INFORMATION SHEET

PRESIDING: Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, McKissick, and Kemerait
PLACE: Dobbs Building, Raleigh, NC
DATE: Monday, September 26, 2022
TIME: 1:29 p.m. – 4:50 p.m.
DOCKET NO(s): E-100, Sub 179
COMPANY: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC
DESCRIPTION: 2022 Biennial Integrated Resource Plans and Carbon Plan

VOLUME NUMBER: 25

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

CONFIDENTIAL COPIES OF TRANSCRIPTS AND EXHIBITS ORDERED BY:

REPORTED BY: Joann Bunze	TRANSCRIPT PAGES: 189
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DATE: Monday, September 26, 2022

TIME: 1:29 p.m. - 4:50 p.m.

DOCKET NO.: E-100, Sub 179

BEFORE: Chair Charlotte A. Mitchell, Presiding

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Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and

Duke Energy Carolinas, LLC,

2022 Biennial Integrated Resource Plans

and Carbon Plan

VOLUME: 25

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EXAMINATIONS

E X H I B I T S

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Page 21 of the Carbon Plan (Ch. 2) states that "Advanced nuclear reactor costs were based on EPRI's cost and performance estimate and proprietary third-party engineering estimates." Please provide all sources used to formulate advanced nuclear reactor costs (including but not limited to SMR costs), including all EPRI cost and performance estimate and proprietary third-party engineering estimates.

RESPONSE:

All advanced nuclear costs are contained in the Generic Unit Summary, which was provided with the Companies' response to PS DR 3-17. High-level information can be found on the first "Summary" tab of PS DR3-17 CONFIDENTIAL (Carolinas Generic Unit Summary), and additional details can be found on the "Nuclear" tab. Information can be found for each of the included SMR and Advanced Reactor designs on both the Summary and Nuclear tabs.

Responder: Trudy H. Morris, Gen. & Reg. Strategy Director; Adam Reichenbach, Lead Engineer

Tech Customers -
Gabel Report
/A

Review of the Duke Carbon Plan and Presentation of a Preferred Portfolio

PREPARED FOR:

Tech Customers

PREPARED BY:

Gabel Associates, Inc.

North Carolina Utilities Commission

Docket No. E-100, Sub 179

July 15, 2022

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Acknowledgments

This Report is sponsored by Michael Borgatti and Isaac Gabel-Frank, both of whom are Vice Presidents at Gabel Associates. Modeling and technical support was provided by Maria Roumpani and Eliasid Animas of Strategen Consulting.

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1 Report & Recommendations

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively "Duke" or the "Companies") proposed a Carbon Plan that lays out four trajectories toward achieving North Carolina's carbon reduction goal by 2030 and carbon neutrality by 2050 (the "Duke Carbon Plan" or "Companies' Carbon Plan.").

This report ("Report") provides an independent, comprehensive review and analysis of the Companies' Carbon Plan and b) a proposed Preferred Carbon Portfolio that achieves the carbon reduction goals of North Carolina at a lower cost and risk. It was prepared by Gabel Associates ("Gabel") with modeling and related technical support from Strategen Consulting ("Strategen"). Gabel and Strategen were engaged by the Tech Customers, who are intervenors in the Carbon Plan proceeding before the North Carolina Utilities Commission ("Commission").[1] The Report recommends policies and directions that the Commission should adopt in this proceeding to build a Carbon Plan that is feasible, reliable, and achieves the state's decarbonization objectives on schedule at a lower cost and risk to customers.

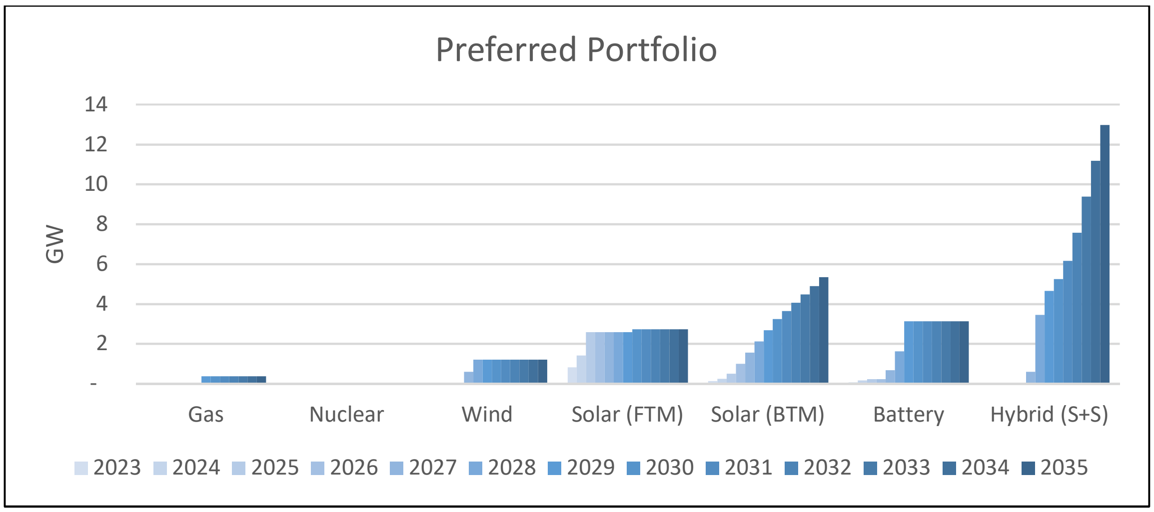
The Companies put forth an ambitious Carbon Plan that contemplates a transformational change to the region's resource mix to achieve the state's near-term emissions reduction goal and carbon neutrality by 2050. While these efforts are commendable, just one of the four potential portfolios in their Carbon Plan achieves the emissions target by 2030. It relies mainly on utility-scale solar deployment and prioritizing near-term investment in new natural gas-fired generation.

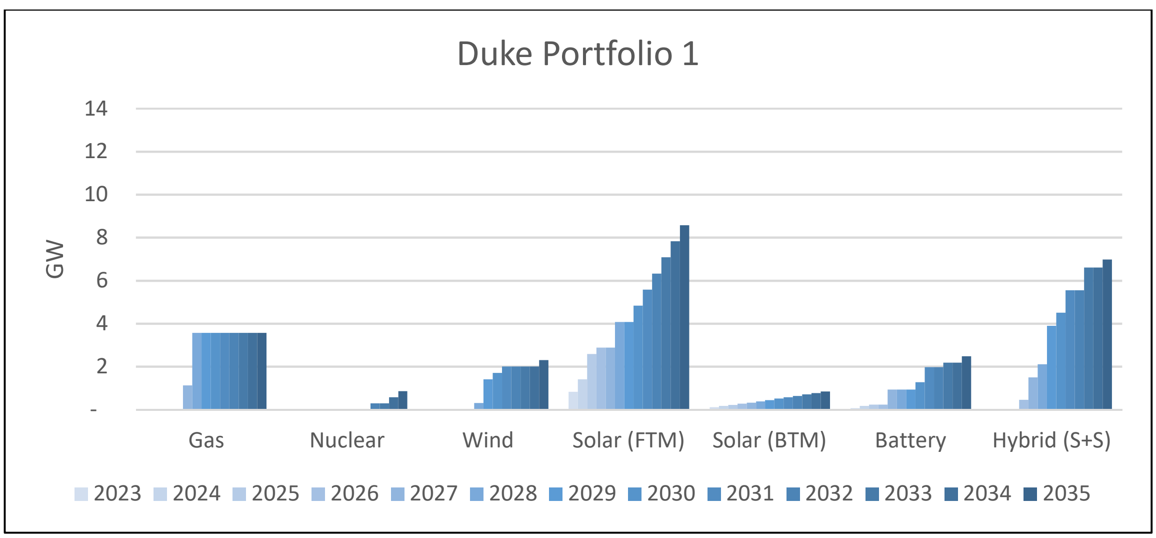
Importantly, significant challenges with the Companies' analytic approach, assumptions, and strategies meant we could not validate the Companies' Carbon Plan or fully optimize our capacity expansion model in the timeline provided by this proceeding. However, we have provided a more effective and beneficial direction by correcting flaws in the Companies' modeling and approach that understated the value of renewables and storage. It empowers customers to pursue their carbon reduction strategies and avoids investment in potentially unnecessary new carbon-emitting generation. It can also deliver significant savings to customers in the process.

[1] The Tech Customers are comprised of Apple Inc., Google LLC, and Meta Platforms, Inc.

The Preferred Portfolio recognizes the reliability benefits of hybrid resources and maximizes the potential of alternatives to conventional interconnection processes to accelerate clean energy resource deployment. It does this by accelerating coal retirements, deferring investment in new unnecessary gas-fired generation, and expanding proven strategies to reduce demand like expanding options for consumers to contract directly with renewable energy suppliers, energy efficiency, and behind-the-meter ("BTM") solar.

Figure 1: Comparison of New Resource Additions in Preferred Portfolio to Companies' Portfolio 1 in 2035

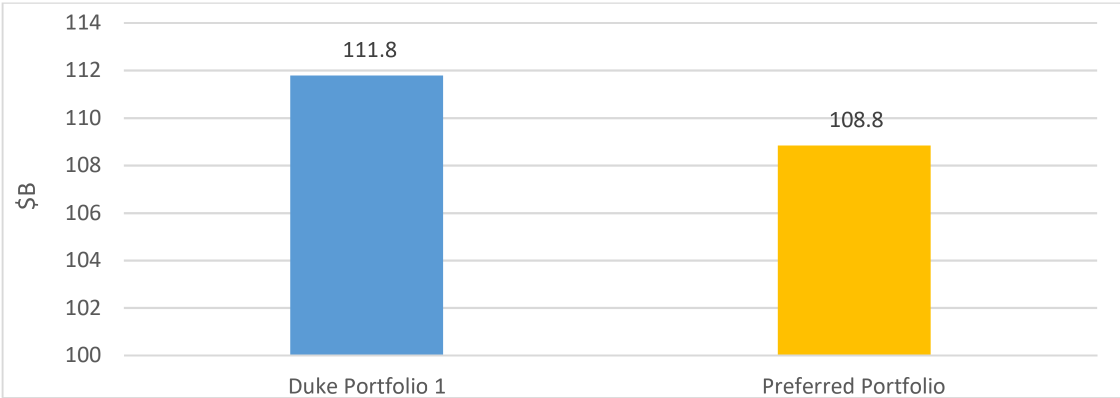




The Preferred Portfolio reduces reliance on near-term investment in natural-gas fired generation, avoids investment in speculative technologies like nuclear Small Modular Reactors

("SMR"), and achieves the state's carbon reduction objectives at nearly $3 billion less than the Companies' Carbon Plan.

Figure 2: Comparison of Costs of Preferred Portfolio to the Companies' Portfolio 1



These meaningful savings do not include the incremental value that utilizing creative interconnection strategies and avoiding the sunk costs for stranded gas-fired assets can realize. Using Replacement Generation Requests and Surplus Interconnection Service can bypass the conventional queue process to accelerate renewable and storage deployment at the sites of retiring and existing thermal assets. These processes also reuse the legacy asset's existing transmission facilities to reduce interconnection costs by upwards of $1.6 billion.

Increasing demand side resources, accelerating investment in wind resources, and using additional hybrid configurations in the Preferred Portfolio provides a cost-effective carbon-free alternative to the new natural gas combined cycle ("NGCC") assets that the Companies seek to procure in this proceeding. Providing a solution that avoids near term-investment in gas-fired generation reduces customers' exposure to another $670 million in potential sunk asset costs. It also reduces the Preferred Portfolio's reliance on speculative hydrogen conversions to achieve carbon neutrality relative to the Companies' Carbon Plan.

Figure 3: Incremental Benefits of "No Regrets" Carbon Plan Strategies

Preferred Portfolio Benefits	NPV ($ billion)
Additional Savings from Preferred Portfolio	(2.94)
Potential Interconnection Cost Savings	(1.60)
Potential Avoided Cost of Stranded Gas-Fired Assets	(0.50)
Total	**(5.04)**

Our comparison to the Companies' Portfolio 1 demonstrates the benefits of relying on proven decarbonization strategies instead near-term investment in gas-fired generation and speculative technologies like SMR nuclear and hydrogen-fueled thermal assets. While these technologies may become features of the Companies' long-term strategy for achieving carbon neutrality, the Preferred Portfolio takes a less risky approach by prioritizing investments in new renewables, energy storage, and transmission infrastructure. Nuclear SMR, non-water-cooled advanced reactors, and hydrogen generation are not commercially viable technologies and are too speculative to be included in or funded through the Carbon Plan. Our analysis demonstrates that Commission should adopt recommendations from this Report to develop a feasible carbon plan that achieves the state's decarbonization goals on time and provides significant value to consumers.

Joining a wholesale power market like PJM would amplify the value of these strategies by providing the flexibility and efficiency to source clean-energy resources across a broad geographic area. Integrating with PJM's centrally planned and operated transmission system would eliminate the cost of energy imports and alleviate the challenge of interconnecting unprecedented amounts of new generation exclusively in the Companies' service territories. The region's vibrant wholesale market provides an efficient platform enabling Duke and end-use customers to source renewable energy directly from suppliers. It would also empower customers to achieve additionality that hastens the state's trajectory toward carbon neutrality. While we summarize specific recommendations from this Report below, the Commission should also initiate a formal investigation into joining PJM.

1.1 Accelerate Coal Retirements to 2030 & Maximize Use of Existing Sites to Install New Renewable Resources & Storage at their Sites Using the Generator Replacement Request Process

Generator Replacement Requests provide a streamlined process that "will allow efficient, ready interconnections ***to meet Carolinas Carbon Plan goals***."[2] It allows a new generator to recycle existing interconnection facilities by locating a deactivating unit's site through a separate interconnection process that takes as little as 180 days to complete. Using the existing infrastructure also decreases generator development costs by avoiding transmission upgrades, reducing the interconnection study time, and reducing construction timelines.[3]

Our capacity expansion analysis assumes the Companies' coal assets all retire by 2030 per the Carbon Plan Schedule for retirements before 2030, and a latest retirement date of 2030 for the rest. Accelerating coal retirements effectively creates headroom on the transmission system that our model makes available to solar interconnections. Because we reasonably assume that recycling the existing generator's interconnection infrastructure eliminates the need for additional transmission system upgrades. Applying this strategy to all the approximately 9,000 MW of coal retirements reduces transmission costs in our Preferred Portfolio by as much as $1 billion through 2035 compared to the Companies' Carbon Plan.

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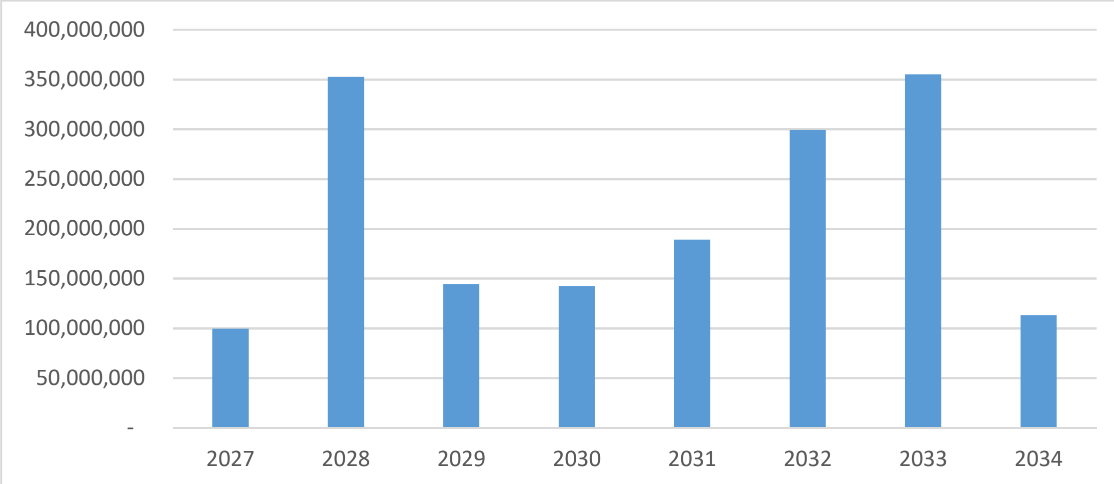
[2] DEC & DEP Generator Replacement Stakeholder Meeting (May 11, 2022). Available at: http://www.oasis.oati.com/woa/docs/DUK/DUKdocs/May_11,_2022_DEC_&_DEP_Stakeholder_Meeting_Presentation.pdf.

[3] *Id*. at 8.

Figure 4: Generator Replacement Request Interconnection Cost Savings ($/Year)



1.2 Use the Surplus Interconnection Service Alternative Interconnection Pathway to Install Low-Cost Energy Storage Resource at the Sites of Duke's Remaining Generation Fleet

Like Generator Replacement Requests, Surplus Interconnection Service provides another alternative interconnection strategy that the Companies' Carbon Plan overlooks. This FERC-approved process allows a new resource to co-locate at the existing facility's point of interconnection, with energy injection split between the resources up to the maximum output level for the existing facility.[4]

For example, the Companies could install a 100 MW battery or hybrid resource at the site of an existing 100 MW NGCT. Either resource or both could inject energy onto the grid so long as the aggregate output does not exceed 100 MW. Surplus Interconnection Service interconnection studies occur outside the conventional queue process and takes about 255 days to complete. Therefore, it provides a viable means of expediting the deployment of new technologies like energy storage necessary for reliability as reliance on renewable resources grows. Because the new resources rely on the existing generator's interconnection facilities, it lowers the Carbon

[4] Duke Energy LGIP Sec. 4.3

Plan's transmission costs. Using the Companies' nearly 5 GW of existing peaking units for Surplus Interconnection Service requests could reduce interconnection costs by up to $500 million.

1.3 Expand Interregional Energy Imports to Source Additional Renewable Generation & Provide a Viable Alternatives to Developing New Gas Fired Generation If Necessary for Reliability

Importing capacity from external resources provides a meaningful opportunity to accelerate the Companies' transition to a cleaner resource mix and potentially reduce costs to ratepayers. The Duke Carbon Plan significantly discounts the potential to import wind and other resources. Our Preferred Portfolio increases the ability for capacity imports to levels that are likely viable without significant transmission upgrades per a recent study from the North Carolina Transmission Planning Collaborative ("NCTPC").[5] This change accelerates the ability for procurement of carbon-free midwestern wind resources that helps eliminate the need for new Natural Gas Combined Cycle ("NGCC") investment and reduces the need for new Natural Gas Combustion Turbines ("NGCT"s) relative to the Companies Portfolio 1. It also delays any new gas deployment until 2029, providing an opportunity to more fully evaluate alternative procurement strategies that rely on carbon-free sources instead of gas.

Increasing import capability increases reliability by accessing a diverse mix of supply resources from a broad geographic area. The Companies' Carbon Plan recognizes the reliability benefits of interregional imports. Its 2020 Resource Adequacy Studies show how the state's minimum reserve margin increases with a lack of assistance from neighboring utilities.[6]

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[5] NCTPC Public Policy Study at 5.
[6] Duke Carbon Plan Attachment I & II

1.4 Correct Flaws in the Companies' Capacity Expansion Modeling Assumptions that Bias Toward Procurement of Natural Gas & Against Renewable Resources

The figure below shows that the Companies' capital cost estimates for new gas generators, as provided in Duke's responses to discovery requests, appear much less costly than those from publicly available cost benchmarks for comparable resource types, as developed by multiple industry-leading cost analyses from the U.S. Energy Information Administration ("EIA")[7], the National Renewable Energy Laboratory ("NREL")[8], Lazard[9], and The Brattle Group ("Brattle").[10] This analysis demonstrates that the Duke Carbon Plan relies on unreasonable assumptions for new gas builds that are out of line with established market benchmarks.

Figure 5: Resource Cost Comparison

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

This analysis shows that market benchmarks for the average cost of new natural gas combustion turbine ("NGCT") builds are approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than Duke's average estimates for the same resource type. Similarly, market benchmarks for the average cost of new natural gas combined cycle ("NGCC") builds are approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than Duke's average estimates for the same resource types. If Duke used cost estimates for new gas generators that were more in line with established market benchmarks, it is unlikely that these

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[7] See EIA's 2022 Annual Energy Outlook at https://www.eia.gov/outlooks/aeo/.
[8] See NREL's 2022 Annual Technology Baseline at https://data.openei.org/submissions/5716.
[9] See Lazard's 2021 Levelized Cost of Energy Analysis at https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf.
[10] See Brattle's 2022 Cost of New Entry Report at https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf.

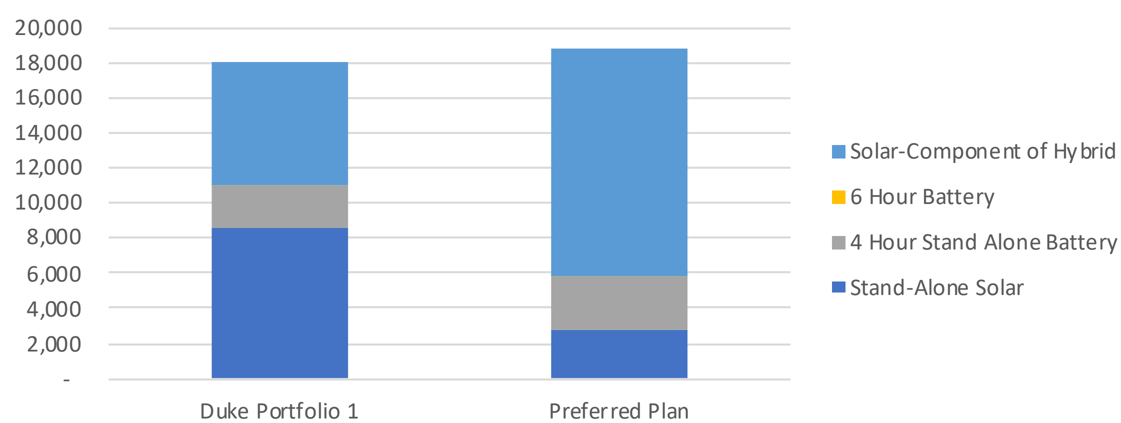
resources would be seen as a viable economic alternative to new renewable generators, as discussed further below.

1.5 Correct Flaws in the Companies' Capacity Analysis that Prevent the Capacity Expansion Model from Recognizing the Energy, Capacity, & Reliability Benefits that Solar Plus Storage Hybrids Provide

Solar plus storage hybrids provide a unique opportunity to harness carbon-free renewable generation in a dispatchable resource that is better able to provide energy, capacity, and ancillary services to meet demand. These characteristics allow hybrid resources the optionality to meet the state's needs relative to stand-alone renewable generation.

However, the Companies' elected to override the capacity expansion model's economic dispatch optimization and manually selected internally developed assumptions that eliminated the ancillary services and flexibility benefits that the storage portion of hybrids provide. The Companies' decision arbitrarily decreases the competitiveness of hybrid resources relative to other technologies like NGCTs in their Carbon Plan. Our analysis corrects this shortcoming and allows the model to capture the full value that hybrid resources provide. This change expands the storage and hybrids in the Preferred Portfolio by about 6 GW more than Portfolio 1 of the Companies' Carbon Plan. This strategy also builds a more flexible and dispatchable resource mix than the Companies' proposal. It can provide reliability and ancillary services that the grid needs without overreliance on new gas-fired generation.

Figure 6: Comparison of Hybrid and Storage Deployment in 2035



1.6 Defer Any Decision on Investment in New Gas-Fired Generation Until a Future Proceeding

The Commission should reject the Companies' request to pursue development and procurement activities for 800 MW of new NGCTs and a new 1,200 MW NGCC in this proceeding based on their assumed need in 2027 and 2028. The Companies' plan includes conversion of these resources to hydrogen beginning in 2035 as the Companies progress toward achieving carbon neutrality by 2050.

However, as shown in the figure below, the Preferred Portfolio achieves the state's carbon reduction target in 2030 by installing only about 350 MW of new NGCTs in 2029. Our sensitivities show that alternatives like offshore wind and incremental imports of renewable resources from external areas may eliminate the need for new gas generation. These results demonstrate that the Commission can reasonably defer the decision on any near-term development activities until a future proceeding and allow time for the Companies to pursue a more fulsome evaluation of carbon-free alternatives.

Figure 7: Comparison of Resource Additions by Technology Type ("MW")

[BEGIN CONFIDENTIAL]

Resource Additions	Preferred Portfolio	Duke Portfolio 1	Delta
NGCT	376	[redacted]	
NGCC	-		
SMR	-		
Onshore Wind	1,200		
Offshore Wind	-		
Standalone Solar (2026+)	2,727		
Solar + Storage Hybrid Resources	12,975		
4-hr Battery	3,075		
6-hr Battery	50		
Pumped Storage Hydro	1,680		
Total	**22,083**		

[END CONFIDENTIAL]

Moreover, the Companies' analysis shows that the new NGCCs in their Carbon Plan solve a transient need for energy from about 2028 to 2032 when renewable deployment reaches sufficient levels to displace their output. The figure below shows this result using the Companies' NGCC generation output data and is consistent with the same trend for the gas units in our analysis. The generation output for both units **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Figure 8: Duke P1 Combined Cycle Production

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

These results demonstrate the risk that investment in these assets now exposes customers to upwards of $700 million NPVRR of potential costs of stranded gas-fired assets. Our Preferred Portfolio eliminates the NGCC entirely and reduces all gas-fired generation in the Carbon Plan by nearly 3.2 GW, significantly reducing this potential risk to customers.

1.7 Unlock Opportunities for Commercial & Industrial Customers to Accelerate Decarbonization & Provide Additionality

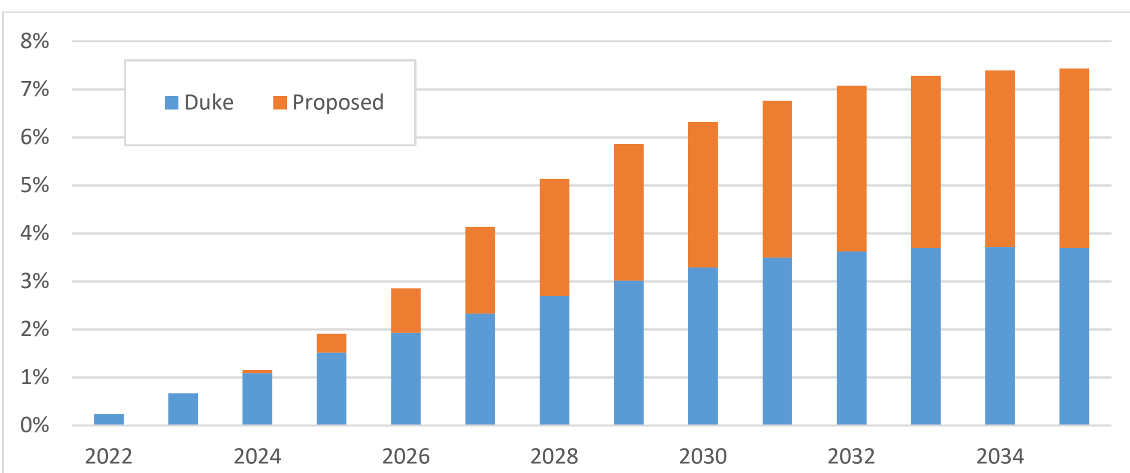
The Commission should direct Duke to develop and propose new program offerings that would unlock commercial and industrial customer activity to contract with new renewable energy projects in North Carolina or any other state where the participating customer can arrange transmission into the applicable Duke service territory. These offerings would have the customer contract for and pay the power supply cost from a new renewable project. This contract purchase would be coupled with a requirement that the customer pays for delivery service through the Duke system at rates set by the Commission and embedded in Duke's tariff. Through this structure, participating customers would not be subsidized by Duke or its other customers. Establishing these programs for commercial and industrial customers will enhance the attractiveness of doing business in North Carolina.

1.8 Utilize Energy Efficiency to Reduce Energy Demand & System Costs

Energy efficiency represents a distributed means of realizing capital and operational savings for customers. When deployed and evaluated as a system resource, energy efficiency is a lower cost resource than a traditional generation and reduces load for no operating or fuel costs.

Our plan expands the utilization of energy efficiency to meet the system's needs to a more reasonable level. Building on various studies and sources, including a 2020 study by ACEEE, which found that an 11.1% load reduction was achievable, a load reduction from energy efficiency of 7.7% by 2030 was used in our analysis. The graph below illustrates the cumulative energy efficiency savings contained in the Companies' Carbon Plan in blue, with the additional cumulative energy efficiency savings stacked in orange for each year through 2035.

Figure 9: Proposed Cumulative Energy Efficiency Savings (% energy consumption)



Achieving this level of savings will require substantial additional effort by Duke to implement a host of customer-focused marketing and programs which have demonstrated success elsewhere.

As part of this effort, the Commission should evaluate energy efficiency against supply-side resources to fully recognize its potential to provide customer cost and emissions savings. The Companies ask for this very relief in their Carbon Plan, stating, "the Companies will need to modernize the current framework for appropriately valuing demand-side DERs so that EE and other demand-side customer programs are evaluated on par with zero-carbon supply-side alternatives."[11] If compared directly against the resource options proposed in Duke's Carbon Plan, energy efficiency would likely be dispatched to well beyond the technical potential identified in the Companies' market potential study.[12]

1.9 Increase BTM Solar Deployment

The Carbon Plan should increase the deployment of behind-the-meter ("BTM") solar to fully achieve the goals of HB 951. The Companies' Carbon Plan is limited with respect to BTM solar generation, comprising only 1% of total load by 2037, which is overly conservative and underutilizes this important market segment. The Commission should direct Duke to develop and propose a best-in-class BTM renewable/storage program that accelerates distributed energy resource deployment, emphasizing onsite storage/hybrid resources. Based on a review of programs and results in other states, where programs and increased marketing have led to saturation as high as 10% of load, the Commission should establish a target of 5% of total load served by BTM solar by 2037. This resource provides effective carbon reductions and reduces energy costs to customers. It also mitigates the challenges Duke faces with interconnecting significant amounts of new utility-scale generation assets to their transmission system.

[11] Duke Carbon Plan Appendix G, at 12.
[12] Duke Carbon Plan Attachment IV.

1.10 Conclusion

The Preferred Portfolio identified herein is cheaper, less risky, and more likely to meet the carbon goals of the State. This Report identifies a series of policy measures that can increase the achievability of Duke's proposed Portfolio 1 while facilitating the transition to carbon-free technologies. Embracing the approaches and recommendations in this Report can help the Commission shepherd the successful implementation of HB 951.

Overall, the Preferred Portfolio allows for no new NGCCs development and reduces or potentially eliminates the need for new NGCTs. It also negates the need for immediate spending on SMR nuclear and hydrogen research and development. Our strategies allow for the possibility of earlier retirement of the highest CO2 emitting resources, emphasize meaningful customer programs, propose a comprehensive and transparent transmission planning process, and consider the possibility of additional market purchases.

While the Preferred Portfolio represents an approach that is beneficial over Duke's Portfolio 1, it is not the only pathway that could realize savings while furthering the goals of the State and the Commission. The Preferred Portfolio contains a small amount of NGCT investment in 2029. The horizon for this investment allows the Commission and Duke to forestall any commitments until there is a clearer picture of the actual landscape that far out. Removing new gas-fired generation from the portfolio (i.e., no NGCCs or NGCTs) may still present a less costly portfolio and further increases emissions savings relative to Duke's Portfolio 1. Similarly, increasing offshore and onshore wind into the footprint also represent viable options that can realize savings relative to Duke's Portfolio 1 and better aligns the Carbon Plan with the goals of HB 951.

Appendix A: Technical Analysis

1 Recommended Approach for Developing a Feasible, Cost-Effective Carbon Plan

The recommendations for the Preferred Portfolio address the issues and challenges of the Duke Carbon Plan using approaches, programs, and technologies shown to be viable and cost-effective. This approach emphasizes that the need for strategic planning for investment in transmission and generation interconnection facilities is a prudent and proven strategy that accelerates decarbonization while maximizing consumer benefits. We acknowledge that various practical uncertainties mean the Companies' actual procurement strategy will undoubtedly differ from the resource mix we propose in this Report. Nonetheless, our Preferred Portfolio demonstrates the value of these recommendations and adaptability to any scenario underpinning the Companies' ultimate Carbon Plan.

1.1 Develop a Holistic, Portfolio-Based Transmission Expansion Plan through the NCTPC

Duke did not engage in a holistic portfolio and scenario-based planning process or optimize its transmission strategy to address public policy and reliability needs. Instead, each transmission and interconnection investment category was developed piecemeal and integrated into the Duke Carbon Plan. The cost assumptions that flow from Duke's piecemeal approach impact the modeling of Duke's four scenarios and the reasonableness of the cost impacts provided by Duke's modeling results.

Numerous examples show that a coordinated, portfolio-based transmission planning strategy is a proven means of increasing renewable generation resources, facilitating decarbonization, and reducing consumer costs. The lack of a proactive and coordinated approach indicates that the Companies' Carbon Plan may not provide the optimal least-cost pathway for achieving the State's emissions reduction goals. Managing new generation interconnection study processes and costs is the biggest challenge the Companies face in implementing the Carbon Plan.

The figure below shows each portfolio's and utility's total transmission costs in 2030 and 2035, respectively. The Companies estimate that an additional $7 billion or more in long-term transmission expansion is necessary to achieve carbon neutrality by 2050.[13] Notably, these costs are incremental to any baseline transmission needs that the Companies would identify through their conventional planning processes.

Figure 10: Transmission Cost Comparison by Scenario[14]

2030	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
DEC	777	626	581	480
DEP	1,847	1,561	1,115	1,285
Total	**2,624**	**2,187**	**1,696**	**1,765**

2035	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
DEC	1,686	1,663	1,630	1,460
DEP	2,743	3,098	2,132	2,403
Total	**4,429**	**4,761**	**3,762**	**3,863**

Recent prospective planning initiatives in the Mid-Continent ISO ("MISO") and Southwest Power Pool ("SPP") demonstrate the value of a coordinated, portfolio based planning strategy. Earlier this year, MISO approved a portfolio of transmission projects that unlock over 20 GW of otherwise non-viable renewable resources, which will significantly reduce regional carbon emissions *and* consumer costs. The estimated $16.9 billion investment yields nearly $52 billion in net benefits to consumers, including $17.4 billion in decarbonization savings which the portfolio achieves by accessing high-value renewable resources over a larger geographic area.[15] By comparison, the Companies' Carbon Plan proposes investing over $10 billion in transmission and infrastructure without leveraging this proactive planning strategy to maximize consumer benefits.

SPP's recent Value of Transmission report demonstrates how portfolio-based transmission planning can accelerate renewable deployment and lower interconnection costs.[16] The study found that transmission expansion during 2015-2019 optimized the deployment of about 7,400 MW of high-value wind resources to lower interconnection costs and avoid local

[13] Duke Carbon Plan – Appendix P at 21.
[14] *Id*. at 19-20.
[15] MISO LRTP Tranche 1 Portfolio April 29, 2022.
[16] See Value of Transmission 2021 at 17. Available at: https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf

upgrades. From 2020 through 2029, SPP estimates that the avoided interconnection costs and other benefits will exceed the portfolio's annual revenue requirement by nearly $7 billion, with $2.3 billion derived from optimal wind deployment.

The infrastructure necessary to develop a comprehensive transmission investment strategy already exists. The Companies correctly point out that the NCTPC produces a single *coordinated* transmission plan annually that "appropriately balances costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources" to meet the State's needs.[17] Therefore, the Commission should leverage the value of this existing opportunity by directing the Companies to develop a coordinated, portfolio-based transmission plan with the NCTPC.

1.2 Combine Holistic Transmission Planning with Resource Procurement Strategies Which Maximize the Value of Capacity Imports from Neighboring Regions

The Duke Carbon Plan does not meaningfully contemplate procuring firm, long-term supply from external resources even though the Companies are "directly connected" to ten Transmission Operators across 78 tie-line circuits with additional transfer capacity available to help meet the Companies' internal energy demands over time.[18] [19] There is more than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of total import transfer capacity from these areas into the Companies' service territories,[20] equating to nearly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of clean energy import potential per year. These resources should be more aggressively explored and used.

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[17] Duke Carbon Plan, Appx. P, at 8.
[18] See Duke Carbon Plan, Appx. C, at 2
[19] Interconnected balancing authorities include the Tennessee Valley Authority ("TVA"), Southern Company ("SOCO"), PJM West &PJM South, Yadkin ("YAD"), Dominion Energy South Carolina (formally known as South Carolina Electric & Gas ("SCEG")) and Santee Cooper ("SC"). See Duke Carbon Plan, Attachment I, at Figure 1.
[20] See Duke CONFIDENTIAL Response to NCSEA et al. DR 3-52 (Transmission Capability) (Index No. 1.10.17.1.18).

Increasing the procurement of external power supply can also accelerate the Companies' progress toward meeting or exceeding the State's carbon reduction targets by mitigating project development and interconnection uncertainty in contracting with existing resources or by reducing the need for costly and lengthy transmission upgrades by contracting with resources that are or can be developed in less constrained transmission and distribution pathways outside of the Companies' service territories. For example, there are about 5,000 MW of renewables, storage, and hybrids in currently PJM's interconnection queue that are under development in North Carolina.[21] This total includes 300 MW of wind and about 900 MW of solar that have completed the study process or will complete it by 2023. Another 3,200 MW will complete the study process by 2025. This example shows the potential to accelerate renewable deployment through external resources.

Additional existing resources outside North Carolina were assumed to be imported from neighboring transmission operators. The Companies' Carbon Plan assumed 600 MW of wind imports to DEC. However, NCTPC analysis suggests that the Companies could accommodate 2,500 MW of wind imports without additional cost. [22] We assumed the 2,500 MW of wind, although the Companies should evaluate increasing import capabilities for other renewable options.

We also note that the Companies currently have a 1,000 MW long-term firm transmission request actively under study in PJM's interconnection queue with a commercial operations date of 2027, suggesting the import cost may not be as burdensome as the Companies assume.[23] This transmission reservation could allow the Companies to access over 5,000 MW of wind, solar, and energy storage under development in North Carolina alone that will complete PJM's interconnection study process between 2022 and 2027. It could also import other forms of generation, should they prove necessary for reliability, and avoid the cost and risk of stranded assets for the new NGCCs and NGCTs currently in the Companies' Carbon Plan.

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[21] See https://www.pjm.com/planning/services-requests/interconnection-queues.aspx.
[22] NCTPC Public Policy Study at 5.
[23] See Long-Term Firm Transmission Service Request No. AI1-034 5180926. Available at: https://www.pjm.com/planning/services-requests/interconnection-queues.

While this option could alleviate supply chain and interconnection constraints by sourcing power from existing resources outside of the Duke service territory and increase the likelihood that Duke will be able to reach its emissions reductions targets, it can also result in significant cost savings for ratepayers because the cost of buying power from internal new gas builds is higher than the cost of purchasing power from external solar capacity even when including a border charge for the imported supply. By way of example, whereas the average levelized cost of energy for new combined cycles equates to approximately $51/MWh,[24] the average levelized cost of energy plus a border charge for new solar equates to about $42/MWh.[25] The difference between these two values, $9/MWh, implies annual cost savings of nearly $350 million, assuming Duke uses the total amount of the transfer capacity specified above.

Furthermore, while border charges for cross-state interchanges would add costs to energy imports, joining PJM or another RTO could eliminate such charges and result in significant cost savings. Being part of PJM's fully integrated transmission system and its vibrant wholesale market can expand access to renewable resources outside of North Carolina, which may have lower development costs or higher energy generation potential. Greater interregional connectivity with neighboring regions and sourcing generation over a broader geographic area also enhances reliability and resiliency, particularly during extreme weather events, which are becoming more common. For example, PJM exported nearly 1.7 million MWh to neighboring regions during Winter Storm Uri, of which 6% was delivered to the Companies.[26]

Based on these considerations, the Commission should direct the Companies to revise their planning and procurement process to consider the benefits of procuring external assets. There is substantial national evidence that being part of a wider integrated power pool offers significant reliability and economic benefits. The Commission should also direct the Companies to

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[24] See EIA 2022 Annual Energy Outlook, Table 1.a at https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf. See also Lazard 2021 Levelized Cost of Energy Analysis at https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf.
[25] cite
[26] Winter Operations of the PJM Grid: December 1, 2020 – February 28, 2021 (August 8, 2021. Available at: https://pjm.com/-/media/committees-groups/committees/oc/2021/20210408/20210408-item-14-winter-operations-review.ashx.

conduct a study on the costs and benefits of joining a competitive wholesale market like PJM and set a timeframe for its submission by Duke and review by the Commission.[27]

1.3 Utilize Reasonable and Well Supported Capital Cost Assumptions in Developing an Optimal Resource Mix

The EnCompass capacity expansion model seeks to select the optimal resource mix needed to meet the Companies' reliability requirements and emissions reduction goals at the lowest overall cost. Therefore, resource cost assumptions significantly impact the modeling results, as cheaper resources will be built sooner instead of more expensive resources, all else being equal. This dynamic is critical because the Companies' analysis overstates the capital costs of new renewable energy generators and understates the capital costs of new gas-fired generators. This faulty assumption creates the false impression that higher-emitting thermal power plants are a better option than renewable resources for advancing the State's emissions reduction goals.

The figure below shows that the Companies' capital cost estimates for new gas generators, as provided in Duke's responses to discovery requests, appear much less costly than those from publicly available cost benchmarks for comparable resource types, as developed by multiple industry-leading cost analyses from the U.S. Energy Information Administration ("EIA")[28], the National Renewable Energy Laboratory ("NREL")[29], Lazard[30], and The Brattle Group ("Brattle").[31] This analysis demonstrates that the Duke Carbon Plan relies on unreasonable assumptions for new gas builds that are out of line with established market benchmarks.

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[27] See Act No. 187 of 2020 Session of South Carolina Legislature (H.B. 4940) (calling for study of benefits of various market participation options).
[28] See EIA's 2022 Annual Energy Outlook at https://www.eia.gov/outlooks/aeo/.
[29] See NREL's 2022 Annual Technology Baseline at https://data.openei.org/submissions/5716.
[30] See Lazard's 2021 Levelized Cost of Energy Analysis at https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf.
[31] See Brattle's 2022 Cost of New Entry Report at https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf.

Figure 11: Resource Cost Comparison

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This figure shows that market benchmarks for the average cost of new natural gas combustion turbine ("NGCT") builds are approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than Duke's average estimates for the same resource type. Similarly, market benchmarks for the average cost of new natural gas combined cycle ("NGCC") builds are approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than Duke's average estimates for the same resource types. If Duke used cost estimates for new gas generators that were more in line with established market benchmarks, it is unlikely that these resources would be seen as a viable economic alternative to new renewable generators, as discussed further below.

The figure below compares the Companies' capital cost estimates with publicly available cost benchmarks for comparable resource types. This analysis shows that the Companies' 2022 capital cost assumptions for new NGCT and NGCC resources are more than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than the EIA and NREL estimates. Conversely, the Companies assume solar will be nearly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than the EIA and NREL estimates. Duke's assumed cost disparity artificially increases the justification for new gas generations to be built in the near term instead of solar. Because power plants have long service lives, building more gas resources now will have lasting impacts that extend decades into the future.

Figure 12: Comparison of EIA & NREL Capitals Cost Proxies to Carbon Plan Assumptions in 2022

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While the figure below shows that the Companies' NGCT and NGCC assumptions converge with the EIA and NREL benchmarks, the discrepancy increases for solar and wind resources. By 2037, the Companies' capital cost assumptions for solar and wind exceed the EIA and NREL proxies by nearly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** respectively. Because Duke's capital cost estimates unreasonably "tip the scales" in favor of gas-fired generation, there is too much gas generation and a lesser, sub-optimal amount of renewable generation in Duke's modeling. This modeling issue artificially limits the pathway for Duke to reach the emissions reduction targets of HB 951.

Figure 13: Comparison of EIA & NREL Capital Costs to Carbon Plan Assumptions in 2037

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To forecast new resource build costs, we utilized the same methodology and modeling framework as the Companies,[32] but relied on different cost inputs based on the more representative market benchmarks outlined above. This entailed the development of annual installed costs and associated fixed charge rates by resource type using the Companies' "Calculations and detailed support for the fixed charge rates" data files.[33] The cost inputs used for these calculations were based on EIA's forecasted "Overnight Capital Costs for New Electricity

[32] As provided in response to discovery request NCSEA *et a*l. DR 3, 3-4.
[33] *Ibid*.

Generating Plants" under the "Reference Case" scenario, adjusted to account for regional cost differences for the "SERC Reliability Corporation/East" area using EIA's "Total Overnight Capital Costs of New Electric Generating Technologies by Region" from the 2022 Annual Energy Outlook.[34]

1.4 Continuously Monitor and Update Assumptions of Fuel Costs, Particularly Natural Gas, to Assure Best Available Information is Captured in Analysis

Natural gas fuel costs are a primary factor for determining which resources the Companies' capacity expansion model selects. The Companies' forecast includes the cost of natural gas commodity priced at the Henry Hub index and a basis adjustment priced at either Transco Zone 4, Transco Zone 5, or Tetco M2.[35] Henry Hub commodity prices were forecast based on forward market prices at the time of development and a quartet of fundamental analyses sourced from the Energy Information Administration's 2021 Annual Energy Outlook ("EIA AEO"), Wood Mackenzie ("WoodMac"), Energy Ventures Analysis ("EVA"), and IHS Markit ("IHS").[36] However, subsequent shifts in gas market fundamentals have impacted natural gas prices to such a degree that the Companies' forecast is no longer reasonable and should be revised to align with current market conditions.

The dramatic change in natural gas prices is evidenced in Henry Hub forward trading settlements. The figure below illustrates the difference in Henry Hub gas commodity prices using the same data as the Companies' forecast.[37] The current forwards range from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than the forwards used by the Companies in early 2023 to **[BEGIN CONFIDENTIAL],** [redacted] **[END CONFIDENTIAL]** in 2030. On average, the current forwards are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than those used by the Companies; that means that for every dollar

[34] Accessed at U.S. Energy Information Administration - EIA - Independent Statistics and Analysis
[35] Delivery costs are also present for many resources; however, the delivery costs are typically less variable and represent only a fraction of the cost of natural gas.
[36] See Companies' Response to NCSEA *et al*. DR 3-37.
[37] NYMEX Henry Hub forwards as of June 22, 2022.

the Carbon Plan ascribes to natural gas purchases, customers will pay **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** based upon current forwards.

Figure 14: Henry Hub Commodity Price Comparison to Carbon Plan Forecast

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Forward trading settlements are a commonly used metric for determining the price of natural gas in the future because they represent the actual price at which market participants are buying and selling natural gas for delivery in the future. The Companies recognized this as they used solely natural gas forwards in their forecast through 2027.[38,] Beyond 2027, the Companies blend forward market prices into the arithmetic average of the fundamental forecasts from EIA AEO, WoodMac, EVA, and IHS over three years. Beginning in 2030, the Companies' forecast relies solely on fundamental forecasts. While the ultimate impact of factors like inflation, supply chain shortages, the state of the local and national economy, and Russia's invasion of Ukraine is

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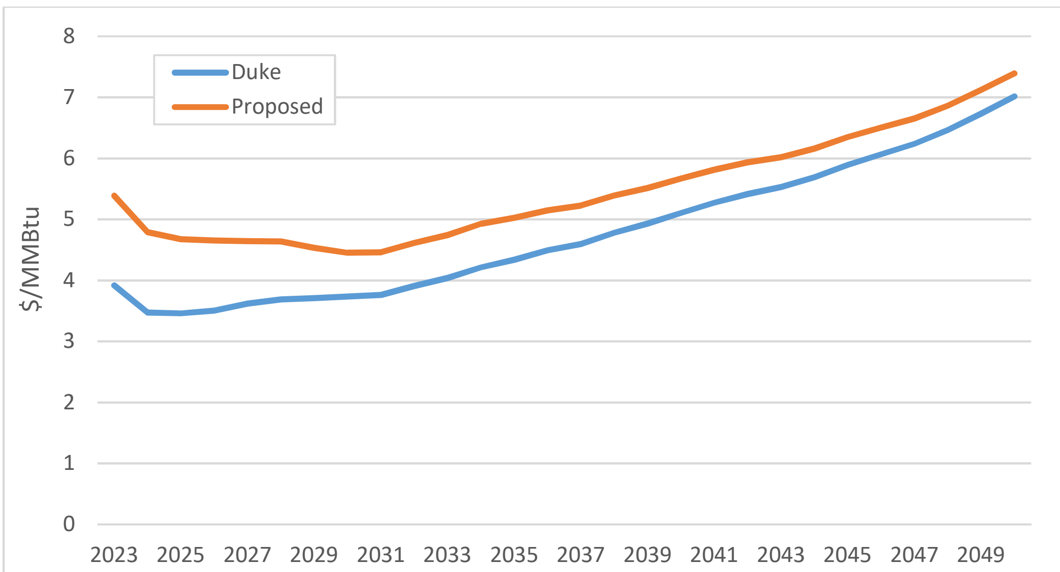
[38] See Companies' Response to NCSEA *et al*. DR 3-37. The Companies also relied on dated transportation basis assumptions that also do not align with current market forward trading settlements. Basis delivery adders in the Companies' analysis were supplied from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** this forecast is out of line with market settlements and again offers an unrealistic expectation of future transportation basis costs. The revised modeling in this Report uses current market gas forwards.

unknown, it is evident that gas market fundamentals are significantly different from those reflected in the Companies' forecast. This reality raises questions about the reasonableness of the Companies' projections that drive their capacity expansion modeling results.

To forecast natural gas costs, we utilized the same methodology and comparable inputs as the Companies but with more current market data.[39] This entailed using current market forward prices and blending them into long-term fundamental forecast escalations. This methodology was used for both Henry Hub commodity and transportation basis. The following graphic illustrates the comparison between the Henry Hub commodity forecast provided by the Companies and the one developed for this analysis using current market data.

Figure 15: Revised Henry Hub Forecast



As described above our forecast used Henry Hub commodity and transportation basis forwards as of June 2020. We also leveraged the Companies' fundamental gas price forecasts, with adjustments to account for changing market fundamentals, in the longer-term Henry Hub commodity and transportation basis price forecast.

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[39] As described in response to discovery request NCSEA *et a*l. DR 3-37.

1.5 Accelerate Coal Retirements to 2030

Coal-fired generation is the single largest source of carbon emissions in the Companies' fleet. Accelerating their retirement is a tangible step towards decarbonization and unlocks the opportunity to interconnect new renewable resources and storage at these sites.

Although the Companies used capacity expansion modeling to identify potential coal unit retirement dates, these dates are often overridden. That is, the final retirement dates assumed for Portfolio 1 differ from the modeled results for nine out of 14 coal units, and for five of these units the manual adjustments delayed retirement by at least two years. The Belews Creek units are not allowed to retire in the model before 2031 even though the Companies state that it can retire after 2026,

While external factors must be considered when evaluating modeling outcomes, such decisions must be made transparently and on the best available data to support such conclusions. For example, the Companies' second supplemental response to discovery request AGO DR 4-7 states that "the capacity expansion model endogenously selected the retirement of Belews Creek in 2030 for portfolio P1, 2032 for P2, and 2038 for P3 & P4."[40] **[BEGIN CONFIDENTIAL]** [redacted][41] **[END CONFIDENTIAL]** Thus, the model selected the earliest retirement date allowed. The Companies **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** earliest practicable date of 2029, which was identified in their IRP.

The chart below summarizes the retirement date assumed in the Companies' Carbon Plan compared to the earliest practicable retirement date provided in the Companies' IRP.

Figure 16: Coal Retirement Date Comparison

Unit	Utility	Earliest Practicable (IRP)	Earliest Planned Date in Carbon Plan	Preferred Portfolio Retirement Date
Allen 1	DEC		2024	2024
Allen 5	DEC		2024	2024
Belews Creek 1	DEC	2029	2036	2030

[40] Duke Second Suppl. Response to AGO DR 4-7.
[41] EnCompass files "HB951 Belews and Marshall 3 4 Opt retire 2031" and "HB951 Belews and Marshall 3 4 Opt retire 2033" included in the P1 and P2 retirement analysis.

Belews Creek 2	DEC	2029	2036	2030
Cliffside 5	DEC	2026	2026	2026
Marshall 1	DEC	2028	2029	2029
Marshall 2	DEC	2028	2029	2029
Marshall 3	DEC	2028	2033	2030
Marshall 4	DEC	2028	2033	2030
Mayo 1	DEP	2029	2029	2029
Roxboro 1	DEP	2029	2029	2029
Roxboro 2	DEP	2029	2029	2029
Roxboro 3	DEP	2028	2028-2034	2028
Roxboro 4	DEP	2028	2028-2034	2028

While acknowledging that actual retirement decisions must be taken with consideration of factors outside those available in the model, for purposes of our modeling exercise to illustrate hypothetical results that may be possible our analysis assumes all coal retirements dates by January 1, 2030, consistent the Companies' Carbon Plan schedule for retirements before 2030 and a latest retirement date of 2030 for the other facilities.

1.6 Defer Action on the Companies' Request to Procure New Gas Fired Generation until a Future Proceeding

The Companies request the Commission's approval in this proceeding of near-term development and procurement activities for 800 MW of new NGCTs and 1,200 MW of NGCCs.[42] They argue that approval is necessary now because their capacity expansion analysis shows that facilities are needed to replace the deactivating coal assets by 2028.[43] By 2035, the new gas generation in each portfolio will grow to at least 1,200 MW of new NGCTs and 2,400 NGCCs, all of which will convert to hydrogen fuel to achieve carbon neutrality by 2050.[44]

Across the Companies' portfolios, gas-fired generation provides about 25% of the system's energy and about 30% of its capacity by 2035, as shown in the figures below. After that,

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[42] Duke Carbon Plan Executive Summary, at 28.
[43] Duke Carbon Plan Execution Plan, at 5.
[44] Duke Carbon Plan Execution Plan, at 13.

the remaining 18 GW of gas-fired generation, representing about a quarter of the fleet's capacity, converts to hydrogen and supplies just 5% of the system's energy.

Figure 17: Energy Generation by Resource Type & Portfolio (TWh)[45]

Resource Type	2022	2030				2035				2050			
		P1	P2	P3	P4	P1	P2	P3	P4	P1	P2	P3	P4
Other Renewables	2%	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%
Offshore Wind	0%	2%	2%	0%	0%	2%	3%	0%	2%	1%	6%	0%	1%
Onshore Wind	0%	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%
Solar	6%	18%	14%	15%	14%	26%	21%	21%	20%	29%	27%	28%	27%
Nuclear	47%	45%	45%	45%	45%	46%	46%	46%	46%	62%	61%	64%	64%
Gas	32%	32%	33%	35%	35%	23%	26%	29%	28%	0%	0%	0%	0%
Hydrogen	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%	4%	5%	5%
Coal	13%	1%	3%	3%	3%	1%	1%	1%	1%	0%	0%	0%	0%

Figure 18: Capacity Supply by Resource Type & Portfolio

Resource Type	2022	Portfolio 1		Portfolio 2		Portfolio 3		Portfolio 4	
		70% CO2 Red.	Net Zero	70% CO2 Red.	Net Zero	70% CO2 Red.	Net Zero	70% CO2 Red.	Net Zero
Grid Edge	4%	5%	3%	4%	4%	4%	3%	4%	4%
Other Ren.	3%	3%	2%	2%	2%	2%	2%	2%	2%
Off. Wind	0%	2%	1%	3%	4%	0%	0%	1%	1%
On. Wind	0%	1%	2%	2%	2%	2%	2%	2%	2%
Solar	11%	23%	31%	22%	29%	25%	29%	24%	29%
Storage	5%	7%	14%	6%	13%	9%	13%	9%	13%
Nuclear	20%	18%	24%	17%	25%	17%	25%	17%	25%
CC / CT	35%	35%	23%	33%	22%	32%	25%	32%	24%
Coal (incl. DFO)	21%	8%	0%	10%	0%	8%	0%	8%	0%

Moreover, the Companies assume that existing gas infrastructure will begin incorporating hydrogen fuel into some of the gas facilities by 2035.[46] On-site hydrogen production or distribution from a new "hydrogen hub" allows all the Companies' NGCTs to transition off natural gas by 2040. The remaining NGCCs will convert to hydrogen by 2050. However, the Companies' capacity expansion modeling erroneously excluded the cost of hydrogen conversion from its analysis. It is unclear whether their analysis includes the capital expense necessary to develop the

[45] See Duke Response to Non-Confidential PSDR1-7.
[46] Duke Carbon Plan Appendix O, at 3.

fuel production and delivery infrastructure. Accordingly, the hydrogen conversion is too speculative to use in the Plan.

The Companies' request for immediate commitment to new natural gas generation is not necessary at this time. As explained later, our modeling shows that new gas generation is not needed until at least 2029 and may not be necessary at all. Future investment in other technologies like battery storage could satisfy the capacity need instead of the gas-fired generation that the Companies seek to develop here. Approving the Companies' investment in gas generation now exposes customers to an unreasonable risk of stranded costs, especially in light of the Companies failure to account for hydrogen-conversion costs.

1.7 If Future Analysis Shows Gas-Fired Generation is Needed for Reliability, the Commission Should Direct that the Companies Exhaust Options to Contract with Existing Resources Before Approving Development and Procurement of New Ones

Duke should exhaust all possible non-emitting options before investing in new gas-fired generation. After all non-emitting options have been exhausted, the Companies should explore shorter-term commitments with existing resources that can defer significant investments in gas-fired generation. By forestalling these commitments, the Companies will preserve the ability to make agile decisions that more closely align with HB 951 and may also avoid stranded costs.

Rather than building new, expensive facilities, Duke should utilize existing resources in North Carolina as a stop-gap to reduce the possibility of stranded assets and to give more time to make decisions as the market evolves. There are three resources in North Carolina with which the Companies already contract for a portion of the output and capacity: Cleveland CT, Rowan CT, and Rowan CC. We analyzed the impact of the Companies expanding the contracted capacity with each of these resources from only a portion of their capacity to the total available generating capacity. The graphics below illustrate the capacity for each resource assumed in the Companies' analysis and the additional available capacity based upon the available termination dates of existing power purchase agreements ("PPAs") for each resource.

Figure 19: Overview of Expanded PPA Capacity

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Expanding the contracted capacity with these three resources can add over 1 GW of capacity to the resource fleet without investing in new gas-fired facilities. Because these resources are currently contracted with other counterparties, we assumed a PPA price premium of 5% above the current contracted price with each resource.

In addition to the three resources listed above, other potential existing in-state resources could help the Companies meet load requirements. These include hydro and wind resources that could further decrease the need for investment in new resources. This approach would also minimize the risks of realizing the Carbon Plan, as these assets are already constructed and are not impacted by construction risk, supply chain risk, interconnection risk, or other risks associated with developing new resources. The Commission should direct Duke to evaluate the potential to accelerate the retirement of legacy thermal generation assets through acquisition/PPAs with existing renewable generation. If gas is necessary for reliability, the Commission should direct Duke to evaluate whether contracting with existing assets provides a more cost-effective alternative to building new NGCT/CCs.

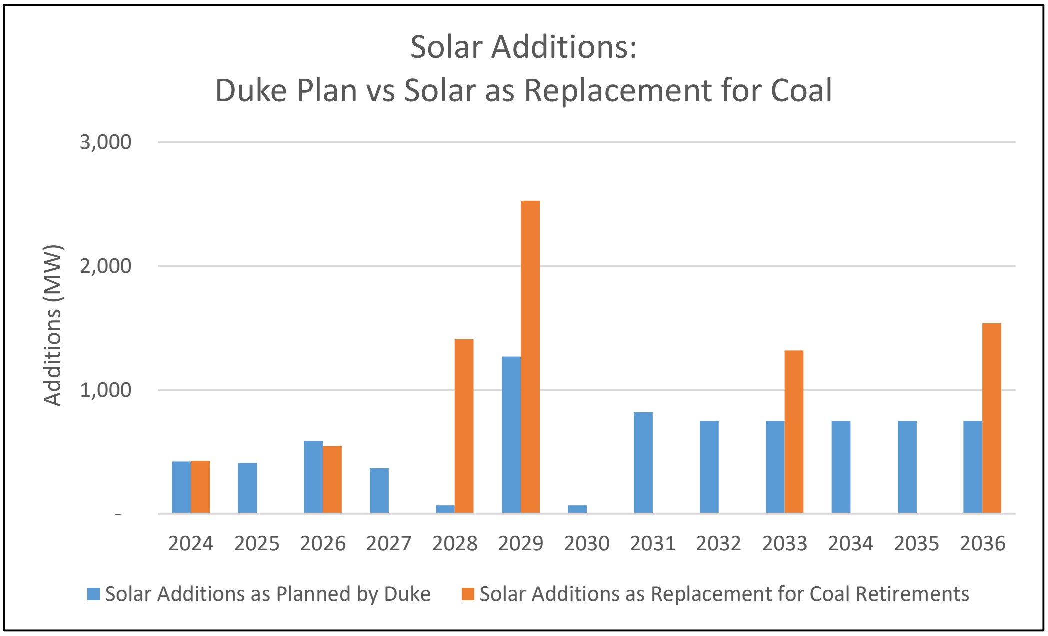
1.8 Relieve Pressure on the Conventional Interconnection Process by Using Generator Replacement Requests to Deploy Renewable Resources & Storage at the Sites of the Companies' Deactivating Coal Units

The Companies recognize that rapidly interconnecting the unprecedented amount of new renewable generation resources that the Carbon Plan requires is the most significant impediment to achieving the State's carbon reduction goal by 2030.[47] Their conventional interconnection study process involves lengthy analyses identifying transmission upgrades. The Generator Replacement Request process is one such pathway and could be better utilized in the Carbon Plan.

According to the Companies, Generator Replacement Requests provide a meaningful opportunity to utilize the 9,000 MW of impending coal retirements to deploy lower-cost renewable resources sooner. Instead, the Companies' Carbon Plan only proposes to use this process to develop their proposed NGCT and NGCC resources. Rather than using Generator Replacement Requests to construct carbon-emitting resources, Duke should reserve this interconnection capacity for renewables and mitigate some of the interconnection issues highlighted throughout their Carbon Plan.

[47] See, e.g., Duke Carbon Plan, Appx. I – Solar

Figure 20: Coal Retirements vs. Solar Additions



This chart shows that solar can not only fill the capacity gap left by the retiring coal units but also interconnect at a much faster pace and with greater certainty than would otherwise be possible if Duke were to use the approach in its Carbon Plan. Notably, the solar additions as a replacement for coal retirements shown above are capped at Duke's proposed 8 GW of new solar capacity to maintain consistency with the Duke Carbon Plan. However, because more than 9 GW of coal will retire by 2036, there will be room for an additional 1 to 2 GWs of new solar to deploy on top of the 8 GW outlined above if Duke uses the Generator Replacement Request process for these new capacity additions.

In addition to the benefits outlined above, this approach can lower costs to Duke ratepayers. Generator Replacement Requests do not require additional network upgrades to interconnect to the grid, all else being equal. Based on Duke's assumptions for network upgrade costs, as specified in Table E-44 of the Carbon Plan, Duke could save about $1 billion on a present value basis just from the avoided network upgrade costs alone.

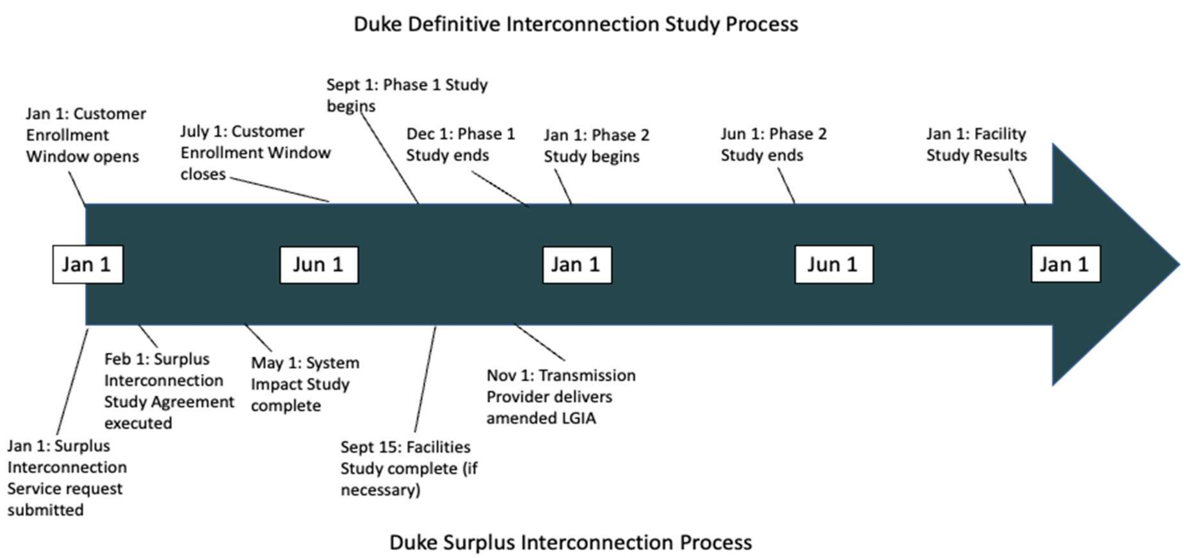
The Commission should direct the Companies to develop a plan to use the existing sites and the Generator Replacement Request process to accelerate renewable resource deployment. The Companies should be required to file the plan with the Commission within six months or explain why this option does not represent the least cost option for achieving the State's emissions reduction goals.

1.9 Use the Surplus Generation Interconnection Process to Deploy Renewable Generation Deployment at Sites of Existing Generation Resources

Like Generator Replacement Requests, Surplus Interconnection Service can accelerate the deployment of new renewable resources and storage at lower costs by using existing interconnection infrastructure. The Companies' Carbon Plan, though, does not use this existing process.

The Surplus Interconnection Service interconnection studies occur outside the conventional queue process and take about 255 days to complete. The chart below illustrates the expedited Surplus Interconnection Service timeline relative to the normal interconnection process.

Figure 21: Surplus Interconnection Process



The Companies currently own about 4.8 GW of NGCTs with average capacity factors of about 6% annually that present a potentially viable opportunity for new co-located renewable generation, energy storage, or hybrid resources using Surplus Interconnection Service.

Adding energy storage can also reduce the existing peaking unit's emissions and increase its operational performance. In 2017, Southern California Edison ("SCE") retrofitted ten MW, four MWh batteries at two existing aero-derivative peaking units. The battery allows the generator to start instantaneously and provide spinning reserves while the gas unit is offline without using fuel.[48] The additional flexibility is critical when responding to fluctuations in renewable generation output. It also reduced the number of times the peaker starts by half, which lowered its carbon emissions by about 60%.[49] This example illustrates how Surplus Interconnection Service can advance the State's decarbonization objectives using technologies that add ancillary services and flexibility to the grid. The Commission should direct Duke to develop a plan that uses Surplus Interconnection Service to deploy clean energy and storage at the sites of its existing thermal generators.

1.10 Expand Opportunities for Customers to Access Self-Sourced Renewable Energy to Support the Achievement of Carbon Reduction Goals with a Market-Based Program

The Commission should – consistent with Section 5 of HB 951 – examine opportunities to leverage customer demand for access to "green" energy and renewable energy credits by creating new programs that allow customers to procure energy and/or renewable energy credits directly from new renewable energy sources. We believe that substantial consumer demand exists for such programs.

The Commission has experience with similar programs, such as the Solar Rebate Rider, the Green Source Advantage Program, and its predecessor, the Green Source Rider. These programs serve to harness the desire of individual customers (in particular, C&I customers) to control their energy costs *and* reduce carbon emissions in support of personal or corporate goals. These efforts can significantly advance the carbon reductions required by HB 951 as demand is directly matched with supply. Relatedly, these programs help to make North Carolina a more

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[48] See https://energized.edison.com/stories/sce-unveils-worlds-first-low-emission-hybrid-battery-storage-gas-turbine-peaker-system.
[49] *Id*.

attractive location for businesses seeking to locate in a regulatory environment that facilitates corporate sustainability goals and initiatives.

One example of a customer-driven approach to reducing carbon emissions that have had positive results in another jurisdiction is the Renewable Generation Supply Service tariff of Dominion Energy.[50] This tariff allows commercial and industrial customers to sign renewable energy contracts to take energy from remote renewable facilities and deliver the energy through the Dominion tariff. Other examples of utilities with viable programs include Xcel Minnesota,[51] Portland General,[52] Georgia Power,[53] and MidAmerican Iowa.[54] Each of these programs has different structures but they each provide customers with the opportunity to control their energy supply choices. The most attractive programs are flexible in that they permit eligible customers to substantially or completely source load from green energy generation and they permit customers to receive the benefit of any negotiated discounts to standard service and/or provide a hedging benefit against price fluctuations.

Duke's Carbon Plan recognizes the benefits of these programs.[55] Therefore, the Commission should direct Duke to develop and propose new program offerings (and expand existing programs) that would unlock commercial and industrial customer activity to enter into power contracts with new renewable energy production projects located in North Carolina or any

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[50]See, https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/business-rates/compliance-filing-schedule-rg.pdf?la=en&rev=5645af752c1244a2b8dbeddb0ccb485d&hash=A94C39106607966AAAAC85FC011EDECF

[51] Order Approving Modified Load-Flexibility Pilots, Minn. Public Utils. Comm'n, Docket No. E-002/M-21-101 (March 15, 2022). (https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b70CD8E7F-0000-C61B-B078-53582B1BC1E4%7d&documentTitle=20223-183794-01); Order Approving Petition with Modifications, Minn. Public Utils. Comm'n, Docket No. 12-33 (Aug. 12, 2019) (https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D0A2866C-0000-C91A-87C1-AC1417111E24}&documentTitle=20198-155110-01).

[52] See https://portlandgeneral.com/energy-choices/renewable-power/green-future-impact.

[53] See https://www.georgiapower.com/company/energy-industry/energy-sources/solar-energy/solar/c-and-i-redi.html.

[54] See https://www.midamericanenergy.com/media/pdf/iowa-electric-tariffs.pdf

[55] See Duke Carbon Plan, Appx. G, at 17.

other state where the participating customer can arrange transmission into the applicable Duke service territory. These contracts would have the customer contract for and pay the power supply cost from a new renewable project. This contract purchase would be coupled with a requirement that the customer pays for delivery service through the Duke system at rates set by the Commission and embedded in Duke's tariff. Through this structure, participating customers would not be subsidized by Duke or its other customers.

Establishing such programs will unleash customers to help Duke reach or exceed its emission reduction targets.

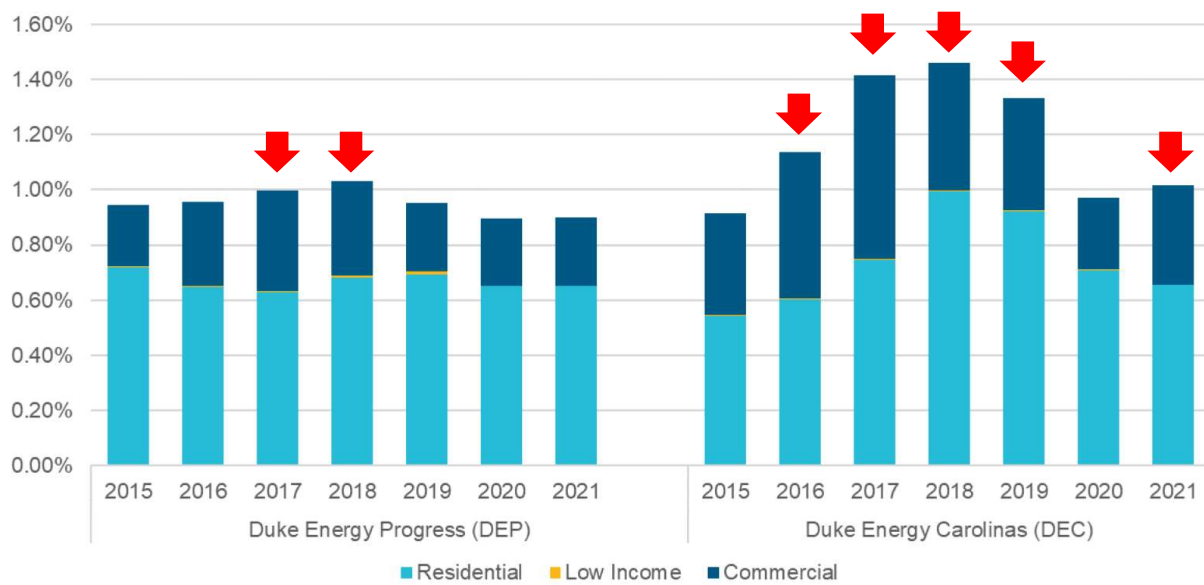
1.11 Increase Energy Efficiency Deployment for All Customers Throughout the Service Territories

Energy efficiency is a unique element in resource planning, and its deployment is a vital component of meeting the goals of HB 951 in a least-cost and reliable manner. It interacts with load, reduces the need for generation, and produces direct benefits (energy savings) to customers. While load reductions from individual energy efficiency measures may be small, the scale of measures installed and the lead time of many measures means savings compound over time, creating cumulative reductions in energy consumption and associated benefits.

Their Carbon Plan proposes reducing their load by 1% on an incremental annual basis.[56] Despite Duke's assertion that the "proposed Plan is built on a foundation that will require substantial advancement of EE in the Carolinas in unprecedented ways," the chart below shows that it only aligns with levels that the Companies achieved between 2016 and 2021.[57]

[56] *See* Duke Carbon Plan Appx. G – Grid Edge and Customer Programs.
[57] *See* Duke Carbon Plan Appx. G – Grid Edge and Customer Programs.

Figure 22: EE Deployment at or Above 1% Deployment Target by Year & Utility



This data shows that the Companies regularly reach the 1% incremental annual savings that the Carbon Plan seeks to achieve. Moreover, EIA data shows that this level of EE deployment would represent the 60th percentile of investor-owned utilities in 2020.[58] The top three-quarters of investor-owned utilities achieved 1.35% incremental annual savings in 2020, and the top 10% achieved 1.75% incremental annual savings or more. The American Council for an Energy-Efficient Economy ("ACEEE") also produces a scorecard that summarizes energy savings by utility. Of the 52 utilities in their 2020 analysis, the average net savings was 1.03% per year, with the 90th percentile at 2.02% per year.

The Commission should evaluate energy efficiency against supply-side resources to fully recognize its potential to provide customer cost and emissions savings. The Companies ask for this very relief in their Carbon Plan, stating that "the Companies will need to modernize the current framework for appropriately valuing demand-side DERs so that EE and other demand-side customer programs are evaluated on par with zero-carbon supply-side alternatives."[59] If

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[58] See U.S. Energy Information Administration Annual Electric Power Industry Report, Form EIA-861 detailed data files at: https://www.eia.gov/electricity/data/eia861/
[59] Duke Carbon Plan, Appx. G, at 12.

compared directly against the resource options proposed in Duke's Carbon Plan, energy efficiency would likely be dispatched to well beyond the technical potential identified in the Companies' market potential study.[60]

As Duke highlights in Appendix G – Grid Edge and Customer Programs, many new programs and program modifications can significantly increase customer participation and energy savings. None of the factors identified in Appendix G are explicitly accounted for in Duke's estimates of energy efficiency savings contained in the Carbon Plan. A 2020 ACEEE study entitled "How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy, Cost, and Greenhouse Gas Impacts" (the "ACEEE Study")[61] provides further guidance on how to increase energy efficiency uptake in North Carolina. In particular, the ACEEE Study suggests: (1) expanding incentives for residential heat pump and heat pump water heating equipment; (2) extending the residential new construction program; (3) incorporating code compliance training into energy efficiency programs; (4) increasing income-qualified weatherization offerings; (5) expanding strategic energy management program participation; (6) enhancing diversity of agricultural offers and providing targeted incentives and agricultural audits; (7) offering Energy Efficiency as a Service ("EEaaS") programs; (8) implementing pilot metered energy efficiency transaction structures for commercial buildings; (9) implementing targeted incentives for small businesses, nonprofits, schools, local government buildings, medical facilities, shelters, community centers, and other public buildings in low-to-moderate income areas; (10) expanding midstream and upstream offerings; (11) expanding the retail products platform; (12) leveraging advanced metering infrastructure to improve program effectiveness; (12) offering on-bill financing and tariffs; (13) implementing geotargeted programs for non-wires alternatives; (14) modifying residential programs to include measures that promote better health outcomes and identifying complementary funding sources for preventative health care services; (15) enabling residential and commercial building benchmarking; (16) expanding targets and savings for state buildings and UNC; (17) catalyzing the development of clean energy markets by issuing loans, providing credit enhancements, offering technical assistance, and investing in projects; (18) using commercial property assessed clean energy financing instruments; (19) providing low- or no-cost measures

[60] Duke Carbon Plan Attachment IV.
[61] Available at: https://www.aceee.org/sites/default/files/pdfs/u2007.pdf.

for low-income efficiency programs; and (20) expanding access for low-income multifamily residences.

Incorporating the ideas already posited by Duke in Appendix G with those offered by ACEEE will significantly increase the energy efficiency landscape in North Carolina. However, Duke needs clear signals from the Commission that energy efficiency is a top priority. The Commission, Duke, and the Carolinas EE/DSM Collaborative must work hand-in-hand to motivate Duke, and its customers, to increase energy efficiency deployment. Recognizing that energy efficiency is a resource on par with other supply-side resources and should be evaluated as such is of particular importance.

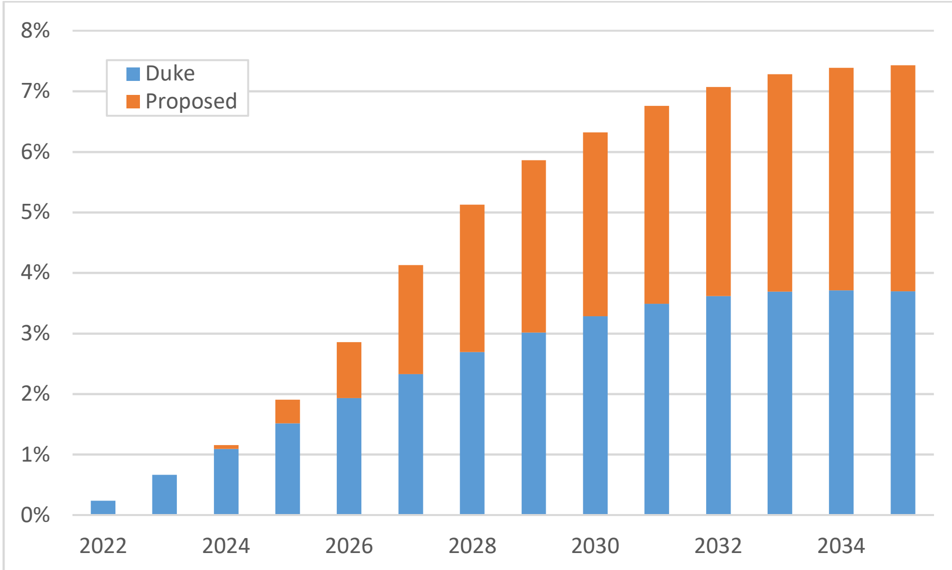
To estimate the energy efficiency potential for our Preferred Portfolio, we relied on various sources, including the Companies' Carbon Plan,[62] responses from the Companies to discovery served in the Carbon Plan matter, data from EIA 861 forms, the 2020 ACEEE Utility Energy Efficiency Scorecard, and the ACEEE Study.

Specifically, our forecast utilized assumptions from the ACEEE Study which provided an energy efficiency policy case incorporating savings targets set forth for electric utilities (in the report these are termed energy efficiency renewable standards), building benchmarking, utility savings initiatives, C-PACE, weatherization, strategic energy management, large customer savings beyond SEM, and agricultural audits and implementation.[63] While this study indicates that North Carolina can achieve 11.1% savings by 2030, we used a more conservative 7.7% as a target when developing our analysis. The graph below illustrates the cumulative energy efficiency savings contained in the Companies' Carbon Plan in blue, with the additional cumulative energy efficiency savings stacked in orange for each year through 2035.

[62] Specifically including Appx. G – Grid Edge and Customer Programs and Attachment IV – DEC.DEP NC MPS.

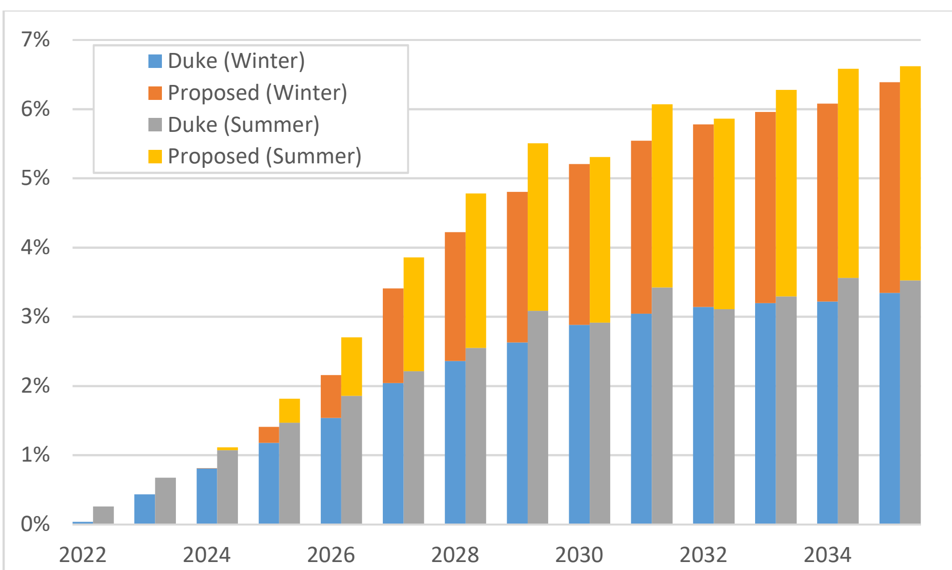
[63] We omitted any savings assumptions associated with co-ops and municipal utilities as well as building code stringency and compliance. While building code stringency and compliance is hypothetically captured in the load forecast, it is likely that recently enacted codes and standards which will have a significant impact on the lighting market are not incorporated in the analysis. Because of this, the estimated impact to load may be conservative.

Figure 23: Proposed Cumulative Energy Efficiency Savings (% energy consumption)



Our proposed plan also reduces summer and winter peak loads in the Companies' service territories. The graphic below illustrates the impacts to summer and winter peaks as a result of the Companies' Carbon Plan with our modifications stacked on top.

Figure 24: Proposed Cumulative Energy Efficiency Savings (% peak load)

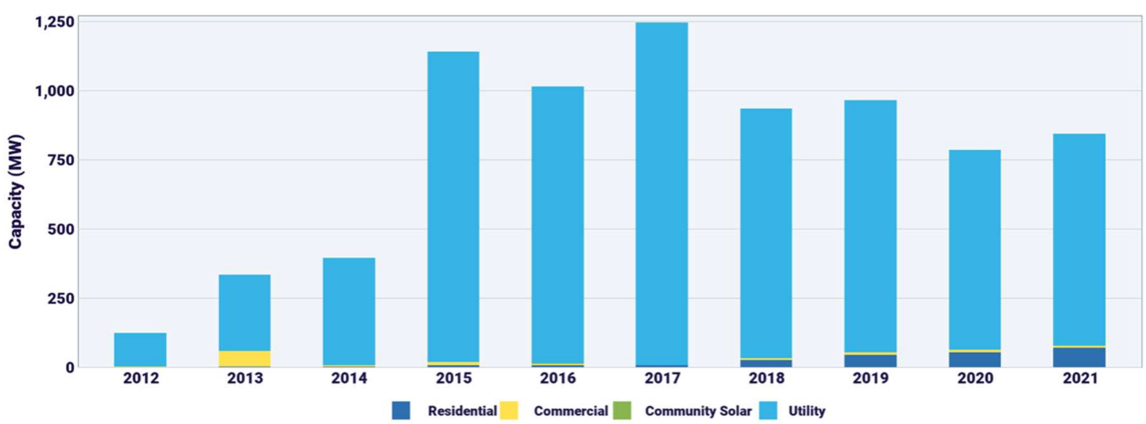


Energy efficiency expenditures were incorporated into the analysis and estimated based upon the unit costs contained the Companies' Carbon Plan.[64]

1.12 Increase Deployment of Behind-the-Meter Generation

The Companies assume that BTM solar generation will comprise just 1% of total load by 2037, climbing from 86 GWh/year in 2023 to 884 GWh/year in DEC territory and from 64 GWh/year to 463 GWh/year in DEP.[65] This plan represents compound annual growth rates ("CAGR") of 18% and 15%, respectively. These assumptions are well below the full potential for the level of BTM generation, which has historically lagged far behind utility-scale installations in the state.

Figure 25: North Carolina Annual Solar Installations[66]



BTM solar growth achieved in other markets shows what a more aggressive approach to BTM solar expansion can achieve. For example, compared to what the Companies' Carbon Plan proposes for fifteen years, New Jersey achieved the same total growth in less than four years, increasing from 84 GWh/year to 921 GWh/year from 2008-2012, with a CAGR of 82% per year.

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[64] Costs were summarized by the Companies in response to NCSEA *et al*. DR3-18.
[65] Duke Carbon Plan Appendix E
[66] Solar Energy Industries Association North Carolina Solar Fact Sheet through Q1 2022. Available at: https://www.seia.org/state-solar-policy/north-carolina-solar.

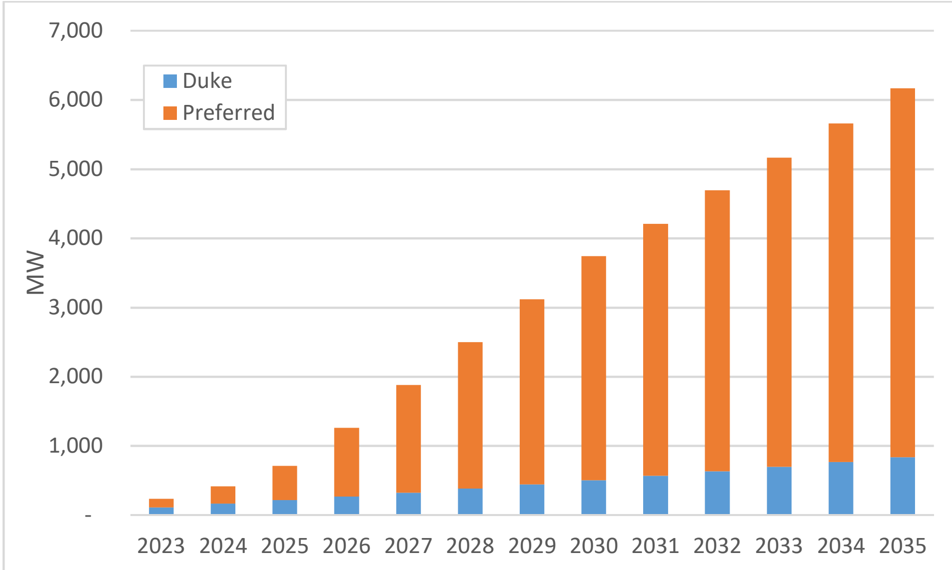
Demonstrating a similar growth path, Pacific Gas & Electric ("PG&E") in California increased from about 82 GWh to 804 GWh from 2005-2012, with a CAGR of 44% per.

Strong growth in both markets resulted in BTM solar now serving more than 5% of New Jersey's electric load and more than 11% of PG&E's load. Between 2007 and 2021 (the same 15-year duration as the Companies' plan), New Jersey achieved a CAGR of 35%, and PG&E achieved a CAGR of 30%. With lessons learned from these and similar markets, it is reasonable to assume that the Companies can achieve the same or better results.

Increasing BTM solar is vital to a successful portfolio as it offers multiple benefits to hosts of the solar arrays, the Companies, and customers at large. BTM solar provides site hosts with bill savings through reduced consumption. This reduced consumption diminishes grid emissions, directly assisting the Companies in meeting their CO2 reduction targets. BTM solar also eases pressure on the need for wholesale grid-connected solar projects, reducing costs to ratepayers for interconnection and transmission. Finally, because site hosts bear many of the installed costs of BTM solar, this again provides savings to ratepayers at large. Because of these benefits, BTM solar should be increased within the Carbon Plan portfolios.

Significant BTM solar growth is achievable in North Carolina as well. North Carolina has a greater total load than New Jersey, substantially more available open land, and better solar irradiance potential (more production per panel) due to its geographic location. We assumed the Companies could achieve annual growth of 33.5% per year. The chart below compares the BTM solar deployment under the Preferred Portfolio compared to the assumptions in the Companies' Carbon Plan.

Figure 26: Proposed BTM Solar Capacity



At this rate, approximately 5% of electric load would be served by BTM solar by 2037. This is not an unreasonable figure, as New Jersey currently has 5% served by BTM solar while PG&E in California exceeds 10%. Costs of BTM solar deployment were estimated based upon the quantity of solar installed and a determination of net costs required to stimulate development by end users.

The Commission should direct Duke to develop and propose a best-in-class BTM renewable/storage program that accelerates Distributed Energy Resource deployment to the levels discussed above, with an emphasis on the use of onsite storage/hybrid resources. This includes revisions to net metering or the development of other incentive approaches. Examples of programs to consider include the Solar Massachusetts Renewable Target[67] ("MA SMART"), and the NY Value of Distributed Energy Resources ("VDER").[68] The Commission should direct Duke to increase the BTM solar limitations for commercial customers; increasing it from 1 MW to 100% of the annual load of a customer. These actions could yield substantial reductions in carbon

[67] See https://masmartsolar.com/
[68] See https://jointutilitiesofny.org/distributed-generation/VDER

emissions and empower customers to reduce their energy costs and enhance their competitiveness.

1.13 Solar and Solar Plus Storage Should be Further Explored and Emphasized

In modeling solar paired with storage, the Companies make several decisions that narrow the range of potential outcomes, such as limiting the examination of solar plus storage options to configurations featuring 2-hour batteries assuming a 50% battery ratio or 4-hour batteries assuming a 25% ratio.[69] These two configurations, though useful, do not represent the full range of possibilities and exclude options that may prove more valuable.

Treatment of solar plus storage in the Companies' portfolios is further limited by the modeling approach implemented for these resources. The Companies chose to assign a fixed profile for configurations pairing storage with solar, rather than allowing the EnCompass model to economically dispatch these resources.[70] This methodology once again introduces analysis conducted external to the model and prevents full optimization. This constitutes another example in which the value of EnCompass, or any modeling tool, is restricted by pre-processed decisions. Due to the selection of a fixed dispatch profile, solar plus storage resources are excluded from providing ancillary service benefits in the Companies' modeling. As discussed in Appendix Q of the Carbon Plan, energy storage resources feature a number of characteristics that make them desirable for providing fast-response reserves, including the flexibility to commit or ramp quickly in response to system needs. Although configurations pairing storage with solar have limitations and their ability to contribute to reserve requirements should therefore be properly examined, excluding their potential value in providing reliability services altogether serves to further limit the analysis.

To address this deficiency, we modeled an additional solar plus storage configuration: solar with capacity of 75 MW paired with storage of 40 MW with a four-hour duration.[71] The solar portion of the paired resource is subject to the solar annual limits in the model. Solar is dispatched

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[69] As outlined in Duke Carbon Plan, Appx. E – Quantitative Analysis.
[70] As noted in response to AGO Data Request item 3-6.
[71] The transmission adder for the resource in the model was based on the first solar tranche, but this was adjusted post modeling to reflect the year of investment per Duke's assumptions.

economically, and the model decides how storage should charge and discharge. Each of the resources is modeled with a capacity contribution equal to their respective standalone resources. This is a conservative approach as combining resources produces a total Effective Load Carrying Capability ("ELCC") that is greater than the sum of its parts.[72] This approach enhances the role of solar plus storage as part of the Preferred Portfolio.

1.14 Potential for Offshore Wind Should be Considered for Public Policy as well as Economic Reasons

Offshore wind represents a unique renewable resource that should be part of North Carolina's resource plan. It can help meet significant energy requirements and support year-round needs with extra winter production. At present, the cost and cost recovery elements related to offshore wind in North Carolina require further definition. However, the long-term benefits of offshore wind are significant, and we expect a portfolio utilizing offshore wind would not only further reduce emissions, but would also have the potential to be less costly than Duke's Portfolio 1. As a coastal state with ample offshore wind opportunity, the ability to utilize this resource could be a gamechanger in meeting and exceeding the goals of HB 951. The Commission should continue to evaluate the development of offshore wind, further substantiate its costs and rate impacts, determine the ratemaking and procurement approach to develop these resources, and then determine the level of capacity to incorporate into the Carbon Plan. In addition, the Commission should recognize that this industry is still developing with a host of offshore wind developers competing for opportunities along the east coast. Multiple entities have already secured lease rights adjacent to the State and the Commission should develop a model for North Carolina that competitively sources offshore wind resources to reduce costs for customers.

2 Modeling Analysis and Results

This section summarizes the modeling methodology, assumptions, and findings performed by Strategen and Gabel Associates. As a starting point, the modeling effort uses the exact model

[72] E3, August 2020, Capacity and Reliability Planning in the Era of Decarbonization, pg. 6, https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

and inputs as provided by the Companies. From there, and as discussed throughout this Report, we make adjustments to align the assumptions and methodology with best practices and current market dynamics. We also incorporate other updates to better align the analysis with the goals of HB 951. This analysis shows the potential to develop a Preferred Portfolio using the recommendations from this Report that achieves the state's carbon reduction goals at lower costs to consumers.

2.1 Preferred Portfolio Overview and Assumptions

The Preferred Portfolio is characterized by: (1) a significant expansion of solar and battery storage with suggestions to mitigate interconnection and transmission limitations; (2) enlarged investment in energy efficiency, resulting in significant savings for ratepayers by reducing system costs; (3) robust investment in BTM distributed generation; (4) retirement of coal resources by 2030; (5) utilization of existing natural gas plants that can be contracted to avoid the construction of new units and the risk of stranded assets; and (6) following a no-regrets approach that preserves optionality. To implement the Preferred Portfolio, input data updates and adjustments to the model contained in the Preferred Portfolio include assumptions. We discuss these items individually below.

2.2 Annual Limits

Modeling tools such as EnCompass are useful in developing solutions based on system economics. However, the model's ability to fully optimize can be hindered by input decisions, and the Companies make several assumptions that constrain their analysis by either imposing annual limits or making manual exogenous adjustments. When the model reaches or is otherwise prevented from surpassing these constraints, results are being driven and implicitly defined by the Companies' assumptions rather than the operational and economic assumptions programmed in EnCompass.

Although the Companies do not impose limits on battery additions within the model, they make adjustments outside of the model to ultimately replace 35% of new battery capacity with combustion turbines.

Below is a table with the capacity additions in the Companies' P1 of the Carbon Plan. This table displays the years 2026 through 2029, a period that has significant (exogenously defined) coal retirement and, thus, an energy and capacity need. Additions in red were limited by an exogenous constraint, preventing the model from selecting more, if allowed. Additions in green were subject to post-model adjustments. The NGCT addition in 2027 was forced in while model-selected storage was forced out. Two NGCC units are presented as the model's economic selection.

Figure 27: Limitation Constraints in the Companies' Carbon Plan

	2026	2027	2028	2029
CT J	-	1,127	-	-
CT J H2	-	-	-	-
2x1CCJ	-	-	2,431	-
2x1CCF	-	-	-	-
SMR	-	-	-	-
Advanced Reactor w/ Integrated Storage	-	-	-	-
Onshore Wind	-	-	300	300
Offshore Wind (2029)	-	-	-	800
Standalone Solar	300	-	1,200	-
S+S 25% Battery Ratio	450	1,050	600	1,800
S+S 50% Battery Ratio	-	-	-	-
4-hr Battery	-	700	-	-

Our analysis relaxed some of these limitations to allow the model to determine the most economic resource options. We also adjusted solar limits to utilize replacement capacity from retiring coal plants as well as wind acquisition dates and annual limits.

2.3 Modeling Horizon

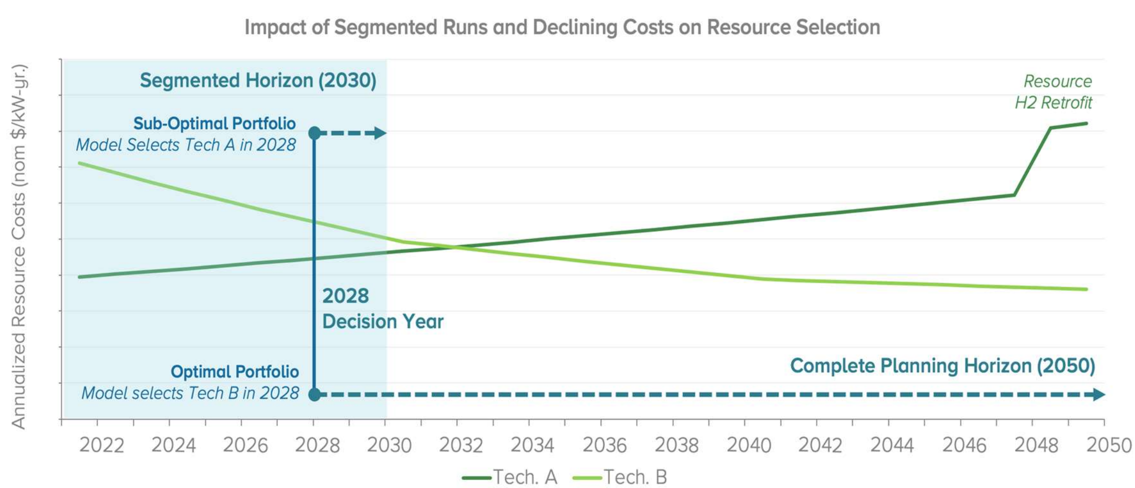
Given an array of input assumptions, such as load forecasts, existing and potential new resources, capital costs, and fuel and operating costs, capacity expansion models such as EnCompass solve for and determine the optimal resource mix over a given planning horizon.

Although the Companies' Carbon Plan is modeled up to 2050, their modeling assumes a segmented future planning horizon. The capacity expansion modeling in EnCompass was done in four segments: 2022-2029, 2030-2037, 2038-2045, and a shorter period of 2045-2050. This methodology is implemented to reduce computation and processing time by running fewer years at once. However, segmenting the time horizon of an analysis has numerous implications for the solutions developed by the model which can lead to distorted results.

For an analysis out to 2050, performing runs on a shorter timeline is highly problematic because it will not allow the model to anticipate and plan for costs or emissions impacts in future years outside of the shortened horizon. For example, the Companies assume new NGCC and NGCT resources built before 2040 will incur costs to operate exclusively on hydrogen by 2047.[73] Converting to operate on hydrogen is a significant future cost that the segmented analysis will not recognize when evaluating the 2022-2029 or 2030-2039 timeframes. Similarly, because these units will initially operate on natural gas, the model does not take hydrogen fuel costs into account when planning for the shortened horizon.

Segmentation is especially troubling for an analysis with resource costs arranged in the unusual structure that the Companies implemented. The image below illustrates how segmentation can bias the results of an analysis. When making a decision in 2028, the model is myopic. The decision sees the annual resource cost of technology A and B and considers A the least cost option without foreseeing that for every year after that the system will incur the annual costs as shown below. Given that declining costs were modeled only for renewable and energy storage resources, this modeling choice led to a bias toward fossil fuel resources.

Figure 28: Illustration of Horizon Segmentation Issues



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[73] See Companies' response to AGO DR 3-28

To address this issue, we evaluated the portfolios on a single time horizon through 2050, while adjusting other settings for computational issues.

2.4 Basis of Comparison

This Report presents a Preferred Portfolio that achieves a 70% reduction in emissions by 2030. The Preferred Portfolio is compared against the Companies' P1 portfolio. To create a consistent comparison between the Preferred portfolio and the Companies' P1 case, we assess both scenarios using the consistent input assumptions. Specifically, that means that the Preferred Portfolio and Duke's Carbon Plan P1 portfolio were evaluated as follows:

- Preferred Portfolio – Conducted a capacity expansion and production cost analysis within EnCompass based upon the recommended solutions identified in this Report, as well as updates to input assumptions including resource costs and natural gas costs.
- Duke P1 portfolio – Conducted a production cost analysis within Encompass to determine the realistic costs of the P1 portfolio based upon updates to input assumptions including resource costs and natural gas.

Following this methodology, the performance of the Preferred Portfolio and the P1 plan proposed by Duke can be fairly evaluated and compared based upon reasonable and consistent input assumptions. This approach provides consistent cost factors so that the comparison only reflects differences in the resource mix between the portfolios.

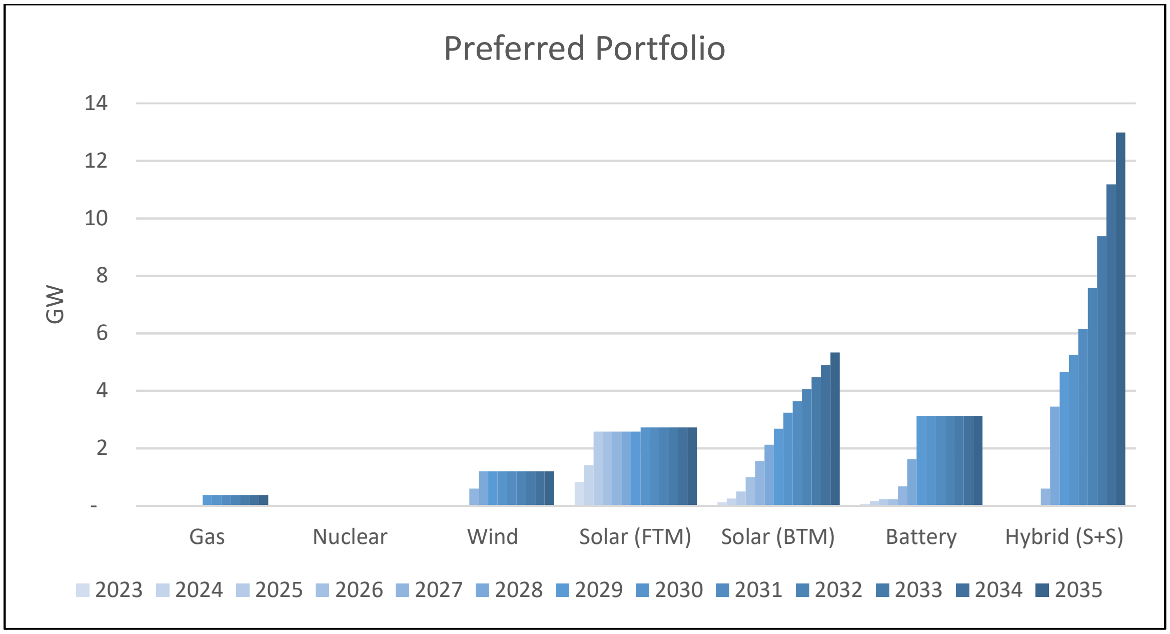
2.5 Results

The Preferred Portfolio includes no new combined cycle units, and only two new combustion turbine (CT) units. This portfolio results in a lower revenue requirement than P1, indicating that it results in savings for ratepayers while also increasing optionality for Duke, and allowing for the flexibility to make more informed decisions in the future. By deferring and removing the need for new gas resources in the short-term, this portfolio also provides more time to allow technologies and markets to develop and for the Companies to re-assess their needs. This option value is not captured in EnCompass but should be weighed heavily when determining whether an investment is prudent. This portfolio, with no new NGCC units, also achieves emissions reductions similar to those in Portfolio 1, meaning that Duke can proceed with a least cost solution that complies with HB 951, is more economic, is reliable, and preserves future optionality to select alternative clean sources over time.

2.6 Installed Capacity and Generation

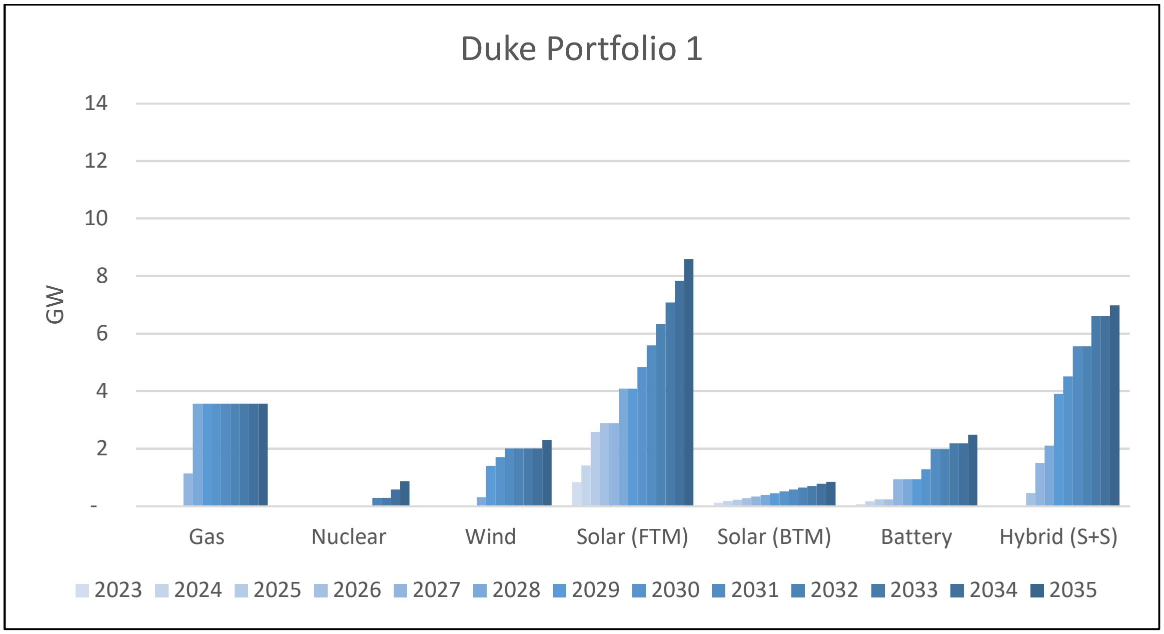
The figure below illustrates the nameplate capacity of new generation resources in the Preferred Portfolio through 2035.

Figure 29: Preferred Portfolio Nameplate Capacity Additions



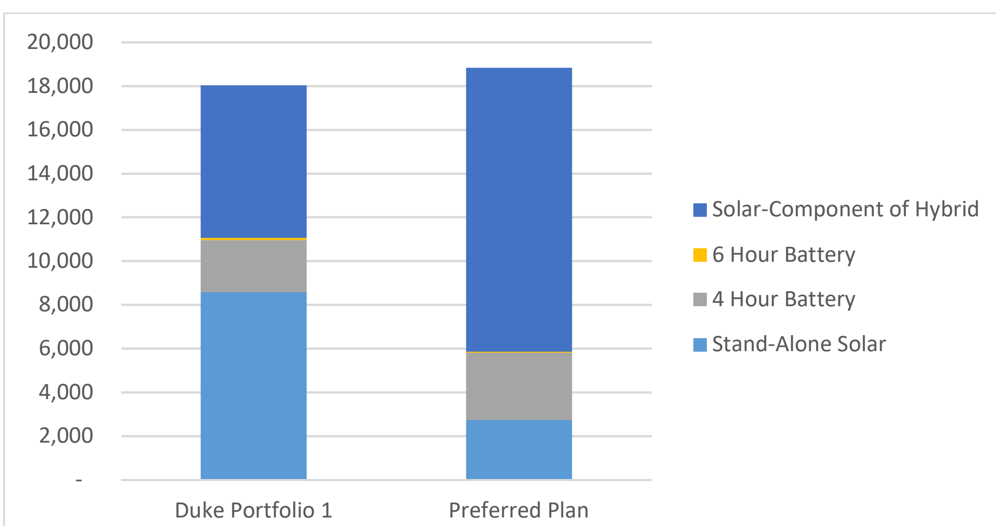
The Preferred Portfolio has a large amount of hybrid solar + storage capacity which provides the flexibility for the portfolio to provide both energy and capacity. It also contains a large amount of BTM solar which mitigates transmission interconnection issues and engages customers. Stand-alone solar is diminished in comparison to Duke's P1.

Figure 30: Duke P1 Nameplate Capacity Additions



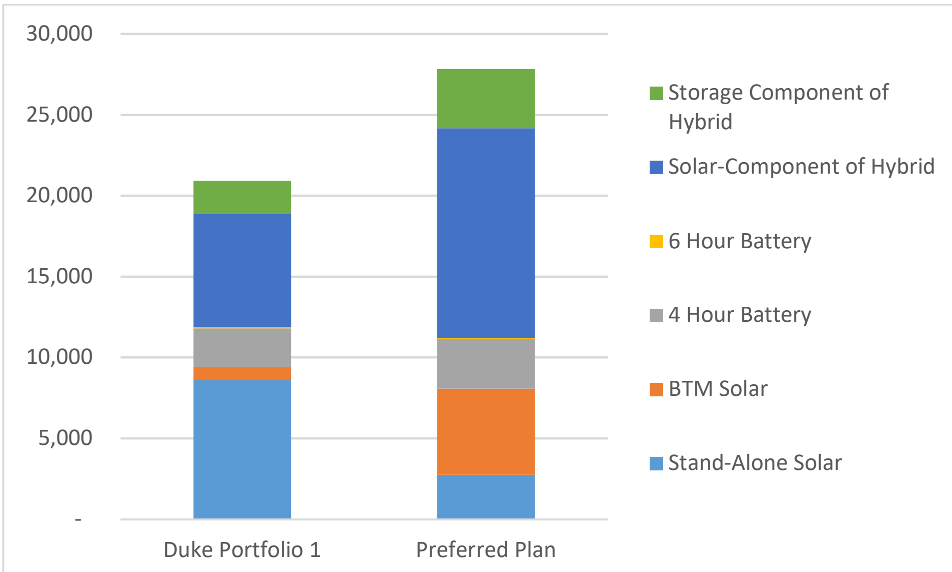
Because of the lack of BTM solar and hybrids in Duke's P1 portfolio, customers are reliant on new gas generation and stand-alone wholesale solar. There is also a significant shift between the Preferred Portfolio and Duke's P1 with respect to the type of solar installed. The Proposed Portfolio largely shifts stand-alone solar to more supportive Hybrid Solar + Storage. The following figure illustrates this shift by comparing the amount of stand-alone solar, batteries, and hybrids in 2035:

Figure 31: Wholesale Solar and Storage Comparison



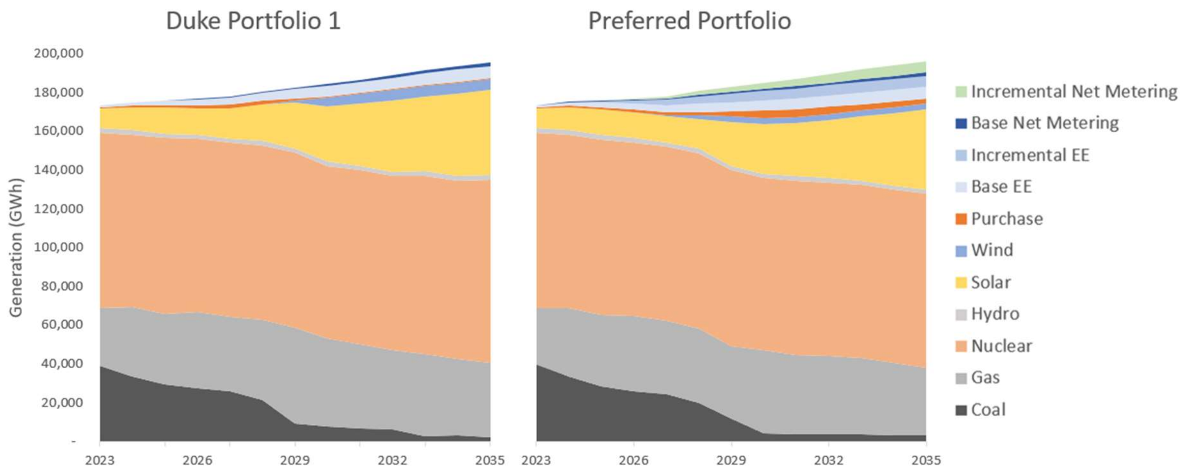
This chart shows a minimal shift in total capacity, but a major change in the type of capacity installed. However, there are other components that further differentiate the solar and storage aspects of the Preferred Portfolio. The follow figure displays the total solar and hybrid capacity, but also includes the battery-component of the hybrid resource as well as BTM solar.

Figure 32: Comprehensive Solar and Storage Comparison



Total capacity is a useful metric but ultimately customer demand and emissions are based upon the generation of the resources available. The generation charts for Duke's portfolio 1 and the Preferred Portfolio are presented below.

Figure 33: Generation Resource Mix Comparison



The Preferred Portfolio replaces coal capacity and significantly reduce new gas capacity allowing room for proven renewable and demand side technologies. Coal generation is projected to be minimal post-2030 for both Duke's P1 portfolio as well as our Preferred Portfolio. However, while the Preferred Portfolio terminates coal by 2030,[74] Duke's P1 portfolio allows the Belews Creek units to remain online and operate infrequently as peakers. While EnCompass sees infrequent operations of coal facilities as a satisfactory outcome in its capacity expansion and production cost analysis, it does not recognize the inherent risks of continued operations. Keeping coal units online poses the risk of future emissions and additional costs, especially if natural gas prices spike causing gas-fired resources to be more costly to operate. This would not only result in higher emissions but would also increase operating costs compared to having invested in resources that are emissions free and indifferent to fuel prices such as solar plus storage. The fact that the emissions and operating costs of the Preferred Portfolio are lower support the conclusion that removing coal is feasible and minimizes risks for ratepayers.[75]

[74] Cliffside 6 is assumed to cease coal operations by the beginning of 2036. The generation chart depicts it as coal even beyond 2036.
[75] Due to time restrictions and the limited information provided by Duke, the analysis did not attempt to study coal retirement decisions on a per unit basis.

2.7 Revenue Requirement

The Preferred Portfolio presented in this Report offers significant savings for ratepayers over Duke's proposed portfolios. Those savings are primarily a result of a more economic selection of resources based on updated costs and commodity forecasts. For comparison, the revenue requirement of Duke's Portfolio 1 has been recalculated to reflect the same resource costs and gas prices used in the Preferred Portfolio analysis. This allows for direct comparison of our portfolios against the Companies'.

Figure 34: NPVRR Comparison

Net Present Value	Duke Portfolio 1	Preferred Portfolio
DEP ($B)	46	43.3
DEC ($B)	65.8	65.5
Total ($B)	**111.8**	**108.8**

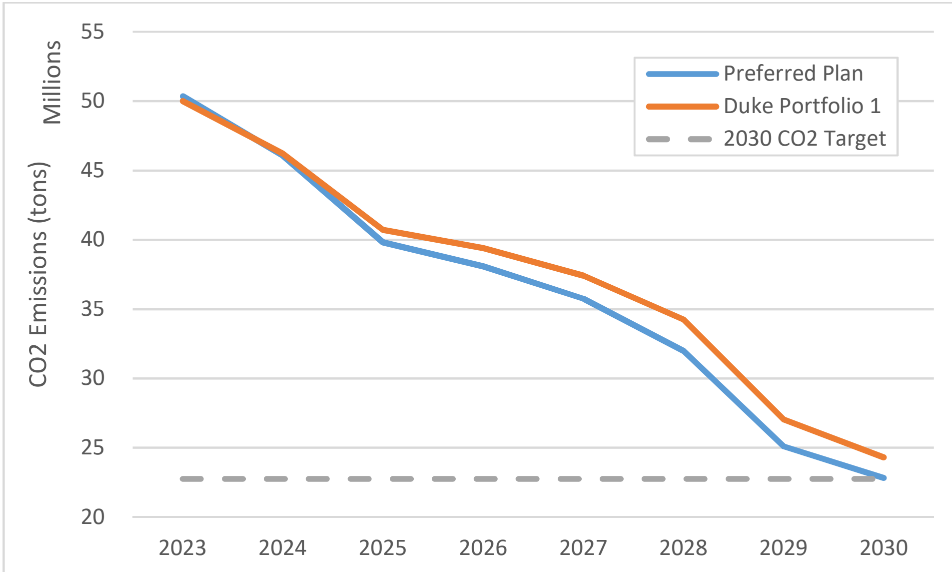
2.8 Risk of Stranded Assets

The calculation of the net present value of revenue requirements as presented above does not reflect the additional risk of new natural gas units becoming stranded assets. These assets could be stranded if gas-fired generation is no longer economical to operate and cannot be converted to clean resources for technical or economic reasons. The risk is embedded in Duke's portfolios but not in our Preferred Portfolio. While extensive analysis can be conducted to determine the cost impact of potential stranded assets, a simple calculation of the net present value of the remaining costs at the end of 2049 would result in additional costs of more than $500 million.

2.9 Emissions

The Preferred Portfolio results in reduced emissions as compared to Duke's portfolios. While both the Preferred Portfolio and the Duke Portfolio 1 are designed to achieve a 70% emissions reduction by 2030, the Preferred Portfolio is able to minimize emissions through a mix of renewables, demand side resources, and already existing natural gas units. The figure below illustrates the carbon emissions savings for the Preferred Portfolio as compared to Duke P1 Portfolio.

Figure 35: Emissions Comparison



Over the entire horizon through 2050, the Preferred Portfolio results in savings of over 6 million tons of CO2, all while reducing financial and emissions related risks. These emissions savings could significantly increase if a higher gas costs result in coal resources operating more frequently in the Duke portfolio. The Preferred Portfolio preserves the optionality to pivot away from the CO2 emitting resources if resource economics or technological advances allow while the Duke portfolios remain locked in the irreversible investment in NGCC units.

2.10 Reliability

Reliability is part of any resource planning process and one of the core objectives that Duke sets in the development of its portfolios. As part of their Integrated Resource Planning process, the Companies requested Astrapé to conduct an analysis of the required Planning Reserve Margin ("PRM") and Effective Load Carrying Capability ("ELCC") for the different resource types in their system. Astrapé examined resource adequacy for several scenarios: an island scenario which assumes no market assistance is available from neighbor utilities; a base case, which reflects the reliability benefits of the interconnected system including the diversity in load and generator outages across the region; and a combined case, which allowed preferential support between DEC and DEP to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority. Astrapé found a required reserve margin of 16 percent was required to meet the one day in 10-year standard (LOLE of 0.1) under the Base Case which assumes neighbor assistance, while a higher margin of 17 percent would be required absent any neighbor assistance. Duke applies a 17 percent minimum PRM in the Carbon Plan Analysis and allows no imports in the EnCompass modeling.[76]

We find this approach to be conservative, given the benefits that the Companies can receive from neighbor assistance. Such benefits would also be evident in the modeling: requiring a lower PRM would result in lower buildout, especially for fossil fuel resources, and allowing imports from neighbors could avoid resources that are idle most of the year. In addition to the avoidance of excess buildout, allowing more imports and exports could allow excess energy to be sold rather than curtailed, resulting in higher valuation for renewable technologies.

To remain on the conservative side, our analysis applies the same reliability constraints that Duke used in the Carbon Plan modeling. Following the same reasoning, our analysis also assumes the same reliability contribution (ELCC values) for different resources as those calculated in the Astrapé studies and used by Duke in its modeling. We further follow Duke's steps and adjust the portfolios for unserved energy, even though this is experienced at the end of the planning horizon and would not constitute reason for concern at this time. Accordingly, the Preferred Portfolio satisfies reliability metrics and objectives.

2.11 Summary of Results

The Preferred Portfolio demonstrates that investment in new CCs can be eliminated without compromising reliability or resulting in costs for ratepayers. In fact, the Preferred Portfolio leads to both cost and emission savings. Importantly, it minimizes significant risks and preserves optionality. Although modeling results clearly indicate that the Preferred Portfolio outperforms P1, it also delivers significant additional value that has not been quantified in the model. The Preferred Portfolio leads Duke to a better position to both achieve the HB 951 targets, as well as be able to take advantage of future developments in resource economics.

[76] DEC Onshore wind is assumed to be imported but modeled as a resource in the Company's area, just with a higher transmission cost adder. No other imports either for reliability or economic reasons are modeled in EnCompass.

These results support the recommendations of the report, showing that there is a "no regrets" pathway that does not include investment in new natural gas resources (or defers that decision until after 2029), and supports compliance with HB 951 with options that alleviate the execution challenges the utility currently faces.

3 Conclusions & Recommendations

Our analysis shows that the Preferred Portfolio, as summarized throughout this Report, can de-risk the Companies' portfolios by:

1. Alleviating the need for new combined cycle resources. Combined cycle resources are subject to fluctuations in natural gas markets and may become stranded in the future if conversion to hydrogen is infeasible or uneconomic.
2. Carefully evaluating the potential for acceleration of the retirement of coal resources. Coal resources are significant contributors to CO2 emissions and, given the availability of substitutable resources, are not exclusively needed to provide reliability. In addition, risk of high natural gas prices presents the possibility that coal will operate more often and emit greater amounts of CO2, in direct conflict with HB 951.
3. Increasing the development of renewable resources and energy efficiency. This is achieved through creative and stimulative approaches such as Generator Replacement Requests, Surplus Interconnection Service, expanded customer access to renewable and energy efficiency programs, increased battery storage, and increased deployment of BTM generation.
4. Evaluating the availability of greater import capability to reduce costs and carbon emissions, including consideration of joining the PJM RTO.
5. Removing reliance on nuclear SMR, non-water-cooled advanced reactors, and hydrogen generation from the Carbon Plan at this time as these options are not currently commercially feasible and are too speculative to be included or funded at this time.
6. Reducing CO2 emissions as compared to the Companies' Carbon Plan.
7. Achieving all these accomplishments at a total cost lower than any of the Portfolios proposed by the Companies.

The corrected EnCompass capacity expansion model shows that new gas-fired generation is not needed in the timeframe that the Companies propose and may not be necessary at all. This outcome allows the Commission to defer any decision to approve investment in developing new gas generation to a future proceeding, if at all. Correcting the modeling issues and unreasonable assumptions in Duke's Carbon Plan produces a Preferred Portfolio with a resource portfolio that relies on available, proven technologies and prudent planning processes to achieve the State's decarbonization objectives at a lower overall cost and reduced risk to consumers.

Collectively, these recommendations provide a no-regrets plan to rapidly decarbonize the State's energy grid in a feasible manner, deliver greater benefits to customers, and avoid the risk of imposing stranded costs on customers.

Appendix B: Curricula Vitae

Michael Borgatti
Vice President of RTO Services & Regulatory Affairs

Overview of Experience

Michael Borgatti, Vice President of RTO Services and Regulatory Affairs, has over 14 years of experience on energy and policy related issues. He is the firm's principal representative addressing the operations, procedures, and markets of regional transmission organizations (RTO). RTOs serve as the foundation of competitive wholesale electricity markets in the United States.

Mr. Borgatti is an expert on the complex, technical operations of RTOs and has been a leader in the development of RTO rules related to energy, capacity, and other structural issues. He translates the technical complexities of RTOs into the business plans of his clients and helps them evaluate the risks, costs, and revenue associated with tariff changes. He also works on project development and risk analysis including generation interconnection, merchant transmission, and credit issues.

Mr. Borgatti is knowledgeable on various RTOs within the country including PJM Interconnection (PJM), California ISO (CAISO), New York (NYISO), Southwest Power Pool (SPP), New England (ISO-NE), Midcontinent Independent System Operator (MISO), and the Electric Reliability Council of Texas (ERCOT).

He is active in a number of RTO committees and working groups including those addressing energy markets, capacity markets, renewable markets, ancillary services, and transmission interconnection issues throughout the wholesale market space. These groups are integral to developing and refining RTO rules, policies, and processes and resolving difficult market and technical issues. As a result, Mr. Borgatti maintains up-to-date detailed expertise on RTO operations and wholesale energy markets.

Although Mr. Borgatti is versed on RTOs throughout the country, he possesses specialized expertise on PJM (the largest RTO in the country). He previously served as the Chair of PJM's Members Committee, which is considered the highest-ranking stakeholder committee at PJM, as well as vice-chair of PJM's Liaison Committee, which is the primary forum where stakeholders discuss strategic concerns with the PJM Board of Managers. He currently resides at the Generation Sector Whip at PJM. He was also extremely active in PJM's reforms to its capacity market through its Capacity Performance model.

Mr. Borgatti facilitates generation interconnection studies and interconnection service agreements among new generation resources, the local transmission system owner, and the RTO. His expertise allows the firm's clients to effectively advance and protect their business interests in the wholesale and retail energy markets.

He also interacts with the Federal Energy Regulatory Commission (FERC) and state utility commissions on a frequent basis, and advocates before various agencies to enhance our clients' positions.

Mr. Borgatti has provided market analysis, risk assessment, and developed financial strategies associated with both the energy and capacity market. He also helps to inform long term forecasting and other analytical efforts.

Mr. Borgatti possesses a strong understanding of regulatory and ratemaking issues and policy based on his assistance with project development activities and his previous years as a legal specialist.

Prior to his role at Gabel Associates, Mr. Borgatti worked as a federal energy litigation and policy legal specialist for the New Jersey Board of Public Utilities, where he advised senior leadership, including the Board President, Chief Counsel, and Governor's Office regarding various issues related to federal energy policy. He developed and executed litigation strategies for matters before the Federal District Courts, United States Circuit Courts of Appeals, and FERC. Mr. Borgatti also managed a multi-disciplinary team that provided policy and litigation advice on all federal energy matters.

Professional Qualifications

J.D., Rutgers University School of Law, 2011

B.A., Environmental Biology, The University of Colorado Boulder, 2006

gabel associates

Years of Experience: 14

Isaac Gabel-Frank
Vice President

Overview of Experience

Isaac Gabel-Frank, Vice President at Gabel Associates, has over 12 years of experience supporting complex energy issues related to renewables and energy efficiency, cost-benefit analysis, energy project development, economic and tariff analysis, electric vehicles (EV), regional transmission organizations (RTOs), and energy procurement. Mr. Gabel-Frank has also submitted expert testimony in matters regarding the cost effectiveness of energy efficiency.

He is an expert on cost-benefit analytics and has supported a multitude of clients in quantifying cost and benefit dynamics related to the economic impact of energy projects. This includes past and present work for private and public sector clients on renewable energy, energy efficiency, cogeneration, and traditional generation projects. Mr. Gabel-Frank also performs sensitivity analysis to help identify risk boundaries and market deviations. This analysis is critical to investment decisions as it allows clients to understand the full value proposition associated with energy initiatives.

Mr. Gabel-Frank also assists in the development of numerous renewable and energy efficiency projects including in-depth economic, technical, and utility tariff analysis, which incorporates long-term utility and energy forecasts. He has developed various tariff models from the ground up, which are customized to reflect the specific parameters of each project. He is also skilled at calculating energy savings associated with various project structures. As a result of his strong analytical skill set, Mr. Gabel-Frank has served an integral role on various progressive projects throughout the region for public and private sector entities.

He also supports energy, capacity, and renewable energy certificate (SREC/REC) sale activities, including request for proposal (RFP) drafting, detailed modeling, and contract negotiation support. This includes the development of effective hedging strategies and creative project approaches to maximize benefits and revenues.

He is extremely knowledgeable on RTO issues and actively monitors activities related to energy and capacity markets, energy efficiency, demand response, ancillary services, interconnection, and general grid issues. Mr. Gabel-Frank helps clients formulate and strategize positions on current RTO rules as well as provides analysis on potential market changes. This includes development of offer and bid strategies for energy efficiency, demand response, renewable, and traditional generation resources into the PJM market. He has also supported capacity price forecasting in ISO-NE and conducted analysis in relation to NYISO issues.

He was a key contributor in the development of the Analytical Likelihood of Availability and Non-Performance Risk (ALAN) model, a proprietary stochastic modeling tool that computes the exposure of capacity resources within the ISO-NE and PJM footprints. ALAN uses resource outage data as well expected performance assessment event information to determine the probabilistic coincidence of outages and performance assessment events.

In addition, Mr. Gabel-Frank is currently supporting energy efficiency filings on behalf of various New Jersey utilities. He has served the role as an expert witness and provided testimony to support the filings.

He has also supported wide-ranging EV analysis and modeling as it relates to energy markets and distribution grid impacts.

Professional Qualifications

BA., Economics, Political Science, English Writing
University of Pittsburgh, 2009

gabel associates

Years of Experience: 12

Gabel Associates, Inc.

www.gabelassociates.com

STRATEGEN

Maria Roumpani, PhD

Senior Manager

Maria is a Senior Manager in the Strategen Consulting practice. Maria leads the economic and technical grid modeling and analysis for the firm, including capacity planning, production cost, and energy storage dispatch modeling.

Maria has served clients including consumer advocates, public interest organizations, energy project developers, trade associations, government agencies, and foundations.

Contact

Location
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Email
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Phone
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Education

PhD
Management Science and Engineering
Stanford University
2018

MSc
Electrical & Computer Engineering
National Technical University of Athens
2009

STRATEGEN.COM

Work Experience

Senior Manager

Strategen / Berkeley, CA / 2017 - Present

+ Leads firmwide technical and economic modeling and analysis to support Strategen consulting engagements. Specializes in the use of modeling tools (capacity expansion, production cost models) to inform grid planning and decarbonization issues.

Research Assistant

Precourt Institute for Energy, Stanford University / Palo Alto, CA / 2011-2017

+ Conducted research in a wide range of topics, from game theoretical approaches in electricity markets to behavioral economics. Representative projects:
    + model for the competition in a two-settlement electricity market, capturing issues of market power and risk aversion
    + border carbon adjustment in international trade
    + model for electric vehicle infrastructure
    + framework for energy efficiency measure classification to inform behavioral program design

Researcher

Energy, Economics, & Environment Modeling Laboratory, National Technical University of Athens / Athens, Greece / 2009-2010, 2015

+ Mathematical modeler developing large scale energy planning models (focusing on capacity expansion of electricity supply)

Expert Testimony

Colorado Public Utilities Commission, Proceeding No. 21A-0141E

Maria Roumpani, PhD

Senior Manager

STRATEGEN

Domain Expertise

Energy Resource Planning

Capacity Expansion and Production Cost Modeling

Storage Economics & Dispatch Optimization

Benefit Cost Analysis

Fossil Fuel Retirement Studies

Coal Plant Commitment and Dispatch Analysis

Selection of Relevant Project Experience

Southwest Energy Efficiency Project

IRP Analysis and Impact Assessment / 2020 - Present

+ Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's two major utilities, APS and TEP.
+ Led the technical analysis and utilized a sophisticated capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRP.

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2021

+ Reviewed in detail PacifiCorp's IRP modeling to identify inputs and assumptions that might lead the model to deviate from a least cost solution.
+ Supported the development of technical comments before the Oregon Public Utility Commission.

Public Service of Colorado 2021 Energy Resource Plan / 2021

+ Conducted EnCompass modeling to evaluate alternative retirement dates for the utility's coal units.

Coal Plant Valuation Study / 2019

+ Assessed Arizona's and Colorado's coal-fired power plants and potential replacement options using cash flow analysis.
+ Analyzed the cost of replacing existing coal plants with wind or solar resources.
+ Examined the social cost of carbon of the coal portfolio and the impact of using Securitization, a financial tool to retire coal plants without burdening ratepayers.

Virginia Department of Mines, Minerals, and Energy

Virginia Energy Storage Study / 2019

+ Developed and used custom modeling tools to estimate the benefit of storage both in front of the meter and behind the meter configurations. Studied all potential revenue streams to evaluate the energy storage potential in the Commonwealth.

California Energy Storage Alliance

Long Duration Energy Storage Special Project / 2020

+ Supported the technical analysis assessing the needs and benefits of long-duration storage in California. The analysis was based on the use of capacity expansion modeling in EnCompass using IRP inputs; results and recommendations were used to identify specific policy opportunities with the CPUC, CAISO, and CEC to advance long-duration storage evaluation and procurement.

Sacramento Municipal Utility District

Virtual net metering tarriff design and analysis / 2021 – Present

+ Supported SMUD in outlining a VNEM tariff framework and constructed a financial model to evaluate the customer value proposition for the proposed tariffs, as well as a comparative look at other California IOUs' VNEM program offerings.

Clean Energy Group

Alternatives to a natural gas peaking unit / 2021 – Present

+ Developed an analysis of a proposed natural gas peaking unit and potential alternatives, including energy storage and market options. The analysis included an energy storage dispatch model in the energy and ancillary services markets of ISO-NE, and an economic comparison with operating the natural gas unit.

Eliasid Animas

Consultant

Eliasid primarily works in Strategen's decarbonization strategy practice area, where he helps utilities, technology companies, governments and NGOs to trace and achieve their clean energy and decarbonization goals. His expertise includes analysis and planning of energy resources; cost-benefit and storage dispatch analysis; and evaluation of long-duration storage, distributed energy resources, and peak energy technologies. Besides energy, Eliasid has working experience in the urban development and transportation sectors.

Contact

Location
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Phone
+1 (510) 369-5941

Education

BA
Urban & Regional Planning
National Autonomous University of Mexico
2017

Fulbright Fellow
Binational Business
University of California, Berkeley
2018

STRATEGEN.COM

Work Experience

Consultant
Strategen / Berkeley, CA / 2019 – Present

+ Advances clean energy transition by supporting the energy strategies of corporations, governments, NGOs, and utilities.
+ Helped clients to create localized visions for energy transitions, identified best practices for regulation of energy storage markets in developing countries, and investigated the value of energy programs to benefit customers and advance clean energy.
+ Familiar with energy market and policy landscape in New York, California, the U.S. Southwest, Mexico, Australia, and the UK.

Senior Urban Planner
TSUS / Mexico City, MX / 2018 – 2019

+ Supported local governments, companies, and civil groups on the development of sustainable solutions for urban landscapes.
+ Business development, project scoping and management.
+ Focus on actionable site diagnostics, urban design, urban mobility, local-government decision-making, and energy efficiency standards.

Consulting Intern
Strategen / Berkeley, CA / 2017-2018

+ Assisted clean energy adoption projects for corporations, governments, and utilities.

Urban Planner
HJM Consultores / Mexico City, MX / 2016-2017

+ Assessed the impacts of real state projects and advised developers to comply with urban regulations, as well as building and efficiency standards.

Eliasid Animas

Consultant

Domain Expertise

+ Energy Storage Development and Regulation
+ Peaker Plant Replacement
+ Green Hydrogen Market Development
+ Transportation Electrification and Infrastructure
+ Urban Energy Transition
+ Distributed Energy Resources (DER)

Relevant Project Experience

Clean Energy Group and PEAK Coalition

New York City Clean Energy Roadmap / 2020 - Present

+ Works with community groups and other NGOs to establish a community-driven, technically feasible roadmap to transition New York City's energy supply to clean energy resources and create local community benefits.

International Finance Corporation and World Bank

Energy Storage Regulatory Best Practices for Latin America / 2020

+ Assessed and explained best practices for energy regulators to create market opportunities for energy storage in Latin America, with a focus on regulatory actions from the United Kingdom, Australia, California and Hawaii.

Green Hydrogen Coalition (GHC)

Green Hydrogen Guidebook and Ad Hoc Consulting / 2020 - Present

+ Supports clean energy non-profit on the development of educational material and research on multi-sectorial opportunities for hydrogen to accelerate the transition to a carbon-free energy system.

Connecticut Public Utility Regulatory Authority

Innovation Sandbox / 2020 - Present

+ Supported project execution through the research and assessment of best practices for regulatory sandbox programs focused on clean energy innovation.

Analysis of the Duke Energy 2022 Carbon Plan

Prepared by:

STRATEGEN

Prepared for:

DEPARTMENT OF JUSTICE N★C ATTORNEY GENERAL

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STRATEGEN

Table of Contents

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

[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

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[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.

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[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.

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[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% CO2 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

[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.

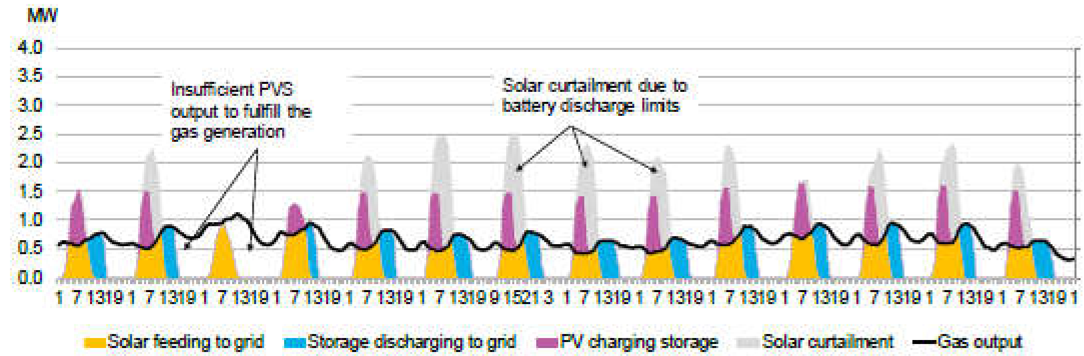
[22] Duke's limit applies to the 50% battery ratio.

[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.

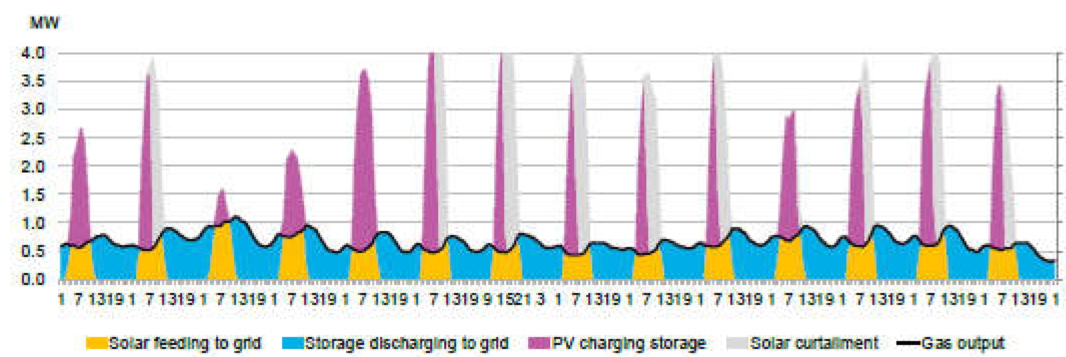
Figure 16: Illustration: 1MW gas vs. co-located PV (4MWDC) plus storage (1MW/4MWh)



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).

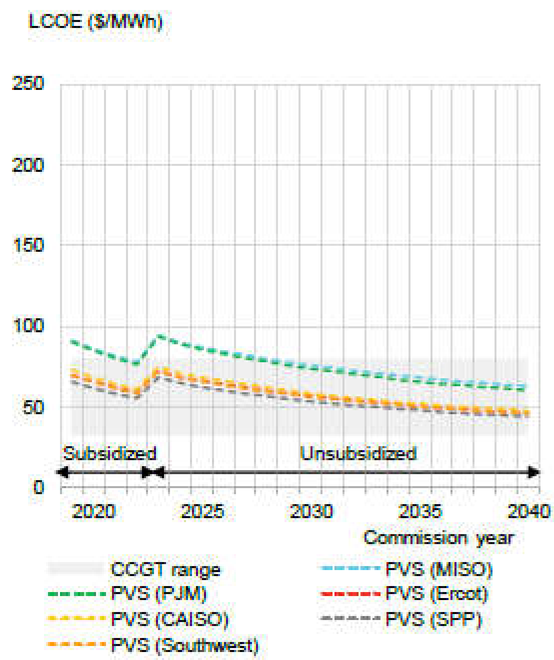
Figure 17: Illustration: 1MW gas vs. co-located PV (7MWDC) plus storage (6MW/24MWh)



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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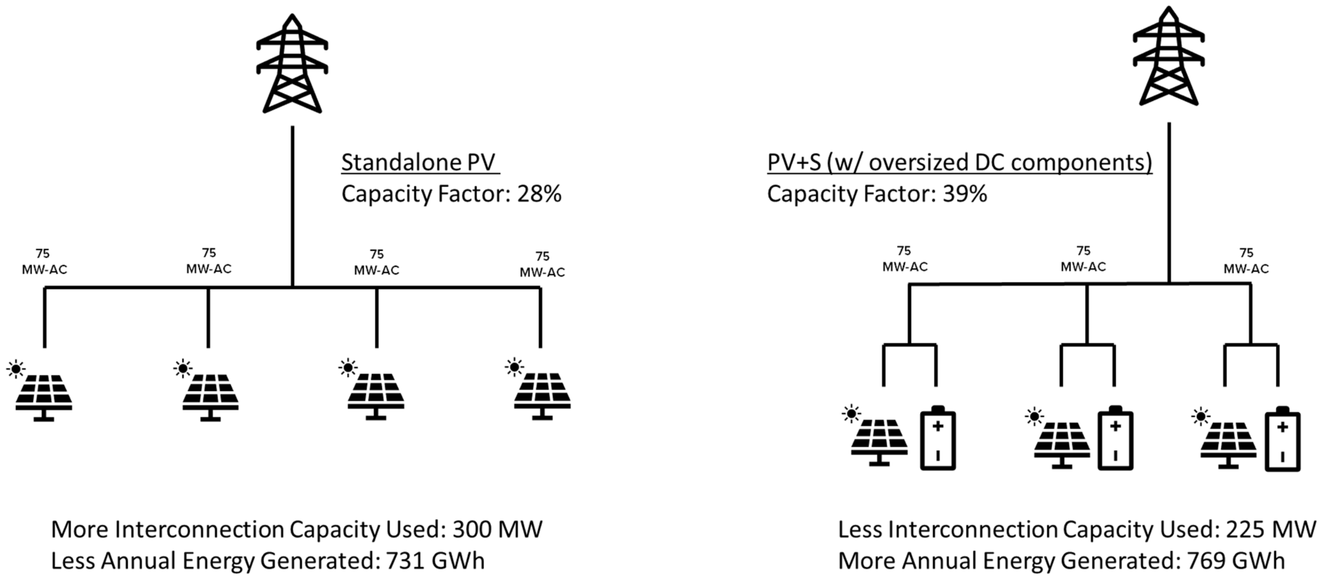
[26] In this context, AC refers to “alternating current” and refers to the final output of the generator to the main power grid at the point of interconnection. The bulk grid operates primarily using AC power flows rather than DC. Often interconnection to the AC power system is the limiting factor on 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]



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.

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[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.

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[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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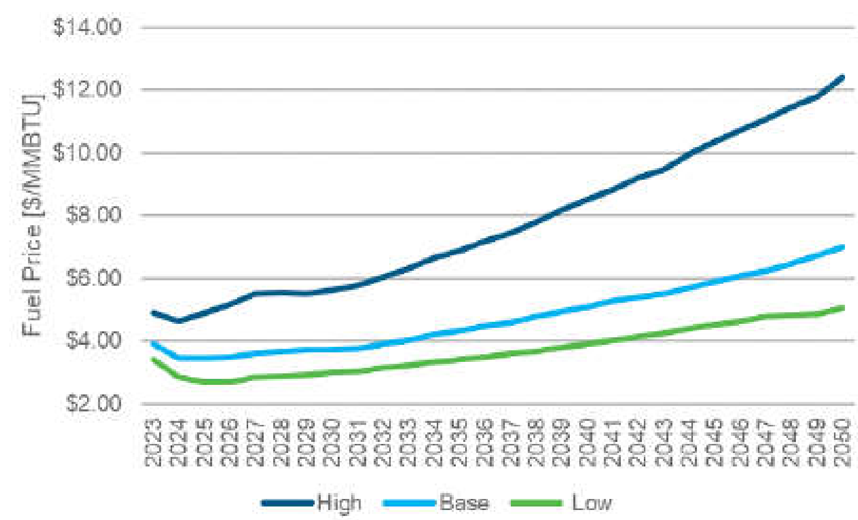
[34] Often "energy only" transmission service is referred to as either Non-Firm Point-to-Point Transmission Service or Energy Resource Interconnection Service, whereas firm transmission service is referred to as Firm Point-to-Point Transmission Service or Network Resource Interconnection Service.
[35] 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 CO2 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

[41] <u>See</u> 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
$P1_A$	0	200	300	400	-1,600	1,000	0	0	0
$P2_A$	0	1,000	200	400	-1,600	0	0	0	0
$P3_A$	0	900	300	1,300	-1,600	400	0	0	0
$P4_A$	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]

[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]

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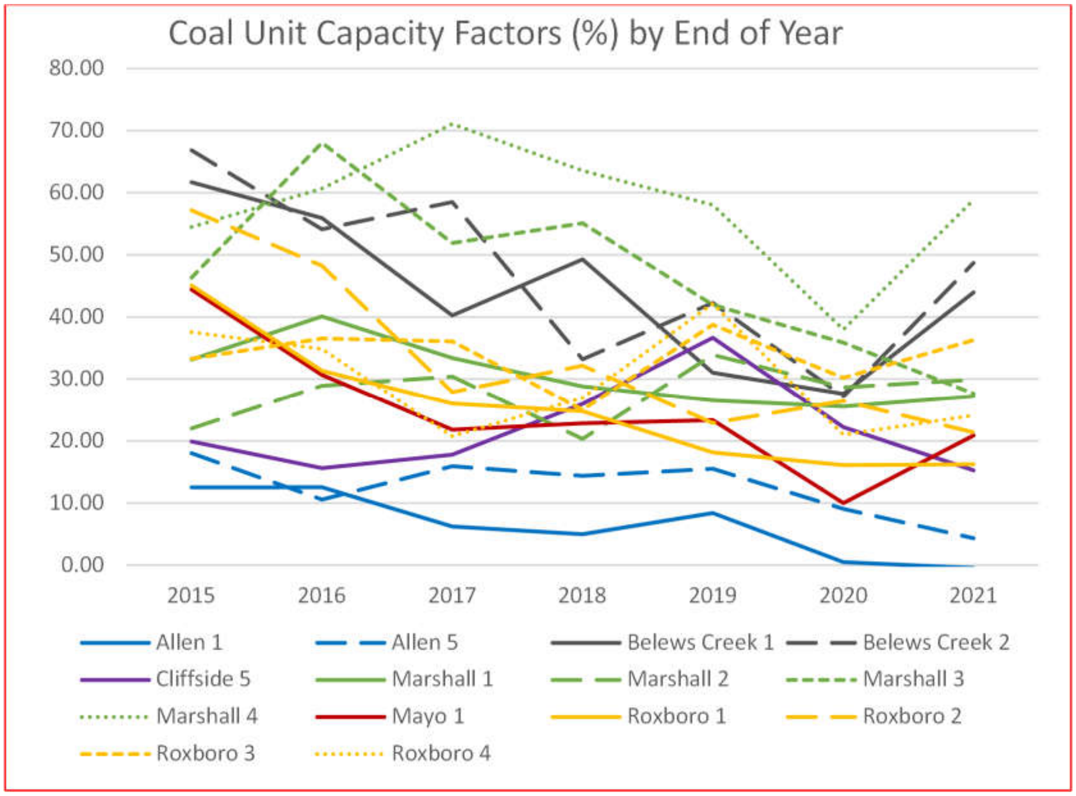
66 AGO DR 4-3.
67 AGO DR 4-4.
68 Plant generation data obtained from the S&P Global Market Intelligence database, July 2022.



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:

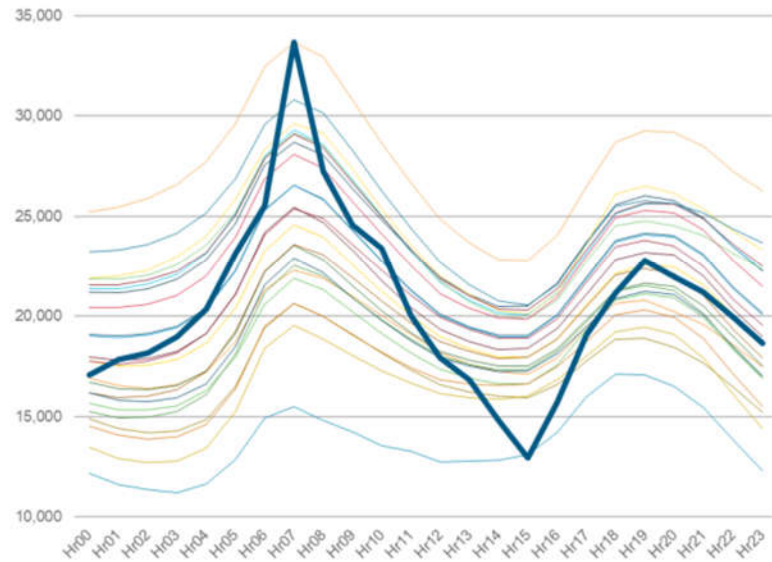
Table E-54: Battery-CT Optimization Results through 2050 [Nameplate MW]

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.

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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.

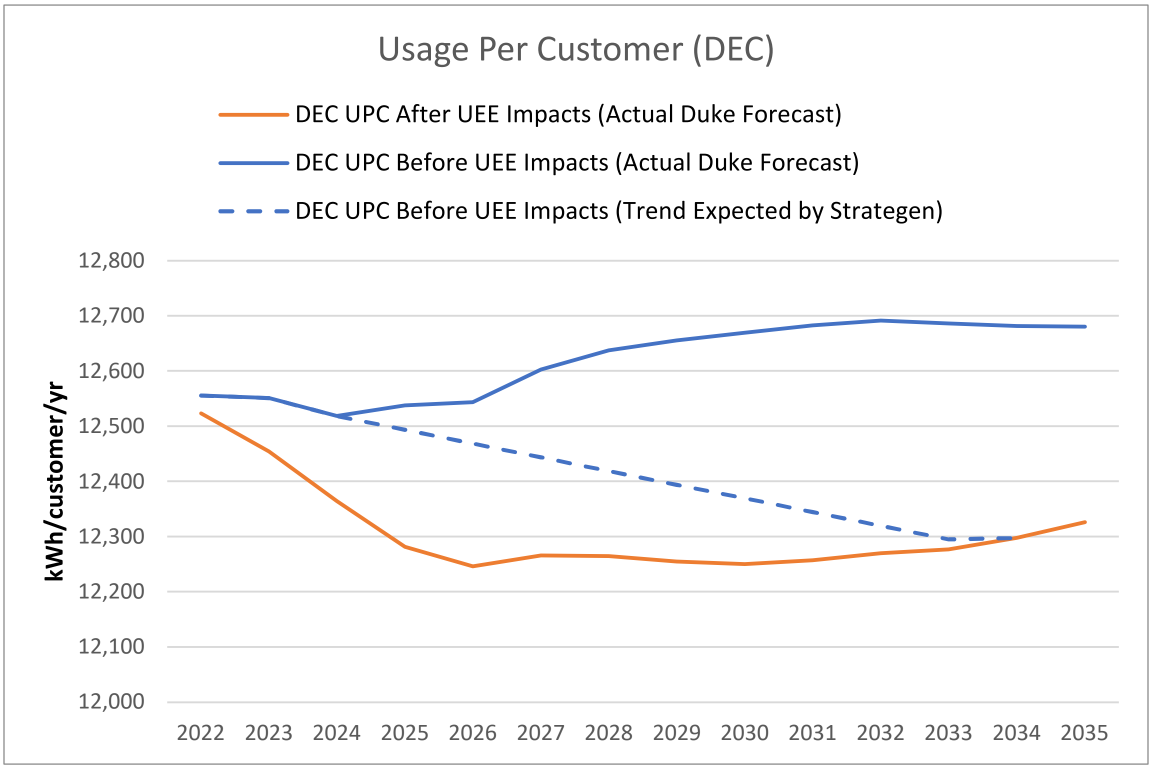
To justify this approach, Duke explains that "As UEE serves to accelerate the timing of naturally occurring efficiency gains, the forecast 'rolls off' or ends the UEE savings at the conclusion of its measure life."[91] This approach would be acceptable if the underlying load forecast also evolved over 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

[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.

/A

Excerpt of "Index.xlsx"
"Lookup Values" tab
Shared 07/28/2022

SACE, et al. Fitch Redirect
Examination Exhibit 1

Input Description	Options
Commitment Option	0: Full commitment
Commitment Option	1: Partial commitment
Commitment Option	2: No commitment
Commitment Option	3: No dispatch (Input Only)

/A

/A

SACE, et al. Fitch Redirect

Examination Exhibit 2

Excerpt of "Index.xlsx"
"Scenario Settings" tab
Shared 07/28/2022

Scenario	CommitOpt
HB951 CapEx-A2 (SMC2030-Seg8-ForceRet-NewZ4FT)	1
__Optimized CapEx	1
__Duke Resources CapEx	1
__Regional Resources CapEx	1
__Duke Resources PC	0
__Optimized PC	0
__Regional Resources PC	0

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Washington, DC. *Senior Associate*, November 2021 – Present.

Conducts regulatory analysis and provides expert testimony on energy & climate issues. Examples include:

- Evaluating utility proposals for additional generation infrastructure against more economic and less carbon-intensive alternatives;
- Assessing the economic viability and prudence of continued operations of legacy coal plants as opposed to alternative resources and market purchases.

Vote Solar, Washington, DC. *Regulatory Director,* February – November 2021; *Regulatory Manager,* August 2018 – February 2021.

Regulatory Director:

- Directed Vote Solar's climate and clean energy regulatory advocacy in the Carolinas, including public-facing reports and webinars; directing regulatory litigation; managing professional services and consultants; and developing advocacy in coalition with clean energy, environmental, and environmental justice stakeholders.
- Authored a technical report assessing stranded asset risk of electric generation infrastructure as a result of corporate carbon neutrality commitments. Results quoted in *Bloomberg, S&P,* and *GreenTechMedia.*
- Implemented a settlement with Duke Energy to conduct a region-leading investigation into physical climate-related impacts to electricity infrastructure in the Carolinas.
- Provided expert testimony in utility integrated resource planning proceedings identifying emergent climate-related risks and implications for utility planning, then providing recommendations for utility resource planning moving forward.

Regulatory Manager:

- Developed nation-leading quantitative assessment and regulatory direction for responding to the increase in residential utility debts as a result of COVID-19.
- Provided expert testimony on best practices in grid modernization in the context of climate-related physical risks to the North Carolina Utilities Commission.
- Provided expert testimony on utility rate design to the Virginia State Corporation Commission and Georgia Public Service Commission.

- Developed a flexible spreadsheet-based tool for assessing solar value proposition across several different rate design and project cost sensitivities.

The University of Michigan, Ann Arbor, MI. *Research Assistant, Urban Energy Justice Lab*, September 2016 – May 2018.

ICF International, Fairfax, VA. *Analyst*, October 2013 – June 2016.

- Developed energy efficiency scores for *ENERGY STAR* buildings using large data sets and multiple linear regression.
- As data lead for the multifamily sector of the *Better Buildings Challenge* wrote data policy and managed data submission for 100+ partners, spanning hundreds of buildings across the country.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Science, School of Natural Resources and the Environment, 2018
Masters Project: *Fueling a Transition: Evaluating the Feasibility for a Hybrid Renewable Microgrid in Beni, Democratic Republic of Congo*

University of North Carolina, Chapel Hill, NC
Bachelor of Science, 2013
Environmental Science, Focus: Energy and Sustainability; Minor: Computer Science

PUBLICATIONS

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TESTIMONY

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South Carolina Public Service Commission (Docket Nos. 2019-224-E and 2019-225-E): Surrebuttal Testimony of Tyler Fitch in the matter of the 2020 Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC. April 15, 2021.

South Carolina Public Service Commission (Docket Nos. 2019-224-E and 2019-225-E): Direct Testimony of Tyler Fitch in the matter of the 2020 Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC. February 5, 2021.

North Carolina Utilities Commission (Docket No. E-2, Sub 1219): Direct Testimony of James Van Nostrand and Tyler Fitch in the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina. April 13, 2020.

Virginia State Corporation Commission (Docket No. PUR-2019-00214): Direct Testimony of Tyler Fitch in the matter of the Application of Virginia Electric and Power Company for approval to establish an experimental residential rate. March 31, 2020.

North Carolina Utilities Commission (Docket No. E-7, Sub 1214): Direct Testimony of James Van Nostrand and Tyler Fitch in the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina. February 18, 2020.

Georgia Public Service Commission (Docket No. 42516): Direct Testimony of Tyler Fitch and Rick Gilliam in the Matter of Georgia Power Company's 2019 Base Rate Case. October 17, 2019.

Resume updated December 2021

I/A

SACE, et al. and NCSEA

Carbon-Free by 2050

Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers

Prepared for North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club

July 20, 2022

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CONTENTS

EXECUTIVE SUMMARY

This report evaluates the proposed Carbon Plan filing in North Carolina by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP), (collectively, Duke Energy or Duke), and, using the shared foundation of Duke Energy's modeling database, revises several inputs to bring them more in line with real-world conditions and presents new resource portfolios that would meet carbon requirements more cost-effectively than Duke Energy's proposal.

Synapse Energy Economics, Inc. (Synapse) has years of experience reviewing Integrated Resource Plans (IRPs), including Duke's 2018 and 2020 IRPs. For this proceeding, Synapse used EnCompass capacity expansion and production cost modeling software to model the Duke Energy system and identify the most cost-effective resource pathway for North Carolinians. This is the first proceeding in the Carolinas in which Duke Energy is also using the EnCompass software.

Using Duke's own EnCompass modeling database as a shared foundation, Synapse revised specific model inputs and allowed the EnCompass model to re-optimize for the most economic resource portfolio. This report presents the results of that revision and re-optimization across two scenarios: The *Optimized* scenario, which allows EnCompass to choose the optimal scenario based on those revised inputs, and the *Regional Resources* scenario, which additionally allows EnCompass to select Midwest wind resources procured via power purchase agreements through the PJM Interconnection (PJM). Synapse also reviews several manual adjustments made by Duke Energy in EnCompass to their Carbon Plan proposals, which deviate from resource planning best practices and add additional costs to ratepayers. The report discusses Duke Energy's EnCompass post-processing in Section 4, and specific changes to Duke Energy's modeling assumptions can be found in Appendices A and B.

The scenarios modeled by Synapse yield large cost savings relative to Duke's Portfolio 1 – Alternate, the only scenario proposed in Duke Energy's Carbon Plan filing designed to reach North Carolina House Bill 951 (HB 951)'s 70% reduction requirement by 2030 without assuming additional Appalachian firm gas transportation capacity.[1] Synapse used this portfolio as a baseline, against which it compared the resource trajectories and costs of the *Optimized* and *Regional Resources* scenarios. Total net capacity changes and net present value revenue

[1] Duke Energy's production cost modeling found that, despite being designed to meet the carbon requirements in in 2030, Portfolio 1 – Alternate would not actually achieve 70 percent reduction in carbon emissions by 2030; See Duke Energy Carbon Plan Appendix E (Appendix E), p. 89.

requirement (NPVRR) 2022-2050 for each Synapse portfolio are shown below in Figure 1 and Table 1.

Figure 1. Capacity by Resource Type, 2022 and 2050, by Scenario

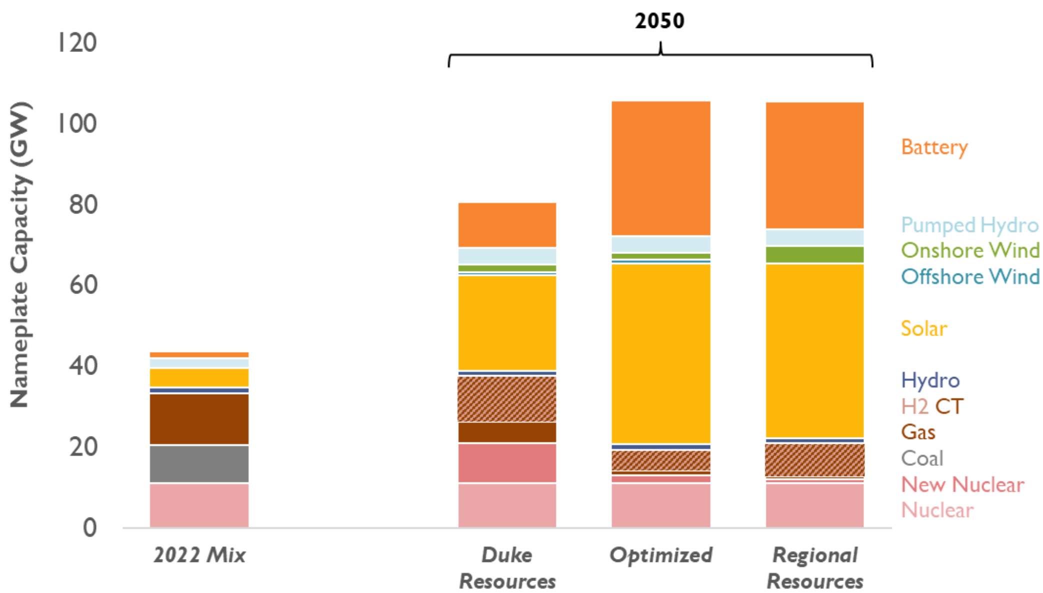

Table 1. Net Present Value Revenue Requirement over Time by Portfolio

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8
2050 NPVRR ($B)	$121.2	$103.5	$98.1

Synapse's modeling shows that, compared to the *Duke Resources* scenario that models the "Portfolio 1 -Alternate" scenario proposed in Duke Energy's Carbon Plan filing, scenarios that rely on proven energy efficiency, solar, storage, and wind resources can deliver a reliable, de-carbonized grid at a lower cost to ratepayers. The most economic path for North Carolina ratepayers requires (i) investing in energy efficiency to cost-effectively reduce overall load; (ii) accelerating deployment and maximizing the value of renewable energy resources; (iii) limiting undue reliance on investments in unproven nuclear technologies and uncertain hydrogen generation; and (iv) avoiding capital investments in risky additional gas-fired generation. Key results of Synapse's analysis include:

- Synapse's analysis shows that **compared to the *Duke Resources* scenario, net present value of revenue requirements savings from the Synapse scenarios range between $700 million and $2.4 billion (2 to 7 percent) through 2030.** By 2050, the range of savings increases considerably, from $17.7 to $23.1 billion (15 to 19 percent) across the Synapse scenarios.

- Synapse's *Optimized* and *Regional Resources* scenarios include utility energy efficiency savings that increase to incremental annual savings of 1.5 percent of total retail load. **Including additional achievable and cost-effective energy efficiency results in the Duke Energy system requiring 2 percent less energy in 2035 and 5 percent less energy in 2050** compared to Duke Energy's baseline energy efficiency assumption. Synapse's analysis shows that increased energy efficiency alone could save ratepayers billions of dollars on an NPVRR basis by 2050.

- Synapse's scenarios **do not select any additional gas combined-cycle (CC) or combustion turbine (CT) units across any portfolio,** despite these resources being available to the economic optimization algorithm model. Synapse's scenarios also rely less on unproven, uncertain future resources like new nuclear technology and zero-carbon hydrogen availability.

- Synapse's scenarios **economically retire 3.5 gigawatts (GW) of coal capacity earlier than the *Duke Resources* scenario** as the system shifts to more economical and less emissions-intensive power.

- Synapse's scenarios select solar, storage and onshore wind to meet energy and capacity needs. In the *Optimized* scenario, EnCompass selects **7.2 GW of incremental solar and 5.6 GW of storage by 2030.** By 2040, the *Optimized* scenario builds a cumulative 22.5 GW of incremental solar, 800 MW of offshore wind, 1.5 GW of onshore wind, and 17 GW of energy storage resources compared to today.

- In the final years of the planning period, Synapse's scenarios **economically retire between 800 and 1,300 megawatts (MW) of existing gas resources, rather than have them undergo retrofits to burn hydrogen.** Combined with ongoing technical and economic uncertainty around hydrogen retrofits, these retirements underscore the risks posed to gas-fired resources.

- Synapse's *Regional Resources* scenario allows EnCompass to choose wind power purchase agreements from the Midwest, as evaluated by the North Carolina Transmission Planning

Collaborative.[2] **Allowing the system to procure 2.5 GW of cost-effective Midwest wind resources results in $1.7 billion in savings to ratepayers by 2030 and $5.4 billion by 2050.** This result demonstrates the ability for regional coordination and transmission to deliver savings to for ratepayers.

- Synapse also performed a sensitivity that assessed the impact on carbon emissions if the Carolinas participated in the Regional Greenhouse Gas Initiative (RGGI). **Synapse finds that RGGI would drive emissions reductions of hundreds of thousands of tons per year in the 2020s and 2030s.**

Synapse's model generates these results while meeting reserve margin requirements established by Duke Energy in every month between 2022-2050. Synapse's modeling reliably meets load in every hour modeled, with no loss of load or unserved energy.

Table 2, below, summarizes near-term actions necessary to launch implementation of the Synapse portfolios. These procurement and analysis activities represent a "no-regrets" series of steps that Duke Energy and stakeholders, with oversight from the North Carolina Utilities Commission (NCUC) and subject to regulatory approvals, can take on the path toward cost-effective, low-carbon power in North Carolina.

Table 2. Short-Term Execution Plan

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2030		
Energy Efficiency	1.5 percent of retail load	• Expand utility energy efficiency savings targets to 1.5 percent of total retail load
Distributed Energy Resources	At least 1 GW by 2035	• Develop and support programs to empower customer-owned energy resources to accelerate contribution to grid needs
Additional Solar	7,200 MW	• Invest in transmission projects to unlock additional cost-effective solar power • Begin procurement of 4 GW of new solar 2022-2024 with target in-service dates of 2025-2028 • Develop interconnection methods that will be robust long-term
Battery Storage	5,600 MW	• Begin procurement for 4 GW of stand-alone storage with target in-service dates of 2025-2028

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

		• Invest in operational capabilities for capitalizing on energy storage resources for grid services
Onshore Wind *(in-state)*	900 MW	• Engage with communities on onshore wind siting • Prepare for continued advancement of onshore wind, long-term
Onshore Wind *(Midwest)*	2,500 MW	• Engage in inter-regional coordination with PJM for facilitating power purchase • Integrate Midwest wind import into short-term transmission planning
Offshore Wind	800 MW	• Initiate development and permitting activities for 800 MW, with eye toward potential additional procurement long-term
Proposed Resource Selections: Options for Long-Term Cost-Effective Carbon Reductions		
Coal Retirement	--	• Develop retirement plans for coal units consistent with economic optimization
Transmission Planning	--	• Develop processes for long-term, prospective and regional transmission planning that can cost-effectively meet economic and carbon reduction requirements of HB 951
Pumped Storage Hydro	1,700 MW	• Conduct feasibility study, develop EPC strategy, and apply at FERC for re-licensing
Hydrogen Planning	--	• Develop more detailed hydrogen fuel cost planning methodology • Conduct studies of hydrogen transport, storage, and distribution • Integrate cost of production and distribution into resource planning

The Carbon Plan process presents an opportunity for North Carolinians to envision what their clean energy future looks like and take decisive steps in that direction. Synapse's analysis charts a path toward a clean energy future that capitalizes on demand-side resources, moves decisively to exit coal generation, avoids unnecessary new gas generation, and deploys proven zero-emissions renewable energy resources at scale, achieving the statutory carbon reduction mandates for 2030 and 2050 at less cost than the Duke Resources scenario.

1. INTRODUCTION

Governor Roy Cooper signed North Carolina House Bill 951 into law on October 13, 2021. Among other things, the bill law directs the North Carolinas Utilities Commission to "take all reasonable steps" to achieve a 70 percent reduction in carbon emissions from the state's power sector by 2030 and carbon neutrality by 2050.[3] The law further requires the NCUC to develop a "Carbon Plan" by December 31, 2022 that achieves these goals. To implement its mandate, the NCUC directed Duke Energy to submit a proposed "Carbon Plan" that achieves these goals and provided that intervenors could file comments on Duke's proposal as well as their own alternative plans. In keeping with core principles of regulating utilities in the public interest and as required by HB 951, the Carbon Plan's resource pathways must also meet ratepayers' energy needs affordably and reliably.

Duke Energy's proposed Carbon Plan filing includes several proposed portfolios of new generation resources designed to meet North Carolinians' energy needs over the long-term, only one of which achieves HB 951's 70 percent reduction requirement by the default 2030 deadline ("Portfolio 1").[4] Each portfolio includes a case where, as directed by the Commission, additional firm gas transport capacity is unavailable,[5] and a case where some additional firm gas transport capacity is available. Cases where additional firm Appalachian gas transport capacity is unavailable are designated as "Alternate" in Duke Energy's proposed Carbon Plan filing.

Duke's proposed portfolios each include two technologies that have yet to be commercially deployed in power generation: small, modular nuclear reactors (SMRs) and widespread production, transport, and storage of hydrogen to either blend into the current gas supply or burn in specialized combustion turbines (CTs). Duke's Carbon Plan proposals place undue reliance on these technologies, rather than commercially available, proven zero-carbon generation and storage technologies combined with investment in energy efficiency, demand response, and transmission, which are elements that high-quality national decarbonization models cite as hallmarks of least-cost power generation in the transition to a low-carbon

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[3] North Carolina House Bill 951. Retrieved at: https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951v5.pdf.

[4] HB 951 allows for delays for meeting the 70 percent reduction target under certain circumstances.

[5] North Carolina Utilities Commission (2021, October). Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Future Direction for Future Planning. Docket No. E-100, Sub 165. Pp. 10-11. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=3142e686-6cb0-43e4-a71a-afb3e2518f94.

energy system.[6] The Duke Energy portfolios' shared dependence on these unproven resources are a meaningful source of operational and cost risks to ratepayers in Duke's proposals.

In addition to reviewing Duke's proposal in detail, Synapse conducted a resource planning analysis using EnCompass, the same capacity expansion and production cost modeling software that Duke Energy used to create their proposed Carbon Plan portfolios. Synapse's EnCompass analysis uses a comprehensive set of modeling inputs from Duke Energy as a baseline and makes several revisions to those model inputs to more accurately account for existing and projected future conditions. Synapse's EnCompass analysis then develops several scenarios that compare the effectiveness of different approaches:

- The *Duke Resources* scenario provides a baseline for comparison with Synapse's *Optimized* and *Regional Resources* scenarios. To provide an "apples-to-apples" comparison, this scenario uses the revised model inputs detailed in Table 3 below but maintains the resources that Duke Energy proposed in "Portfolio 1 – Alternate" portfolio.
- The *Optimized* scenario allows the EnCompass economic optimization algorithm to choose an economically optimal portfolio based on revised model inputs and expanded availability of zero-carbon resources. The resulting *Optimized* portfolio results in a broader range of resources—including energy efficiency, renewable energy, and battery storage—playing a greater role in meeting HB 951's carbon-reduction targets and the needs of Duke's ratepayers at a lower long-term cost.
- The *Regional Resources* scenario illuminates the potential economic benefit of access to Midwest wind resources. The resulting *Regional Resources* portfolio selects Midwest wind resources, in addition to energy efficiency, solar, and storage, and achieves more cost reductions while facilitating earlier retirement of some of Duke Energy's coal units.

All scenarios use the same set of core modeling inputs, allowing for a consistent comparison between the *Duke Resources* baseline and the Synapse scenarios. Portfolios developed in EnCompass meet all resource adequacy requirements and meet 100% of load in all hours modeled over the planning period.

This report describes in detail the development of Synapse's EnCompass scenarios (Section 2) and presents the results of Synapse's modeling analysis (Section 3). Section 4 explores the

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[6] *See:* Princeton *Net Zero America* study (2020); MIT *Value of Inter-regional Coordination* study (2021); Electric Power Research Institute *Powering Decarbonization: Strategies for Net-Zero CO_2 emissions* (2021); and NREL *Seams* Study (2017).

EnCompass modeling conducted by Duke Energy in the development of their proposed Carbon Plan portfolios. The final section of the report provides Synapse's conclusions.

Economic optimization analysis can help to ensure that North Carolina pursues the resource pathway that is in the best interest of North Carolina ratepayers. Synapse's analysis shows that when costs are accounted for appropriately and cost-effective resources are allowed to compete, North Carolina can design a Carbon Plan that achieves HB 951's carbon-reduction requirements with lower costs and less risk than Duke's proposals.

2. SYNAPSE SCENARIO ANALYSIS

2.1. Duke Inputs and Revised Inputs

Duke Assumptions Adopted by Synapse

Synapse used the EnCompass database shared by Duke Energy as the foundation for their development of alternative resource portfolios. This scenario analysis maintains the vast majority of the data inputs and modeling parameters used by Duke in their own modeling, including the following key inputs:

- **System Transmission Topology**: Like Duke, Synapse modeled the DEC, DEP-East, and DEP-West areas individually, with transfer capability between areas. Consistent with the EnCompass analysis presented in Duke Energy's proposed Carbon Plan, the combined Duke Energy system is treated as an "island," separate from neighboring systems.

- **Reserve Margin:** Synapse's analysis maintained the same 17 percent winter reserve margin for the system, with a 15 percent reserve margin in the summer months. Portfolios developed by the EnCompass optimization must meet reserve margin requirements for every month and year in the analysis period.

- **Coal Prices:** Synapse used identical coal price projections to Duke's.

- **Carbon Constraint:** Synapse used the same carbon constraint as Duke Energy's Portfolio 1, which charts a linear mass-based carbon restraint from 2022 to 70 percent reduction from 2005 levels by 2030 and zero carbon, without the use of offsets, by 2050.

- **Ancillary Service Requirements:** Synapse used the same ancillary service requirements as Duke's analysis.

- **Gas Fuel Distribution and Cost Adders:** The Synapse analysis used the same gas fuel distribution infrastructure and cost adders as Duke's analysis.

- **Operating Characteristics of Generation Resources:** Except for the revisions shown in Table 3 below, Synapse adopted Duke Energy's specifications of the operational parameters of their existing conventional and renewable resources, as well as candidate resources. These parameters include, for example, heat rate, capability for co-firing, solar generation curves, and ancillary service capability.

- **Effective Load Carrying Capability:** This analysis assigned the same capacity value to conventional, energy-limited, and variable energy resources as Duke Energy does, using the same effective load carrying capability (ELCC) approach.

- **Transmission "Adders" for New Capacity:** Synapse analysis maintained the same approach to transmission investment that Duke Energy used in their EnCompass analysis by applying an additional cost per megawatt of new capacity to represent the carrying costs of additional transmission. Just as in Duke Energy's analysis, these additional transmission costs vary by resource.

Revisions to Duke Modeling Inputs

After evaluating and analyzing Duke Energy's modeling assumptions and EnCompass files, Synapse made several revisions to the modeling inputs used by Duke in developing their proposed Carbon Plan. These revised inputs provide a more accurate and realistic projection of future conditions. Table 3 provides a summary of these revisions. Additional details for these inputs can be found in Appendix A.

Table 3. Duke Inputs and Revised Inputs

INPUT	DUKE INPUTS	REVISED INPUTS
	System Settings	
Gas Prices	NYMEX futures for 5 years, blended into EIA 2021 AEO 'base' forecast[7]	NYMEX futures for 24 months, blended into EIA 2021 AEO 'base' forecast
Hydrogen Prices	Duke Energy internal forecast	Industry reference (BloombergNEF, Hydrogen Council)
	Existing Resources	
Coal Fixed Operations & Maintenance Costs	Internal Duke estimate	Forecast based on EIA's Sargent & Lundy fixed operations & maintenance study[8]
Gas Plant Depreciation	35 year book and operational lifetime[9]	Book life 20 years; Operational life 25 years
	Candidate Resources	
SMR Nuclear Capital Costs	Internal Duke estimate	EIA AEO 2022[10]
Gas New-Build Capital Costs	Internal Duke estimate	EIA AEO 2022
H2 New-Build Capital Costs	[BEGIN CONFIDENTIAL] [redacted]	[BEGIN CONFIDENTIAL] [redacted]

[7] Appendix E, p. 39.

[8] Sargent & Lundy (2018, May). Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs. Prepared for US Energy Information Administration. Retrieved at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[9] Appendix E, p. 31.

[10] US Energy Information Administration (2022, March). Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2022*. Retrieved at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

	[redacted] [END CONFIDENTIAL]	[redacted] [END CONFIDENTIAL]
H2 Retrofit Costs	Internal Duke estimate	25 percent of initial capital cost[12]
Solar Costs	Duke estimate from Guidehouse	NREL ATB 2022 – Moderate[13]
Solar-plus-Storage Costs	Duke estimate from Guidehouse	Mix of NREL ATB 2022 – Moderate (Solar) and Advanced (Storage)
Onshore Wind Costs	Duke estimate from Burns & McDonnell	NREL ATB 2022 – Moderate
Offshore Wind Costs	Duke estimate from Guidehouse	NREL ATB 2022 – Advanced
Storage Costs	Duke estimate from Guidehouse	NREL ATB 2022 – Advanced

To ensure consistency in comparing scenario results, Synapse used these revised inputs to calculate costs and economically optimize capital projects, retirements, and dispatch across all scenarios included as part of its analysis.

Synapse also adjusted some EnCompass settings compared to Duke Energy's configuration for its analysis. These are detailed, alongside other relevant issues that Synapse encountered in its EnCompass analysis, in Appendix B.

2.2. Baseline Portfolio for Scenario Analysis

Synapse's analysis includes a baseline scenario, which can be thought of as a "business as usual" counterfactual. Using a baseline in this way allows the comparison of resource additions and costs with a consistent set of underlying assumptions. Comparing results across analyses with different underlying assumptions can obscure why two outcomes might be different; this analysis uses a baseline scenario to avoid that issue.

Synapse identified as the baseline scenario the portfolio labeled by Duke Energy as "Portfolio 1 – Alternate" in their Carbon Plan proposal because it is designed to comply with the default HB 951 requirement of reaching 70 percent emissions reductions by 2030 and does not assume additional firm gas transmission capacity. Based on least-cost planning principles of avoiding major risks and on recent developments affecting Appalachian gas transmission, including the cancellation of the Atlantic Coast Pipeline and the uncertain future of the Mountain Valley

[11] Confidential Duke Energy Response to North Carolina Public Staff (NC Public Staff) Data Request (DR) 8-20.

[12] Öberg, S., Odenberger, M., & Johnsson, F. (2022). Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems. *International Journal of Hydrogen Energy*, 47(1), 624-644. Retrieved at: https://www.sciencedirect.com/science/article/pii/S0360319921039768.

[13] National Renewable Energy Laboratory (2022, June). Annual Technology Baseline. Retrieved at: https://atb.nrel.gov/.

Pipeline,[14] planning for a future without access to firm Appalachian gas represents a "no-regrets" approach.

2.3. Synapse Scenarios

Duke Resources Scenario

The *Duke Resources* scenario re-creates the set of resources proposed by Duke in "Portfolio 1 – Alternate."

Due to the extent of changes made in post-processing by Duke Energy in the development of their proposed scenarios and the analytical issues with these approaches described in Section 4, it was not feasible to re-create the same post-processing in Synapse's analysis. Instead, Synapse re-created precisely the same set of resources from Duke Energy's proposed "Portfolio 1 – Alternate" (P1-Alt). For this scenario, EnCompass was not allowed to economically optimize resource builds or retirements; instead, additions and retirements were all explicitly defined based on Duke Energy's proposed P1-Alt. This treatment places the set of resources to be either approved or denied by the NCUC in the context of a set of assumptions that better reflect actual and projected market conditions.

Optimized Scenario

The *Optimized* scenario allows the EnCompass model to select the set of resources and retirements that result in the most economic portfolio for North Carolina ratepayers under revised inputs and assumptions.

Duke Energy constrains deployment of several resources in their EnCompass modeling, which impede EnCompass's options for economic optimization in their proposed Carbon Plan. On the demand side, Duke Energy's baseline energy efficiency forecast assumes that incremental utility energy efficiency savings will decline from present levels to 1 percent of retail load (net of opt outs) over the long term. This treatment pre-emptively forecloses the ability for energy efficiency to cost-effectively compete with other resources or meet the system's energy needs. For the *Optimized* scenario, Synapse assumes that Duke Energy expands, rather than contracts, incremental energy efficiency savings to 1.5 percent of total retail load. For more details on Synapse's energy efficiency forecast, see Appendix A. Synapse also assumes that market trends and Duke Energy policies will continue to support the growth of distributed energy resources

[14] In its October 21 Order on Duke Energy's 2020 IRPs, the NCUC stated that "Cancellation of the Atlantic Coast Pipeline and the present status of the Mountain Valley Pipeline extension both counsel the need for consideration of such possibility [of constrained transmission capacity." NCUC (2021), p. 7.

including rooftop solar, and the *Optimized* scenario adopts Duke Energy's high net energy metering (NEM) forecast.

Duke Energy's availability assumptions on the supply side constrain some resources, while allowing for the dramatic expansion of others. For example, Duke Energy allowed EnCompass to select a total of 10 GW of new nuclear capacity over the planning period, while constraining 4-hour batteries to 3.3 GW over the same period.[15] Synapse made several revisions to these inputs, consistent with reasonable expectations about future resource availability. These include a modest increase to solar availability to account for future procedural and policy innovations in interconnection, removing the aforementioned cap on 4-hour battery storage, and applying a more conservative approach to new nuclear deployment. Such assumptions about resource availability do not force EnCompass to choose these resources; instead, they provide more flexibility for the model to choose optimal resources. Synapse implemented changes to resource availability for the *Optimized* scenario as well as the *Regional Resources* scenario.

Table 4, below, shows the limitations that Duke placed on selected demand- and supply-side resources' eligibility to be selected by the EnCompass model, and compares those to the limitations that Synapse imposed in the Optimized Portfolio. The availability of each resource is expressed in capacity and/or number of units. Notably, incremental gas generation resources are not further constrained in the Synapse optimization compared to Duke Energy's assumptions around no further Appalachian firm gas transport. Additional details on these parameters can be found in Appendix A.

Table 4. Demand-Side Resources and Resource Availability Limits in Synapse *Optimized* Portfolio

Input	Duke Inputs	Revised Inputs
Energy Efficiency & DERs	Incremental savings at 1% of 'available' retail load; 'base' net metering forecast[16]	Ramping up to incremental savings of 1.5% of total retail load; 'high' net metering forecast
New Gas CCs and CTs	One 812 MW CC unit; no limits on CTs[17]	Same as Duke

[15] Synapse found that, for at least some portion of capacity expansion runs in Duke Energy's EnCompass database, 4-hour batteries were constrained to 3.3 GW (cf. the "HB951 CapEx-A2 (SMC2030-Seg8-ForceRet-NewZ4FT)" scenario and the "HB 951-Declining Bat ELCC-3.24.22 w/ BCPH2 Update" dataset). Counsel from Duke Energy verified that no confidential material has been divulged relating to this portion of the confidential EnCompass database.

[16] Appendix E, p. 16-17.

[17] Appendix E, p. 30-32.

SMR Deployment	Up to 20 units through 2050[18]	Up to 4 units through 2050
Economic Coal Retirement	Manually set by Duke Energy	Endogenous to EnCompass
Existing Gas Retirement	Not allowed to retire	Endogenous to EnCompass
Annual Solar Deployment Limits	Ramping from 750 MW in 2027; 1,800 MW in 2028 onwards[19]	1,200 MW in 2025; 1,800 MW 2026–2028; 2,300 MW in 2029 onwards
4-hour Storage Deployment Limits	System maximum 3.3 GW[20]	No maximum
Offshore Deployment Limit	1,600 MW through 2032, up to 4.8 GW through 2044[21]	8 GW by 2040; 10 GW by 2050

Regional Resources Scenario

In addition to the resources made available to the model in the *Optimized* scenario, the *Regional Resources* scenario allows the model to select power purchase agreements (PPAs) for Midwest wind, imported through the PJM Interconnection (PJM). These PPA resources were designed to imitate the Midwest wind resources identified in the North Carolina Transmission Planning Consortium's 2021 Public Policy Study.[22] Costs for these PPAs include the PJM border charge for firm point-to-point transmission service. Further details about these PPAs can be found in Appendix A.

[18] Appendix E, p. 33-36.

[19] Appendix E, p. 30.

[20] See footnote 15.

[21] Appendix E, p. 38.

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

3. Synapse EnCompass Modeling Results

For each scenario, Synapse performed a two-step analysis in EnCompass. First, Synapse performed a capacity expansion analysis for each scenario, which identifies the pathway of new resources and retirements that the scenario will take 2022–2050. Next, Synapse performed a production cost analysis for each scenario, which simulates the operation of the identified resource pathway under more granular technical and temporal settings. The results of capacity expansion modeling are presented in Sections 3.1 and 3.2; results of production cost modeling are used for Sections 3.3 through 3.6.

3.1. Capacity Expansion Modeling Results

Figure 2 shows incremental resources and retirements chosen by capacity expansion modeling for each portfolio through 2030. In the *Duke Resources* scenario, a substantial amount of coal capacity is retired, and several additional gigawatts of gas capacity are accompanied by an increase in solar and storage capacity. The *Optimized* scenario retires the same amount of coal and focuses capacity deployment on solar plus storage. In the *Regional Resources* scenario, more of Duke's coal fleet can retire because of additional cost-effective Midwest wind resources.

Figure 2. Incremental Resource Builds and Retirements, 2022–2030

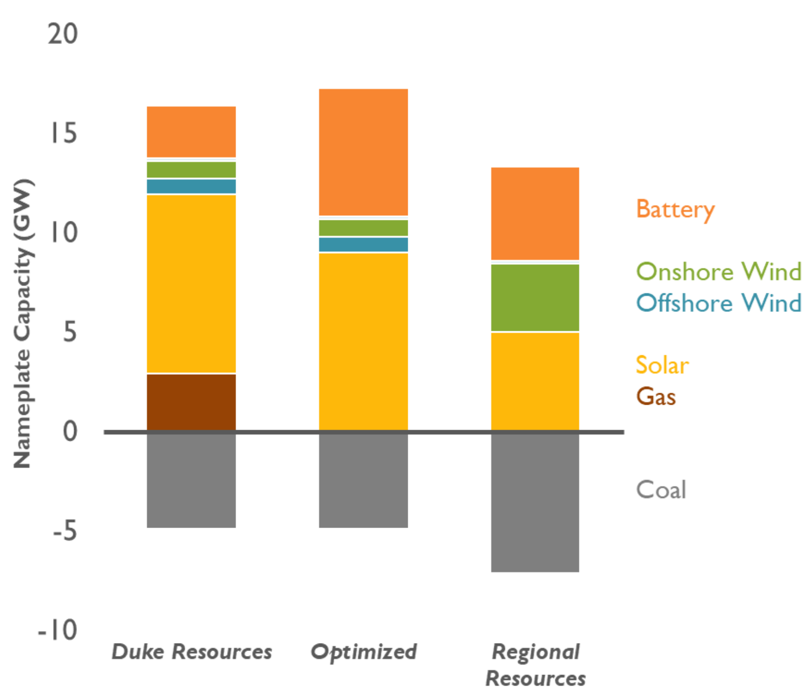


Figure 3 below shows the capacity expansion modeling results for the scenarios Synapse evaluated compared to the present capacity mix in 2022. By 2030, both the *Optimized* and *Regional Resources* scenarios show a notable decrease in carbon-emitting capacity, while the *Duke Resources* scenario's fossil capacity shifts incrementally toward gas from coal capacity. All scenarios contemplate an expansion of solar and energy storage resources, with the *Regional Resources* scenario selecting the most wind capacity (2.5 GW of onshore wind) of the scenarios over this period. Each 2030 portfolio was selected to achieve the 70 percent HB 951 carbon reduction requirement by 2030.

Figure 3. Capacity by Resource Type, 2022 and 2030, by Scenario

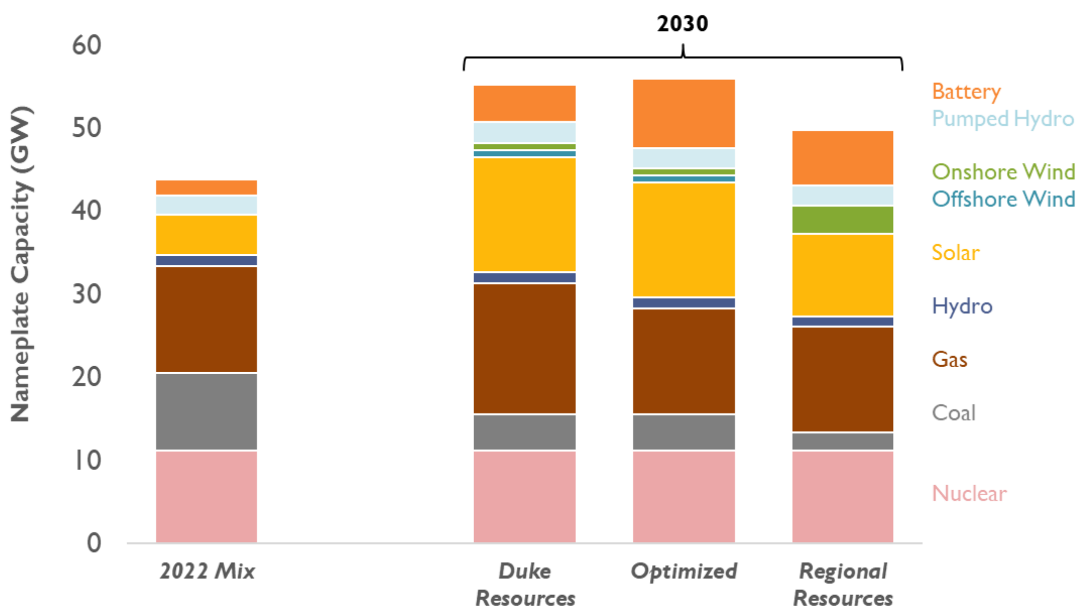


Figure 4 shows incremental resources and retirements between 2030 and 2050 for each scenario. Over this period, the *Duke Resources* scenario is noticeably different from the other scenarios, contemplating roughly 10 GW of incremental capacity of both new nuclear and hydrogen-burning resources. Both the *Optimized* and *Regional Resources* scenarios continue to build out solar and storage capacity. All resources retire the remainder of Duke's coal fleet over this period, and much of Duke Energy's gas capacity is also retired. The *Optimized* and *Regional Resources* scenarios retire an incremental 800 to 1,200 MW of gas capacity instead of retrofitting those units to burn 100% hydrogen.

Figure 4. Incremental Resource Builds and Retirements, 2030–2050

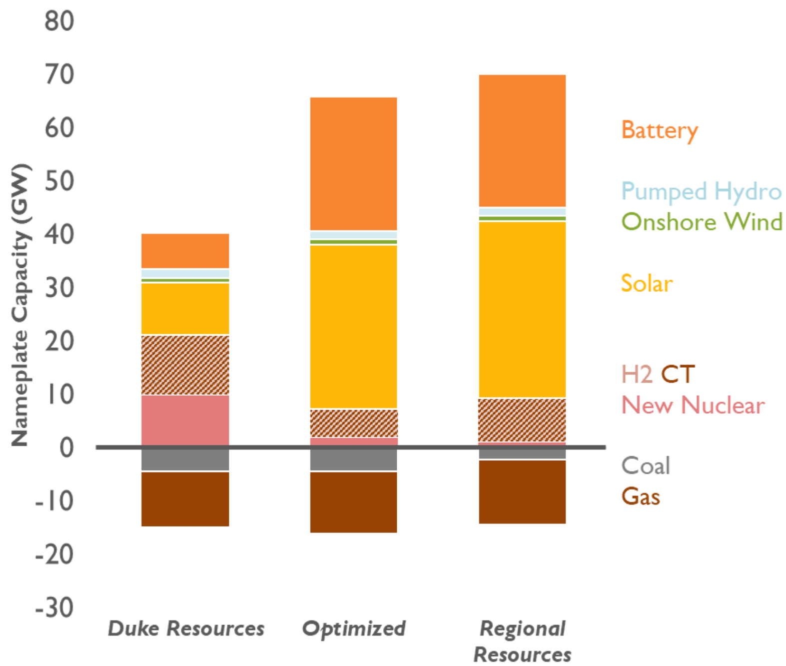
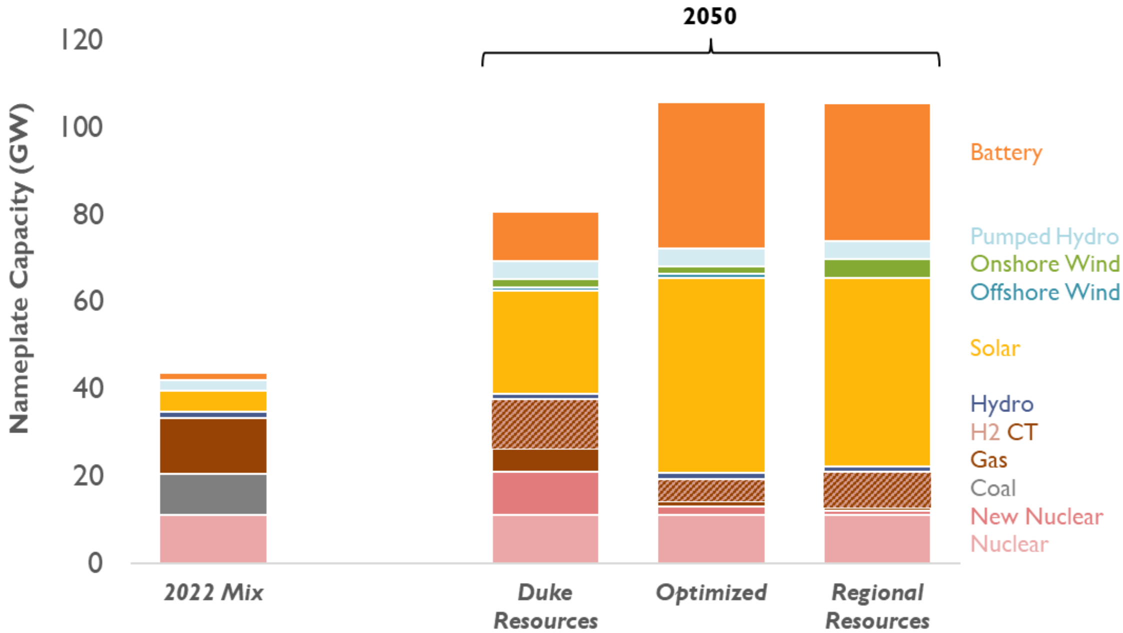


Figure 5 shows the total capacity for each portfolio in 2050 versus the 2022 capacity mix. In this case, differences in resource capacity are much clearer between the *Duke Resources* and the Synapse *Optimized* and *Regional Resources* portfolios. The *Duke Resources* portfolio includes substantial additions of new nuclear and hydrogen CTs, bringing 2050 nuclear, gas, and hydrogen capacity roughly equivalent to total generating capacity in 2022. In the *Optimized* and *Regional Resources* scenarios, EnCompass selects additional solar and storage resources instead of new nuclear and hydrogen. Load and capacity tables for these scenarios can be found in Appendix C.

Figure 5. Capacity by Resource Type, 2022 and 2050, by Scenario



3.2. Optimized Retirements

Retirement of Coal Units

Table 5 shows retirement years for Duke Energy's coal units by scenario. In the *Duke Resources* scenario, these retirement years are set manually, subject to the process described in Section 4; in the Synapse scenarios, these coal units are eligible to be economically retired by EnCompass.[23]

[23] Transmission must-run designations were left intact to ensure no adverse impacts to transmission conditions.

Table 5. Retirement Year for Selected Coal Units, by Scenario

Coal Unit	Capacity (MW)	Retirement Year		
		Duke Resources	*Optimized*	*Regional Resources*
Belews Creek 1-2	2,220	2036	2034	2030
Cliffside 5	546	2026	2023	2023
Marshall 1-2	760	2028	2026	2026
Marshall 3-4	1,318	2032	2032	2032
Mayo 1	713	2028	2028	2028
Roxboro 1-2	1,053	2028	2028	2028
Roxboro 3-4	1,400	2027	2027	2027

Source: Appendix E, p. 49.

Synapse's optimization finds that, even without building incremental gas CC or CT resources, accelerating retirement of coal units is still in the best interest of ratepayers. EnCompass modeling shows that, for instance, Duke could retire the Cliffside 5 unit in 2023 and continue to meet system reserve margin requirements and serve load, while delivering more cost-effective power. The Synapse scenarios also choose to retire the Belews Creek units either two or six years earlier and Marshall Units 1-2 two years earlier, reflecting the uneconomic nature of these units.

Retirement of Gas Units

Duke Energy's Carbon Plan assumes that, by 2047, hydrogen infrastructure and retrofit technology will allow for existing gas-fired units to be retrofitted to be capable of burning 100 percent hydrogen. [24] Duke Energy's scenarios assume that gas-fired resources with lives that extend past 2050 will each be retrofitted. In the Synapse scenarios, these units may be either retired or retrofitted for 100 percent hydrogen operations, depending on which choice is most economical. The status of each of these resources in 2050 by scenario is presented in Table 6.

[24] Appendix E, p. 23.

Table 6. 2050 Status of Gas-Fired Resources, by Scenario

Gas Unit	Capacity (MW)	2050 Status		
		Duke Resources	*Optimized*	*Regional Resources*
Asheville Combined Cycle	560	Retrofitted	Retrofitted	Retrofitted
W.S. Lee Combined Cycle	750	Retrofitted	Retired	Retired
Lincoln Combustion Turbine 17	402	Retrofitted	Retrofitted	Retired
Sutton Combustion Turbines	84 units (42 MW x 2 units)	Retrofitted	One unit retired	Retired

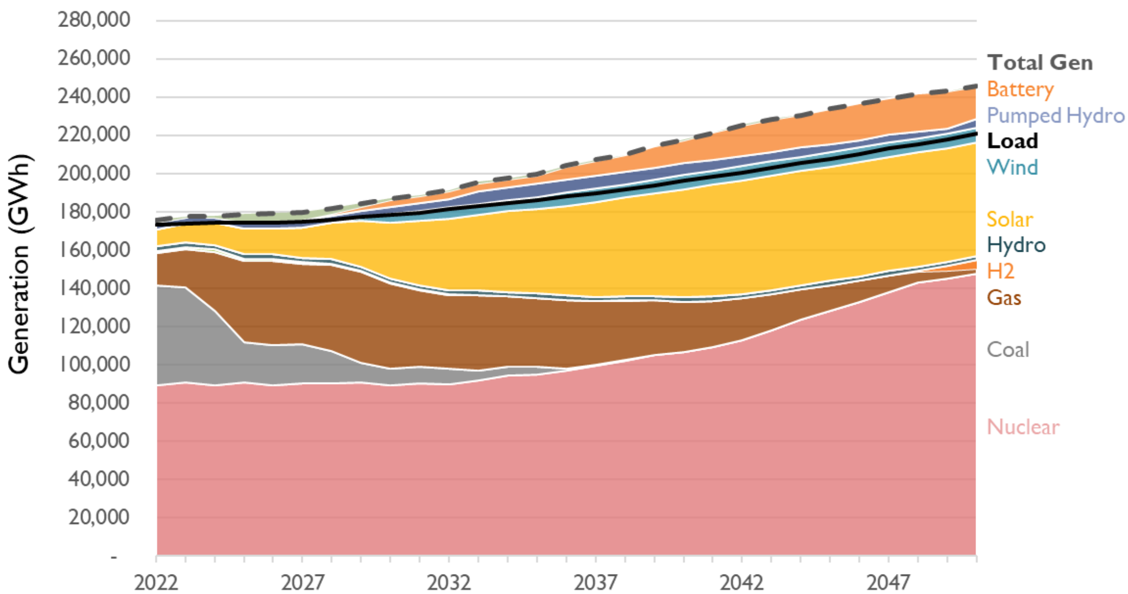
Source: Appendix E, p.23.

In both the *Optimized* and *Regional Resources* scenarios, some gas units are retired rather than being retrofitted for hydrogen use to avoid the incremental capital cost of hydrogen retrofitting. Retirement of these units reflects the additional risk of carbon-emitting generation: As carbon reduction requirements tighten, these units must either reduce generation or undergo substantial technical changes to maintain operation. Given the uncertainty around the feasibility and cost of zero-carbon retrofits, the assumption that such a retrofit is available is a substantial source of risk for prospective and existing gas units.

3.3. Production Cost Modeling Results

Figure 6 shows annual generation over time for the *Duke Resources* scenario, as optimized by EnCompass's production cost modeling function. The most striking feature of *Duke Resources'* generation curve is the substantial increase in total nuclear generation over time, producing 65 percent more generation in 2050 than the technology did in 2022. In the later years, solar and storage grow to serve most of the load not already served by nuclear. Gas share of total generation peaks at 30 percent in 2029.

Figure 6. Annual Generation Over Time, *Duke Resources* Scenario



Annual generation by technology for the *Optimized* scenario is provided in Figure 7. Nuclear generation remains constant in this scenario, generating roughly as much in 2022 as it does in 2050. Solar and energy storage grow to meet remaining load over the period, with renewable generation representing 62 percent of total generation in 2050. In both scenarios, gas and hydrogen generation combine to serve 3% of total load in 2050.

Figure 7. Annual Generation over Time, *Optimized* Scenario

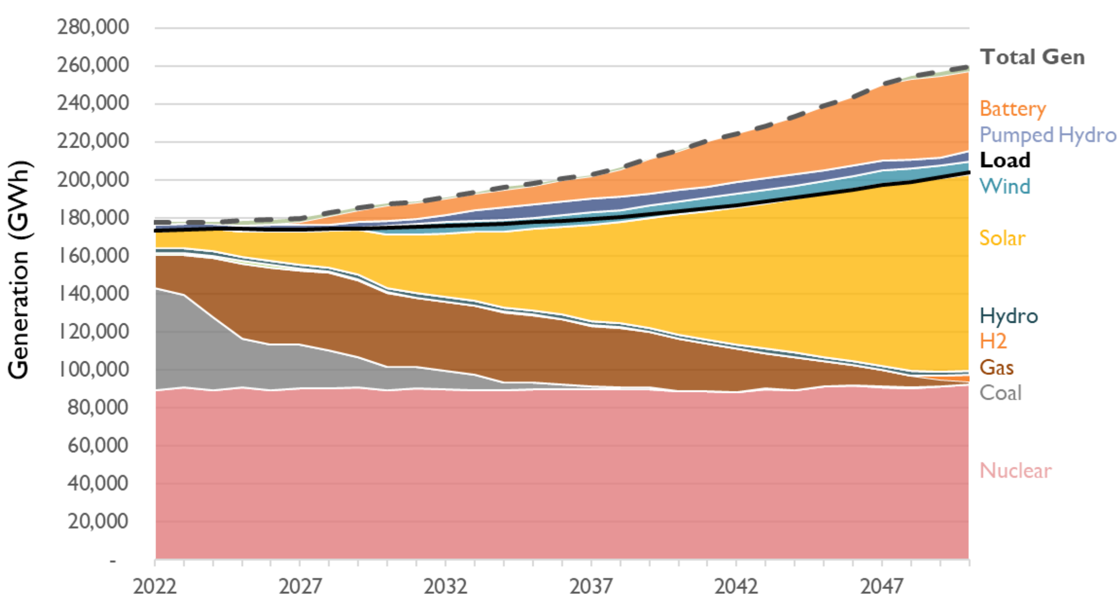
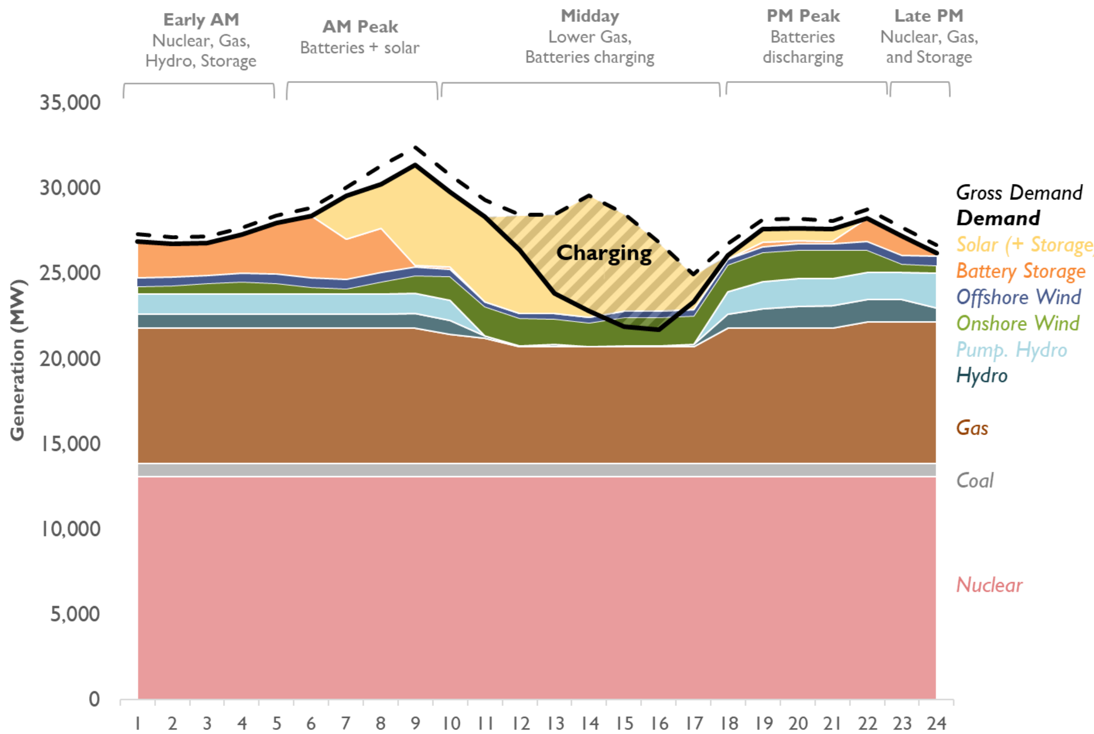


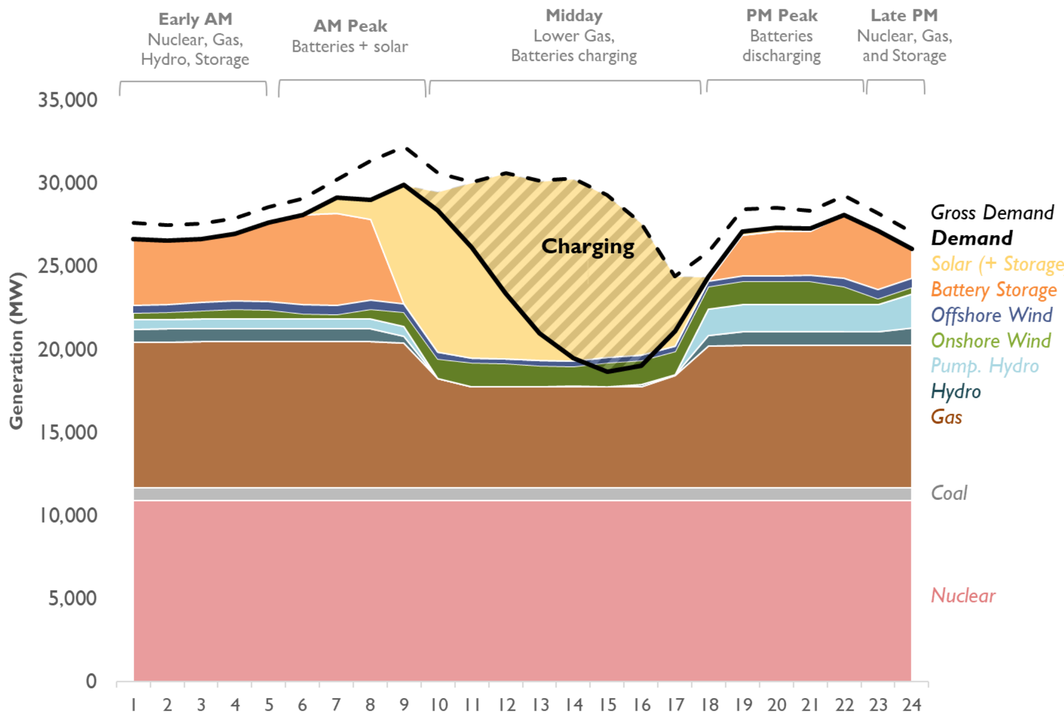
Figure 8 and Figure 9, below, show the mix of energy technologies that serve load during winter peaks in 2040 in the *Duke Resources* and *Optimized* scenarios. These graphs provide additional detail on how the system could dispatch its available resources to meet load under high-stress conditions.

Figure 8. Winter Peak Generation by Technology, January 2040, *Duke Resources* Scenario



The black line represents net demand served by generation resources, with shaded areas above the line representing charging for battery storage resources. The dotted "gross demand" line shows the impact of both battery charging and utility energy efficiency on load. In the *Duke Resources* scenario, the system has roughly 22 GW of nuclear, gas, and coal resources (although the lone coal unit, Cliffside 6, is running on 100-percent gas). The *Duke Resources* scenario selects considerable amounts of solar-plus-storage resources, which are able to shift dispatch to earlier in the day to meet the winter morning peak. In the middle of the day, solar generation allows higher-cost resources to ramp down and charges battery storage. Overnight, hydro, gas, and storage resources ramp up to meet demand.

Figure 9. Winter Peak Generation by Technology, January 2040, *Optimized* Scenario



In the *Optimized* scenario shown in Figure 9, the relative proportions of gas and nuclear are lower while the proportions of solar and storage are higher. This graph also shows the impact of investment in increased energy efficiency over time (2022–2040), as cumulative EE savings push morning net peak load down by roughly 2 GW. As before, battery storage is used to meet load overnight and charged during mid-day, when low-cost solar generation is available.

Both of these graphs demonstrate the basic dynamics of a grid with increased penetration of renewable energy resources. Renewables provide plentiful, low-cost power, and flexible resources like storage and pumped hydro are able to charge during high-solar periods and discharge when needed. Effectively, these storage resources shift low-cost renewable energy around to meet load. Compared with the *Duke Resources* scenario in Figure 8, the *Optimized* scenario in Figure 9 shows the incremental benefit of additional energy efficiency, which drives down load in all hours, and the flexibility of battery storage, which is able to support generation around the clock.

3.4. Carbon Dioxide Emissions

Consistent with Duke Energy's production cost modeling, Synapse did not include any per-ton carbon costs in its base production cost modeling. Nevertheless, the portfolios generally trace the linear carbon target to 70 percent reduction by 2030 and zero carbon by 2050. Synapse's analysis finds that, without per-ton pricing of carbon emissions, the *Duke Resources* scenario does not comply with the HB951 70 percent reduction requirement in 2030. Table 7 shows carbon emissions in 2022, 2030, and 2050 across scenarios.

Table 7. Carbon Emissions by Scenario

Carbon Emissions (Million Tons)	*HB 951 Carbon Requirement*	*Duke Resources*	*Optimized*	*Regional Resources*
2022	*None*	59.4	59.4	59.4
2030	24.9	25.2	24.8	24.9
2050	0	0	0	0

3.5. Net Present Revenue Requirements of Synapse Portfolios

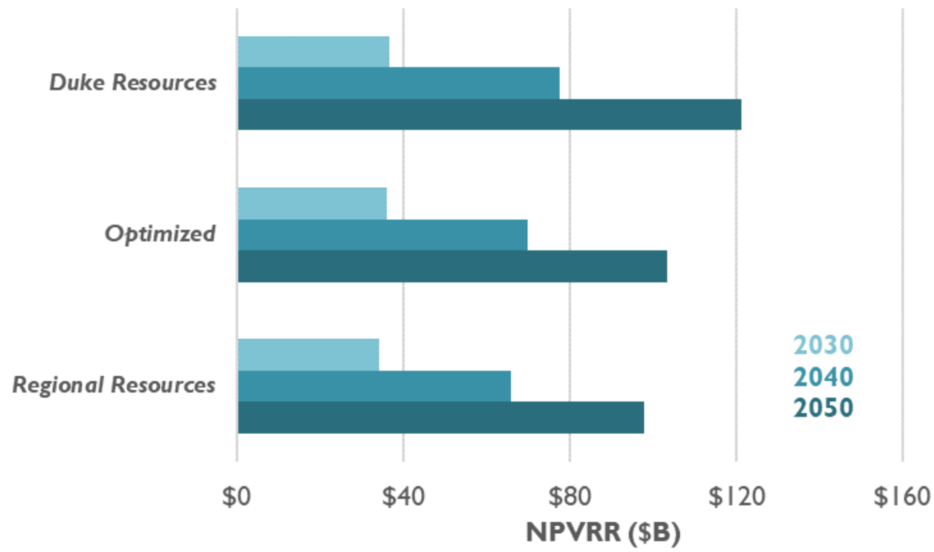
Table 8 shows the net present revenue requirement (NPVRR), or long-term system cost to ratepayers, for each portfolio over time, discounted by Duke Energy's weighted average cost of capital. Each of the Synapse portfolios has a lower NPVRR than the *Duke Resources* portfolio, with $8 to 12 billion in savings to ratepayers in 2030 and $18 to 23 billion in 2050. These savings are principally driven by avoiding the high capital expenditures associated with Duke Energy's buildout of nuclear reactors, gas units, and hydrogen units in the *Duke Resources* case and the higher energy efficiency forecast that results in less total load to be served by supply-side resources. Again, the *Regional Resources* portfolio stands out for its sizable cost reductions even compared to the *Optimized* scenario, with savings of $5 billion compared to the *Optimized* scenario and $23 billion compared to the *Duke Resources* scenario on a net present basis through 2050. This result demonstrates the economic benefit of accessing cost-effective, zero-carbon power from outside the Duke Energy service territory.

Table 8. Net Present Value Revenue Requirement over Time by Scenario

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8
2050 NPVRR ($B)	$121.2	$103.5	$98.1

Figure 10 shows the revenue requirement by scenario for 2030, 2040, and 2050.

Figure 10. Revenue Requirement by Scenario



In general, the revenue requirement produced by EnCompass is not designed to be comprehensive or directly comparable to the entire set of costs incurred by a utility as presented in a rate case. Instead, the NPVRR reported by EnCompass represents the portion of total revenue requirement that goes toward construction and operation of generation resources, as well as incremental transmission. Synapse added incremental energy efficiency costs to both scenarios to ensure consistent treatment of demand-side resources.

3.6. Sensitivity Analysis

Synapse ran several sensitivities using EnCompass's production cost modeling function to evaluate the impact of other potential future conditions on the different portfolios.

RGGI Sensitivity

Synapse included a sensitivity in which the Carolinas joined the Regional Greenhouse Gas Initiative (RGGI) to assess the impact that RGGI would have on Duke system emissions.[25] This sensitivity is implemented by applying a per-ton price to carbon emissions based on the projected RGGI-wide clearing price. Compared to Duke Energy's carbon risk sensitivities, which

[25] Synapse used an annual RGGI allowance cost forecast from the Horizons Energy National Database's Fall 2021 release.

start at $5 per ton and increase by up to $10 annually, this RGGI forecast adds a per-ton cost to carbon emissions in the range of $10 to $50 per ton of CO_2.

The RGGI sensitivity impacted generation mix and projected emissions for the *Duke Resources* scenario. The incentive provided by RGGI shifted marginal generation from coal to gas resources, resulting in a decrease in coal generation of 10,000 GWh. Through 2035, inclusion of RGGI resulted in reductions of emissions of 0.2 to 1.1 million tons annually. This amount of reduction was sufficient to reduce the *Duke Resources* scenario's emissions to reach the HB 951 70 percent reduction requirement in 2030.

Per-ton costs on carbon generate RGGI revenues, which are deployed in a variety of ways across RGGI states to the benefit of ratepayers.[26] In the *Duke Resources* case, RGGI revenues reach $2 billion on a net-present basis by 2030 and $3.7 billion by 2050. These revenues could pay for the entirety of *Duke Resources'* utility energy efficiency expenditures over that period.

High Gas Price Sensitivity

Synapse modeled the *Duke Resources* and *Optimized* scenarios with a higher gas price forecast based on Duke Energy's high gas price forecast and Synapse's hydrogen price forecast. For these sensitivities, Synapse found an increase in costs in both scenarios to reflect the higher cost to run Duke's existing gas resources. Table 9 shows the revenue requirement for high gas price sensitivities for the *Duke Resources* and *Optimized* portfolios.

Table 9. Revenue Requirement for High Gas Sensitivities

Results (2022-2050)	*Duke Resources*	*Duke Resources – High Gas Price*	*Optimized*	*Optimized – High Gas Price*
2030 NPVRR ($B)	$36.7	$39.8	$36.0	$38.7
2040 NPVRR ($B)	$77.7	$84.2	$69.8	$76.0
2050 NPVRR ($B)	$121.2	$128.7	$103.5	$110.7

Lower Energy Efficiency Sensitivity

To ensure that the *Optimized* portfolio would remain cost-effective even with a lower level of energy efficiency, Synapse conducted a sensitivity that assumed energy efficiency savings

[26] Regional Greenhouse Gas Initiative, Inc. (2022). The Investment of RGGI Proceeds in 2020. Retrieved at: https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2020.pdf.

equivalent to 1 percent, rather than 1.5 percent, of total retail load. The resulting revenue requirements for this lower-EE sensitivity are shown in Table 10.

Table 10. Net Present Revenue Requirement over Time, Energy Efficiency Sensitivities

Results (2022-2050)	*Optimized*	*Optimized – Low EE*
2030 NPVRR ($B)	$36.0	$36.0
2040 NPVRR ($B)	$69.8	$71.0
2050 NPVRR ($B)	$103.5	$106.4

Increased energy efficiency investment in the short term keeps the *Optimized* and *Optimized – Low EE* scenarios at the same NPVRR through 2030, but those investments pay off in the long term where they result in a reduction of revenue requirement through 2050 of $2.9 billion. In terms of resources, the *Optimized – Low EE* sensitivity builds substantially more resources to serve additional load compared to the *Optimized* scenario: Overall, the *Low EE* case builds an additional 752 MW of gas combustion turbines, 3.8 GW of solar, and 2.6 GW of energy storage. Savings over time in the *Optimized* case demonstrates that investment in energy efficiency is a more cost-effective choice than selecting additional supply-side resources.

4. Duke's EnCompass Analysis and Post-Processing Methodology

Duke Energy used the EnCompass capacity expansion and production cost modeling software as the starting point for their resource planning analysis. When used appropriately, economic optimization software like EnCompass can identify the resource pathway that delivers power at least cost. When model inputs do not accurately represent current and future conditions, or when the user overrides resource selections identified by EnCompass with manual post-processing changes, however, the analytical power of EnCompass software is diminished. As a result, selected portfolios are not likely to be most cost-effective for ratepayers.

Rather than providing a wide selection of resource options and allowing EnCompass economic optimization to select an optimal portfolio, Duke Energy's methodology constrained resource choices and, over several analytical steps, directly over-rode selections made by EnCompass by "forcing in" additional resources or making substitutions. These actions undermine the ability for portfolios to meet HB 951's requirements that portfolios deliver carbon reductions at least cost. The proposed Carbon Plan filing details the alterations Duke Energy made in developing their proposed portfolios:

- **Coal Retirement.** Duke Energy used a combination of EnCompass analysis and additional, manual delays to identify the retirement years for coal units proposed in the Carbon Plan.
- **Replacement of Battery Storage with Combustion Turbines.** Duke Energy manually replaced battery storage selected by the economic optimization model with additional gas-fired CTs.
- **Resource Adequacy and Reliability Verification.** Duke Energy added additional CTs based on a high-level assessment of continued portfolio reliability metrics.

4.1. Duke's Coal Retirement Methodology

In its order reviewing Duke Energy's 2020 IRPs, the NCUC directed Duke Energy to further analyze the retirement timing of Duke Energy' coal fleet.[27] Duke Energy conducted their previous coal retirement analysis without a capacity expansion and production cost model like EnCompass, and instead used a non-economic "ranking" of coal units and an imprecise estimate of the value of the legacy coal fleet's capacity and energy.[28] In contrast, using economic optimization software to dynamically select coal retirement dates allows the retirement of coal resources to be timed optimally with the addition of new resources and re-dispatch of existing resources, resulting in lower total costs across the entire portfolio. In terms of coal unit economics, endogenous retirement analysis that allow the portfolio as a whole to adapt and evolve provides a much more precise analytical tool than discrete analyses that must approximate the value of energy and capacity to the system.

In developing their proposed Carbon Plan, Duke Energy did allow EnCompass to co-optimize coal retirement timing with new resource construction and resource dispatch as a part of their overall coal retirement analysis. Duke Energy's subsequent manual changes to retirement dates, however, functionally over-rode the conclusions of the endogenous retirement analysis conducted in EnCompass.

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[27] *See:* North Carolina Utilities Commission (2021, October). Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning. Docket No. E-100 Sub 165. P. 10. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=3142e686-6cb0-43e4-a71a-afb3e2518f94.

[28] *Ibid.*

Duke Energy's manual adjustments created a difference of up to six years between the endogenously-identified least-cost retirement timeline selected by Duke Energy's original EnCompass results and the proposed retirement timeline Duke Energy ultimately chose.[29] Compared to the "Earliest Practicable" retirement years identified in Duke Energy's 2020 Integrated Resources Plans, this difference grows to eight years. Synapse's EnCompass analysis projects that keeping these coal units online to meet Duke Energy's proposed retirement dates (rather than those selected by EnCompass) would cost ratepayers an additional $1.4 billion, even before accounting for fuel costs or variable operation and maintenance costs, which would further increase total costs to ratepayers. Delaying these retirements also diminishes the value of securitizing these assets.

Table D-1, in Confidential Appendix D, shows coal unit retirement years as selected by EnCompass (labeled as "2022 Most Economic Retirement Year" in the table) versus those chosen by Duke Energy (labeled as "2022 Proposed Retirement Year"). The table also includes earliest practicable coal retirement dates from Duke Energy's 2020 Integrated Resources Plans as "2020 Earliest Practicable Retirement Year."

Duke Energy justifies their proposed delays beyond the economically optimal coal retirement dates by noting the need to consider transmission constraints and replacement resources when retiring legacy coal units. However, Duke's proposed Carbon Plan does not provide enough information to systematically understand the nature of these constraints, identify potential solutions, and develop resources to facilitate coal retirement. [30] Duke Energy's Appendix P states that the Belews Creek units "will continue to operate into the 2030s," for example, even though Duke Energy's 2020 Integrated Resource Plans identified 2029 as the earliest practicable retirement date for these units.[31] To the extent that local transmission or generation resources are needed to retire these units, Duke Energy could identify and accelerate development of these resources, including using transparent, all-source procurement for replacement generation resources, to meet economical retirement dates.[32] Instead, Duke Energy's methodology results in continued operations of uneconomical coal plants to ratepayers' detriment.

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[29] Confidential Duke Energy response to North Carolina Sustainable Energy Association and Southern Alliance for Clean Energy (NCSEA-SACE) DR 3-39(L). Counsel from Duke Energy verified that no confidential material has been divulged relating to this confidential response to data request.

[30] Appendix E, p. 48.

[31] Duke Energy Carbon Plan Appendix P (Appendix P), p. 15 and Duke Energy Carolina Integrated Resource Plan 2020 Biennial Report, p. 175.

[32] For an example of all-source procurement used for coal unit retirement, see Northern Indiana Public Service Company's 2018 Integrated Resource Plan.

4.2. Duke's Manual Replacement of Battery Storage with CTs

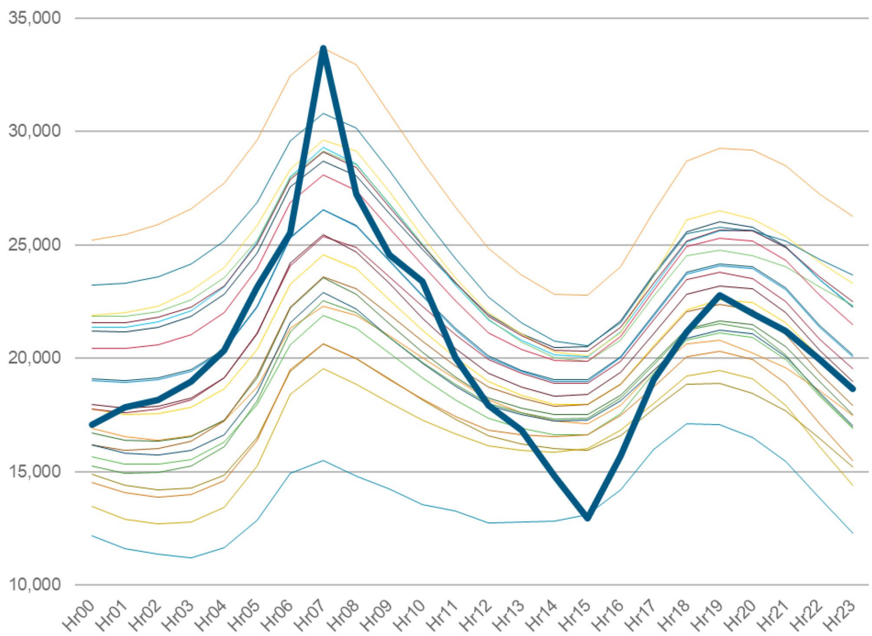
After the coal retirement analysis, Duke Energy completed a capacity expansion and production cost modeling exercise with Duke's chosen coal retirement dates "locked in." Next, Duke Energy replaced battery storage identified by EnCompass as economically optimal with additional gas CTs. As a result of this process, Duke Energy manually removed between 1.6 and 2 GW of battery storage that had been selected by the EnCompass model from their portfolios and added between 1.5 and 1.9 GW of natural gas CTs.[33] This represents a substantial portion of the total new natural gas-burning CTs built over the planning period in Duke Energy's proposed portfolios: In "Portfolio 1 – Alternate," CTs added during this step represent five of the seven total natural gas-burning CTs added (or over 70 percent of total gas CT capacity added).[34]

Duke Energy's justification for the manual replacement of battery storage selected by EnCompass with gas CT capacity is that the "typical day" load construct used by EnCompass to ensure that resource portfolios can serve a wide variety of conditions favors battery storage technologies that can serve a narrow 'peak' over CTs that can provide capacity over a longer period. Figure 2 provides an example of this "typical day" load shape.

[33] Appendix E, p. 60.

[34] Appendix E, p. 60.

Figure 11. Capacity Expansion "Typical Day" Load Shape, Example



Source: Appendix E, p. 58. Each line on the above graph represents total load over time for an individual day. The bold line, representing the "typical day" load shape, is designed to capture the wide range of potential load conditions in a single day.

This justification relies on an inaccurate characterization of Duke Energy's capacity expansion modeling process, applies a remedy that does not treat all resources consistently, and ultimately creates additional risk of stranded generation assets and non-attainment of carbon reduction requirements.

First, while it is true that the Duke Energy's capacity expansion runs use the "Typical Day" load construct, Duke also applies additional simplifications to system load for these runs. Duke Energy's capacity expansion runs condense each 24-hour day into six 4-hour intervals.[35] This interval represents the smallest unit of time available to EnCompass during one of Duke's modeling runs: load is constant over the course of a single interval, and dispatch choices, for example, cannot change during an interval. Therefore, at a minimum, any "peak" observed in the capacity expansion would need to be at least four hours in duration. Given this additional transformation, "Typical Day" daily peak loads are not, in fact, modeled as "needle peaks."

[35] *See* "HB951 EnCompass Scenarios and Datasets - Master Import File - 5.13.22.xlsx." from Duke Energy's May 16, 2022 EnCompass data share. Counsel from Duke Energy verified that no confidential material has been divulged relating to this information from the confidential EnCompass database.

Second, Duke Energy's proposed remedy to this solution contemplates substituting only one resource type—gas-fired CTs—for one other resource type—battery storage. This approach runs directly counter to the resource planning principle of allowing all resources to compete and choosing the most economical portfolio. Solar generation, for example, would generate a substantial portion of its energy between Hour 9 and Hour 15 on Figure 11. Some combination of solar and other resources, including longer-duration storage, might have even more cost-effectively addressed load, but Duke Energy did not consider other configurations of resources beyond additional CTs. Duke Energy did not provide the PVRR value of this replacement in their proposed Carbon Plan, nor did it cite any specific reliability standard in justifying these replacements.[36]

Finally, by 'forcing in' carbon emitting resources outside of capacity expansion modeling during this process, Duke Energy bypassed the model's evaluation of HB 951 's carbon requirements compliance for the additional gas turbines. Duke Energy is unable to test whether these resources endanger compliance with carbon requirements or determine whether these resources are cost-effective when planning for a de-carbonized grid. Effectively, these resource replacements represent a selective application of HB 951's emissions requirements: applicable to most resources selected by EnCompass, but not applicable to resource additions and substitutions after the fact. Duke Energy's finding that some of their portfolios are unable to meet carbon reduction requirements in subsequent production cost modeling could be a reflection of these *ex post* resource decisions.[37]

4.3. Additional Manual Resource Additions

Portfolio Reliability and 2050 CO_2 Reduction Verification

In this step, Duke Energy added between 900 and 1,100 megawatts (MW), varying by portfolio, of additional "Reliability and CO2 Reduction Requirement" resources to their portfolios to address "resource insufficiencies" identified during production cost modeling.[38]. Although the technology is not explicitly identified in their proposed Carbon Plan, Duke Energy has confirmed that the contemplated technology is additional SMRs.[39] As with other decisions described above, this decision undermines the analytical power of EnCompass's economic optimization. If Duke Energy desired additional reliability from the system over a given time period, it could revise system requirements in EnCompass such as the reserve margin, and the economic

[36] Appendix E, p. 57-59.

[37] Appendix E, p. 89.

[38] Appendix E, p. 61.

[39] Duke Energy response to NCSEA-SACE 3-43.

optimization will select the most cost-effective resource to meet those needs, while co-optimizing against carbon and cost-effectiveness requirements. Manually "forcing in" additional resources is not consistent with an economically optimal approach.

Portfolio Loss of Load Expectation (LOLE) and Resource Adequacy Validation

Finally, Duke Energy used extrapolated values from their 2020 Resource Adequacy study to characterize future reliability for their Carbon Plan proposed portfolios and add additional gas CTs if these portfolios did not reach a future reliability threshold constructed from the results of those studies.[40]

To summarize Duke Energy's methodology for this process, Duke Energy re-ran the DEC-DEP "Combined" scenario from their 2020 Resource Adequacy Studies with and without assistance from neighboring utility systems (an "interconnected" and an "islanded" case). Duke Energy converted the net benefit from neighboring utility systems in these model runs into a static "interconnection benefit" that could allow a system to achieve resource adequacy targets, even if the system might not meet those targets in an "islanded" case. Duke Energy performed additional SERVM runs on the proposed portfolios to determine if the system's own resources plus the static "interconnection benefit" would be sufficient to meet an established loss of load expectation (LOLE) threshold. If LOLE for any of the portfolios in 2030 or 2035 exceeded this threshold in SERVM analysis, Duke Energy added additional CTs to that portfolio.

This treatment represents a meaningful departure from the typical use of resource adequacy studies in resource planning, and Duke Energy acknowledges that it is not aware of any analysis or Commission decision that has contemplated, deployed, or approved this practice.[41] Typically, resource adequacy studies are used to develop a capacity reserve margin that can ensure reasonably reliable service over the planning period; each of these portfolios was designed to meet the 17 percent planning reserve margin developed by the 2020 Resource Adequacy Studies. Given the expected change in generation portfolios between now and 2030 and 2035, extrapolating LOLE results from today to those future dates is not appropriate. Further, this practice embeds an assumption that additional regional capacity coordination will not develop

[40] *See:* Duke Energy Carbon Plan Attachment I – DEC Resource Adequacy Study; and Duke Energy Carbon Plan Attachment II - DEP Resource Adequacy Study.

[41] Confidential Duke Energy Response to NCSEA-SACE DR 3-45. Counsel from Duke Energy verified that no confidential material has been divulged relating to this confidential response to data request.

in the intervening years, despite leading research showing that such coordination is cost-effective[42] and existing state and federal efforts to facilitate regional coordination.[43]

Similarly to the previous "Portfolio Reliability and 2050 CO_2 Reduction Verification" step, Duke Energy's decision to insert resources into the portfolio manually, rather than adjusting the reliability parameters in EnCompass, effectively circumvents the economic optimization process. Future reliability concerns could be addressed, for example, by increasing the reserve margin in future years; once these changes are set, EnCompass could select the most cost-effective resource given these updated reliability needs and existing carbon constraints. By contrast, the choice to manually insert CTs does not reflect planning best practices and is not as likely to achieve the most cost-effective outcomes for North Carolina ratepayers.

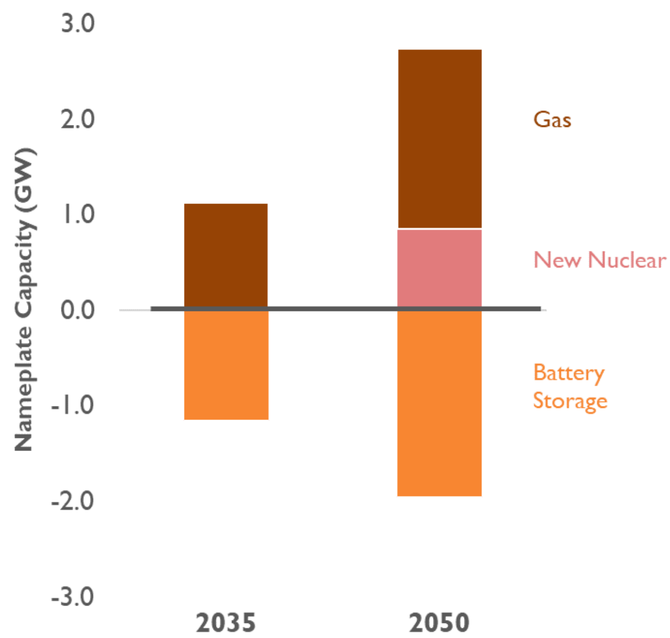
4.4. Cumulative Effect of Duke's Manual Portfolio Changes

Duke's manual revisions had a sizable impact on the system capacity mix for Duke Energy's portfolios. Figure 12 below shows the cumulative impact of manual revisions on Portfolio 1.

[42] *See:* Brown, P. R., & Botterud, A. (2021). The value of inter-regional coordination and transmission in decarbonizing the US electricity system. Joule, 5(1), 115-134.

[43] *See:* US Department of Energy (2022, January). Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization. Retrieved at: https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web_1.pdf; *and* Sweeney, D. (2020, January). "SC lawmakers introduce joint resolution to study electricity market reform." S&P Global. Retrieved at: https://www.spglobal.com/marketintelligence/en/news-insights/trending/k_4edpusx8hnvqivnsh-7q2.

Figure 12. Manual Changes to Duke Energy Portfolios through 2035 and 2050, Duke Energy Portfolio 1



Source: Duke Energy Response to NC Public Staff DR 9-10.

For context, the total nameplate capacity of Duke Energy's generation fleet across all resources today is roughly 40 GW; the 5 GW net change in 2050 represents roughly one eighth of Duke Energy's total nameplate capacity today. This represents a substantial deviation from the portfolio selected by EnCompass's economic optimization software. As stated above, these resources were not subject to the declining HB 951 carbon mass cap that guided EnCompass resource selection in Duke Energy's initial cost runs. Given that Duke Energy adds gas and removes energy storage in the first half of the planning period, this might help to explain why some of Duke Energy's portfolios fail to meet carbon reduction requirements by their intended dates.[44]

4.5. Review of Duke Energy's Proposed Carbon Plan Portfolios

Based on Duke Energy's EnCompass analysis and their post-processing manual revisions described above, Duke Energy proposed eight distinct but similar portfolios in their proposed Carbon Plan. The primary distinguishing feature across portfolios is the year in which Duke achieves the 2030 carbon reduction requirement of 70 percent. The "Portfolio 1" (P1) portfolios

[44] See: Appendix E, p. 89.

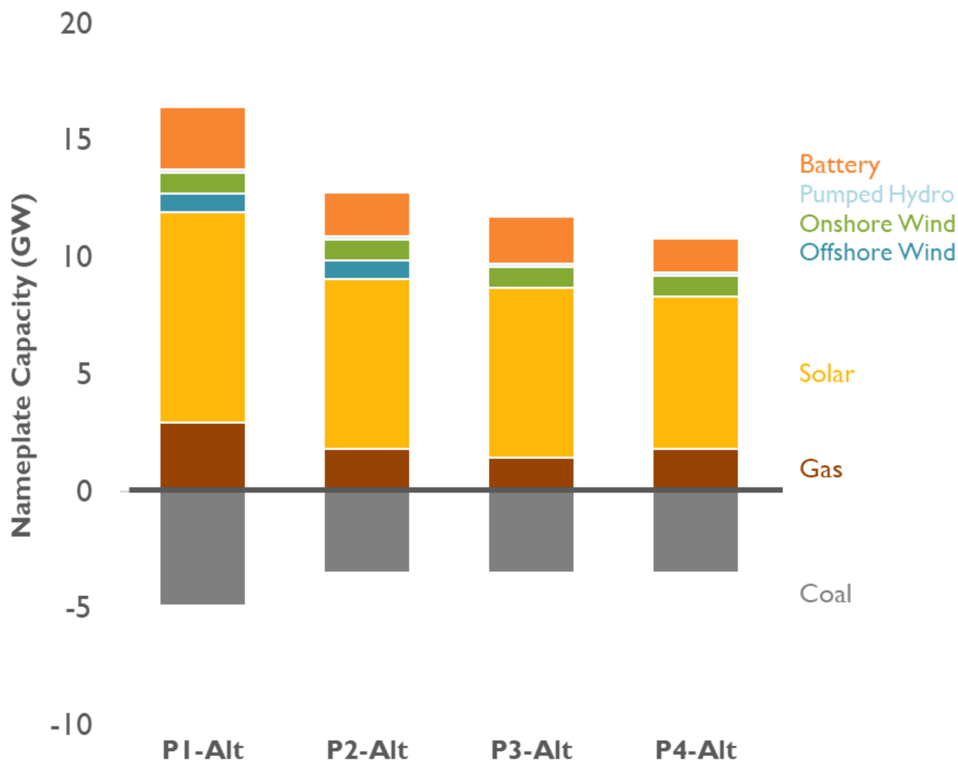
achieve the 70 percent reduction requirement in 2030. "Portfolio 2" and "Portfolio 3" (P2 and P3) achieve the interim reduction requirement by 2032, while deploying offshore wind and SMRs, respectively. "Porfolio 4" (P4) portfolios deploy both offshore wind and SMRs in the first half of the 2022–2050 planning period and meet the 70 percent reduction requirement in 2034.

As directed by the NCUC, each proposed portfolio includes a case that assumes additional firm Appalachian gas transport capacity is not available;[45] Duke Energy identifies these portfolios as the "alternate" portfolios. In practice, reduced access to firm gas transportation reduces the total number of combined-cycle (CC) units deployed and results in higher delivery costs for gas fuel. This section will compare the scenarios that do not assume additional firm capacity, but the "alternate" portfolios are broadly indicative of resource trajectories for the scenarios without additional firm capacity.

Figure 13, below, shows incremental capacity builds and retirements 2022-2030 across scenarios.

[45] North Carolina Utilities Commission (2021, October). Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning. Docket No. E-100 Sub 165. P. 10. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=3142e686-6cb0-43e4-a71a-afb3e2518f94.

Figure 13. Incremental Resource Builds and Retirements, 2022–2030



P1-Alt, P2-Alt, P3-Alt, and P4-Alt designate the "alternate" portfolios that do not assume additional firm Appalachian gas transport capacity for Portfolios 1 through 4, respectively.

The four portfolios follow a similar trajectory, 2022–2030: Substantial investment in solar, while retiring a portion of Duke's coal fleet and investing in incremental gas-fired resources. Duke's scenarios also build out the first on- and off-shore wind projects and invest in several GW of energy storage.

Although the timing of the 70 percent reduction is different by portfolio (2030 for P1-Alt, 2032 for P2-Alt and P3-Alt, and 2034 for P4-Alt), there are few substantial differences in the portfolios through 2030. Figure 14 shows total capacity by resource type for each portfolio in 2022 versus 2030.

Figure 14. Capacity by Resource Type, 2022 and 2030, by Scenario

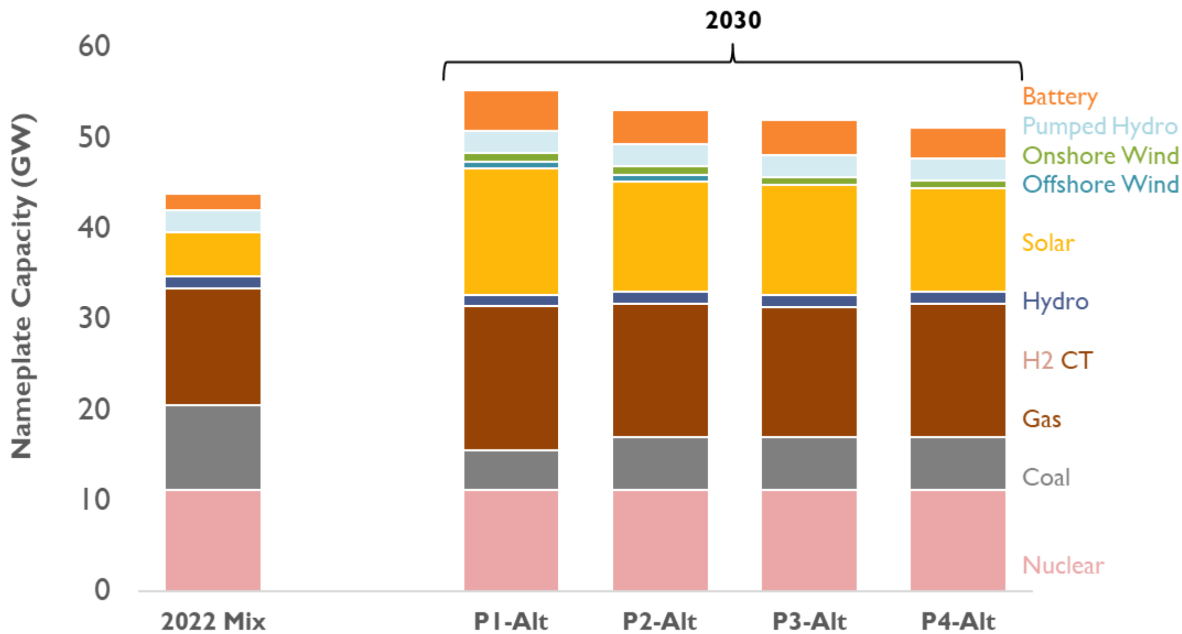


Figure 15 shows incremental resource builds and retirements between 2030 and the end of the planning period. The 2030–2050 period presents a dramatically different set of resource additions and retirements than capacity changes 2022–2030. Over this timeframe, roughly half of capacity additions are over 20 GW of new nuclear and hydrogen gas turbines, while a substantial amount of Duke's existing gas capacity and Duke Energy's remaining coal units are presumed to retire. Addition of solar and storage technologies slow substantially compared to the first decade of the planning period. The only immediately noticeable difference between portfolios is Portfolio 2's investment in offshore wind resources in the early 2030s.

Figure 15. Incremental Resource Builds and Retirements, 2030–2050

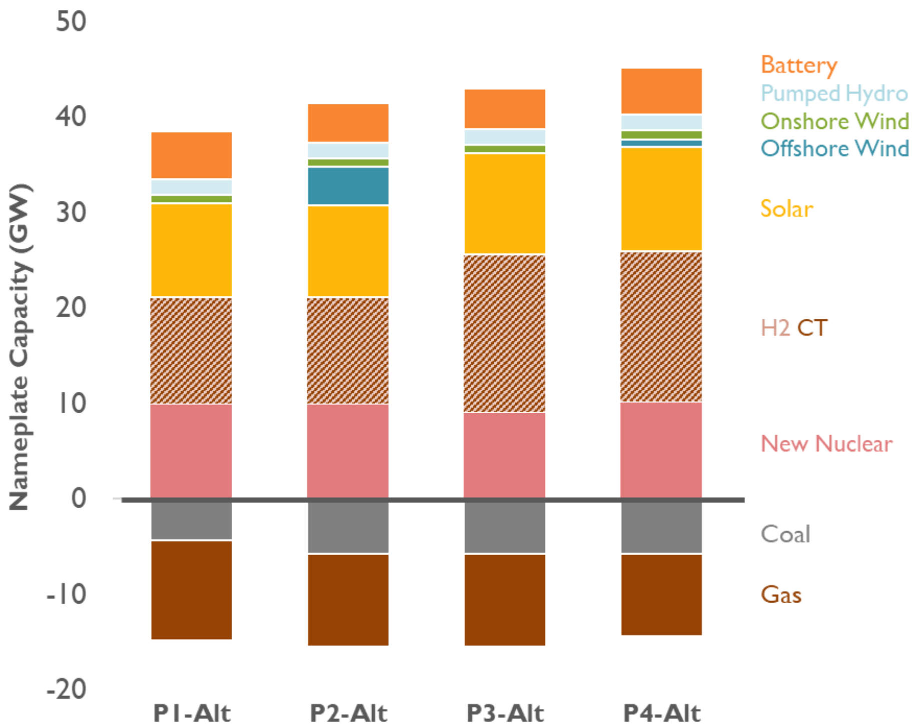
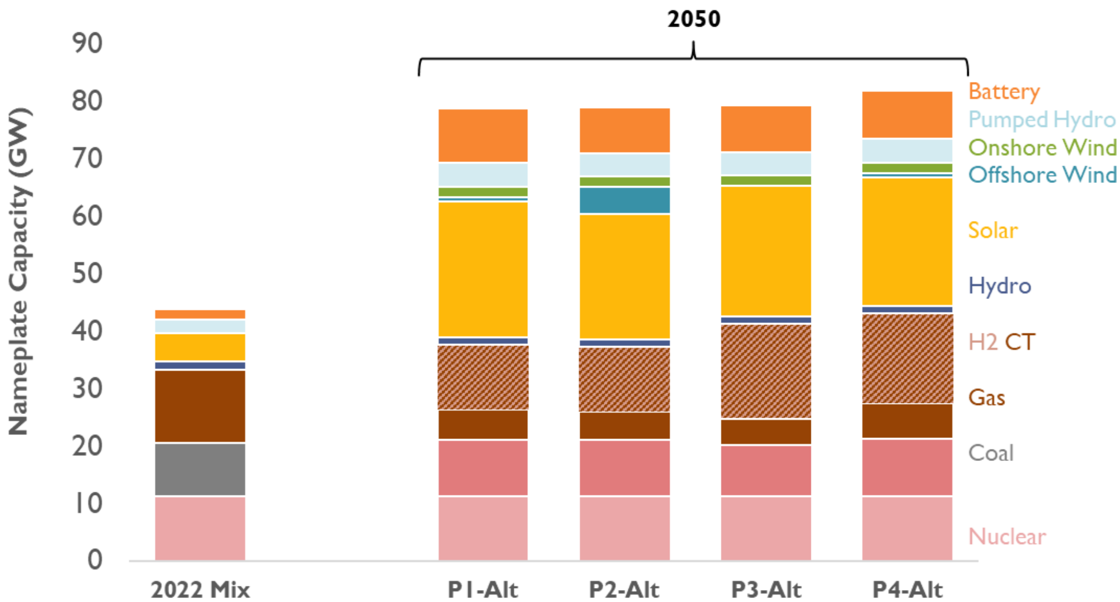


Figure 16 shows the final capacity mix of resources across Duke Energy portfolios in 2050 versus present-day capacity in 2022. Roughly half of capacity across portfolios is comprised of existing and new nuclear resources plus hydrogen-burning resources. Most of the remaining capacity is solar resources, with several GW of pumped hydro and battery storage. Again, one of the only noticeable differences between portfolios is several GW of offshore wind found in P2-Alt.

Figure 16. Capacity by Resource Type, 2022 and 2050, by Scenario



Overall, Duke Energy's proposed portfolios might better be thought of as variations on a single resource pathway than four distinct approaches to achieving a zero-carbon energy system. The portfolios share an identical short-term action plan, and, despite some differences in resource timing, they all have very similar total builds and projected generation mixes in 2050. Despite these similarities, only Portfolio 1 is designed to meet HB 951's 70 percent carbon reduction requirement by 2030. Nevertheless, Duke Energy's modeling shows that their P1–Alt scenario fails to meet its 70 percent carbon requirement in 2030.[46]

Consistent with their generation and capacity mixes, net present-value revenue requirements are also very similar across proposed portfolios. NPVRR results for each portfolio are presented below in Table 11. These costs are based on Duke Energy's model inputs, which are further discussed in Section 2 and Appendix A; these costs should not be directly compared with the results of Synapse's analysis, but are helpful for comparing between portfolios. As expected, there is little cost variation in Duke Energy's reported results.

[46] Appendix E, p. 89.

Table 11. Net Present Value Revenue Requirement over Time, Duke Portfolios

Results (2022-2050)	P1-Alt	P2-Alt	P3-Alt	P4-Alt
2050 NPVRR ($B)	$105.5	$102.7	$99.8	$100.2

Note: Costs reported by Duke Energy, adapted from Confidential Duke Energy Response to Public Staff Data Request 3-13 Corrected. Counsel from Duke Energy verified that no confidential material has been divulged relating to this confidential response to data request.

4.6. Role of New Nuclear and Green Hydrogen Resources

A common thread across all the portfolios in Duke Energy's proposed Carbon Plan is their dependence on SMR and zero-carbon hydrogen resources, neither of which are commercially available today. Duke Energy's proposed portfolios plan to deploy around 10 GW of new nuclear units over the next 20 years, alongside enough zero-carbon hydrogen generation, transport, and distribution to supply 11 to 16 GW of new-build hydrogen-burning units or retrofitted natural gas units. Both technologies present economic and operational risks to Duke Energy ratepayers, who will ultimately bear the economic burden of building and fueling these resources.

While several small nuclear reactors are in the early stages of development, it is not clear that any will be operational in the 2020s. In 2020, several utilities that had recently partnered with SMR first-mover Nuscale announced that they would back out of a deal to purchase power from the plant after Nuscale announced a $2 billion cost overrun.[47] More recently, changing geopolitics and supply chains have destabilized the supply of enriched uranium used to fuel the Natrium reactors contemplated by Duke Energy in their proposed portfolio.[48] Risks associated with construction costs and timelines have haunted recent nuclear projects in the Southeast, including the VC Summer plant in South Carolina[49] and Plant Vogtle in Georgia,[50] and while SMRs represent a new technology, these predominantly unlicensed designs bring their own

[47] Cho, A. (2020, November). Several U.S. utilities back out of deal to build novel nuclear power plant. *Science*. Retrieved at: https://www.science.org/content/article/several-us-utilities-back-out-deal-build-novel-nuclear-power-plant.

[48] Bleizeffre, D. (2022, March). Nixed Russian fuel supply complicates Natrium schedule. *Wyofile.* Retrieved at: https://wyofile.com/nixed-russian-fuel-supply-complicates-natrium-schedule/.

[49] Associated Press (2022, May). "$61 Million in Refunds for Customers in SC Nuclear Debacle." *US News & World Report*. Retrieved at: https://www.usnews.com/news/us/articles/2022-05-04/61-million-in-refunds-for-customers-in-sc-nuclear-debacle.

[50] Jones, E. (2022, June). "Plant Vogtle co-owners sue Georgia Power over cost overruns." *WABE*. Retrieved at: https://www.wabe.org/plant-vogtle-co-owners-sue-georgia-power-over-cost-overruns/.

risks and uncertainties. Early commitment to an unproven technology before it has reached commercial viability could present substantial risks for ratepayers' bills and carbon emissions trajectories.

Hydrogen electrolysis represents a more mature technology because of the use of hydrogen in industrial settings. Uncertainties remain, however, in the role that hydrogen will play as a fuel for power generation.

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Industry publications point toward the broader use of zero-carbon hydrogen across a de-carbonized economy;[51] Duke Energy's hydrogen supply analysis does not contemplate demand for zero-carbon hydrogen outside of power generation.[52]

Industry publications also continue to indicate the need for future research to develop a pathway for retrofitting existing gas turbines to burn 100-percent hydrogen for existing gas units.[53] At the same time, hydrogen resources will continue to struggle to compete economically against other generation resources. The Hydrogen Council notes that "Hydrogen is only relevant in regions constrained in renewables potential," and projects that the long-term cost of hydrogen power will be $140/MWh.[54] Finally, operation of hydrogen at scale for power generation in the Carolinas presumes the successful buildout of a hydrogen production, transport, and distribution infrastructure that does not exist today, as well as a tectonic shift from the emissions-intensive steam methane reformation process, which emits carbon dioxide and is used to produce 95 percent of hydrogen in the United States today, to hydrogen electrolysis powered by clean electricity.[55] Beyond the build-out of renewable generation capacity (e.g., wind and solar) to provide zero-carbon power for electrolysis, building out the

[51] Hydrogen Council (2020, January). Path to hydrogen competitiveness: A cost perspective. Retrieved at: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.
[52] Appendix E, p. 102.
[53] ETN Global (2020, January). Hydrogen Gas Turbines. Retrieved at: https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf.
[54] Hydrogen Council (2020, January). Path to hydrogen competitiveness: A cost perspective. Retrieved at: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.
[55] Hernandez, D. D., & Gençer, E. (2021). Techno-economic analysis of balancing California's power system on a seasonal basis: Hydrogen vs. lithium-ion batteries. *Applied Energy*, 300, 117314.

infrastructure for green zero-carbon hydrogen will require substantial investment in electrolyzers and transport infrastructure (i.e. hydrogen-capable pipelines). These investments and their attendant costs are not captured by Duke's modeling in their proposed Carbon Plan.[56]

While these technologies show promise as tools in the clean energy toolkit, there are still substantial cost and operational uncertainties and concerns for their large-scale deployment. Duke Energy's proposed portfolios place an undue dependence on these technologies, driving additional risks and potential costs to ratepayers.

5. Conclusions

Synapse's EnCompass analysis shows that the most cost-effective portfolios to achieve affordable, de-carbonized power for North Carolina are those that prudently invest in proven, low-cost, zero-emissions resources like energy efficiency, solar, wind, and battery storage, and avoid any additional investments in fossil fuel-based generation. These proven resources support an accelerated exit from coal in the short term and, in the long term, drive substantial cost savings compared to Duke Energy's proposals. Based on this analysis, Synapse provides the following conclusions:

- While Duke Energy's adoption of the EnCompass resource planning tool created the opportunity for increased transparency, several manual overrides by Duke in their proposed portfolios undermined the EnCompass software's ability to optimize for the most cost-effective portfolio.
- Synapse's analysis found no justification for any additional gas-fired resources on the basis of cost-effectiveness or capacity reserve requirements. Given the carbon emissions associated with gas plants, the uncertainties around de-carbonizing these units in the future by repowering them to burn hydrogen or another fuel, the risk of price spikes from volatile gas markets, the costs of these units, and the capacity value of available alternative zero-carbon resources, there is little justification for building additional gas-fired resources.
- Energy efficiency reduces both peak loads and total energy needs and represents a key part of any cost-effective long-term energy plan. Synapse's base energy efficiency assumption of 1.5 percent of total retail load is consistent with peer

[56] Duke Energy Response to Clean Power Supply Association ("CPSA") DR 1-6.

utilities,[57] and Duke Energy ratepayers would benefit from this higher level of energy efficiency savings. Ratepayers also benefit from expanded adoption of distributed energy resources, which further reduce load and avoid the need to invest in supply-side resources.

- Across Duke Energy's and Synapse's modeling, accelerated and increased solar deployment is a cornerstone of a cost-effective carbon-reduction portfolio. Duke Energy should not only continue to procure cost-effective solar power from third-parties, but also take decisive steps now to improve their transmission planning process to lift the constraints currently hindering solar deployment.

- In all scenarios, battery storage plays an important role by bolstering the economic value of low-cost solar power. Duke Energy should move ambitiously to integrate battery storage resources and build out operational capabilities for capitalizing on their services to the grid.

- Synapse's modeling finds that a scenario that includes power purchase agreements for Midwest wind deliver power at a lower cost to ratepayers. This is true even when accounting for the cost of transmission from PJM using firm point-to-point transmission rates. This result shows the potential for increased regional coordination and transmission to unlock lower-cost resources and ultimately lower costs for ratepayers. Expanded transmission and regional coordination should continue to be an area of detailed analysis in ongoing resource planning.

- In the later years of the planning horizon, Synapse's EnCompass analysis found that it was more economical to retire existing gas resources rather than retrofit them for burning hydrogen. This result reflects the present and accelerating risk that incremental gas-fired resources play due to their carbon emissions. Any incremental investments in gas-fired resources would face these risks even earlier in their operating lifetimes. Ongoing technical and economic uncertainties around hydrogen retrofits compound these risks for existing and potential gas-fired units.

- In the long term, Duke Energy's Carbon Plan portfolios lean heavily on assumptions that small, modular nuclear reactors and zero-carbon hydrogen will be available and more cost-effective than proven technologies on the grid today. While both SMRs and hydrogen may play a role in a decarbonized energy grid, substantial cost and operational questions about these resources remain. Relying heavily on these unproven technologies, especially by building additional carbon-emitting units with the hope that they may later be decarbonized by an

[57] Relf, G., Cooper, E., Gold, R., Goya, A., & Waters, C. (2020, February). 2020 Utility Energy Efficiency Scorecard. American Council for an Energy Efficient Economy. P. 26. Retrieved at: https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf.

effective retrofit process and a commercialized supply of widely available, zero-carbon hydrogen, subjects ratepayers to substantial economic risk. Synapse's analysis shows that using proven technologies available today can deliver a cost-effective, zero-carbon grid without relying heavily on unproven resources.

- A sensitivity testing the impact of joining the Regional Greenhouse Gas Initiative on Duke Energy's emissions found that joining RGGI would reduce emissions by hundreds of thousands of tons of carbon per year in the late 2020s and early 2030s. Notably, incremental emissions reductions from participation in RGGI allowed the *Duke Resources* portfolio to achieve their HB 951 carbon reduction requirement in 2030.

Appendix A. DETAILED DESCRIPTION OF REVISIONS TO DUKE MODELING ASSUMPTIONS

A.1. Revised Inputs

Gas Fuel Price Forecast

Figure A-1 shows Synapse and Duke Energy gas price forecasts. Synapse's gas price forecast is based on a blend of the most recent near-term New York Mercantile Exchange (NYMEX) futures prices, and long-term fundamental gas price forecasts from the US Energy Information Administration's (EIA) 2022 Annual Energy Outlook (AEO). Consistent with Duke's methodology, the Henry Hub price forecast was also blended with a hydrogen price forecast beginning in 2035, as Duke Energy's proposed Carbon Plan includes blending of relatively low levels of hydrogen starting in 2035. Synapse made no changes to the timing and rate of blending. Synapse applied Duke's zonal adders for Transco Zones 4 and 5.

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Synapse's approach to developing the internal gas price forecast is very similar to Duke's. Both rely on the EIA's AEO for long-term gas price trajectory, although Synapse's fundamental forecast exclusively relies on the 2022 AEO forecast, while Duke Energy's forecast relies on an average of several long-term projections from Wood Mackenzie, EIA, and IHS Markit.[1]

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[1] Appendix E, p. 40.

Hydrogen Fuel Price Forecast

Synapse developed a hydrogen price forecast using a hydrogen production trajectory derived from Bloomberg New Energy Finance data[2] and hydrogen transportation costs from McKinsey & Company on behalf of the Hydrogen Council.[3] Figure A-3 shows a comparison between Synapse's hydrogen price forecast and Duke Energy's hydrogen price forecast. All hydrogen is assumed to be zero-carbon "green" hydrogen, generated using electrolysis with zero-carbon electricity.

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[2] Mitsubishi Power (2020, October). Advancing Green Hydrogen for the Danskammer Project. Retrieved at: https://www.greenhydrogenny.com/wp-content/uploads/2020/11/Mitsubishi-Advancing-Green-Hydrogen-for-the-Danskammer-Project.pdf.

[3] Hydrogen Council and McKinsey & Company (2020, January). Path to Hydrogen Competitiveness: A cost perspective. Retrieved at: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.

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Fixed Operations and Maintenance Costs of Existing Coal Resources

Synapse derived fixed operations and maintenance costs for Duke Energy's legacy coal units using a study conducted by Sargent & Lundy for EIA in 2018.[8] As opposed to the engineering approach used by Duke Energy, the Sargent & Lundy study used a regression-based analysis of historical operations and maintenance costs for coal units across the United States, using information reported by those units to EIA and the Federal Energy Regulatory Commission.[9]

Capital Expenditures, Project Lifetimes, and Hydrogen Retrofit Costs

Synapse relied on publicly available, industry-standard data sources to set capital expenditures for available resources in its optimization runs. For combustion turbines, combined-cycled units, and the two advanced nuclear technologies modeled by Duke Energy, Synapse used the same process as described by Duke Energy in its "New Supply-Side Resource Capital Cost Sensitivity Analysis," detailed in Appendix E.[10] Duke Energy sourced the cost references in its capital cost sensitivity from EIA's cost estimates characterized in EIA's 2022 AEO. For solar, wind, and storage technologies, Synapse used values from NREL's 2022 Annual Technology Baseline (ATB). The *Regional Resources* scenario uses a wind PPA cost estimate from NREL's 2022 ATB Moderate case.

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[4] US Department of Energy (2021, November). H2@Scale. Retrieved at: https://www.energy.gov/eere/fuelcells/h2scale.

[5] National Renewable Energy Laboratory (2021, October). Electric Hydrogen Partnership Hopes to Repeat Success with Renewable Hydrogen Technology. Retrieved at: https://www.nrel.gov/news/features/2021/electric-hydrogen-partnership-hopes-to-repeat-success-with-renewable-hydrogen-technology.html.

[6] Confidential Duke Energy Response to NCSEA-SACE DR 3-31.

[7] *Ibid.*

[8] Sargent & Lundy Consulting (2018, May). Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs. Prepared for US Energy Information Administration. Retrieved at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[9] *Ibid.,* p. 4.

[10] Appendix E, p. 99-102.

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Synapse also revised the book and operating lives of several future resources. Table A-1, below, details changes to operating and depreciation lifetimes of selectable future resources.

Table A-1. Operating and Depreciation Lifetime for Selected Resources, Duke Energy and Synapse

Resource	Operational Lifetime		Depreciation Lifetime	
	Duke Energy	**Synapse**	**Duke Energy**	**Synapse**
Gas Combined-Cycle Unit	35	25	35	20
Gas Combustion Turbine	35	25	35	20
Offshore Wind	25	30	25	30

Source: Appendix E, p. 31, 32, 37.

Synapse assigned a 25-year operating lifetime and a 20-year depreciation lifetime to new construction gas-fired units to reflect the risk associated with carbon emissions from these units under North Carolina Session Law 2021-165 (HB 951) emissions requirements. There are still substantial cost, operations, and feasibility questions around retrofitting existing gas units for 100-percent hydrogen operations, and turbine manufacturers have called for more research into hydrogen retrofits.[11] Duke Energy's proposed Carbon Plan filing also states the need for more research into 100-percent hydrogen retrofits.[12] Duke Energy allows all additional combustion turbines to be converted to 100-percent hydrogen in its resource planning, despite this uncertainty. The depreciation and operational timelines used by Synapse allow new combustion turbines to take advantage of zero-carbon retrofits if they are available, but depreciate the assets in order to avoid stranded asset risk.

Synapse implements a 30-year operational lifetime for offshore wind projects, consistent with the NREL ATB.

Finally, Synapse used a publicly available academic article published in the *International Journal of Hydrogen Energy* to project hydrogen retrofit costs for existing and new-build gas-fired units.[13] The article projected 100-percent hydrogen retrofit costs would be equivalent to 25 percent of the unit's initial capital cost. Synapse's model implements retrofits in 2046 to ensure that units are available in 2047 for 100-percent hydrogen operation.

A.2. *Optimized* Scenario

Energy Efficiency Savings Forecast

Synapse developed a forecast of energy efficiency savings based on the same methodology used by Duke Energy. Synapse's energy forecast targeted incremental energy efficiency savings

[11] ETN Global is an international association of turbine manufacturers. Their January 2020 *Hydrogen Gas Turbines: The Path Towards a Zero Carbon Future* report states: "There is a requirement for research to address system, materials, operations, and control of gas turbines for their safe and economically effective transition to a hydrogen-containing fuel stream… [Research] is significantly less advanced at higher hydrogen firing levels." General Electric and Mitsubishi Hitachi Power Systems are members of ETN Global. *See:* ETN Global (2020, January). Hydrogen Gas Turbines: The Path Towards a Zero Carbon Future. P. 10. Retrieved at: https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf.

[12] *See:* "To progress to 100% hydrogen-fueled turbines, substantial advancements in turbine technology are required." Appendix O, p. 6.

[13] Öberg, S., Odenberger, M., & Johnsson, F. (2022). Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems. *International Journal of Hydrogen Energy*, 47(1), 624-644. Retrieved at: https://www.sciencedirect.com/science/article/pii/S0360319921039768.

of 1.5 percent of total retail load per year, which is in line with peer utilities.[14] Steps followed by Duke and Synapse in developing energy efficiency forecasts are described below:

First, Duke Energy and Synapse identified annual incremental savings targets based on incremental savings projected in 2023 and retail load forecasts for Duke Energy Carolinas and Duke Energy Progress. Duke Energy calculates its base energy efficiency target as a percentage of 'eligible' retail load, or retail load net of entities that have opted out of energy efficiency programs. Duke Energy forecasts progress toward meeting incremental load targets by 2040.

Consistent with metrics used by the American Council for an Energy-Efficient Economy, Synapse used total retail load as the denominator for incremental savings targets. In Synapse's energy efficiency forecast, incremental savings achieve 1.5 percent of total retail load by 2030. Figure A-5 shows the incremental savings associated with the Duke Energy 'base' and 'high' incremental savings target and the Synapse incremental savings target. The graph shows results for Duke Energy Carolinas only, but it is broadly indicative of relative trajectories in both service territories.

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[14] The American Council for an Energy Efficiency Economy's 2020 Utility Efficiency Scorecard evaluated the 52 largest electric public utlities and included Incremental Energy Efficiency savings as a scoring category. The scorecard's sliding scale assigned a maximum of 8 points for annual incremental savings at 3 percent of retail load. The Scorecard awarded Duke Energy Carolinas 3 points and Duke Energy Progress 2.5 points in that category. *See:* Relf, G., Cooper, E. Goyal, A., Waters, C. (2020, February). 2020 Utility Energy Efficiency Scorecard. American Council for an Energy Efficient Economy. P. 26. Retrieved at: https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf.

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[15] Confidential Duke Energy response to NC Public Staff DR 17-4.

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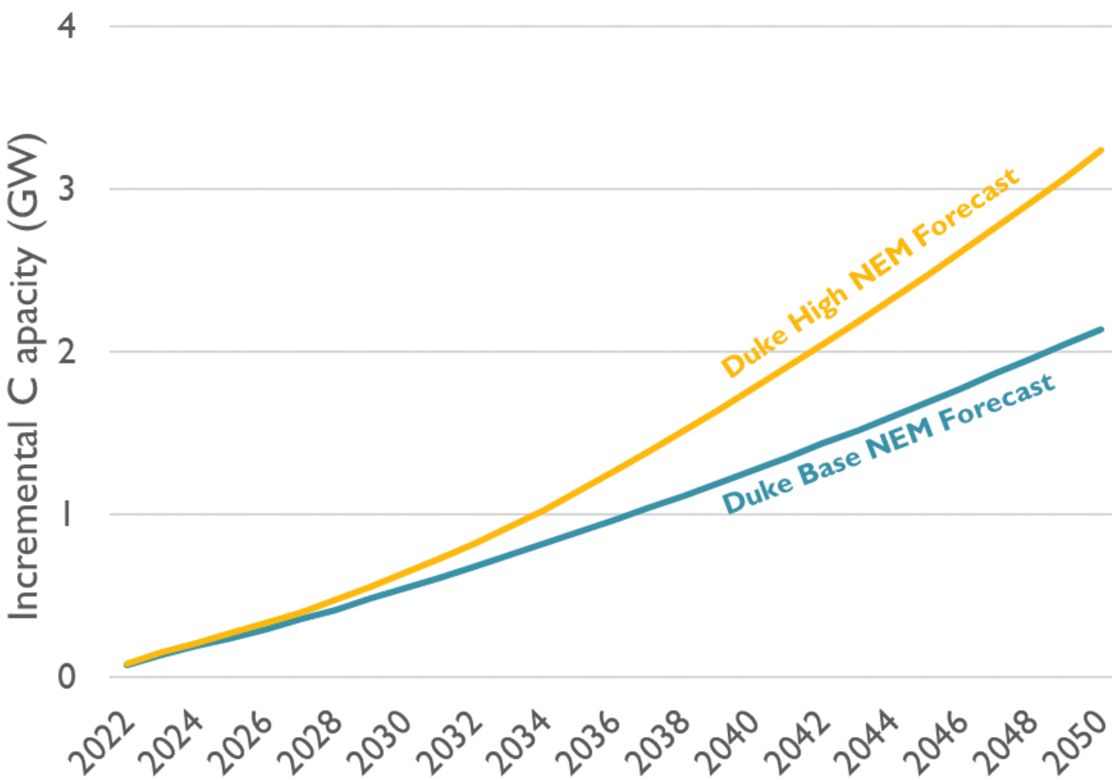
Synapse's energy efficiency forecast does not account for organic energy efficiency gains that might be induced from additional utility-sponsored energy efficiency (e.g., additional customers continuing to choose energy-efficient equipment after a utility incentive program ends, or after the utility-discounted equipment's operating lifetime). Incorporating induced energy efficiency would further reduce total load in the long term; maintaining the same level of organic energy efficiency represents a conservative approach to incremental energy efficiency.

Distributed Energy Resources Forecast

Synapse used net energy metering (NEM) forecasts provided by Duke Energy as an input to its load forecast. Figure A-7, below, shows incremental forecasted solar capacity by Duke Energy, in Duke's base and high net metering scenarios.

Figure A-7. Duke Energy Cumulative New NEM Capacity Forecast, 2022–2050



Source: Duke Energy Response to NCSEA-SACE DR 3-20.

Duke Energy's base NEM forecast assumes a relatively linear increase of 75 to 95 MW of incremental rooftop solar annually through 2050, resulting in just over 2 GW of incremental NEM capacity by 2050. The high NEM case assumes some acceleration of deployment, reaching 3.2 GW of incremental NEM capacity by 2050. The *Optimized* load forecast assumes Duke's high NEM forecast, while the *Duke Resources* load forecast assumes the base NEM forecast. Incremental capital expenditures are not included in these scenarios' NPVRR calculations.

Coal Retirements

Table A-2 shows coal units available for economic retirement by the EnCompass economic optimization algorithm in Synapse's EnCompass analysis. Synapse allowed all coal units expected to be operated after 2023 (apart from Cliffside 6, which is expected to run on 100-percent gas fuel) to be economically retired by the economic optimization algorithm during its capacity expansion runs. The latest possible retirement date for each year was set by Duke Energy's retirement dates in its proposed Carbon Plan portfolios; earlier retirement dates for each of these units could be selected by the economic optimization algorithm if doing so would be cost-effective. Synapse maintained the requirement that paired units (Marshall units 1-2 and 3-4, Roxboro units 1-2 and 3-4) be retired simultaneously.

Table A-2. Coal Units Available for Economic Retirement

Coal Units	Nameplate Capacity (MW)	Latest Retirement Year
Belews Creek 1	1,110	2036
Belews Creek 2	1,110	2036
Cliffside 5	546	2026
Marshall 1	380	2029
Marshall 2	380	2029
Marshall 4	660	2033
Marshall 3	658	2033
Mayo 1	713	2029
Roxboro 1	380	2029
Roxboro 2	673	2029
Roxboro 3	698	2028
Roxboro 4	711	2028

Source: Appendix E, p. 49.

Existing Gas Retirements

The *Optimized* and *Regional Resources* scenarios also allowed Duke Energy's existing gas-fired resources that are projected to undergo a hydrogen retrofit in Duke Energy's proposed Carbon Plan to be economically retired by EnCompass. Table A-3 shows a list of existing gas resources that were available to be retired by EnCompass in the *Optimized* and *Regional Resources* scenarios.

Table A-3. Existing Duke Energy Gas-Fired Units Projected for Hydrogen Retrofit

Gas Unit	Nameplate Capacity (MW)	Construction Year	Projected Retirement Year
Asheville Combined Cycle	560	2019	None
W.S. Lee Combined Cycle	750	2017	None
Lincoln Combustion Turbine 17	402	2020	None
Sutton Combustion Turbines	84	2017	None

New Nuclear Availability

Duke Energy's scenarios project that up to 21 new advanced and small modular nuclear reactor units could be built in Duke Energy's territory through 2048.[16] With the first units only available

[16] Appendix E, p. 33-36.

to come online in 2033, this pace is roughly equivalent to more than one new-construction nuclear unit per year every year in the Carolinas through the 2030s and 2040s.

Neither of the nuclear unit designs contemplated by Duke Energy in its proposed Carbon Plan have been constructed, nor have they received licenses from the US Nuclear Regulatory Commission.[17] The Tennessee Valley Authority (TVA) has made some limited progress toward developing a small, modular nuclear reactor, but noted in February 2022 that decisions made to date are "not a commitment to build."[18] TVA's goal for the project is for an advanced reactor to be deployed in the 2032 timeframe. Efforts to develop a small modular nuclear unit at the site have been under way since before 2016, when TVA applied for an early site permit at the Clinch River site.[19] While first-of-a-kind construction timelines are expected to be significantly longer than subsequent deployments, construction and operational uncertainties remain given the relatively untested nature of these designs.

Given that even the first small modular and advanced nuclear units are projected to be built in the late 2020s or early 2030s, Synapse applied a more reasonable availability trajectory that would allow North Carolina ratepayers to learn from early deployments without committing to nuclear unit designs before they are tested in the field. Synapse optimization runs allow for up to four nuclear units to be selected across Duke Energy Carolinas and Duke Energy Progress through 2050, with the first nuclear unit to be built in 2035.

Solar Availability

Like Duke Energy, Synapse modeled maximum annual solar deployment ramping up to 1,800 MW per year in the mid-to-late 2020s. To account for planned solar deployment through the mid-2020s, Synapse capped incremental solar additions at 1,200 MW in 2025, before increasing to 1,800 MW in 2026–2028. In 2029 and onward, Synapse incrementally increased maximum annual solar deployment to 2,300 MW, representing additional technical and procedural

[17] United States Nuclear Regulatory Commission (2022). GE-Hitachi BWRX-300. Retrieved at: https://www.nrc.gov/reactors/new-reactors/smr/bwrx-300.html.
United States Nuclear Regulatory Commission (2022). Natrium. Retrieved at: https://www.nrc.gov/reactors/new-reactors/advanced/licensing-activities/pre-application-activities/natrium.html.
[18] Patel, S. (2022, February). "TVA Unveils New Nuclear Program, First SMR at Clinch River Site." *POWER Magazine*. Retrieved at: https://www.powermag.com/tva-unveils-major-new-nuclear-program-first-smr-at-clinch-river-site/.
[19] US Nuclear Regulatory Commission. Early Permit Site Application – Clinch River Nuclear Site. Retrieved at: https://www.nrc.gov/reactors/new-reactors/smr/clinch-river.html.

benefits that will be realized over the next decade. This is consistent with national studies that anticipate continued improvements in solar deployment ability.[20]

Storage Availability

Given the modular nature and small footprint of lithium-ion batteries and the potential benefit of this technologies for operating the grid and integrating variable renewable energy resources, Synapse removed the constraints on cumulative deployment applied by Duke Energy to energy storage resources in its capacity expansion runs. Synapse applies an annual deployment ceiling of 1.5 GW of 4-hour storage batteries in Duke Energy Carolinas and Duke Energy Progress respectively to ensure operational viability, but otherwise does not apply additional constraints to storage deployment.

A.3. *Regional Resources* Scenario

Midwest Wind Purchase

In the *Regional Resources* scenario, Synapse included a Midwest wind resource that represented a power purchase agreement from the PJM region. These resources were designed to imitate the Midwest wind resources contemplated in the North Carolina Transmission Planning Consortium's 2021 Public Policy Study.[21] Notably, the NCTPC did not specify any transmission project identified through the study as being exclusively or mainly to support Midwest wind import. Power purchase agreement prices were projected from NREL's 2022 ATB, using the "Moderate" case levelized-cost-of-energy projection for Class 6 onshore wind resources. Once purchased, the energy price for each power purchase agreement is projected to escalate at the rate of inflation.

Consistent with Duke's methodology for onshore wind, Synapse modeled the projected costs of transmission by using PJM's current border charge of $67,625 per MW-year, rising at the rate of inflation over the planning period.

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[20] Princeton University's 2021 *Net Zero America* study; National Renewable Energy Laboratory's *Solar Futures* Study.

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

Appendix B. Additional Description of EnCompass Validation and Configuration

Synapse and Duke Energy both used the EnCompass analysis software for the purposes of developing and analyzing Carbon Plan resource portfolios. Synapse is confident that this shared foundation of model inputs will create opportunities for collaboration and learning between parties in this and future proceedings, and Synapse is appreciative of the efforts undertaken by the North Carolina Utilities Commission and Duke Energy staff to make the sharing of data inputs possible. Duke Energy's EnCompass database, shared with intervenors on May 16, forms the backbone of Synapse's analysis. This appendix provides additional detail on Synapse's EnCompass analysis, including validation with Duke Energy results, resolution of an error caused by a later version of EnCompass, and changes to EnCompass configuration that Synapse implemented in its analysis.

Issues with Validation of Duke Energy's EnCompass Results. Duke Energy provided model outputs alongside their EnCompass database inputs to intervenors on May 16, 2022. These outputs allowed intervenors to perform validation of their own EnCompass database configurations: If the results of any intervenor's EnCompass analysis using Duke Energy inputs matched the results provided by Duke Energy, then the intervenor could be confident that their EnCompass database was configured appropriately and Duke Energy inputs were successfully imported. However, Synapse encountered several issues with model validation, which Duke Energy confirmed when it sent an update memo to intervenors on June 8:

- An issue with one portion of Duke Energy's EnCompass database caused the modeling runs to fail to complete.
- Outputs provided by Duke Energy were generated from an EnCompass database that was configured differently than the database that Duke Energy provided to intervenors. As a result, intervenors' modeling analyses consistently generated discrepancies with Duke Energy's own outputs.

Synapse recognizes that resource planning models are complex and encountering and resolving issues is an inevitable part of sharing modeling data; nevertheless, these issues delayed Synapse's, and presumably other intervenors', ability to engage with Duke Energy's modeling in ways that would be productive in building a shared understanding of least-cost carbon emissions reduction pathways for North Carolina.

EnCompass Versioning Issues. When Synapse began EnCompass analysis of Duke Energy's Carbon Plan filing, Synapse's EnCompass infrastructure used version 6.0.9, which included several modeling improvements compared to EnCompass version 6.0.4 that Duke Energy used in developing its Carbon Plan. After getting confirmation from Anchor Power Solutions that versions 6.0.9 and 6.0.4 used the same data structure, Synapse decided to use the more recent version of EnCompass for its own analysis. Synapse provided analysis results generated using EnCompass version 6.0.9 to RMI for its Optimus analysis.

On July 13, Synapse received an email from Anchor Power Solutions, EnCompass's vendor, confirming a previously unidentified error within EnCompass. This error caused EnCompass version 6.0.9 to model units capable of co-firing, such as Belews Creek 1 and 2, Cliffside 5 and 6, and Marshall 3 and 4, inaccurately. Effectively, these units were able to run on gas exclusively, rather than co-firing with coal. While the issue affected only these units directly, it created indirect impacts on coal unit retirements, system dispatch, energy prices, and CO_2 emissions for the 2022-2036 period while these units were in operation. In terms of net present value revenue requirement, Synapse observes a difference of 1 to 3 percent between *Duke Resources* outcomes using versions 6.0.4 and 6.0.9. After learning of the issue, Synapse decided to re-develop its scenarios with EnCompass version 6.0.4 to avoid any inaccuracies caused by this error. Table B-1, below, shows net present value revenue requirement for the *Duke Resources* scenario for EnCompass versions 6.0.9 (which contained the EnCompass error) and 6.0.4 (which matches Duke Energy's analysis).

Table B-1. Net Present Value Revenue Requirement by EnCompass Version, *Duke Resources* Scenario

Results (2022-2050)	*Duke Resources – 6.0.9*	*Duke Resources – 6.0.4*
2030 NPVRR ($B)	$35.8	$36.7
2040 NPVRR ($B)	$76.5	$77.7
2050 NPVRR ($B)	$120.0	$121.2

Changes to EnCompass Configuration:

Planning horizon. When conducting capacity expansion and production cost modeling, the "planning horizon" represents the span of time over which the algorithm optimizes costs. While longer planning horizons allow economic optimization to plan for the future and incorporate more information into planning decisions, the computing resources and time needed to solve problems with long time horizons can increase substantially. Analysts must strike a balance by setting a planning horizon that is long enough for the optimization to meaningfully plan for the future without creating modeling challenges for their hardware. One strategy to manage computing resources Is to solve a long planning period in "segments," where the user sets the software planning horizon for a fraction of the total span of time being analyzed, then EnCompass performs economic optimization on each fraction in sequence.

In the context of the current energy transition, where technology costs are changing rapidly and emissions are expected to decline over a multi-decadal time scale, longer planning horizons are important for integrating long-run industry transitions. Planning horizons that are too short may prevent resource planning tools like EnCompass from adequately taking long-term trends into account. Because the operation and depreciation lifetime of most resources typically extends past the modeling horizon, planning horizons that are too short can commit a system to a given resource in the early years that ultimately proves uneconomical in the long-term.

Capacity expansion modeling runs performed by Duke Energy to develop its Carbon Plan proposed portfolios used a series of 8-year segments and a final 5-year segment (i.e., 2022-2029, 2030-2037, 2038-2045, and 2046-2050).[22] While 8-year planning segments are within the reasonable range of planning horizons used in detailed capacity expansion modeling, they also introduce risks that resources selected in the earliest segments may not be economical resource choices when viewed over the long term.

Synapse's capacity expansion modeling runs also used a segmented approach, but the Synapse capacity expansion runs used one 15-year segment and one 14-year segment (i.e., 2022-2036, 2037-2050). This 15-year approach strikes an appropriate balance between computing resource efficiency while allowing economic optimization to make decisions that take a long-term view of emissions and technology price trajectories into account.

Capital Expenditures. EnCompass includes a detailed financial model that replicates the key components of utility financial analysis, including rate base, total carrying costs, and annual revenue requirement. For its Carbon Plan proposal, Duke Energy used its own proprietary calculation of a real fixed levelized costs for each new resource, which it imported directly into EnCompass. While this approach does not necessarily add any inaccuracy into EnCompass results, it inhibits the ability for stakeholders to make changes or revisions to capital cost calculations without re-developing Duke Energy's proprietary economic carrying cost calculations. Synapse's analysis converted the Duke Energy real fixed levelized costs back to capital expenditures and financial parameters (e.g. debt and equity rates, treatment of advanced funds used during construction) that are directly readable by EnCompass.

[22] Duke Energy response to NCSEA-SACE DR 3-7.

APPENDIX C. LOAD AND CAPACITY TABLES BY SCENARIO

Tables C-1 and C-2. Total Nameplate and Capacity and Net Builds and Retirements, *Duke Resources* Scenario

Year	Net Load (GWh)	Total Nameplate Capacity (MW)									
		Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022	156,000	11,200	9,300	12,900	0	1,300	4,900	0	0	2,300	0
2025	157,000	11,200	8,900	12,700	0	1,300	6,500	0	0	2,500	300
2030	161,000	11,200	4,400	15,800	0	1,300	13,900	800	900	2,500	2,100
2035	169,000	12,000	3,100	15,800	0	1,300	19,500	800	1,800	4,100	3,600
2040	179,000	14,300	800[1]	15,300	1,500	1,300	23,500	800	1,800	4,100	7,100
2045	190,000	18,600	800[1]	9,900	2,300	1,300	23,800	800	1,800	4,100	9,300
2050	203,000	21,000	0	5,300	11,300	1,300	23,800	800	1,800	4,100	8,600

Year	5- Year Net Builds and Retirements (MW)									
	Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022-2025	0	-400	-200	0	0	1,600	0	900	200	300
2026-2030	0	-4,500	3,100	0	0	7,400	800	900	0	1,800
2031-2035	855	-1,300	0	0	0	5,600	0	0	1,600	1,500
2036-2040	2,300	-2,300	-500	1,500	0	4,000	0	0	0	3,500
2041-2045	4,300	0	-5,400	800	0	300	0	0	0	2,200
2046-2050	2,400	-800[1]	-4,600	9,000	0	0	0	0	0	-700

[1] Cliffside 6, which is projected to run exclusively on gas.

Tables C-3 and C-4. Total Nameplate and Capacity and Net Builds and Retirements, *Optimized* Scenario

Year	Net Load (GWh)	Total Nameplate Capacity (MW)									
		Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022	156,000	11,200	9,300	12,900	0	1,300	4,900	0	0	2,300	0
2025	157,000	11,200	8,300	12,700	0	1,300	7,300	0	0	2,500	300
2030	157,000	11,200	4,400	12,700	0	1,300	13,900	800	900	2,500	5,900
2035	160,000	11,200	800[1]	12,700	0	1,300	20,300	800	1,200	4,100	7,600
2040	166,000	11,200	800[1]	11,900	0	1,300	28,900	800	1,500	4,100	17,300
2045	175,000	12,700	800[1]	6,400	0	1,300	38,400	800	1,700	4,100	26,000
2050	186,000	13,200	0	1,000	5,300	1,300	44,800	800	1,800	4,100	30,800

Year	5- Year Net Builds and Retirements (MW)									
	Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022-2025	0	-1,000	-200	0	0	2,400	0	0	200	300
2026-2030	0	-3,900	0	0	0	6,600	800	900	0	5,600
2031-2035	0	-3,600	0	0	0	6,400	0	300	1,600	1,700
2036-2040	0	0	-800	0	0	8,600	0	300	0	9,700
2041-2045	1,500	0	-5,500	0	0	9,500	0	200	0	8,700
2046-2050	500	-800[1]	-5,400	5,300	0	6,400	0	100	0	4,800

Tables C-5 and C-6. Total Nameplate and Capacity and Net Builds and Retirements, *Regional Resources* Scenario

Year	Net Load (GWh)	Total Nameplate Capacity (MW)									
		Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022	156,000	11,200	9,300	12,900	0	1,300	4,900	0	0	2,300	0
2025	157,000	11,200	8,300	12,700	0	1,300	7,000	0	0	2,500	300
2030	157,000	11,200	2,200	12,700	0	1,300	9,900	0	3,400	2,500	4,200
2035	160,000	11,200	800[1]	12,700	0	1,300	16,700	0	3,700	4,100	5,000
2040	166,000	11,200	800[1]	11,500	0	1,300	26,200	0	3,700	4,100	13,700
2045	175,000	11,700	800[1]	6,000	800	1,300	36,100	0	4,200	4,100	24,800
2050	186,000	12,200	0	600	8,300	1,300	43,200	0	4,300	4,100	28,900

Year	5- Year Net Builds and Retirements (MW)									
	Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022-2025	0	-1,000	-200	0	0	2,100	0	0	200	300
2026-2030	0	-6,100	0	0	0	2,900	0	3,400	0	3,900
2031-2035	0	-1,400	0	0	0	6,800	0	300	1,600	800
2036-2040	0	0	-1,200	0	0	9,500	0	0	0	8,700
2041-2045	500	0	-5,500	800	0	9,900	0	500	0	11,100
2046-2050	500	-800[1]	-5,400	7,500	0	7,100	0	100	0	4,100

CONFIDENTIAL APPENDIX D. DUKE COAL UNIT RETIREMENT DATES

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 179

In the Matter of: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC 2022 Biennial Integrated Resource Plans and Carbon Plan	)	Verification of Tyler Fitch

VERIFICATION

I, Tyler Fitch, first being duly sworn, say that I am employed as a Senior Associate at Synapse Energy Economics, Inc. and have read the foregoing report entitled, "Carbon-Free by 2050: Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers," and know the contents thereof; and that the contents are true, accurate and correct to the best of my knowledge, information, and belief.

Signature

STATE OF Washington

COUNTY OF DC

Signed and sworn to (or affirmed) before me this 20th day of July, 2022.

Signature of Notary Public

Dominique Brown
Printed or Typed Name of Notary Public

My Commission Expires: 4-14-2026

[Official Seal or Stamp]

DOMINIQUE ANGELENE BROWN NOTARY PUBLIC Exp. - 04 14 2026 DISTRICT OF COLUMBIA

Exhibit 2: AGO Supplemental Portfolio Modeling Results

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

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

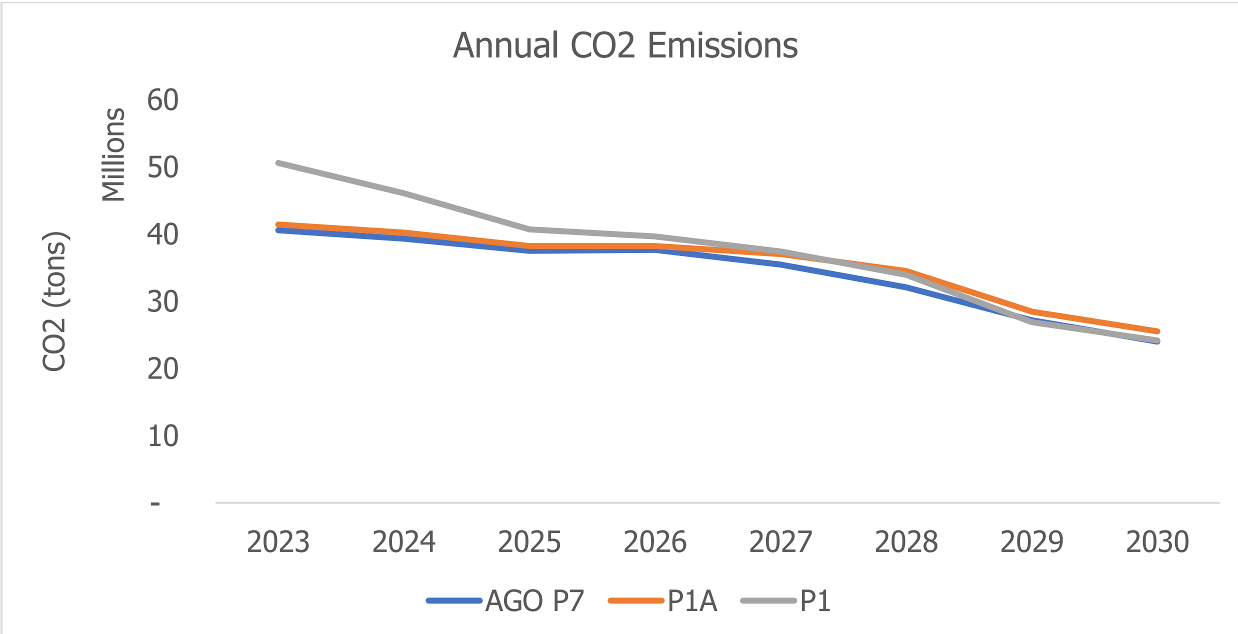
Carbon Plan Portfolios	P1		SP-AGO	
	Resources (MW) Start of Year (2030 | 2035)			
Total System Solar	12,307	18,829	12,445	16,264~~17,427~~ ~~24,109~~
Incremental System Solar (excludes projects in development)	5,400	11,850	6,126	9,945~~10,740~~ ~~17,580~~
Incremental Onshore Wind (incl. imports)	600	1,200	~~3,000~~2,250	3,600
Incremental Offshore Wind	800	800	800	800
Incremental SMR Capacity	0	570	0	~~855~~570
Incremental Energy Storage	2,067	5,671	3,490[2]	6,800
Incremental Gas (CC)	2,430	2,430	0	0
Incremental Gas (CT)	1,128	1,128	462	462
Incremental Coal to Gas Conversion	849	849	1959	1959
Early Coal Retirements	*Subcritical by 2030; MSS 3&4 in 2032*		*Subcritical by 2030 except Rox 3&4 in 2033; MSS 3&4 in 2032; Belews Creek conversion by 2028*	
Total Coal Retirements [MW] by End of 2035	8,445		9,294	

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

Portfolio	Year in which 70% NC CO_2 Reduction Achieved (2030 compliant portfolios in bold)	Present Value Revenue Requirement (PVRR) through 2050 (DEP/DEC Combined System) [$B]
P1	**2030**	**$101**
P2	2032	$99
P3	2034	$95
P4	2034	$96
$P1_A$	**2030**	**$104**
$P2_A$	2032	$101
$P3_A$	2034	$99
$P4_A$	2034	$99
SP5	2032	$102
SP6	2034	$98
$SP5_A$	2032	$98
$SP6_A$	2034	$95
SP-AGO	**2030**	**$100**

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

III. Emissions Performance Of All 2030-Compliant Portfolios



IV. SP-AGO, Cumulative Resource Additions by Year

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

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Incremental Gas (CC)	2,430	2,430	0	0
Incremental Gas (CT)	1,128	1,128	462	462
Incremental Coal to Gas Conversion	849	849	1959	1959
Early Coal Retirements	*Subcritical by 2030; MSS 3&4 in 2032*		*Subcritical by 2030 except Rox 3&4 in 2033; MSS 3&4 in 2032; Belews Creek conversion by 2028*	
Total Coal Retirements [MW] by End of 2035	8,445		9,294	

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Portfolio	Year in which 70% NC CO_2 Reduction Achieved (2030 compliant portfolios in bold)	Present Value Revenue Requirement (PVRR) through 2050 (DEP/DEC Combined System) [$B]
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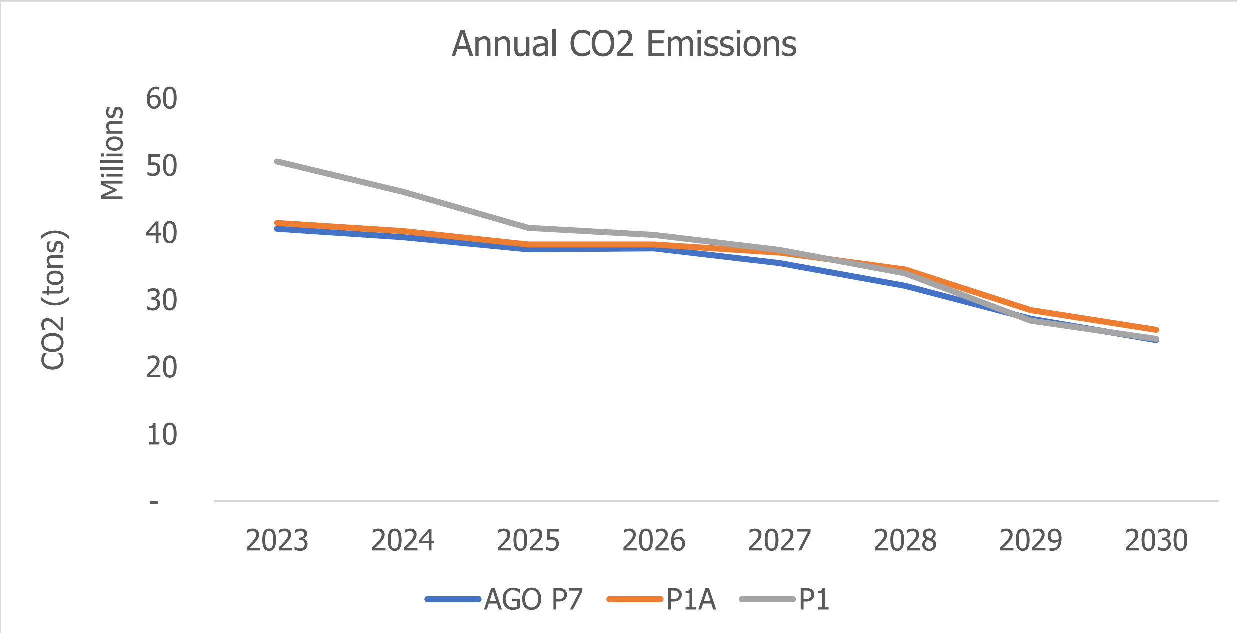
$P4_A$	2034	$99
SP5	2032	$102
SP6	2034	$98
$SP5_A$	2032	$98
$SP6_A$	2034	$95
SP-AGO	**2030**	**$100**

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

III. Emissions Performance Of All 2030-Compliant Portfolios



IV. SP-AGO, Cumulative Resource Additions by Year

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

STRATEGEN

Edward Burgess

Senior Director

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

Contact

Location

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Education

PSM
Solar Energy Engineering and Commercialization
Arizona State University
2012

MS
Sustainability
Arizona State University
2011

BA
Chemistry
Princeton
2007

STRATEGEN.COM

Work Experience

Senior Director

Strategen / Berkeley, CA / 2015 - Present

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

Senior Policy Director

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

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

Consultant

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

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

Consultant

Schlegel & Associates / Phoenix, AZ / 2012 - 2015

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

Edward Burgess

Senior Director

STRATEGEN

Selected Recent Publications

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

Domain Expertise

Vehicle Grid Integration

Distributed Energy Resources

Electric Vehicle Rates, Programs and Policies

Energy Resource Planning

Benefit Cost Analysis

Electricity Expert Testimony

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

STRATEGEN.COM

Relevant Project Experience

Arizona Residential Utility Consumer Office (RUCO)

IRP Analysis and Impact Assessment / 2015 - 2018

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

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 - 2019

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

Massachusetts Office of the Attorney General

SMART Program / 2016 - 2017

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

New Hampshire Office of Consumer Advocate

NEM Successor Tariff Design / 2016

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

Edward Burgess
Senior Director

STRATEGEN

Relevant Project Experience (con't)

Southwest Energy Efficiency Project

IRP Technical Analysis and Modeling / 2018 - 2020

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

California Energy Storage Alliance

California Hybridization Assessment / 2018 - 2019

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

Portland General Electric

Energy Storage Strategy / 2016

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

Xcel Energy

Time-of-use Rates / 2017 - 2018

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

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2020 - 2021

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

North Carolina, Office of the Attorney General

Duke Energy 2020 IRP Technical Support / 2020 - 2021

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

University of Minnesota

Energy Storage Stakeholder Workshops / 2016 - 2017

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

Edward Burgess

Senior Director

STRATEGEN

Expert Testimony

California Public Utilities Commission

- Pacific Power 2020 Energy Cost Adjustment Clause (Docket No. A.19-08-002)
- Pacific Power 2021 Energy Cost Adjustment Clause (Docket No. A.20-08-002)
- CPUC Rulemaking on Emergency Summer Reliability (Docket No. R.20-11-003)

Indiana Utility Regulatory Commission

- Duke Energy Fuel Adjustment Clause (Cause No. 38707 FAC 125)
- Duke Energy Fuel Adjustment Clause – Sub-docket Investigation (Cause No. 38707 FAC 123 S1)

Louisiana Public Service Commission

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

Massachusetts Department of Public Utilities

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

Michigan Public Service Commission

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

Nevada Public Utilities Commission

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

Oregon Public Utilities Commission

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

South Carolina Public Service Commission

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

Washington Utilities and Transportation Commission

- Avista Utilities General Rate Case (Docket No. UE-200900)

CONFIDENTIAL

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

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

[redacted]

CONFIDENTIAL RESPONSE:

[redacted]

[redacted]

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

[redacted]

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AGO
Docket No. E-100, Sub 179
2022 Carbon Plan
AGO Data Request No. 4
Item No. 4-7
Page 1 of 2

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

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

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

SECOND SUPPLEMENTAL RESPONSE (July 7, 2022):

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

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

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

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

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

Responder: Gerald W. Morgan, Lead Engineer

SUPPLEMENTAL RESPONSE (June 29, 2022):

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

Responder: Gerald W. Morgan, Lead Engineer

INITIAL RESPONSE:

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

Responder: Gerald W. Morgan, Lead Engineer

AGO
Docket No. E-100, Sub 179
2022 Carbon Plan
AGO Data Request No. 6
Item No. 6-4
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DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please refer to AGO DR3-30.xlsx

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

RESPONSE:

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

Responder: Jeffrey A. Day, Lead Load Forecasting Analyst

I/A

CIGFUR II/II Direct Testimony of Bradford D. Muller
Docket No. E-100, Sub 179
Exhibit 1
Page 2

CIGFUR II/II Direct Testimony of Bradford D. Muller
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Exhibit 1
Page 3

I/A

CIGFUR
Docket No. E-100, Sub 179
2022 Carbon Plan
CIGFUR Data Request No. 2
Item No. 2-16

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

With respect to Duke's Response to CIGFUR's Data Request 1-4 and 1-5, please provide an exhaustive list of the costs included; please also provide an exhaustive list of the costs that are excluded (both related and unrelated to the Carbon Plan).

RESPONSE:

The following costs are included in the Carbon Plan analysis:

- Fuel costs
- Firm fuel supply costs
- Emissions allowance costs
- Unit commitment costs
- Fixed O&M for new units
- Variable O&M
- Firm generating capacity purchases
- Solar PPA costs
- Ongoing capex and FOM for coal units
- Capital for new generation
- Transmission capital associated with new generation and coal retirements
- EE, DR, and IVVC costs

Costs unrelated to the Carbon Plan are excluded.

Responder: Nathan Gagnon, Principal Planning Analyst

AGO
Docket No. E-100, Sub 179
2022 Carbon Plan
AGO Data Request No. 3
Item No. 3-6
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DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

How was the storage dispatch profile determined? Was a fixed shape used instead of allowing the EnCompass model to dispatch the storage resource? If so, why?

RESPONSE:

Encompass economically dispatched standalone storage and other types of energy storage. A fixed shape was not used. The only storage resource which used a fixed profile was Solar + Storage units.

Batteries and other energy storage provide the ability to operate as a load when charging, to help the system maintain minimum operating limits, or as a generator to supply energy at peak demand and times of high marginal energy cost. Perhaps most importantly, batteries provide for the ability to move excess carbon-free energy from one period to another to offset marginal carbon emissions.

The Solar + Storage dispatch profile was developed based on the standalone solar profiles used in the Carbon Plan that were paired with the 40 MW/ 80 MWh and 20 MW/80 MWh batteries. The batteries were dispatched within an independent dispatch model according to hourly avoided cost rates. Each hour was ranked within a rolling 24-hour period in a 48-hour total window based on the capacity and duration of the batteries. The standalone dispatch model first charges the battery with any available DC clipped energy and then allows for charging directly from what would be the AC solar output based on whether there is more economic benefit to charge the battery or send the solar energy directly to the grid based on the hourly rankings.

See the selection titled "Selectable Supply-Side Resources" starting on page 27 of Appendix E (Quantitative Analysis) if more information is needed.

Responder: Thomas Beatty, Senior Engineer

NCSEA and SACE, et al.
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Carbon Plan – 2022
Joint Data Request No. 2
Item No. 2-12
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Please reference page 2 of Appendix I to the Proposed Carbon Plan. Please explain how Duke came to the assertion in the Table on Page 2 of Appendix I that a solar+storage facility would have a capacity factor of 32%. Please reference any materials or information that led to this assertion.

Response:

The capacity factor for solar plus storage is determined by using the standalone solar profile combined with a battery capacity (MW) and energy (MWh). The standalone solar profiles are developed using historical, hourly irradiance from 22 (9 DEP and 13 DEC) locations within the Carolinas. Monthly irradiance values for each historical year are averaged, and the closest individual month average from all historical years that best matches the overall historical monthly average is used to create a 'best fit' year by combining the months (Jan-Dec). This best fit year (8760) is then matched to the load forecast and forecasted out through the planning horizon. The solar plus storage profile uses the standalone solar profile paired with a specific battery configuration (20MW, 4-hr and 40MW, 2-hr). The solar and storage combination is dispatched over the planning horizon. The battery storage is charged first with clipped energy and then charged directly from solar that would normally go to the grid when economical. The standalone solar profile for a single axis tracking, 1.6 inverter/load ratio, achieves 29% capacity factor on its own. The solar plus storage profile, because it can utilize the clipped energy of the solar facility that is normally lost, achieves a 32% capacity factor.

Responder: Randall Heath, Project Manager II; Matthew Kalemba, Director of DET Planning & Forecasting