Docket E-100, Sub 179
Exhibit 1

Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal

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

July 15, 2022

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Executive Summary

This report presents the results of RMI's analysis of the ratepayer and financial effects of Duke Energy's Carbon Plan proposal. RMI appreciates the opportunity to conduct this analysis and summarize its findings in support of the North Carolina Utilities Commission's effort to develop the least cost path toward the statutory requirements of 70% carbon dioxide emission reduction from 2005 levels by 2030 and carbon neutrality by 2050.

This analysis was conducted using Optimus, an open-source utility financial model developed by RMI. Optimus uses the results from capacity expansion modeling to estimate the ratepayer, utility earnings, and shareholder impacts of a given resource portfolio under a variety of sensitivity scenarios.

Due to a significant software error discovered by Synapse in EnCompass model version 6.0.9, RMI did not have access to an alternative scenario from Synapse to analyze in time for the July 15th filing deadline.[2] RMI's analysis of Duke Energy's Carbon Plan proposal is based on Synapse EnCompass version 6.0.9 modeling of a scenario that was designed to replicate Duke's Portfolio 1 with no new Appalachian gas transmission. This scenario is referred to as "Duke Resources." Should the Commission allow, RMI can conduct an Optimus analysis of any alternative scenarios developed using EnCompass by Synapse or any party to this proceeding as a supplement to this report.

<u>Key Insights</u>

RMI's analysis of the Duke Resources portfolio finds that:

1. ***Expensive nuclear and gas units drive up the total ratepayer costs for the Duke Resources scenario throughout the planning period.*** In particular, near-term investment in gas capacity introduces significant risks to ratepayers by locking in significant capital costs for assets that will either be converted to hydrogen (at uncertain cost) or will be obsolete before they are fully depreciated, translating to higher costs for ratepayers.
    a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis*** to examine whether an alternative portfolio that relies less on new gas plants and new modular nuclear plants would present a lower total cost with less uncertainty for ratepayers.

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[2] See Motion for Extension of Time to File Comments and Expert Report, NCUC Docket No. E-100, SUB 179. (July 14, 2022)

2. ***Total ratepayer costs for the Duke Resources scenario are distributed unequally across ratepayer classes.*** Duke's gas-heavy and speculative-technology scenario would disproportionately saddle residential customers in Duke Energy Carolinas (DEC) territory, and industrial customers in Duke Energy Progress (DEP) territory, with larger average bill volatility. This finding is propelled by the current cost causation framework, which channels variable costs (driven by fuel prices) primarily to residential customers, while capital costs (which are proportionally higher relative to variable costs in cleaner scenarios) can be passed to commercial and industrial customers in the form of demand charges.
    a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis*** to explore whether an alternative portfolio more equitably distributes costs amongst the different ratepayer classes.
3. ***New gas capacity is not a cost-effective hedge against fuel price shocks — but accelerating renewable deployment could be.*** In the near and medium term, the Duke Resources scenario adds new gas combined cycle (CC) and combustion turbine (CT) generation capacity. While new CCs and CTs are more fuel-efficient than coal units converted to gas co-firing, the cost savings from greater efficiency do not exceed the incremental fixed capital and operating costs of the new build in any year — even in the event of a doubling in fuel prices. Factors beyond the scope of RMI's Optimus modeling analysis — such as the likely high cost of later conversion of CC and CT units to hydrogen, and the accelerated cost recovery of unneeded gas infrastructure upon conversion — will likely exacerbate this dynamic. However, the new proposed renewable portfolio in the Duke Resources scenario becomes cost-effective as a hedge against a fuel price doubling starting in 2032. Moreover, there is a strong correlation between increased deployment of renewable resources and decreasing ratepayer exposure to fuel price shocks in the Duke Resources scenario.
    a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to investigate whether*** an accelerated deployment of solar, battery storage, and wind resources in the near and medium term would be a more cost-effective hedge against future fuel price volatility.
4. ***The Duke Resources scenario underutilizes securitization as a source of ratepayer relief to mitigate rate spikes from early retirement of coal.*** The later coal retirements occur, the smaller the potential savings that can be derived from securitization. Securitization is a low-cost refinancing mechanism that drives savings for ratepayers when applied to larger unrecovered balances. RMI estimates that the Duke Resources scenario would result in approximately $14.1 million in savings for ratepayers as a net present value (NPV) in 2022 dollars. RMI also modeled the securitization of 50% of all unrecovered balances following a retirement of all subcritical Duke coal plants at the end of 2022 and estimated an

additional $446 million in savings (NPV, 2022$) for ratepayers. From this perspective, the Duke Resources scenario captures only 3% of the ratepayer savings available from securitization under H951. For informational purposes, RMI also modeled a securitization scenario outside the limits of H951. If all unrecovered balances from all Duke coal plants, including the supercritical Cliffside 6 and the recently retired G.G. Allen units, were securitized at the end of 2022, ratepayer savings from such a refinancing could reach $1.26 billion (NPV, 2022$).

   a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to review whether*** an alternative scenario that enables an earlier retirement of coal assets than Duke projected will translate into greater total ratepayer savings.

5. ***The Duke Resources scenario leaves ratepayers vulnerable to rate de-stabilization from large increases in load and fuel price.*** When higher loads associated with faster electrification are assumed and then combined with a fuel price shock, all ratepayers are worse off under more fuel-dependent and less energy-efficient resource portfolios. RMI's analysis shows that high load projections coupled with a fuel price shock increases the average retail monthly bill 3% for DEC and 4% for DEP on a present value basis under the Duke Resources scenario.
   a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to understand*** whether a higher penetration of fuel-free resources will temper the impacts of a fuel price shock in a high load future scenario.
6. ***The implementation of multi-year rate plans (MYRPs) and revenue decoupling as specified by H951 would exacerbate the rate impact of higher-than-expected demand and fuel prices relative to a scenario without these mechanisms in place.*** The use of forecasted costs to set the revenue allowance in the H951 performance-based regulation (PBR) design may motivate the utility to conservatively estimate the costs associated with fuel- and variable cost-dependent resources to account for uncertainty and price volatility, which increases the cost to consumers. RMI's modeling of a MYRP and residential decoupling in Optimus reveals substantial risk to ratepayers from the concurrence of these factors. When coupled with higher load growth due to electrification and a prolonged fuel price increase, a MYRP and revenue decoupling mechanism cause the average retail bills associated with the Duke Resources scenario to rise approximately 9% for both DEC and DEP on a present value basis.
   a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to examine whether*** PBR could provide a stronger incentive for

the utility to control operating costs when applied to an alternative resource portfolio.

7. ***If implemented, federal policy changes in the next decade will present significant cost savings opportunities that can be passed through to ratepayers; the Duke Resources scenario would capture $5.4 billion***. Using the policies outlined in the Build Back Better Act as a proxy for potential future policy changes, RMI asserts that cleaner energy portfolios possess an "option value" associated with the potential benefits of new or enhanced federal policies that will subsidize zero-emitting resources. The Duke Resources scenario has an estimated option value of $5.4 billion, which can be passed through to ratepayers in the form of savings. Conversely, portfolios with a higher concentration of emitting resources have a "risk value" for future policies that may penalize or increase the cost of emitting resources.
    a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to explore*** how much additional savings to ratepayers could be attained by an alternative resource portfolio.

Key Caveats

RMI's Optimus financial modeling is offered as a companion analysis to the modeling provided by Synapse and Duke. The Optimus financial modeling examines paths to achieve the State's carbon reduction requirements, as outlined in H951, with attention to how the utility service costs will be reflected in rates and bills. This analysis includes a broader set of drivers (including fuel price shock and federal policy reform) than is currently considered in Duke's Carbon Plan proposal. RMI recommends that that the NCUC consider making this approach to analyzing resource planning proposals a standard in future Carbon Plan processes to ensure that the full scope and measure of potential risks and benefits to ratepayers are considered when determining the least-cost path.[3]

As is true of all models, RMI's efforts cannot perfectly predict future impacts. However, the findings contained in this report are the product of a model with a high degree of resolution for data inputs and calculations. Nevertheless, it must be stressed that this analysis depended on a re-creation of Duke's Portfolio 1 scenario ("Duke Resources") as modeled by Synapse rather than Duke's EnCompass outputs themselves. As such, there are inevitable differences between certain RMI metrics and similar calculations conducted by Duke in its Carbon Plan proposal. In these instances, the difference is likely

[3] Optimus is an open-source tool developed by RMI. The LBNL FINDER tool has been deployed in a similar fashion in other settings.

due either to the use of a simplified rate and bill impact estimate in Duke's modeling or because RMI was unable to acquire the same data sources or formulas used by Duke.

A key example of the latter circumstance relates to RMI's calculation of rates for each ratepayer class. RMI's analysis is not as robust nor as accurate as Duke Energy's cost-of-service study. Through the discovery process, RMI requested the necessary information to replicate the cost-of-service cost allocation methodology but did not receive granular enough detail to replicate it in sufficient time for the July 15 filing deadline. Consequently, RMI employed a simplified approach using public data on historical revenue collection and assumptions that provide directional insight rather than precision.[4]

Although PBR and securitization may be outside the scope of the Carbon Plan proceeding, RMI simulated the impact of these mechanisms in this analysis because their impacts can vary greatly depending on composition and timing of the resource portfolio. To ignore the potential impact of these mechanisms, which are included in the same authorizing legislation, risks making costlier choices for ratepayers than are justified.

Some of the sensitivities and policy scenarios analyzed in this report are, concededly, speculative — as is any forecast and sensitivity analysis. For example, the enhanced federal policy sensitivity uses the Build Back Better Act provisions as a proxy for future policy changes. While it is impossible to definitively forecast the scope, form, and timing of future policies, this scenario is intended to provide an illustration of the possible scale and impact of benefit to ratepayers from future policy action.

Finally, RMI conducted this analysis on Synapse's EnCompass results before Synapse identified the EnCompass version 6.0.9 software bug. **The EnCompass bug is very unlikely to have affected the EnCompass 6.0.9 Duke Resources scenario.**

However, in light of the extension granted for the Synapse report, Synapse will run the Duke Resources scenario again in the same downgraded version of EnCompass that Duke utilized for its proposed Carbon Plan. Synapse's re-run of the Duke Resources Scenario is unlikely to result in portfolio changes; however, the two EnCompass versions likely contain other differences in model logic which will change dispatch of the portfolio to an uncertain degree relative to the dispatch projected by EnCompass 6.0.9. In turn, operating projections and costs will vary between the two versions of the Duke Resources scenario results, which impacts all the Optimus calculations and findings presented in this report.

Cognizant of these differences, RMI offers this report as an illustrative and directionally accurate analysis of the Duke Resources scenario.

[4] The simplified approach is described in detail in the appendix.

Introduction

About RMI

RMI is an independent, non-partisan, nonprofit organization of experts across disciplines working to accelerate the clean energy transition and improve lives. RMI's mission is to transform the global energy system to secure a clean, prosperous, zero-carbon future for all.

RMI's previous work in North Carolina was in support of the creation and implementation of the NC Department of Environmental Quality's Clean Energy Plan and the North Carolina Energy Regulatory Process (NERP). RMI appreciates the opportunity to provide this report in support of the implementation of the H951 legislation — specifically, the development of North Carolina's first Carbon Plan.

About Optimus

Optimus is an open-source financial modeling tool that quantifies the distribution of economic impacts of utility planning scenarios among ratepayers, the utility, and the utility's shareholders. RMI created Optimus because state policies across the country are increasingly requiring utility regulators to play a leading role in achieving decarbonization goals while simultaneously controlling expenses and allocating costs fairly. Optimus is designed to support the task of resource planning by providing robust and timely insights to inform decisions that balance decarbonization alongside fair distribution of risks and benefits to ratepayers.

Optimus leverages the outputs from capacity expansion modeling as inputs for further analyses that yield results for ratepayers, the utility, and utility shareholders.[5] Optimus was created to quantify the distributional impacts for a range of policy, regulatory, and market sensitivities, including, but not limited to:

- State and federal policies, such as expanded production tax credits for clean energy,
- Refinancing mechanisms, such as securitization,
- Performance-based regulatory mechanisms, such as multi-year rate plans and performance incentive mechanisms, and

[5] Though Optimus can assess utility earnings and shareholder impact, this analysis examines only the ratepayer impacts due to time and resource constraints as well as EnCompass output limitations.

- Unpredictable market dynamics, such as demand shocks or fuel cost spikes.

Purpose of this Analysis

SELC, and their clients, and NCSEA retained RMI to conduct an analysis using Optimus to quantify the allocation of economic impacts of differing Carbon Plan scenarios. The objective of this analysis is to inform the efforts of the North Carolina Utilities Commission (NCUC) in fulfillment of H951 directives, specifically to "take all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO2) emitted in the State from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050."[6]

The law empowers the NCUC with the "discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals."[7] The Optimus analysis described herein supports the selection of the least cost resource portfolio by shedding light on the distributional economic impacts of a portfolio proposed by Duke Energy ("Duke") as modeled by Synapse Energy Economics ("Synapse"),[8] and how the distributional impacts might be further affected by plausible future events — such as fuel price shocks, state utility regulation reform, and the adoption of new federal policies. RMI is capable of producing a similar, comparative analysis for any other portfolios developed with EnCompass, should the NCUC allow a supplemental report.

Methodology

This section briefly represents the sensitivity scenarios modeled in Optimus and the differences between the Optimus and EnCompass analytical approaches. A full description of how Optimus works and the results from calibrating Optimus and EnCompass results can be found in the Appendix.

Duke Resources Scenario from EnCompass

The EnCompass scenario RMI modeled in Optimus for this report is described in ***Table A.*** RMI leveraged the Duke Resources portfolio from Synapse's forthcoming analysis,[9] which

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[6] North Carolina General Assembly, Session 2021, Session Law 2021-165, House Bill 951, 1.
[7] Ibid., 2.
[8] Synapse Energy Economics (2022). *Carbon-Free by 2050; Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers*.
[9] Motion for Extension of Time to File Comments and Expert Report, NCUC Docket No. E-100, SUB 179. (July 14, 2022)

recreated Portfolio 1-Alternate (P1-Alt) from Duke Energy's proposed Carbon Plan. Should the Commission allow, RMI can conduct a supplemental Optimus analysis on alternative proposed Carbon Plan scenarios for which analysis of Synapse's Duke Resources scenario can serve as a comparable baseline.

Table A. Scenario Analyzed in Optimus[10]

Scenarios	Description
Duke Resources	This scenario was created by Synapse to replicate the resources selected in Duke's P1-Alt portfolio, which does not assume firm Appalachian gas capacity.[11]

It was RMI's intent to compare the ratepayer impact results of the Duke Resources scenario to those of alternative scenarios modeled by Synapse. Due to a significant software error discovered by Synapse in EnCompass model version 6.0.9, RMI did not have access to an alternative scenario from Synapse to analyze in time for the July 15 filing deadline.[12] RMI's analysis of Duke Energy's Carbon Plan proposal is based on Synapse EnCompass modeling of a scenario that replicates Duke's Portfolio 1 with no new Appalachian gas transmission. This scenario is referred to as "Duke Resources." Should the Commission allow, RMI can conduct an Optimus analysis of any alternative scenarios developed using EnCompass by Synapse or any party to this proceeding as a supplement to this report.

Optimus Policy and Sensitivity Scenarios Modeled

In this analysis, RMI used Optimus to model the impacts of a set of existing federal policy incentives, potential future policies, regulatory mechanisms from North Carolina's H951 legislation, and several macroeconomic sensitivities on the Duke Resources scenario.[13] Each of the policy and sensitivity scenarios RMI modeled is described in brief below. More detail on the assumptions and application of each scenario can be found in the appendix.

1. *High load projection:* This sensitivity explores how each scenario would fare in the event of an unexpected growth in load driven by electrification. This assumes the

[10] Please see Synapse's Report for further description of this scenario and Synapse's revised assumptions.
[11] RMI conducted this analysis on Synapse's EnCompass results before Synapse identified the EnCompass version 6.0.9 software bug. The EnCompass bug is very unlikely to have affected the EnCompass 6.0.9 Duke Resources scenario.
[12] See Motion for Extension of Time to File Comments and Expert Report, NCUC Docket No. E-100, SUB 179. (July 14, 2022)
[13] The policies included in Optimus are primarily economic in nature and limited to those described here and in the Appendix. Other regulatory levers, such as existing and potential tightening of public health rules, were not analyzed.

load grows 2% faster than the projected trend in the baseline ("Duke Resources") scenario. This corresponds to a 25% higher load in 2050 when compared with the baseline.[14]

2. *<u>Fuel price sensitivities</u>:*[15] RMI explored two sensitivities to gauge how the Duke Resources scenario would fare in the event of an unexpected, temporary price spike — similar to the global gas market shock since Russia's invasion of Ukraine. The two fuel price sensitivities modeled include:
    a. <u>A single-year extreme fuel price shock</u> to assess the temporary impact of market turbulence. This sensitivity assumes doubling the fossil fuel prices for the entirety of one single calendar year, and the test year range is 2029-2035 because these are the peak years for generation from gas and co-firing units (and thus, consumption of gas) in the Duke Resources scenario. The metric used to evaluate the impact is the percentage increase of annual total ratepayer cost driven by the fuel price shock in that year, and by comparing the impact across the range of 2029-2035, RMI was able to identify the year where the portfolio is most susceptible to fuel price volatility.
    b. <u>A prolonged, multi-year increase in fuel price (2029 through 2035)</u> to assess the medium-term impact on prices of a longer-term shift in fuel market dynamics. This sensitivity assumes 50% higher fossil fuel prices for the entirety of calendar years 2029 through the end of 2035 on each resource scenario and is also coupled with a higher load projection as described above to analyze the effect of these two compounding risks.

3. *<u>Securitization</u>:* H951 allows for half of the costs associated with early retirement of subcritical coal-fired electric generating facilities to be securitized.[16] This scenario assumes that 50% of the remaining plant balance of all of Duke's subcritical coal units is securitized at the time of retirement, while the other 50% of the balance remains in the rate base and is turned into a regulatory asset.

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[14] Appendix A.5 provides a visual comparison of the application of the Optimus high load sensitivity in contrast to the high load assumption modeled in EnCompass.

[15] Fuel price volatility could reasonably be assumed to have a positive impact on the cost-effectiveness of energy efficiency (EE) as a resource. However, EE is treated as an exogenous resource in all scenarios and sensitivities modeled within EnCompass (rather than economically selected) -- thus an exogenous input into Optimus as well—as it is dependent on the potential prescribed by Duke's energy efficiency cost estimates.

[16] North Carolina G.A., Session Law 2021-165, House Bill 951, 2.

A brief description of *how* Securitization works

Securitization is a refinancing mechanism that uses low-cost debt backed by non-bypassable ratepayer charges to pay off undepreciated plant balances. When securitization bonds are issued, the utility receives funds allowing it to pay off existing creditors and equity contributors. The new securitized debt is an obligation neither of the state nor the company, but rather of all current and future utility customers over the life of the bonds. Securitization legislation typically includes valuable protections for creditors that result in extremely high credit ratings for the bonds — higher than any U.S. utility's current credit rating — and correspondingly low interest rates. Because ratepayers are paying lower interest rates when securitization is utilized, thereby avoiding paying for the higher returns demanded by equity providers, they ***realize savings that scale in proportion with the size of the refinanced balances*** and ***the duration of the avoided period*** of traditional utility finance.

For more on securitization, see Christian Fong and Sam Mardell, "Securitization in Action: How US States Are Shaping an Equitable Coal Transition," RMI (March 4, 2021).[17]

4. *PBR mechanisms:* This Optimus sensitivity scenario models the design elements of a MYRP described in statute (i.e., 36 months, 4% annual revenue adjustment, revenue requirement based on forecasted costs) and residential class revenue decoupling.

5. *Existing federal policy scenario:* Existing federal policies include the Production Tax Credit (PTC) for wind generation and the Investment Tax Credit (ITC) for utility-scale solar, which are currently available for facilities that enter service through the end of 2025 but subject to a gradual phase-out (PTC) or phase-down (ITC). Optimus modeled the benefit of these credits as a savings opportunity for scenarios that incorporate new wind and solar facilities within this timeframe. Of note, the benefits from PTC are not applicable to any of the Duke's Carbon Plan P1-P4 portfolios because those portfolios do not add new eligible capacity within the required timeframe.

6. *Enhanced federal policy scenario:* Future federal policies may provide greater rewards for investment in clean electricity resources. Conversely, they may also introduce penalties (e.g., a carbon price) or regulatory requirements that increase the cost of investment in, and operation of, carbon-emitting resources. To

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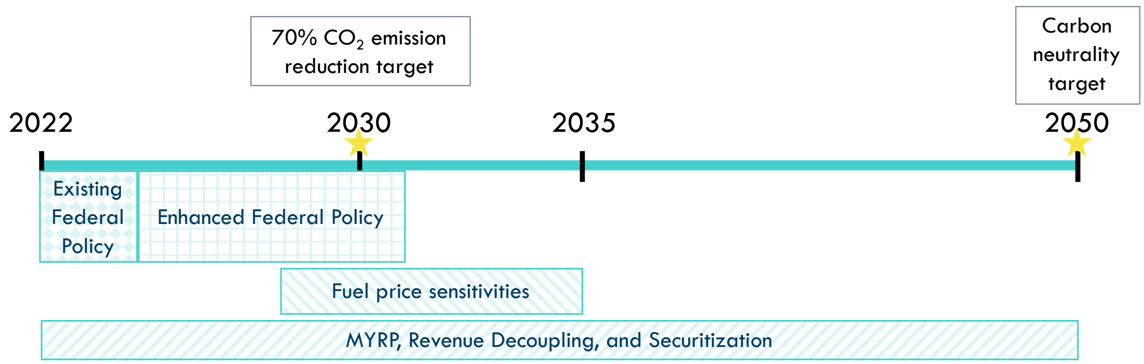
[17] Available at https://rmi.org/securitization-in-action-how-us-states-are-shaping-an-equitable-coal-transition/

approximate the potential savings that further federal action may implicate, this scenario modeled an extension of the scope and applicability of the current ITC and PTC policies through 2031, as conceived in the Build Back Better Act (H.R. 5376).

The scenarios and sensitivities are applied over the same timeframe as modeled by Duke in its Carbon Plan proposal (through 2050). RMI's analysis of the net present value for costs associated with scenarios and sensitivities are calculated for 2022-2050. RMI focused primarily on medium-term metrics and outcomes that are relevant to achieving the first of the state's two statutory emission reduction goals. RMI's modeling horizons within this timeframe are in ***Figure 1***.

Figure 1 1. Policy and sensitivity scenario application relative to Duke's Carbon Plan proposal



Key Differences between the EnCompass and Optimus Methodologies

Optimus is a utility financial model designed to assess the full ratepayer cost and shareholder impact of utilities' planning decisions.[18] There are several key factors that set it apart from the revenue requirement assessment in capacity expansion and production cost modeling tools like EnCompass. ***Table B*** outlines these key differences and briefly summarizes their implications for this analysis. Please see the appendix for a more complete description and discussion of these differences.

Table B. Key Differences Between EnCompass and Optimus Methodologies

Difference	Brief Description
Full revenue requirement	Duke estimated ratepayer cost using only the forward-looking incremental costs. This has the effect of treating expenses

[18] Though Optimus can assess utility earnings and shareholder impact, this analysis only examines the ratepayer impacts due to time and resource constraints and EnCompass output limitations.

vs. forward-looking incremental system cost	associated with the existing electric fleet as a foregone conclusion, ignoring potential changes in those costs from early retirement and securitization, and adjustments to the depreciation schedule of regulatory assets. In contrast, RMI calculated ratepayer costs using the full revenue requirement to better reflect the cumulative impact on ratepayers and help the utility, the Commission, and intervening parties identify opportunities to reduce the cumulative costs of each portfolio scenario through mechanisms such as securitization.
Full vs. incremental rates and bills impact assessment	Duke's approach to the residential bill impacts assessment represents an average impact of the incremental portfolio additions, which again ignores how the costs of the existing portfolio could change and also implies that the costs of the future portfolio would be spread evenly across retail customer classes. RMI's approach considers the evolution of the entire portfolio (both existing assets and additions) and estimates the differential impact amongst the four primary classes of customers (residential, commercial, industrial and wholesale).
Fixed O&M expenses vs. capitalization	In Duke's EnCompass modeling, transmission upgrade costs and the maintenance capital expenditures (or "CapEx") associated with existing assets are treated as fixed O&M cost adders. In Duke's EnCompass outputs, these costs are inextricably combined with other generation project-specific costs from the "Fixed Cost" category in EnCompass. As a result, Optimus's calculations of securitization benefits in this report represent an underestimate; moreover, utility earnings (though not calculated here) will similarly be challenging to calculate accurately.
Discount factor for Net Present Value calculation	In Duke's EnCompass modeling, the net present value (NPV) calculation uses a single discount factor: the Weighted Average Cost of Capital (WACC) for the entire planning horizon. RMI used the same constant WACC for the incremental NPV calculation. However, for the full revenue requirement assessment beyond incremental NPV, RMI used a hybrid, forward-looking ROR approach which provides a more nuanced picture of the value of different portfolio decisions. RMI's approach more accurately reflects the nature of the capital markets that utilities encounter and the costs they face and consequently right-sizes the NPV estimation.

Limitations of this Analysis

Important Disclaimer Regarding this Report

RMI conducted this analysis on Synapse's EnCompass results before Synapse identified the EnCompass version 6.0.9 software bug. **The EnCompass bug is very unlikely to have affected the EnCompass 6.0.9 Duke Resources scenario.**

However, in light of the extension granted for the Synapse report, Synapse will run the Duke Resources Scenario again in the same downgraded version of EnCompass that Duke utilized for its proposed Carbon Plan. Synapse's re-run of the Duke Resources Scenario is unlikely to result in portfolio changes, However, the two EnCompass versions likely contain other differences in model logic which will change dispatch of the portfolio to an uncertain degree relative to the dispatch projected by EnCompass 6.0.9. In turn, operating projections and costs will vary between the two versions of the Duke Resources scenario results, which impacts all the Optimus calculations and findings presented in this report.

Cognizant of these differences, RMI offers this report as an illustrative and directionally accurate analysis of the Duke Resources scenario.

In light of time and data constraints, RMI employed several workarounds and simplified assumptions in this modeling exercise. RMI acknowledges that these may have influenced the findings in this report to varying degrees. However, the influence is unlikely to materially change the direction of the findings in this report. RMI is open to revisiting these simplifying assumptions with the Commission, utilities, and other intervenors to examine the potential change in findings if sufficient time and interest exists.

For projects constructed over multiple years, RMI made a simplifying assumption to apply the total installed cost in the single year when construction is completed (i.e., when the project enters into service) rather than spreading the installation cost across multiple years. RMI did not use Construction Work in Progress (CWIP) or Allowance for Funds Used During Construction (AFUDC) to account for the difference in rate base and tax treatment, due to time constraints. This leads to a smaller NPV of the revenue requirements since the rate impact is added at later years.

RMI was unable to fully model Duke's Carbon Plan proposal P1 scenario using the EnCompass outputs Duke provided. This was infeasible because Duke's EnCompass outputs did not provide the installed cost associated with each asset, which is a necessary input for Optimus. As a workaround, RMI analyzed Synapse's "Duke Resources" scenario since it produced the same resource portfolio as Duke's proposed P1 buildout. However, this workaround complicates direct comparison of the ratepayer impacts calculated by Optimus with similar metrics included in Duke's Carbon Plan proposal.

Considering the above, RMI's findings in this report should be construed as an analysis of a scenario similar to, but not exactly the same as, Duke's P1 scenario. RMI's findings should not be interpreted as applicable to Duke's P2-P4 scenarios, though some findings may be directionally indicative.

Findings

This section presents seven high-level findings from RMI's analysis using the Optimus model to analyze the ratepayer impacts associated with the Duke Resources scenario. RMI calibrated its results from Optimus against those from Synapse's EnCompass run which resulted in NPVRR calculations that are less than 1% different from Synapse's numbers through 2030 and within 3% through 2050.

1. Expensive nuclear and gas units drive up the total ratepayer costs for the Duke Resources scenario throughout the planning period.

Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

The Duke Resources scenario contains gas combined cycle and combustion turbine generation capacity which together represent 12% and 9% of the of the total annual ratepayer cost in 2035 and 2050, respectively.[19] Nuclear, which is also a significant cost driver in the Duke Resources scenario, represents 13% and 36%, respectively. ***Table C*** demonstrates the Full Portfolio NPVRR as calculated by Optimus for the medium and long-term planning horizon.

Table C. Full Portfolio NPVRR Comparison across Scenarios, 2022-2050

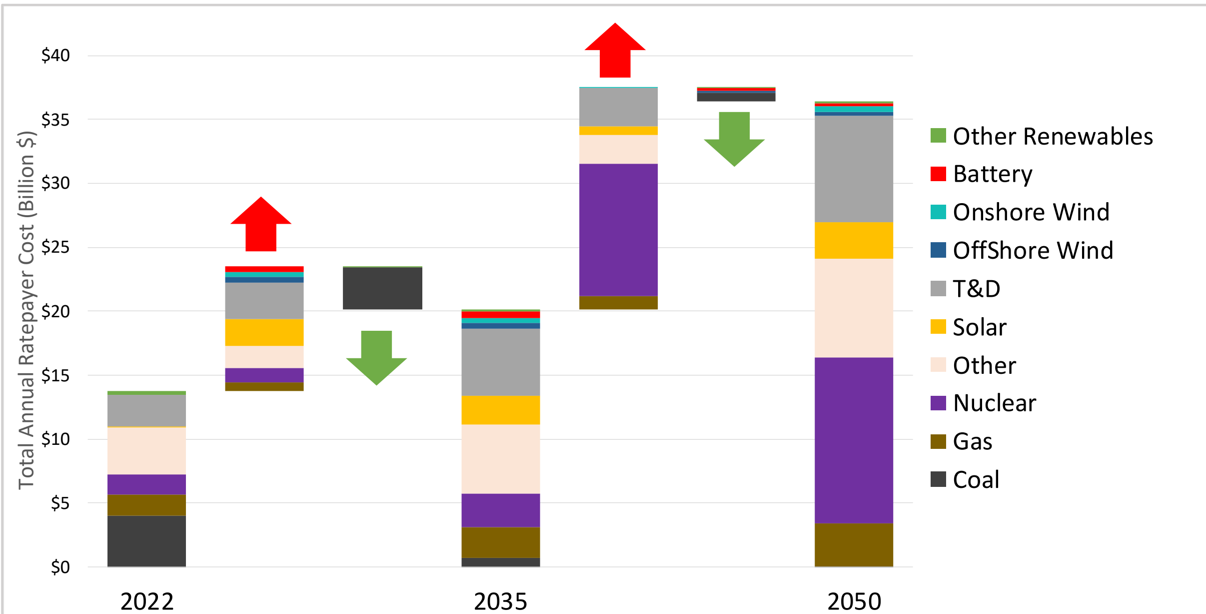
(Billion $)	**Duke Resources**
NPVRR through 2035	143.9
NPVRR through 2050	244.4

Figure 2 breaks down the annual ratepayer cost impact by technology and showcases the key drivers of the total cost increase. Gas and nuclear are significant drivers of the total

[19] This finding is agnostic of PBR policies enabled by H951 and potential federal policy enhancement but does reflect the current ITC and PTC federal policies.

ratepayer costs in the Duke Resources scenario.[20] This is a reflection of the generally high cost associated with these resources. ***Figure 2*** also shows factors that drive ratepayer cost reduction. Coal cost decreases over time are related to coal plant retirements, or to fuel switching for plants with co-firing capability. Battery cost decreases by the end of the modeling period are a result of battery storage deployed in 2030 reaching the end of its accounting life and being replaced by either much cheaper batteries (due to technology cost declines) or by other resources deployed before the batteries' end of life. Moreover, there is significant cost uncertainty associated with both small modular nuclear (SMR) technology and the conversion of gas to hydrogen given that neither has been commercially scaled to date, which is not reflected here.

Figure 2. Annual Ratepayer Cost Comparison of 2022/2035/2050 in the Duke Resources Scenario



In particular, near-term investment in gas capacity introduces significant risks to ratepayers by locking in significant capital costs that will either be converted to hydrogen (at uncertain cost) or, if the conversion does not pan out, will be depreciated more quickly, translating to higher costs for ratepayers. Should the Commission allow, RMI can conduct a supplemental Optimus analysis to examine **whether an alternative portfolio that relies less on new gas plants and new modular nuclear plants would present a lower total cost with less uncertainty for ratepayers.** RMI is able to analyze and compare

[20] The "Other" category depicted in ***Figure 2*** includes investment in energy efficiency, purchases, and non-production expenses. Non-production expenses grow proportional to sales, load, and operational expenses. In a scenario where more efficiency and demand-side management are deployed, the Other cost category would decrease proportionally.

alternative portfolio scenarios to examine the differential total ratepayer impacts using Optimus once those alternative portfolio scenarios are completed.

2. Total ratepayer costs of the Duke Resources scenario are distributed unequally across ratepayer classes.

> **Disclaimer**: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

Under the current cost causation framework,[21] the Duke Resources scenario disproportionately saddles residential customers in the DEC territory, and industrial customers in the DEP territory, with larger average bill volatility.

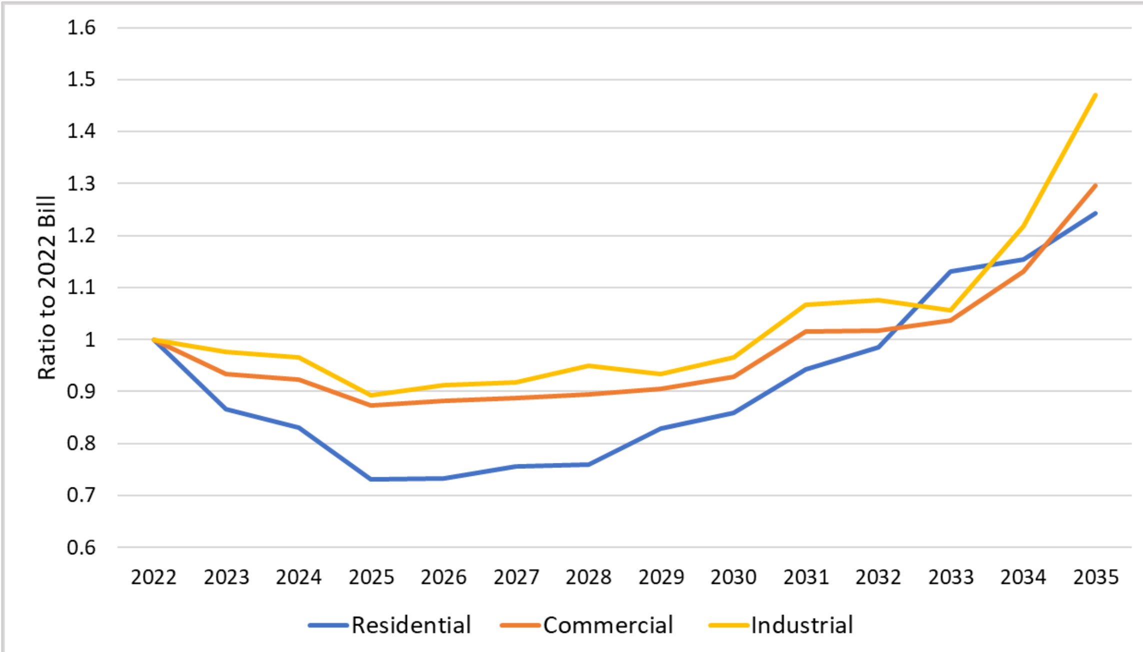
Figures 3 and 4 illustrate how DEC and DEP average monthly bills for each customer class would change over time relative to 2022 average bills under the current policy framework (absent PBR and securitization).

For DEC, the Duke Resources scenario maintains roughly parallel paths for average residential, commercial, and industrial bills through 2027. After that, the Duke Resources scenario results in a steeper "take-off" of residential charges relative to other classes' bills beginning in 2025. After 2032, when DEC sees generation increase from both gas-fueled and carbon-free resources, average commercial and industrial (C&I) bills also increase sharply. In 2035, average commercial, industrial, and residential bills, would be 48%, 30% and 24% higher than 2022, respectively.

The Optimus model shows a near-term decrease in bills, especially for the residential class. This results from (1) the cost allocation framework as exposed by Duke's rate structures, and (2) a precipitous decline in natural gas costs in the near term. In terms of cost allocation, the only additions to rate base between 2022 and 2027 are maintenance capex of existing transmission and distribution assets, which are costs heavily related to demand and thus borne more heavily by C&I customers. As for the natural gas price projection, the unit prices of the fuel drop to half of 2022 prices by 2025. Appendix A.9 provides further details on the natural gas price assumptions used in the model.

[21] *See* Appendix A.7, which lists the information sources that informed RMI's analysis in this section.

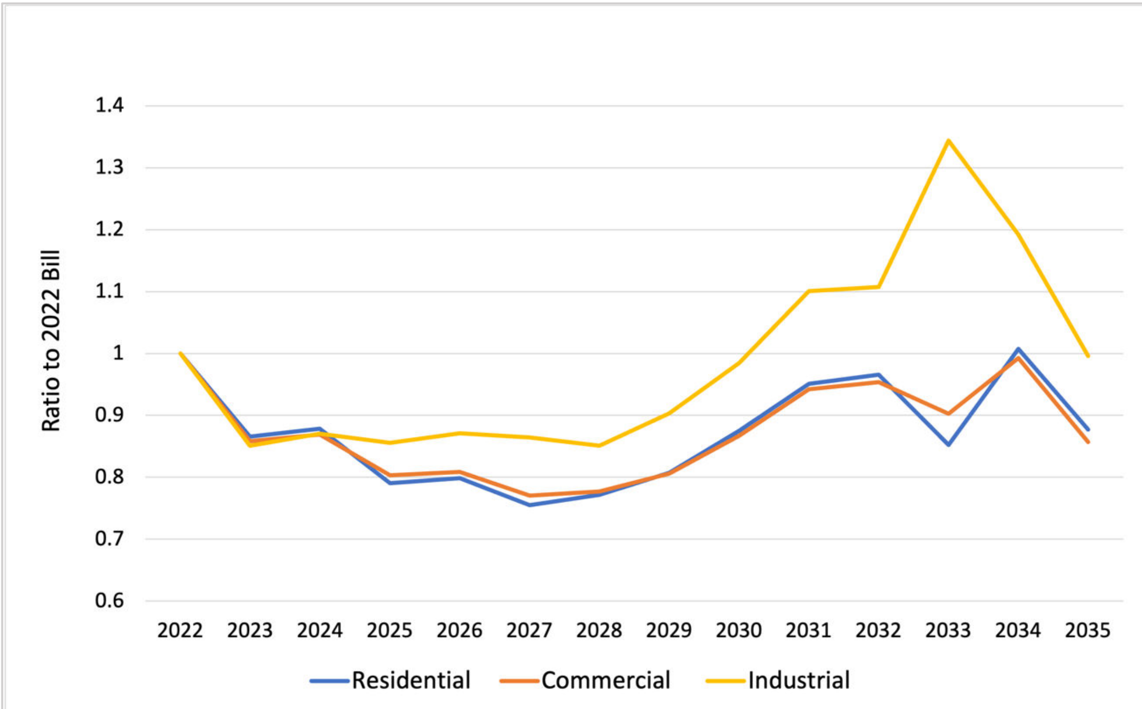
Figure 3. Average Monthly DEC Bill Change by Customer Group for Duke Resources Scenario



For DEP, the Duke Resources scenario yields rapidly increasing residential, commercial, and industrial average bills starting in 2028. In 2027, the paths for average bills between industrial, residential and commercial classes sharply diverge, with industrial customers disproportionately bearing the brunt of the total cost of the portfolio. Discrepancies in other specific years (for instance, 2033) result from costs incurred at the level of the whole balancing area or company included in EnCompass modeling that are hard to disaggregate with the limited information made available; the general trends in bills and the direction of the results are robust results regardless of single year discrepancies introduced by the quality of the data.

Between 2027 and 2032, when portfolio expansions are most crucial to meet carbon reduction requirements, different customer classes see larger increases in their average bills than others. In DEC, *residential* customers incur a disproportionate share of the portfolio expansion costs between 2027 and 2032. In DEP, *industrial* customers see the disproportionate share from 2024 onwards with increasing volatility over the years. After that, parallel trajectories are seen in most customer classes for both utilities. This inverse dynamic is driven by the interaction of resource portfolio differences and the cost allocation framework. In the Duke Resources scenario, DEC has more gas generators combined with slow retirement of coal units and addition of renewable resources. In contrast, DEP's resource portfolio sees faster renewable resource additions. Renewable resources are associated with a higher proportion of capital expenses whereas gas and coal-fired units have higher proportions of variable costs, largely attributable to fuel. The cost causation framework used by Duke (see the Appendix for an explanation of how this cost causation framework was derived using publicly available data) collects a higher proportion of capital expenses from industrial customers, through demand charges, whereas energy charges are paid for more by residential and commercial customers.

Figure 4. Average Monthly DEP Bill Change by Customer Group for Duke Resources Scenario



Given the disproportionate burden placed on residential customers in DEC and industrial customers in DEP associated with the Duke Resources scenario, RMI can conduct a supplemental Optimus analysis to explore **whether an alternative portfolio more equitably distributes costs amongst the different ratepayer classes**. RMI hypothesizes that a cleaner alternative portfolio would more equitably distribute costs to the extent that the breakdown of energy-, demand- and customer-cost components resulting from the alternative resource portfolio is parallel to Duke's rate structure allocation. Further analysis of alternative resource portfolios in Optimus can provide a substantive basis to explore whether Duke's cost allocation methodology should be adjusted to be closer to cost causation, while balancing the impact across classes through rate cases.

3. New gas capacity is not a cost-effective hedge against fuel price shocks – but accelerating renewable deployment could be.

Unlike the other findings, some of the key results in Finding 3 were verified against Duke Energy's own EnCompass results. As such, the disclaimer found in other sections does not apply here.

RMI's analysis shows that investing in new, more efficient gas combustion turbines (CT) and combined cycle (CC) units to replace existing fossil assets is not a cost-effective hedge against fuel price shocks for ratepayers. The incremental additional capital costs required for Duke's proposed near-term investment in gas generating capacity far outweighs the potential hedging value of more efficient gas capacity, relative to less efficient co-fired units, even in extreme high fuel-cost scenarios. However, RMI presents evidence that **deployment of additional solar, storage and wind to avoid fuel utilization is likely a no-regrets solution to limit ratepayer exposure** to the risks of:

1. Globally driven fossil fuel price volatility, particularly if natural gas supplies remain constrained over the near and medium-term,
2. Uncertain future cost and performance challenges associated with the potential conversion of gas CC and CT units to hydrogen, and
3. Accelerated cost recovery of any natural gas infrastructure that is no longer needed upon such conversion.

RMI modeled a fuel price "shock" in Optimus which assumed that fuel prices for gas and coal unexpectedly double (100% higher) for a single year relative to Synapse's assumed long-term fuel prices. Given recent global fuel market trends,[22] such a shock is well within the realm of possibility, even if Duke has implemented strategies to hedge against fuel price risks. A shock of the modeled magnitude will generally be difficult for a utility to contain with operational adjustments alone. With greater financial hedging of fuel risks, ratepayers might reduce volatility exposure in exchange for heftier insurance premia. But even if expanded hedging contracts could be secured,[23] counterparty default risk in the event of a major fossil fuel shock would be considerable.

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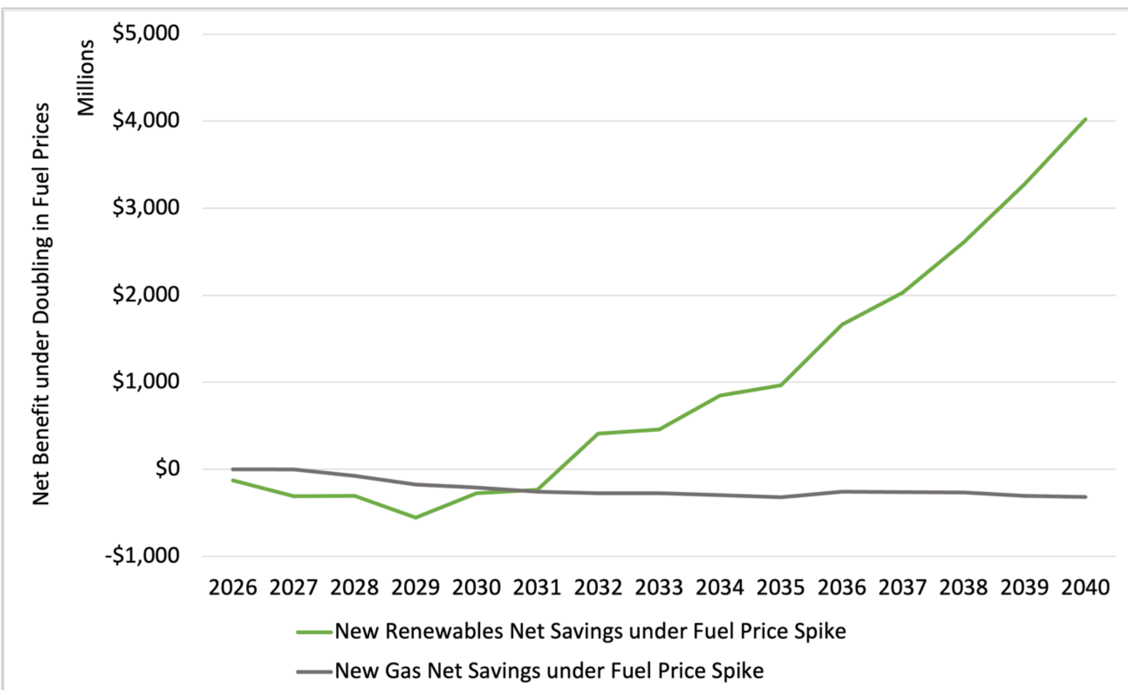
[22] See the coal and gas price chart included in Appendix A.8.

[23] See Direct Testimony and Exhibits of Gregory M. Lander on Behalf of The Sierra Club," In the Matter of: Application of Duke Energy Carolinas, LLC Pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities, DOCKET NO. E-7, SUB 1263, DOCKET NO. E-7, SUB 1263, 12.

In order to assess the cost-effectiveness of the deployment of more efficient gas CT and CC units to hedge against fuel price shocks, RMI compared the capital, fuel, and operating costs under a high fuel price sensitivity in the Duke Resources scenario to a counterfactual case without those units, instead utilizing existing, less efficient generators. RMI analysis of Duke's Encompass results show that the potential savings to ratepayers from the utilization of more efficient new gas generation in the event of a 100% price spike never exceeds the incremental capital and operating costs of the new gas facilities. Even in 2029, the year with the greatest potential savings from gas plant efficiency gains, a price spike of nearly 500% would be necessary to see a net hedging benefit from switching to new gas units. Thus, new gas units do not meaningfully provide a cost-effective hedge against high fuel prices.

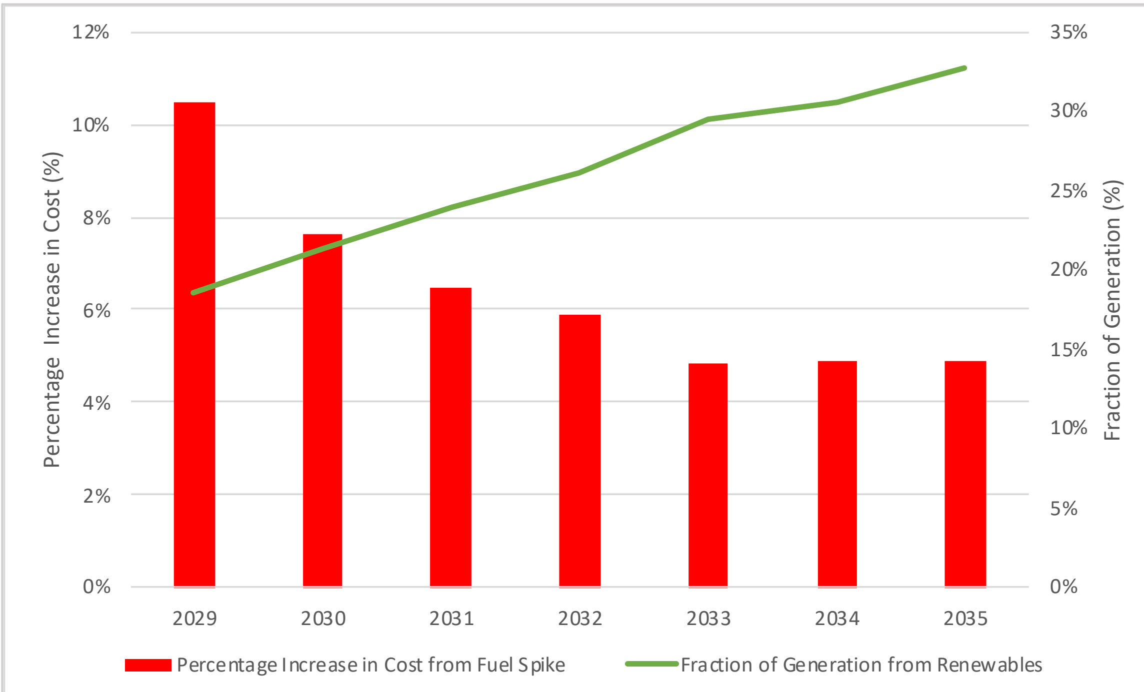
In contrast, when RMI performed a similar analysis of **all renewable assets deployed in the Duke Resources case from 2026 onwards, net hedging benefits in the event of a 100% price spike were seen for every year starting in 2032** (see ***Figure 5*** below)**.**

Figure 55. Net savings or costs from the deployment of new gas or renewables relative to continued operation of existing fossil assets under a fuel price shock in each year



Moreover, RMI found evidence that the decrease in dependence on fossil fuels tied to greater deployment of renewable energy that fully displaces fossil fuel use is correlated over time with lower ratepayer exposure to fuel price shocks. Fossil fuel operating costs in the absence of a fuel shock represent roughly 7% of the total ratepayer costs in DEC for the Duke Resources scenario in 2029 through 2035 and 9% in DEP. When a single-year fuel cost spike is introduced in Optimus in each of the years from 2029 through 2035, there is a decreasing relative impact of the shock on ratepayer costs over time, roughly in direct proportion to the increase in the fraction of generation from renewable sources (see **Figure 6** below).

Figure 66. Annual Generation and Costs under Single-year Fossil Fuel Cost Spike Sensitivity (2029 through 2035)



Ultimately, these findings provide evidence that economic capacity expansion modeling alone falls short of tabulating the tradeoffs between capacity costs and risks of fuel price volatility.[24] Optimus modeling can provide support to inform consideration of the best resource composition to insulate ratepayers from fossil fuel price increases, hedging premia, and hedging counterparty default risk using alternative scenarios as a point of comparison. For example, should the Commission allow, RMI can conduct a supplemental Optimus analysis to investigate **whether an accelerated deployment of solar, battery storage, and wind resources in the near and medium term would be a more cost-effective hedge against future fuel price volatility**.

[24] This is true not just for EnCompass, but all traditional capacity expansion models.

4. The Duke Resources scenario underutilizes securitization as a source of ratepayer relief to mitigate rate spikes from early coal retirement.

Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

As described above, securitization mitigates the rate spikes that would otherwise be associated with retiring a coal plant early. It does so by avoiding the use of accelerated depreciation schedules to recover the remaining book value of a plant. In addition, securitization further lowers costs by replacing expensive equity with lower cost debt.

The Duke Resources scenario constrains the magnitude of potential cost savings from securitization that could be passed onto Duke's customers due to exogenous determinations Duke made in selecting the retirement year of certain plants in its proposed portfolios. RMI modeled a baseline for securitization savings aligned with Duke's proposed retirement schedule and issuing ratepayer-backed securitization bonds upon plant retirement for 50% of the unrecovered balances of subcritical plants not yet retired.[25] If not securitized, unrecovered balances were treated as regulatory assets and received the same rate of return as in-service assets.

RMI estimates that the Duke Resources scenario would result in approximately $14.1 million in savings for ratepayers as a net present value (NPV) in 2022 dollars. RMI also modeled the securitization of 50% of all unrecovered balances following a retirement of all subcritical Duke coal plants at the end of 2022 and estimated an additional $446 million in savings (NPV, 2022$) for ratepayers.[26] Of the total incremental securitization savings, $238.3 million would be attributable to DEC plants and $207.8 million to DEP plants. From this perspective, the Duke Resources scenario captures only 3% of the ratepayer savings available from securitization under H951.

For informational purposes, RMI also modeled a securitization scenario outside the limits of H951. If all unrecovered balances from all Duke coal plants, including the supercritical

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[25] The retirement years for each plant in the Duke Resources scenario are presented in the appendix.

[26] This calculation assumed "AA"-rated bonds priced off July 2022 US Treasury Yield Curves and issued in tranches for tenors stretching through the final recovery dates of the various coal asset balances as proposed by Duke.

Cliffside 6 and the recently retired G.G. Allen units), were securitized at the end of 2022, ratepayer savings from such a refinancing could reach $1.26 billion (NPV, 2022$).

The Duke Resources scenario leaves extremely large securitization benefits — which could be passed along to ratepayers to mitigate the cost of the transition — off the table. Should the Commission allow, RMI can conduct a supplemental Optimus analysis to review **whether an alternative scenario that enables an earlier retirement of coal assets than Duke projected will translate into greater total ratepayer savings** for the Commission's consideration.

5. The Duke Resources scenario leaves ratepayers vulnerable to rate de-stabilization from large increases in load growth and fuel prices.

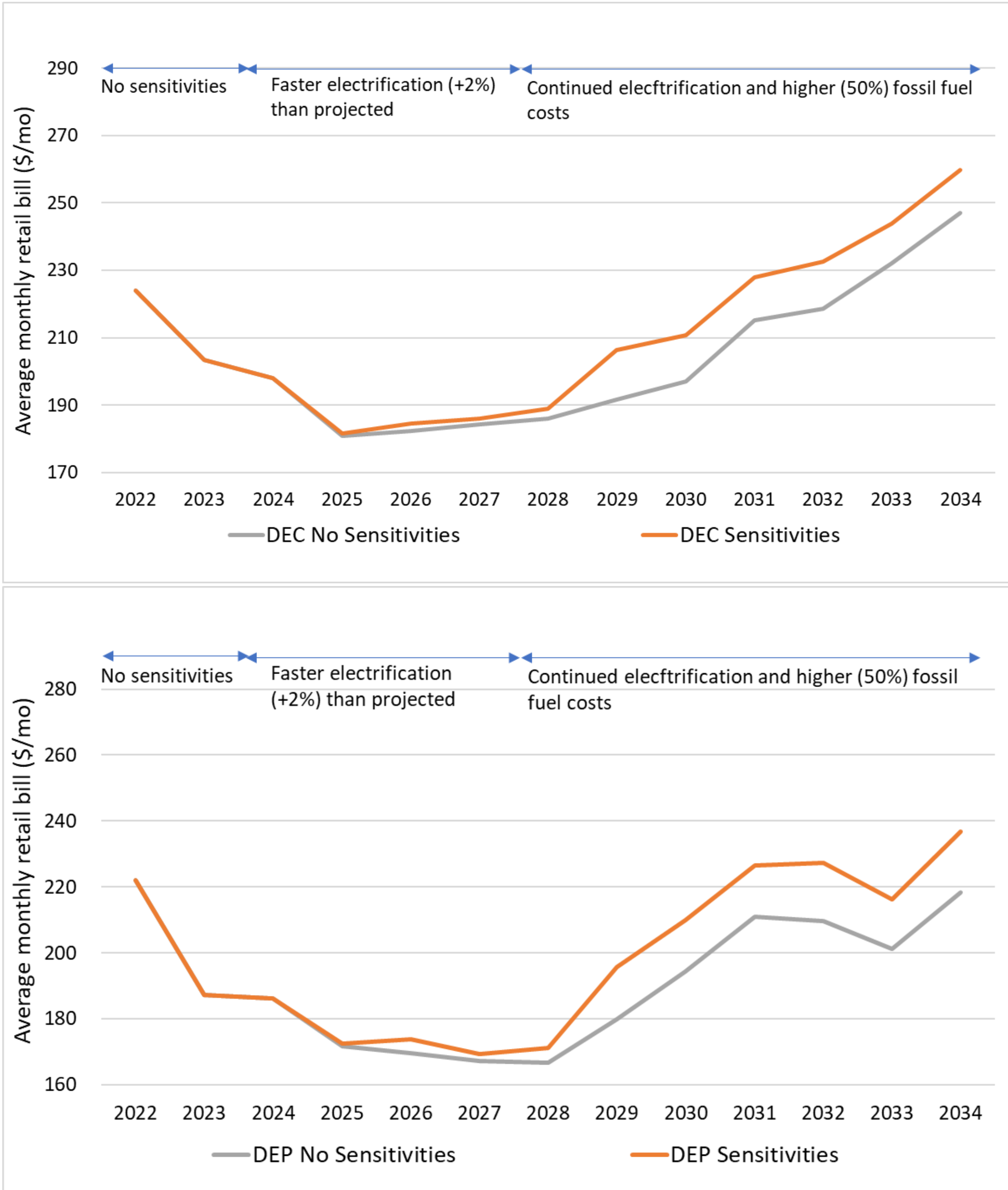
Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

Transportation and building electrification will be key drivers of load growth in the Duke territory, which reinforces the need to prepare the system for a higher penetration of demand-side resources. Unexpected and unprepared for higher load could drive up the cost for all ratepayers where more fuel-dependent resource portfolios are present. This finding is exacerbated when a fuel price increase sensitivity is layered in.

Figure 7 illustrates the average normalized rate over time when a prolonged, 50% increase in fuel price occurs from 2029 through 2035 along with a 2% faster load growth and compares it to the baseline Duke Resources scenario without Optimus sensitivities. [27] DEC, which has a significant proportion of fuel-consuming resources, sees average monthly bills increase steadily. In DEP, higher electrification coupled with fuel price sensitivity increases average ratepayer bills by 4% (in 2022$) on a present value basis.

[27] The 2% faster load growth sensitivity is roughly 0.5% higher than Duke's high-load projections and high EV adoption rates. RMI selected 2% faster load growth because of uncertainty in the timing of the adoption of EVs. See the section on load growth assumptions in Appendix A.5 for a full explanation and a plot comparing the load projections.

Figure 77. Normalized Ratepayer Bill Sensitivity to Higher Electrification and Fuel Price Shock



Should the Commission allow, RMI can conduct a supplemental Optimus analysis to understand ***whether a higher penetration of fuel-free resources will temper the impacts of a fuel price shock in a high-load future scenario.*** It is reasonable to assume that it would because a greater portion of demand would be satisfied with capital assets that are essentially fixed in cost and independent of the generation output. Optimus analysis of an alternative scenario can help to validate or disprove the extent to which this hypothesis is realistic and feasible for North Carolina.

Though not quantified in this analysis, there are also likely significant additional benefits from leveraging demand side resources, including demand response and energy efficiency, to mitigate the rate impact of higher load driven by EVs and building electrification. Compared to the fossil-dependent resource portfolios proposed by Duke, a portfolio of resources that can better leverage and realize the synergistic benefits of demand-side resources on the entire electric and gas distribution systems can add flexibility and lower the total cost of the portfolio.

6. The implementation of MYRPs and revenue decoupling as specified by H951 would exacerbate the rate impact of higher-than-expected demand and fuel prices relative to a scenario without these mechanisms in place.

Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

RMI's modeling of a multi-year rate plan (MYRP) and residential decoupling in Optimus for the Duke Resources scenario reveals that ratepayers are even more vulnerable to inflated rates in the medium and long term than they would be without these PBR mechanisms.

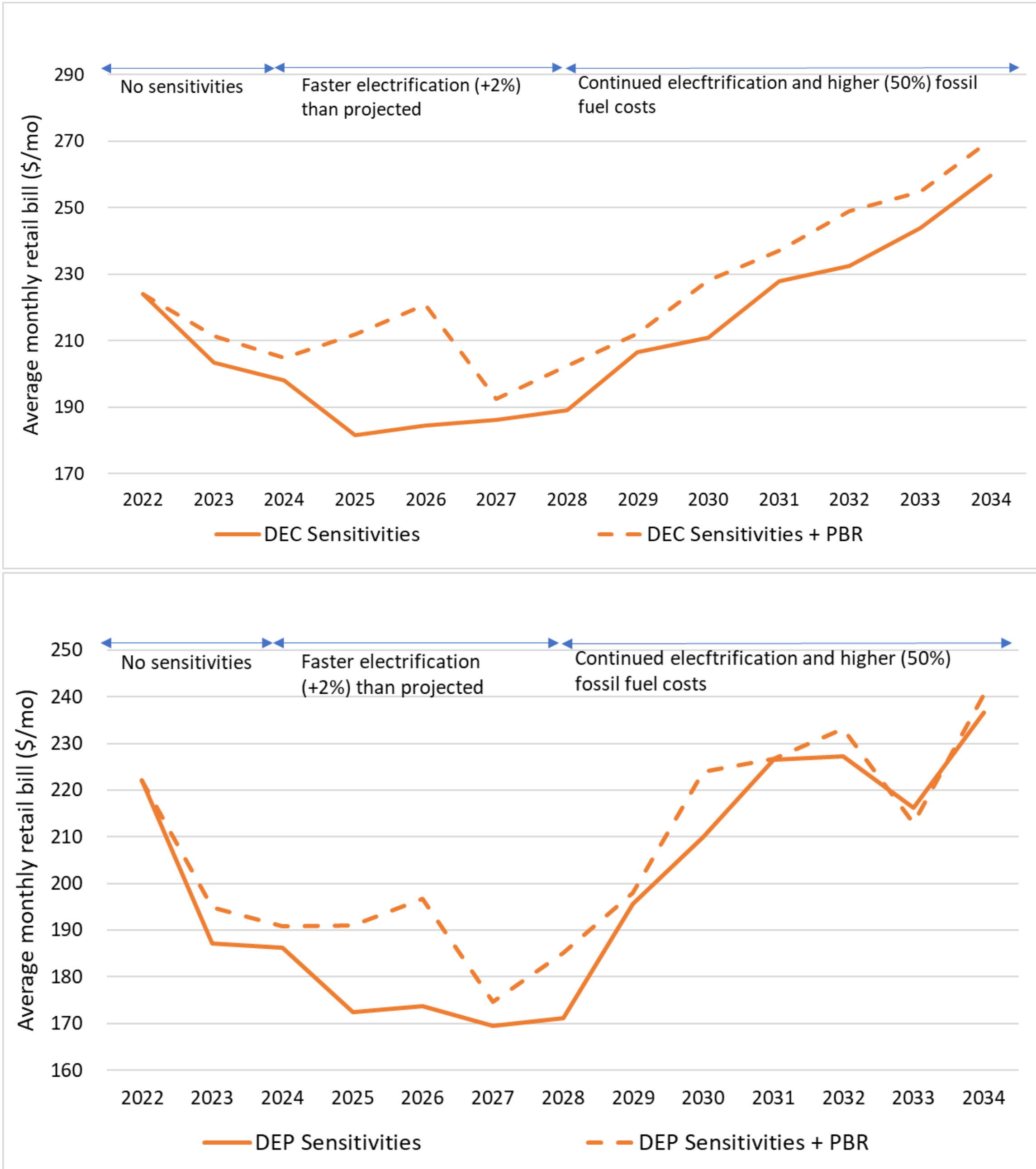
RMI modeled a MYRP and residential revenue decoupling applied to the higher load growth and fuel cost increase sensitivities. The results indicate that in 2035 the Duke Resources scenario would result in 26% and 16% higher average retail bills for DEC and DEP, respectively, compared to 2022 bills. Design parameters for a MYRP and decoupling mechanism that incentivize rates closer to the actual cost to serve customers would have resulted in an increase in average retail bills in 2035 of 16% and 7% for DEC and DEP, respectively, compared to 2022 baseline bills.

RMI attributes these cost increases to the H951 specifications regarding the use of forecasted costs to set the revenue allowance (instead of a historical base year). In MYRPs that use forecasts, portfolio scenarios that include higher mixes of fuel- or variable cost-dependent resources will motivate the utility to conservatively estimate costs in forecasts to account for fuel price uncertainty and volatility.

Figure 8 illustrates the effects of a MYRP and revenue decoupling mechanisms paired with high electrification and fuel cost increase sensitivities on average bills. In the DEC example, the MYRP 4% revenue adjustment mechanism[28] would compound an already higher level (50%) of fuel cost projection. Presumably, this phenomenon would occur to a much lower extent with a portfolio comprised of a higher proportion of renewables. This is yet another question that Optimus can explore with an alternative resource scenario as a counterfactual to the Duke Resources scenario; Should the Commission allow, RMI can conduct a supplemental Optimus analysis to examine ***whether PBR could provide a stronger incentive for the utility to control operating costs when applied to an alternative resource portfolio.***

[28] As prescribed in H951, the utility is allowed to increase revenues between years within a MYRP up to a maximum of 4% of the revenue requirement used to set rates during the first year of the rate plan. SL 2021-165 sec 4(c)1.a

Figure 88. Impact of MYRP and Decoupling under High Electrification and Fuel Cost Increase Scenarios



In addition to examining a less fuel-dependent portfolio for the Carbon Plan, the NCUC can leverage its discretionary authority to protect ratepayers from the potentially compounding effects of the MYRP design specified by H951. In the process that determines the justifiable costs for the MYRP, the Commission can foster transparency that will allow intervenors and the Commission the opportunity to closely examine proposed costs, including the effect of riders. Finally, the Commission could consider expanding targeted programs for low-income customers to mitigate any potential impacts on already burdened customers.

7. If implemented, federal policy changes in the next decade will present significant cost savings opportunities that can be passed to ratepayers; the Duke Resources scenario would capture $5.4 billion.

> **Disclaimer**: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

The suite of enhanced federal policy levers for renewables, as detailed in Appendix A.2, could dramatically lower the costs associated with a cleaner scenario. The Duke Resources scenario could realize cumulative annual ratepayer savings of $7.7 billion in 2035, and net present value savings of $5.4 billion. It is unclear in relative terms how much additional ratepayer savings could be realized without comparison against an alternative scenario.

Assuming a non-zero probability of the policy enhancements RMI modeled, renewables have an "option value" for both Duke and ratepayers. No such value reasonably attaches to fossil plants since the likelihood of major new federal tax credits for these technologies is negligible. The option value of clean scenarios should be considered in Carbon Plan decision-making as a benefit to rate payers that would be lost or diminished if Duke's Carbon Plan proposals are selected.

Conversely, there is a "risk value" associated with the potential for policies that will penalize the utilization of, or investment in, fossil fueled resources. Though not analyzed in this report, the risk value of more stringent policies will similarly be passed along to ratepayers and should be considered alongside any portfolio that relies on fossil-fueled generation assets.

Figure 9 and ***Figure 10*** below show the annual and total ratepayer cost impact with and without state and federal policy changes for the Duke Resources scenario. Coal plant securitization on an annual and NPV basis, as discussed in Finding 4, yields limited savings under the requirement of H951. In ***Figure 9***, the difference between the annual ratepayer costs is negligible with and without securitization. Federal policy enhancements could be a more significant source of costs savings through provision of tax credits for deployment of zero-emission resources.

Figure 99. Annual Ratepayer Cost Impact with and without Federal Policy Changes

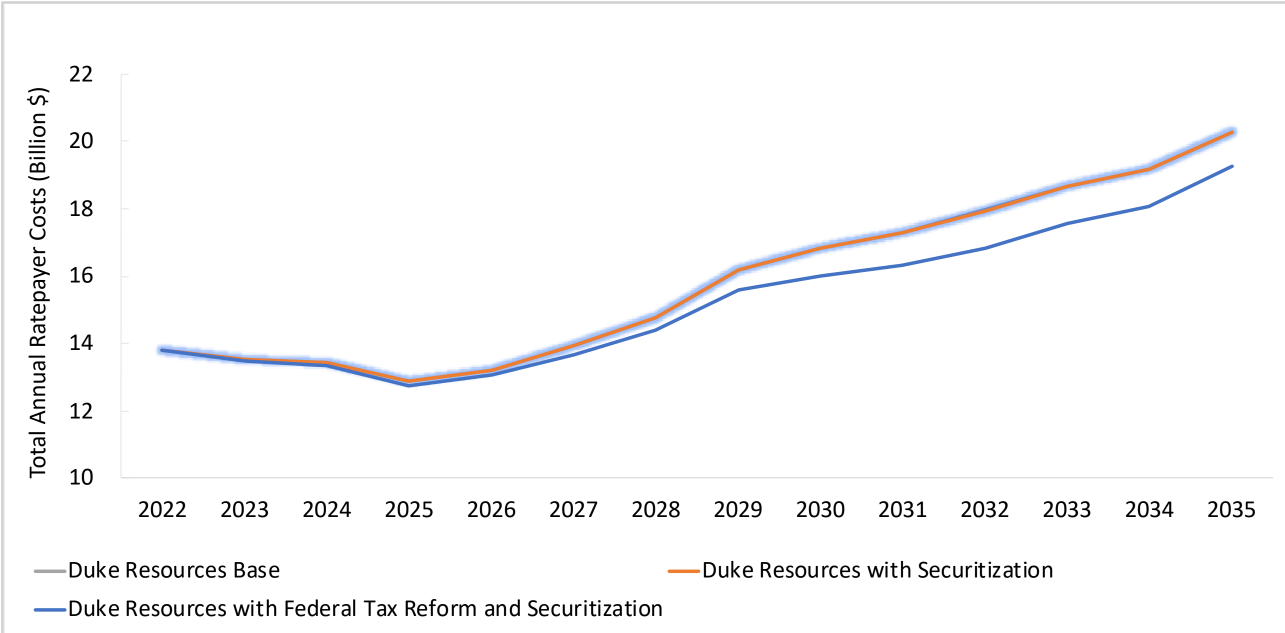
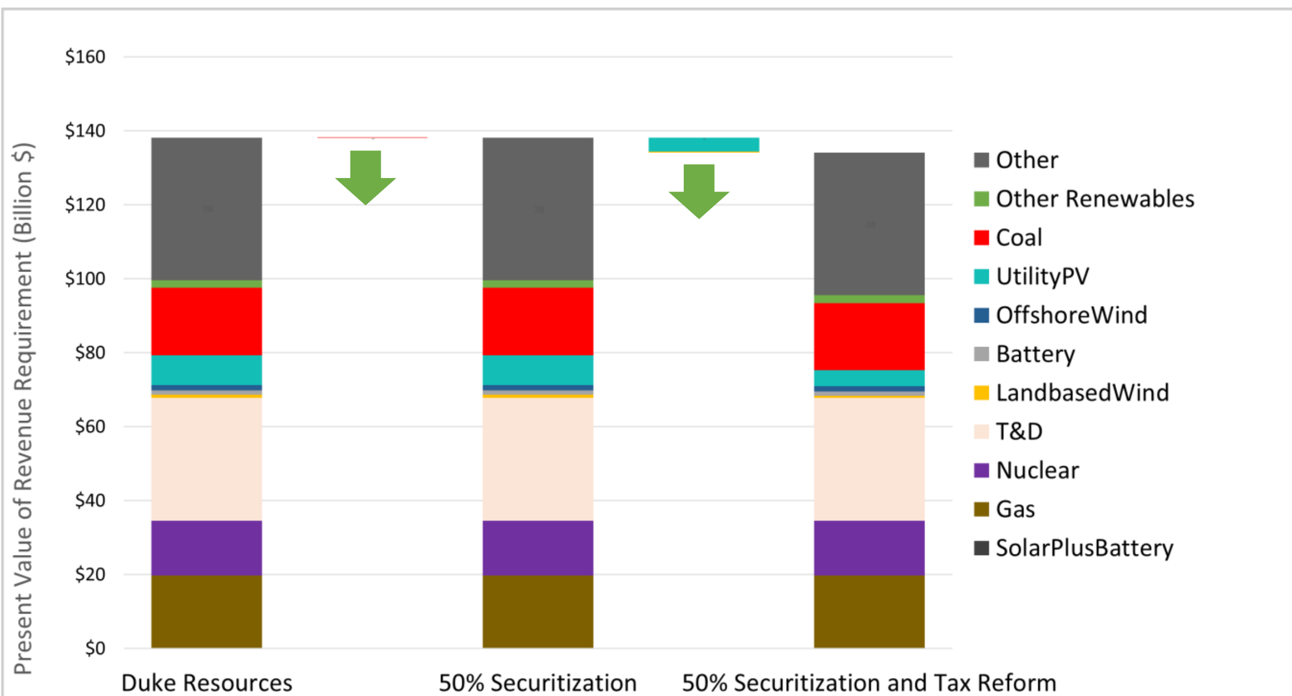


Figure 1010. Total Ratepayer Cost Comparison with Securitization and Federal Policy Changes



Implications and Recommendations for Future Carbon Planning Efforts

General Implications of this analysis

The analysis included in this report supports the conclusion that the P1-Alt scenario proposed by Duke Energy in its Carbon Plan presents considerable risks to ratepayers that are not captured by EnCompass modeling. This suggests that further analysis of alternative portfolio scenarios may be warranted to identify a different and more optimal least-cost Carbon Plan that can achieve both the 2030 and 2050 targets while better balancing the trade-offs of known capital costs with macro-economic, policy, and forecasting uncertainties. A variety of sensitivities modeled on the Duke Resources scenario provide a baseline for further analysis and comparison. Further analysis should explore whether an alternative cleaner resource portfolio that relies more on solar, storage, and wind than the ones proposed by Duke Energy could be more resilient from a ratepayer cost perspective to the uncertainty of future fuel prices, electricity demand, and policy and regulatory changes.

Conventional wisdom has long held that the CapEx intensity associated with portfolios that contain higher concentrations of zero-emitting resources makes them more costly relative to gas-heavy portfolios. However, this truism may be at an inflection point considering the following dynamics:

- Existing and increasing future price risks for the entire fuel requirement may outweigh the efficiency gains of new gas-fueled assets, undermining the rationale for the incremental CapEx costs for these carbon-emitting resources;
- Securitization and PBR can smooth out the cost of the transition for ratepayers and encourage cost efficiency on the part of the utility, but investment in fuel-dependent resources may diminish the efficacy of these cost-containment mechanisms; and
- Existing federal policy provides the opportunity for near-term savings associated with new wind and solar capacity that the Duke Carbon Plan scenarios largely bypass, while potential future federal policy enhancements are more likely than not to degrade the economics for fuel-dependent resources.

This analysis suggests that it would be unwise for the NCUC to determine North Carolina's Carbon Plan without:

- Analyzing the potential recurrence of destabilizing macro-economic and socio-political disruptions, such as those that the global economy has experienced in the last two years, and the downstream impacts these events may pose to ratepayers — collectively, and by class — under various Carbon Plan proposals (e.g., the risks associated with increasing and potential volatile fuel costs, and uncertain fuel availability uncertainty);

- Considering the potential impacts on the distribution of benefits and risks that are associated with forthcoming coming regulatory changes (e.g., PBR) in combination with each portfolio;
- Examining the impact of a fully economic retirement schedule (such as a scenario that allows EnCompass to select the economic retirements without exogenous limitations) inclusive of and considering the associated benefits of securitization; and
- Weighing the potential benefits and risks posed by federal policy changes, and downstream ramifications for ratepayers (in terms of lost or accrued "option" and "penalty" values).

With further study of alternative scenarios, RMI analysis using Optimus can support the exploration of the above considerations holistically and contribute to the selection of a Carbon Plan that appropriately balances near-term investment decisions with their associated risks, thereby achieving a more optimal, cost-effective path from a ratepayer perspective. Additional time would also enable an exploration of the impact to the utilities' earnings from the Duke Resources scenario compared to alternatives.

The consequences of PBR as stipulated by H951 *may* mitigate costs to ratepayers but could possibly inflate them. Commission scrutiny, provision of a transparent process, and leveraging all discretionary tools within its disposal can be used to ensure that multi-year rate plans are mutually beneficial for ratepayers and the utilities.

Recommendations for Future Carbon Planning Efforts

To better improve upon and replicate the analysis contained herein for future iterations of the Carbon Plan, RMI offers the following recommendations for the Commission's consideration:

1. The Commission should require Duke to use ***the full revenue requirement to estimate ratepayer costs*** (instead of just the forward-looking incremental costs, which treats expenses associated with the existing electric fleet as a foregone conclusion). This will better reflect the cumulative impact on ratepayers and help the utility, the Commission, and intervening parties identify opportunities to reduce the cumulative costs of each portfolio scenario, including early retirement with refinancing options such as securitization or depreciation schedule adjustments of regulatory assets.

2. The Commission should require Duke to ***provide disaggregated cost projections associated with both existing assets and incremental additions for each portfolio scenario***. Such disaggregation must differentiate maintenance capital expenditures and transmission-related levelized fixed charge rates from fixed O&M costs. This will enable Duke, intervenors, and the Commission to understand and accurately reflect projected rates and bills trajectories, as well as the full potential benefits of mechanisms such as securitization.
3. Using Duke's cost-of-service methodologies, functional allocation of costs results in marked differences in impacts across customer classes for different resource portfolios. The Commission and interested parties should be aware of these varying impacts across classes. As such, ***the Commission should require Duke to estimate rate impacts for each customer class*** in addition to an average value (across all ratepayer classes) in its carbon plan filings.
4. The use of the weighted average cost of capital (WACC) in net present value (NPV) calculations does not holistically reflect the impact of regulatory accounting and utility finance. The Commission should ***consider requiring Duke to utilize a more nuanced approach to discounting the NPV and apply a rate of return on the full revenue requirement*** to yield more accurate NPV estimates for each portfolio.
5. The Commission should consider requiring Duke to ***make each of the following financial line items available in a disaggregated format*** to intervenors in future Carbon Plan updates:
    a. For incrementally added assets, for each scenario:
        i. The associated installed costs before and after AFUDC and CWIP are considered
        ii. A breakdown of how the company expects to spend the installed cost associated with each incrementally added asset over its construction period
        iii. Book depreciation, tax depreciation, book values, accumulated deferred incomes taxes (ADIT), and property taxes over time, by asset
        iv. Any cost adders that should be considered capital expenditures per accounting principles, but are incorporated as O&M costs for EnCompass modeling purposes
    b. For existing assets:
        i. Most current net plant balance, and any capex that will add to the book value of these over the planning period
        ii. Book depreciation, tax depreciation, book values, ADIT, and property taxes over time, by asset
        iii. Decommissioning and asset retirement costs
    c. Separate fixed and variable charges for purchased power for current contracts, with an indication of which of these would be incurred regardless of the dispatch of resources associated with the purchased power (i.e., "take-or-pay")

d. For purchased power additions (such as 3rd-party-owned solar), a separate calculation of costs utilizing project finance (as opposed to utility finance) methodologies, and earmarked as such
e. A breakdown of any costs incurred at any level above a resource (for instance, costs at a balancing area level or at a company level like contract costs or ancillary purchases) included in the capacity expansion or production cost modeling, and how these relate to the resource selection
f. A detailed calculation and associated breakdown of any costs bucketed as "Other Costs" in EnCompass modeling

Appendix

A.1 Optimus Modeling Steps & Key Metrics

RMI imported the EnCompass results from Synapse's replication of Duke's P1 scenario, the Duke Resources.[29] Optimus was then used evaluate Duke's P1 scenario on a variety of metrics for measuring ratepayer cost, utility earnings, and utility shareholder impacts for the Carbon Plan planning period of 2022-2050. ***Figure 11*** below provides an overview of the analytical steps in Optimus.

Figure 11 11. Optimus Analytical Steps

Step 1: Import EnCompass results from Synapse scenarios

- Physical plant characteristics and retirement dates
- Load demand projections
- Annual resource and capital costs

Step 2: Import utility data

- Depreciation schedules
- Rate structures
- Allowed rate of return

Step 3: Ensure consistent results between EnCompass and Optimus

Step 4: Run analysis for each EnCompass scenario to assess and compare key metrics for risks and benefits

Step 5: Run policy and sensitivity scenarios on each EnCompass scenario

- Extreme fuel price shock
- Securitization of retiring fossil fueled units
- Multi-year rate plan and revenue decoupling
- Expansion of federal policies

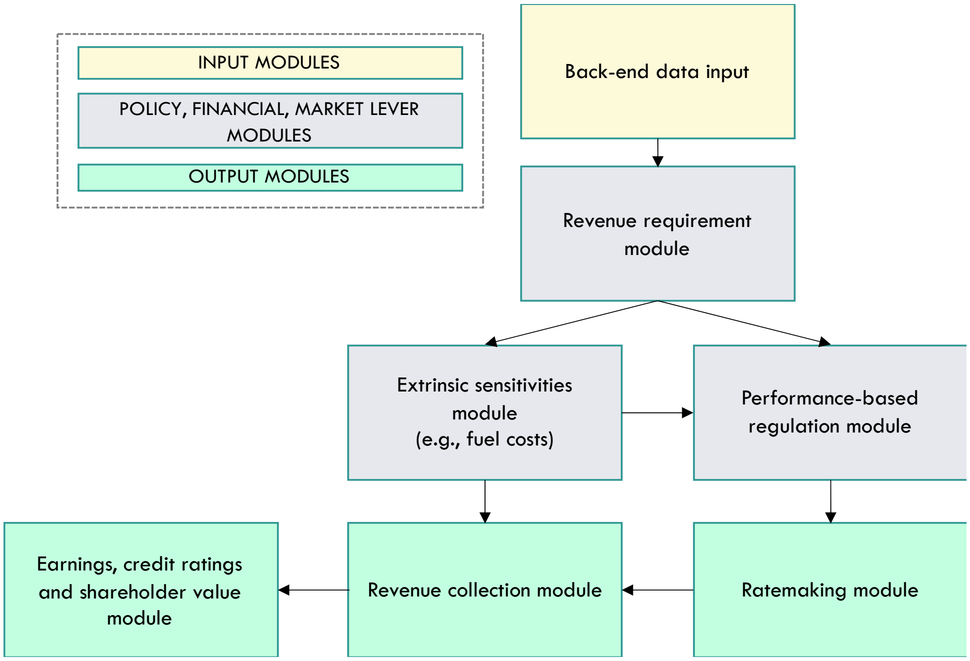
Step 6: Compare results and assess the distribution of risks and benefits

- Full ratepayer costs
- Rates and bill impacts
- Utility earnings and shareholder value assessment

Optimus is comprised of a series of modules that post-process data and perform financial calculations as illustrated in ***Figure 12***.

[29] Optimus takes in the most granular level of Encompass results made available for each scenario: full production cost runs, if performed, or capacity expansion runs otherwise.

Figure 12 12.The Optimus model's high-level architecture



The modules depicted in green in ***Figure 12*** provide data outputs for metrics calculation. The metrics that can be derived from Optimus analysis are provided in ***Table D*** Metric results for resource scenarios and sensitivities analyzed for this report are presented in the ***Findings*** section of the report.

Table D. Optimus Analytical Metrics

Categories	Metrics
Ratepayer cost	• Total ratepayer cost ($) • Average ratepayer cost per MWh consumption ($/MWh) • Average ratepayer cost by residential, commercial, and industrial classes and by fixed, demand, and energy rates ($/MWh) • Incremental average bill impact by residential, commercial, and industrial classes compared to a baseline scenario ($/month)
Utility earnings	• After-tax earnings ($) • Incremental change in earnings compared to a baseline scenario (%)
Utility shareholder impact	• Incremental change in shareholder value compared to a baseline year (% accretion or dilution) • Credit rating impact (Moody's Financial Strength Metrics, Implied Rating, Aggregated Grid Rating Scores)

A.2 Policy and Sensitivity Scenario

The following table describes in greater detail the policy and sensitivity scenarios RMI run in service of this analysis.

Table E. Optimus Policy & Sensitivity Assumptions

Modeled Policies/Scenarios	Description
Existing Federal Policies	The federal Production Tax Credit (PTC) for wind generation is earned for each MWh sold for ten years after facility enters service. The last cohort of facilities eligible for the PTC must enter service by the end of 2025 and have begun construction by the end of 2021. These facilities will be credited with $15/MWh (subject to inflation adjustment from 2019$). Utility-scale solar and associated battery storage facilities are eligible for an Investment Tax Credit (ITC) of 30% of the asset cost if they enter into service by the end of 2023 and 10% if entering service after 2025, with incremental phasedowns of credit percentages for facilities entering service in 2024 and 2025. Stand-alone storage is not eligible for the ITC. The ITC may be claimed for assets owned by regulated utilities but must be normalized. Where Duke and Synapse resource portfolios include facilities that met the criteria for the PTC, the credits were applied as a cost reduction passed through to customers as soon as claimed for tax purposes. For the ITC, the credits for utility-owned assets are passed through to customers over the life of the relevant asset, or "normalized," as required by federal law.
Potential Federal Policy Enhancements	Federal policies are already an influential force on the competitiveness of resources today. As recognition of the necessity to decarbonize the US economy become increasingly mainstream, future federal policies may provide greater rewards for investment in clean electricity resources or introduce penalties (e.g., a carbon price) and/or regulatory requirements that increase the cost of investment in, and operation, of carbon-emitting electric resources. Such new policies could result in significant costs and benefits that for the utility, its shareholders, and ratepayers and thus cannot be ignored, despite their uncertainty. As a proxy for a tangible set of future federal policies that extend existing federal policies in terms of both applicability and duration, RMI modeled key elements of Build Back Better Act (BBBA), or H.R. 5376, that was passed by the House of Representatives in the 117th Congress but which did not secure approval in the Senate. BBBA enhancements modeled in Optimus include: (1) Extend applicability of PTC-type credit to include solar facilities. (2) Wind and solar facilities are eligible for PTC if they begin construction by the end 2031 and are valued at $25/MWh ($10 higher than current and still subject to inflation adjustment from 2019$). (3) Stand-alone battery storage facilities are eligible for 30% ITC if they begin construction by the end of 2031.

	(4) Transmission investments newly eligible for 30% ITC. (5) PTC and ITC are made available as direct pay awards from the US Treasury to entities without sufficient tax capacity to monetize credits in the year earned. (6) Normalization of ITC would not be required. Note: This suite of policy enhancements has been supported by the Edison Electric Institute (EEI), the association of U.S. investor-owned utilities, of which Duke is a member.[30]
PBR Mechanisms	H951 authorized the Commission to approve performance-based regulation applications upon application by an electric public utility. As such, Duke Energy has ability to file multi-year rate plans (MYRP) inclusive of an earnings sharing mechanism, revenue decoupling for residential rate class, and performance incentive mechanisms. Additionally, the same legislation enables securitization of 50% of unrecovered balances when subcritical coal plants are retired early. The consequences of these mechanisms — for ratepayers and the utility — will vary based on the composition of the resource portfolio. RMI modeled the impact of securitizations occurring at the time of a unit's retirement as prescribed in the Duke Baseline. To operationalize the MYRP, RMI assumed application by the utility of the maximum (4%) increase of the base year revenue requirement in each year of the MYRP. For the cost forecast in between rate plans, RMI used capital costs and associated expenses and fixed costs corresponding to the first year of the MYRP, and unit variable costs from one year before the rate plan takes effect applied to the projected system load in the first year of the MYRP. The MYRPs were modeled as taking effect in 2023 and recurring at three-year intervals. H951 gives Duke the *option* to exclude rate schedules/riders for EV charging from the decoupling mechanism. However, EV load in Duke's load projection is combined with other load for each customer classes. Without disaggregation, RMI cannot model EV load decoupling discretely. Instead, our decoupling analysis will focus on two edge cases: • decoupling all load, including EV load, and • decoupling all residential load, including home EV chargers.
Securitization	H951 allows for half of the costs associated with early retirement of subcritical coal-fired electric generating facilities to be securitized.[31] Briefly described, securitization is a refinancing mechanism that uses low-cost debt backed by non-bypassable ratepayer charges to pay off undepreciated plant balances. The utility receives funds

[30] EEI news release from 19 November 2021, available at https://www.eei.org/resources-and-media/energy-talk/Articles/2021-11-eei-welcomes-house-passage-of-the-build-back-better-act

[31] North Carolina G.A., Session Law 2021-165, House Bill 951, 2.

	when the securitization bonds are issued, allowing it to pay off existing creditors and equity contributors. The new securitized debt is an obligation neither of the state nor the company, but rather of all current and future utility customers over the life of the bonds. Securitization legislation typically includes valuable protections for creditors that result in extremely high credit ratings for the bonds — higher than any U.S. utility's current credit rating — and correspondingly low interest rates. Because ratepayers are paying lower interest rates when securitization has been utilized, thereby avoiding paying for the higher returns demanded by equity providers, they realize savings that scale in proportion with the size of the refinanced balances and the duration of the avoided period of traditional utility finance. Securitization transactions have fixed and variable transaction fees, as well as ongoing servicing costs, all of which RMI includes in its modeling. When transaction fees would exceed savings from a securitization, Optimus is designed to use regulatory assets to warehouse plants balances over time in order to reduce the number of bond issuances with their fixed fees. If securitization cannot provide net ratepayers savings, Optimus rejects the transactions. The RMI securitization sensitivity scenario assumes that 50% of the remaining plant balance of each Duke subcritical coal plant/unit is securitized upon future retirement, while the other 50% of the balance remains in the rate base and is turned into regulatory asset. Since EnCompass is not easily adapted to model the impacts of securitization endogenously, sensitivity analysis in Optimus is used to identify scenarios where securitization can deliver significant net benefits for ratepayers, as well as scenarios where the benefits of securitization are left unrealized.
Fuel Price Sensitivity	RMI modeled two types of fuel price sensitivities in Optimus: (1) A single-year extreme fuel price shock to assess the temporary impact of market turbulence. This sensitivity assumes doubling the fossil fuel prices for the entirety of one single calendar year, and the test year range is 2029-2035 because these are the peak years for generation from gas and co-firing units (and thus, consumption of gas) in the Duke Resources scenario. The metric used to evaluate the impact is the percentage increase of annual total ratepayer cost driven by the fuel price shock in that year, and by comparing the impact across the range of 2029-2035, it enables identification of the year where the portfolio is most susceptible to fuel price volatility. (2) A prolonged, multi-year increase in fuel price (2029 through 2035) to assess the medium-term impact on prices of a longer-term shift in fuel market dynamics. This sensitivity assumes 50% higher fossil fuel prices for the entirety of calendar years 2029 through the end of 2035 on each resource scenario and is also coupled with a higher load projection as described above to analyze the effect of these two compounding risks.

	See Appendix A.8 below for an overview of recent fuel price for justification of the fuel price assumptions.

A.3 Further Explanation of the Key Differences Between the EnCompass and Optimus Calculations

1) Full revenue requirement vs. forward-looking incremental system cost

In its Carbon Plan proposal, Duke employed the traditional approach of using capacity expansion optimization to estimate ratepayer impacts. This approach considers only the capital expense components of capacity additions and the operational expenses of the full generation portfolio.[32] This implies that Duke has assumed capital and other expenses of the current generation fleet to be sunk costs, constant (in real dollars), and independent of future factors.

In contrast, RMI used Optimus to estimate ratepayer impacts utilizing the full revenue requirement, including *all cost components* of both existing assets and incremental resources added to the portfolio by EnCompass, as well as capital and operating costs associated with non-production assets.[33] Finance and accounting principles were applied to the full revenue requirement to derive total ratepayer costs.

The primary rationale for this approach is that a more comprehensive set of costs must be modeled to capture the potentially important impacts of regulatory and financing options such as securitization and PBR mechanisms on the distribution of costs and risks of potential resource scenarios. RMI believes this approach enables a wholistic examination of the impacts of future resource portfolios — in addition to the economic, policy, and regulatory dynamics described above — on all cost components, all of which can translate to ratepayer costs (and savings).

2) Full vs. incremental rates and bills impact assessment

The full revenue requirement approach also allows RMI to conduct forward-looking estimates of rates and bills differentiated by class in Optimus. To do this, the model employs a functional allocation methodology that classifies and assigns all cost components in the projected revenue requirement using cost causation principles and

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[32] Duke, *Carolinas Carbon Plan*, Appendix E, Page 44.

[33] Non-production assets include transmission and distribution operating costs, Selling, General and Administrative (SG&A) expenses (which are the operating costs associated with utility operation), pension obligations, etc.

the historical allocation across customer classes (as observed in collected revenue and rate schedules).[34] The result is a differentiated average bundled rate and average monthly bill for the residential, commercial, industrial, and wholesale classes.

In contrast, Duke calculated the incremental impact per MWh of a residential bill of each scenario in its Carbon Plan proposal. Duke did this by applying their average cost allocation to all retail sales, without differentiating how costs would be allocated amongst ratepayer classes. Additionally, Duke assumed that the 2021 year-end average bundled price per MWh for the residential class will stay constant such that any cost allocated to residential customers from the incremental resources added by EnCompass would be in addition to the baseline. This approach effectively eliminates consideration of how the baseline costs will inevitably change due to depreciation of existing assets, evolution of fuel costs, and changes in capacity factors across time, among others.

In sum, Duke's approach to the residential bill impacts assessment represents an average impact of the incremental portfolio additions, omits consideration of how such additions change the costs of the existing portfolio, and implies the impact would be spread evenly across customer classes. RMI's approach tries to bridge the gap between capacity expansion analyses and the realities of cost-of-service studies and rate cases by considering the evolution of the entire portfolio (both existing assets and additions) and differentiating its impact to the main four classes of customers (residential, commercial, industrial and wholesale).

3) Fixed O&M expenses vs. capitalization

In Duke's EnCompass modeling, transmission upgrade costs and the maintenance capital expenditures (or "CapEx") associated with existing assets are treated as fixed O&M cost adders. In Duke's EnCompass outputs, these costs are inextricably combined with other generation project-specific costs from the "Fixed Cost" category in EnCompass. Duke's approach forced Synapse to do the same in its own scenarios. As a result, RMI was unable to disentangle the maintenance CapEx to incorporate it into Optimus's calculation of securitization benefits, which means that this analysis likely represents an underestimate of this potential value.

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[34] RMI's calculations of bill impacts using the cost causation framework were informed by a variety of sources: A RAP publication titled, *Electric Cost Allocation for a New Era: A Manual* (2020) by Lazar, Chernick, Marcus, and LeBel; National Renewable Energy Lab's Utility Rates Data Base; FERC Form 1 tables: sales by schedule and sales by customer class; and, NCUC Dockets E-2 Sub 1219 DEP Cost of Service Studies & Cost of Service Manual, and E-7 Sub 1026 DEC Cost of Service Study.

If sufficient breakdown of cost data had been provided, RMI's ideal approach would be to (1) treat the transmission and maintenance CapEx cost as an upfront capital expense (as it commonly would in cost-of-service regulation), and (2) estimate the impact of annual depreciation and rate of returns based on the depreciation schedule of each asset. In theory, both approaches will yield similar ratepayer cost outcomes *if* the fixed O&M cost adders incorporate the levelized impact of annual depreciation and authorized returns. However, the following factors would cause the outcomes to be different:

- Given the circumstances, the maintenance CapEx cost of existing assets was not subject to the Optimus securitization calculations. This reduces the potential savings of securitizing coal plants because the significant costs of maintenance CapEx are not added to net plant balances and included in the rate base calculation. Consequently, the overall securitization benefits are underestimated. RMI recommends revisiting the approach in future EnCompass modeling to reflect the benefits of mechanisms like securitization more accurately.
- Since fixed O&M cost adders are treated as direct pass-throughs in the EnCompass analysis, it would not be reflected in the earnings calculation. Consequently, the utility earnings are underestimated. RMI recommends revisiting the approach in future EnCompass modeling to allow for a comprehensive assessment of earnings and shareholder value.

4) Discount factor for Net Present Value calculation

In Duke's EnCompass modeling, the net present value (NPV) calculation uses a single discount factor: the Weighted Average Cost of Capital (WACC) for the entire planning horizon. This is the commonly used approach across capacity expansion modeling analysis to estimate the system costs when the analysis focuses more on the operational impact rather than the detailed financing structure.

To ensure comparable and consistent NPV estimate with EnCompass results, RMI used the same constant WACC for the incremental NPV calculation. For the full revenue requirement assessment beyond incremental NPV, RMI used a hybrid, forward-looking ROR approach which provides a more nuanced picture of the value of different portfolio decisions. RMI's forward looking ROR approach considers two factors:

- The dynamic nature of the cost of debt as captured in forward interest rate curves, which directly affects the company's cost of capital and tax deductibility of interest
- The continuous need to incorporate new equity and new debt into the capital structure of the Companies depending on the deployed capital to build the capacity expansion

These factors attempt to reflect the nature of the capital markets that utilities would face in the future, and thus affect the costs they bear. In a stricter sense (and if the data were available), different components of the revenue requirement should be discounted at different rates, depending on which group bears the risk associated with each cost component. For instance, direct pass throughs to ratepayers ought to be discounted at a lower rate, similar to a social discount rate.

The Optimus analysis and findings described in the next section indicate that the hybrid, forward-looking ROR has an upward trajectory (starting at 6.4% in 2022 and growing to 7.1% by 2050), which would yield lower NPV numbers compared to the EnCompass approach. RMI recommends the Commission revisit this methodology in future Carbon Plan EnCompass modeling.

A.4 Optimus & EnCompass Calibration Results

Before starting the full revenue requirement impact assessment, RMI calibrated its model with EnCompass to ensure Optimus yielded consistent baselines. ***Table A.3*** below lays out Optimus's estimate of the forward-looking incremental system cost, which is equivalent to the Incremental net present value for the *total* revenue requirement (NPVRR) calculated by Synapse.

Optimus's incremental NPVRR results are less than 1% different from Synapse's numbers through 2030 and within 3% difference through 2050. The difference is driven by the caveats laid out in the methodology section above; primarily the simplified treatment of the AFUDC account. RMI believes that the close agreement between the EnCompass and Optimus models provides strong evidence that the results from Optimus can be viewed as faithfully providing complementary analyses and metrics for the scenario that will be presented in Synapse's replication of Duke P1 scenario.

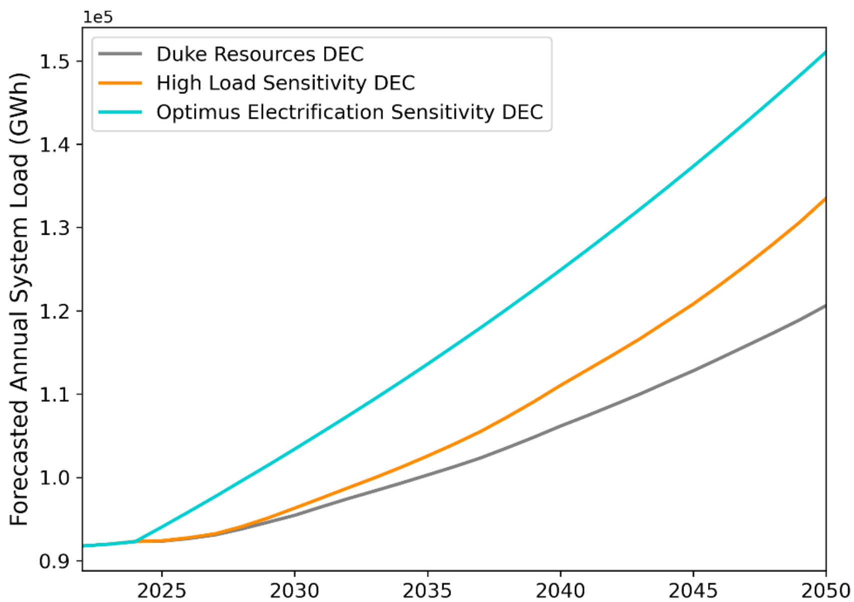
Table F. Incremental NPVRR Results from Optimus for all Scenarios, 2022-2050

(Billion $)	Duke Resources
NPVRR through 2030	36.5
NPVRR through 2040	77.8
NPVRR through 2050	120.7

A.5 Load Growth Assumptions

RMI compared the load growth assumptions under the Duke Resources scenario and the Optimus electrification sensitivity scenario against the ones under Duke's own High Load sensitivity scenario. RMI only compared the DEC region as Duke only provided the load projection data under the High Load sensitivity for DEC and DEP-East, and as a result RMI is not able to provide a complete comparison of the entire DEP region. ***Figure 14*** below shows a comparison of those assumptions, indicating that Duke's High Load scenario, which reflects "commitments made by vehicle manufacturers to achieve 40% to 50% of new vehicle sales being EVs by 2030,"[35] is roughly 0.4% faster growth than the base load projection. This is relatively conservative compared with the high electrification assumptions used in Optimus sensitivity, which is roughly reflecting 2% annual growth (1.5% faster than Duke's baseline).

Figure 14 13. DEC load growth scenarios for the baseline Duke Resources scenario (grey), Duke's high load and high EV sensitivity (orange), and the Optimus 2% load growth assumption (cyan).



A.7 Rates & Bills Impact Methodology

The first step in projecting the impacts to rates and bills is to model a typical ratemaking process, including a certain rate case frequency, a regulatory lag, a type of test year, and any PBR mechanisms that might be in effect. As standard assumptions, Optimus assumes rate cases will happen every other year, with a regulatory lag of one year, and use historical costs ("actuals") except for the MYRP. The result is a certain level of "revenue allowance" that the utility will seek to allocate and collect across its customers that differs slightly from the EnCompass revenue requirement due to ratemaking dynamics.

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[35] Duke, *Carolinas Carbon Plan*, Appendix E, Page 18.

The second step is applying functional allocation to this "revenue allowance." The following table describes the data sources and references that RMI used to reconstruct a functional allocation methodology that follows cost causation principles and Duke's revenue collection parameters from publicly available data:

Table G. Data sources for functional allocation

Calculation	Data Sources	Assumption derived	Methodology
Collected revenue	FERC Form 1 Sales by Rate Schedule table	$ amounts and kWh sold under each rate schedule	Paired with the URDB to calculate collected revenue from each bill component per customer class
	FERC Form 1 Sales by Customer Class table	$ amounts and total kWh sold to each customer class	To calculate the fraction of revenues and load that each customer class represents
	NREL's Utility Rate Database (URDB) in conjunction with EIA 714 load information	Bill components in each rate schedule ($/kWh, $/kW-month and $/month)	Paired with FF1 Sales by Rate Schedule table to calculate collected revenue from each bill component per customer class
Cost allocation	Regulatory Assistance Project's Utility Cost Allocation for A New Era manual	Best practice guidance and average industry observations on functional classification percentages per asset type	To allocate cost components of each asset to fixed, demand or volumetric rates on a forward-looking basis
	Publicly available functionalized cost of service studies	Cost allocation of functions (generation, T&D, etc.) to each rate schedule	Calibration of functional allocation results
Cost baseline	FERC Form 1 revenues by cost component	Revenue $ amounts attributed to utility cost components	To get a historical breakdown of cost functionalization and classification as baseline

Functional allocation results in a matrix that specifies what percentage of each cost component in the revenue requirement would be collected from each customer class when applying cost causation principles and the current rate structure.

When applying said matrix to the asset level breakdown of costs, three main metrics can be obtained:

- Normalized average rates: total "revenue allowance" divided by total net load served
- Average bundled rate per customer class: fraction of the "revenue allowance" to be collected from each customer class (per the functional allocation matrix) divided by the net load of each customer class
- Average monthly bill: fraction of the "revenue allowance" to be collected form each customer class (per the functional allocation matrix) divided by the average annual customer count and then by 12

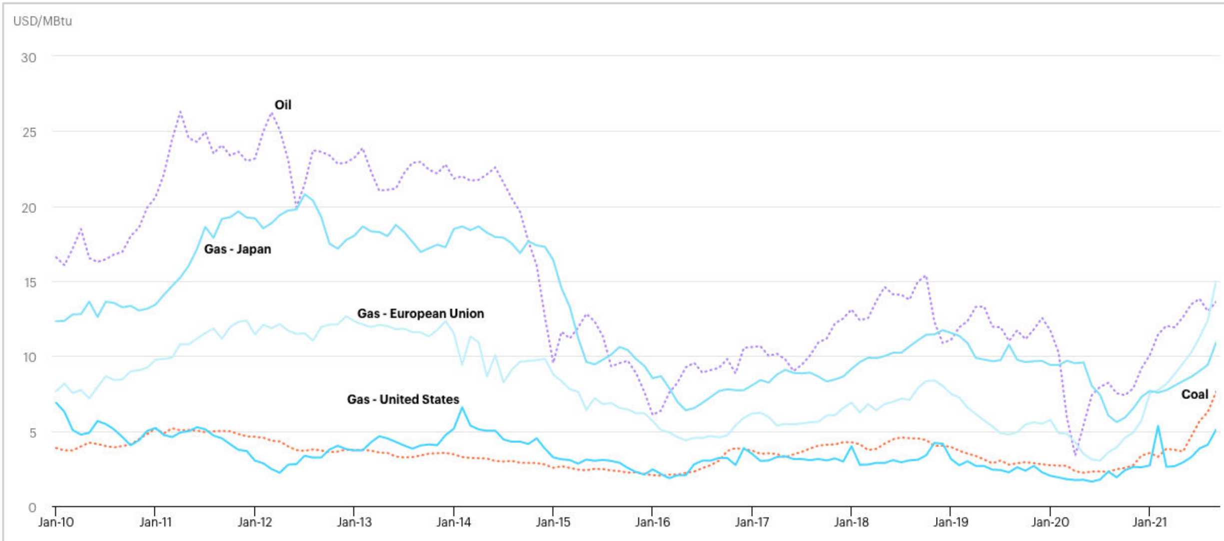
Since the analysis used a wide range of publicly available data, results are not expected to be exact. Rather, their intent is to provide medium to long-term directional insights into the distributional impacts of different resource selections. For the bills trajectory analysis under the Duke P1 scenario presented above, the results for 2022 are set as the baseline, and the changes relative to such baseline are plotted over time. According to NCSEA-SACE DR 2-23, Duke used 2022 bills estimates as baseline and projected bill impacts using changes relative to this baseline as well.

A.8 Recent Fuel Price Trajectories

Figure 15 below shows the recent historical price trajectory of global oil, gas, and coal prices, demonstrating the linkage in price amongst these energy sources.[36]

[36] IEA, *Oil, natural gas and coal prices by region, 2010 - 2021*, IEA, Paris https://www.iea.org/data-and-statistics/charts/oil-natural-gas-and-coal-prices-by-region-2010-2021

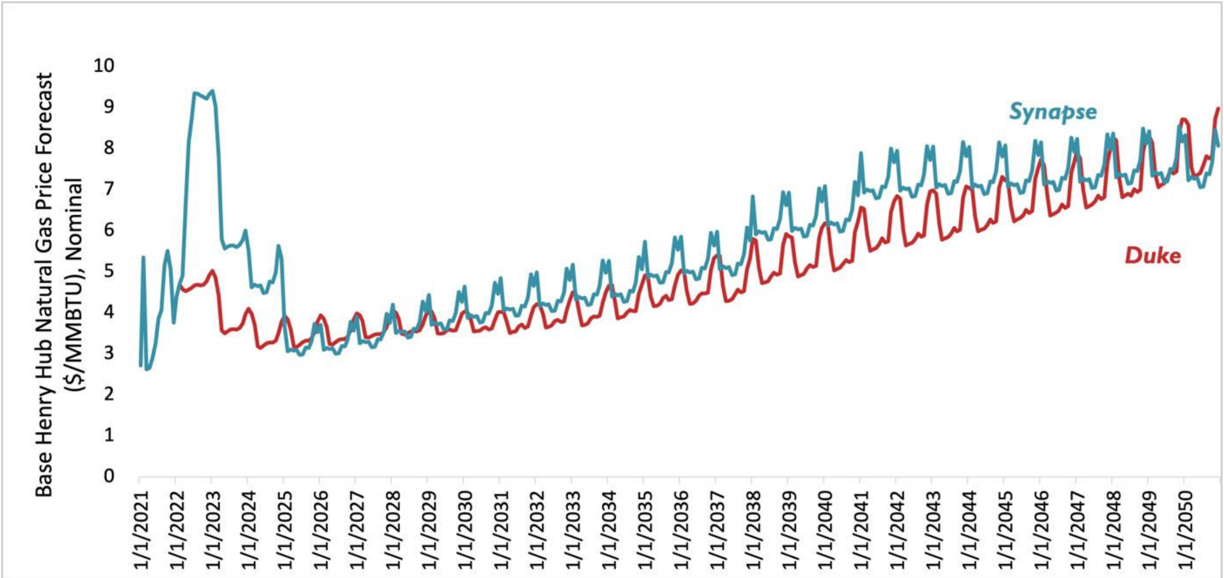
Figure 1145. IEA Oil, natural gas, and coal prices by region, 2010 - 2021 ($USD/MBtu)



A.9 Comparison of Synapse and Duke Natural Gas Price Forecast

Figure 16 below shows the forecast Henry Hub natural gas prices used by both Synapse and Duke. A notable deviation occurs between 2022 – 2025 where both forecasts predict a temporary price spike. Although the shape of the spike is similar in both forecasts, Synapse predicts that prices will peak about twice as high as the maximum forecast used by Duke in its proposed Carbon Plan. This big spike in 2022-2023 is reflected in the operating cost projection and results in a sharp incline in the following years, which explains the near-term bill decline particularly seen by the residential customers in the DEC territory given the cost allocation assumptions described in Appendix A.7 above.

Figure 16. Henry Hub Natural gas price forecast from Synapse and Duke (Source: Synapse)



BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 179

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

VERIFICATION

I, Gennelle Wilson, first being duly sworn, say that I am employed as a Senior Associate at RMI and have read the foregoing Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal, and know the contents thereof; and that the contents are true, accurate and correct to the best of my knowledge, information, and belief.

Gennelle Wilson

Signature

STATE OF Colorado

COUNTY OF Boulder

Signed and sworn to (or affirmed) before me this 14th day of July, 2022.

Paras Patel

Signature of Notary Public

Paras Patel

Printed or Typed Name of Notary Public

My Commission Expires: June 4, 2025

[Official Seal or Stamp]

PARAS PATEL
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20214021632
MY COMMISSION EXPIRES JUN 4, 2025