprehensive EE/DSM programs to their customers unless directed to do so by the Commission. In North Carolina's case, although there is an opt-out provision, the Commission may still have the latitude to direct Duke to improve its C&I offerings even if participation is not compulsory. Meanwhile, there are successful examples of C&I programs that can be drawn upon from other regions (*e.g.*, the Pacific Northwest).

Second, Public Staff is concerned that Duke's approach veers outside of the normal Market Potential Study approach that is commonly used by utilities. However, it is worth noting that Market Potential Studies are not without flaws. In general, they are an exercise in winnowing down the EE/DSM considered to be available; however, they also contain subjective choices. For example, the maximum level of incentive deemed allowable for certain measures can be a key factor (and a subjective choice) determining the "achievable potential" versus the "economic potential."

Third, it is worth noting that no other resource considered by Duke (*e.g.*, natural gas, nuclear) must pass a cost-effectiveness test in the same manner that EE does. Given the new planning paradigm of HB951, which prioritizes carbon-free resources like EE, it may be worthwhile to consider a more flexible approach to EE cost-effectiveness. For instance, Duke has proposed a new approach to cost-effectiveness evaluation that considers other carbon-free portfolio resources beyond those that have been typically used in the past. This is an appropriate development.

Fourth, there are significant new tax incentives and rebates for energy efficiency included in the IRA that could be leveraged as part of any UEE program offering going forward.

Finally, I do share some of Public Staff's concerns with Duke's high reliance on behavioral EE programs to meet its obligations. As such, I believe there should be a concerted effort to supplement these behavioral programs with increased investment in non-behavioral EE that includes longer lasting measures.

B. Going forward, the Commission should consider improvements to how the appropriate level of UEE is determined. These issues should be addressed in future Carbon Plans and/or other EE/DSM-related proceedings.

Q. WHAT WOULD BE A MORE REASONABLE WAY TO MODEL UEE?

A. It would be technically feasible for Duke to model different amounts of UEE as a selectable resource in EnCompass. In fact, Strategen has had experience doing this as part of other utility resource planning processes in recent years where a 70% target was also being considered. Generally speaking, this practice led to more EE/DSM measures being selected than was previously assumed by the utility. This is not surprising since UEE are often the lowest-cost resource available, let alone the lowest-cost carbon free resource. EE/DSM portfolios also tend to match the utility's load shape and can be considered akin to a "baseload" resource.

Because Duke did not model UEE as a resource that could be selected by the EnCompass model, neither the base level of UEE included in all of Duke's portfolios nor the higher amount included in the Low Load sensitivity are likely to represent the most optimal level of UEE from both a cost perspective and a carbon emissions reduction perspective. For example, it may be more cost effective to increase UEE rebate/incentive levels (even beyond those levels considered in the market potential studies) to achieve greater deployment of EE/DSM measures if doing so were able to avoid or defer more expensive carbon-free resources. While this additional step may not be feasible in the current Carbon Plan cycle, I recommend that this be explored in future iterations of the Carbon Plan.

Q. DUKE DISAGREED WITH THE AGO'S RECOMMENDATION FOR ALLOWING UEE TO BE A SELECTABLE RESOURCE, STATING THAT "MODELING A RESOURCE THAT IS ALMOST ENTIRELY DEPENDENT ON CUSTOMER PREFERENCES AND PARTICIPATION AS A SELECTABLE RESOURCE IS PROBLEMATIC"[59] HOW DO YOU RESPOND?

A. While it is true that efficiency measures are the result of customer decisions, it is not true that Duke and other utilities have zero ability to influence the outcome of these decisions. For example, Duke has control (with Commission authorization) over the level of rebates or incentives it offers for efficient

[59] Snider, et al., p 124.

appliances. In this sense incentive levels and resulting UEE program budgets can be tuned to increase (or decrease) the level of UEE that reflects the optimal Carbon Plan. This could readily be modeled as a selectable resource by selecting among different levels of UEE deployment, and corresponding program budgets for each deployment, within EnCompass. The same principle could also apply for NEM resources.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO COUNTING UEE SAVINGS?

A. Even if UEE rebate/incentive levels were increased to cover the full incremental measure cost—or more—it is possible that they would still be less costly than other more expensive carbon-free options modeled by Duke, such as nuclear SMR. Traditionally, EE/DSM cost-effectiveness tests have relied on proxy supply resources that are usually in the form of a natural gas plant as a way to determine the benefits of avoiding incremental supply-side resources. However, under a Carbon Plan framework, the comparable resource may no longer be a gas plant and instead may reflect other options. For this reason, I am generally supportive of Duke's proposal to modify the Cost-Benefit test, as described in Appendix G, with the understanding that there are more detailed changes still to be made.

C. Duke's approach to UEE Roll Off and "naturally occurring efficiency" is likely inflating its underlying load forecast.

Q. PLEASE EXPLAIN DUKE'S APPROACH TO UEE ROLL OFF.

A. As part of the development of the load forecast used in its Carbon Plan, Duke has projected the long-term effects of UEE measures. Duke's approach to "UEE Roll Off" whereby the initial effects of UEE measures are essentially removed after a period of time. For example, in 2030 this "roll off" effect erases nearly half of the load reduction attributable to incremental UEE implemented by DEC.

Q. DID DUKE EXPLAIN WHY THEY TOOK THIS APPROACH?

A. Yes. Duke explains that "As UEE serves to accelerate the timing of naturally occurring efficiency gains, the forecast 'rolls off' or ends the UEE savings at the conclusion of its measure life."

Q. WHY IS DUKE'S UEE ROLL OFF APPROACH NOT REASONABLE?

A. Duke's approach would be acceptable if the underlying load forecast also evolved over time to reflect the "naturally occurring efficiency gains" that Duke describes in tandem with the UEE roll off. In other words, the baseline appliance efficiency trends will improve over time, leading to declining energy usage per customer, even without UEE effects. In this sense, the "rolled off" UEE benefits will persist, but they will be separately accounted for as part of the fundamental load forecast, not as part of the UEE program.

In principle, Duke seems to agree with this, stating that "the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption."[60] However, these statements do not appear congruent with the actual load forecast data that Duke provided. Rather than showing a trend towards declining consumption due to "naturally occurring efficiency," Duke actually forecasts an increase in usage per customer for DEC.[61]

Q. DO YOU THINK THIS CALLS INTO QUESTION DUKE'S UNDERLYING GROSS LOAD FORECAST, PRIOR TO ADJUSTMENTS?

A. Yes. Duke's testimony stated that "most intervenors do not appear to take issue with the process utilized to develop the gross peak demand forecast."[62] However, the AGO/Strategen did raise concerns about the underlying forecast in its July comments and report. If the underlying approach is found to be incorrect it could have a significant effect on the overall load forecast, and could significantly decrease the overall resource need regardless of which Carbon Plan portfolio is selected.

Q. DUKE WITNESS DUFF TESTIFIES THAT STRATEGEN'S RECOMMENDATIONS REGARDING UEE ROLL-OFF ARE INCORRECT BECAUSE "LOAD IMPACTS OF EV ADOPTION AND BENEFICIAL ELECTRIFICATION ARE INCLUDED IN THE LOAD FORECAST, WHICH CAN MORE THAN MASK THE EE ROLL-OFF

---

[60] Duke Carbon Plan, Appendix F, p. 5.
[61] *See* Strategen Report, p 42-43.
[62] Snider, et al., p 117.

BEING REFLECTED IN USAGE PER CUSTOMER."[63] HOW DO YOU RESPOND?

A. Witness Duff's testimony directly contradicts a response that Duke provided to a data request.[64] According to the data request response provided to the AGO, the impact of EV adoption, behind-the-meter solar, and energy efficiency programs are not included in the underlying "before impacts" load forecast. The underlying load forecast is then modified based on projections for those items. This is also consistent with the way the Company described the process in its initial Carbon Plan filing:

> The Companies develop the Load Forecast in four steps: (1) a service area economic forecast is obtained; (2) an energy forecast is prepared by estimating statistical models based on these economic conditions; (3) ex post modifications that account for the growth in electric vehicle, solar and energy efficiency programs must be considered; and (4) using the energy forecast, summer and winter peak demand forecasts are developed.[65]

Therefore, the underlying "before impacts" should show a declining per customer usage as UEE is rolled off. However, as explained in more detail in the Strategen report, it does not.[66]

Q. DO YOU AGREE WITH PUBLIC STAFF'S ASSESSMENT THAT DUKE DID NOT SUFFICIENTLY OR TRANSPARENTLY EXPLAIN

---

[63] Direct Testimony of Lon Huber and Tim Duff for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 179 (Aug. 19, 2022), p 18-19.
[64] Duke Energy Response to AGO DR 6-4 (attached as Exhibit 5).
[65] Duke Energy Carbon Plan, Appendix F at p 1.
[66] Strategen Report at pp 42-43.

HOW IT CONSIDERED "MARKET TRANSFORMATION"[67] OF ENERGY EFFICIENCY MEASURES?

A. Yes. As was explained in the Strategen report,[68] and in the discussion above on UEE Roll Off, it is not clear how Duke ultimately incorporated "naturally occurring efficiency" into its load forecast as this market transformation occurs. In fact, the trends in this regard appear counterintuitive and should be closely examined by the Commission in this and all future resource planning exercises.

D. Duke's proposal to move towards an "as-found" baseline methodology should be rejected.

Q. PLEASE EXPLAIN DUKE'S PROPOSED "AS-FOUND" BASELINE.

A. Duke proposes to change the method for calculating the savings associated with UEE. Currently, when evaluating UEE program performance, the level of UEE savings attributable to the installation of a more efficient appliance is calculated in comparison to the level of energy consumption for a baseline appliance, which is meant to reflect what is generally available in the market at the time. This baseline performance is typically informed by the minimum efficiency and performance requirements set by the federal or state level codes and standards, since these generally dictate the baseline efficiency of appliances being offered in the market.

---

[67] Public Staff Comments, p 58.
[68] Strategen Report, p 42.

Duke proposes shifting to an "as-found" baseline methodology, which would erroneously compare the energy consumption of the newly purchased appliance to that of the broken one being replaced (*i.e.*, the "as found" appliance). In doing so, Duke's method would include fictitious energy savings in its accounting since, realistically, the only available replacement options would be at today's baseline level of efficiency, not the old appliance's level of efficiency.[69]

Q. WHY IS DUKE'S APPROACH NOT REASONABLE?

A. Duke's new "as-found" method is problematic for several reasons. First, by setting the obsolete appliance as the baseline, Duke would be able to claim UEE savings for installing the most *<u>in</u>*efficient appliances the market has to offer—appliances which only meet the bare minimum of prevailing standards.

Additionally, while Duke claims that the "as found" approach will increase the overall amount of UEE savings achieved, the opposite is true. By simply increasing the kWh savings attributable to each measure, but not actually increasing the actual efficiency of the measures being installed, Duke will simply be artificially inflating the amount of savings counted for each measure. This means that Duke will be able to reach its 1% savings target with fewer overall measures being deployed than it would have needed under the traditional baseline accounting method.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE "AS-FOUND" BASELINE?

---

[69] *See* Strategen Report, p. 43-44.

A. I recommend that the Commission reject Duke's proposal to move to the "as-found" methodology outlined in its proposed Carbon Plan. Instead, the Commission should maintain the current approach to counting EE savings using the minimum federal efficiency and performance requirements.

E. Future carbon plans should include a more comprehensive evaluation of different levels of distributed energy resources, including steps to achieve these levels.

Q. PLEASE EXPLAIN HOW NET ENERGY METERING AND DISTRIBUTED GENERATION WERE TREATED IN DUKE'S PROPOSED CARBON PLAN.

A. As it did with EE/DSM, Duke embedded net energy metering ("NEM") resources into its load forecast as a fixed input, rather than allowing it to be a selectable resource to explore different levels of deployment. While Duke did develop both a "Base NEM" and a "High NEM" case as part of its load forecast, it is not clear how these two cases were ultimately used by Duke or compared in the final portfolios.

Q. ARE THE "BASE NEM" AND "HIGH NEM" SCENARIOS SUFFICIENT?

A. No. These two cases represent a relatively narrow set of possibilities.

Q. WOULD IT HAVE BEEN REASONABLE FOR DUKE TO INCLUDE MORE DISTRIBUTED GENERATION IN ITS PROPOSED CARBON PLAN?

A. Yes. Duke's proposed plan could have done more to evaluate different levels and forms of distributed generation. This is especially true in light of the fact that Duke has expressed significant concerns about the limitations on larger scale solar resources to achieve interconnection status on its transmission grid. For distributed solar, there may be fewer barriers to achieve interconnection status which means distributed solar could serve as an important complement to large scale projects.

In his direct testimony, Duke witness Snider stated that "Duke Energy's projections of NEM adoption are in line with recent trends. It is true that both future state and federal policy changes may change these trends, but until there is more certainty, Duke Energy agrees with the Public Staff that the point-in-time NEM forecast used in the Carbon Plan is appropriate for planning purposes." As explained above, the IRA is a major federal policy change and provides significant new financial incentives for customers to pursue distributed resources in the form of both solar and battery storage. If customers are willing to make significant personal investments in distributed generation, the Commission should seek to leverage that willingness as much as possible to add low cost, carbon free generation.

Q. WHAT WOULD BE A MORE REASONABLE WAY TO INCLUDE NEM IN THE CARBON PLAN?

A. It might be possible to consider NEM resources as selectable resource in EnCompass and scale the associated costs accordingly. Notably, Duke has recently proposed a novel approach to distributed solar that would potentially couple it with other EE/DSM measures (*e.g.*, smart thermostats) and time-of-use pricing. As such, it might be possible to consider different levels of distributed solar deployment based on incentive levels associated with this offering. Duke should consider steps to ensure the additional grid benefits from offerings like this are fully captured. In addition, Duke should seek to analyze new potential offerings. For example, if distributed solar is coupled not only with a smart thermostat, but also with a battery storage system, or managed EV charging, then the effects on the load shape could be significantly improved over standalone solar. This could potentially provide much greater capacity and/or energy benefits during peak hours. As such, I recommend that in the next Carbon Plan cycle, Duke evaluate a larger variety of distributed generation offerings beyond simply NEM. This is especially important in light of the IRA which is likely to accelerate adoption of distributed solar and storage beyond what Duke assumed in its proposed Carbon Plan.

XI. RELIABILITY

A. The Commission should continue to develop and monitor reliability metrics as part of its future Carbon Plan evaluation process.

Q. DO YOU AGREE WITH PUBLIC STAFF'S ANALYSIS REGARDING THE MAGNITUDE OF "NET LOAD RAMPS" AND "CC STARTS" AS INDICATORS OF SYSTEM RELIABILITY WHEN COMPARING PORTFOLIOS?

A. Partially. I agree that these two metrics are useful indicators for how the system might perform under different scenarios. However, in isolation they are not meaningful for evaluating system reliability. Neither ramping nor unit starts are the primary reliability metrics that are typically evaluated by system planners and operators (*e.g.*, LOLE, EUE, etc.). Furthermore, it is necessary to consider both of these metrics in the context of other system limits. For example, even if net load ramps increase, it is not clear when or if these ramps would exceed the total flexible ramping capability available on Duke's system. Developing transparent metrics around ramping capability and ramping needs will be an important step for the Commission to consider going forward. Additionally, any evaluation of these metrics needs to consider steps that are currently being implemented, or could be implemented, that would mitigate their effects. For example, meaningful steps towards regional market operation could have a significant effect on mitigating the cost and reliability impacts of net load ramps.

XII. EXECUTION RISKS

A. All resources carry some degree of execution risk and solar is not unique in this regard.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO EXECUTION RISKS?

A. In the AGO's initial comments and Strategen report, the AGO and Strategen recommended that the Commission consider a 2030 target date for compliance versus a later date (e.g. 2032 or 2034) as a means to provide greater optionality if execution challenges emerge. I recognize that targeting an earlier compliance date creates significant potential execution risk due to the shorter timeline for developing new resources, including unprecedented amounts of new solar. However, it is important to recognize that solar is not unique in terms of having significant execution risks. For example, additional natural gas additions have execution risk if new pipeline capacity for firm fuel supply is not secured. Small nuclear reactors and green hydrogen generation have execution risks if research and development do not proceed as quickly as anticipated or if costs do not reach predicted levels. Battery storage has supply chain risks that could delay deployment. EE/DSM carries risks in terms of customer participation levels achieved. Finally, the presumption that new CTs will operate on ULSD at least some of the time will add to their emissions contribution, thus introducing potential execution risk in terms of obtaining necessary air permits.

Q. HOW WOULD YOU CHARACTERIZE PUBLIC STAFF'S ASSESSMENT OF THE VARIOUS CARBON PLAN PORTFOLIOS THAT DUKE PROPOSED?

A. Public Staff was less favorable towards Portfolio 1 due to its higher cost and potentially higher execution risks. Meanwhile, Public Staff was more favorable towards Portfolio 4 due to it being the "most achievable."[70]

Q. DO YOU THINK THIS IS A FAIR CHARACTERIZATION?

A. No. First, it should be no surprise that Portfolio 4 might appear to be the "most achievable" but that is simply due to the fact that it has the most delayed

[70] Public Staff Comments, p 19.

compliance deadline (*i.e.*, 2034 versus 2030). However, the Commission should not equate "most achievable" with "most preferred." It may be better to aim high and miss the mark by a year or two, rather than aim low out of an over-abundance of caution, and fail to meet the statutory requirements.

Second, any concerns about costs due to accelerated deployment of solar and battery storage needs to be re-evaluated in light of the IRA, which will significantly reduce the costs of both resources that were at the heart of Public Staff's concerns with the P1 portfolio.

B. Strategies can be pursued to minimize the risk of solar and wind additions.

Q. DO YOU THINK THE SP-AGO PORTFOLIO IS REASONABLE FROM AN EXECUTION RISK PERSPECTIVE?

A. Yes. While all the portfolios presented to the Commission have execution risks I believe the SP-AGO portfolio provides an appropriate balance of these for several reasons:

1) By aiming for a 2030 compliance date, SP-AGO preserves the option to delay if there are unforeseen challenges,

2) SP-AGO significantly minimizes the risk of securing firm pipeline capacity in comparison to the P1-P4, SP5 and SP6 portfolios.

3) While solar and wind nameplate additions may appear relatively high, the execution risk of this can be minimized through proactive transmission planning, as well as some of the strategies identified above in Section IV-A, namely:

- Pursue additional solar plus storage configurations, including those with higher capacity factors than what has been modeled to date, which can reduce needed interconnection space.
- Pursue additional wind options including imports with non-firm transmission.
- Increase opportunities for distributed resources.
- Site facilities at or near retiring coal plants to minimize transmission constraints.
- Invest in grid-enhancing technologies to increase interconnection limits.
- Identify low-cost, incremental transmission improvements following larger upgrades that can unlock greater interconnection potential.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STRATEGEN

Edward Burgess

Senior Director

Ed leads the integrated resource planning practice at Strategen. Ed has served clients including consumer advocates, public interest organizations, Fortune 500 companies, energy project developers, trade associations, utilities, government agencies, universities, and foundations. He has led or contributed to expert testimony, formal comments, technical analyses, and strategic grid planning efforts for clients in over 25 states. These have focused on a range of topics including resource planning and procurement, utility system operations, transmission planning, energy storage, electric vehicles, utility rates and rate design, demand-side management, and distributed energy resources.

Contact

Location
Berkeley, CA

Email
eburgess@strategen.com

Phone
+1 (941) 266-0017

Education

PSM
Solar Energy Engineering and Commercialization
Arizona State University
2012

MS
Sustainability
Arizona State University
2011

BA
Chemistry
Princeton
2007

STRATEGEN.COM

Work Experience

Senior Director

Strategen / Berkeley, CA / 2015 - Present

+ Focuses on energy system planning via economic analysis, technical regulatory support, integrated resource planning and procurement, utility rates, and policy & program design.
+ Supports clients such as trade associations, project developers, public interest nonprofits, government agencies, consumer advocates, utilities commissions and more.

Senior Policy Director

Vehicle-Grid Integration Council / Berkeley, CA / 2019 - Present

+ Leads advocacy and regulatory policy for a group representing major auto OEMs and EVSEs
+ Advances state level policies and programs to ensure the value from EV deployments and flexible EV charging and discharging is recognized and compensated
+ Leads all policy development, education, outreach, and research efforts

Consultant

Kris Mayes Law Firm / Phoenix, AZ / 2012 - 2015

+ Consulted on policy and regulatory issues related to the electricity sector in the Western U.S.

Consultant

Schlegel & Associates / Phoenix, AZ / 2012 - 2015

+ Conducted analysis and helping draft legal testimony in support of energy efficiency for a utility rate case.

Edward Burgess
Senior Director

STRATEGEN

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.*"
+ SunSpec Alliance for California Energy Commission.,2018. *Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California.*

Domain Expertise

Vehicle Grid Integration

Distributed Energy Resources

Electric Vehicle Rates, Programs and Policies

Energy Resource Planning

Benefit Cost Analysis

Electricity Expert Testimony

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

STRATEGEN.COM

Relevant Project Experience

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.
+ Ed was the lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

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. Ed served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

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.

Relevant Project Experience (con't)

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 sophisticated 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.

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.

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2020 - 2021

+ Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp's IRP 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.

Edward Burgess

Senior Director

STRATEGEN

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)
- CPUC Rulemaking on Emergency Summer Reliability (Docket No. R.20-11-003)

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)

Oregon Public Utilities Commission

- Pacific Power 2021 Transition Adjustment Mechanism (Docket No. UE-375)
- Pacific Power 2022 Transition Adjustment Mechanism (Docket No. UE-390)

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 General Rate Case (Docket No. UE-200900)

Exhibit 2: AGO Supplemental Portfolio Modeling Results

The following exhibit provides a summary of the results from the SP-AGO Supplemental Portfolio. These results were derived from the EnCompass model run performed by Strategen for the AGO and described in the AGO's testimony. Post processing was conducted in the same manner as other portfolios analyzed in this proceeding.

I. Summary of Key Resource Additions and Retirements in SP-AGO and P1 Portfolios[1]

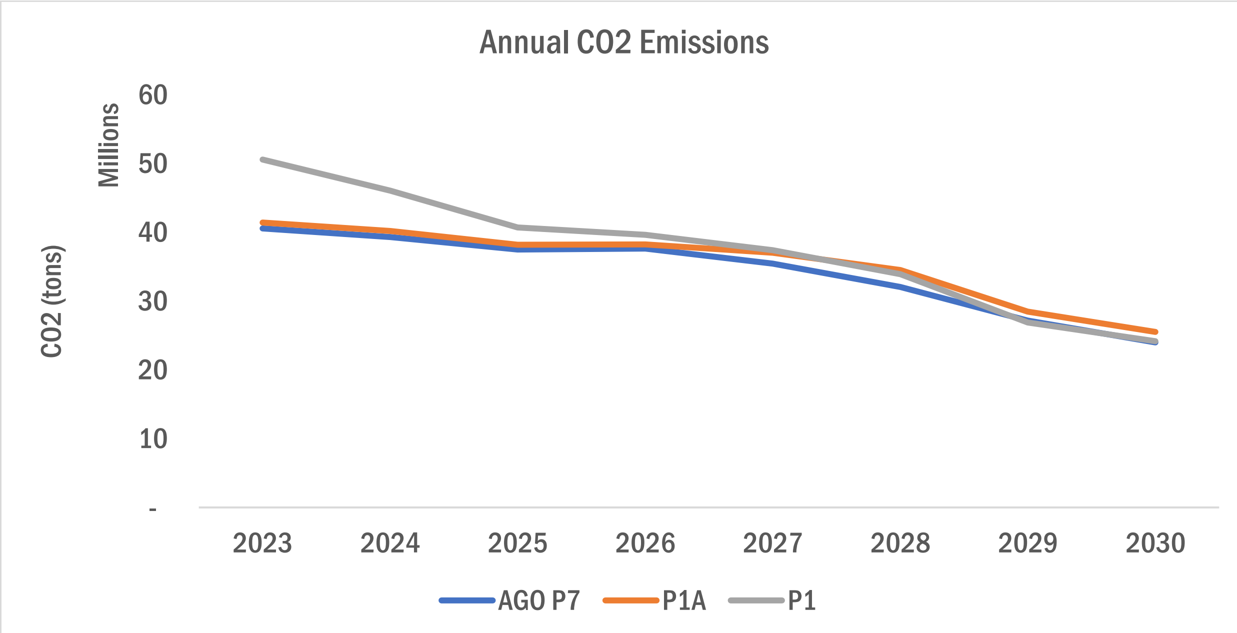
Carbon Plan Portfolios	P1		SP-AGO	
	Resources (MW) Start of Year (2030 | 2035)			
Total System Solar	12,307	18,829	17,427	24,109
Incremental System Solar (excludes projects in development)	5,400	11,850	10,740	17,580
Incremental Onshore Wind (incl. imports)	600	1,200	3,000	3,600
Incremental Offshore Wind	800	800	800	800
Incremental SMR Capacity	0	570	0	855
Incremental Energy Storage	2,067	5,671	3,490[2]	6,800
Incremental Gas (CC)	2,430	2,430	0	0
Incremental Gas (CT)	1,128	1,128	462	462
Incremental Coal to Gas Conversion	849	849	1959	1959
Early Coal Retirements	*Subcritical by 2030; MSS 3&4 in 2032*		*Subcritical by 2030 except Rox 3&4 in 2033; MSS 3&4 in 2032; Belews Creek conversion by 2028*	
Total Coal Retirements [MW] by End of 2035	8,445		9,294	

II. HB 951 Compliance and Cost for all Duke-modeled Portfolios and SP-AGO

Portfolio	Year in which 70% NC CO_2 Reduction Achieved (2030 compliant portfolios in bold)	Present Value Revenue Requirement (PVRR) through 2050 (DEP/DEC Combined System) [$B]
P1	**2030**	**$101**
P2	2032	$99
P3	2034	$95
P4	2034	$96
P1$_A$	**2030**	**$104**
P2$_A$	2032	$101
P3$_A$	2034	$99
P4$_A$	2034	$99
SP5	2032	$102
SP6	2034	$98
SP5$_A$	2032	$98
SP6$_A$	2034	$95
SP-AGO	**2030**	**$100**

[1] Derived from Duke Energy Carbon Plan, Chapter 3, Table 3-3.
[2] Includes both standalone storage and pumped hydro.

III. Emissions Performance Of All 2030-Compliant Portfolios



IV. SP-AGO, Cumulative Resource Additions by Year

SP-AGO, Cummulative MW Additions	2023-2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
CT J	-	-	-	462	462	462	462	462	462	462	462
CT J H2	-	-	-	-	-	-	-	-	-	-	-
2x1 CCJ	-	-	-	-	-	-	-	-	-	-	-
2x1 CCF	-	-	-	-	-	-	-	-	-	-	-
SMR	-	-	-	-	-	-	-	285	285	570	855
Advanced Reactor w/ Storage	-	-	-	-	-	-	-	-	-	-	-
Onshore Wind	-	-	750	1,500	2,250	3,000	3,450	3,600	3,600	3,600	3,600
Offshore Wind (2029)	-	-	-	-	800	800	800	800	800	800	800
Standalone Solar	1,418	1,787	1,856	1,925	1,994	2,063	2,063	2,063	2,063	2,063	2,063
S+S 25% Battery Ratio, 4hrs	-	675	1,950	2,400	2,400	2,400	3,375	3,825	4,050	4,425	5,400
S+S 50% Battery Ratio, 2hrs	-	-	-	600	600	600	600	600	750	750	750
S+S 50% Battery Ratio, 4hrs	-	-	-	750	2,550	3,525	3,825	3,825	3,825	4,125	4,650
4-hr Battery	297	297	297	947	947	947	997	997	997	1,097	1,097
6-hr Battery	-	-	-	-	-	-	-	-	-	-	-
8-hr Battery	-	-	-	-	-	-	-	-	-	-	-
Bad Creek II	-	-	-	-	-	-	-	1,680	1,680	1,680	1,680

CONFIDENTIAL

AGO
Docket No. E-100, Sub 179
2022 Carbon Plan
AGO Data Request No. 8
Item No. 8-9
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

[redacted]

CONFIDENTIAL RESPONSE:

[redacted]

[redacted]

[redacted]

CONFIDENTIAL
Docket #E-100, Sub 179
AGO 8-9
[redacted]

[redacted] [redacted]

[redacted]

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please refer to Appendix E, page 49 which states: "For this reason, the Companies view the endogenous results as representative and directional in nature, and therefore applied limited professional engineering judgements making minor adjustments to coal retirements used in development of the Carbon Plan portfolios."

a. Please provide a complete list of the retirement dates before and after the "minor adjustments" were made. In each case, please explain the reason for the adjustment.

SECOND SUPPLEMENTAL RESPONSE (July 7, 2022):

- Roxboro 3&4 & Marshall 1&2 - Adjustments to the retirement dates were addressed in Appendix E page 48.

- Roxboro 1&2 and Cliffside 5 - No adjustments were made from model selected retirement dates.

- Mayo 1 - The capacity expansion model selected retirement in 2026 for P1-P4; however, the effective date for retirement for the study is 2029. The earliest 70% CO2 reduction target was 2030 in portfolio P1, so any retirement date prior to 2030 will have no impact on the ability to achieve the target. The retirement date of January 2026 is the earliest date allowed in the model without regards to the ability to secure replacement generation, needed gas pipeline infrastructure or to implement required transmission upgrades. Depending on the type and location of replacement generation the earliest retirement date is expected to be between 2027 to 2029. The retirement date of 2029 was selected to provide optionality in retirement of Roxboro 3&4 (2028-2034), preserve replacement options for replacement generation located in Person County, and allow time for technological development of battery technology and supply chain normalcy.

- Belews Creek 1&2 - The capacity expansion model endogenously selected the retirement of Belews Creek in 2030 for portfolio P1, 2032 for P2 and 2038 for P3 & P4. The effective date for retirement in this study was the beginning of year 2036.

Belews Creek 1&2 are efficient supercritical coal units, have the ability to co-fire 50% natural gas at full load and totals over 2,200 MW of generation. The retirement date of 2036 was selected based on a number of considerations including the units' flexibility to co-fire natural gas, the sheer size of the replacement generation, reliability benefits, providing additional time for development of SMR technology and supporting the corporate goal to be out of coal generation by the end of 2035.

Responder: Gerald W. Morgan, Lead Engineer

SUPPLEMENTAL RESPONSE (June 29, 2022):

Please refer to the Company's response to NCSEA-SACE DR 3-39-k for explanation of the "minor adjustments" made to model selected retirement dates.

Responder: Gerald W. Morgan, Lead Engineer

INITIAL RESPONSE:

a. Please refer to our response to NCSEA-SACE DR 3-39-L for a modified version of Table E-47 that shows the model selected retirement dates for each portfolio alongside the retirement dates reported in the Carbon Plan.

Responder: Gerald W. Morgan, Lead Engineer

AGO
Docket No. E-100, Sub 179
2022 Carbon Plan
AGO Data Request No. 6
Item No. 6-4
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please refer to AGO DR3-30.xlsx

a. Please explain whether the columns labeled "DEC UPC Before Impacts" and "DEP UPC Before Impacts" includes the effects of electric vehicles.
b. If so, please explain how these effects are distinct from the effects of electric vehicles shown in tables F-18 and F-19.

RESPONSE:

Figures prepared "before impacts" typically do not include the effects of electric vehicles, and this was the case in tables F-18 and F-19. The difference between "before impacts" and "after impacts" figures includes EV impacts, but also impacts of behind-the-meter solar and Energy Efficiency programs intended to reduce sales. All of those items are displayed in the referenced tables already.

Responder: Jeffrey A. Day, Lead Load Forecasting Analyst