BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 165

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	)	PARTIAL INITIAL
In the Matter of:	)	COMMENTS OF NCSEA,
	)	CCEBA, AND SACE, ET AL.
2020 Biennial Integrated Resource	)	ON DUKE ENERGY
Plans and Related 2020 REPS	)	CAROLINAS, LLC AND
Compliance Plans	)	DUKE ENERGY PROGRESS,
	)	LLC'S 2020 INTEGRATED
	)	RESOURCE PLANS
	)	

PARTIAL INITIAL COMMENTS OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, SIERRA CLUB, AND NATURAL RESOURCES DEFENSE COUNCIL ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S 2020 INTEGRATED RESOURCE PLANS

Pursuant to North Carolina Utilities Commission ("Commission") Rule R8-60(k), the Commission's January 8, 2021 *Order Granting Extensions of Time*, and the Commission's February 26, 2021 *Order Granting Second Extension of Time*, the North Carolina Sustainable Energy Association ("NCSEA"), the Carolinas Clean Energy Business Association ("CCEBA"), the Southern Alliance for Clean Energy ("SACE"), the Sierra Club, and the Natural Resources Defense Council ("NRDC") (SACE, the Sierra Club, and NRDC, collectively, "SACE et al.") submit the following comments on the evaluation of resource options in the 2020 integrated resource plans ("IRPs") submitted by

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc. ("DEP") (collectively, "Duke").[1]

I.   INTRODUCTION

This proceeding presents the Commission with the opportunity to meet historic challenges with bold and transformational action. Out of ecological and economic necessity, the country and the world are moving to a carbon-constrained future. The question before this Commission and all the parties to this proceeding is whether we will heed the call of the scientific community and Governor Cooper to take the actions necessary to meet this moment, or continue with business as usual and ignore the serious and undeniable risks facing all current and future North Carolina ratepayers.

Duke has presented this Commission with deeply flawed IRPs. It suggests that the "least cost" plan for ratepayers is one that (i) continues reliance on dirty, uneconomic coal plants without regard to the certain increased cost of operating those plants due to more stringent federal regulations; (ii) adds massive volumes of new natural gas capacity without regard to the potential for those assets to become stranded based on Duke's own de-carbonization goals; and (iii) adds minimal amounts of new solar and storage despite the demonstrated cost-effectiveness of these technologies. Even under Duke's own analysis, this plan is not "least cost" under many of the sensitivity analyses performed by Duke, and if accepted by this Commission would expose ratepayers to unacceptably high risk of increased costs. But as demonstrated by intervenors through exhaustive analysis and expert testimony, Duke's IRPs are riddled with inaccurate data, unrealistic assumptions, and

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[1] In addition to these Partial Initial Comments, NCSEA and CCEBA, collectively, and SACE et al. are contemporaneously filing additional, separate comments regarding other aspects of Duke's 2020 IRPs.

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flawed methodologies. When these glaring errors are corrected – as they should be – it becomes apparent that the "least cost" plan for North Carolina ratepayers is one that relies heavily on cost-effective and reliable clean energy options that avoid the ecological risk of contributing further to global climate change and the economic risk of billions of dollars of stranded assets.

At this historic moment, it is critical that Duke and this Commission produce and immediately begin implementing a plan for the state's energy future that is based on sound science and analysis, and a proper consideration of the risk presented to ratepayers by business as usual. There is too much at stake and the urgency is too great to defer resolution of these issues to a future proceeding.

Given the importance of the evaluation of resource options that is the heart of the IRP process, NCSEA, CCEBA, and SACE et al. jointly retained Synapse Energy Economics, Inc. ("Synapse") to review the capacity expansion and production cost modeling of resource options that Duke used to develop the 2020 IRPs, and to perform new, independent modeling. Synapse's modeling corrects significantly flawed and inaccurate assumptions and inputs in Duke's modeling and demonstrates that a very different resource plan than those developed by Duke is in the best interest of Duke ratepayers. The results of Synapse's modeling are summarized in the following comments and fully detailed in the report attached as Exhibit A.

Synapse's analysis demonstrates that when the inaccurate assumptions in Duke's evaluation of resource options are corrected, modeling will produce portfolios that, in comparison to Duke's lowest-cost portfolio, reduce overall system cost by $7.2 billion while reducing carbon dioxide emissions by tens of millions of tons per year, deploying

large volumes of solar and energy storage, and avoiding natural gas capacity additions, all while maintaining resource adequacy. Synapse's scenario retires coal based on Duke's "earliest practicable" retirement schedule and builds no new gas, instead deploying significant volumes of solar and battery storage capacity while maintaining Duke's 17% planning reserve margin. This result contrasts markedly with Duke's "No New Gas" portfolio which has a Present Value of Revenue Requirement ("PVRR") 31% *higher* than Duke's "Base Case with Carbon Policy."

For the reasons set forth in these comments, the parties respectfully request that the Commission find that Duke's 2020 IRPs are not reasonable for planning purposes, and direct DEC and DEP to modify and refile their IRPs after completing the modifications recommended herein.

II.   IRP REQUIREMENTS IN NORTH CAROLINA

Duke's 2020 IRPs must be evaluated in the context of North Carolina law, which deems the operations of public utilities to be "affected with the public interest" and declares it to be the State's policy to promote adequate, reliable and economical utility service to all of its citizens and residents, and to provide just and reasonable rates and charges "consistent with long-term management and conservation of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy." N.C. Gen. Stat. § 62-2(a)(3-4).

To this end, the statute establishes a state policy of assuring that resources for future growth include use of the "entire spectrum of demand-side options" and "requir[ing] energy planning and fixing of rates in a manner to result in the *least cost mix of generation* and demand-reduction measures which is achievable. . . ." N.C. Gen. Stat. § 62-2(a)(3a) (emphasis added). The statute goes on to deem it state policy to "promote harmony between public utilities, their users and the environment" and to "foster the continued service of

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public utilities on a well-planned and coordinated basis." N.C. Gen. Stat. § 62-2(a)(5),(6). Finally, the statute declares a policy to "promote the development of renewable energy and energy efficiency" through the implementation of a renewable energy and energy efficiency standard that diversifies "the resources used to reliably meet the energy needs of consumers in the State," provides "greater energy security through the use of indigenous energy resources available within the State," encourages "private investment in renewable energy and energy efficiency," and provides "improved air quality and other benefits to energy consumers and citizens of the State." N.C. Gen. Stat. § 62-2(a)(10).

To meet these objectives, the Commission is vested with the authority to regulate public utilities, including "their expansion in relation to long-term energy conservation and management policies and statewide development requirements, and in the manner and in accordance with the policies set forth in this Chapter." N.C. Gen. Stat. § 62-2(b). The General Assembly also directed this Commission under N.C. Gen. Stat. § 62-110.1(c) to:

> . . . develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power . . . and other arrangements with other utilities and energy suppliers to *achieve maximum efficiencies* for the benefit of the people of North Carolina. . . .

N.C. Gen. Stat. § 62-110.1(c) (emphasis added). The Commission must annually submit a report to the Governor and the General Assembly setting out a plan for meeting the future requirements of electricity for North Carolina, progress to date in carrying out such plan, and program regarding such plan over the ensuing year. *Id.*

The final statutory provision informing the Commission's review of IRPs is found within the Competitive Procurement of Renewable Energy Program ("CPRE") established

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by Session Law 2017-192. Following a 45-month procurement period, "a new renewable energy resources competitive procurement and the *amount to be procured* shall be determined by the Commission, based on a showing of need evidenced by the electric public *utility's most recent biennial integrated resource plan or annual update approved by the Commission* pursuant to G.S. 62-110.1(c)." N.C. Gen. Stat. § 62-110.8(a) (emphasis added). [2] The initial CPRE program was approved by the Commission on February 21, 2018. Thus, pursuant to N.C. Gen. Stat. § 62-110.8(a), the initial CPRE program will expire in November 2021. While Duke will file IRP update reports on September 1, 2021, those reports will not be approved prior to the expiration of the original CPRE program.

To implement the provisions of N.C. Gen. Stat. §§ 62-2(3a) and 62-110.1(c), the Commission has promulgated rules governing "least cost integrated resource planning by the utilities in North Carolina." NCUC Rule R8-60(a). Under the rules, electric utilities must develop and submit IRPs that, "at a minimum" must incorporate a "*comprehensive analysis of all resource options* (supply-and demand side)" including resources chosen to provide reliable electric utility service *"at least cost* over the planning period." NCUC Rule R8-60(c) (emphasis added). In developing their IRPs, utilities must "compare a *comprehensive* set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the *least cost combination* (on a long-term basis) of reliable resource options for meeting the anticipated needs of its

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[2] The use of the word "approved" in this context creates some ambiguity in that neither the IRP statute, N.C. Gen. Stat. § 62-110.1(c), nor the Commission's IRP Rule R8-60, make any reference to approval by the Commission of a utility's IRP. Rather, the Commission must determine whether or not to accept the plan as adequately and accurately providing the required information and analysis. The best way to resolve this inconsistency is to understand the phrase "approved by" in N.C. Gen. Stat. § 62-110.8(a) to mean "accepted by."

system." NCUC Rule R8-60(g) (emphasis added). The comparison must also "analyze potential resource options and combinations of resource options to serve its system needs" taking into account sensitivity to "variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation," as well as applicable "system operations, environmental impacts, and other qualitative factors." *Id.*

To ensure that a comprehensive analysis of least-cost options is undertaken and disclosed in an IRP, the Commission's rules set out the necessary elements that an IRP must include. Among other things, the IRP must consider and assess: "supply-side and demand-side resources, including alternative supply side energy resources" for the "provision of reliable electric utility service at least cost"; compliance with the Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"); "the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity"; any benefits of "reasonably available alternative supply-side energy resource options" including "solar thermal, solar photovoltaic, municipal solid waste, fuel cells, and biomass"; and "programs to promote demand-side management" including "demand response programs and energy efficiency and conservation programs." NCUC Rule R8-60(d)-(f).

Taken together, the Commission's rules and the statutes animating them establish a substantial and consequential process of resource planning and evaluation to yield a "comprehensive analysis of all resource options" to meet electrical service needs "at least

cost over the planning period." NCUC Rule R8-60(c); N.C. Gen. Stat. § 62-2(a)(3a) (requiring energy planning to result in the "least cost mix of generation and demand-reduction measures which is achievable"). Given the requirement that multiple resource scenarios be evaluated based on a variety of assumptions and sensitivity analyses, it will often be the case that one scenario has the lowest cost based on certain assumptions while another is least cost under different assumptions. Neither the statute nor the rules provide any guidance as to how to identify the "least cost" plan under these circumstances, but they certainly cannot intend that the resource portfolio that should be labeled as "least cost" is the one that has the lowest absolute cost, without regard to the accuracy of its underlying assumptions or the risk that those assumptions present to ratepayers. A better understanding of "least cost" planning is that it requires the utility and the Commission either (i) to make a judgment about what set of assumptions are most likely to be accurate; or (ii) to factor in the risk to ratepayers of potentially inaccurate assumptions. [3]

As summarized in these comments and as detailed in Exhibit A, Synapse's analysis shows that Duke's evaluation of resource options does not meet this Commission's applicable requirements because it is based on inaccurate data and assumptions. Further, Synapse's analysis shows that correcting Duke's erroneous analysis results in a lower-cost, lower-risk plan.

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[3] Risk is a form of cost that cannot be ignored. That is why people incur significant additional costs to purchase insurance.

III.   **SYNAPSE'S ANALYSIS OUTLINES A CLEANER AND CHEAPER ENERGY FUTURE THAN DUKE'S IRPS**

A.   **Methodology**

1.   *Synapse compares a scenario modeled substantially on Duke's "Base Case with Carbon Policy" IRP scenario to one which addresses flawed assumptions of that scenario.*

Synapse utilized EnCompass, an industry-standard capacity expansion and production cost modeling tool that Duke has stated it will adopt for future resource planning, to model two core scenarios: 1) "Mimic Duke" and 2) "Reasonable Assumptions." The Mimic Duke scenario attempts to model a similar portfolio to Duke's Base Case with Carbon Policy, in order to provide a basis for comparison. The Reasonable Assumptions scenario corrects a number of flawed assumptions from Duke's IRPs.

In the Mimic Duke scenario, Synapse used the same core assumptions Duke relied on, including the same load forecast, energy efficiency assumptions, renewable energy and storage resource costs, coal price and operation costs, gas price methodology, reserve margin assumptions, and Duke's assumed modest "shadow" carbon price of $5/ton beginning in 2025, escalating by $5/ton per year. Synapse did not prescribe the same portfolio as Duke; rather, the model determined the optimal capacity expansion based on the same input assumptions used in Duke's IRP. The Synapse Mimic Duke scenario results are relatively similar to Duke's portfolio, which validates this approach. Duke's PVRR for the combined system Base Case with Carbon Policy was $82.5 billion, while the PVRR of Synapse's "Mimic Duke" portfolio was $75.6 billion. The portfolio of resources in this scenario was also quite close to Duke's portfolio, which built 7.3 GW of new gas, while the Synapse model built 8.7 GW.

Synapse's Reasonable Assumptions scenario corrects a number of flawed assumptions from Duke's IRP, including the future capital and operating costs of battery storage; onshore and offshore wind costs; and energy efficiency savings. The results demonstrate that these core assumptions have a significant impact on the resources selected by the model, and by updating these inputs, this scenario provides a much-improved portfolio for Duke's combined system. The Reasonable Assumptions scenario is informed by the report of Kevin Lucas [4] submitted by CCEBA and NCSEA, which details a number of key input assumptions from Duke's modeling that are faulty or premised on poor underlying data, and recommends more reasonable assumptions.

2. *Synapse's analysis adjusts for changes in battery storage and wind costs, energy efficiency gains, tax law, and the interconnectedness of DEP's and DEC's service territories.*

Duke's IRPs contain a variety of assumptions that are incorrect, outdated, or unreasonable, including battery storage and wind costs, energy efficiency savings, federal tax policy, and the interconnectedness of DEP and DEC's service territories. Synapse's Reasonable Assumptions scenario corrected and updated these assumptions.

With respect to battery storage and wind, Synapse employed cost forecasts from the National Renewable Energy Laboratory's ("NREL") Annual Technology Baseline ("ATB"), which details the current and projected cost trajectories of key generating resources, based on publicly available, up-to-date assessments of current market conditions, policy, and trends. The NREL ATB is widely respected and is largely

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[4] Report of Kevin Lucas, Exhibit 3 to Initial Comments of NCSEA and CCEBA on Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Integrated Resource Plans, which are being filed contemporaneously with these comments.

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considered the gold standard for resource cost and performance forecasts, and is increasingly used by utilities and others across the country in public regulatory dockets.

With respect to energy efficiency, Synapse assumed a higher but achievable level of energy efficiency savings than Duke. Synapse assumed that Duke will ramp up its energy efficiency programs starting in 2022 from the 5-year EE plan levels and increase first year savings by 0.15 percent per year to 1.5 percent, and that this level of savings will persist through the study period. Reaching a 1.5 percent annual savings level is a reasonable scenario for Duke, given that the American Council for an Energy Efficient Economy found that the implementation of energy efficiency policies and measures could increase energy efficiency savings by nearly double by 2030 over a business as usual case,[5] and that leading states in energy efficiency such as Massachusetts and Rhode Island have been achieving much higher savings ranging from 2 percent to 3 percent per year over the past decade. In contrast, Duke's own savings have been at about 1 percent per year or less during that time frame.[6]

With respect to tax policy, Synapse updated the Federal ITC assumptions to reflect legislation passed in December 2020. The recently passed legislation extends the ITC stepdown such that projects begun by December 31, 2022 will enjoy a 26% tax credit and those started by December 31, 2023 will receive the 22% credit. The extended "safe

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[5] Rachel Gold, et al., *How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy, Cost, and Greenhouse Gas Impacts*, American Council for an Energy-Efficient Economy (Sept. 2020), available at: https://www.aceee.org/sites/default/files/pdfs/u2007.pdf.
[6] Forest Bradley-Wright, *SACE's Third Annual "Energy Efficiency in the Southeast" Report: A Solution to Multiple Crises* (Jan. 26, 2021), available at: https://cleanenergy.org/blog/saces-third-annual-energy-efficiency-in-the-southeast-report-a-solution-to-multiple-crises/.

harbor" provision also enables developers to "lock in" the credit as long as the project is in service by 2026.

Synapse also modeled the DEC and DEP systems as a single Balancing Authority Area ("BA"). Duke modeled the DEC and DEP service territories as independent islands, which does not reflect real-world physical grid operations, in which both the DEC and DEP systems are within the broader Eastern Interconnect, and do not in fact operate as islanded systems. Even Duke's joint planning case only modeled neighbors that are one transmission tie away, an overly conservative approach that ignores the reliability and economic benefits that DEC and DEP receive through interconnected operations.[7] By modeling the DEC and DEP systems as a single BA, Synapse allowed the model to consider the reliability and economic benefits of broader geographical, resource, and load diversity. It similarly mirrors the real-world operation of the electric grid, in which the combined Duke systems are simply one region physically interconnected among the broader Eastern Interconnect. Finally, Duke's own joint planning case shows that representing the two systems as merged introduces operational efficiencies and overall benefits, highlighted by the reduced planning reserve margin in the joint planning case.

3.   *Synapse's "Reasonable Assumptions" scenario models no new gas resources to protect ratepayers from the risk of stranded assets.*

To protect ratepayers from the risk of stranded assets, the Reasonable Assumptions scenario disallows new gas resources as an option available for selection by the capacity expansion model. North Carolina's Department of Environmental Quality has announced a goal of zero power sector carbon emissions by 2050, and Duke Energy has announced a similar corporate-wide net zero by 2050 goal. Although the form it takes

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[7] Brendan Kirby Report, Exhibit 1 to Initial Comments of NCSEA and CCEBA.

is not yet known, carbon regulation is coming, and any fossil fuel plant—including a gas plant—constructed today will need to be retired well before the end of its useful life and before the cost of that plant can be fully depreciated. As such, construction of new gas plants could potentially saddle ratepayers with unnecessary stranded assets. The Reasonable Assumptions scenario seeks to evaluate the cost implications of eschewing new investments in gas plants, which would position Duke for compliance with inevitable carbon regulation while protecting ratepayers from the risk of stranded assets.

4.   *Synapse's Reasonable Assumptions scenario leaves many of Duke's IRP assumptions in place.*

Although it changed a few key assumptions, Synapse's Reasonable Assumptions scenario kept intact many of the assumptions made by Duke, including coal prices and coal plant operating costs, wind/solar effective load carrying capability ("ELCC"), and the planning reserve margin of 17%.[8] Synapse also maintained a gas price forecast based on settled forward prices through 2032, rather than the fundamentals-based forecast recommended by Lucas. Tellingly, updating a few assumptions results in a considerably cheaper and cleaner portfolio compared to the scenarios Duke presents in the IRPs.

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[8] While other experts have provided strong critiques of these assumptions, Synapse retained them in its modeling and focused on the most glaring erroneous inputs. This includes retaining the assumptions in Duke's IRP of having the DEC and DEP systems operate as islands and ignoring the benefits of having Duke pursue greater regionalization as described by other experts retained by our organizations.

The table below compares the assumptions in Synapse's Mimic Duke and Reasonable Assumptions scenarios.

Input	Mimic Duke	Reasonable Assumptions
Carbon Constraint	None	None
DEC/DEP BA's	Merged	Merged
Imports/Exports	Not Allowed	Not Allowed
Load Forecast	From IRP	From IRP
EE/DSM	From IRP	Synapse Forecast
Solar Costs	Duke IRP Costs	Duke IRP Costs
Battery Costs	Duke IRP Costs	ATB 2020 Low
Onshore Wind Costs	Duke IRP Costs	ATB Low: Class 7
Offshore Wind Costs	Duke IRP Costs	ATB Low: Class 6
Coal Retirement	Duke Economic	Earliest Practicable
Coal Operations Costs	Duke IRP Costs	Duke IRP Costs
Coal Prices	Duke IRP Costs	Duke IRP Costs
Gas Prices	EnCompass defaults	EnCompass defaults
Planning Reserve Margin	17% (from IRP)	17% (from IRP)
Wind/Solar Capacity Credit	ELCC from Duke	ELCC from Duke
ITC Assumptions	From COVID relief bill	From COVID relief bill
New Gas Builds Allowed	Yes	No

B. **Results of Reasonable Assumptions Scenario**

1. *The Reasonable Assumptions scenario results in a low-cost, low-carbon resource plan that drives down fossil generation and ramps up clean energy resources.*

The Reasonable Assumptions scenario developed by Synapse results in a resource plan that, compared to the Mimic Duke scenario, is 10% cheaper on a PVRR basis, while reducing gas capacity by 34%, increasing solar deployment by 178% and reducing carbon dioxide emissions by 78%. Overall, the Reasonable Assumptions scenario adds 16 GW of new utility-scale solar, 2.5 GW of new onshore wind, and 10 GW of new battery storage by 2035. At the same time, the plan developed under this scenario deploys no new fossil fuel resources and retires coal according to the Earliest Practicable Retirement schedule in

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the Duke IRPs. Cliffside Unit 6, which runs at extremely low capacity factors, is assumed to run on gas after 2030. Some gas capacity is retired and replaced with new renewable resources. The model shows that the plan developed under the Reasonable Assumptions scenario reliably meets load in every hour of the planning period.

The Mimic Duke scenario, in comparison, retains over 3 GW of coal through 2035, adds nearly 9 GW of new gas capacity, while adding just 3.3 GW of utility-scale solar in the final two years of the planning period and negligible battery storage capacity. The results of the Mimic Duke and Reasonable Assumptions Scenarios are summarized in the following table.

	Mimic Duke - 2035	Reasonable Assumptions - 2035	Delta
NPV Total ($Billion)	$75.6	$68.4	-10%
CO2 Emissions (million tons)	30.7	6.6	-78%
Utility Solar (MW)	7,300	20,285	+178%
Onshore Wind (MW)	0	2,500	
Offshore Wind (MW)	0	0	
Storage (MW)	9	9,893	
Gas (MW)	23,389	15,487	-34%
Coal (MW)	3,069	0	

While neither scenario modeled enforces a binding carbon constraint, under the Reasonable Assumptions scenario, Duke is able to achieve the Clean Energy Plan's 70% by 2030 carbon emissions reduction goal ahead of schedule. In contrast, under the Mimic Duke scenario, Duke's carbon emissions remain well above the goal even in 2035.

The Reasonable Assumptions scenario results in rapid additions of renewable capacity, beginning in 2023 and every year thereafter throughout the planning period. This includes 3,100 MW of renewable additions from 2021-2026, followed by 9,000 MW of additions from 2027-2031. These volumes account for reasonable limits on annual renewable capacity additions, with a cap of 500 MW starting in 2021. The model assumes this annual cap rises incrementally over time due to greater learning and industry resources, increasing to 1,800 MW by 2030. The aggregate capacity in each year of the Reasonable Assumptions scenario is presented in the chart below.
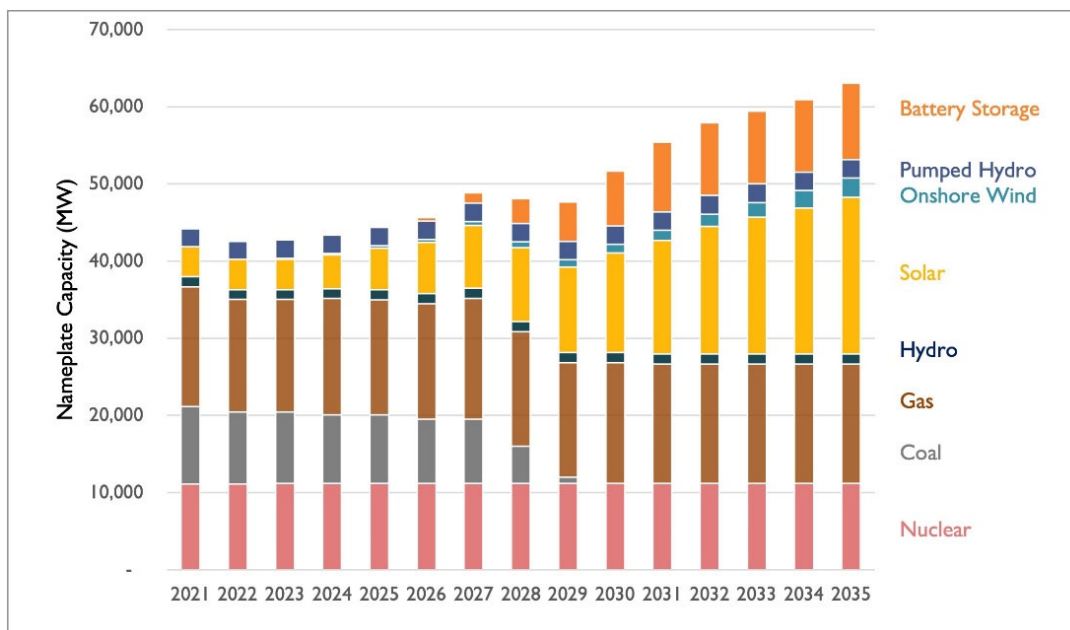
The Reasonable Assumptions scenario results in a more diverse resource mix compared to the Base Case with Carbon Policy presented in Duke's IRPs. Most notably, as coal generation draws down over the 15-year planning period, increasing amounts of clean energy fills the loss of both generation and capacity, creating a more diverse generation stack by 2035. This replacement strategy requires Duke to begin immediate procurement of new renewable energy resources, including utility-scale solar, battery storage, and onshore wind. The rapid introduction of new onshore wind suggests that the resource is cost-effective, and also offers significant resource diversity by serving load in evening hours and winter months. Importantly, Synapse relies on ambitious yet achievable energy efficiency savings projections that enable the Duke system to draw down fossil fuel generators while still meeting load reliably. Thanks to greater deployment of demand-side resources (detailed in Appendix A of Exhibit A), peak demand in the Reasonable Assumptions is 2 GW lower than peak demand in the Mimic Duke scenario.

2.   *The Reasonable Assumptions scenario results in a reliable resource plan.*

The Reasonable Assumptions scenario results in a resource plan that reliably meets load in every hour of the 15-year planning period (e.g., there are no hours of loss of load or unserved energy). The recent events in Texas underscore the need for robust evaluation of resource adequacy, reliability, and the contribution of all generating resources to meet expected extreme weather events. The EnCompass model employed by Synapse is a detailed capacity expansion and production cost model that takes these critical factors into account and evaluates load and generation on an hourly basis, utilizing historic load profiles and renewable energy generation profiles.

In order to simulate the impact of extreme weather conditions on generation and load in the Reasonable Assumptions plan, Synapse identified the period in which cold winter temperatures drive load to peak levels and renewable generation falls. To illustrate how the system responds during such an event, the figure below presents a representative winter peak day in January 2030.
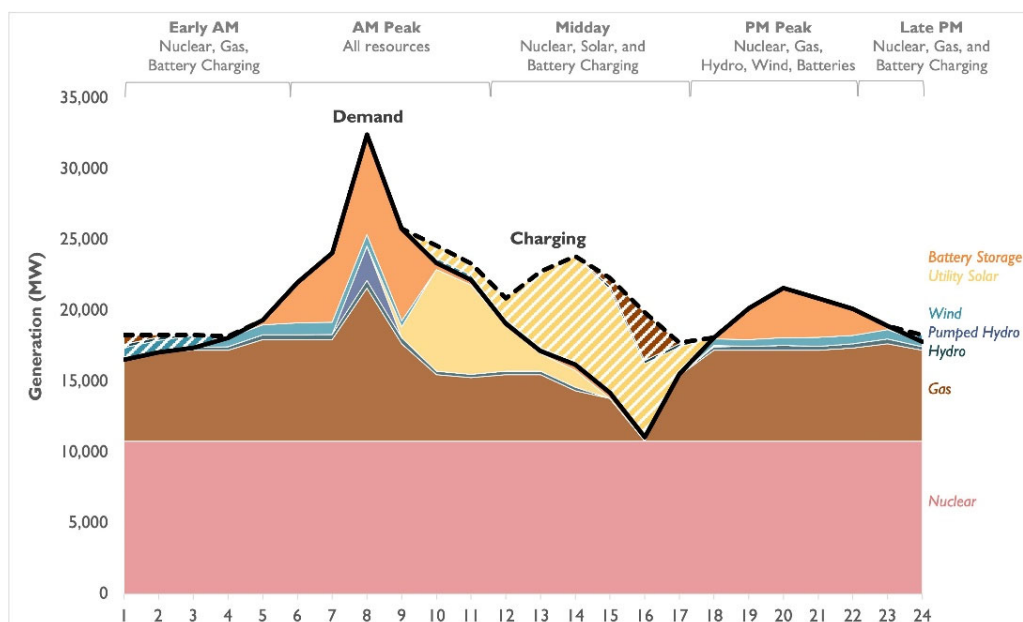
As the figure details, batteries begin charging in the early morning to prepare for an extreme winter peak towards the late morning. During the morning peak, around 9 am, all existing generation resources, including a significant amount of nuclear and gas generation, as well as hydropower, wind, solar, and discharging batteries are online to meet load. During the midday lull in power demand, the 7 GW of utility-scale battery storage uses excess solar generation to charge and prepare for the afternoon peak. Despite the near-zero capacity contribution that Duke assigns winter solar generation, a significant share of midday load is met by utility-scale solar. All resources are once again dispatched to meet demand as load rises in the evening.

The performance of the Reasonable Assumptions resource plan shown in the above figure represents a robust and diverse approach to meeting extreme winter peak events. Predicting and preparing for peak demand events is manageable given a diverse portfolio of generating resources, robust investments in energy efficiency and demand-side measures, and coordinated, region-wide grid planning. The existing gas and nuclear capacity on Duke's combined system, coupled with a robust expansion of utility-scale solar, wind, and battery storage, are sufficient to meet demand. The model determined that new gas or coal plants are not necessary to meet load reliably, and sufficient deployments of clean energy and battery storage, plus significant investments in energy efficiency can produce a portfolio that reliably serves Duke's customers.

3.   *Conclusion*

The Reasonable Assumptions scenario presents just one alternative to the resource plans presented in Duke's 2020 IRPs. It demonstrates that changes to a few key assumptions have dramatic impacts on the overall resource plan, and thus the total system costs, potential risks to consumers, and total carbon emissions reductions. While Duke's

Base Case with Carbon Policy features a massive buildout of new gas capacity to replace retiring coal, with under-reliance on demand-side resources and minimal additions of renewable energy, the Reasonable Assumptions scenario rapidly retires coal, de-emphasizes risky new gas capacity and maximizes clean, low-cost demand-side and renewable energy resources. The resulting resource plan is a diverse resource mix that ensures consumer costs remain low, carbon emissions steadily decline, and load is reliably served in all hours.

IV. **DUKE'S COAL RETIREMENT ANALYSIS FAILS TO COMPLY WITH THE COMMISSION'S DIRECTIVES**

In its order on the 2018 Duke IRPs, the Commission directed Duke to "include the information, analyses, and modeling regarding economic retirement of coal-fired units and consideration of all resource options" in its 2020 IRPs.[9] While Duke states that it has determined both the most "economic" retirement dates and the "earliest practicable" retirement dates, Duke's methodology was insufficiently robust to answer the Commission's complex question, and the DEC and DEP 2020 IRPs lack the necessary documentation and stakeholder process to give the Commission confidence that Duke has arrived at an optimal set of retirement dates for its coal-fired units.[10]

Duke's methodology for determining retirement dates contained three steps: (1) Ranking plants for retirement analysis; (2) Sequential Peaker Method; and (3) Portfolio Optimization. In the first step, ranking plants for retirement analysis, Duke performed capacity expansion and production cost modeling to determine the value of the units, and

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[9] *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, Docket No. E-100, Sub 157 at 92 (Aug. 27, 2019).
[10] Exhibit A at 4.

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determined that the ranking should be based on the capacity of the units, with the smallest units retiring first.[11] Retiring units based on their capacity is a flawed concept, however, as it ignores the operating costs associated with the units; it could actually be more economic to retire larger units first, as they have higher fixed costs, and then retire smaller units later.[12] In fact, the capacity factors listed in Duke's retirement analysis are very low for these types of units, indicating the units are not being used as designed. Using coal units in this way increases the need to invest in the units to maintain their reliability. There is no indication that this was considered in Duke's overly simple coal retirement analysis. Simply ranking the units based on their capacity does not accomplish the Commission's goal of providing the greatest benefit to ratepayers by identifying and retiring the worst performing and most costly units to operate.[13]

In its second step, Duke utilized an internally developed process, termed the "Sequential Peaker Method" ("SPM") to determine the most economic retirement dates.[14] The SPM is based on what Duke calls a Net Cost of New Entry ("Net CONE") method, which compares the capital and fixed costs of a new natural gas combustion turbine peaker plant to the existing coal units.[15] However, Duke's methodology is opaque and was considered confidential by the Company.[16] Moreover, Duke's application of the Net CONE method appears in most cases to use an artificially high cost for replacement capacity, thus making Duke's coal units appear more economic to continue operating.[17] The results of the

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[11] *Id.*
[12] *Id.* at 5.
[13] *Id.*
[14] *Id.* at 7.
[15] *Id.*
[16] *Id.*
[17] *Id.*

SPM evaluation are also problematic, given that, with the exception of Allen units 2-4, they precisely match Duke's 2018 depreciation study, as if Duke undertook a methodology with the intent of producing the same results as their depreciation study.[18] Finally, Duke performed a portfolio optimization.[19] At this point, however, retirement dates had already been established.[20]

Determining the optimum date for coal retirement is a complex process.[21] Duke's modeling tries to accomplish three things at once: (1) determining if a unit should be retired, (2) determining when a unit should be retired, and (3) determining the best replacement for a unit's capacity, energy, and ancillary services.[22] Instead, Duke should have conducted a full economic analysis of coal units, including all of the costs associated with each unit and the value that the units provide to Duke's system, on both a capacity and energy basis.[23] Numerous other utilities have successfully modeled coal retirements.[24] The Commission directed Duke to "provide an analysis showing whether continuing to operate each of its existing coal-fired units is the least cost alternative compared to other supply-side and demand-side resource options, or fulfills some other purpose that cannot be achieved in a different manner[]" and "model the continued operation of these plants under least cost principles, including by way of competition with alternative new

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[18] *Id. at* 8.
[19] *Id. at* 9.
[20] *Id.*
[21] *Id.*
[22] *Id.*
[23] Synapse Report, p. 9.
[24] Synapse Report, pp. 9-10.

resources."[25] However, Duke's retirement analysis fails to comply with either of these directives, as it fails to produce the most "economic" retirement dates for coal units and fails to compare the coal units with alternative resources such as wind, solar, storage, and energy efficiency.[26]

V. THE COMMISSION SHOULD DECLINE TO ACCEPT THE DUKE 2020 IRPS AS REASONABLE FOR PLANNING PURPOSES, AND SHOULD REQUIRE DUKE TO REVISE ITS IRPS

This Commission's rules enable and direct careful implementation of IRPs to achieve the policies articulated in Chapter 62 and their intended benefits for ratepayers and the State of North Carolina. By requiring a "comprehensive" analysis of all resource options to meet electrical service needs "at least cost over the planning period" and enumerating numerous elements that must be presented and evaluated to meet North Carolina's statutory and regulatory IRP requirements, the legal framework makes plain that if sufficient information is not presented, or if incorrect or misleading information or analysis is used, the letter of the law will not be met and the benefits of the IRP process cannot be achieved. Duke's 2020 IRPs do not meet the letter or the spirit of governing North Carolina law and fail to put the Commission in a position to determine that a comprehensive analysis of all resource options to meet electrical service needs at least cost over the planning period has been submitted, as required by NCUC Rule R8-60(c).

As recently recognized by the Commission's sister agency in South Carolina, "[w]hen implemented prudently," IRPs "can save ratepayers billions of dollars, help

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[25] *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, Docket No. E-100, Sub 157 at 90 (Aug. 27, 2019).
[26] Synapse Report, p. 10.

regulators understand risk exposure, and make decisions that align with their risk preferences, improve environmental outcomes, and facilitate stakeholder buy-in for utility plans.".[27] IRPs are thus a "powerful tool but must be implemented carefully to provide these benefits." *Id*.

Synapse's analysis shows that the DEC and DEP 2020 IRPs, while extensive, are built on incorrect and incomplete information that precludes each of them from being a "comprehensive analysis of all resource options" to meet electrical service needs "at least cost over the planning period," NCUC Rule R8-60(c). For an analysis to be comprehensive, it must not merely be extensive – it must include, and be built upon, the best data, assumptions, and facts available. Otherwise, the requirement for a "comprehensive" evaluation could be satisfied by the submission of lengthy but incorrect information, surely the opposite of what this Commission and the legislature intended. Further, in addition to being as accurate and detailed as possible, the information and analysis submitted must be aligned towards the "least-cost" generation plan over the planning period. A lengthy yet incorrect submission that fails to reveal what is likely actual least-cost plan does not meet the law's requirements.

Duke's evaluation of resource options as reflected in the 2020 IRPs does not meet this Commission's applicable requirements because it is based on inaccurate data and

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[27] *Order Rejecting Dominion's Integrated Resource Plan and Requiring Dominion to Make Modifications to Its 2020 Integrated Resource Plan, Future Updates and Future Integrated Resource Plans*, Order No. 2020-832 at 8 (S.C. Public Service Commission Dec. 23, 2020), https://dms.psc.sc.gov/Attachments/Order/a4b59f43-e545-43bd-9f35-a846b7602c39. The South Carolina Public Service Commission shares jurisdiction over Duke Energy's operations in the Carolinas, and is among the agencies that the North Carolina Commission is directed to confer in developing its annual energy planning report under N.C. Gen. Stat. § 62-110.1(c).

assumptions. Among other things, Synapse's Reasonable Assumptions scenario corrected federal solar ITC assumptions to reflect legislation passed in December 2020, updated battery and wind costs to match the NREL ATB projections, and updated the gas price forecast from Duke's market-based approach to a forecast using the EnCompass gas price forecast based on a fundamentals approach recommended in the Lucas report. Synapse also corrected Duke's failure to model the DEC and DEP systems as a single BA, thereby allowing the model to consider the reliability and economic benefits of broader geographical, resource, and load diversity. Finally, in light of impending carbon regulation, Synapse excluded new gas generation resources to avoid saddling ratepayers with the cost of stranded assets that would be forced to retire before fully depreciated.

Synapse's analysis shows that correcting Duke's erroneous assumptions results in a lower-cost, lower-risk plan. By correcting Duke's data and analysis errors, the Synapse Reasonable Assumptions scenario presents a more comprehensive evaluation of portfolios and produces a least-cost plan that would reduce overall system cost by $7.2 billion, reduce carbon dioxide emissions by tens of millions of tons per year, result in deployment of more demand-side resources, renewable energy and storage in the near term, and avoid natural gas capacity additions, all while meeting resource adequacy requirements.

VI. CONCLUSION

In light of the flaws summarized in these comments and detailed in the Synapse report attached as Exhibit A, the Commission should decline to accept Duke's IRPs as reasonable for planning purposes. Instead, the Commission should direct Duke to replace its Coal Retirement Study with a more transparent and detailed analysis that reflects the true costs of operating its existing coal fleet. In addition, the Commission should direct require Duke to correct the faulty assumptions identified by Synapse, conduct further

modeling consistent with the inputs to Synapse's Reasonable Assumptions scenario, and

file revised IRPs within 60 days of the Commission's order on the 2020 IRPs.

Respectfully submitted, this the 1st day of March 2021.

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/s/ Gudrun Thompson
Gudrun Thompson
N.C. State Bar No. 28829
Southern Environmental Law Center
601 W. Rosemary Street, Suite 220
Chapel Hill, NC 27516
919-967-1450
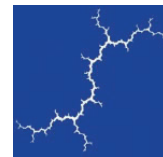gthompson@selcnc.org
Counsel for SACE et al.

Benjamin W. Smith
N.C. State Bar No. 48344
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
919-832-7601 Ext. 111
ben@energync.org

Peter H. Ledford
N.C. State Bar No. 42999
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
919-832-7601 Ext. 107
peter@energync.org
Counsel for NCSEA

John D. Burns
N.C. State Bar No. 24152
811 Ninth Street, Suite 120-158
Durham, NC 27705
919-306-6906
Counsel@CarolinasCEBA.com
Counsel for CCEBA

</div>

CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing filing by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 1st day of March 2021.

/s/ Gudrun Thompson
N.C. State Bar No. 28829
Southern Environmental Law Center
601 W. Rosemary Street, Suite 220
Chapel Hill, NC 27516
919-967-1450
gthompson@selcnc.org

Counsel for SACE et al.

Clean, Affordable, and Reliable

A Plan for Duke Energy's Future in the Carolinas

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

March 1, 2021

AUTHORS

Rachel Wilson
Iain Addleton
Kenji Takahashi
Jackie Litynski

Synapse
Energy Economics, Inc.

CONTENTS

EXECUTIVE SUMMARY

The purpose of this report is to evaluate the 2020 Integrated Resource Plans (IRP) filed in North Carolina by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP), collectively "Duke Energy" or "Duke" and to present an alternative, optimized resource portfolio for the state.

Synapse Energy Economics (Synapse) used state-of-the-art electric simulation software to compare the relative cost to ratepayers of continuing Duke's investments in existing and new fossil-fueled resources versus a scenario that replaces Duke's coal fleet with a portfolio of renewables, storage, and energy efficiency reflecting updated and more realistic cost assumptions. The EnCompass model, licensed from Anchor Power Solutions, utilizes a detailed capacity expansion and production cost model that evaluates load and generation on an hourly basis, utilizing utility-specific load and generation profiles.

The results of Synapse's modeling demonstrate that the most economic path for North Carolina ratepayers is to retire Duke's coal-fired units at the Earliest Practicable retirement dates as determined by Duke, in contrast to keeping several units online beyond 2035. Results include:

- Synapse's model produces an alternate clean energy resource portfolio that **reduces total system cost by $7.2 billion** and **CO$_2$ emissions by 78 percent** compared to a scenario similar to Duke's modeled Base Case with Carbon Policy.

- Synapse's alternative scenario includes an increase in first year energy efficiency savings of 0.15 percent per year until it reaches 1.5 percent, at which point it is held constant. This results in approximately **16,500 GWh of net annual savings for 2035**, or 9.6 percent of the projected system load.

- Synapse's model selects new solar, wind, and battery storage resources to meet future capacity and energy needs, with no incremental gas capacity additions. This includes **16 gigawatts of new utility-scale solar**, **2.5 gigawatts of new onshore wind**, and **10 gigawatts of new battery storage** by 2035.

- Synapse's alternative scenario results in immediate additions of renewable energy capacity, beginning in 2023 and every year thereafter. This includes **3,100 MW of new renewable capacity from 2021-2026** and **9,000 MW from 2027-2031**, accounting for limitations to annual capacity additions.

- Synapse's model generates these results while **maintaining Duke's full 17 percent planning reserve margin**. Synapse's modeling reliably meets load in every hour of the 15-year planning period with no hours of loss of load or unserved energy.

Coal-fired power plants across the country are facing both rising fuel costs and increasing capital expenditures, and Duke's coal units are no exception. Synapse reviewed Duke's coal retirement analysis, and found that it does not properly account for the cost and benefits of the coal-fired capacity and energy and thus fails to produce the most "economic" retirement date for individual units and for

combinations of units. The method Duke used for its analysis avoids optimization, avoids a full economic analysis of coal units, and avoids competition with alternative resources like wind, solar, storage, and energy efficiency.

The cost of renewable resources has declined dramatically over the past decade and is expected to continue to do so. This trend has reached the point where it costs less to build and run renewables and storage than it does to maintain and operate existing coal units. These resources are currently competing head-to-head with gas-fired combustion turbines and are expected to become more economic than new combined cycle units in the coming years. Investments in renewables and storage also avoid the stranded asset risk that comes with investments in new gas capacity.

Duke has a viable pathway toward meeting a clean energy future, and that pathway is less expensive than continuing to invest in fossil-fueled power plants. However, it will require that Duke move affirmatively to retire existing coal, commit to renewables, storage and demand-side resources, and actively invest in the clean energy economy of the Carolinas.

1. INTRODUCTION

The Integrated Resource Plans (IRPs) filed by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) in September 2020 will shape the energy future of the Carolinas through 2035. These planning documents are driven by the need to forecast energy and peak demand in the DEC and DEP service areas between 2021 and 2035 and plan for a mix of generation and capacity resources that will achieve system reliability, meet state environmental goals, and provide cost-effective service to DEC and DEP ratepayers.

Duke's 2020 IRPs for North Carolina and South Carolina include six potential portfolios, five of which contain between 6,100 MW and 9,600 MW of new gas-fired generating units.[1] In Duke's IRP modeling, the need for these new combined cycle and combustion turbine gas units is driven by a combination of projected increases in electricity demand and the retirement of Duke's coal units. However, most of Duke's scenarios fail to achieve state climate goals – specifically, North Carolina's Clean Energy Plan, which calls for a 70 percent reduction in carbon dioxide (CO_2) emissions from the electric sector by

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[1] Unless otherwise stated, references to "Duke IRP" include the combined results of DEC and DEP. Duke's six IRP scenarios are (A) Base With No Carbon Policy, (B) Base With Carbon Policy, (C) Earliest Practicable Coal Retirements, (D) 70% Reduction High Wind, (E) 70% Reduction High SMR, and (F) No New Gas.

2030.[2] In fact, the three Duke scenarios that rely most heavily on natural gas fail to achieve the 2030 target even by 2035.

Given the inevitability of carbon regulation, coupled with state carbon-reduction goals and Duke's own corporate goals, investments in gas infrastructure are increasingly at risk of becoming stranded assets. Duke's reliance on gas in its IRP modeling scenarios places the environmental and financial risks of new gas builds on ratepayers in North and South Carolina, and ignores alternative portfolios of solar, wind, storage, and energy efficiency resources that could also form the basis of Duke's electricity supply.

Synapse Energy Economics, Inc. (Synapse) conducted a capacity expansion and production cost modeling analysis that demonstrates the viability of an alternative resource portfolio that adds increasing amounts of energy efficiency, renewable energy, and battery storage resources in amounts above Duke's resource portfolios. Using the EnCompass model, Synapse developed two scenarios. In the first, Synapse uses Duke's input values to create a resource portfolio, "Mimic Duke," that results in a similar, but not identical, portfolio to that put forth in Duke's Base Case With Carbon Policy. In our alternative scenario, "Realistic Assumptions," Synapse modeled an alternate scenario that speeds the pace of coal retirements while increasing energy efficiency savings and adjusting the costs for specific renewable resource options offered to the model for replacement capacity and energy. The purpose of the Mimic Duke scenario is to show the importance of relying on a set of realistic assumptions in IRP modeling, and that the software is not the main driver of differences in the portfolio presented in the Realistic Assumptions scenario.

In contrast to Duke's Base Case portfolios, the Synapse alternative portfolio offers ratepayers in the Carolinas a more economic generation portfolio that also achieves state environmental goals and puts Duke on track to meet its corporate emission reduction goal of net-zero CO_2 by 2050.

2. CRITIQUE OF DUKE'S RETIREMENT STUDY

Economic assessments of existing coal units have become an increasingly common component of utility resource planning, whether undertaken voluntarily by utilities or done as the result of a state utility commission order. Examples include:

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[2] North Carolina Department of Environmental Quality. October 2019. *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System.* Available at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

- In its 2018 IRP, Northern Indiana Public Service Company (NIPSCO) examined alternative retirement dates for its five existing coal units, concluding that customers would save more than $4 billion by retiring those units in 2023 rather than 2030.[3]
- PacifiCorp included a unit-by-unit retirement analysis of alternative retirement dates for its 22 coal units in its 2019 IRP, examining retirement dates occurring several years before the end of the units' depreciable lives.[4]
- Georgia Power included a retirement analysis for each of its existing coal units in its 2019 IRP.[5]
- Dominion Energy Virginia's 2020 Integrated Resource Plan compared the forecasted costs and benefits of retiring its coal units versus continuing to operate them in the PJM market, finding that it was economically beneficial to retire its Chesterfield and Clover units earlier than planned in the previous IRP under all scenarios analyzed.[6]
- As recently as December 2020 the Public Service Commission of South Carolina stated in its Order Rejecting Dominion's Integrated Resource Plan that "the evidence shows that the retirements included… were not based on a robust retirement analysis, assessing all the costs and benefits associated with near and mid-term retirement dates such as capital expenditures, environmental expenditures while considering all available resources as potential replacements."[7]

As part of the 2018/2019 process in North Carolina, the NCUC ordered Duke Energy Carolinas and Duke Energy Progress to include such an analysis as part of this 2020 IRP process.[8] Both companies state that they have conducted detailed coal plant retirement analyses that are intended to assess the on-going

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[3] Northern Indiana Public Service Company (NIPSCO). October 2018. *2018 Integrated Resource Plan*. Available at: https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15.

[4] Robert Walton, Utility Dive. September 2019. *PacifiCorp sees 2 GW coal retirements, $599M savings by 2040 in latest planning scenarios*. Available at https://www.utilitydive.com/news/pacifcorp-sees-2-gw-coal-retirements-599m-savings-by-2040-in-latest-plann/562670/.

[5] Georgia Power. January 2019. *2019 Integrated Resource Plan Technical Appendix Vol. 2: Unit Retirement Study.* Available at: https://psc.ga.gov/search/facts-document/?documentId=175473.

[6] Dominion Energy Virginia. *May 2020. 2020 Integrated Resource Plan, p. 83–84.* Available at: https://scc.virginia.gov/docketsearch/DOCS/4m_m01!.PDF.

[7] South Carolina Public Service Commission. December 23, 2020. Docket No. 2019-226-E, Order No. 2020-832: Order Rejecting Dominion's Integrated Resource Plan and Requiring Dominion to Make Modifications to its 2020 Integrated Resource Plan, Future Updates and Future Integrated Resource Plans. Available at: https://dms.psc.sc.gov/Attachments/Order/a4b59f43-e545-43bd-9f35-a846b7602c39.

[8] State of North Carolina Utilities Commission. February 2019. *Docket No. E-100 Sub. 157: Order Accepting Integrated Resource Plans and REPS Compliance Plan, Scheduling Oral Argument, and Additional Analyses.* Available at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=143d85de-b1e7-4622-b612-5a8c77e909d4; State of North Carolina Utilities Commission. April 2020. *Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans, p. 8–9*. Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=86f15be3-7617-4910-aeae-d8568 c4d0983.

value of the plants and determine the most "economic" retirement dates.[9] Duke also examined a second set of retirement dates for its coal assets, which it called the "earliest practicable." However, Duke's methodology was insufficiently robust to answer this complex question. Duke's lack of documentation and nonexistent stakeholder process should give the North Carolina Utilities Commission little confidence that Duke has arrived at an optimal set of retirement dates for its coal-fired units.

The methodology that underlies Duke's retirement analysis has three steps: (1) Ranking plants for retirement analysis; (2) Sequential Peak Method (SPM); and (3) Portfolio Optimization. The first step in Duke's process was to develop a rank order in which the coal retirements would occur. While Duke did run capacity expansion and production cost models to examine the value of the units, it ultimately determined that the ranking should be based on the capacity of the units, retiring the smallest units first. Duke's unit rankings are shown in Table 1, below.

Table 1. Duke ranking of coal plants for retirement analysis[10]

Coal Facility	Capacity (MW Winter)	CF% Range Through 2035	Years in Service (As of 1/2020)	Rank
Allen 1-3	604	3%-11%	60-62	1
Allen 4-5	526	2%-9%	58-59	2
Cliffside 5	546	2%-23%	47	3
Mayo	746	1%-12%	36	4
Roxboro 1-2	1,053	5%-34%	51-53	5
Roxboro 3-4	1,409	1%-32%	39-46	6
Marshall 1-4	2,078	1%-49%	49-54	7
Belews Creek 1-2	2,220	16%-57%	44-45	8

Ranking the unit retirements based on capacity is a flawed methodology, as it ignores the costs associated with the operation of those units. Capacity and energy value both have a part to play in the overall economics of individual coal units and a rigorous retirement analysis would consider them both together. Due to the low capacity factors at even the largest of Duke's units, it could be more economic to retire the larger units first, which incur greater fixed costs due to their size, and retire the smaller units later in the analysis period. While Duke states it considered incremental coal ash costs in this step, it does not appear that Duke considered additional costs and risks associated with future environmental regulations when evaluating the costs of these plants to ratepayers. A robust analysis would identify and retire the worst performing and most costly units first to provide the most benefit for customers. Simply ranking the units from lowest to highest capacity does not accomplish that goal.

The range of capacity factors shown for groups of units in Table 1 represent the range in all years of the analysis period. The higher number in the range typically occurs in the first year of the analysis and

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[9] *Duke Energy Progress 2020 Integrated Resource Plan*, p. 79 (Nov. 6, 2020) ("DEP 2020 IRP"); *Duke Energy Carolinas 2020 Integrated Resource Plan*, p. 77 (Nov. 6, 2020) ("DEC 2020 IRP").
[10] DEP 2020 IRP. Page 82.

capacity factors fall quickly to single digits for certain units. An examination of the capacity factors of individual units, averaged over the number of years in which the unit is operational, is shown in Table 2 and presents a very different picture and rank order.

Table 2. Average Unit Capacity Factors During Operational Years (Duke Screening Study)[11]

Coal Facility	Area	Capacity (Summer MW)	Average Capacity Factor
Mayo 1	DEP	727	2.6%
Allen 2	DEC	162	3.4%
Allen 5	DEC	259	3.7%
Allen 1	DEC	162	3.8%
Allen 4	DEC	257	4.5%
Allen 3	DEC	258	6.0%
Roxboro 3	DEP	691	6.6%
Roxboro 1	DEP	379	7.7%
Roxboro 4	DEP	698	7.8%
Marshall 1	DEC	370	8.1%
Marshall 2	DEC	370	8.4%
Cliffside 5	DEC	544	12.0%
Roxboro 2	DEP	665	14.3%
Marshall 3	DEC	658	22.0%
Belews Creek 2	DEC	1,110	24.8%
Marshall 4	DEC	660	29.0%
Belews Creek 1	DEC	1,110	30.5%
Cliffside 6	DEC	844	N/A

The poor performance of Duke's coal units cannot be understated. The average capacity factors shown in Table 2 are very low for units that have historically been designated as "baseload," meaning they provide consistent, lower-cost energy over most hours in the year. However, many of Duke's coal-fired "baseload" units are instead being operated as peaking units. Data from the United States Environmental Protection Agency's Air Markets Program show that Allen Unit 1 operated for only nine days in all of 2020 and Allen Unit 2 operated for only eight days, notably in the summer months of July and August.[12]

The unit with the highest output in Duke's projections has an average capacity factor of only 30.5 percent, and more than half of Duke's units have average capacity factors of less than 10 percent. Units that are forced to cycle and go through more startups and shutdowns incur more wear and tear and

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[11] Values were calculated from Duke's response to ORS AIR 2-22 and the attachment "ORS_AIR 2-22 Coal Retirement Screening.xlsx"

[12] US Environmental Protection Agency. Air Markets Program Data. Available at: https://ampd.epa.gov/ampd/.

thus require increased investments to ensure their reliability. Duke is getting little payback for these investments, though, as the units are providing little energy value to Duke's system, and that value is diminishing over time.

Duke's ranking methodology purposefully ignores these declining energy values. Duke explicitly states the following: "For instance, while Cliffside 5 has a higher capacity factor than Mayo, which would indicate Cliffside 5 has a higher production cost value, the lower capacity of Cliffside 5 requires less replacement generation at the time of retirement. For this reason, Cliffside 5 was ranked above Mayo in the order for conducting the retirement analysis."[13] This dubious logic avoids the most important criteria in retiring coal plants, or any piece of utility infrastructure – identifying the point in time when these units become economically disadvantageous to customers and ratepayers.

The second step in Duke's coal unit retirement approach is the "Sequential Peaker Method" (SPM), an internally developed process for determining the most economic retirement dates for coal plants. Duke applied this process to all of its coal units except Cliffside 6, which it expects to run on gas. The SPM method is based on what Duke calls a Net Cost of New Entry (Net CONE) method that considers the capital and fixed costs of a generic combustion turbine peaking unit, as well as the net production cost value of the peaker versus the existing coal unit being retired.[14] Each of the coal units is compared to a replacement combustion turbine; however, Duke's analysis is opaque at best and discovery responses to questions asking for more detailed information on the process were marked Confidential by Duke.

The application of Net CONE for a combustion turbine likely uses an artificially high cost for replacement capacity in many cases. Combustion turbines are a technology type that are unlikely to experience the kind of rapid price declines that are currently being seen for renewables and storage technologies, meaning that these costs will stay relatively constant over time, while costs for renewables and storage will go down over the next decade. A 2018 report by GTM Research and Wood Mackenzie predicted that energy storage technologies will regularly compete head-to-head with new gas-fired peaking units by 2022, and that new gas peakers will be rare by 2028.[15] Pairing a replacement battery with solar or allowing it to charge from the grid would make up the energy component associated with the gas-fired combustion turbine used by Duke in its SPM analysis.

The replacement energy cost associated with a gas-fired peaking unit could also be artificially high. Traditionally, combustion turbines have been thought of as being "cheap to build but expensive to run." Replacement resources with low variable costs, like wind and solar, would provide a better energy value for customers than a gas-fired peaking unit. Also missing from Duke's analysis is the inclusion of additional demand-side resources. The most economic resource portfolio will include both enhanced demand-side measures in addition to supply-side resources as a replacement for the capacity and

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[13] DEP 2020 IRP. Page 83.

[14] DEP 2020 IRP. Page 83.

[15] Greentech Media. March 1, 2018. *Will Energy Storage Replace Peaker Plants?* Available at: https://www.greentechmedia.com/webinars/webinar/will-energy-storage-replace-peaker-plants#gs.6JwDozs.

energy from Duke's retiring coal units. If lower cost replacement resources were used as part of Duke's analysis, it would likely change the most "economic" retirement date of Duke's coal-fired units. Portfolio analysis like that used in Duke's Step 3 is required at this step in the analysis in order to select replacement resources that replace all of the grid services of the retiring coal units and determine true economic retirement dates for these units.

Duke's SPM produces a result that is no different than the estimated depreciable lives that resulted from Duke's 2018 depreciation study.[16][17] A comparison of the depreciable life dates, the economic retirement dates, and the earliest practicable retirement dates is shown in Table 3. Except for the Allen units 2-4, which are taken at the plant level in the depreciation study, none of the economic retirement dates identified in Duke's retirement analysis occur any earlier than the end of the units' depreciable lives. Duke did not do an economic assessment of its coal fleet in its retirement analysis, but rather undertook a methodology that produces the exact same result as its depreciation studies.

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[16] Direct Testimony of John J. Spanos for Duke Energy Progress, LLC. *In the Matter of: Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.* Before the North Carolina Utilities Commission Docket No. E-2, SUB 1219. Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=22094489-2fd5-46de-a228-571757f06434.

[17] Direct Testimony of John J. Spanos for Duke Energy Carolinas, LLC. *In the Matter of: Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.* Before the North Carolina Utilities Commission Docket No. E-7, SUB 1214. Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=46f3ba8e-b73a-4555-9d99-688087ed70b6.

Table 3. Comparison of Depreciable Life, Economic, and Earliest Practicable retirement dates[18]

Plant Name	Depreciable Life Date	Economic Retirement Dates (Jan 1)	Earliest Practicable Retirement Dates (Jan 1)
Allen 2	2024	2022	2022
Allen 3	2024	2022	2022
Allen 4	2024	2022	2022
Allen 1	2024	2024	2024
Allen 5	2024	2024	2024
Cliffside 5	2026	2026	2026
Roxboro 3	2028	2028	2028
Roxboro 4	2028	2028	2028
Roxboro 1	2029	2029	2029
Roxboro 2	2029	2029	2029
Mayo 1	2029	2029	2029
Marshall 1	2034	2035	2028
Marshall 2	2034	2035	2028
Marshall 3	2034	2035	2028
Marshall 4	2034	2035	2028
Belews Creek 1	2037	2039	2029
Belews Creek 2	2037	2039	2029
Cliffside 6	2048	2049	2049

The ability to replace coal-fired units with alternative resources like renewables and storage does not come into Duke's analysis until Step 3 – the Portfolio Optimization step. This included capacity expansion and production cost modeling based on the optimal retirement dates established using the SPM methodology. This modeling step is the basis for two portfolios that became Duke's "Base Case with No Carbon Policy" and "Base Case with Carbon Policy" scenarios. By this stage, however, Duke has already established the coal unit retirement dates, using a subjective rank-ordered screening study and a simple comparison to a generic peaker as opposed to a fully optimized retirement analysis. Duke's "optimization" step occurs long after coal plant retirement dates have been established. Duke should have instead conducted a full economic analysis of coal units that includes all of the costs associated with each unit as well as the value that the units provide to Duke's system, on both a capacity and energy basis.

A coal retirement analysis of this type is complex, as Duke must try to solve for three things at once: 1) if a unit should be retired; 2) what year it should be retired; and 3) the best replacement for that unit's

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[18] DEP 2020 IRP, page 174. DEC 2020 IRP, page 175.

capacity, energy, and ancillary services. Duke's methodology fails to answer these questions at every step of the process.

Other utilities offer examples of methodologies that better achieve these goals. PacifiCorp's unit retirement analysis, for example, also had a number of steps which were presented to stakeholders as part of a public process.[19] The first step was a unit-by-unit analysis, which ranked the PacifiCorp units on both a capacity and energy basis using both the System Optimizer and Planning and Risk models. PacifiCorp then examined four different alternate retirement dates for those units that it identified as being the least economic and performed a stacked analysis for those least economic units. Finally, candidate retirements were included in the IRP portfolio development process.[20]

Similarly, NIPSCO did both a unit-by-unit and stacked retirement assessments to determine optimal coal unit retirements. Replacement resource costs were based on bids from a recent Request for Proposals (RFP) issued by NIPSCO. The utility found that accelerating coal unit retirements to 2023 and 2028 and replacement with renewable resources offered a cost-effective solution to its customers.[21]

The North Carolina Utilities Commission's previous IRP order in 2018 "[requires] Duke to provide an analysis showing whether continuing to operate each of its existing coal-fired units is the least cost alternative compared to other supply-side and demand-side resource options, or fulfills some other purpose that cannot be achieved in a different manner." The order further states that "the utilities shall model the continued operation of these plants under least cost principles, including by way of competition with alternative new resources."[22] Duke's retirement analysis fails to accomplish either of these objectives. A closer look at Duke's methodology shows that Duke does not properly account for the cost and benefits of the coal-fired capacity and energy and thus fails to produce the most "economic" retirement date for individual units and for combinations of units. The SPM avoids optimization, avoids a full economic analysis of coal units, and avoids competition with alternative resources like wind, solar, storage, and energy efficiency.

Duke's retirement analysis should be redone in a process that involves more transparency via a public process and the opportunity for stakeholders to review and comment on input assumptions and results.

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[19] PacifiCorp. December 3-4, 2018. *2019 Integrated Resource Plan (IRP) Public Input Meeting*. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2018-12-03-04%20-%20General%20Public%20Meeting.pdf.
[20] *Id.* Slide 5.

[21] NIPSCO. *2018 Integrated Resource Plan.* Available at: https://www.nipsco.com/our-company/about-us/regulatory-information/irp.

[22] State of North Carolina Utilities Commission. February 2019. *Docket No. E-100 Sub. 157: Order Accepting Integrated Resource Plans and REPS Compliance Plan, Scheduling Oral Argument, and Additional Analyses.* Available at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=143d85de-b1e7-4622-b612-5a8c77e909d4.

3. SYNAPSE SCENARIO ANALYSIS

Synapse used the EnCompass capacity expansion and production cost model, licensed from Anchor Power Solutions, to examine two different scenarios: Mimic Duke and Reasonable Assumptions.[23]

The EnCompass model uses information about forecasted peak and energy demand along with the capital and operating costs of existing and new resources to produce an optimal, least-cost resource portfolio and generation mix. Specifically, the model does the following: (1) builds new resources when necessary to meet peak demand, plus a required reserve margin; (2) simulates economic dispatch of the various generating resources; and (3) calculates the total cost (capital and operating) of the respective resource portfolio options.

Mimic Duke scenario

Our modeling focused on two scenarios, with the first, Mimic Duke, acting as a reference to Duke's Base Case with Carbon Policy. In Mimic Duke, all modeling assumptions originate in Duke Energy Progress (DEP) and Duke Energy Carolina's (DEC) 2020 Integrated Resource Plans (IRPs). These assumptions include:

- Modeling DEC and DEP as "islands" in which the utilities do not have the ability to import energy and capacity from each other or their neighbors;[24]

- Coal unit retirements based on the "most economic" retirement dates;[25]

- Replacement resource capital and operating costs for new combined cycle, combustion turbines, standalone solar, standalone battery storage, onshore wind, offshore wind, and paired solar-plus-storage resources;[26]

- Coal prices;[27]

- Effective Load Carrying Capability (ELCC).[28]

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[23] Capacity and production cost models like EnCompass are used to simulate future utility operations under different scenarios to help determine the best strategy for minimizing costs and risks while meeting all specific reliability and transmission constraints.

[24] Duke response to NCSEA Data Request 7-17.

[25] DEP 2020 IRP, page 147. DEC 2020 IRP, page 146.

[26] PSDR 3-7 Confidential – IRP Generic Unit Summary DEC 2020.xlsx.

[27] PSDR 3-4_2020 IRP_Model Inputs_CONFIDENTIAL (5).xlsx.

[28] NCCEBA DR 3-3_Renewable_Storage CTP.xlsx.

- A CO_2 price of \$5/ton (nominal) starting in 2025 and escalating by \$5/ton each year, as assumed in the Base Case with Carbon Policy.[29] This emissions price is intended to be a proxy for future CO_2 regulations at either the federal or state level.

The Mimic Duke scenario does make three updates that relate to the way in which gas-fired resources are represented in the model. The first update is to use the gas price forecasts from Horizon's Energy National Database (NDB), which includes forecast assumptions and unit level data for generating units across the United States. The base gas forecast reflects actual prices through September 2020 and settled forward prices as reported on September 30, 2020 through 2032. Beyond 2032, Horizons grows the price based on a growth trend of the Henry Hub forward in nominal dollars. Second, all new gas-fired resources offered to the model assume a retirement date of 2050 and adjust the operating life and the book life of each resource accordingly. Lastly, a gas price adder of \$1.50/mmbtu was included in the operating characteristics of new combined cycle units to represent the cost of acquiring firm gas transportation rights to fuel the units.

The EnCompass model calculates the cost to operate the existing resources and adds resources as necessary over the analysis period to meet peak and energy requirements.

Reasonable Assumptions scenario

The second scenario, Reasonable Assumptions, uses the same assumptions as in the Mimic Duke scenario with only a few exceptions. This scenario uses the "Earliest Practicable" retirement dates as determined by Duke in the IRPs, while the Mimic Duke scenario uses the "Economic" retirement dates as also determined by Duke in the IRPs. Those values are shown in Table 3 in Section 2.

The Reasonable Assumptions scenario updates the capital and operating costs for both onshore and offshore wind based on the NREL Annual Technology Baseline (ATB), released in 2020.[30] While the Reasonable Assumptions scenario uses Duke's capital cost forecast for new solar resources, the operating costs for these units were taken from ATB 2020 as well. Costs for wind and solar resources were levelized using Duke's financing assumptions on weighted average cost of capital and construction schedule for the different resources and offered to the EnCompass model on a \$/MWh basis. This was done to allow for the model to choose resources based primarily on their energy benefit to the system rather than on the capacity need each year.

New gas additions are restricted in the Reasonable Assumptions scenario. EnCompass's optimization algorithm attempts to minimize the carrying charge associated with the addition of new resources but calculates the capital component of the revenue requirement as the sum of book depreciation, property

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[29] Duke Energy Progress (DEP). 2020. *Integrated Resource Plan 2020 Biennial Report, p. 152-153.* Available at: https://www.duke-energy.com/_/media/pdfs/our-company/irp/202296/dep-2020-irp-full-plan.pdf?la=en; Duke Energy Carolinas (DEC). 2020. *Integrated Resource Plan 2020 Biennial Report, p. 152-153.* Available at: https://www.duke-energy.com/_/media/pdfs/our-company/irp/202296/dec-2020-irp-full-plan.pdf?la=en.

[30] National Renewable Energy Laboratory (NREL). 2020. *2020 Annual Technology Baseline.* Available at: https://atb.nrel.gov/.

taxes, other costs, and allowed return. This can result in a scenario in which gas capacity is added to the system, but the total revenue requirement associated with this gas scenario is higher in that scenario than in one that does not add new gas-fired resources. Synapse ran a scenario in which new gas builds were allowed with other updated inputs. The result was the addition of 1,185 MW of new gas-fired capacity and an increased revenue requirement above the Reasonable Assumptions scenario of approximately $400 million.

Lastly, Synapse used updated energy efficiency (EE) and demand side management (DSM) projections, through a combination of the savings shape of DEC and DEP programs provided in discovery and an updated forecast on future energy savings from EE/DSM. For the Realistic Assumptions scenario, we assume that Duke will ramp up its energy efficiency programs starting from 2022 from the 5-year EE plan levels and increase first year savings by 0.15 percent per year to 1.5 percent. We then assume that this level of savings will persist through the study period. Reaching a 1.5 percent savings level is a reasonable scenario for Duke because leading states in energy efficiency, such as Massachusetts and Rhode Island, have been achieving much higher savings ranging from 2 percent to 3 percent per year over the past decade while Duke's own savings have been at about 1 percent per year or less during that time frame.[31] Our analysis incorporates energy savings decay effects by taking into account Duke's own assumptions for measure lives used for its 5-year EE plans. We estimate the projected net annual savings for the Realistic Assumptions scenario is 9.6 percent of projected system load in 2035. The American Council for an Energy Efficient Economy (ACEEE) found in a recent study that the state of North Carolina could meet 18.5 percent of its forecasted need with energy efficiency by 2040[32] and confirms that 9.6 percent by 2035 is a reasonable assumption.

Synapse estimated winter and summer peak load reductions from Duke's energy efficiency programs under the Realistic Assumptions scenario based on our analysis of Duke's assumptions for hourly energy savings. More specifically, we obtained the hourly energy savings profiles that Duke used for its own IRP EE analysis, and developed and applied a composite hourly load savings profile for the entire program portfolio.

In projecting program costs for the Realistic Assumptions scenario, we relied on Duke's own per unit program cost estimate for 2020 from its 5-year EE plans and kept the per unit cost constant in real dollars. Historical evidence suggests that energy efficiency programs cost tend to stay at the same level or even decrease when programs are expanded due to economies of scale.[33] A brief review of historical

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[31] Historical savings data were obtained from Duke Response to NCSEA DR7-48; Savings level from leading states are available from the American Council for an Energy Efficiency Economy (ACEEE)'s State Energy Efficiency Scorecard reports, available at: https://www.aceee.org/state-policy/scorecard.

[32] American Council for an Energy Efficiency Economy. September 2020. *How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy, Cost, and Greenhouse Gas Impacts*. Available at: https://www.aceee.org/sites/default/files/pdfs/u2007.pdf

[33] For example, see Takahashi et al. 2015. Review of TVA's Draft 2015 Integrated Resource Plan. Synapse Energy Economics. Figure 2. Available at https://www.synapse-energy.com/sites/default/files/Review-TVA-Draft-2015-IRP-14-022.pdf.

energy efficiency costs in different jurisdictions is presented in the appendix section. Our analysis treats program costs separately for the Home Energy Report (HER) and the rest of conventional energy efficiency programs as HER accounts for a large portion of Duke's program portfolio and the cost and measure life of HER program are very different from other programs.

A comparison of the similarities and differences between the input assumptions between the modeled scenarios is shown in **Error! Reference source not found.**, below.

Table 4. Input assumption comparison between Mimic Duke and Reasonable Assumptions scenarios

Input	Mimic Duke	Reasonable Assumptions
Carbon Constraint	None	None
DEC/DEP BA's	Merged	Merged
Imports/Exports	Not Allowed	Not Allowed
Load Forecast	From IRP	From IRP
EE/DSM	From IRP	Synapse Forecast
Solar Costs	Duke IRP Costs	Duke IRP Costs
Battery Costs	Duke IRP Costs	ATB 2020 Low
Onshore Wind Costs	Duke IRP Costs	ATB Low: Class 7
Offshore Wind Costs	Duke IRP Costs	ATB Low: Class 6
Coal Retirement	Duke Economic	Earliest Practicable
Coal Operations Costs	Duke IRP Costs	Duke IRP Costs
Coal Prices	Duke IRP Costs	Duke IRP Costs
Gas Prices	EnCompass defaults	EnCompass defaults
Planning Reserve Margin	17% (from IRP)	17% (from IRP)
Wind/Solar Capacity Credit	ELCC from Duke	ELCC from Duke
ITC Assumptions	From COVID relief bill	From COVID relief bill
New Gas Builds Allowed	Yes	No

Synapse analyzed the impacts of these scenarios on DEP and DEC's joint annual capacity, annual energy mix, and CO_2 emissions. We provided details on these scenarios and impacts in Section 4, below.

4. ELECTRIC SECTOR MODELING RESULTS

The model selected new generating capacity during the analysis period to meet the 17 percent planning reserve margin in both the Mimic Duke and Reasonable Assumptions scenarios; however, the type of capacity selected differs between scenarios. The Mimic Duke scenario relies heavily on the addition of new gas-fired combined cycle and combustion turbine units, with solar PV additions of just over 3 GW.
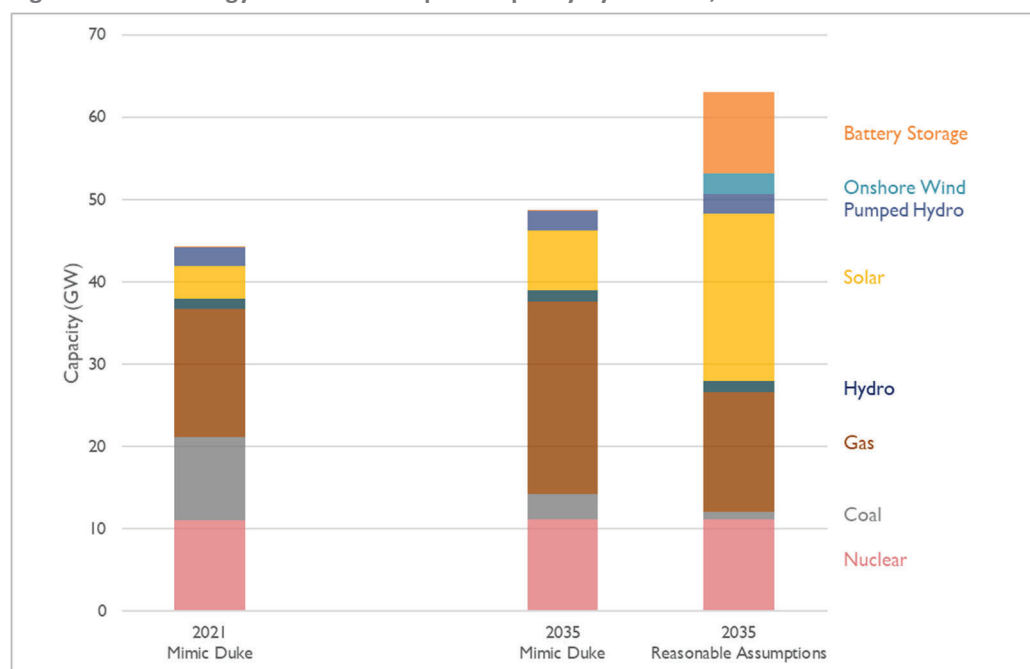
The Reasonable Assumptions scenario, on the other hand, relies on a slate of clean energy resources to meet its energy and capacity requirements that includes energy efficiency, utility-scale stand-alone solar and storage, new onshore wind, and paired solar-plus-storage resources. EnCompass model results are presented here for the entirety of Duke Energy's service territory in both North and South Carolina.

4.1.   Capacity Results

Figure 1, below, shows the generating capacity in the Mimic Duke and Reasonable Assumptions scenarios in 2035 compared to Duke's actual capacity mix in 2021. As shown in Figure 1, approximately 58 percent (25.6 GW) of Duke's installed capacity in 2021 is fossil fuel-powered thermal (coal- or natural gas-fired), 25 percent (11.1 GW) of capacity is nuclear, and the remaining 17 percent (7.5 GW) comes from hydroelectric, renewable, and storage resources. By 2035, the proportion of fossil-fired resources in the Mimic Duke scenario only decreases slightly to 54 percent (26.5 GW), while renewable resources have increased modestly to 23 percent (11.0 GW).

**Figure 1. Duke Energy modeled nameplate capacity by scenario, 2021 and 2035**

In contrast, gas and coal resources in the Reasonable Assumptions scenario drop to 25 percent (15.5 GW) of the capacity mix by 2035, and renewable energy resources comprise 58 percent (36.4 GW) of the capacity mix. Nuclear capacity remains constant in both throughout the period, though it makes up a smaller percentage of the capacity mix in 2035.

4.2.   Generation Results

As shown in Figure 2, below, the generation mix in Duke's service territory changes slightly over time in the Mimic Duke scenario but is primarily a shift from one fossil fuel to another. Coal makes up 5 percent of generation in 2035, while natural gas generation increases over the study period to make up 31 percent of the mix in the final year of the analysis period. Renewable generation (solar and hydro) increases only slightly over the study period and makes up 9 percent of generation in 2035. Note that discharges from pumped hydro and battery storage resources are not shown in these figures.

Figure 2. Modeled generation in the Mimic Duke scenario, 2021 and 2035
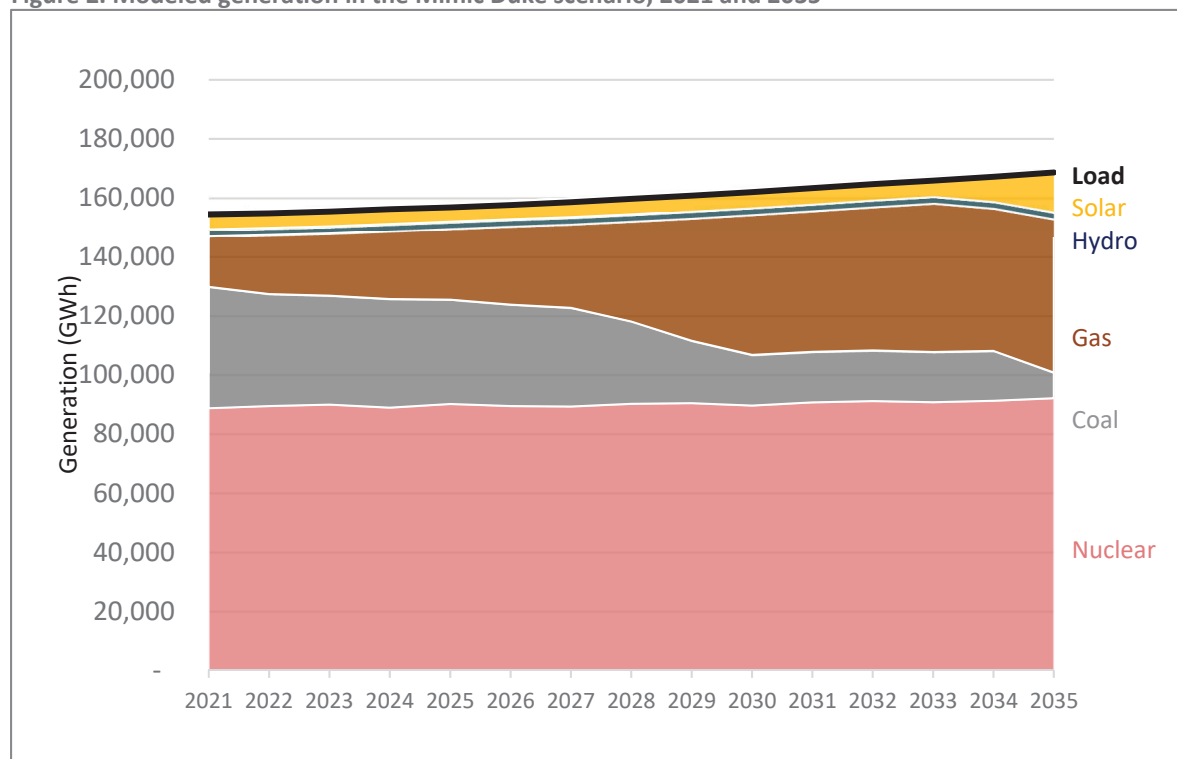
In the Reasonable Assumptions scenario, shown in Figure 3, renewable generation (including hydroelectric, utility solar, pumped hydroelectric storage, onshore wind, and battery storage) makes up 32 percent of the generation mix in 2035 as compared to 9 percent in the Mimic Duke scenario. Natural gas generation falls to 10 percent of total generation in 2035, as compared to 31 percent in the Mimic Duke scenario in that same year. By 2035, the coal has disappeared in the Reasonable Assumptions scenario. Note that generation above the load line is going to charge battery and pumped storage resources.

Figure 3. Modeled generation in the Reasonable Assumptions scenario
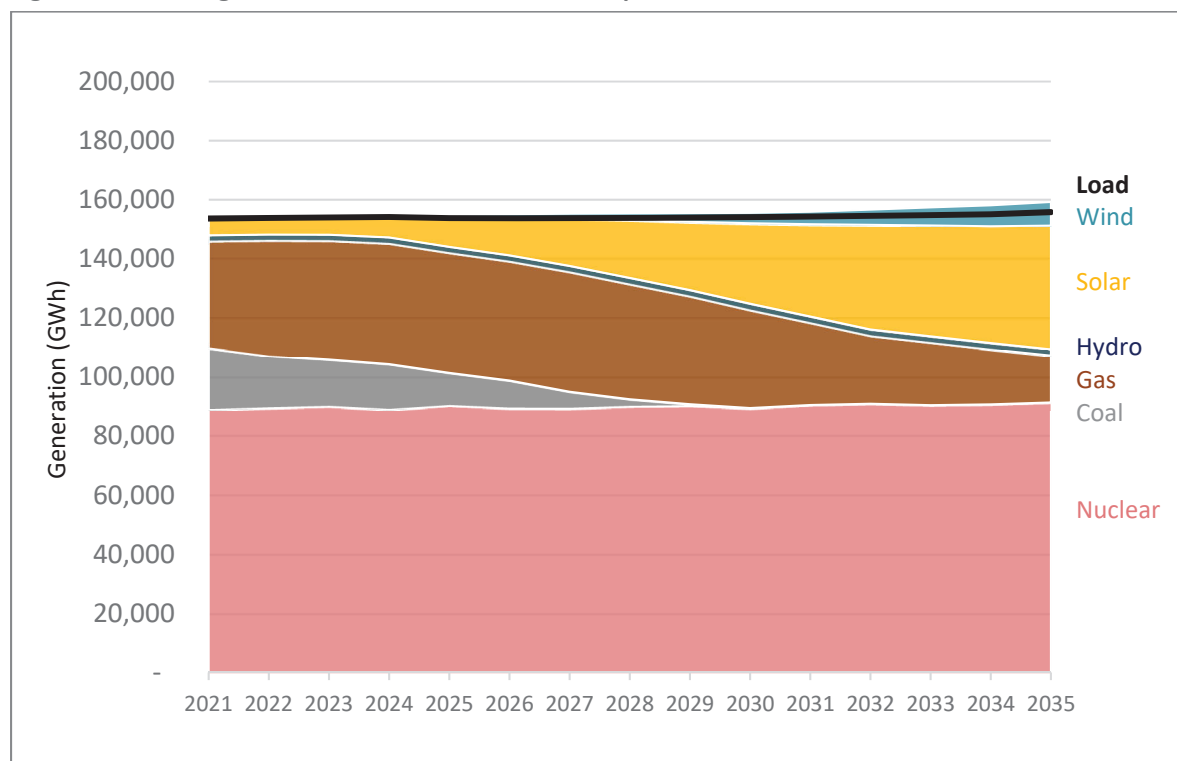
From a reliability perspective, under the Reasonable Assumptions scenario Duke Energy meets its hourly demand requirements in all modeled days and hours during the analysis period. The Reasonable Assumptions scenario maintains the 17 percent planning reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy.

Figure 4 and Figure 5, below, show energy generation in January 2030 —a representative winter peak day—for the Mimic Duke and Reasonable Assumptions scenarios. Duke Energy's hourly load requirements are shown by the solid line. The area between the dashed line and the solid line in the two Figures represents the time in which battery resources are being charged by solar or other resources within Duke's service territory.

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Figure 4. Sample winter peak generation by fuel type, January 2030, Mimic Duke scenario
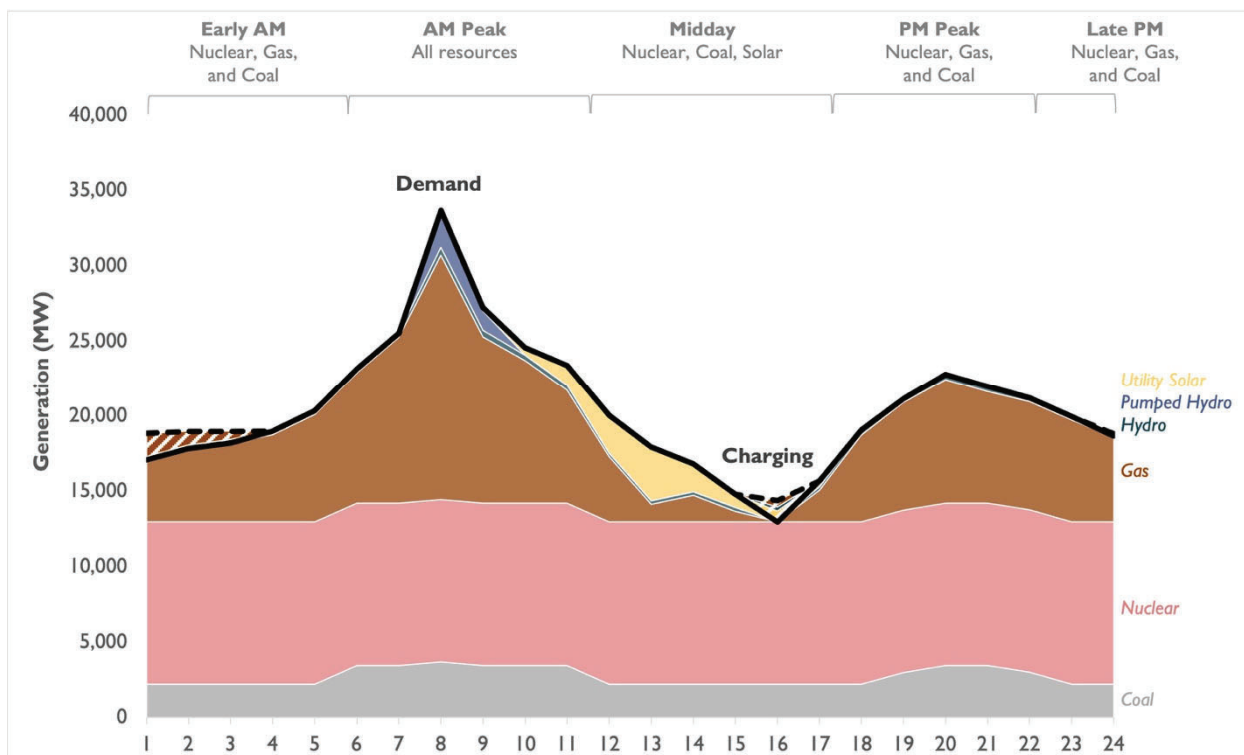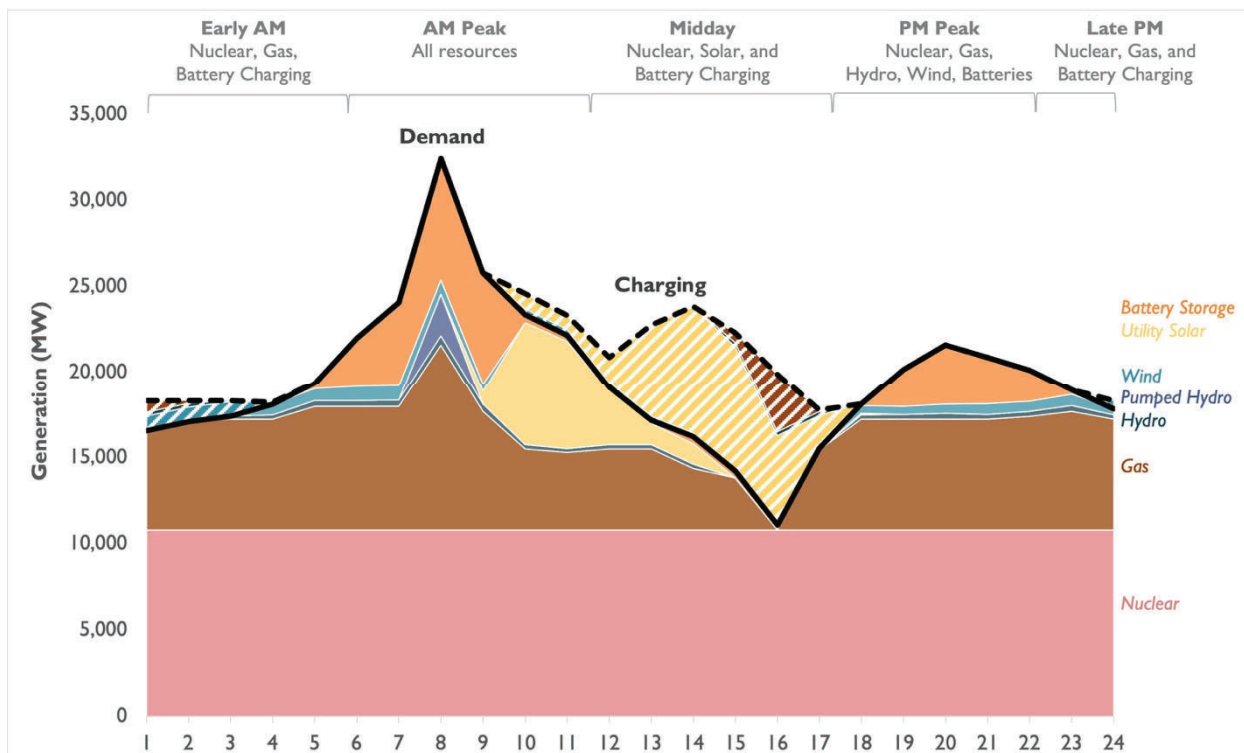

Figure 5. Sample winter peak generation by fuel type, January 2030, Reasonable Assumptions scenario

Both scenarios rely on nuclear generation as a baseload resource. The Mimic Duke scenario dispatches coal units throughout the day, and relies primarily on gas-fired generators, with small amounts of pumped storage, to meet the morning and evening peaks. Conversely, the Reasonable Assumptions scenario uses no coal, less natural gas-fired generation, and relies on a greater mix of resources. Battery capacity is charged by afternoon solar generation and some wind and gas in the early morning hours, which allows batteries to discharge during both morning and evening hours to help meet the daily peaks.

The presence of increased solar and battery capacity in the Reasonable Assumptions scenario puts less stress on the gas generators to ramp up and down over the course of the day to respond to hourly changes in demand. Generation from solar in the afternoon leads to a much more gradual decline in gas generation between 8 am and 4 pm than in the Mimic Duke scenario. The discharging of stored energy from the higher number of battery resources during the morning and afternoon peaks requires a lower contribution from gas generation to meet demand in those hours. Similarly, the wind generation that exists in the Reasonable Assumptions scenario is generating during both the morning and afternoon peaks. The complementary relationship between wind and solar generation over the course of the day is clear from Figure 5. Incremental wind additions in the EnCompass model were constrained such that the model could add only 100 MW per year from 2023 through 2027, then 200 MW per year from 2028 through 2031, and finally 300 MW per year from 2032 through 2035.[34] EnCompass hits that constraint in every year and would take even more wind it had been available.

4.3. Carbon Dioxide Emissions

Finally, as expected based on the substantial difference in carbon-free capacity and generation between the two scenarios, the CO_2 emissions in the Reasonable Assumptions scenario are well below those in the Mimic Duke scenario. The removal of the must-run designations for coal units immediately leads to a reduction in CO_2 emissions of almost 12 million tons in 2021. Though both scenarios see overall emissions decline, the gap between the two widens by the end of the period, when the Mimic Duke scenario continues to emit 31 million tons of CO_2 while the Reasonable Assumptions scenario emits 6.6 million tons. Figure 6 depicts this widening gap.

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[34] These constraints were included to reflect the current difficulty of permitting wind in the Carolinas as well as estimates of onshore wind potential in the two states.

Figure 6. Duke Energy CO$_2$ emissions by year by scenario

Neither scenario enforced a binding carbon constraint. Nonetheless, we see that under the Reasonable Assumptions scenario, Duke can meet the Clean Energy Plan 70 percent emissions reductions goal before the 2030 target date and is also much closer to meeting Duke Energy's corporate goal of net-zero carbon dioxide emissions by 2050.

4.4. Revenue Requirements

Revenue requirements are substantially lower under the Reasonable Assumptions scenario than in the Mimic Duke scenario. The cost of the Reasonable Assumptions scenario is $68.4 billion and represents a savings to ratepayers of $7.2 billion when compared to the Mimic Duke scenario. This is due primarily to the increasing competitiveness of renewable and battery storage resources as their capital costs fall over time. Total revenue requirements are also lower because of the difference in operating costs attributable to zero-variable cost renewables, and the penetration of those resources as a percent of Duke's fuel mix in the Reasonable Assumptions scenario. Those revenue requirements are shown in Table 5.

Table 5. Comparison of revenue requirements

Scenario	PVRR (Billion $)
Mimic Duke	$75.6
Reasonable Assumptions	$68.4
Delta	($7.2)

Annual incremental revenue requirements are similar between the two cases until 2024, when we begin to see a difference in the trajectory of coal unit retirements and the addition of a greater number of renewable and storage resources. At no point in time do we see a higher annual revenue requirement under the Reasonable Assumptions scenario. Those annual incremental revenue requirements are shown in Figure 7.

Figure 7. Comparison of annual incremental revenue requirements between Mimic Duke and Reasonable Inputs scenarios
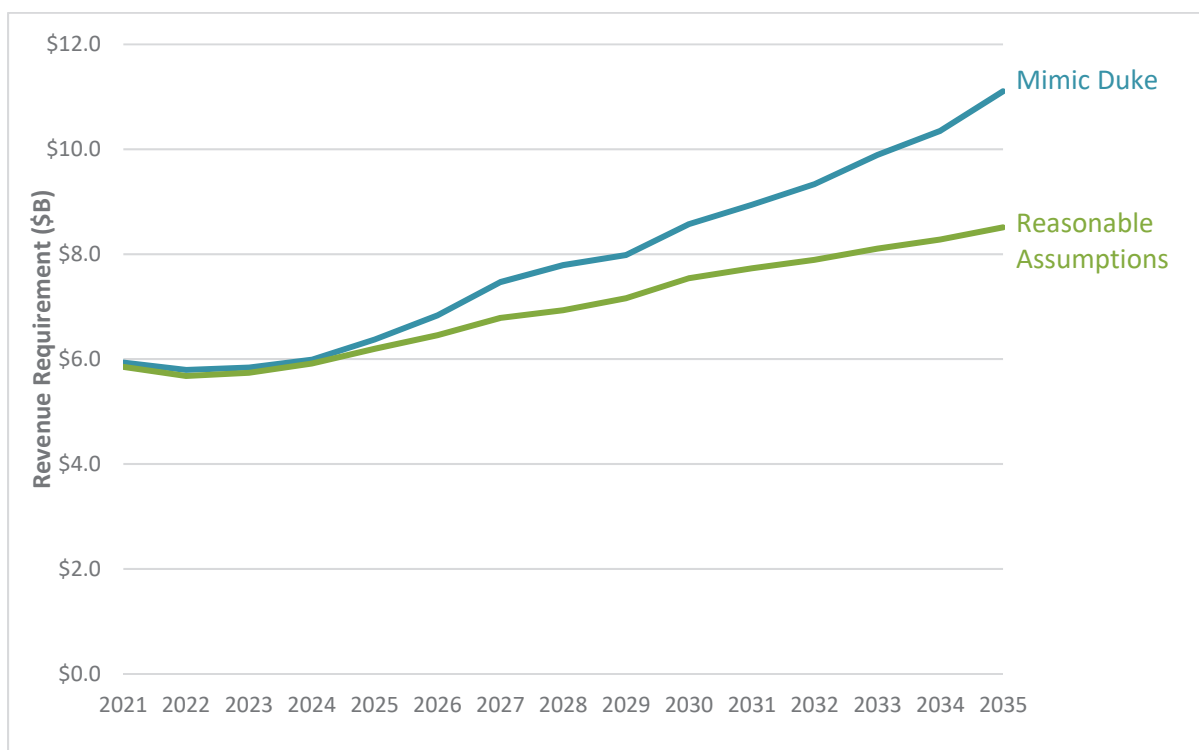
Duke has noted that additional transmission investments would be needed both to retire existing coal units and to bring new renewable generators online. Interconnection costs for new renewables were included in Duke's forecasts of capital costs for renewable resources as a component of the cost of those resources in this analysis. Our analysis does not include the potential costs of other transmission investments, however, in either the Mimic Duke or the Reasonable Assumptions scenario. Each of the resource portfolios presented by Duke in the 2020 IRPs have some transmission upgrade cost associated with it, ranging from a low of $0.9 billion in the Base without Carbon Policy scenario to $8.9 billion in the No New Gas Generation scenario.

With respect to how the addition of these transmission costs might influence the revenue requirements of our scenarios, there are specific things to note. First, certain upgrade costs associated with retirement of existing coal will be the same or similar (differences might be due to a change in the timing of a

retirement and the discounting of those transmission upgrade costs) between the two scenarios when specific units retire in both scenarios. Second, Duke's most expensive "No New Gas Generation" scenario has transmission costs of $8.9 billion, some of which are associated with the interconnection of 2,650 MW of offshore wind. The Reasonable Assumptions portfolio does not add any offshore wind resources and would avoid Duke's most expensive transmission cost estimate. Synapse did not examine Duke's transmission assumptions in detail and there may be a number of non-wires alternatives that were not examined by Duke and that would result in a lower total cost for transmission improvements. One of the benefits of renewables and storage is that they are smaller, more modular, and able to be sited more widely across a utility's service territory. Strategic siting of these resources on the grid could help alleviate transmission constraints and avoid some of the additional transmission benefit. Given these factors, and the delta in revenue requirements of $7.2 billion between the two scenarios modeled in this analysis, Duke could make sizable transmission investments under a Reasonable Assumptions pathway and still arrive at the same or lower total cost as in the Mimic Duke scenario.

5. CONCLUSIONS

The results of the Synapse modeling analysis show that Duke can most economically meet its customers' needs for capacity and energy through the Earliest Practicable retirement of its existing coal-fired units and their replacement with new solar, wind, and battery storage resources. This report presents one potential pathway that would meet forecasted demand while also seeking to minimize both costs and CO_2 emissions. There may be other paths that would do the same; however, there are several key conclusions that should influence any future Duke modeling analysis. First, that Duke's coal unit retirement analysis was not robust and did not accurately determine the "economic" retirement dates of its existing units. Second, that increased energy efficiency will be an essential part in the decarbonization of Duke's system, as it allows Duke to avoid the addition of more expensive supply-side resources. Third, that the addition of renewable energy resources and new battery storage capacity add value to Duke's system. Duke should attempt to maximize these additions, which can be strategically sited to provide support to the grid and additional value to customers, over the next decade. Finally, Duke should seek to minimize additions of new gas-fired combined cycle and combustion turbines to minimize risk to customers and avoid stranded costs.

Appendix A. ENERGY EFFICIENCY METHODOLOGY

Synapse developed two distinct scenarios for Duke's energy efficiency programs in our IRP scenario modeling analysis, included in the Mimic Duke scenario and the Reasonable Assumptions scenario. The Mimic Duke scenario adopts Duke's own Base Case efficiency savings forecast included in DEP and DEC's 2020 IRPs. This scenario projects that first year savings will start at approximately 0.9 percent of the retail sales in 2020 and decline to 0.4 percent by 2035. Duke's first year energy savings data were obtained via responses to discovery.[35] The Reasonable Assumptions scenario, in contrast, assumes that first year program savings will start to increase from 2022 by 0.15 percent of retail sales per year until they reach 1.5 percent and stay at this level through the study period.

Reaching a 1.5 percent savings level is a reasonable scenario for Duke because leading states in energy efficiency such as Massachusetts and Rhode Island have been achieving much higher savings ranging from 2 percent to 3 percent per year over the past decade while Duke's own savings have been at about 1 percent per year or less during that time frame. Figure 8 presents historical first year savings for Duke (combining DEP and DEC's programs), North Carolina as well as three leading states in energy efficiency. Compared to these leading states, Duke and other utilities in North Carolina have missed a substantial amount of energy savings over the past decade. However, this also means that there are plenty of untapped energy savings potential available for Duke.

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[35] Data file "NCSEA DR7-46 Part F.xlsx" obtained from Duke.

Figure 8. Historical First Year Savings: Duke and North Carolina vs. Leading States
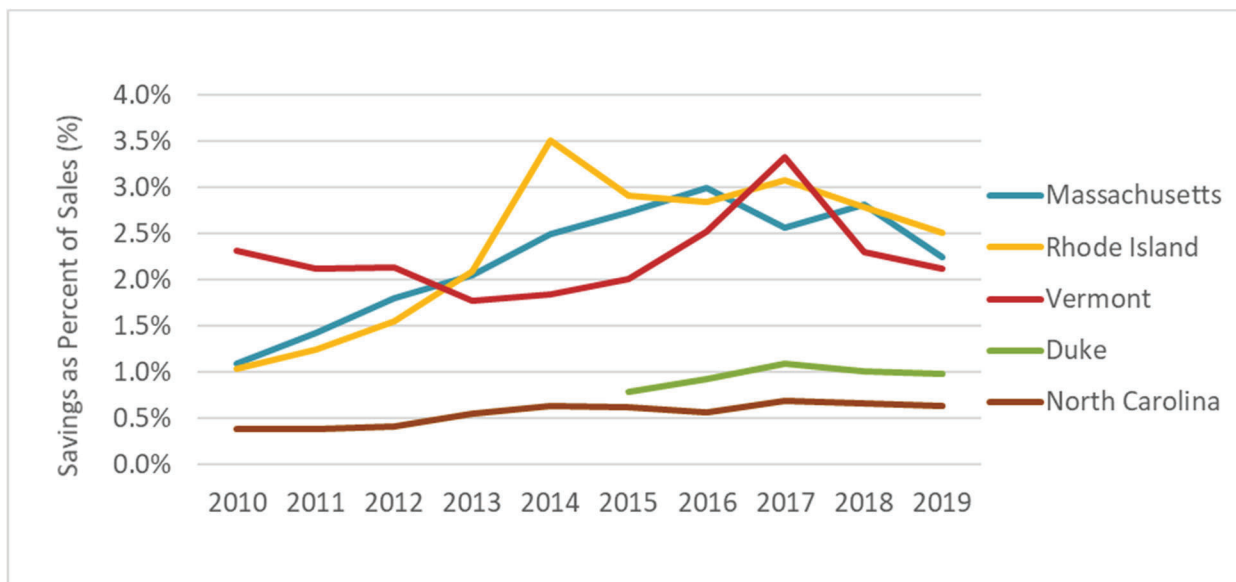
Source: ACEEE's State Energy Efficiency Scorecard reports; data files "NCSEA DR7-48 DEP Projection and True up Filings 2015-2019.xlsx" and "NCSEA DR7-48 DEC Projection and True up Filings 2015-2019.xlsx" obtained from Duke.

Figure 9 below compares projections of annual net energy savings between Mimic Duke and Reasonable Assumptions. Net annual energy savings represent total annual cumulative energy savings that are in effective in each year, taking into account energy savings decay effects.[36] The net annual savings for 2035 under Mimic Duke are approximately 2,248 GWh for DEP and 4,120 GWh for DEC in 2035.[37] The Mimic Duke scenario, for the two jurisdictions combined, projects 6,370 GWh of net annual savings for 2035 or 3.7 percent of the projected system load. The Reasonable Assumptions scenario, on the other hand, projects about 16,500 GWh of net annual savings for 2035 or 9.6 percent of the projected system load. This is slightly over 2.5 times more than the savings projected under the Mimic Duke scenario.

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[36] Duke's measure live estimates range from 1 year for the Home Energy Report program to 20 years for insulation and some HVAC measures with an average measure life of 7 to 8 years. We obtained Duke's measure life data sets used for DEP and DEC's 5-year EE plans through our data request NCSEA DR9-3a.

[37] Duke Energy Progress, 2020, page 70; Duke Energy Carolinas, 2020, Page 69.

Figure 9. Projection of Net Annual Energy Savings: Mimic Duke vs. Reasonable Assumptions (GWh)
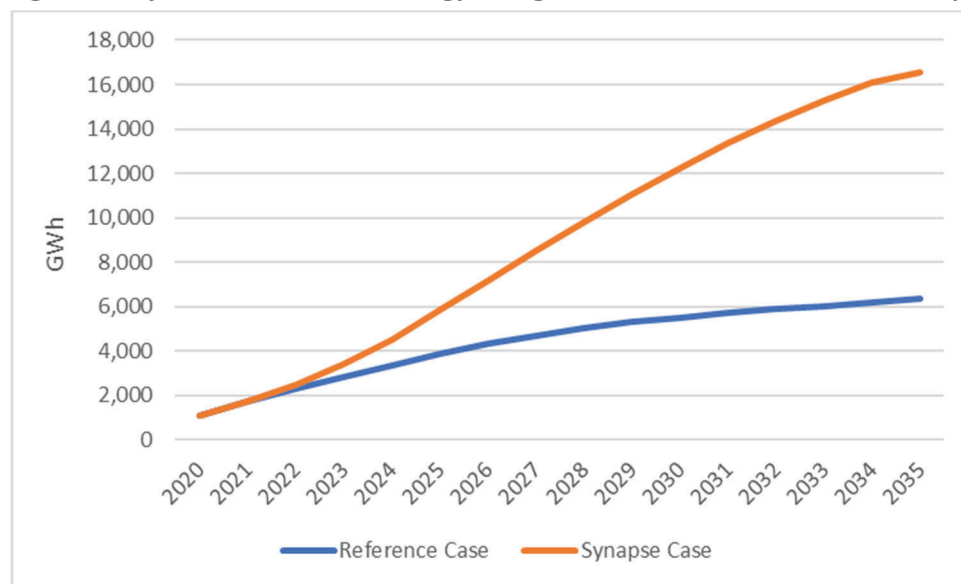

Source for the Mimic Duke scenario: Duke Energy Progress, 2020, Integrated Resource Plan 2020 Biennial Report, page 70; Duke Energy Carolinas, 2020, Integrated Resource Plan 2020 Biennial Report, page 69.

For the purpose of projecting net annual savings and program costs under the Reasonable Assumptions scenario, we projected savings and costs separately for the Home Energy Report (HER) program and for the traditional energy efficiency programs because the HER program accounts for a large portion of Duke's program portfolio and the cost and measure life of HER program are very different from other programs. Historically the HER program savings accounted for about 30 to 40 percent of the total residential program savings, but Duke estimates the HER savings share increases to 46 percent to 49 percent in its DEC and DEP EE 5-year plans. Given these levels of savings are already at a very high level for the HER-type program compared to other jurisdictions, we assumed that the annual savings level from this program stay at the 5-year EE plan level through the study period.

Synapse estimated winter and summer peak load reductions from Duke's energy efficiency programs for the Reasonable Assumptions scenario by adopting Duke's assumptions for measure level hourly energy savings. More specifically, we obtained the hourly energy savings profiles that Duke used for its own IRP EE analysis that differ by measure type and developed a composite hourly load savings profile for the entire program portfolio for Duke's 5-year EE plans.[38] We then applied this portfolio level savings profile to the projected annual energy savings for the Mimic Duke scenario and for the Reasonable Assumptions scenario in order to estimate winter and summer peak load reductions. Figure 10 shows illustrative hourly load savings as winter and summer peak savings.

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[38] NCSEA DR7-59c – DEC Savings Shapes.xlsx and NCSEA DR7-59c – DEP Savings Shapes.xlsx.

Figure 10. Estimated Composite Hourly Load Savings for Duke's Energy Efficiency Programs in 2022 under the Reasonable Assumptions scenario
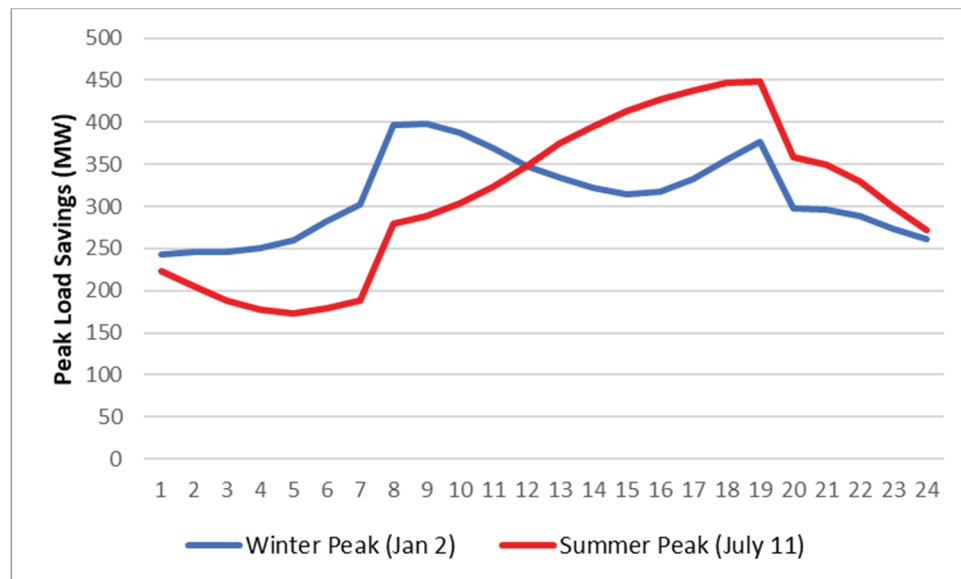
Source: Synapse calculations

Synapse relied on DEP and DEC's 5-year energy efficiency program forecasts to estimate program costs for the first five years, and then estimated program costs in the following years through 2035 based on (a) the per unit program cost data (in dollars per first year MWh savings) from the 5-year program plans, and (b) the first year program savings estimates for those years that we obtained through our data request.[39] The per unit costs of saved energy used in our analysis are presented in Table 6 below separately for the Home Energy Report (HER) program and other EE programs by DEC and DEP. Finally, Synapse amortized the program costs for DEP's programs over a 3-year period with the company's weighted average cost of capital.[40]

Table 6. Cost of Saved Energy ($ per First Year Savings)

	DEC	DEP
HER program	0.04	0.05
Other EE programs	0.26	0.31

Source: NCSEA DR7-49 - 2020 IRP 5-year plan.xlsx

For projecting program costs for the Synapse Case, we relied on Duke's own per unit program cost estimate for 2020 from its 5-year EE plans and kept the per unit cost constant in real dollars. Historical evidence suggests that energy efficiency programs

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[39] NCSEA DR7-46 Part F.xlsx.

[40] North Carolina Utilities Commission. 2020. Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms. Docket No. E-2, Sub 931 and E-7, Sub 1032.

cost tend to stay at similar levels or sometimes even decrease when program scales are expanded due to economies of scale.[41]
Figure 11 and Source: ACEEE's State Energy Efficiency Scorecard reports

Figure 12 presents costs of saved energy by selected states including two top states in energy efficiency programs (Massachusetts and Rhode Island), two mid-level leading states (Arizona and Michigan) (at a savings level of 1.5 percent), and North Carolina. As can be seen in these figures, the costs of saved energy have been mostly either flat or slightly decreased over several years from 2011 to 2014 to 2016 for Massachusetts and Rhode Island when they increased energy saving levels. These historical data support our assumption of keeping the cost constant for the Reasonable Assumptions scenario where we assumed first year savings increase to 1.5 percent per year.

**Figure 11. Costs of Saved Energy for Selected States from 2010 to 2019 ($ per kWh first year)**
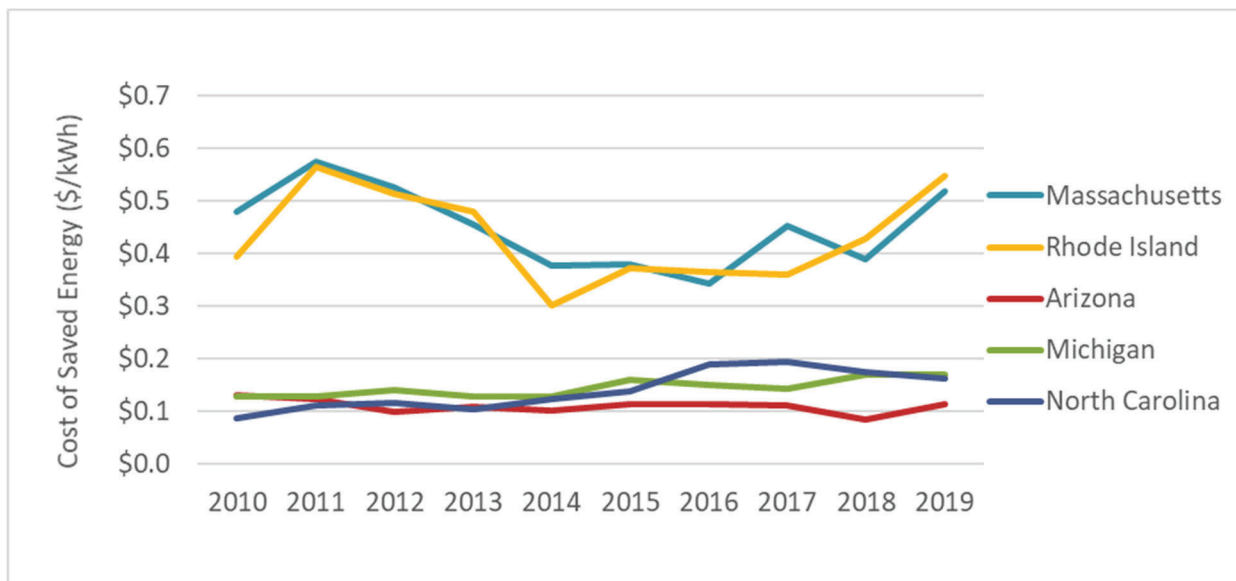
Source: ACEEE's State Energy Efficiency Scorecard reports

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[41] For example, see Takahashi et al. 2015. Review of TVA's Draft 2015 Integrated Resource Plan. Synapse Energy Economics. Figure 2. Available at https://www.synapse-energy.com/sites/default/files/Review-TVA-Draft-2015-IRP-14-022.pdf.

Figure 12. First Year Savings Comparison for Selected States from 2010 to 2019
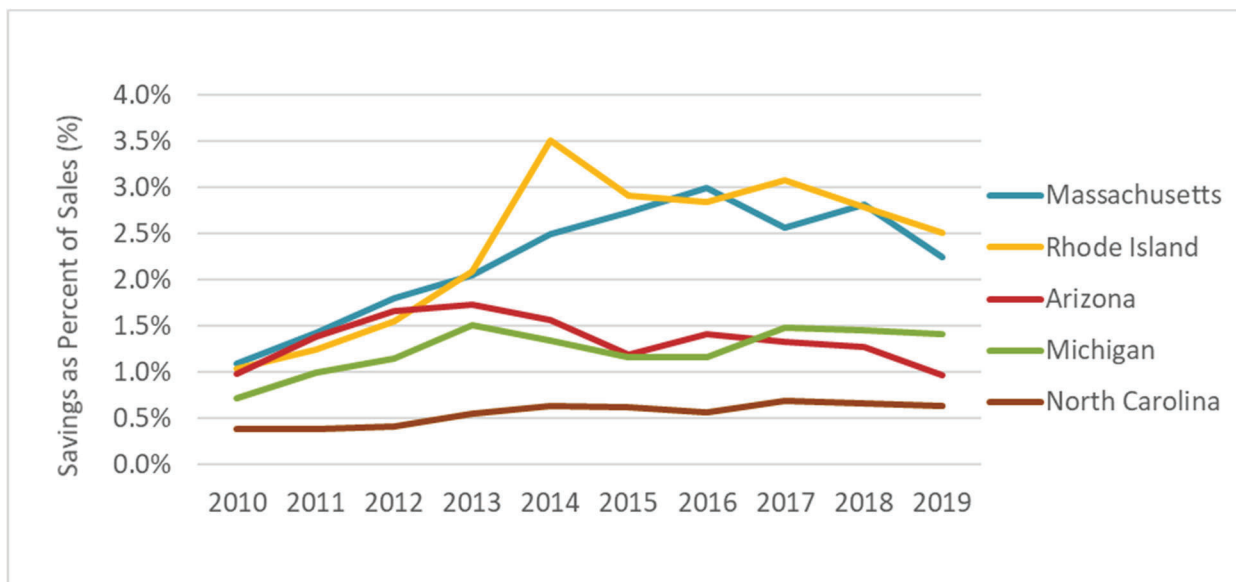
Source: ACEEE's State Energy Efficiency Scorecard reports

Projected energy efficiency program costs are presented in Table 7 (see next page) for both the Mimic Duke and the Reasonable Assumptions scenarios. Program costs start around $170 million for both scenarios. Under Mimic Duke, the program costs are projected to increase to $250 million in 2025 and decline to $150 million by 2035. Under Reasonable Assumptions, the program costs are projected to increase to $746 million by 2035.

Table 7. Projected Energy Efficiency Program Costs by Scenario ($000)

	Reference Case			Synapse Case		
	DEC	DEP	Total	DEC	DEP	Total
2020	27,928	145,867	173,795	27,928	145,867	173,795
2021	54,787	168,034	222,821	54,787	170,991	225,779
2022	81,586	193,945	275,532	89,894	237,612	327,506
2023	79,999	188,485	268,484	105,591	289,873	395,464
2024	79,761	186,410	266,171	131,122	353,041	484,163
2025	78,456	192,343	270,799	157,822	419,365	577,187
2026	76,453	187,203	263,656	180,532	447,294	627,826
2027	71,851	178,153	250,003	195,619	466,948	662,567
2028	65,955	167,586	233,541	202,520	478,588	681,108
2029	58,689	155,421	214,111	206,221	487,252	693,473
2030	51,107	142,703	193,810	210,117	496,139	706,256
2031	43,526	132,073	175,599	214,172	505,295	719,467
2032	37,440	126,048	163,489	218,319	514,537	732,857
2033	33,970	123,696	157,666	222,625	524,175	746,800
2034	32,937	123,920	156,857	227,050	533,916	760,965
2035	32,988	125,369	158,357	231,699	544,283	775,983