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

PREPARED FOR:

Tech Customers

PREPARED BY:

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North Carolina Utilities Commission

Docket No. E-100, Sub 179

July 15, 2022

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Acknowledgments

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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.

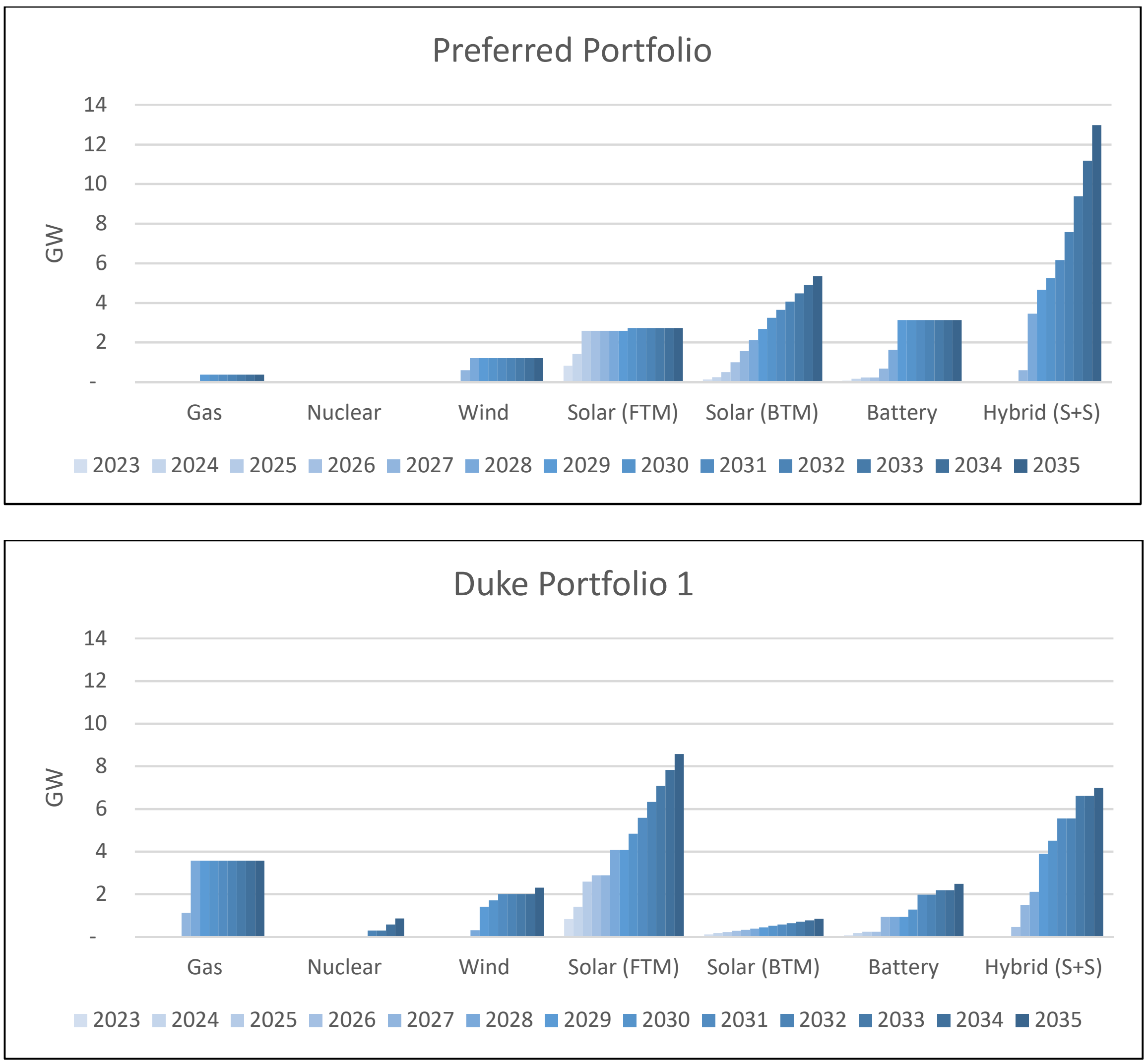
The Companies put forth an ambitious Carbon Plan that contemplates a transformational change to the region's resource mix to achieve the state's near-term emissions reduction goal and carbon neutrality by 2050. While these efforts are commendable, just one of the four potential portfolios in their Carbon 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

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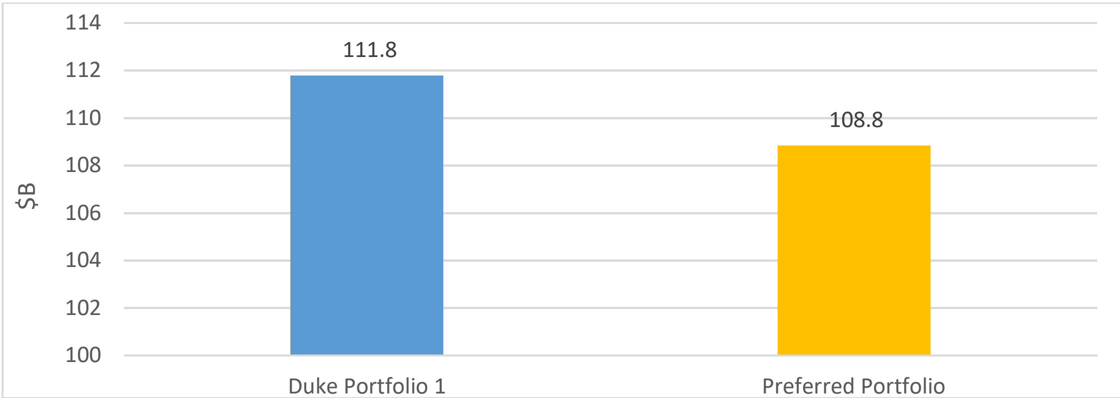
("SMR"), and achieves the state's carbon reduction objectives at nearly $3 billion less than the Companies' Carbon Plan.

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)**

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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.

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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.

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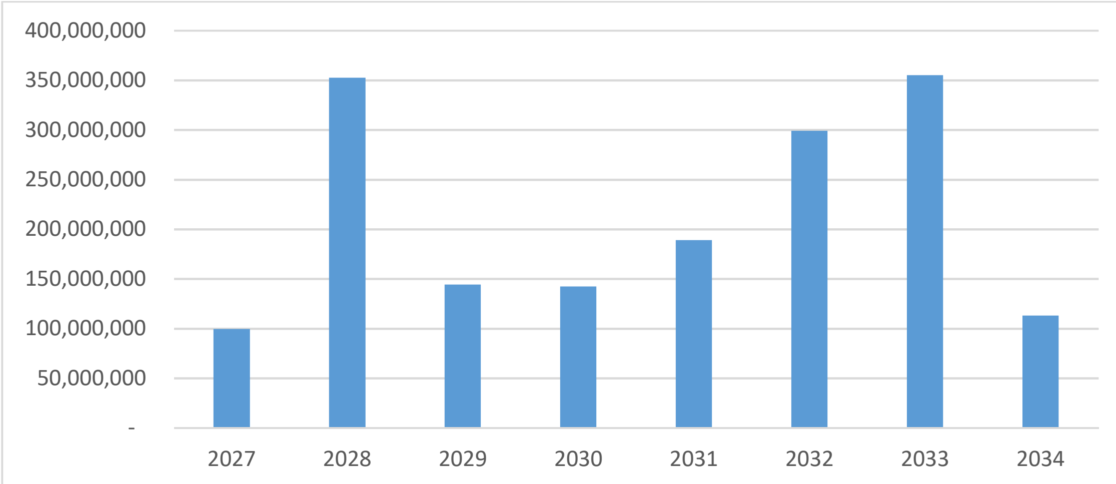
Figure 4: Generator Replacement Request Interconnection Cost Savings ($/Year)



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

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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]

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

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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

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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.

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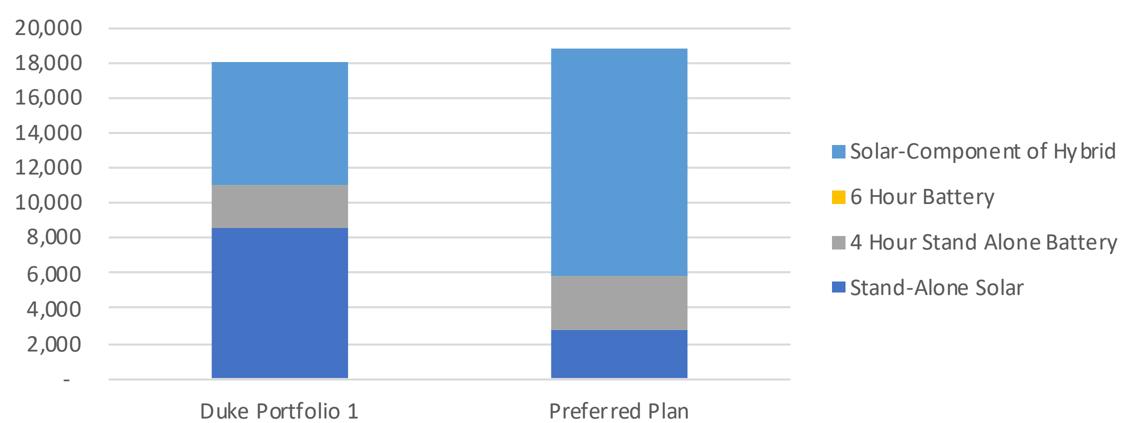
resources would be seen as a viable economic alternative to new renewable generators, as discussed further below.

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



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

[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

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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

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[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

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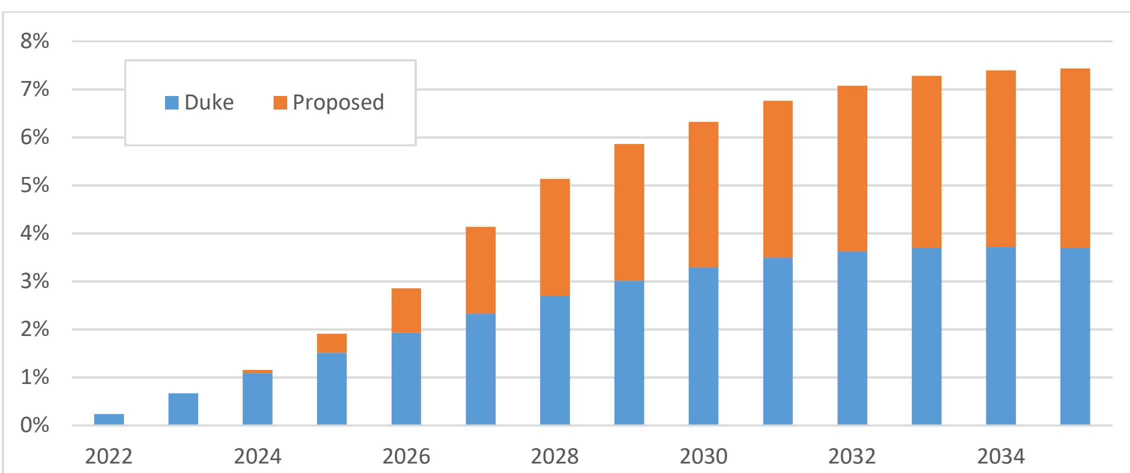
transmission into the applicable Duke service territory. These offerings would have the customer contract for and pay the power supply cost from a new renewable project. This contract purchase would be coupled with a requirement that the customer pays for delivery service through the Duke system at rates 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)



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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.

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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.

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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

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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

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[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

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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).

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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.

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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.

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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.

[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.

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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.

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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.

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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*.

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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

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[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.

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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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[redacted]

[END CONFIDENTIAL]

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.

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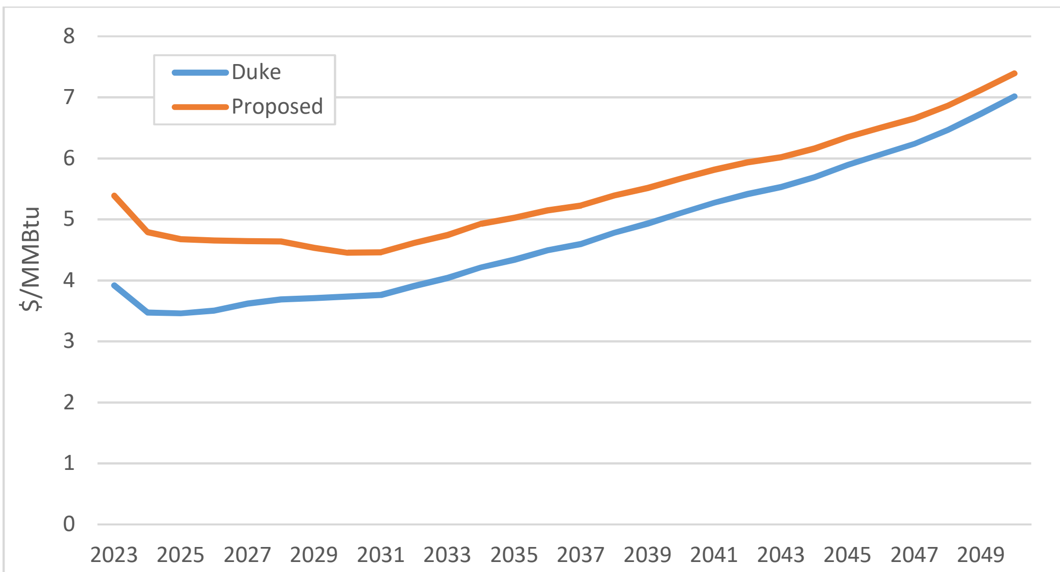
unknown, it is evident that gas market fundamentals are significantly different from those reflected in the Companies' forecast. This reality raises questions about the reasonableness of the Companies' projections that drive their capacity expansion modeling results.

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.

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

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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.

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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.

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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.

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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.

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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.

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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

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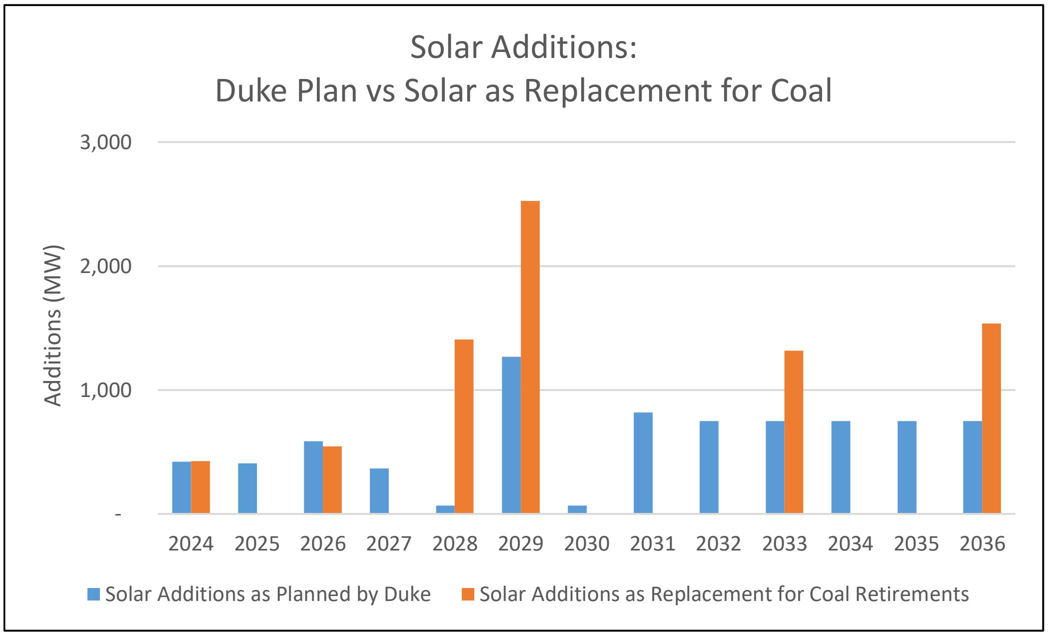
Figure 20: Coal Retirements vs. Solar Additions



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

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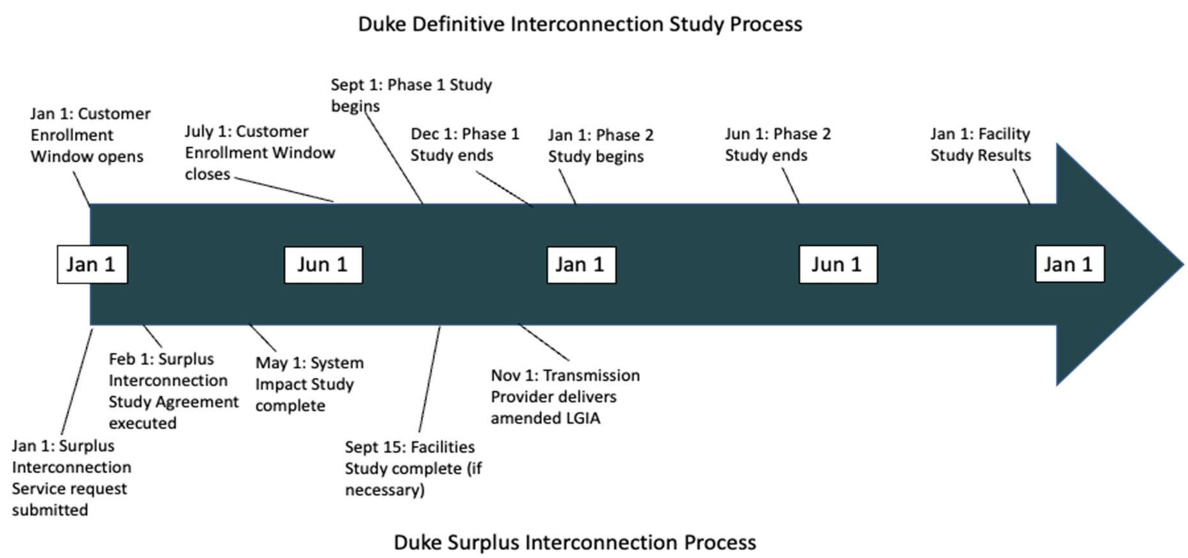
explain why this option does not represent the least cost option for achieving the State's emissions reduction goals.

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.

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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*.

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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.

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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.

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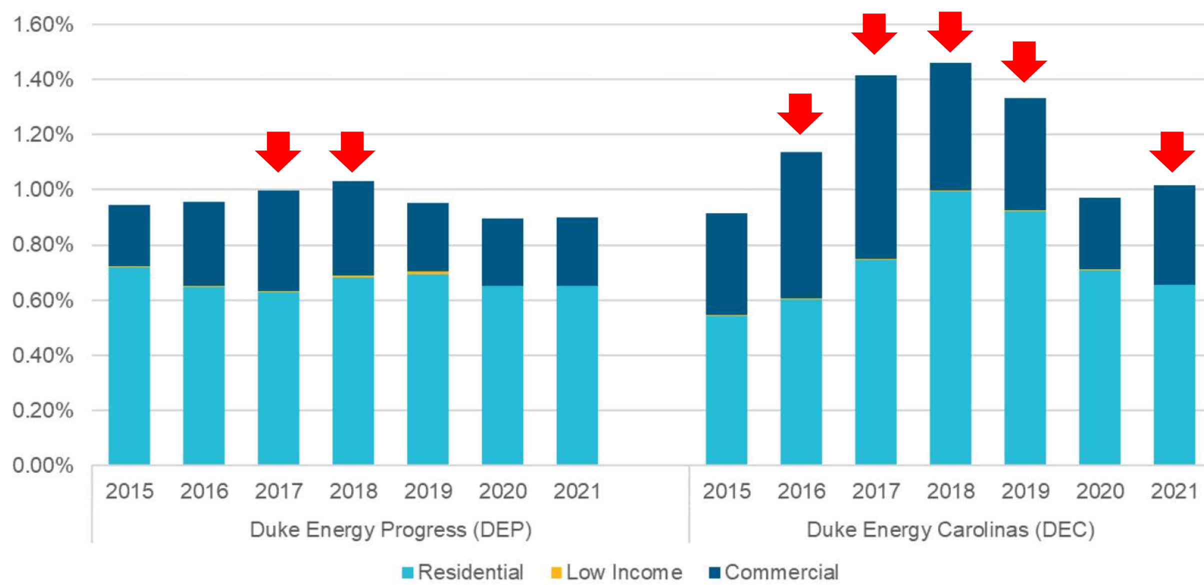
Figure 22: EE Deployment at or Above 1% Deployment Target by Year & Utility



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

[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.

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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.

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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.

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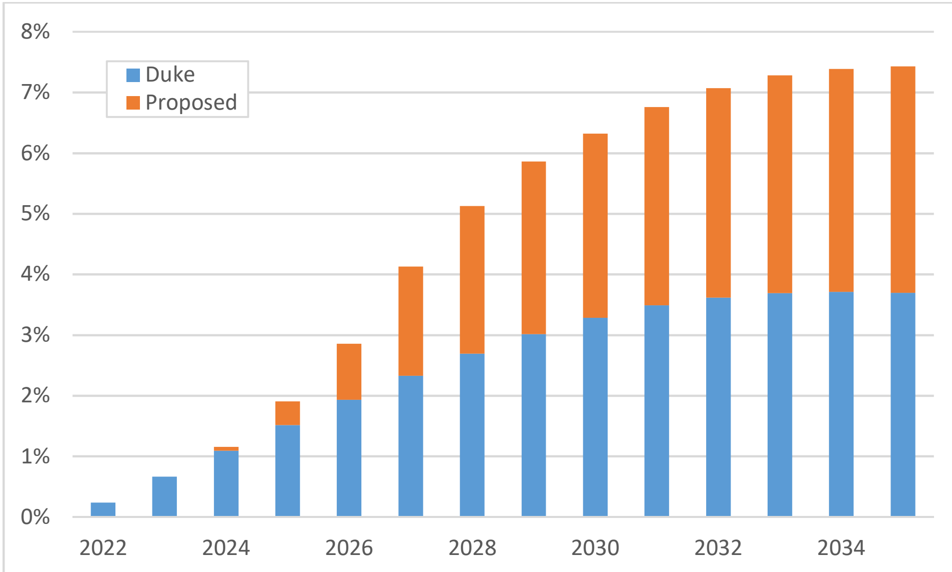
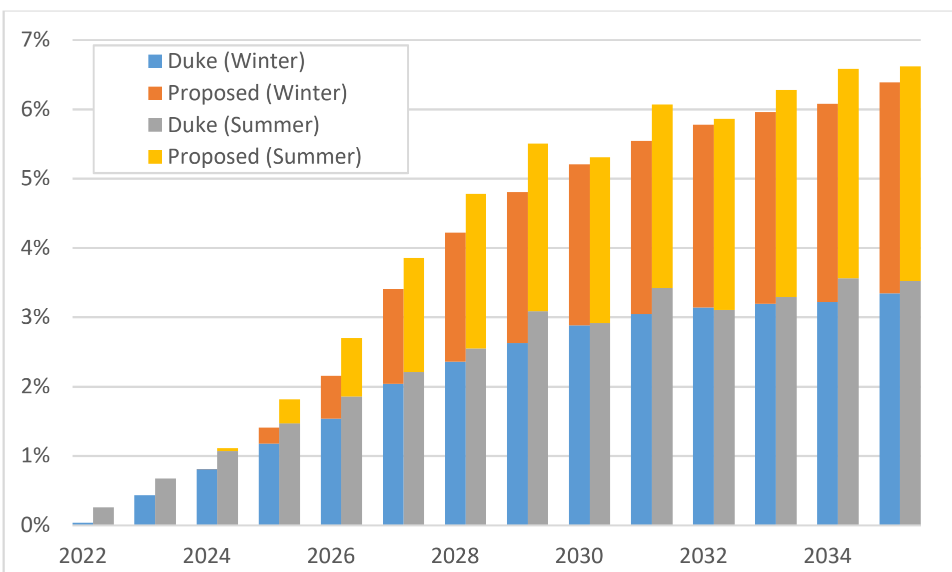
Figure 23: Proposed Cumulative Energy Efficiency Savings (% energy consumption)



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)



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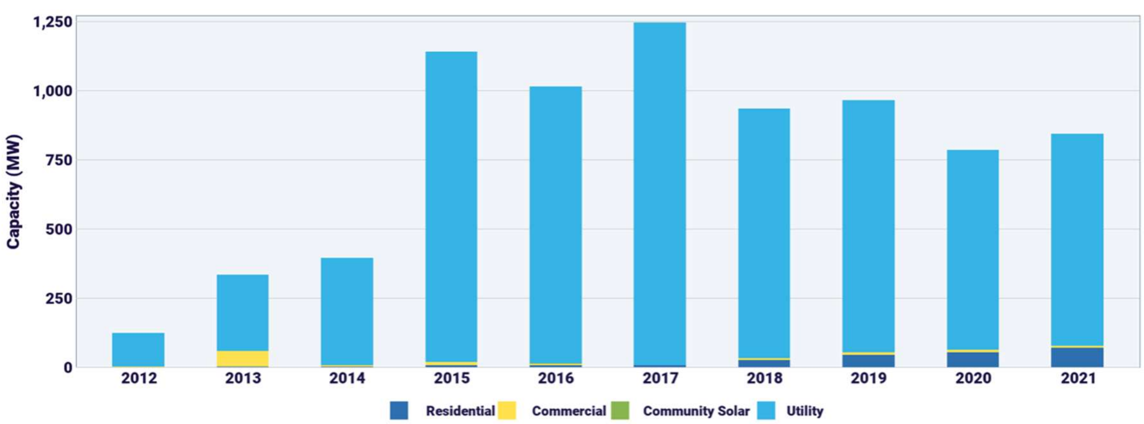
Energy efficiency expenditures were incorporated into the analysis and estimated based upon the unit costs contained the Companies' Carbon Plan.[64]

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.

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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 CO_2 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.

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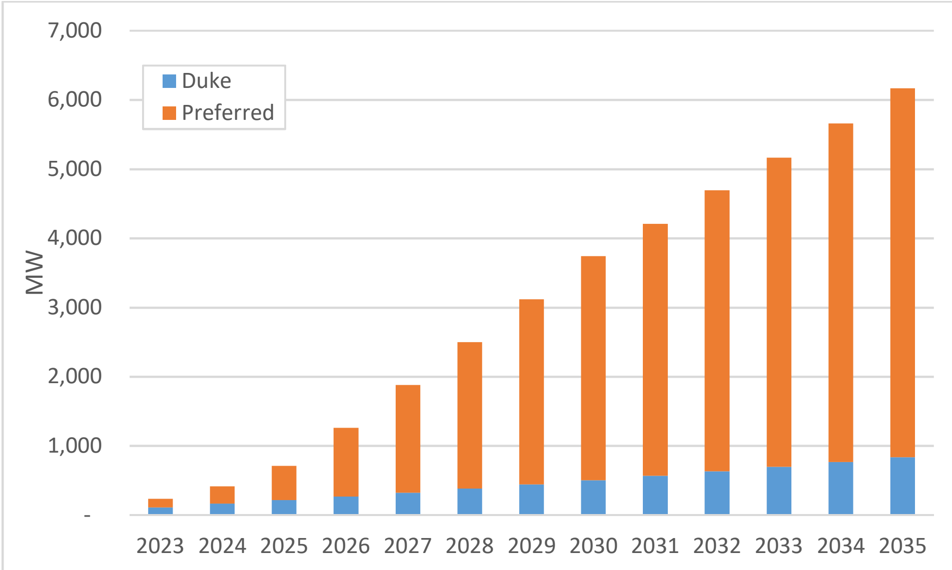
Figure 26: Proposed BTM Solar Capacity



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

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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.

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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

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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.

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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

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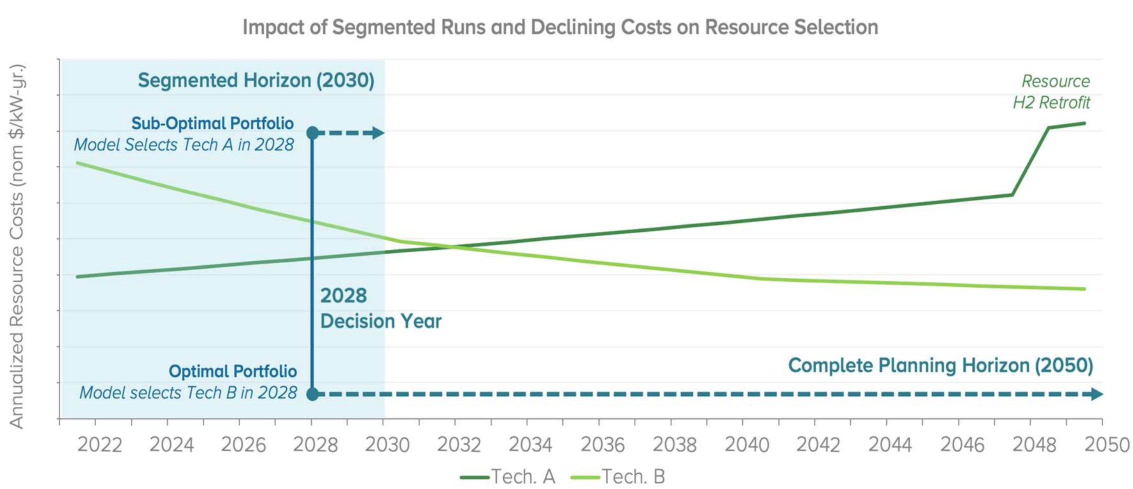
at once. However, segmenting the time horizon of an analysis has numerous implications for the solutions developed by the model which can lead to distorted results.

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



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

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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

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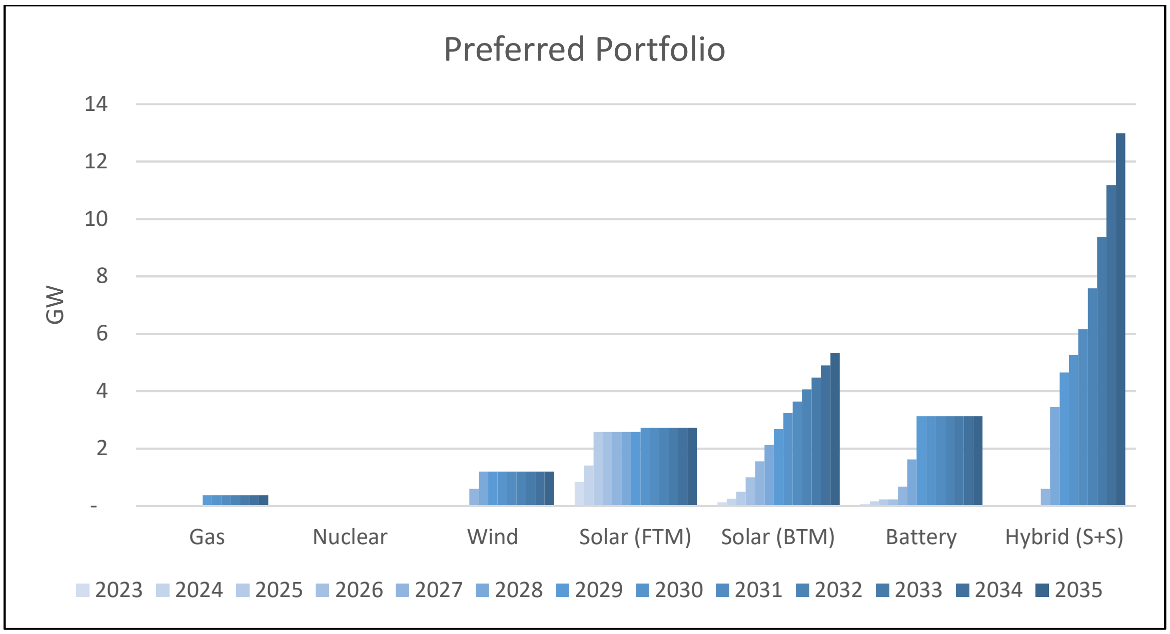
whether an investment is prudent. This portfolio, with no new NGCC units, also achieves emissions reductions similar to those in Portfolio 1, meaning that Duke can proceed with a least cost solution that complies with HB 951, is more economic, is reliable, and preserves future optionality to select alternative 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.

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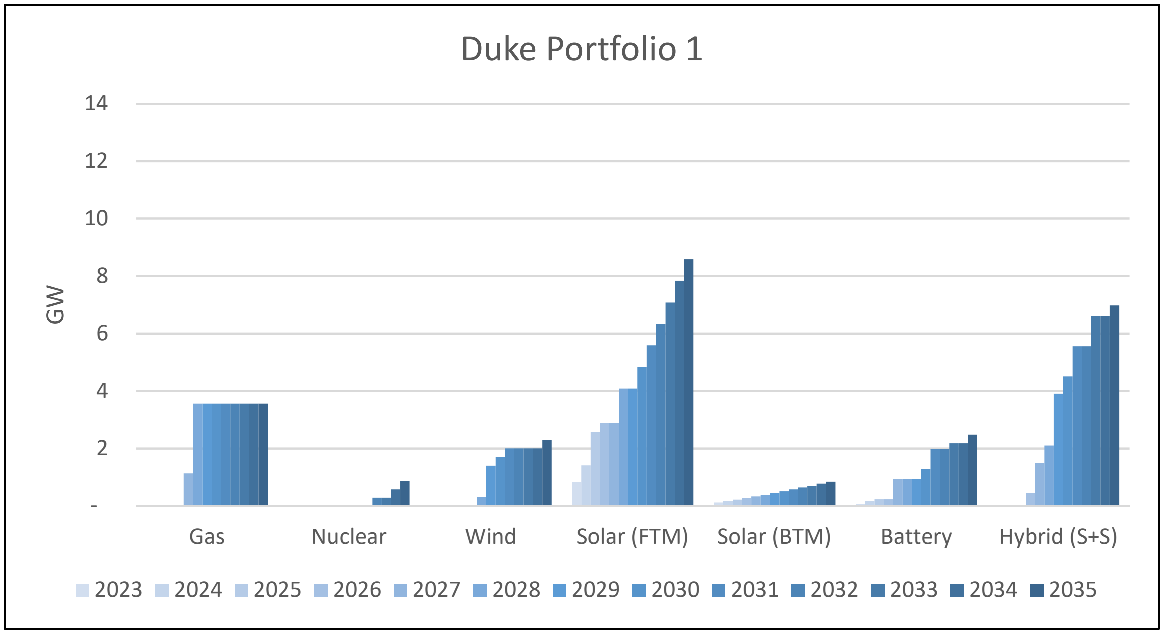
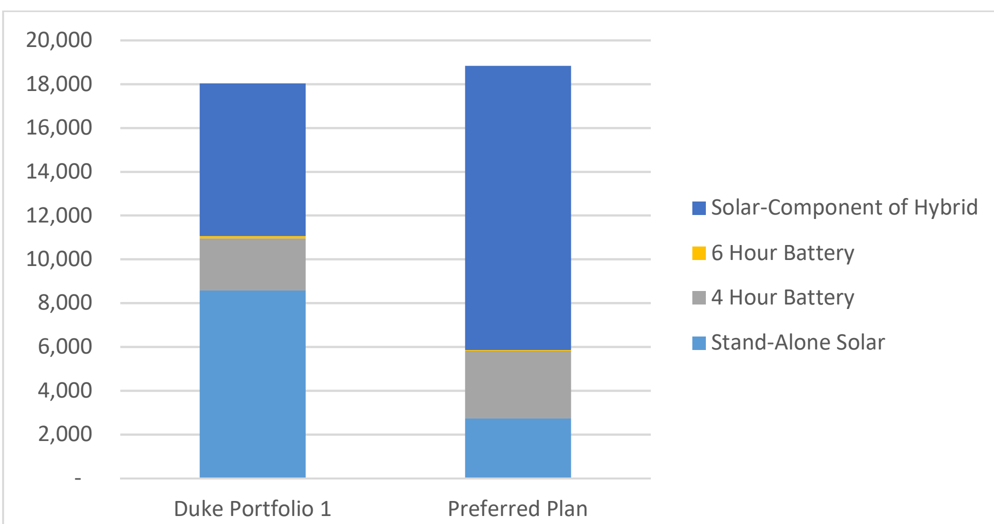
Figure 30: Duke P1 Nameplate Capacity Additions



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



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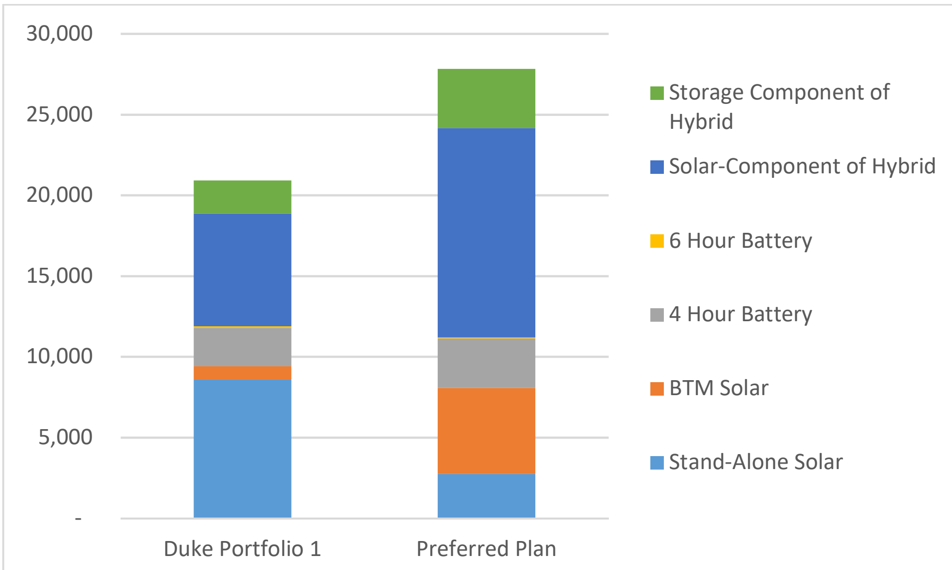
This chart shows a minimal shift in total capacity, but a major change in the type of capacity installed. However, there are other components that further differentiate the solar and storage aspects of the Preferred Portfolio. The follow figure displays the total solar and hybrid capacity, but also includes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

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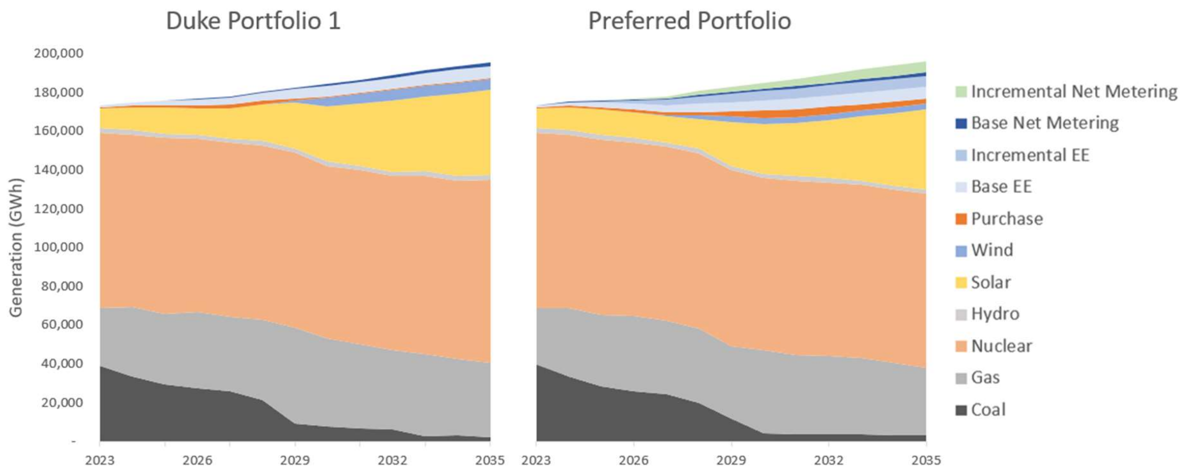
Figure 33: Generation Resource Mix Comparison



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.

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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.

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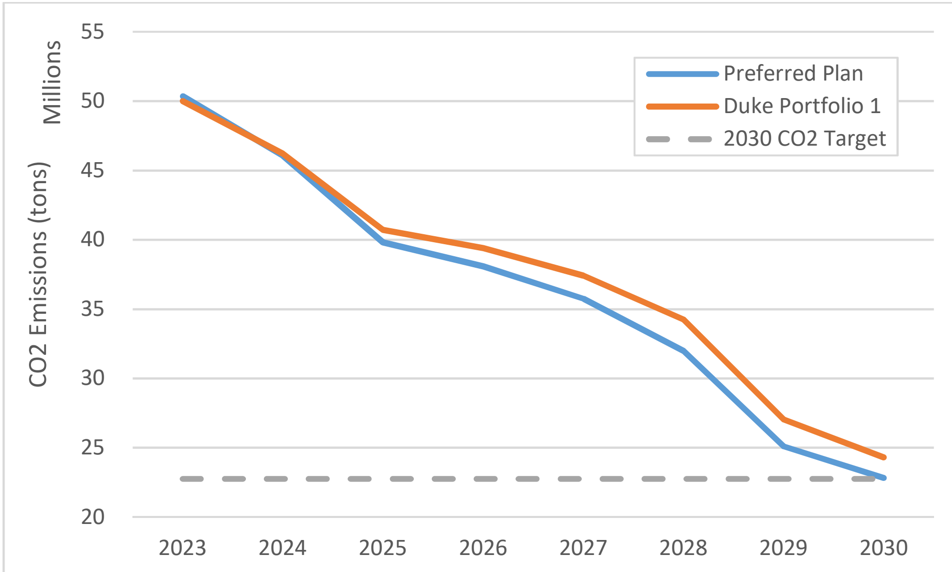
Figure 35: Emissions Comparison



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

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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.

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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.

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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.

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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

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Years of Experience: 14

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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

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Years of Experience: 12

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Maria Roumpani, PhD
Senior Manager

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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

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Berkeley, California

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Education

PhD
Management Science and Engineering
Stanford University
2018

MSc
Electrical & Computer Engineering
National Technical University of Athens
2009

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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

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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

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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

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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

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Education

BA
Urban & Regional Planning
National Autonomous University of Mexico
2017

Fulbright Fellow
Binational Business
University of California, Berkeley
2018

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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

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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.