Docket No. E-100, Sub 179
AGO Initial Comments
Attachment 1

Analysis of the Duke Energy 2022 Carbon Plan

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DEPARTMENT OF JUSTICE N★C ATTORNEY GENERAL

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1. Introduction

This memorandum is prepared for the North Carolina Attorney General's Office (AGO) and summarizes Strategen's review of the 2022 Carbon Plan that was submitted by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (referred to collectively as Duke or the Company). The memorandum provides analysis supporting Strategen's conclusions, along with recommendations to the North Carolina Utilities Commission (Commission) regarding several key issues.

2. Overarching Issues

Strategen has conducted a detailed review of the specific modeling work and resource selections made by Duke in developing its proposed Carbon Plan. However, before turning to these specifics we believe it is important as an initial matter to address some overarching issues that may help the Commission's evaluation and ultimate adoption of a Carbon Plan.

A. Resource Diversity and Grid Flexibility Are Essential

Over the last decade numerous studies have been conducted across the US to examine the feasibility for achieving high levels of clean energy (particularly variable renewable energy), in some cases with amounts similar to or exceeding 70%. Some examples of these include the following:

- Western Flexibility Assessment (the "WEIB Study").[1]
- CAISO Senate Bill 350 Study.[2]
- Western Wind & Solar Integration Study.[3]
- Net Zero America- Princeton Study.[4]
- The Boston University / Brattle Study.[5]
- 2035, The Report - UC Berkley.[6]
- Interconnections Seam Study.[7]

From this large and growing body of work several key themes and common findings have emerged, which are summarized below.

- **Increasing grid flexibility**: as carbon free resources that are variable are added, such as wind and solar, there is an increased need for flexibility, which can be provided through the addition of balancing resources like battery storage, pumped hydro, and flexible load. It can also be provided through increased transactions with neighboring regions.
- **Resource diversity and geographic diversity**: to sustain a reliable grid with greater variable resources, it is important to build a diverse portfolio of resources that can complement each

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[1] Energy Strategies, 2019. *Western Flexibility Assessment: Investigating the West's Changing Resource Mix and Implications for System Flexibility.* Commissioned by the Western Interstate Energy Board.
[2] The Brattle Group, 2016. *Senate Bill 350 Study.* Prepared for California ISO.
[3] NREL, 2010-2015. *Western Wind and Solar Integration Study.*
[4] Princeton University, 20221. *Net-Zero America: Potential Pathways, Infrastructure, and Impacts.*
[5] Boston University, 2020. *The Value of Diversifying Uncertain Renewable Generation through the Transmission System.* Boston University Institute for Sustainable Energy.
[6] UC Berkeley, 2020. *2035 The Report.* Goldman School of Public Policy.
[7] IEEE, 2021. *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*. In Institute of Electrical and Electronics Engineers (IEEE) Transactions on Power Systems, vol. 37.

other. For example, some wind resources are more productive at night, whereas solar is available during the day. Drawing across a broad geographic range also helps ensure resources are more often available at times they are needed.

- **Enhanced regional market operations and coordination**: a pivotal source of flexibility is simply improving the efficient dispatch of resources across a broad region, both in real-time as well as through day-ahead unit commitments. Markets can also provide more seamless transactions between utilities, which can assist renewable integration and provide reliability benefits.
- **Greater interconnection across regional transmission networks**: the quality and output of variable wind and solar can vary by location, making the transmission network vital to ensuring power is delivered to where it's needed. This includes not just local transmission within Duke's service area, but also making greater use of regional and interregional transmission options. The value of the transmission network can also be improved at low-cost through Grid Enhancing Technologies.[8]

To ensure that the Carbon Plan the Commission develops is not only viable, but also cost-effective, it will be important for the Commission to consider each of these elements.

B. Most Resource Additions Will Grow Duke's Rate Base

In developing its proposed Carbon Plan, Duke should be credited for making substantial improvements over its previous resource planning analyses.[9] There are many modeling assumptions that Strategen agrees with, and many aspects of the methodology are in line with good planning practices. However, there are a variety of other assumptions selected by Duke that may tilt the proposed plan towards a resource portfolio that is beneficial for the Company's investors, but not as beneficial to ratepayers or the public interest as it could be. Below is a summary of the resources being considered in the Carbon Plan, categorized by their likelihood for Duke-ownership. It is important to evaluate the final resource portfolios that Duke proposed with this lens in mind; that is, an investor-owned utility like Duke may be motivated to use an approach that selects for resources towards the top of this list, more so than those towards the bottom of the list.

- Assets Already Owned by Duke:
    - Existing Coal
- New Assets Likely to be Owned by Duke:
    - Combined Cycle ("CC")
    - Combustion Turbine ("CT")
    - Small Modular Reactor ("SMR")
    - New Electric Transmission (including for offshore wind)
    - New Gas Pipelines

[8] DOE Study Shows Maximizing Capabilities of Existing Transmission Lines through Grid-Enhancing Technologies (GETs) Can Reduce Transmission Investment and Increase Renewable Integration, Department of Energy: Office of Electricity (April 20, 2022), https://www.energy.gov/oe/articles/doe-study-shows-maximizing-capabilities-existing-transmission-lines-through-grid.

[9] For example, some resource cost assumptions appear to better align with industry expectations (though Strategen still has concerns about many assumptions). Additionally, Duke responded to stakeholder concerns by not assuming that compliance could be met simply by siting new fossil resources outside of North Carolina.

  - Pumped Hydro
  - Offshore wind
  - Onshore wind (Carolinas)
  - Battery Storage
- New Assets Partially Duke-owned (45/55% split):
  - Solar
  - Solar Plus Storage
- New Assets Not Likely to be Owned by Duke:
  - Demand Side Management/Energy Efficiency ("DSM/EE")
  - Rooftop Solar
  - On-shore wind (imported)
  - Other contracted resources

It is important for the Commission to ensure Duke's interests are appropriately balanced with those of other stakeholders.

C. Modeling Concerns

While Duke's modeling of the Carbon Plan in EnCompass reflects an improvement over its past Integrated Resource Plans ("IRPs"), there are two main concerns that Strategen has with Duke's general approach: 1) the large number of constraints applied to certain resource types, and 2) the significant number of "out-of-model" steps that were taken. Both of these are areas with a high potential for subjectivity on Duke's part and may be driving towards an outcome that is not least cost, and may be favorable for the company but less favorable for its customers.

i. Model Constraints

Most modern resource planning efforts rely upon an optimization approach, using software tools like EnCompass to minimize costs while ensuring a variety of constraints are met. These constraints are often numerous and typically include things such as physical limits for reliability (e.g., ensuring there are enough megawatts ["MW"] on the system to meet peak load), policy limits (e.g., 70% carbon reduction), as well as other resource-specific planning constraints.

In its proposed Carbon Plan, Duke includes an extensive number of resource-specific planning constraints for certain resource types. Strategen is concerned that some of these resource-specific limits appear to be somewhat arbitrary. Moreover, when 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. Thus, it is crucial to understand which of these constraints are binding and to examine them very closely to see if they are accurate or should be adjusted.

Below is a list of some of the key modeling constraints in Duke's proposed Carbon Plan that Strategen identified as being potentially problematic or arbitrary. Several of these are discussed in more detail further below in this report. In the case of annual solar, Strategen also understands that Duke is grappling with real technical limitations on how much solar can realistically be interconnected each year due to constraints on the transmission system and the time it takes to complete necessary interconnection studies. Thus, we are not disputing that there is a justifiable constraint for this resource, even though it is not obviously clear what the exact MW limit should be for modeling purposes. Meanwhile, we believe the other constraints are much less explainable or have not been adequately justified.

Table 1. Resource Constraints Assumed in Duke's Carbon Plan Analysis and Suggested Alternatives

Category	**Limit/Constraint**	**Binding in Duke's Plan?**	**Suggested Alternative**
Annual Solar	0 MW selectable in 2026 (beyond forecasted deployment). 750 MW in 2027 increasing to 1,800 MW in 2030	Yes	Include incremental MW for 2026 and/or Increase 2027 limit to at least 1000 MW.[10]
Cumulative Solar Plus Storage	450 MW (DEC)/ 750 MW (DEP)	Yes	No limit
First year of solar	2027	Yes	2026[11]
Annual Onshore Wind	300 MW (DEC+DEP)	Yes	Increase to 400 MW (if imported)
Cumulative Onshore Wind	600 MW (DEC)/1,200 MW (DEP)	Yes	No limit[12]
First year of wind	2029	Yes	2026 or 2027
Solar Plus Storage configurations	2 configurations	Yes	3-4 configurations (incl. ones w/ larger DC components)
NG Combined Cycle	Only 1,200 MW configuration is selectable in Base runs (not 800 MW configuration used in Alt Fuel runs)[13]	Yes	Allow both 1,200 MW and 800 MW resources to be selected in Base runs

To the extent that any of these limits are shown to reflect real practical limitations, it may still be worth modeling the relaxed constraints to understand whether there is significant value in trying to alleviate those practical limits.

[10] Based on 2-3 year development cycle, an early 2023 solicitation could feasibly yield 250 MW of incremental solar additions in late 2026.
[11] Note that if incremental solar can be deployed prior 2026 it could be eligible for a higher federal investment tax credit, which would significantly reduce costs.
[12] At a minimum, this limit should be increased to 2500 MW consistent with the NCTPC 2021 Public Policy Study, http://www.nctpc.org/nctpc/document/REF/2022-05-10/NCTPC_2021_Public_Policy_Study_Report_05_10_2022_Final_%20Draft.pdf.
[13] See Public Staff Data Request (DR) 10-2 and discussion in Section 5 below.

ii. Out-of-Model Steps

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.[14] This is concerning to Strategen because 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.

In fact, the ability to co-optimize resource choices within the same model run was precisely the reason why during Duke's past IRP, the AGO and other stakeholders advocated for, and the Commission ultimately required, Duke to present the results obtained using "endogenous" (i.e., within the model) coal retirements.

In contradiction to this, Duke continues to include questionable out-of-model adjustments to its coal retirement dates. However, coal retirement dates are not the only out-of-model adjustment step that Duke performed. Some of the more consequential out-of-model steps Duke performed included the following:

- Adjustments to coal retirement dates
- Replacement of model-selected batteries with additional gas CTs
- Setting a predetermined solar plus storage dispatch profile, rather than letting the model flexibly dispatch the resource
- Selection of the level of demand-side resources (including large amounts of UEE roll-off)[15]
- Final reliability adjustments

Many of these steps can and should have been performed as part of the core EnCompass optimization routine. Below is a table describing the rationale for this:

[14] At their core, planning tools like EnCompass employ a computer algorithm, typically using advance mixed-integer programming techniques, that analyzes thousands of possible portfolio additions and timing to select the optimal set of resource additions and retirements. An important feature of mixed-integer programming models is that each choice made by the model is simultaneously co-optimized with every other choice, thus leading to the best overall outcome across the full suite of decisions being made. To maintain the integrity and optimality of the results, it is important that model selections be done within a single optimization step rather than broken into a sequence of steps.

[15] "UEE roll-off" refers to Duke's assumption that energy savings achieved through utility-administered energy efficiency (UEE) programs are short-lived and should be removed from the load forecast after a period of time. Strategen has concerns about Duke's specific approach which are further discussed in section 9-A.

Table 2. Out-of-model adjustments included in Duke's Carbon Plan analysis and suggested alternatives.

"Out-of-model" Adjustment	Duke's Approach	Alternative Approach	See Section:
Adjusted Coal Retirement Dates	Retirements were postponed beyond the economic dates for Mayo 1, Marshall 1 & 2, and Belews Creek 1 & 2 due to required transmission upgrades (if on-site generation can't be sited).	EnCompass' economic retirement dates should be considered feasible if: 1) on-site generation is installed earlier (e.g., battery storage before 2026[16] at Mayo or Marshall), or 2) transmission upgrades are installed earlier (e.g., by 2030 for Belews Creek).	8
Battery-CT Replacement	Adjustment needed since EnCompass uses a "typical day" profile that overselects battery resources.	To address the concern and then rerun the model, EnCompass settings can be adjusted to create a different "typical day" profile that more closely reflects real world conditions.	6
Solar Plus Storage Dispatch Profile	Solar Plus Storage dispatch was pre-determined using a separate analysis.	Allow EnCompass to flexibly dispatch storage for solar plus storage resources.	3
Demand-side Resources	Fixed level of demand-side resources available; naturally occurring efficiency not linked to UEE roll-off.	Allow EnCompass to select demand-side resources; ensure that load forecast includes a corresponding amount of naturally occurring efficiency to the amount of UEE roll-off.	9
Final Reliability Adjustments	Add CTs to portfolios where reliability issues were identified	See discussion below	N/A

Strategen does not believe all out-of-model adjustments are necessarily unwarranted. For example, one of the steps mentioned above is a post-modeling Reliability Adjustment, whereby Duke adds additional resources that were not selected by the EnCompass model. It is essential that reliability be evaluated comprehensively, to ensure that any simplifications in models like EnCompass do not overlook any potential gaps. However, in Strategen's experience, these kinds of additional steps can

[16] Note that Duke assumes 2025 to be the earliest date that new battery storage resources can be deployed (based on Duke Carbon Plan, Appendix E, Table E-36).

also introduce a new potential "black box" that can be difficult to assess. This may allow utilities like 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. Strategen has not recommended additional modeling for this adjustment because, according to Duke, the only reliability adjustments made were two CTs added in 2034 for the P3-A and P4-A portfolios.[17] As such, Strategen is not too concerned by these changes since they are relatively limited and well into the next decade. 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.

iii. Recommendations

- Direct Duke, prior to the evidentiary hearing, to develop additional scenarios based on EnCompass model runs that eliminate or significantly relax the constraints identified above in Table 1. Allow other parties to do so. This model run will be useful for informational purposes, even if the results are not incorporated in the Commission's final plan.
- Portfolio model runs with these relaxed constraints should also be included in the supporting analysis Duke provides as part of its applications for a certificate of public convenience and necessity (CPCN applications) for the near-term resources selected in the Carbon Plan.
- Direct Duke, prior to the evidentiary hearing, to develop additional scenarios using the Alternative Approaches identified above in Table 2. Allow other parties to do so. At a minimum, the first 3 items in the table above should be feasible to accomplish for this purpose.
- Portfolio model runs with these alternative approaches should also be included in the supporting analysis Duke provides as part of its applications for a certificate of public convenience and necessity (CPCN applications) for the near-term resources selected in the Carbon Plan.
- In future iterations of its Carbon Plan, the Commission should require Duke to minimize the number of out-of-model adjustments made.
- In future iterations of its Carbon Plan, the Commission should 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.

D. House Bill 951 ("HB951") Compliance Issues

i. Timeline

Duke's proposed Carbon Plan includes four potential resource portfolios that achieve a 70% reduction in carbon emissions. However, only Portfolio 1 reaches this target by 2030, which was the intended objective of HB951. For Portfolios 2-4, Duke asks the Commission to interpret HB951 to allow that 2032 and 2034 may be acceptable compliance deadlines under certain conditions – specifically, if the portfolios include either offshore wind or new nuclear resources (or both) that may lead to construction delays.

[17] AGO DR 4-9.

The ability for Duke to voluntarily postpone a compliance deadline does not appear obvious or intended from the law as written. Instead, the provisions in HB951 appear more akin to a "safety valve" in case of unexpected circumstances during the development of large utility-owned nuclear and offshore wind projects. This concept of a "safety valve" is one that has historically been a central part of policy debates around carbon emissions limits and is generally intended to give relief to companies or industry sectors at a later point in time in the event that their compliance obligations become too burdensome or costly. The inclusion of a safety valve in carbon policies (let alone exercising it) has been a source of significant controversy, with those in favor of emissions limits arguing that it significantly undermines the overall policy goal.[18] Additionally, setting a later compliance deadline from the start essentially removes the flexibility that this safety valve is intended to offer.

For example, if Duke discovered in 2033 that an SMR project was behind schedule and its operation was needed to meet a 2034 compliance date, then there would be little the Company could do to ensure its compliance with the statutory 70% target. In contrast, if the company initially planned to reach this target by 2030, but realized it would fall short around 2029, then the safety valve would provide an option for meeting compliance.

The difference in timing also makes it somewhat difficult to compare the four portfolios Duke has presented. Unsurprisingly, meeting the earlier compliance deadline causes Portfolio 1 to appear to be more costly for utility customers. This is primarily because Portfolio 1 contains accelerated investments in solar and battery storage resources, relative to the other portfolios. Meanwhile, there is almost no change in coal retirements across the portfolios except for Roxboro 3 & 4. In fact, the four portfolios that Duke put forward are largely similar to one another. While the later timing of Portfolios 2, 3, and 4 could alleviate near-term cost pressures by granting a longer window to meet the 70% reduction policy, they also carry greater risk of not meeting that policy in a timely manner.

There is also a public policy rationale for pursuing a 2030 target rather than the later targets envisioned by Portfolios 2, 3, and 4. One of the primary reasons for pursuing the carbon reduction policy is to mitigate catastrophic climate change. However, the climate impacts of carbon emissions are the result of cumulative emissions, not annual emissions. Thus, even if Portfolios 2-4 ultimately reach a 70% reduction just a few years later, the overall trajectory of these reductions matters from a climate perspective – that is, a faster pace of reduction such as P1 will lead to fewer cumulative emissions. As Duke explains, the P1 Portfolio results in 11% fewer cumulative carbon emissions than P3 and P4.[19] Thus, it would have an 11% greater impact on mitigating catastrophic climate change.

It is worth noting that all four of the portfolios Duke developed, including Portfolio 1, would be able to use this safety valve if necessary because they all contain offshore wind, new nuclear, or both.

Given these considerations, it may be prudent for the Commission to work towards a plan that initially targets a 2030 compliance date, while keeping the option for delaying to 2032 or 2034 open for future consideration. In fact, there could be some risk to ratepayers if the Commission were to explicitly adopt a 2032 or 2034 compliance date now. That is, approving a plan with these deadlines in mind from

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[18] See, e.g., Charles Komanoff, Behind the Cap-and-Trade "Safety Valve" (March 11, 2008), https://www.carbontax.org/blog/2008/03/11/guest-column-behind-the-cap-and-trade-safety-valve/.

[19] Duke Carbon Plan, Chapter 3, p. 26.

the start would more explicitly link the Carbon Plan to costly nuclear and offshore wind resources, and could be construed as tacit approval for those long lead-time resources, which may not be necessary or appropriate to approve at this early stage. Since those resources will not be operational until 2030 or later, there would be plenty of time for the Commission to further review these resources and the related compliance timeline in future iterations of the Carbon Plan.

ii. Execution Risk

Strategen recognizes that targeting a 2030 compliance date creates significant potential execution risk due to the shorter timeline for developing new resources. In particular, there has been much discussion among stakeholders around the challenges of bringing online an unprecedented amount of new solar due to transmission and interconnection constraints. However, it is important to recognize that solar is not unique in terms of significant execution risks. Each of the resources being contemplated for near-term development carry significant execution risks as summarized below:

Resource Type	**Key Execution Risk Factors (non-exhaustive)**
Solar	Interconnection Timelines & Transmission Availability
Onshore Wind	Limited Development Experience in Region to Date
Natural Gas	Securing New Pipeline Capacity for Firm Fuel Supply
Battery Storage	Supply Chain Delays
EE/DSM	Lack of Commercial & Industrial Participation Due to Opt-Outs
Offshore Wind	Limited Development Experience in US

iii. Recommendations

- The Commission should develop a Carbon Plan that aims to meet the 70% reduction in CO_2 by 2030, consistent with the intent of HB951, and adjust the final compliance date in the future, allowing some flexibility if appropriate under circumstances that develop. This timing should continue to be evaluated in future iterations of the Carbon Plan.
- In the event the Commission does adopt a plan based on a 2032 or 2034 compliance timeline, the Commission should clarify that this does not necessarily constitute a determination of prudency or preauthorization for any future nuclear or offshore wind resources.

E. Core Recommendations and Next Steps towards adopting a 2022 Carbon Plan

Given the modeling concerns described above, it is premature for the Commission to adopt the Carbon Plan proposed by Duke, and premature to approve all of the near-term actions the Company has proposed.

Instead, Strategen recommends that Duke's analysis be revised to address several technical issues. Specifically, additional EnCompass runs should be performed that address the following issues:

1. Relax model constraints as recommended above in Section 2.C.i.
2. Use a 20-year lifetime for new gas resources as discussed below in Section 5.E.
3. Include 1-2 additional solar plus storage configurations (e.g., 50% battery ratio, 4-hr duration, with ILR >1.6). See Section 3.D.
4. Eliminate the following out-of-model steps (based on approaches described in Section 2.C.ii):
    a. Coal retirement adjustments;
    b. Fixed solar plus storage dispatch;
    c. Battery-CT replacement.
5. Use 2030 as the 70% CO_2 emissions reduction compliance deadline. See Section 2.D.
6. Adjust the load forecast to more accurately reflect "naturally occurring efficiency" replacing roll-off of Utility Energy Efficiency ("UEE") program impact (as discussed in Section 9.A.ii).

There is a strong possibility that these revised model runs would yield different results than what Duke has presented, and lead to a different set of near-term actions than what Duke has proposed, particularly around the size, timing, and type of new gas resources.

In addition, another run should be performed under the High Gas Price sensitivity case that both a) selects optimal resources and b) meets HB951 compliance. This can be considered a contingency plan in the event that gas prices remain high. This is discussed further in Section 5.A below.

Finally, although key uncertainties remain, Strategen also believes 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 the revised model run. In fact, it may be important to move expeditiously on these and signal the opportunity to prospective developers sooner rather than later. For example, although the timing may be challenging, if solar and wind can be deployed prior to 2026, they may still benefit from higher levels of the federal renewable investment tax credit and production tax credit (assuming continuity safe harbor provisions are met), thereby reducing their costs. The procurements of solar, storage, and wind procurements that Duke has identified in its proposed near-term action plan may be part of a "least regrets" strategy. However, any solicitation for solar plus storage resources should consider configurations beyond those modeled by Duke in its plan.

3. Limitations on Solar Plus Storage Additions and Operations

Many groups who participated in the Carbon Plan stakeholder process were understandably focused on the annual limits that Duke has assumed regarding the amount of new solar facilities that can be interconnected. Solar is one of the least-cost zero-carbon resources available to Duke, and these annual limits appear to significantly constrain the overall magnitude of solar resources that Duke's modeling selects as part of its proposed Carbon Plan. However, these limits also reflect the unprecedented challenge Duke faces in scaling up a large amount of new resources on its transmission system, which may already be saturated in certain places and require significant and costly upgrades. As such, some limits of this nature may be warranted. However, it is difficult to assess what the right assumptions for these limits should be based on the information Duke has provided thus far. At a minimum, it would be informative to model a scenario where these constraints were relaxed to understand whether more solar would be optimal, even if difficult to achieve. To this end, Strategen recommends increasing the limitations on solar additions in the early years from 750 MW to at least 1000 MW. Additionally, while perhaps ambitious, incremental additions in the 2025-2026 timeframe should be contemplated since this could yield additional cost savings from a higher federal ITC (assuming Continuity Safe Harbor provisions are met). The figure below illustrates this timing and is based on the assumptions used in PacifiCorp's 2021 IRP.[20]

Phaseout of Wind PTC

Date Construction Begins	In-Service Date*	% of Full PTC Rate
Before 12/31/2015	Before 01/01/2020	100%
01/01/2016 - 12/31/2016	Before 01/01/2022	100%
01/01/2017 - 12/31/2017	Before 01/01/2023	80%
01/01/2018 - 12/31/2018	Before 01/01/2023	60%
01/01/2019 - 12/31/2019	Before 01/01/2024	40%
01/01/2020 - 12/31/2020	Before 01/01/2025	60%
01/01/2021 - 12/31/2021	Before 01/01/2026	60%
On or After 01/01/2022	Any	0%

* In-Service date assumes the use of the Continuity Safe Harbor which is 4 years after the calendar year during which construction, 5 years for projects beginning construction in 2016 and 2017.

Phaseout of Solar ITC

Date Construction Begins	In-Service Date	ITC Rate
Before 01/01/2020	Before 01/01/2026	30%
01/01/2020 - 12/31/2020	Before 01/01/2026	26%
01/01/2021 - 12/31/2021	Before 01/01/2026	26%
01/01/2022 - 12/31/2022	Before 01/01/2026	26%
01/01/2023 - 12/31/2023	Before 01/01/2026	22%
Before 01/01/2024	On or After 01/01/2026	10%
On or After 01/01/2024	Any	10%

Additionally, in future Carbon Plan cycles (and to the extent possible now), any limits that are imposed should be well-grounded and informed by independent studies on transmission limits, such as those conducted by the North Carolina Transmission Planning Collaborative ("NCTPC").

Meanwhile, in addition to standalone solar, Duke's proposed plan also appears to place other limits on solar plus storage additions that may be similarly consequential. These limits are not as well justified as those for solar overall. There are three primary ways that Duke's modeling appears to artificially limit the selection of solar plus storage resources that may otherwise be economic.

A. Fixed Storage Output Profile

Duke has modeled solar plus storage resources with a fixed storage output profile, rather than allowing EnCompass to flexibly dispatch the storage component. This means that the dispatch of energy storage to the grid is predetermined through a separate analysis Duke performed and EnCompass is not allowed to make modifications to this dispatch schedule even if the modeled grid conditions would suggest otherwise. For example, if a wind resource were to momentarily subside for one hour in the model, it may be optimal for the storage component to respond accordingly by ramping up its output. Instead, since Duke's approach uses a predetermined schedule, meaning other more expensive resources might need to be dispatched instead. This approach significantly undervalues the ability of the storage component to respond to Duke's generation needs over the

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[20] 2021 Integrated Resource Plan, PacifiCorp (September 1, 2021), https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf.

course of a year and diminishes its contribution to resource adequacy and flexibility as the portfolio evolves over many years. If the storage component were allowed to be dispatched with more flexibility in the EnCompass model, it is very likely that more of this resource would have been selected since it would provide greater value to the system per MW deployed.

For example, Duke has explained that the most critical resource needs occur during its winter peaks, which are typically around 6-9am in December through February. The data files provided by Duke that were attached to their response to Public Staff DR 16-3 show the solar plus storage output profile assumptions within Duke's plan. Based on Strategen's preliminary review, it appears that storage dispatch is targeted towards meeting these winter morning peak hours. However, as more storage is added to the system with the same fixed dispatch profile, the needs may shift towards other times of day, and other seasons during which storage dispatch may become more valuable. Since Duke's modeling does not allow the storage resource to be dispatched flexibly, this additional value is not captured.

B. Limited Number of Configurations

During the stakeholder workshops preceding the Carbon Plan, Strategen (on behalf of the AGO) recommended that Duke include additional solar plus storage configurations as resource options in its modeling, including those with larger sized DC components, such as batteries. While shorter duration batteries are especially helpful for meeting near-term "needle peak" loads, over time longer duration batteries are likely to become more valuable from a resource adequacy perspective. While Duke's plan does include two possible configurations of solar plus storage, this still represents a very limited set of choices and does not reflect the range of potential options available to Duke. Strategen recognizes that there are limits to the total number of resource types that can reasonably be modeled, but we do not believe that Duke's two solar plus storage resource options are necessarily representative of the configurations that would maximize value into the future as the Carbon Plan evolves.

Other utilities have shown that, over time, solar plus storage facilities with increasingly larger sized DC components, such as batteries, can provide greater value to the power system, especially when facing interconnection limits. For example, PacifiCorp went from initially modeling its solar plus storage resources primarily with a 25% battery ratio, but soon increased it to 50%, and eventually to 100%, as is discussed in the following excerpt from a July 30, 2021 stakeholder meeting discussing PacifiCorp's 2021 IRP.[21]

> - These interconnection and transmission upgrade options are limited and can be expensive
>   - Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere
>   - Maximizing the "firmness" of each MW of interconnection capacity can provide greater value:
>   - Modeling of combined solar and storage resources now reflects storage with capacity equal to 100% of solar nameplate, and four-hour duration—up up from 50% of solar capacity identified in previous 2021 IRP meetings and from 25% of solar capacity in the 2019 IRP.

[21] Integrated Resource Plan: 2021 IRP Public Input Meeting, PacifiCorp Meeting, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/07-30-31-2020_PacifiCorp_2021_IRP_PIM.pdf

PacifiCorp's final plan included over 2,400 MW of this resource by 2030 while still meeting the reliability needs for its system, which has a peak load (plus reserve margin) of about ~10,000 MW. In other words, the nameplate capacity of solar plus storage selected by PacifiCorp was on the order of 24% of its peak load, whereas Duke has limited this resource to a cumulative 1,200 MW,[22] which is less than 4% of DEC and DEP's combined peak.

Through a data request, the AGO asked Duke why it did not model a configuration more similar to what PacifiCorp has used (e.g., a 50% battery ratio, with 4-hr storage).[23] In response, the Company stated that, although this configuration "would have provided additional capacity value, the Company believed that the incremental capital cost for the larger battery would not have yielded a high enough energy output to justify the added expense." Strategen is concerned that Duke may be unnecessarily discarding viable solar plus storage resource options based on untested "beliefs" that the incremental costs would not be justified. In fact, this is exactly the type of question that a modeling tool like EnCompass is designed to address. Rather than simply discard the resource option at the outset without any further analysis, the Company could have included this resource as an option and allowed the model to analytically determine whether it should be economically selected or not.

Oversizing the DC components[24] (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). Moreover, if these resources are sized appropriately, there is evidence that they can still be cost-competitive with those conventional resources. Below are some excerpts from a recent analysis conducted by Bloomberg New Energy Finance (BNEF) illustrating this point.[25] The first chart shows a solar plus storage resource with a configuration similar to Duke's 25% battery ratio resource. As is evident, there are many gaps in the solar system's production relative to the gas unit as denoted by the white areas under the black curve that represents the gas unit. This means that the overall energy output and reliability contribution is generally lower for this solar plus storage system configuration.

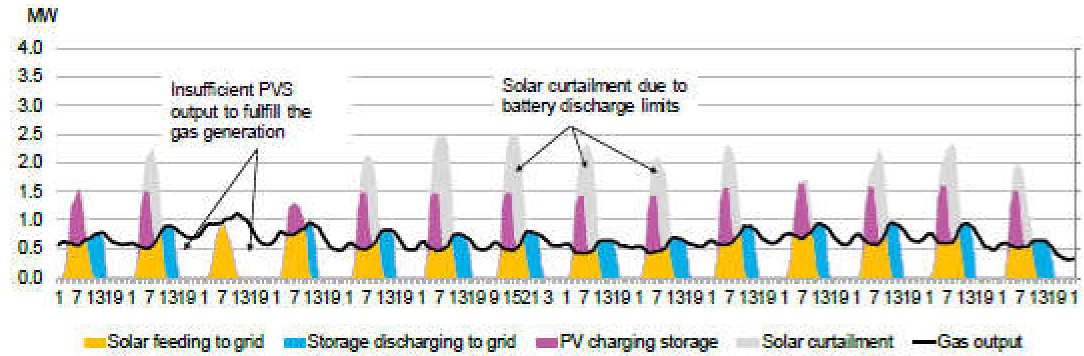
[22] Duke's limit applies to the 50% battery ratio.

[23] AGO DR 3-5.

[24] The DC or "direct current" components of a solar plus storage system refer to the solar PV panels as well as any battery storage connected on the DC side of the inverter. In recent years, the industry has developed "DC coupled" solar plus storage systems which can provide many advantages including cost synergies and improved capacity factors.

[25] How PV-Plus-Storage Will Compete With Gas Generation in the U.S., BloombergNEF (November 23, 2020), https://assets.bbhub.io/professional/sites/24/BloombergNEF-How-PV-Plus-Storage-Will-Compete-With-Gas-Generation-in-the-U.S.-Nov-2020.pdf.

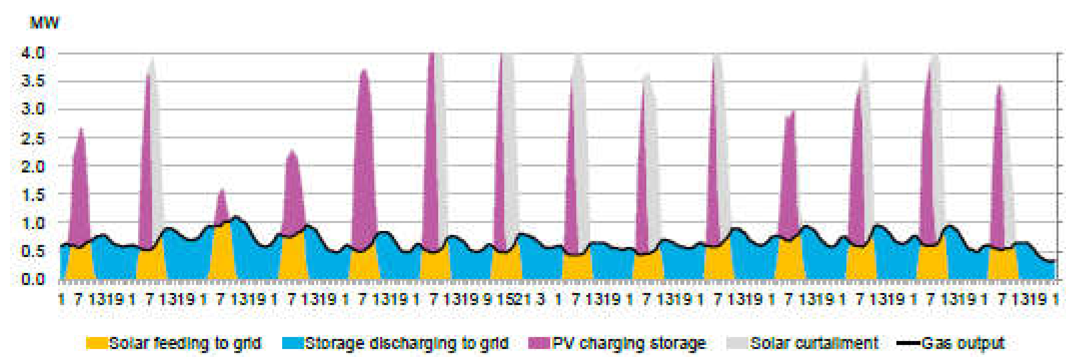
Figure 16: Illustration: 1MW gas vs. co-located PV (4MWDC) plus storage (1MW/4MWh)



Source: BloombergNEF. Note: To simplify the study, we normalize the gas plant capacity to 1MW. X axis numbers represent hour of the day. Due to the length constraints, we only show a few days' simulation here. In our analysis, we sized PVS to simulate the whole year's output.

In contrast, the second chart below shows a solar plus storage resource with a configuration that equates to an 85% battery ratio. Notably, this second configuration has little to no white areas under the black curve, and therefore performs similarly to a combined cycle unit with a ~50% capacity factor. In other words, it provides substantial "firm dispatchable" capability. In theory, this configuration could potentially provide similar value to other high-capacity factor resources that Duke is evaluating (e.g., combined cycle, offshore wind and nuclear SMR).

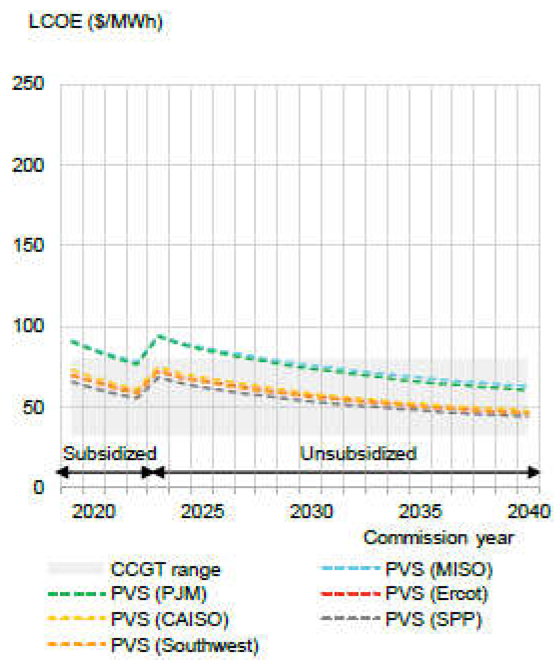
Figure 17: Illustration: 1MW gas vs. co-located PV (7MWDC) plus storage (6MW/24MWh)



Source: BloombergNEF. Note: To simplify the study, we normalize the gas plant capacity to 1MW. X axis numbers represent hour of the day. Due to the length constraints, we only show a few days' simulation here. In our analysis, we sized PVS to simulate the whole year's output.

Additionally, the BNEF study concludes that such a configuration is economically competitive, stating that "A PVS system sized to meet 90% of CCGT generation time can now outcompete a new CCGT operating at a 50% capacity factor." This is also illustrated in the chart excerpted below.

Figure 28: Regional PVS vs CCGT LCOE comparison with 90% of gas profile covered, 2019-40



One other key advantage of this approach of oversizing the DC components of the solar plus storage resource is that it can provide "more bang for the MW buck" of AC interconnection space.[26] As mentioned earlier, Duke is claiming severe limits in the ability to interconnect new solar resources due to AC transmission limits. However, additional configurations with larger DC components can increase the overall energy output (i.e., capacity factor) and capacity value (i.e., ELCC[27]) for each MW-AC connected, thereby maximizing each resource's value per interconnection, while minimizing the need for costly transmission upgrades. For example, in the chart shown above (labeled "Figure 17" in the excerpt), the hypothetical solar plus storage resource depicted provides the energy output of a 7 MW-DC facility while only requiring 1 MW-AC of interconnection capacity. Although this increases the cost per MW-AC, it is not impossible that such a resource would be economically selected by EnCompass, especially in light of the fact that Duke's analysis selects relatively expensive offshore wind and nuclear resources.

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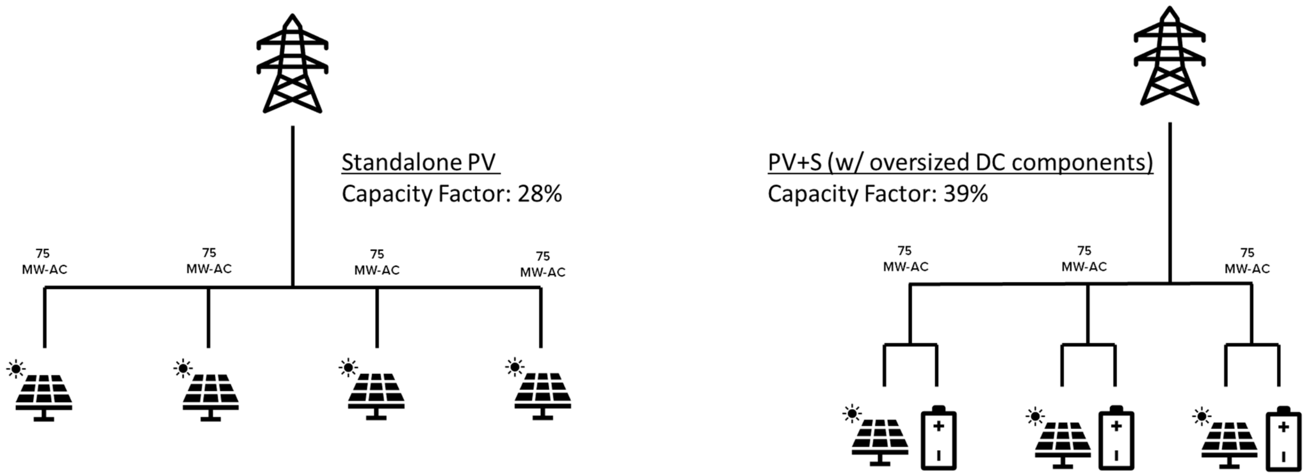
[26] In this context, AC refers to "alternating current" and refers to the final output of the generator to the main power grid at the point of interconnection. The bulk grid operates primarily using AC power flows rather than DC. Often interconnection to the AC power system is the limiting factor on new resources being added without transmission upgrades. Oversizing the DC components of a solar system will generate more power, but not all of that power can be delivered instantaneously due to the constraints of the AC interconnection. However, battery storage can increase the overall deliverability by storing the excess power generation to be delivered during a later time period.

[27] ELCC, which stands for "Effective Load Carrying Capability," is a measure of the reliable capacity contribution of a resource being added to an existing generation portfolio. The ELCC of a resource depends on many factors such as the load and load shape to be served, the existing resource mix, and the adoption of different resource types. See Appendix E, p. 11.

Below is an illustration, based on Strategen's calculations, of how solar plus storage resources with larger DC components might be able to provide greater value in terms of energy and capacity than standalone solar when interconnection space is limited.[28]



More Interconnection Capacity Used: 300 MW
Less Annual Energy Generated: 731 GWh

Less Interconnection Capacity Used: 225 MW
More Annual Energy Generated: 769 GWh

C. Cumulative Limits

In addition to the annual solar limits mentioned previously, Duke also applies a *cumulative* overall limit on additions of solar paired with storage resources (50% Battery Ratio) at a level of 450 MW and 750 MW (for DEC and DEP, respectively). Meanwhile, no such cumulative limit is placed on the solar paired with storage (25% Battery Ratio), standalone solar, or standalone storage resources.

This limit may be leading Duke to propose a Carbon Plan that includes less Solar paired with Storage than is actually feasible or would be prudent under least cost principles. For example, in the case of DEP, the 750 MW limit is exhausted (i.e., "binding") in all of the portfolios studied (including P1-P4, and P1a-P4a), generally around the 2030 timeframe.[29]

Without this arbitrary limit, or if additional configurations were considered, Duke's EnCompass analysis likely would have economically selected more solar plus storage resources rather than other more expensive alternatives, particularly for DEP.

Duke claims that this arbitrary limit was necessary to address reliability concerns about being overly reliant on the short duration storage included in the 50% ratio resource.[30] However, this claim appears disingenuous for several reasons.

[28] The resources on the left-hand side are similar to Duke's assumptions for standalone solar. The resources on the right-hand side are based on Strategen's estimates for a DC-coupled solar plus storage resource with a 50% battery ratio, 4-hours of storage duration, and an ILR of 2.0.
[29] NCSEA and SACE, et al. DR 3-46.
[30] AGO DR 3-2; AGO DR 5-1.

First, Duke already has the tools to resolve reliability concerns elsewhere in its analysis, including through the EnCompass modeling itself and the separate reliability adjustments that Duke made outside of EnCompass. Second, Duke places no limits on the 25% battery ratio resource, even though the Company admits that this resource would technically have an equivalent reliability performance to the 50% ratio resource, depending on the operating regime.[31] In fact, the 50% ratio resource should have greater reliability value than the 25% ratio resource since its output can be increased during brief instances that call for this need, whereas the 25% resource does not have this option. Third, while Duke has expressed general concerns with the reduced reliability contribution of short duration resources, it has provided no specific analysis showing that further additions of a 50% battery ratio resource, beyond the arbitrary limit prescribed, would negatively impact reliability.

D. Recommendations

- The Carbon Plan should not include arbitrary limits on certain configurations of solar plus storage during the resource selection process. If there are reliability concerns about over-selection of short duration batteries, these should be evaluated through supporting technical analysis.
- Solar plus storage resources should be modeled such that the storage component can be flexibly dispatched.
- Additional solar plus storage configurations should be modeled beyond those selected by Duke, including those with larger sized DC components.

4. Limitations on Onshore Wind

In addition to solar, onshore wind is the only other category of 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, onshore wind will undoubtedly play an important role in the Carbon Plan, whether developed in the Carolinas or imported from neighboring regions. However, Duke's proposed Carbon Plan places artificial limits on onshore wind deployment that appear to limit the resource's role. Most notably Duke does not allow the EnCompass model to add onshore wind resources until 2029 at the earliest.[32]

It is not clear why this limitation is needed. For comparison, Duke's near term action plan seeks procurement of other resources with in-service dates as soon as 2026. There does not seem to be a good reason why wind could not also be sought sooner.

In response to AGO DR 3-13, Duke explained that "The Company assumed that, given that wind development in the region is still in its nascent stages, developers would first seek to introduce new onshore wind projects in the 2024 procurement cycle (and interconnection cluster study process) which would result in projects being available no earlier than 2028 (or January 1, 2029)."

However, this timeline seems excessive, given that typical wind project development timelines are often 2-3 years. This is especially true for wind projects imported from PJM that may already be in

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[31] AGO DR 5-2.

[32] Duke Carbon Plan, Appendix E, p. 37.

advanced stages of development. Currently the PJM queue has over 70 onshore wind projects totaling more than 2400 MW of capacity with targeted in-service dates of 2026 or sooner.

Delaying the procurement of wind resources also reduces the overall MW amount that can be deployed by 2030. This is because, like solar, Duke also places an annual 300 MW limit on the amount of wind resources that can be deployed. Thus, by delaying the target in-service date of new wind by 3 years (i.e., from 2026 to 2029) the cumulative maximum that could be deployed by 2030 is reduced by 900 MW in total.

Moreover, it is not clear whether the 300 MW annual limit is appropriate either; in fact, it may be overly limiting. Significantly, Duke's EnCompass model results show that the maximum amount of wind resource (i.e., 300 MW) is economically selected for four consecutive years as soon as it is allowed to be selected (i.e., in the 2029 timeframe). This is true despite some fairly significant transmission costs that Duke has assumed for both wind located in the Carolinas (serving DEP) and imported from PJM (serving DEC). This suggests that the model would likely select even greater amounts of wind if this constraint were relaxed beyond 300 MW, or if wind could be selected in earlier years.

Notably, the 300 MW limit is significantly less than that assumed for solar. As Duke implies in response to AGO DR 3-14, this 300 MW limit is less due to physical interconnection limits than it is due to the lack of wind development in the region to date. However, it is premature to presume a 2029 in-service date prior to testing the market through a true competitive solicitation. Additionally, it is concerning to Strategen that the wind limit is less than half of that of solar without any further justification from Duke. It is possible that there are localized limits that arise from wind resources developed in the same area within NC, however these limits have not been clearly described by Duke. Meanwhile, this limitation does not seem applicable to wind resources that might be imported from other regions. For example, the recent NCTPC 2021 Public Policy Report which studied an HB951 scenario assumed at least 2500 MW of onshore wind resources could be imported, including 1500 MW to DEC and 1000 MW to DEP.[33]

Strategen is concerned that these combined limitations put wind at a significant competitive disadvantage versus other potential resources that could be selected in the 2026-2029 timeframe. For example, it is possible that earlier and larger wind procurements in the 2026-2029 timeframe might reduce or eliminate the need for new natural gas CC additions that Duke is also targeting for the 2027-2028 timeframe. Since onshore wind is not even an option the model can select during this time period, this possibility was not actually considered in Duke's analysis.

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 of particular concern. Moreover, it is not clear that Duke even considered imports for DEP.

[33] Draft Report on the NCTPC 2021 Public Policy Study, North Carolina Transmission Planning Collaborative (May 9, 2022), http://www.nctpc.org/nctpc/document/REF/2022-05-10/NCTPC_2021_Public_Policy_Study_Report_05_10_2022_Final_%20Draft.pdf.

Finally, 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. Duke should explore whether there are any advantages to seeking non-firm or "energy only" type of transmission service for these wind imports.[34] While this will diminish the value of the resource, it will also reduce the cost and may still provide substantial carbon free energy to Duke's system. For example, in Duke's plan, the Company's assumption of Firm Point-to-Point Transmission Service of $67,625/MW-yr[35] for imports from PJM equates to approximately $26/MWh for a wind resource with a 30% capacity factor. This could increase imported wind resource costs by over 30%. Meanwhile, PJM's Non-Firm Point-to-Point Transmission Service is discounted to just $0.67/MWh,[36] a significantly smaller amount. Even if Duke had to procure local capacity to make up for the lack of firm transmission for wind, this may still be a more economical solution.

Additionally, Duke should consider whether there are other locations to import wind from besides PJM, including TVA or MISO.

Recommendations

- Revise modeling constraints to allow for onshore wind additions prior to 2029, and in greater amounts (particularly for imports).
- Consider a near-term solicitation to test market readiness with a target in-service date in the 2026-2027 timeframe.
- Explore opportunities for "energy only" wind resource imports.

5. New Natural Gas Combined Cycle ("CC") Additions

Each of the four portfolios in the proposed Carbon Plan includes 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. Meanwhile, there are a variety of tradeoffs that need to be considered. 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.

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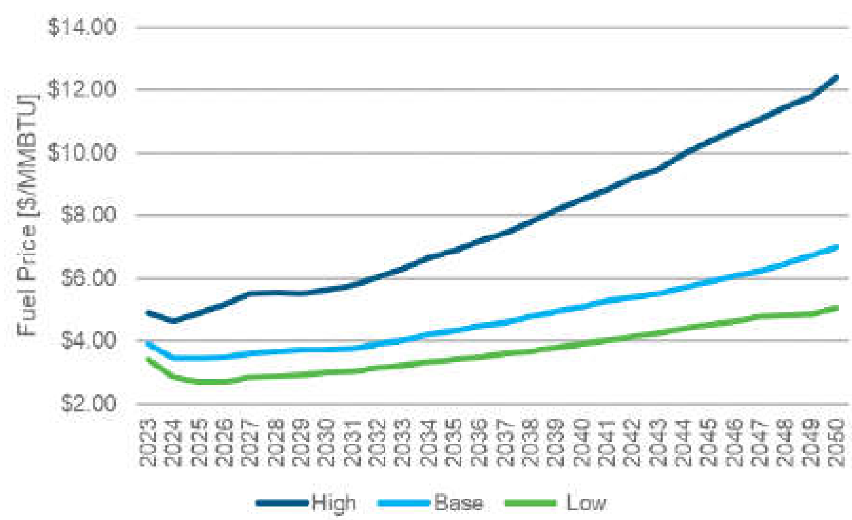
[34] Often "energy only" transmission service is referred to as either Non-Firm Point-to-Point Transmission Service or Energy Resource Interconnection Service, whereas firm transmission service is referred to as Firm Point-to-Point Transmission Service or Network Resource Interconnection Service.
[35] Duke Carbon Plan, Appendix E, Table E-44.
[36] PJM Manual 27: Open Access Transmission Tariff Accounting, PJM (2022), https://www.pjm.com/directory/manuals/m27/index.html#Sections/61%20PointtoPoint%20Transmission%20Service%20Accounting%20Overview.html.

This section discusses several risk factors associated with new gas additions that could end up harming customers and/or HB951 compliance. The Commission should carefully consider these factors in its development of the Carbon Plan. Additionally, since Duke is proposing at least one CC to be pursued in 2023 as part of its near-term action plan, the Commission should require Duke's certificate application (CPCN) to include specific information about these risk factors and an alternatives analysis which are described further below.

A. *Natural gas price forecast*

Duke's natural gas price forecast methodology utilizes five years of natural gas market-based pricing, followed by three years of transitioning from market-based pricing before fully utilizing fundamentals-based natural gas pricing forecast starting in 2031.[37] Duke also developed high and low natural gas price forecasts based on the ratio between the Reference Case and "side cases" under the Energy Information Administration's ("EIA") 2021 Annual Energy Outlook:[38]

Figure E-7: High, Base and Low Henry Hub Natural Gas Price Forecasts [$/MMBtu]



However, Duke's plan was developed before the recent and significant increase in natural gas prices driven in part by Russia's invasion of Ukraine. According to the most recent data from the EIA's website, the Henry Hub natural gas spot price was $8.14/MMBTU for the month of May 2022 and $7.70 for the month of June 2022.[39] These recent price figures exceed Duke's base projections through 2050, and even Duke's high natural gas price forecast does not reach $7.70/MMBTU until about 2037-2038 (see Figure E-7 above). This means that current gas prices are significantly higher than the "worst case scenario" that Duke assumed in its Carbon Plan.

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[37] Duke Carbon Plan, Appendix E, pp. 39-40.
[38] Duke Carbon Plan, Appendix E, pp. 40-41.
[39] Henry Hub Natural Gas Spot Price, U.S. Energy Information, https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.

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.

It must be acknowledged, however, that these sensitivity case results are of limited value in considering potential changes to the underlying resource portfolio. This is because Duke *did not re-optimize* the resource selection under each gas price sensitivity case (the gas price sensitivities should not be confused with the Alternate Fuel Supply scenarios, which represent different portfolios that were re-optimized). If Duke had re-optimized the portfolio under higher gas prices, then it is probable that fewer gas units (and CC units in particular) would have been selected.

On the other hand, if Duke's proposed portfolio is pursued as is, and the higher gas prices are maintained, then there could be a considerable increase in the present value revenue requirement (PVRR)[40] as evidenced by Table E-94 shown below which shows a $7-9 billion increase under the "High Gas" case. Strategen estimates a single 1200 MW CC addition could potentially account for over $1 billion (PVRR) of this portfolio-wide increase in fuel costs.

Table E-94: Combined DEC and DEP PVRR through 2050, Final Carbon Plan Portfolios, Delta from Base Fuel Supply Base Gas Price Assumption [2022, $B]

	High Gas Price Forecast	Low Gas Price Forecast
P1	$7.7	-$3.4
P2	$8.1	-$3.7
P3	$8.6	-$3.9
P4	$8.5	-$3.8

Since gas fuel prices 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, Strategen recommends that the Commission consider all options available to reduce exposure to gas fuel prices, including alternatives that could reduce new CC buildouts.

Additionally, under high natural gas price conditions, the economic dispatch of coal units occurs more frequently, introducing additional risk for HB951 compliance. In fact, Duke's analysis shows that all four of Duke's portfolios fail to meet HB951's 70% reduction target under the high gas price scenario. This is illustrated in Table E-96 below.

[40] The PVRR is the total revenue that must be collected by the utility from ratepayers to recover the costs of each portfolio (subject to Commission approval), in terms of today's dollars (i.e., the present value). PVRR can be understood as the total costs of each portfolio to ratepayers and is a common metric for evaluating resource portfolios.

Table E-96: CO_2 Reduction in Interim Target Year, Final Carbon Plan Portfolios

	High Gas Price Forecast	Base Gas Price Forecast	Low Gas Price Forecast
P1	63.8%	71.1%	71.5%
P2	61.6%	71.8%	72.7%
P3	62.7%	71.6%	72.3%
P4	63.0%	71.9%	72.6%

Given this fact, Strategen recommends that the Commission direct Duke, and allow other stakeholders, to develop a contingency plan for meeting HB951's targets in the event that high gas prices persist. Ideally, this exercise would be performed through a re-optimized EnCompass model run that uses the high gas scenario when selecting resources. If such a model run is not possible, then one potential solution would be to consider accelerated retirement and replacement of certain coal units in the 2030 timeframe (e.g., Belews Creek).

Lastly, Tables E-94 and E-96 show that the risks related to natural gas prices largely run in one direction. The PVRR increases associated with high gas prices are more than twice the potential savings associated with low gas prices, and there is little upside opportunity for additional CO_2 emissions reductions with a low natural gas price forecast.

B. Natural gas fuel supply assumptions

Duke's base fuel supply assumption for the Carbon Plan is that the Companies will be able to obtain a limited amount of incremental firm transportation service to supply Duke's existing CC fleet as well as a limited amount of new CC units with low-cost Appalachian gas.[41]

This assumption is very significant because it suggests that – absent new gas pipeline capacity – Duke's CC fleet does not have access to a firm fuel supply. Moreover, 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, Strategen is 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. As such, it may be appropriate to derate their capacity contribution by assigning a lower ELCC value.

Moreover, the "incremental firm transportation service" Duke is assuming in its base case does not appear insignificant. According to the Company's confidential response to Public Staff DR 13-1, the incremental firm transportation service means **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** This means that Duke's base case assumes that the Company would be able to secure enough capacity to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** what it currently receives from one of its primary gas sources, namely **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** Moreover, it is not obvious that the costs of this additional pipeline capacity are fully accounted for in

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[41] 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."

[42] Confidential Response to Public Staff DR 13-1 (e).

Duke's EnCompass analysis for resource selection. Duke states that it includes **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** Strategen estimates that this would roughly equate to **BEGIN CONFIDENTIAL** [redacted]**ND CONFIDENTIAL** in additional fixed costs for each new CC addition, assuming a 70% capacity factor. However, according to the Attachment to Public Staff DR 3-17 (Corrected), the firm transport cost component for a new CC could be as high as **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** Notably, this transport cost is significant and appears to be **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** than the capital investment for the new CC plant itself. Strategen is concerned that Duke's modeling process may be underestimating the significant fixed costs necessary to secure firm fuel transportation for new CC resources. Even if Duke's assumptions for intrastate firm transport were included, it does not appear to be enough to account for this discrepancy.

Meanwhile, to account for the likelihood that Duke is unable to secure access to Appalachian gas, Duke also modeled 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, reducing the amount of new CC from 2,400 MW to 800 MW:

Table E-83: Final Resource Additions by Alternate Fuel Supply Sensitivity Portfolio [MW] for 2035, Delta from Final Carbon Plan Portfolios

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
P1A	0	200	300	400	-1,600	1,000	0	0	0
P2A	0	1,000	200	400	-1,600	0	0	0	0
P3A	0	900	300	1,300	-1,600	400	0	0	0
P4A	0	1,100	0	300	-1,600	1,100	0	0	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

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 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 natural gas customers for fuel supply. The lack of firm natural gas delivery was one factor that led to the near collapse of the ERCOT power grid in Texas in February 2021.[44]

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[43] Confidential Response to Public Staff DR 13-1 (e).

[44] For example, a report from UT Austin stated that " Unit-specific data indicate that other types of generators – mostly those fueled with natural gas – were facing pre-blackout fuel supply issues, and were starting to go offline or derate capacity as early as February 10 due to fuel delivery curtailments." The Timeline and Events of the February 2021 Texas Electric Grid Blackouts, University of Texas at Austin (July 2021), https://www.puc.texas.gov/agency/resources/reports/UTAustin_(2021)_EventsFebruary2021TexasBlackout_(002)FINAL_07_12_21.pdf.

Notably, one recent pipeline project being developed in the region, the Atlantic Coast Pipeline, was recently cancelled,[45] and another, the Southgate extension of the Mountain Valley Pipeline has had many delays and cost increases.[46]

Duke's affiliate gas company, Piedmont, recently announced a new contract to upgrade the Transco pipeline and increase capacity serving the region. However, a company spokesperson stated that "none of this additional capacity is currently earmarked for making electricity."[47]

Additionally, in response to Public Staff DR 13-3, Duke revealed that it plans to "locate the new CC at our Roxboro Station (DEP) which would require new gas service on PSNC to be fed from Transco and/or Southgate."[48] This suggests that Duke may be relying on higher cost Transco fuel for at least one planned CC addition rather than lower cost Appalachian gas, even though Duke's base fuel supply assumption in the Carbon Plan relied on incremental Appalachian gas supply.[49]

Duke also explained that this would require a new pipeline lateral to be constructed, and that PSNC's existing supply line is not large enough to meet Duke's needs without an expansion. It is not clear if these additional gas infrastructure costs are accounted for in Duke's Carbon Plan analysis, however the AGO has a pending discovery request on this matter.

Given the potential risk of gas deliverability to the proposed new CC projects, and the reliability risks this may impose, Strategen strongly recommends that the Commission consider Duke's Alternate Fuel Supply Sensitivity as a better primary scenario for the Carbon Plan that Duke submitted rather than the Base Fuel Supply case. At a minimum, if Duke files a CPCN for a new CC plant in 2023 as it proposes to do for its near-term action plan, the Commission should require that application to include an option for a 800 MW facility (rather than a 1,200 MW facility) in the 2027-2028 timeframe, as consistent with the Alternate Fuel Supply Sensitivity. Similarly, if Duke files a CPCN for new CTs in 2023, these should consider an option with a corresponding increase in capacity (e.g., 1,200 MW versus 800 MW) in the 2027-2028 timeframe.

C. CC resource options allowed in base fuel supply case

According to Public Staff DR 10-2, when conducting its base fuel supply case analysis, Duke restricted EnCompass such that "only 1200 MW CC resources were allowed to be selected." Strategen is concerned that this unnecessarily limits the model's flexibility and ability to select a smaller sized CC unit. It is possible that the 800 MW configuration would be more economic and sufficient to meet the

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[45] Julia Gheorghiu, Duke, Dominion cancel $8B Atlantic Coast Pipeline (July 7, 2020), https://www.utilitydive.com/news/duke-dominion-cancel-8b-atlantic-coast-pipeline/581028/.

[46] Sarah Vogelsong, More delays, cost increases for Mountain Valley Pipeline (May 4, 2021), https://www.virginiamercury.com/blog-va/more-delays-cost-increases-for-mountain-valley-pipeline/; Maya Weber, Regulatory hurdles prompt delays in MVP, Southgate pipeline target dates (May 4, 2021), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/050421-regulatory-hurdles-prompt-delays-in-mvp-southgate-pipeline-target-dates.

[47] John Downey, Piedmont Natural Gas contracts with Transco on $213M project to boost NC supply (June 10, 2022), https://www.bizjournals.com/charlotte/news/2022/06/10/piedmont-natural-gas-transco-pipeline-project.html.

[48] Public Staff DR 13-3.

[49] Duke Carbon Plan, Appendix E, p 42.

needs of the base portfolios, but unfortunately the model was unable to examine this choice. Strategen recommends that the Commission direct Duke, prior to the evidentiary hearing, to develop additional scenarios based on EnCompass model runs that allow for all CC options to be selected and also allow other parties to do so. This recommendation is reflected in the table above in section 2-C.

D. Natural gas ELCC value

For its modeling, Duke assumed an unrealistic ELCC value of 100% for CCs and CTs.[50] Duke's figure does not account for the typical outage rates for these resources. For example, the average forced outage rate of Duke's existing CC and CT units is **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** while CCs in PJM territory had a 3.8% forced outage rate and CTs had a 5.5% forced outage rate in 2021:[52]

Table 5-31 EFORd by unit type: 2007 through 2021

	Annual														
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	8.4%	8.4%	8.2%	9.4%	10.5%	10.1%	10.9%	12.2%	9.4%	9.4%	11.4%	11.0%	10.1%	8.6%	11.8%
Combined Cycle	4.0%	3.8%	4.3%	3.8%	3.5%	4.5%	2.6%	4.6%	3.0%	3.5%	2.7%	2.1%	2.7%	3.9%	3.8%
Combustion Turbine	11.5%	11.7%	10.3%	9.7%	8.7%	8.3%	11.1%	16.5%	9.2%	5.6%	5.4%	6.2%	5.3%	4.3%	5.5%
Diesel	11.7%	10.3%	9.3%	6.4%	9.2%	4.8%	6.6%	15.0%	9.0%	6.9%	7.0%	6.7%	7.6%	7.7%	11.6%
Hydroelectric	2.0%	2.1%	3.3%	1.2%	2.9%	4.5%	3.7%	4.0%	5.5%	3.9%	3.4%	3.5%	2.0%	5.7%	10.7%
Nuclear	1.4%	2.0%	4.3%	2.6%	2.9%	1.8%	1.0%	1.8%	1.5%	1.8%	0.5%	0.8%	0.6%	1.4%	1.1%
Other	9.3%	9.9%	8.4%	7.8%	10.1%	9.0%	10.9%	13.3%	13.2%	9.2%	13.7%	9.2%	9.2%	19.5%	17.3%
Total	6.8%	7.0%	7.2%	7.0%	7.6%	7.2%	7.6%	9.6%	7.0%	6.0%	6.5%	6.1%	5.5%	6.3%	7.3%

Moreover, a 100% ELCC value would require CC and CT units to have firm transportation of gas fuel in order to guarantee adequate supply 100% of the time. As discussed above, firm transportation is not necessarily relied on for Duke's CC and CT additions. Thus, assuming an ELCC value of 100% for CCs and CTs will lead to the over-valuation of these resources compared to their actual real-world performance. Strategen recommends that the Commission consider derating the ELCC of CC and CT units to reflect the lack of firm fuel supply.

E. Conversion to hydrogen

Since Duke models natural gas plants with a 35-year lifetime, any new CC or CT would operate past the 2050 deadline under HB951 for achieving net zero carbon emissions.[53] 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.[54]

As part of Duke's modeling, the Companies included the following assumptions about the incremental costs to ensure CCs and CTs can operate on hydrogen:

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[50] Duke Carbon Plan, Appendix E, pp. 31-32.

[51] Calculated based on information provided in AGO DR 3-20.

[52] 2021 State of the Market Report for PJM: Capacity Market, Monitoring Analytics, LLC (2021), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec5.pdf.

[53] Duke Carbon Plan, Appendix E, pp. 31-32.

[54] Duke Carbon Plan, Appendix O, p. 3.

- A transportation cost of $2.00/MMBTU;[55]
- Retrofit conversion costs of $100-175/kW for CTs and $65-110/kW for CCs for units built before 2040 to enable them to operate on hydrogen by 2050;[56]
- A cost premium of 20% for CTs added after 2040 to account for additional components and equipment for these units to operate on hydrogen.[57]

However, Duke provides insufficient bases for these cost estimates. Duke states that the $2.00/MMBTU transportation cost is a "generic transportation cost assumption" based on "current practices of supplying gas via pipelines for generation."[58] Regarding capital costs for 100%-hydrogen capable CCs and CTs, Duke reports that it has "spoken with several [Original Equipment Manufacturers ("OEMs")] about 100%-hydrogen capable turbines" but "none of the OEMs have been able to share estimated costs due to the preliminary nature of the technology."[59] Thus, Duke's "best estimate cost from the limited information available"[60] is highly speculative.

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.[61] 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. **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** The Company also did not attempt to account for the increased carbon-free generation capacity necessary to produce this hydrogen in the Carbon Plan,[63] further demonstrating the lack of rigorous analysis behind Duke's assumed conversion of its natural gas fleet to hydrogen.

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. For example, existing pipelines can only accommodate a ~20% hydrogen blend and will require existing pipelines to be upgraded and/or new pipelines to be built.[64] Similarly, it is unclear if current turbine technology can combust hydrogen within legal limits for NOx emissions.[65] Future advancements in turbine technology may be able to reduce NOx emissions; however to Strategen's knowledge, such technologies have not been demonstrated or

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55 AGO DR 3-28.
56 NCSEA and SACE, et al. DR 2-5.
57 AGO DR 3-28.
58 Public Staff DR 8-20.
59 Public Staff DR 8-20.
60 Public Staff DR 8-20.
61 Duke Carbon Plan, Appendix E, p. 102.
62 AGO DR 4-14.
63 AGO DR 4-13.
64 Hadley Tallackson, High risk, small reward: Regulators should tread carefully when reviewing utility hydrogen proposals (April 5, 2022), https://www.utilitydive.com/news/high-risk-small-reward-regulators-should-tread-carefully-when-reviewing-u/621390/.
65 Five Reasons to be Concerns About Green Hydrogen, Clean Energy Group (September 2021), https://www.cleanegroup.org/wp-content/uploads/Five-Reasons-to-be-Concerned-About-Green-Hydrogen.pdf.

commercialized. 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 of 2,400 MW of CCs and up to 7,500 MW of CTs:

Table E-71: Final Resource Additions by Portfolio [MW] for 2050

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
P1	-9,300	19,900	1,800	7,400	2,400	6,800	800	9,900	1,700
P2	-9,300	18,200	1,700	5,900	2,400	6,400	3,200	9,900	1,700
P3	-9,300	19,000	1,800	6,400	2,400	7,500	0	10,200	1,700
P4	-9,300	18,100	1,800	6,100	2,400	6,800	800	10,200	1,700

Note 1:Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.
Note 3: Includes SMR and advanced nuclear with integrated storage.

Unless hydrogen combustion ultimately becomes feasible, the natural gas plants would likely need to retire early and impose significant additional stranded costs on Duke customers. Given the significant uncertainty around the potential costs of hydrogen conversion, as well as around whether a robust hydrogen market will materialize, it may be more prudent for the baseline Carbon Plan scenario to assume that all new natural gas plants have lifetimes that do not exceed the 2050 timeframe.

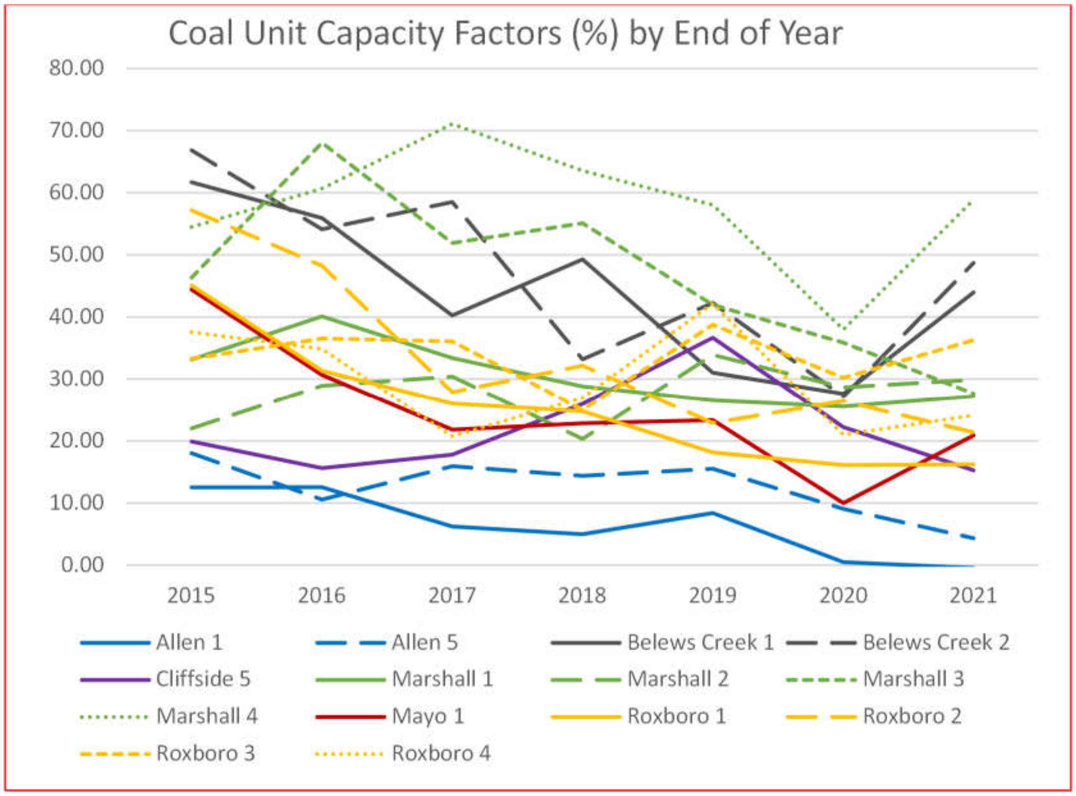
Practically speaking, this means that the CC and CT additions contemplated as part of the near-term action plan (i.e., with in-service dates in the 2029 timeframe) should be modeled assuming 20-year lifetimes, rather than the 35-year lifetimes that Duke has assumed. Strategen estimates that this would increase the capital costs by over 11% from a PVRR perspective. The Commission should require that any CPCN applications for these plants include an updated portfolio analysis using a 20-year lifetime as the base assumption.

Additionally, the assumed conversion to hydrogen fuel in the 2050 timeframe may underestimate the portfolio costs of any new gas resource from a PVRR perspective. This is because all PVRR calculations performed by Duke are done only through 2050,[66] including any necessary fixed cost investments.[67] 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.

F. Reliance on combustion turbines versus combined cycle units as coal units retire

Duke's proposed portfolios rely extensively on CCs to replace retiring coal units, but – to the extent gas generation is found to be needed – recent operations of the coal units indicates that they have been used more to meet peaking needs than to supply intermediate or baseload energy, and simple combustion turbines or batteries may be a better replacement fit. From the end of 2015 to the end of 2021, the capacity factors of Duke's coal units with planned retirements were as follows:[68]

66 AGO DR 4-3.
67 AGO DR 4-4.
68 Plant generation data obtained from the S&P Global Market Intelligence database, July 2022.



According to the EIA, the average capacity factor of CC units in the US in 2021 was 54.4%.[69] As shown in the figure above, by the end of 2021, several of Duke's coal units have capacity factors significantly lower than this level, particularly the Allen 1 and 5, Mayo, and Roxboro 1, 2, and 4 units which operated with capacity factors of less than 25%. The majority of the coal plants have also experienced decreasing capacity factors over the years, and this trend is likely to continue as the economics of coal plants become increasingly disadvantageous compared to that of other resources. Lower capacity factors mean that coal plants are operating more infrequently, and more akin to peaking resources, like CT units, which had an average capacity factor 12.1% in 2021, rather than to CC units.[70] Therefore, CTs and battery storage may be better replacement options for retiring units than CCs, especially under a high gas price scenario.

In the 2021 Public Policy Study, the NCTPC considered adding a CC unit at Roxboro but then determined that the unit was not needed to serve load under the scenario assessed in the study.[71] This determination demonstrates that other resources are able to serve load while ensuring that Duke's system can meet HB951 carbon reduction targets. Additionally, compared to CCs, CT units provide more operational flexibility, which will become increasingly important as the penetration of variable

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[69] U.S. Energy Information Administration, *Electric Power Monthly*, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[70] US. Energy Information Administration, *Electric Power Monthly*, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[71] Draft Report on the NCTPC 2021 Public Policy Study, North Carolina Transmission Planning Collaborative (May 9, 2022), http://www.nctpc.org/nctpc/document/REF/2022-05-10/NCTPC_2021_Public_Policy_Study_Report_05_10_2022_Final_%20Draft.pdf.

renewable energy on Duke's system increases. For instance, a CC plant typically has a startup time of 4-hours, while a CT can often ramp up within 10 minutes.

G. *Potential environmental policies and standards*

Even though natural gas produces less emissions than coal, it is still a GHG-emitting resource. If more stringent environmental policies and standards are enacted in the future, the costs for natural gas plants to comply with such requirements will increase, weakening the economics of natural gas plants compared to other, carbon-free resources. For instance, Duke has identified the potential for EPA permitting standards to be tightened and for a Social Cost of GHG to be incorporated into NCUC decisions in the coming year.[72] Duke's Federal CO2 Tax Production Cost Sensitivity Analysis demonstrates the potential significant cost increases that a carbon tax could cause to Duke's portfolios:

Table E-98: Federal CO_2 Tax Production Cost Sensitivity Analysis PVRR through 2050 [2022, $B]

	No Price on CO_2 Emission	Proxy Federal CO_2 Tax
P1	$101.1	$124.2
P4	$95.5	$121.3
Delta	$5.6	$2.9

However, Duke did not perform a capacity expansion sensitivity analysis that would illustrate how a carbon tax would affect the model's resource selections. If resource selections were re-optimized, it is highly likely that more carbon-free resources, such as solar, storage, and wind, would be selected over fossil fuel resources like CCs and CTs.

H. *Recommendations*

- The Commission should require Duke's proposed upcoming CPCN for a new CC to include an option for an 800 MW unit (rather than a 1,200 MW unit) in the 2027-2028 timeframe, as consistent with the Alternate Fuel Supply Sensitivity
- The Commission should require any updated Carbon Plan modeling, or CPCN for new natural gas units, to include an updated portfolio analysis, which includes re-optimized resource selections, with:
    - Updated natural gas price forecasts
    - Updated ELCC for CC and CT units to reflect forced outage rates and the lack of firm transportation capacity
    - A 20-year book life for natural gas units to account for the risks and uncertainties related to future conversion to hydrogen

[72] Duke Carbon Plan, Appendix M, pp. 5-6.

6. New Natural Gas Combustion Turbine ("CT") Additions

Duke's preliminary EnCompass model runs selected no new CT units through 2035 for any of the four Carbon Plan portfolios.[73] However, Duke forced in significant CT additions through various out-of-model "Portfolio Verification" steps. Generally speaking, CT unit additions have a much lower impact on overall cost, fuel price risk, and emissions contribution than the CC units described above. Additionally, they have a greater contribution to operational flexibility and can better aid renewable integration. Thus, at a high level, Strategen is less concerned about the additions of CT than additions of CC units. In any case, Duke's analysis in support of its proposed CT additions also includes certain deficiencies and carries some similar risks that the Commission should consider.

A. Battery-CT Optimization

The preliminary resource additions in Duke's model included between 2,800 and 5,500 MW of battery capacity by 2035, depending on the portfolio.[74] However, Duke then replaced between 1,600 and 2,000 MW of batteries in each portfolio with CT units as part of a "Battery-CT Optimization" step:

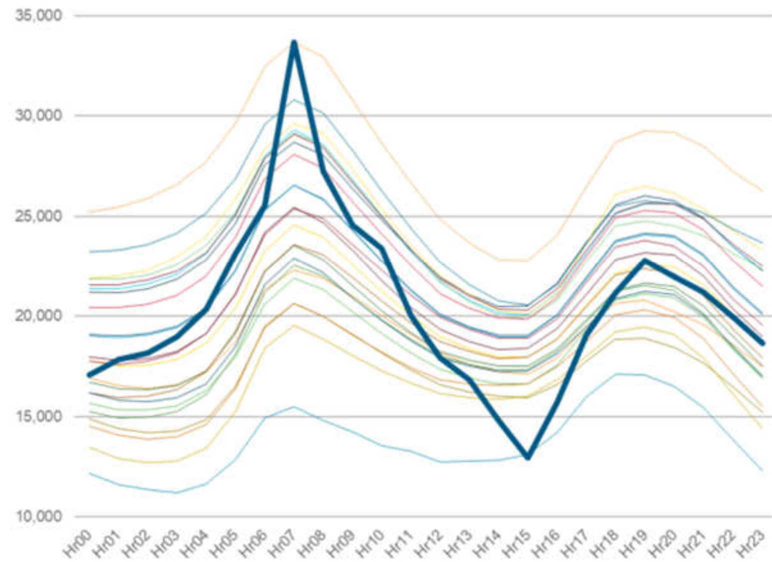
Table E-54: Battery-CT Optimization Results through 2050 [Nameplate MW]

Portfolio	Battery Capacity Removed	CT Capacity Added
P1	2,000	1,900
P2	2,000	1,900
P3	2,000	1,900
P4	1,600	1,500

To justify this step, Duke claims that the "typical day" load shape utilized by the EnCompass model over-values short duration storage. According to Duke, "the narrow, 'needle peak' followed by a deep, midday valley in the simplified load shape" shown on the graph below creates "an optimal daily shape for energy storage resources" by allowing short duration batteries to "fully discharge over a very brief peak and then immediately recharge with the midday valley:"[75]

[73] Duke Carbon Plan, Appendix E, Table E-52.
[74] Duke Carbon Plan, Appendix E, pp. 54-55
[75] Duke Carbon Plan, Appendix E, p. 58

Figure E-10: Capacity Expansion "Typical Day" Load Shape, Example



To correct for this over-valuation of battery storage, Duke ran the preliminary portfolio output through the detailed production cost model, then ran an additional production cost model run with a fraction of the batteries replaced with the equivalent capacity of CTs. Through this process, Duke determined that it was economic to replace approximately 35% of the battery capacity with CTs in each portfolio.

While Duke's optimization appears to have some merit, the lack of transparent information about this secondary analysis makes it difficult to evaluate. For example, the Company explained that it "[did] not save hourly model outputs."[76] As such, Strategen was not able to review the full set of "typical day" load shapes generated by Duke's EnCompass modeling. **BEGIN CONFIDENTIAL** [redacted]**ND CONFIDENTIAL** These factors raise questions about the robustness of the battery-to-CT analysis. Additionally, it is Strategen's understanding that there are multiple ways to construct the typical daily load shape within EnCompass. For example, multi-hour block averages could be used to minimize the "needle peak" and also create a more representative load shape that would not be biased towards battery storage. In Strategen's view this would have been a superior approach since it would eliminate the need to undertake a separate out-of-model step that could lead to suboptimal outcomes and would ensure that all resource selections were co-optimized.

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[76] AGO DR 4-10.

[77] Public Staff DR 9-6.

[78] NCSEA and SACE, et al. DR 3-41.

B. Reliance on Ultra Low Sulfur Diesel ("ULSD") back up fuel

Duke states that it assumed a $0/MMBTU interstate transportation cost for new CTs because these units will rely on ULSD back up fuel to ensure fuel supply during system peaks, rather than rely on firm gas transportation service.[79] Duke explains that the reliance on ULSD is necessary because Duke is currently deficient of firm transportation capacity from Transco Zone 5, meaning that natural gas supply will be limited during times of high utilization.[80] However, Duke also admits that ULSD only provides for a short-term fuel alternative to natural gas, since CT units are not currently designed to support extended ULSD run periods.[81] Given the lack of firm natural gas supply, Strategen is concerned about the reliability of Duke's system during periods of high demand, as discussed in the "Natural gas fuel supply assumptions" section above (Section 5.B).

Depending on the amount of on-site ULSD available, it is possible that the CT units would not be capable of providing firm dispatchable service during some grid conditions. As such, it may be necessary to derate the CT units' capacity contributions accordingly.

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. It would also introduce potential execution risk in terms of obtaining necessary air permits.

C. Recommendations

- The Commission should require Duke to utilize other "typical day" load shape constructs in EnCompass in order to minimize the need for subjective post-model "portfolio verification" steps, such as occurred in the "optimization" that replaced batteries with CT units.
- The Commission should require Duke to make necessary adjustments to the ELCC value of CT additions to account for the lack of firm gas transport. This should occur both in an updated modeling exercise as part of this proceeding as well as any analysis presented as part of a future CPCN.
- The Commission should require any future CPCN for new gas CTs to provide a comprehensive assessment of any incremental costs for onsite ULSD storage and additional permitting requirements.

7. Long lead-time resources (SMR, OSW, PSH)

Duke's proposed plan includes several long lead-time resources that are expected to be completed in the 2030s. These include nuclear SMR, offshore wind, and the Bad Creek II pumped storage hydro project.

If completed, each of these 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. They also all carry significant execution risk due to

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[79] AGO DR 5-3.
[80] NCSEA and SACE, et al. DR 3-37.
[81] NCSEA and SACE, et al. DR 3-37.

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.

In Strategen's view, the one of these resources with the most certainty (least execution risk) is pumped hydro. Pumped hydro is a mature technology with a well proven track record and is widely deployed across the US. Thus, from an execution risk standpoint, it may make sense to approve further development activities for this resource.

Meanwhile, offshore wind has a proven track record in Europe, but not yet in the US. Strategen recommends that the Commission apply more caution in approving development activities for this resource but recognizes it may also make sense to move forward due to the significant amount of carbon free energy that offshore wind can generate.

Regarding nuclear resources, Duke's plan relies on the unproven SMR technology that could carry significant risk to Duke's customers in the event of cost overruns, which have been common among recent nuclear projects in the US.[82] In its modeling, Duke assumed a capital cost for SMR technology that was **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** than traditional nuclear resources.[83] 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, this may represent an overly optimistic assumption.

As such, the Commission should use extreme caution in approving any development activities for new nuclear and ensure that all other options have been explored first. In this vein, it may be more appropriate for the Commission to defer formal approval of SMRs development activities until the next Carbon Plan cycle. Duke should also be required to model a contingency plan in the event that new SMR resources are not able to be developed within Duke's proposed timeframe.

Resource	**Pros**	**Cons**	**Priority Rank (based on technology readiness)**
Offshore Wind	• Proven track record in Europe • Strong federal support w/ BOEM lease program • Output profile highly complementary to solar and less intermittent than other renewables • Relatively high capacity value and energy output (especially versus other renewables)	• High cost • Emerging market in US • Extensive & costly transmission needs	Medium

[82] 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-atlanta-7555f8d73c46f0e5513c15d391409aa3.

[83] Based on Confidential Attachment to Public Staff DR 3-17.

Pumped Storage Hydro	• Dispatchable resource provide very high capacity value (ELCC) • High degree of flexibility for integrating variable renewables (e.g. solar, wind) • Mature technology	• Environmental permitting and review could be challenging • No direct emissions reductions (but supports wind & solar)	High
Small Modular Reactors	• Dispatchable resource provides very high capacity value (ELCC) • High capacity factor provides significant energy value (i.e., MWh delivered)	• High cost • Unproven technology • Extensive development cycle and rigorous permitting process (likely 10+ years) • Recent US nuclear projects have had substantial cost overruns and even cancellations	Low

8. Adjustments to Coal Retirement Dates

A. *Adjustments from economic retirement dates*

At the conclusion of the 2020 IRP, the Commission required Duke's future planning model runs (i.e., EnCompass) to provide information on the most economic retirement dates of its coal plants – also known as "endogenous retirement." In its proposed Carbon Plan, Duke claims to have initially run its model using endogenous retirements. However, Duke then made subjective changes to these dates without further explanation of each change being made in its filing. This is concerning because it may mean that Duke is not aligning its coal retirement schedule with the dates that are most optimal for reducing customer costs under HB951's requirements.

While not included in its initial filing, Duke ultimately provided the endogenous retirement dates as a Supplement to NCSEA and SACE, et al. DR 3-39L on June 29, 2022. The Company later provided explanations of these adjustments in a Second Supplemental response to AGO DR 4-7 on July 7, 2022.

Strategen is concerned that there appear to be numerous adjustments made between the economically optimal "endogenous" retirement dates, and those ultimately proposed by Duke, including for every plant except for Cliffside. These discrepancies are highlighted in the table below comparing Duke's proposed retirement dates ("effective year") the model selected dates for the P1 portfolio.

Unit	Utility	Winter Capacity [MW]	Effective Year (Jan 1)	P1	P1alt
Allen 1[2]	DEC	167	2024	NA	NA
Allen 5[2]	DEC	259	2024	NA	NA
Belews Creek 1	DEC	1,110	2036	2030	2033
Belews Creek 2	DEC	1,110	2036	2030	2033
Cliffside 5	DEC	546	2026	2026	2026
Marshall 1	DEC	380	2029	2026	2026
Marshall 2	DEC	380	2029	2026	2026
Marshall 3	DEC	658	2033	2034	2035
Marshall 4	DEC	660	2033	2034	2035
Mayo 1	DEP	713	2029	2026	2026
Roxboro 1	DEP	380	2029	2029	2029
Roxboro 2	DEP	673	2029	2029	2029
Roxboro 3	DEP	698	2028-2034[3]	2030	2030
Roxboro 4	DEP	711	2028-2034[3]	2030	2030

Notably, 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. Duke characterized these changes as "minor adjustments."[84] However, these changes are actually quite noteworthy since they overlap substantially with 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.[85] 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.[86] 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.

84 Duke Carbon Plan, Appendix E, p. 49
85 AGO DR 4-7 Second Supplement.
86 AGO DR 4-7 Second Supplement.

As such, 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).

For Belews Creek 1 & 2, Duke explains that the economic retirement date was as early as 2030 (for the P1 portfolio), yet the Company selected 2036 as the retirement date. In Appendix P, Duke has cited the need for transmission upgrades as being necessary for retirement of certain coal plants including Belews Creek. However, there should be ample opportunity to complete any necessary transmission upgrades prior to 2030, rather than waiting until 2036. In its Second Supplemental response to AGO DR 4-7, Duke did not provide a precise reason for this delay but pointed to a number of tangential considerations, including "providing additional time for development of SMR technology." This suggests to Strategen that Duke may be targeting the Belews Creek site for a potential SMR deployment in the mid-2030s rather than considering alternatives.

Additionally, during the 2020 IRP process, Strategen raised significant concerns about Duke's assessment of the need for these retirement-related transmission upgrades. 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.

Finally, Duke also downplays the importance of the "minor" retirement date adjustments by stating that they do not impact the final portfolio for the year in which the 70% interim target is reached. However, this is not necessarily true for Belews Creek, for which the economic retirement date may cause it to fall within the 2030 compliance timeframe. Additionally, while HB951's 2030 target is important there are also reasons to minimize carbon emissions in the interim, which were explained above in Section 2-D.

Since Belews Creek currently has the ability to co-fire on 50% natural gas, the Commission should also explore whether it would be feasible to modify the plant to operate on 100% natural gas as an alternative to retirement. According to Duke's response to AGO DR 6-2, **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** For comparison, the capital cost of a new natural gas CC plant of similar capacity (i.e., ~1,110 MW, which is 50% of Belews Creek's total) would likely be in the range of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** million according to the estimates provided by Duke in PSDR 3-17.

B. Coal Retirements Under High Gas Price Forecast

One additional area of concern regarding Duke's proposed coal retirement dates is the relationship they have with the gas price forecast. This was briefly discussed above in Section 5 (on combined cycle units).

Given recently high gas commodity prices, 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., P1A-P4A). In reviewing these cases, Strategen is concerned that all of the high gas price sensitivity runs result in portfolios that do not comply with the HB951 statute. 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. However, 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.

In Strategen's opinion, this represents a significant risk factor for which Duke should have developed or at least evaluated a contingency plan. Due to the ongoing conflict in Ukraine, which is affecting global market for energy commodities like natural gas, there is a distinct possibility that we will be headed 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 show CO2 reductions far below the 70% statutory target.

Notably, 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 clean resources to take their place. This seems 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 the endogenous runs, but it may also be able to close the gap towards HB951 compliance for a scenario with high gas prices. In fact, based on Table A-3, if Belews Creek's 2021 emissions were removed from Duke's system, this would account for a 10% incremental carbon reduction versus the 2005 baseline. Alternatively, it may be worth considering whether Belews Creek could be converted completely to operate on natural gas rather than coal.

C. Recommendations

- Direct Duke, prior to the evidentiary hearing, to develop additional scenarios using the economic retirement dates discussed above for Marshall 1 & 2, Mayo 1, and Belews Creek 1 & 2 units. Allow other parties to do so.
- Direct Duke to explore the feasibility of retiring Belews Creek by 2030 or operating the plant on 100% natural gas by that date. Direct Duke to include this gas conversion as an option in all future scenarios developed prior to the evidentiary hearing.
- Direct Duke, prior to the evidentiary hearing, to develop additional "contingency plan" scenarios that meet HB951's requirements under a high gas price forecast. Allow other parties to do so.

9. Load Forecast and Demand Side Resources

A. *Energy Efficiency and Demand Side Management ("EE/DSM")*

i. EE/DSM Portfolio

In its proposed Carbon Plan, Duke intends to pursue utility-implemented EE/DSM measures ("UEE") that collectively achieve savings of 1% of eligible retail load annually. 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.[87]

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. Thus, 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.

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.[88]. As such, Strategen was unable to assess the incremental value of including additional demand side resources in the Carbon Plan portfolio.

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 four 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 GHG emissions reduction perspective. For example, it may be more cost effective to increase UEE rebate/incentive levels 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, Strategen recommends that this be explored in future iterations of the Carbon Plan, as well as any alternatives analyses Duke includes in its planned CPCNs for new gas generation.

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.[89] 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.

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

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[87] See ACEEE 2020 State Energy Efficiency Scorecard, https://www.aceee.org/research-report/u2011.
[88] AGO DR 6-5.
[89] See for example: TEP IRP Analysis, Strategen Consulting (May 2020), https://www.tep.com/wp-content/uploads/SWEEP-Analysis_TEPworkshop_520.pdf.

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, Strategen is generally supportive of Duke's proposal to modify the Cost-Benefit test, as described in Appendix G.[90] However, this support is contingent on further review of the specific methodological changes Duke plans to make, which Strategen has not had the opportunity to do yet.

ii. UEE Roll-Off and Naturally Occurring Efficiency

As part of the development of the load forecast used in its Carbon Plan, Duke has projected the long-term effects of UEE measures. Strategen has some concerns with 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.

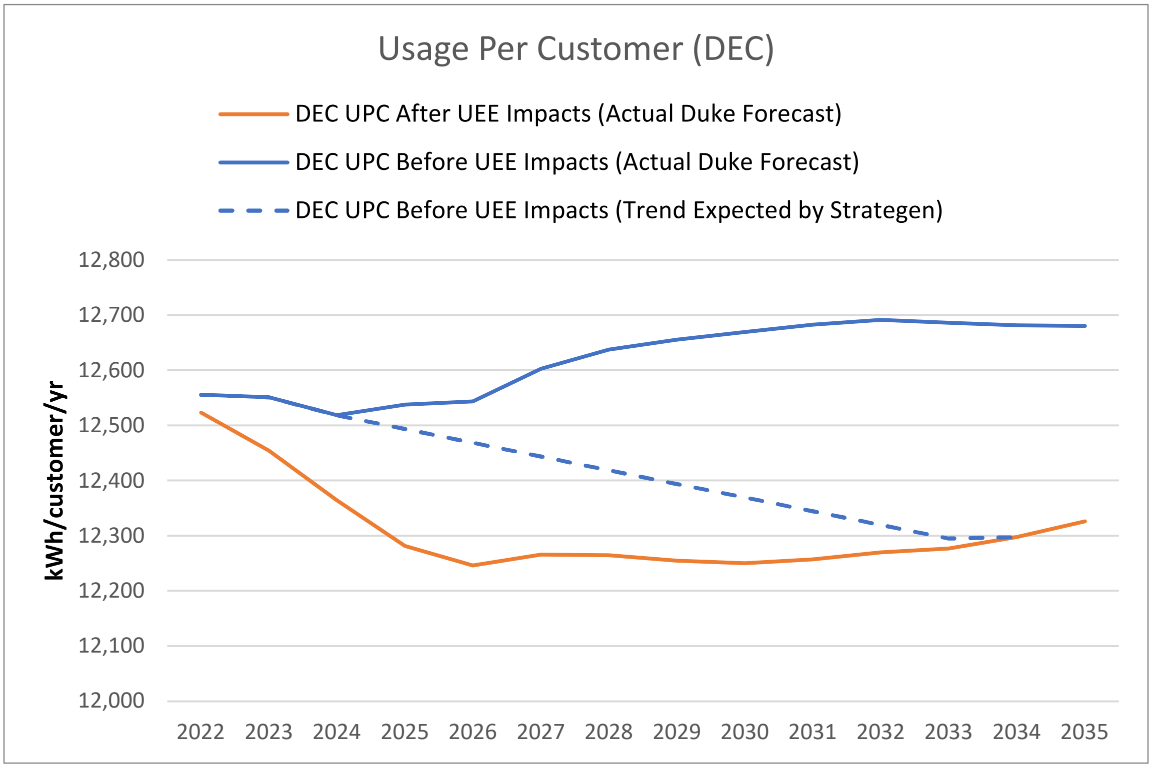
To justify this approach, Duke explains that "As UEE serves to accelerate the timing of naturally occurring efficiency gains, the forecast 'rolls off' or ends the UEE savings at the conclusion of its measure life."[91] This approach would be acceptable if the underlying load forecast also evolved over 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."[92] However, these statements do not appear congruent with the actual load forecast data that Duke provided in response to AGO DR 3-30. In fact, rather than showing a trend towards declining consumption due to "naturally occurring efficiency," Duke actually forecasts an *increase* in usage per customer for DEC. This is illustrated in the chart below where the solid blue line is actually increasing over time, rather than decreasing as would be expected if "naturally occurring efficiency" were accurately being accounted for. If this naturally occurring efficiency were being accounted for, then Strategen would expect the trend to resemble the dashed blue line more closely. Meanwhile, the orange line shows the effects of UEE, which accelerates the adoption of EE/DSM measures relative to those that "naturally occur" as depicted in the blue line.

When examining usage per customer for DEP and DEC, there is no clear indication that baseline appliance efficiency trends are "replacing" the rolled off UEE. If that were the case, Strategen expects that the usage per customer before UEE would decline over time as baseline appliance efficiencies "catch up" to the accelerated performance levels implemented by UEE programs. This raises some

[90] Pages 12-13.
[91] Duke Carbon Plan, Appendix F, p. 5.
[92] Duke Carbon Plan, Appendix F, p. 5.

fundamental questions about the accuracy of Duke's load forecast and suggests that the Company may be over-forecasting its load relative to what is realistic.

Bear in mind that Duke maintains a separate forecast for electrification loads, such as for EV adoption, that is applied after the underlying "before impacts" load forecast.[93] Thus, electrification load does not explain the increase in usage per customer shown in DEC.



iii. "As-found" baseline

Duke proposes to change the method for calculating the savings associated with UEE. Now, 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.

For example, if a homeowner's 15-year-old HVAC system breaks down, that person has a choice of replacement options. Those choices would include an HVAC system that meets the minimum prevailing performance requirements (i.e., the least efficient HVAC system on the market at the time), or an HVAC system that exceeds the minimum requirements (i.e., a more efficient HVAC system). The

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[93] AGO DR 6-4.

homeowner generally *does not* have the choice of purchasing the same 15-year-old HVAC system that broke down, and which would typically have a lower efficiency than today's market products. This outdated, and less efficient model would be unavailable in the current marketplace.

However, Duke's proposal to shift towards an "as-found" baseline methodology 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 the only available replacement options would be at today's baseline level of efficiency, not the outdated model's level of efficiency. In other words, Duke's method incorrectly suggests that the homeowner somehow would be able to purchase a 15-year-old appliance model, and that this obsolete model is the appropriate point of comparison for the newly purchased appliance.

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 *in*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.

For these reasons, Strategen recommends against using the "as found" methodology that Duke has included in its proposed Carbon Plan.

B. Distributed Generation/Net Energy Metering ("NEM")

Much like the EE/DSM portfolio described above, 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.

As it did with EE/DSM, Duke embedded 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 to Strategen how these two cases were ultimately used by Duke or compared in the final portfolios.

Moreover, these two cases represent a relatively narrow set of possibilities. Instead, 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.

Additionally, in light of this proposal, Duke should consider steps to ensure the additional grid benefits from offerings like this are fully captured. This would include modeling distributed solar as a potential selectable resource in EnCompass. Moreover, the Company 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, Strategen recommends that in the next Carbon Plan cycle, Duke evaluate a larger variety of distributed generation offerings beyond simply NEM.

C. Recommendations

- The Commission should require future iterations of Duke's modeling to include EE/DSM and distributed solar as selectable resources.
    - At a minimum, more than one EE/DSM and distributed solar scenario should be evaluated by providing complete performance metrics for cost and emissions for different load sensitivity cases.
- The Commission should require future iterations of Duke's modeling to evaluate the costs and benefits of different levels of EE/DSM and rooftop solar deployment by varying the level of incentives provided.
- The current cost benefit analysis (i.e., UCT) should be re-evaluated to reflect currently proposed carbon free resources (e.g., SMR, OSW) as the alternative rather than traditionally used proxy resources like CTs.
- The Commission should require Duke to maintain the current approach to counting EE savings using the minimum federal efficiency and performance requirements (rather than Duke's proposed "as found" savings method).
- The Commission should evaluate Duke's method for including UEE roll-off in its load forecast relative to "naturally occurring" efficiency to ensure that the forecast is not overly inflated.

10. Comments On Duke's Proposed Near-Term Action Plan

Perhaps the most important outcome to be adopted in the 2022 Carbon Plan process is the near-term action plan since it will dictate Duke and other stakeholders' activities in the coming years.

Strategen reaffirms its core recommendation that a near-term action plan cannot be determined at this point in time without the benefit of additional analysis. However, if the Commission determines that such additional analysis will not be performed, the Commission should consider certain actions for each resource type as part of any near-term action plan adopted.

The table below summarizes some Strategen's recommendations as compared to elements of Duke's proposed near-term action plan. The recommendations and rationales are summarized at a high level, however each of these is discussed in much further detail throughout this report.

Resource	Duke's Proposed Near-Term Action	Strategen Recommendation	Rationale
Proposed Resource Selections: In-Service through 2029			
Carbon Plan Solar	• Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage	• Pursue timely addition of ≥3,100 MW of new solar as a "least regrets" option. • Consider increased procurement of solar plus storage, including systems with larger DC components	• Duke only included a limited number of solar plus storage configurations and excluded configurations with higher capacity values
Battery Storage	• Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar	• Pursue timely addition of ≥1,600 MW of new storage as a "least regrets" option. • See above re: solar plus storage • Seek to site battery storage at retiring coal facilities as replacement generation by 2025 to 1) avoid transmission upgrade requirements and 2) advance economic retirements in 2026 timeframe	• Duke only included a limited number of solar plus storage configurations and excluded configurations with higher capacity values • The use of batteries as replacement generation for coal units instead of CTs/CCs can mitigate the need for transmission upgrades
Onshore Wind	• Engage wind development community in preparation for procurement activities • Procure 600 MW in 2023-2024	• Pursue timely addition of ≥600 MW of new wind as a "least regrets" option. • Accelerate target in-service dates to 2026-2027.	• Duke does not allow EnCompass to select onshore wind until 2029
New CT	• Submit CPCN for 2 CTs totaling 800 MW in 2023	• Require additional Carbon Plan scenario analysis as described above in 2-C, before including. • Require any future CPCN to study risk factors associated with high gas prices, the lack of firm transportation, and the feasibility and cost of future conversion to hydrogen	• Recent increases in gas price, the lack of firm transportation capacity, and uncertainty around the feasibility of future hydrogen conversion introduce significant financial and reliability risks to natural gas deployments
New CC	• Submit first CPCN for 1,200 MW in 2023 • Evaluate options for additional gas generation pending determination of gas availability	• Require additional Carbon Plan scenario analysis as described above in 2-C, before including. • The first CPCN should not be for more than 800 MW, in line with the Alternate Fuel Supply Sensitivity Portfolio. • Require any CPCN to study risk factors associated with high	• Recent increases in gas price, the lack of firm transportation capacity, and uncertainty around the feasibility of future hydrogen conversion introduce significant financial and reliability risks to natural gas deployments

		gas prices, the lack of firm transportation, and the feasibility and cost of future conversion to hydrogen.	
Proposed Resource Development: Options for 70% Interim Target			
Offshore Wind	• Secure lease • Initiate development and permitting activities for 800 MW • Conduct interconnection study • Initiate preliminary routing, right-of-way acquisition for transmission	• Allow Duke to conduct limited development activities, with appropriate reporting requirements.	• Mature technology, without track record in the US
New Nuclear	• Begin new nuclear early site permit for one site • Being development activities for the first of two SMR units	• Defer approval until next Carbon Plan cycle.	• New technology without a track record
Pumped Storage Hydro	• Conduct feasibility study for 1,700 MW • Develop EPC strategy • Continued development of FERC Application for Bad Creek relicensing	• Allow Duke to conduct development activities.	• Mature technology with track record in the US
Other Resources			
Coal Retirement[94]	• 2029: Retire Marshall 1 & 2 and Mayo 1 after transmission upgrades or on-site generation completed. • 2036: Retire Belews Creek after transmission upgrades or on-site generation completed.	• Accelerate the retirement of Marshall 1 & 2 and Mayo 1 to the more economical 2026 date. • Evaluate options for retiring Belews Creek in 2030 in next Carbon Plan, including installing transmission upgrade needs before then.	• The use of batteries as replacement generation in the 2025 timeframe can mitigate the need for transmission upgrades. • Ample time for transmission upgrades and/or replacement generation prior to 2030.
EE/DSM[95] & Distributed PV	• Target 4,230 MW of contribution by 2035	• Consider higher incentive levels for EE/DSM programs, and for rooftop solar, to enable more deployment than current forecast	• EE/DSM measures that pass the cost-effectiveness test are the least expensive carbon-free resources but were not included as a selectable resource in EnCompass.

[94] Duke Carbon Plan, Chapter 4, Table 4-2.
[95] Duke Carbon Plan, Chapter 4, p. 8.

11. Summary of Recommendations

The Commission should:

1. Adopt a Carbon Plan that aims to meet the 70% reduction in CO_2 emissions by 2030, consistent with the intent of HB951, and adjust the final compliance date in the future iterations of the Carbon Plan, allowing some flexibility, if appropriate, under circumstances that develop.
    - In the event the Commission adopts a Carbon Plan based on a 2032 or 2034 compliance timeline, the Commission should clarify that this does not necessarily constitute a determination of prudency or preauthorization for any future nuclear or offshore wind resources.
2. Direct Duke and allow other parties to, before the evidentiary hearing, develop additional portfolios based on EnCompass capacity expansion model runs that:
    - Eliminate or significantly relax the constraints identified in Section 2.C.i. and discussed in Sections 3-5. This includes adjusted modeling constraints for solar, solar plus storage, onshore wind, and natural gas.
    - Use the alternative approaches described in Section 2.C.ii, in order to minimize out-of-model adjustment steps.
    - Adjust assumptions on natural gas, including price forecasts, ELCC values, and book life as discussed in Sections 5-6, in order to account for price increases, the lack of firm supply, and the uncertain feasibility of hydrogen conversion.
3. Require Duke to include these additional portfolios in the supporting analysis as part of CPCN applications for near-term resources selected in the Carbon Plan.
4. Consider a near-term solicitation for onshore wind to test market readiness with a target in-service data in the 2026-2027 timeframe. Allow for wind imported from other regions (including as "energy only" resources).
5. Require 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
6. Direct Duke to explore the feasibility of retiring Belews Creek by 2030 and/or operating the plant on 100% natural gas. Direct Duke to include this gas conversion as an option in all future scenarios developed prior to the evidentiary hearing.
7. Direct Duke and allow other parties to, prior to the evidentiary hearing, develop additional contingency plan scenarios that meet HB951's requirements under a high natural gas price forecast.
8. Require future iterations of the Carbon Plan to:
    - Include EE/DSM and distributed solar as a selectable resource
    - Evaluate the costs and benefits of different levels of EE/DSM and rooftop solar deployment by varying the level of incentives provided
9. Re-evaluate the current cost-benefit analysis for EE/DSM (i.e., the UCT) to reflect currently proposed carbon-free resources (e.g., SMR, OSW) as the alternative to the traditionally used proxy resources (e.g., CTs)
10. Require Duke to maintain the current approach to counting EE savings, using the minimum federal efficiency and performance requirements as the baseline.

11. Evaluate Duke's method for including UEE roll-off in its load forecast relative to "naturally occurring" efficiency to ensure that the forecast is not overly inflated.