Analysis of Duke Energy's Carolinas Carbon Plan and a Least Cost Decarbonization Alternative

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July 11, 2022

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Executive Summary

North Carolina law concerning electricity provision calls for "adequate, reliable and economical utility service to all of the citizens and residents of the State" and, just as important, "the least cost mix of generation and demand-reduction measures which is achievable."[1] The reason for these consumer protection measures is spelled out: "the rates, services and operations of public utilities … are affected with the public interest," and going further, "the availability of an adequate and reliable supply of electric power and natural gas to the people, economy and government of North Carolina is a matter of public policy."[2]

Pursuant to House Bill (HB) 951[3] passed on October 13, 2021, Duke Energy Progress, LLC and Duke Energy Carolinas, LLC (jointly, "Duke Energy" or "Duke") filed its Carolinas Carbon Plan with the North Carolina Utilities Commission.[4] The Duke Carbon Plans include four alternative scenarios for reducing carbon dioxide (CO_2) emissions.

As a longtime advocate for North Carolinians, their families, and their communities, Locke recognizes electricity as a basic human necessity, the provision of which affects everyone. In recent reports we have sought to educate policymakers and the public in critical policy discussions surrounding electricity policy. We have shown there is an enormous range among energy sources not just in terms of CO_2 emissions, but more vitally in terms of cost and reliability. As demonstrated by our recent "Energy Crossroads"[5] and "Big Blow"[6] reports, decisions made by the Commission regarding North Carolina's future generation mix affect North Carolina families, local employers, schools, and industries deeply.

Given the critical importance of electricity provision to North Carolina families, local employers, schools, and industries, the Center for Food, Power, and Life at the John Locke Foundation reached out to energy analysts at the Center of the American Experiment for critical analysis of the costs and implications of each of the Duke plans. This report contains the results of that analysis, conducted by Isaac Orr and Mitch Rolling.

Our analysis models the cost and reliability implications for Duke's four carbon reduction plans and provides an alternative scenario, the Least Cost Decarbonization (LCD) scenario, that is lower-cost and more reliable than any of Duke's carbon plans and relies on technology that is more established. It

[1] North Carolina General Statutes § 62, https://www.ncleg.gov/EnactedLegislation/Statutes/HTML/ByChapter/Chapter_62.html.
[2] N.C.G.S. § 62.
[3] House Bill 951/Session Law 2021-165, North Carolina General Assembly, https://www.ncleg.gov/BillLookUp/2021/h951.
[4] Duke Energy, Carolinas Carbon Plan, "Executive Summary," accessible at https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/carolinas-carbon-plan/executive-summary.pdf?la=en&rev=489fd2ab6211481484eb4beb9b62a25a.
[5] Jordan McGillis, "Energy Crossroads: Exploring North Carolina's Two Energy Futures," Policy Report, John Locke Foundation, June 23, 2021, https://www.johnlocke.org/research/energy-crossroads.
[6] Jon Sanders, "Big Blow: Offshore Wind Power's Devastating Costs and Impacts on North Carolina," Policy Report, The Center for Food, Power, and Life, John Locke Foundation, June 1, 2022, https://www.johnlocke.org/research/big-blow-offshore-wind-powers-devastating-costs-and-impacts-on-north-carolina.

concludes that none of Duke's plans are the least-cost means of providing reliable electricity to North Carolina residents.

The main takeaway is this: North Carolinians can either have a least-cost, reliable electric grid or reduce carbon dioxide emissions. They cannot have both.

What Is HB 951?

HB 951 establishes three primary requirements, all of which must be satisfied in the plan developed by the North Carolina Utilities Commission to achieve the targeted carbon dioxide (CO_2) reductions.[7] The first requirement is that the Commission must comply with current law and practice with respect to least-cost planning for generation. The second requirement is that any generation and resource changes must maintain or improve upon the adequacy and reliability of the existing grid.

The third requirement is that any new generation facilities or other resources selected by the Commission in order to achieve the CO_2 emissions reduction goals for electric public utilities must be owned and recovered on a cost-of-service basis by the applicable electric public utility, except in the case of energy efficiency measures and demand-side management, for which existing law applies, and in the case of solar generation, which is to be allocated according to the specified percentages.

Section 1 of HB 951 directs the Commission to take all reasonable steps to achieve two emissions reductions targets: (1) a 70 percent reduction in CO_2 emissions from electric generating facilities owned or operated by electric public utilities in North Carolina by 2030 from 2005 levels and (2) carbon neutrality by 2050. It further provides that the timing of achievement of the interim 70 percent reduction target may be adjusted based upon certain factors.

Primary Findings

The main conclusion of our analysis is that none of the four carbon plans created by Duke Energy appear ready for prime time. Each would rely heavily upon investments in variable renewable energy (VREs) to meet HB 951 requirements to reduce CO_2 emissions by 70 percent, relative to 2005 levels, by 2030, and speculative technologies that have not proved they can scale at a reasonable cost thereafter.

Each of the scenarios studied, including the LCD scenario, would cost over $100 billion through 2050 and increase the cost of electricity by at least $170 per customer per month by 2050. Given the magnitude of the costs, these carbon plans deserve a thorough vetting by the public and the state legislature to ensure North Carolinians are willing to pay the costs associated with meeting the goals established in HB 951.

Carbon Plans Are Highly Dependent on Hydrogen Assumptions

It is important to note that in order to achieve 100 percent carbon neutrality by 2050, each scenario in Duke's Carbon Reduction Plan would rely heavily on the use of hydrogen fuel at new and some existing natural gas units, which constitute between 8,800 MW–9,900 MW of capacity, depending on the scenario.

The primary shortcoming of this strategy is Duke's fuel-cost assumptions for hydrogen, which are substantially lower than current costs. Duke assumes a cost of $1 per kilogram (kg) of so-called green

[7] Carolinas Carbon Plan, "Executive Summary."

hydrogen, which is made using carbon-free electricity. $1/kg translates to a fuel cost of $7.40 per million Btu (MMBtu).

These cost assumptions were based on the Department of Energy ("DOE") price target for clean hydrogen and are not a reflection of current costs for hydrogen fuel produced using the methods outlined by DOE.[8] Currently, hydrogen from renewable energy costs about $5/kg, which translates to a fuel cost of $37/MMBtu.[9]

Duke also notes the uncertainties surrounding whether there will be an adequate supply of hydrogen fuel for these facilities, as powering these facilities with green hydrogen would necessitate the construction of an entirely new supply chain. As a result, Duke's heavy reliance on hydrogen to achieve carbon neutrality is highly speculative.

Conclusion

Each of the scenarios discussed would cause substantial increases in electricity costs for North Carolina families and businesses, but a portfolio that focuses on building reliable, dispatchable power plants would decarbonize at the lowest possible cost.

Furthermore, nuclear power plants, which can last for up to 80 years, would provide lower-cost electricity in the future as they depreciate and repay initial capital costs. That is not the case for wind and solar assets that only last 20 and 25 years, respectively. They would necessitate a constant "build and rebuild" treadmill of capital expenditures that virtually guarantee ratepayers never have low-cost electricity after capital costs are recouped.

Duke's Carbon Plans are predicated on large capital expenditures for wind and solar and rely on optimistic hydrogen cost assumptions that are not reflective of the current state of the technology. For this reason, more study is needed by stakeholders through a thorough public information process.

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[8] Duke Energy, Carolinas Carbon Plan, "Appendix O. Low-Carbon Fuels and Hydrogen," https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/carolinas-carbon-plan/supplemental/appendix-o.pdf?la=en&rev=773bc08b34804b4dbb217424a83fe7b8.

[9] "Hydrogen Shot," U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/fuelcells/hydrogen-shot.

Introduction

On November 19, 2021, pursuant to House Bill (HB) 951[10] passed in 2021, the North Carolina Utilities Commission ("Commission") issued an Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines requiring Duke Energy Progress, LLC and Duke Energy Carolinas, LLC (jointly, "Duke Energy" or "Duke") to file a proposed Carbon Plan with the Commission by April 1, 2022, a deadline extended to May 16, 2022. Duke has complied with this order with the filing of its Carolinas Carbon Plan,[11] which provides four alternative scenarios for reducing carbon dioxide (CO_2) emissions.

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Section 1 of HB 951 directs the Commission to take all reasonable steps to achieve two emissions reductions targets: (1) a 70 percent reduction in CO_2 emissions from electric generating facilities owned or operated by electric public utilities in North Carolina by 2030 from 2005 levels and (2) carbon neutrality by 2050. It further provides that the timing of achievement of the interim 70 percent reduction target may be adjusted based upon certain factors.

The vital importance that electric power be least-cost, adequate, and reliable

North Carolina law concerning electricity provision calls for "adequate, reliable and economical utility service to all of the citizens and residents of the State" and, just as important, "the least cost mix of generation and demand-reduction measures which is achievable."[13] The reason for these consumer protection measures is spelled out: "the rates, services and operations of public utilities … are affected with the public interest," and going further, "the availability of an adequate and reliable supply of electric power and natural gas to the people, economy and government of North Carolina is a matter of public policy."[14]

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[10] House Bill 951/Session Law 2021-165, North Carolina General Assembly, https://www.ncleg.gov/BillLookUp/2021/h951.

[11] Duke Energy, Carolinas Carbon Plan, "Executive Summary," accessible at https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/carolinas-carbon-plan/executive-summary.pdf?la=en&rev=489fd2ab6211481484eb4beb9b62a25a.

[12] Carolinas Carbon Plan, "Executive Summary."

[13] North Carolina General Statutes § 62, https://www.ncleg.gov/EnactedLegislation/Statutes/HTML/ByChapter/Chapter_62.html.

[14] N.C.G.S. § 62.

Provisions in HB 951 hearken back to those established tenets in law even in pursuit of additional reductions in carbon dioxide emissions. For example, HB 951 seeks to chart a "least cost path … to achieve compliance with the authorized carbon reduction goals." It specifically calls for the Commission to "Comply with current law and practice with respect to the least cost planning for generation." It also includes that the Commission must "Ensure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."

HB 951 also allows the Commission discretion over the timing, generation, and resource mix in getting to the least cost path of compliance. If the Commission found it necessary, it could delay the achievement of the CO_2 reduction goal by up to two years — or it could delay it further if the Commission "authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion."

The full implication in law that the Commission's decisions concerning Duke's Carbon Plan scenarios are "affected with the public interest" is not lost on the John Locke Foundation. As a longtime advocate for North Carolinians, their families, and their communities, Locke recognizes electricity as a basic human necessity, the provision of which affects everyone. In recent reports we have sought to educate policymakers and the public in critical policy discussions surrounding electricity policy. We have shown there is an enormous range among energy sources not just in terms of CO_2 emissions, but more vitally in terms of cost and reliability. As demonstrated by our recent "Energy Crossroads"[15] and "Big Blow"[16] reports, decisions made by the Commission regarding North Carolina's future generation mix affect North Carolina families, local employers, schools, and industries deeply.

Given the critical importance of electricity provision to North Carolina families, local employers, schools, and industries, the Center for Food, Power, and Life at the John Locke Foundation reached out to energy analysts at the Center of the American Experiment for critical analysis of the costs and implications of each of the Duke plans. This report contains the results of that analysis, conducted by Isaac Orr and Mitch Rolling.

Each of the plans would greatly increase the cost of electricity in North Carolina, greatly increase the average monthly bills of North Carolina households, compromise the reliability of the grid, and do so at an enormous cost per metric ton of CO_2 reduced. According to our estimates:

- The cost of the portfolios would range from $141.7 billion to $162.3 billion by 2050, and most of those costs would be backloaded till after 2035.
- Residential bills by 2050 would have increased between $86 to $95 per month, and commercial and industrial bills would see great increases as well.
- Hourly load estimates during a model week in August found capacity shortfalls of 31 to 41 hours, which could be significant enough to trigger load-shedding.

[15] Jordan McGillis, "Energy Crossroads: Exploring North Carolina's Two Energy Futures," Policy Report, John Locke Foundation, June 23, 2021, https://www.johnlocke.org/research/energy-crossroads.

[16] Jon Sanders, "Big Blow: Offshore Wind Power's Devastating Costs and Impacts on North Carolina," Policy Report, The Center for Food, Power, and Life, John Locke Foundation, June 1, 2022, https://www.johnlocke.org/research/big-blow-offshore-wind-powers-devastating-costs-and-impacts-on-north-carolina.

- The average cost of CO_2 reduced would range from $246 to $259 per metric ton, which would be several times higher than even the Obama administration's questionable estimates of the Social Cost of Carbon.

Going further, all of this would occur among a great increase in the amount of installed capacity in North Carolina. Starting from 36.3 gigawatts (GW) in 2021, by 2050 the total amount of installed capacity would be from 66.9 GW (Portfolio 4, representing an increase of 84.3 percent) to as much as 69.8 GW (Portfolio 1, representing an increase of 92.3 percent). Portfolio 2 would increase capacity to 68.4 GW (88.4 percent), and Portfolio 3 would increase capacity to 68.0 GW (87.3 percent). By way of comparison, the North Carolina Office of State Budget and Management projects the total state population to increase by 32 percent from 2020 to 2050, from 10.5 million to 13.82 million.[17] Each of the portfolios in Duke's Carolinas Carbon Plan not only expects the state's installed capacity to get much larger and more expensive, but also much less efficient as well.

Without a doubt a significant reason for seeking such a massive buildout in installed capacity is the perceived need to overbuild renewable resources, which do not emit CO_2 but which are inherently intermittent and unreliable, in order to overcome their intermittence. It not only increases the facilities' cost per megawatt-hour, but it also means greater costs to ratepayers in the facilities' property taxes. Our analysis estimates property-tax expenses to ratepayers increasing by $11.4 billion to $12.5 billion.

[17] County/State Population Projections, Updated 2/15/2022, North Carolina Office of State Budget and Management, https://www.osbm.nc.gov/facts-figures/population-demographics/state-demographer/countystate-population-projections.

Analysis of Portfolio 1

Scenario Overview: Portfolio 1 (P1): "70 percent by 2030" — Portfolio 1 targets achieving the 70 percent CO_2 emissions reductions by 2030.

To meet this aggressive target, P1 would require 800 MW (one 800 MW block) of offshore wind to be placed in service by year-end 2029, new solar interconnections ramping up to 1,800 MW/year by year-end 2028 (approximately 2.5 times the maximum amount interconnected in any previous year), and the addition of nearly 1,800 MW of new battery energy storage capacity (including batteries paired with solar), up from only 13 MW in service today. Portfolio 1 would also plan for a slightly accelerated retirement of Roxboro Units 3-4 (1,409 MW) with all other coal retirements consistent across the portfolios.

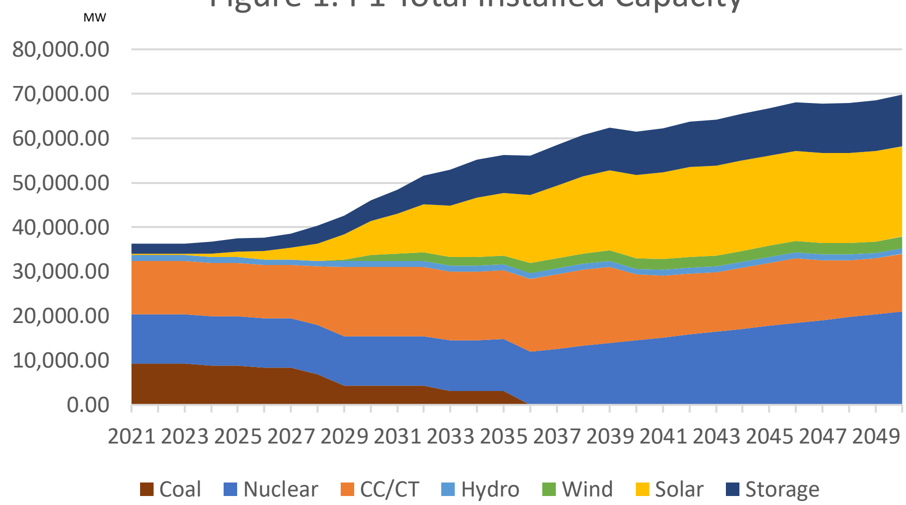
By 2035, P1 would retire 6,300 MW of coal and add 13,800 MW of solar, 1,200 MW of onshore wind, 800 MW of offshore wind, 4,300 MW of battery storage, 2,400 MW of combined cycle, 1,200 MW of combustion turbine, 600 MW of nuclear, and 1,700 MW of pumped storage.

By 2050, P1 would retire 9,300 MW of coal and add 19,900 MW of solar, 1,800 MW of onshore wind, 800 MW of offshore wind, 7,400 MW of battery storage, 2,400 MW of combined cycle, 6,800 MW of combustion turbine natural gas and hydrogen, 9,900 MW of nuclear, and 1,700 MW of pumped storage.

Under Portfolio 1, the amount of installed capacity on North Carolina's electric grid would increase from 36.3 GW in 2021 to 56.2 GW by 2035 and increase to 69.8 GW by 2050, representing a near doubling of the amount of installed capacity on Duke Energy's electric system (see Figure 1).

While that may sound like a good thing, increasing capacity merely to meet carbon reduction goals rather than meeting demand is an unnecessary cost that will harm North Carolina families and the state's economy. Furthermore, increasing the amount of renewable capacity on the grid at the expense of reliable power plants like coal and natural gas leads to a less reliable grid overall, as shown below.

Figure 1. P1 Total Installed Capacity



Cost

Portfolio 1 would cost $158.5 billion through 2050, much of which would occur after 2035.

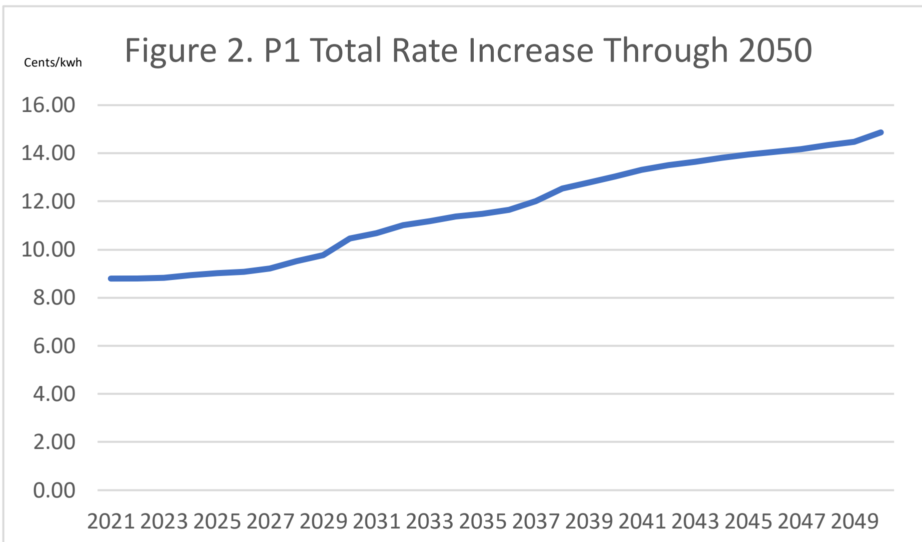
The two largest sources of expenses consist of $90.6 billion in utility returns and $51.5 billion in additional generation costs, while $4 billion in transmission expenses and $12.3 billion in additional property tax expenses are also included.

Ratepayer Impact

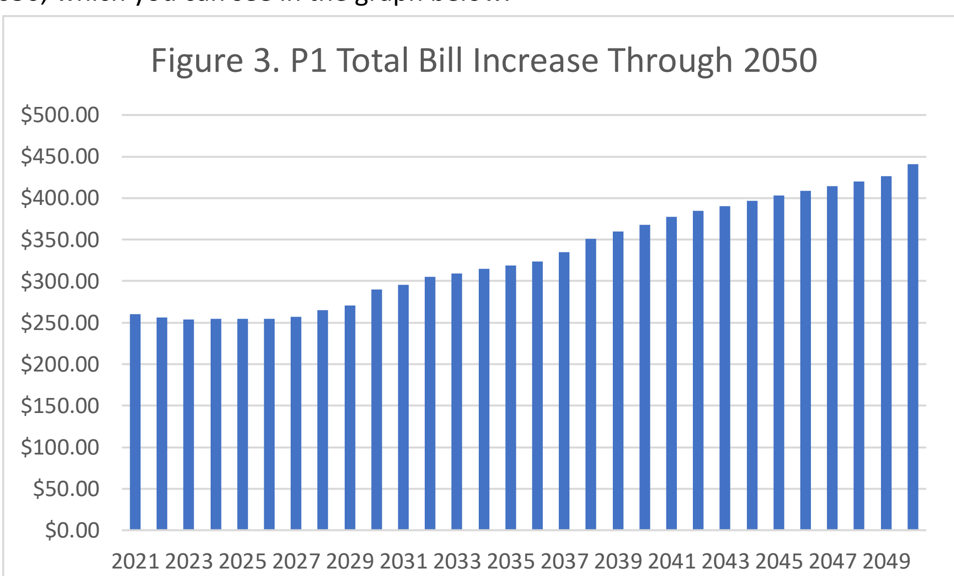
This resource plan would increase the cost of electricity substantially for each customer rate class.

Total

The graph below shows the projected annual cost increase in total electricity prices from 2021 through 2050. Rates would increase by 2.70 cents/kWh in 2035 and 6.74 cents/kWh by 2050.

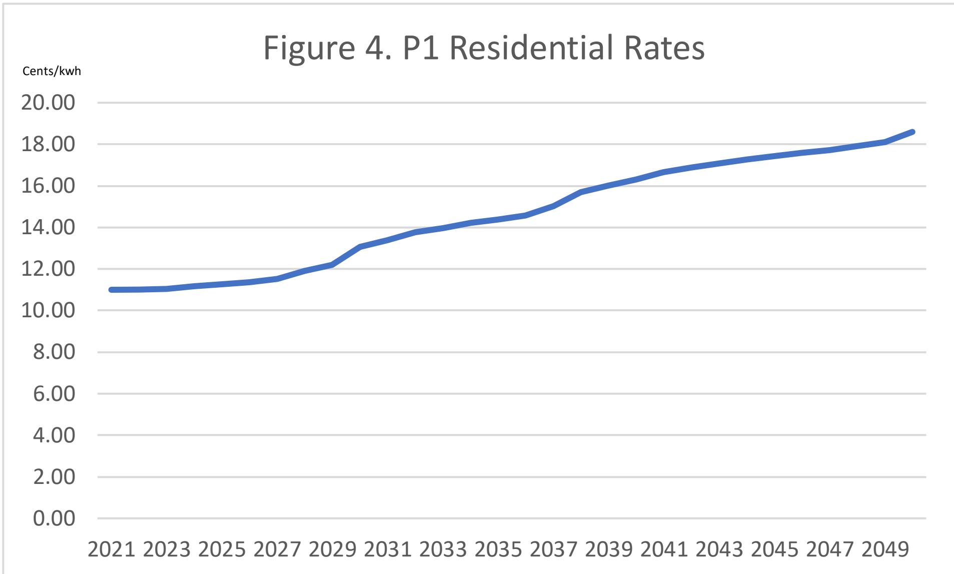


Rising rates would increase average monthly electric bills by $58.21 per month by 2035 and $180.87 per month by 2050, which you can see in the graph below.

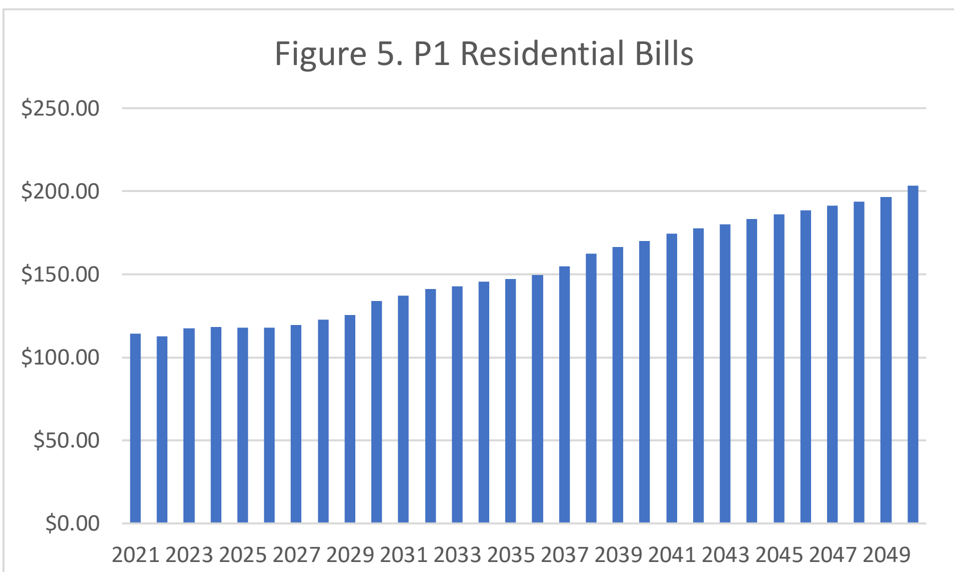


Residential

The graph below shows the projected annual cost increase in residential electricity prices from 2021 through 2050. Rates would increase by 3.38 cents/kWh in 2035 and 7.6 cents/kWh by 2050.

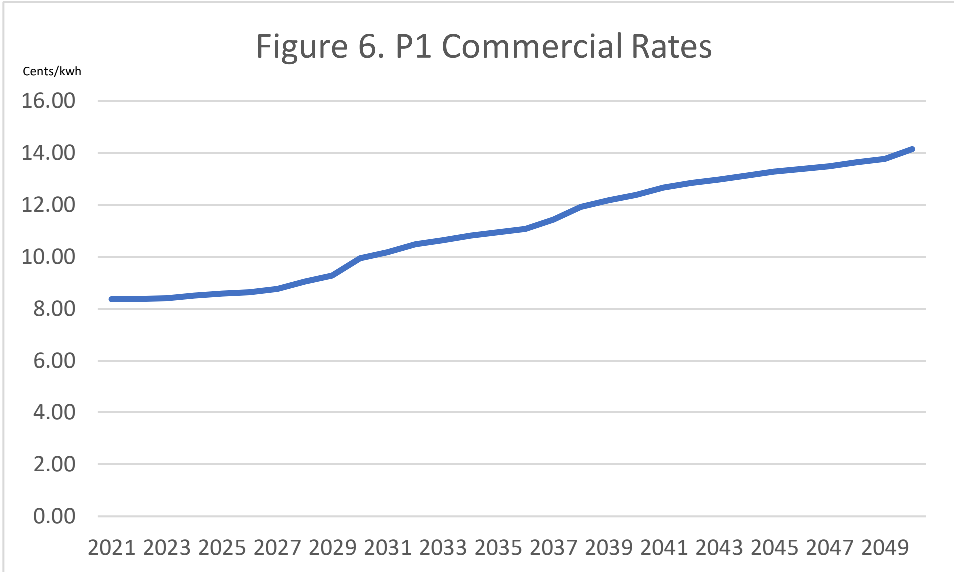


Rising rates would increase average monthly electric bills by $33.03 by 2035 and $89.07 by 2050, which you can see in the graph below.

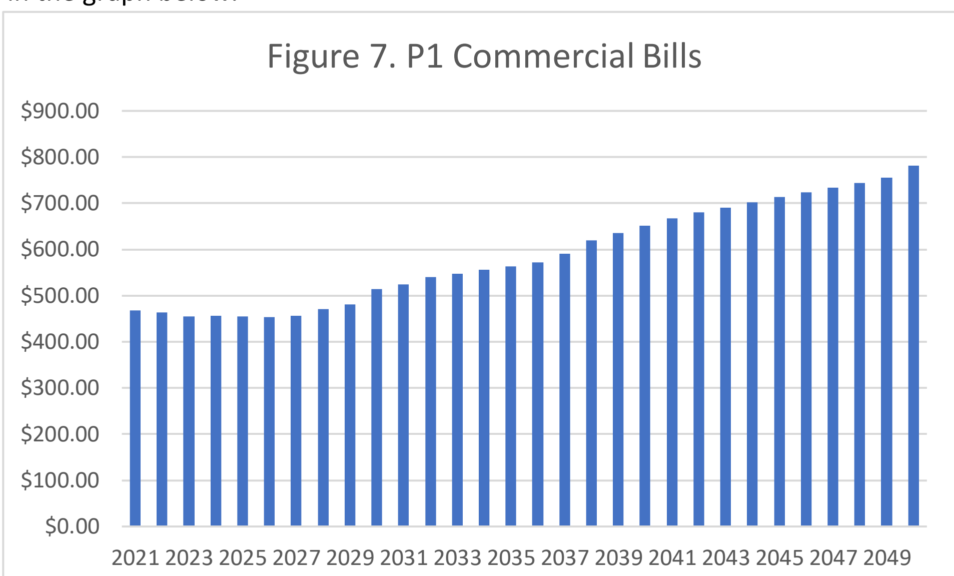


Commercial

The graph below shows the projected annual cost increase in commercial electricity prices from 2021 through 2050. Rates would increase by 2.57 cents/kWh in 2035 and 5.78 cents/kWh by 2050.

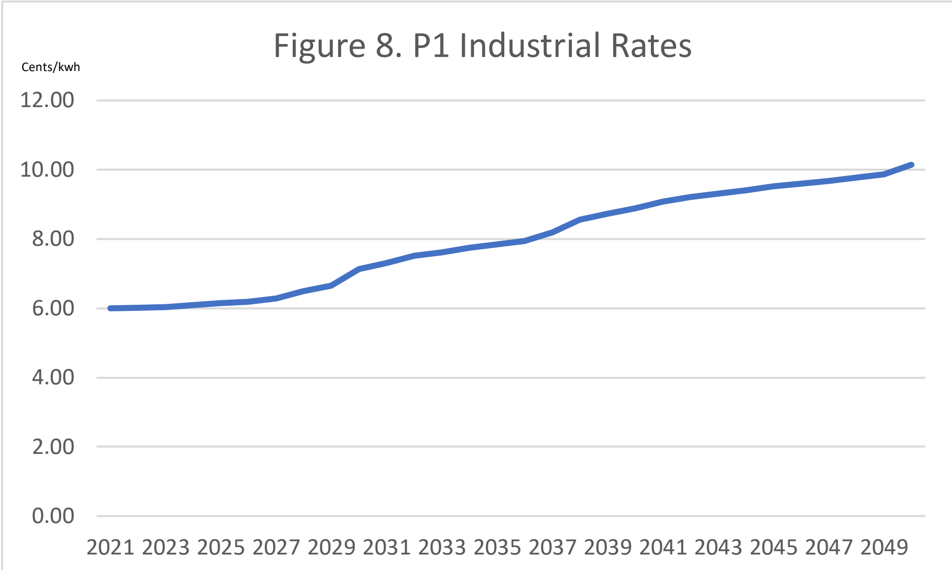


Rising rates would increase average monthly electric bills by $95.24 in 2035 and $313.54 in 2050, which you can see in the graph below.

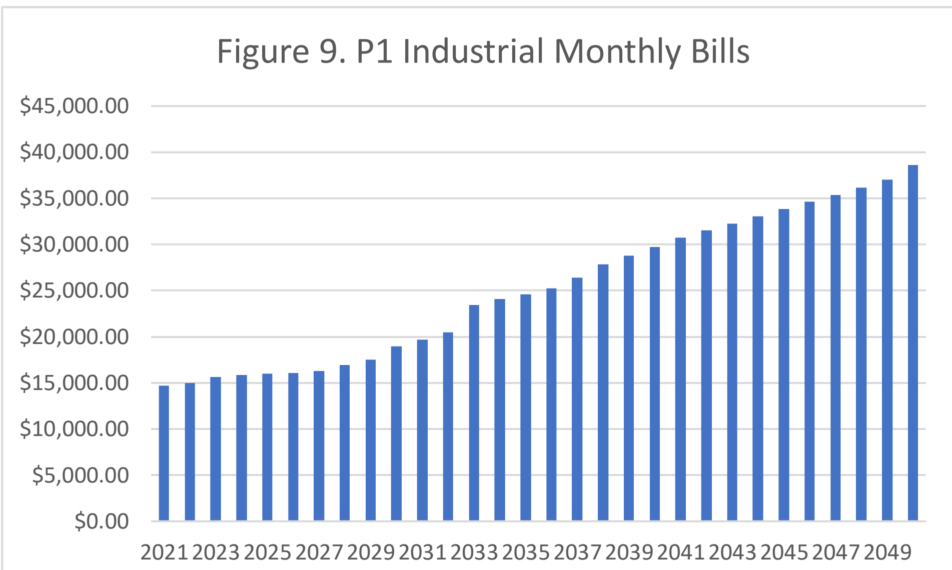


Industrial

The graph below shows the projected annual cost increase in industrial electricity prices from 2021 through 2050. Rates would increase by 1.84 cents/kWh in 2035 and 4.14 cents/kWh by 2050.



Rising rates would increase average monthly electric bills by $9,896.45 in 2035 and $23,856.28 in 2050, which you can see in the graph below.



The Levelized Cost of Energy for Each Resource Type

To compensate for the different reliability attributes of dispatchable and nondispatchable resources, this analysis includes the additional costs that are incurred from maintaining a reliable electricity system using high levels of intermittent renewable resources.

Additional expenses include costs for transmission, utility profits, property taxes, battery and pumped hydro storage used for providing electricity during periods of low wind and solar output, and curtailment of wind and solar resources when they are supplying more electricity than can be stored or utilized at a given moment.[18]

Our model attributes these additional costs to the wind and solar generators on a per-megawatt-hour (MWh) basis to provide readers with an apples-to-apples comparison of the cost of providing reliable electricity service after accounting for the different reliability attributes for dispatchable and nondispatchable resources.

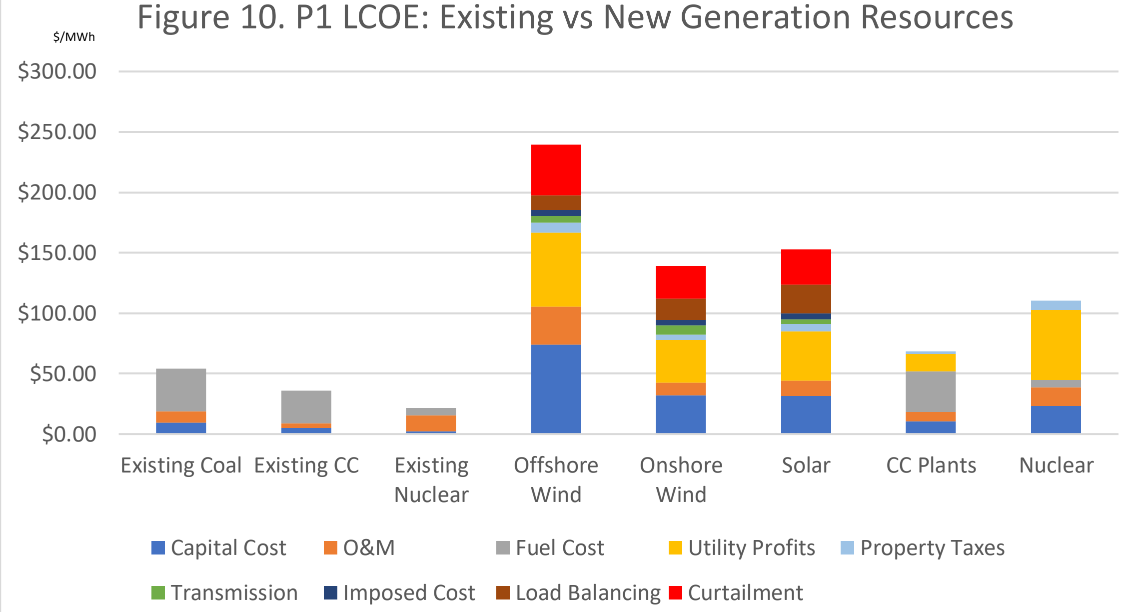
These costs are then compared to the Levelized Cost of Energy (LCOE) of existing nuclear, natural gas, and coal plants operating in North Carolina.

Data from the Federal Energy Regulatory Commission (FERC) show North Carolina's nuclear plants are some of the lowest-cost sources of electricity in the state, generating electricity for $21.71 per MWh in 2019. North Carolina's combined cycle natural gas plants generated electricity for $35.83 per MWh, and coal plants in the state generated electricity for $54.00 per MWh, on average (Figure 10).

It is important to note that projected costs for each portfolio will vary because our analysis uses a systemwide cost approach where additional costs of wind and solar are attributed to these intermittent resources.

Systemwide LCOE values for new offshore wind, onshore wind, and solar facilities are $239 per MWh, $139 per MWh, and $153 per MWh, respectively. LCOE values for new combined cycle and nuclear plants are $68 per MWh and $110 per MWh, respectively.

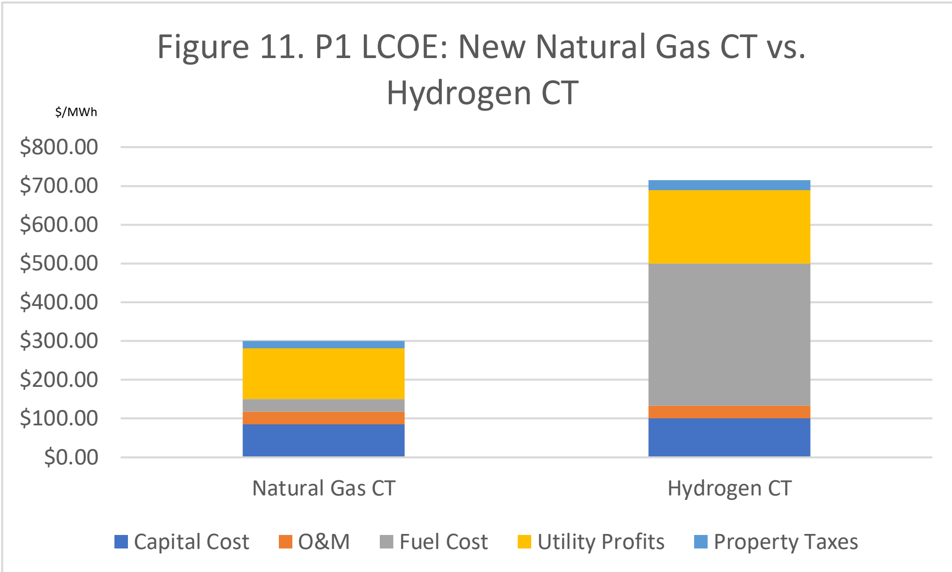
Figure 10. P1 LCOE: Existing vs New Generation Resources



[18] See Appendix, "Factors Affecting the 'All-In' Levelized Cost of Renewables."

Costs are higher for wind and solar facilities because, unlike with traditional fossil fuel plants and nuclear plants, grids powered with large concentrations of intermittent wind and solar projects require much more transmission than systems consisting largely of dispatchable power systems.[19]

Additionally, the chart below compares the cost of combustion turbine (CT) peaker plants using natural gas and hydrogen fuel. As you can see, the cost of using hydrogen, $716 per MWh, is substantially higher than that of natural gas, $300 per MWh[20] (Figure 11).



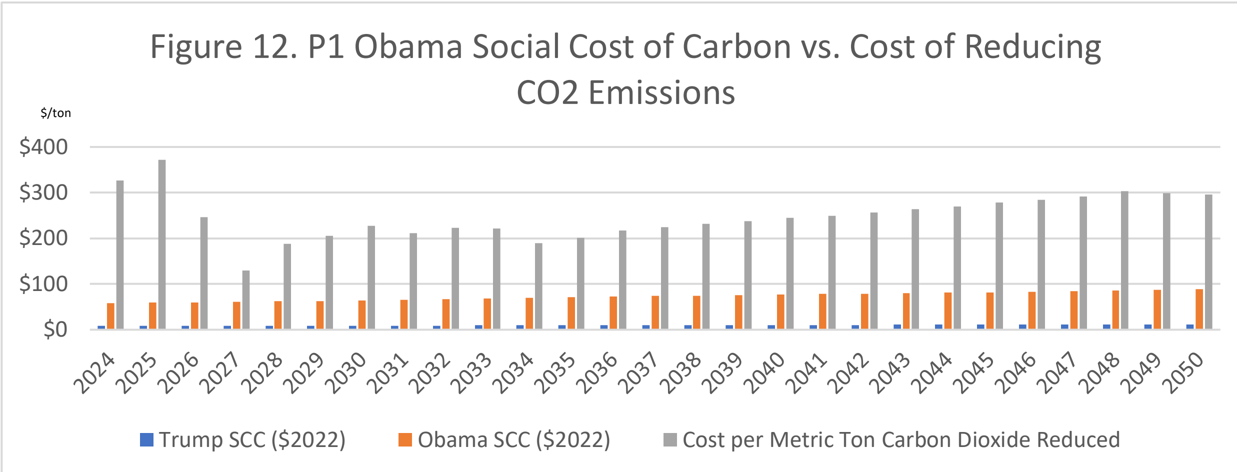
Emissions Reductions

In 2050, Duke Energy would see total CO_2 reductions of 643.9 million metric tons compared with 2021 levels. It would be an average CO_2 emission reduction of 22.2 million metric tons per year through 2050.

The average cost of reducing CO_2 emissions would be $246 per metric ton reduced through 2050. This cost is exorbitant even when compared against Social Cost of Carbon (SCC) values estimated by both the Obama and Trump administrations. In fact, the cost of CO_2 reductions resulting from building offshore wind facilities would exceed SCC estimates from both administrations every single year (Figure 12).

[19] See Appendix, "Factors Affecting the 'All-In' Levelized Cost of Renewables."

[20] Combustion turbine LCOEs are listed separately because their LCOE values dwarf that of other energy sources.

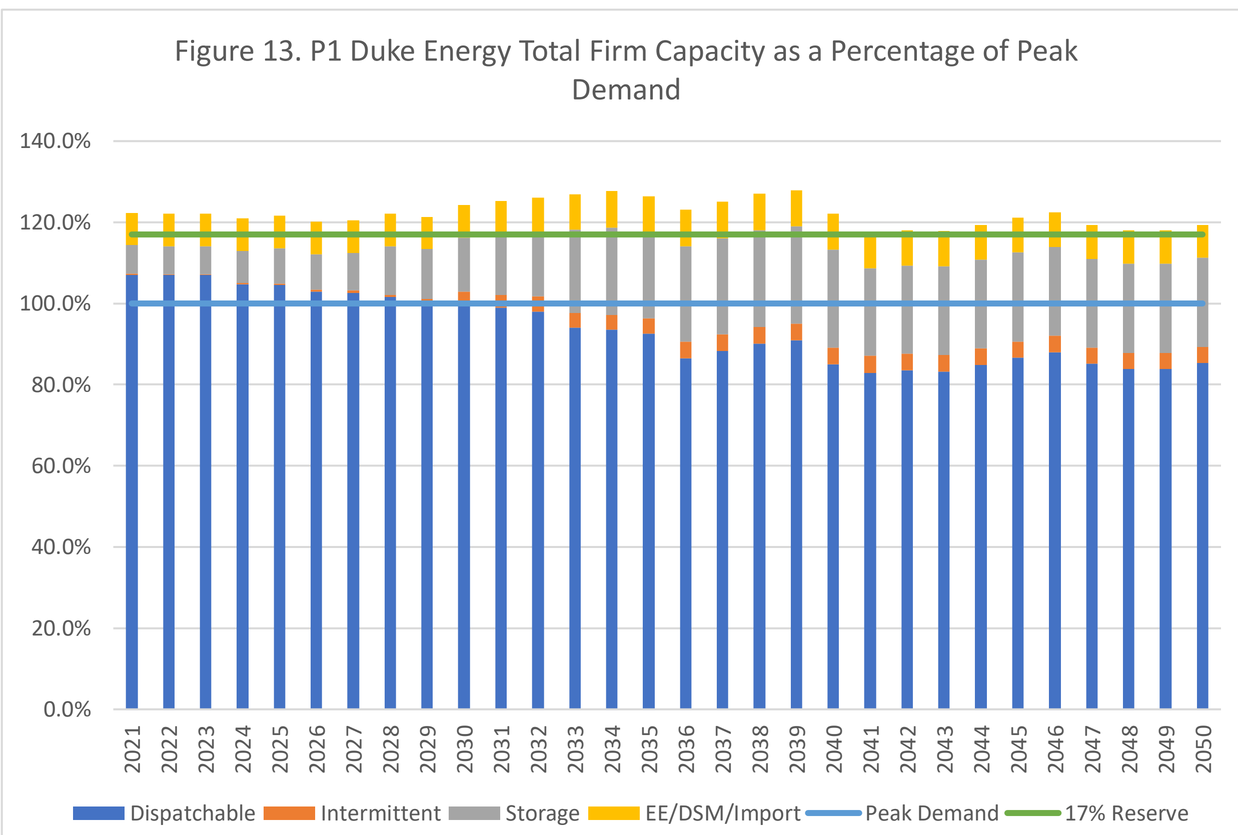


Reliability

This analysis evaluated reliability of Portfolio 1 on an *annual* and *hourly* basis.

Figure 13 shows Duke's planned reliable capacity compared with peak winter load. Winter values are shown because it is when electricity demand is highest. Wind and solar effective load-carrying capacities produced by Duke are used for this analysis.

Alarmingly, Duke plans to rely upon the accredited capacity of wind and solar, storage, and load management resources to meet net load after 2031. Such reliance would be irresponsible because, as we learned in California and Texas, accredited capacities for wind and solar generation are not



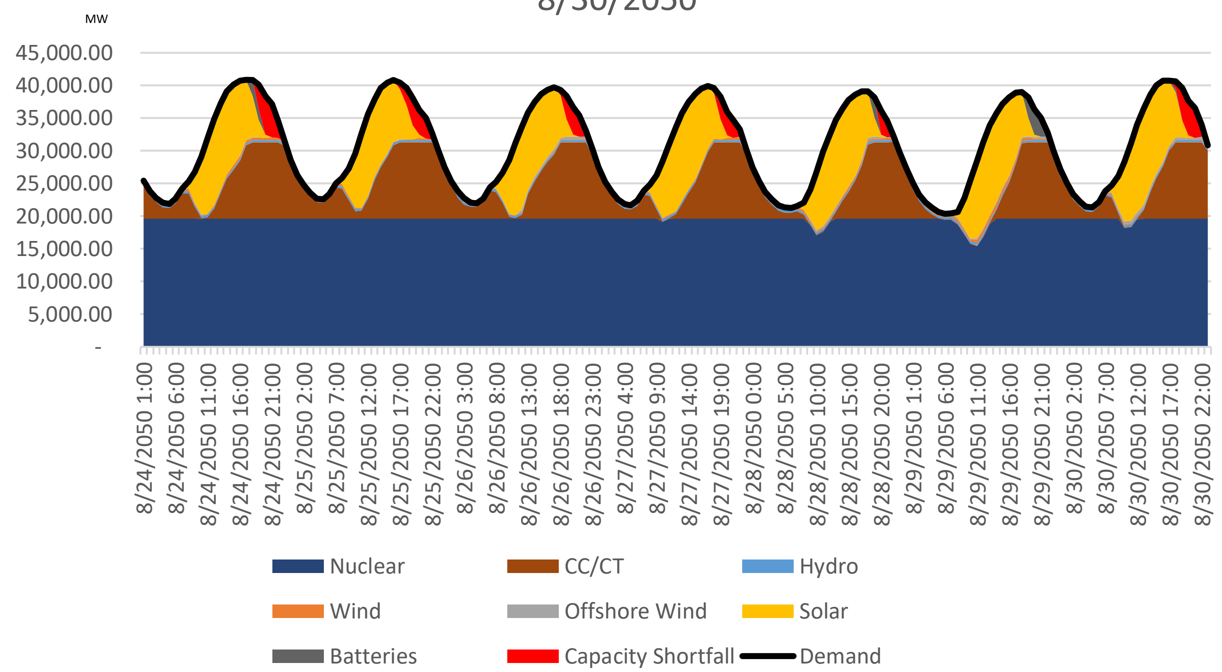
guaranteed, and an overreliance on these technologies could result in capacity shortfalls. Storage systems charged with intermittent renewables are not guaranteed to be available when power is needed most, which would potentially leave the grid short of capacity during peak demand periods.

The amount of fuel-based dispatchable capacity used to meet Duke's reserve margin is dwindling because maintaining an adequate safety net with wind and solar is extremely expensive due to their lower accredited capacity. For example, Duke anticipates capacity values for stand-alone solar will eventually be as little as 1 or 2 percent during peak demand periods, which occur in Duke's system during winter months.[21]

The *hourly* reliability of this scenario (Figure 14) was evaluated comparing real-time hourly load for Duke Energy Progress and Duke Energy Carolinas for estimated hourly generation from all resource types for every hour of the year.[22]

This model utilizes hourly load shape and generation data from EIA's electric grid monitor to obtain hourly demand data, peak load, and capacity factors for onshore wind and solar.[23] For offshore wind capacity factors, the data are utilized power data for offshore wind in Eastern North Carolina from the SAM (System Advisor Model) database for the National Renewable Energy Laboratory.[24] These were the best representations of hourly wind and solar resources for North Carolina. Nuclear, with the addition of

Figure 14. P1 Hourly Load Shape, Capacity Shortfalls: 8/24/2050-8/30/2050



[21] Duke Energy, Carolinas Carbon Plan, " Appendix E. Quantitative Analysis," https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/carolinas-carbon-plan/supplemental/appendix-e.pdf?la=en&rev=7f483297a7304a919833d2ee7c6b0e4d.
[22] See Appendix, "Reliability."
[23] Hourly Electric Grid Monitor, U.S. Energy Information Administration, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.
[24] System Advisor Model (SAM), National Renewable Energy Laboratory, https://sam.nrel.gov.

more flexible SMR (Small Modular Reactors) technologies, natural gas/hydrogen power plants, and storage facilities are used as peaking resources for intermittent power. Excess wind, solar, and nuclear power are allowed to charge storage facilities when room is available to store additional energy. The model also assumes no power loss from charge to discharge.

Using this metric, we have identified 34 hours in this scenario where there is insufficient capacity available to meet electricity demand. The maximum capacity shortfall in this scenario was found to be 5,929 MW at 8:00 P.M. on August 24. This shortfall could potentially be sufficient to trigger load shedding if adequate demand-side resources and imports are not available, of which the company models having just over 3,000 MW of winter-peak resources available. However, this projected availability is dependent on imports from neighboring utilities remaining the same, which as the company notes, is highly questionable[25]:

> *It is expected that if current trends hold, as neighboring systems continue to install solar and storage resources, the neighbors' LOLE (Loss of Load Expectation) risk may shift to the winter months as it has for Duke Energy. This could potentially lower the amount of neighbor assistance available in the future since there may be fewer capacity reserves available during winter peak periods. Thus, it is difficult to project the level of firm market resources and available transmission for providing reliability assistance in the next decade and beyond.*

[25] Carolinas Carbon Plan, "Quantitative Analysis."

Analysis of Portfolio 2

Scenario Overview: Portfolio 2: "70 percent by 2032 OSW" — Portfolio 2 would aggressively deploy two 800 MW blocks of offshore wind, the first in 2029 and the second in 2031, to achieve the 70 percent interim target by 2032. As described in greater detail in Appendix P, "Transmission Planning and Grid Transformation," connecting the second block of offshore wind would require extensive additional transmission upgrades.

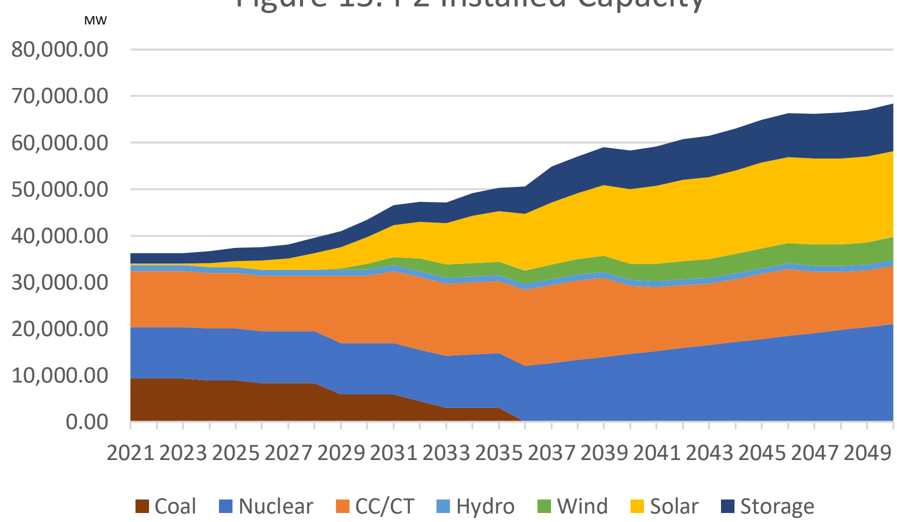
Importantly, Portfolio 2 would extend the timeframe for achieving the 70 percent interim target relative to P1, allowing time for constructing needed additional transmission, enabling greater contributions from grid edge resources and customer programs, and a slightly less aggressive pace of new solar and energy storage additions. Portfolio 2 would plan for the same coal unit retirement schedule as Portfolio 1, except that Roxboro Units 3-4 (1,409 MW) are proposed to be retired by 2032.

By 2035, P2 would retire 6,300 MW of coal and add 10,600 MW of solar, 1,200 MW of onshore wind, 1,600 MW of offshore wind, 2,400 MW of battery storage, 2,400 MW of combined cycle natural gas/hydrogen, 1,200 MW of combustion turbine natural gas/hydrogen, 600 MW of nuclear, and 1,700 MW of pumped storage.

By 2050, P2 would retire 9,300 MW of coal and add 18,200 MW of solar, 1,700 MW of onshore wind, 3,200 MW of offshore wind, 5,900 MW of battery storage, 2,400 MW of combined cycle natural gas/hydrogen, 6,800 MW of combustion turbine natural gas and hydrogen, 9,900 MW of nuclear, and 1,700 MW of pumped storage.

Under Portfolio 2, the amount of installed capacity on North Carolina's electric grid would increase from 36.3 GW in 2021 to 50.2 GW by 2035 and increase to 68.4 GW by 2050, representing a near doubling of the amount of installed capacity on Duke Energy's electric system (Figure 15).

Figure 15. P2 Installed Capacity



Cost

Portfolio 2 would cost $162.3 billion through 2050, much of which would occur after 2035.

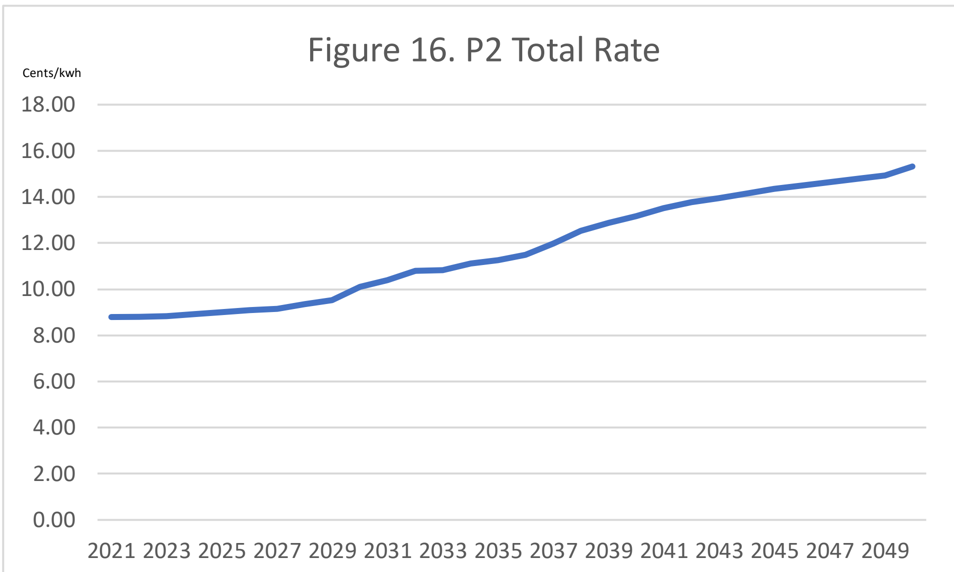
The two largest sources of expenses consist of $91.8 billion in utility returns, and $53.9 billion in additional generation costs, while $4 billion in transmission expenses, and $12.5 billion in property tax expenses are also included.

Ratepayer Impact

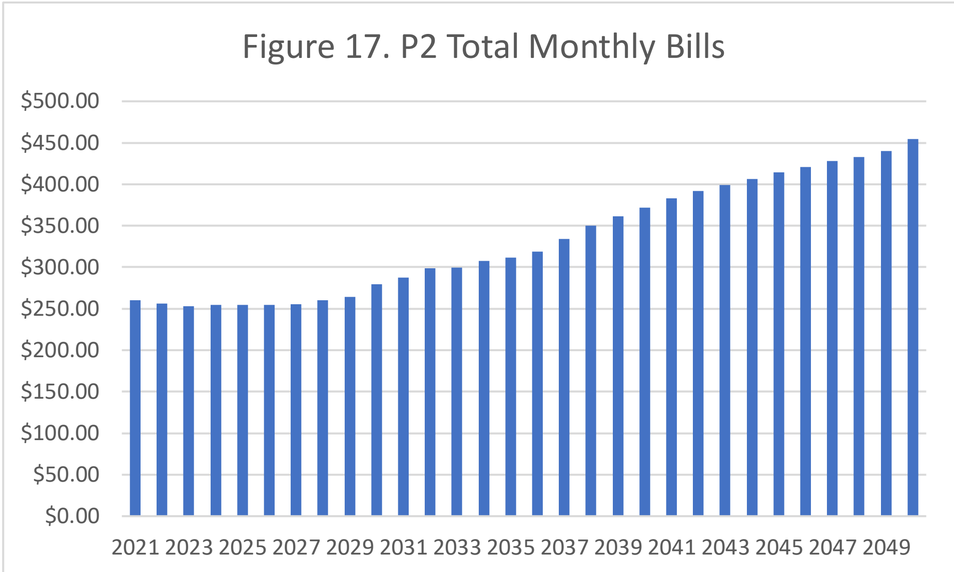
This resource plan would increase the cost of electricity substantially for each customer rate class.

Total

The graph below shows the projected annual cost increase in total electricity prices from 2021 through 2050. Rates would increase by 2.47 cents/kWh in 2035 and 6.53 cents/kWh by 2050.



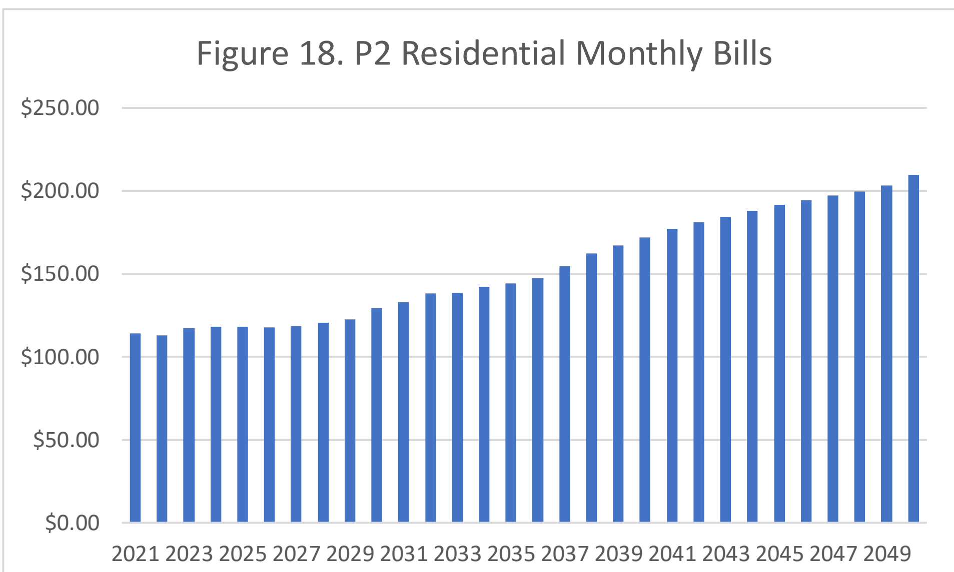
Rising rates would increase average monthly electric bills by $51.75 per month by 2035 and $194.24 per month by 2050, which you can see in the graph below.



Residential

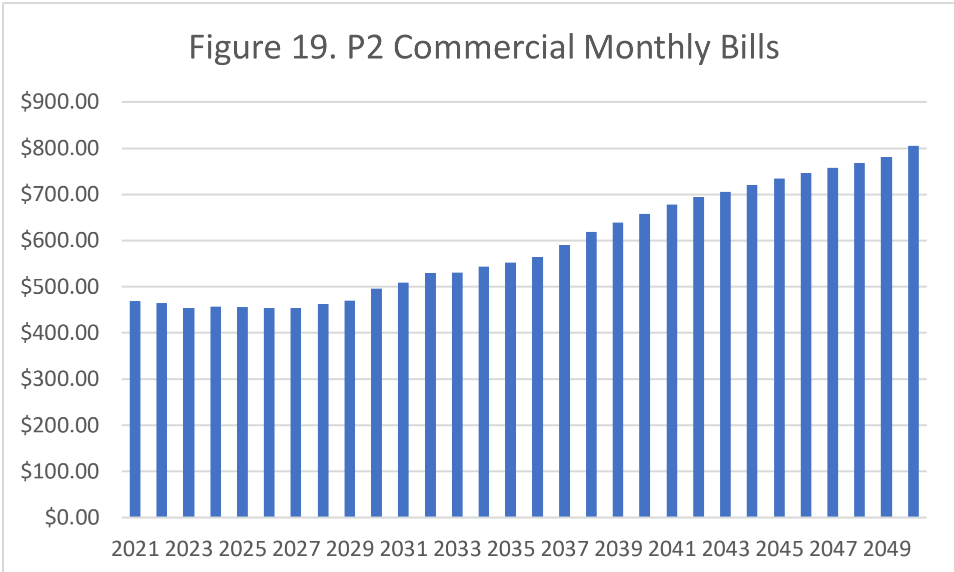
Residential rates would increase by 3.08 cents/kWh in 2035 and 8.16 cents/kWh by 2050.

Rising rates would increase average monthly electric bills by $30.04 per month by 2035 and $95.23 per month by 2050, which you can see in the graph below.



Commercial

Commercial rates would increase by 2.35 cents/kWh in 2035 and 6.21 cents/kWh by 2050.Rising rates

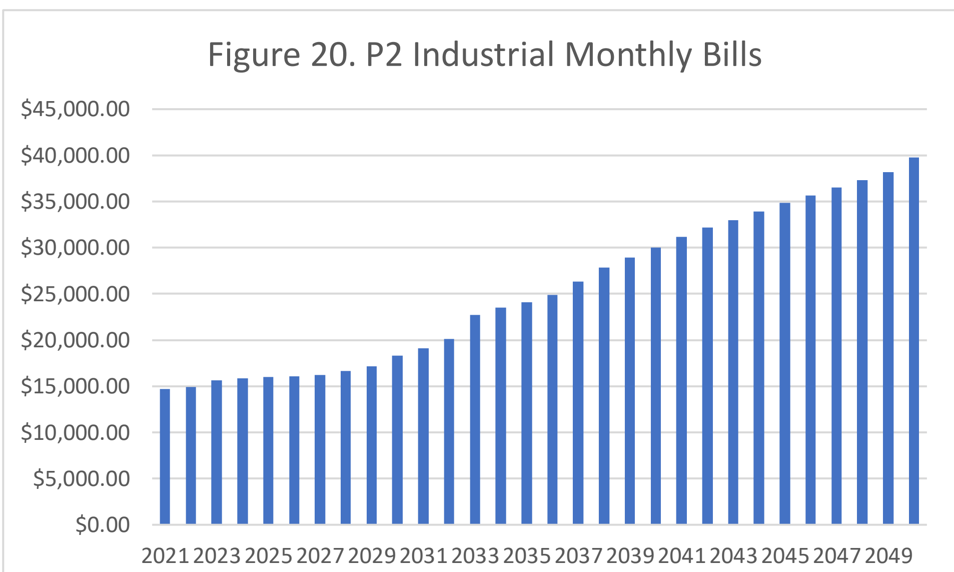


would increase average monthly electric bills by $83.81 per month by 2035 and $337.24 per month by 2050, which you can see in the graph.

Industrial

Industrial rates would increase by 1.68 cents/kWh in 2035 and 4.45 cents/kWh by 2050.

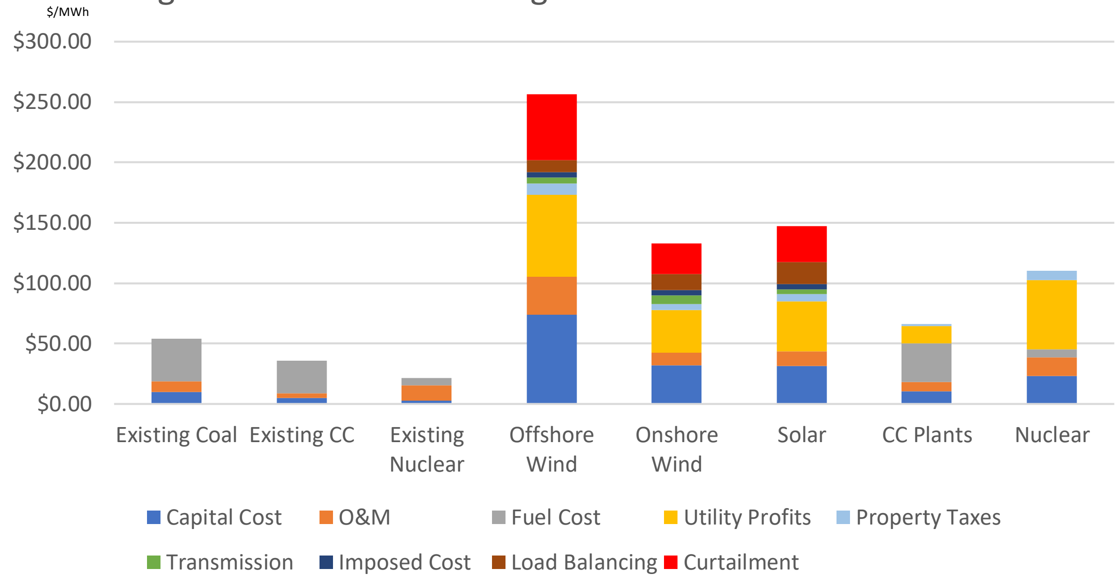
Rising rates would increase average monthly electric bills by $9,397.06 per month by 2035 and $25,025.45 per month by 2050, which you can see in the graph below.



The Levelized Cost of Energy for Each Resource Type

In P2, costs are highest for wind and solar facilities because, unlike with traditional fossil fuel plants and nuclear plants, they have large transmission, load balancing and overbuilding and curtailment costs. Small Modular Nuclear plants are also costly but less so than intermittent renewables or hydrogen-powered turbines.

Figure 21. P2 LCOE: Existing vs New Generation Resources



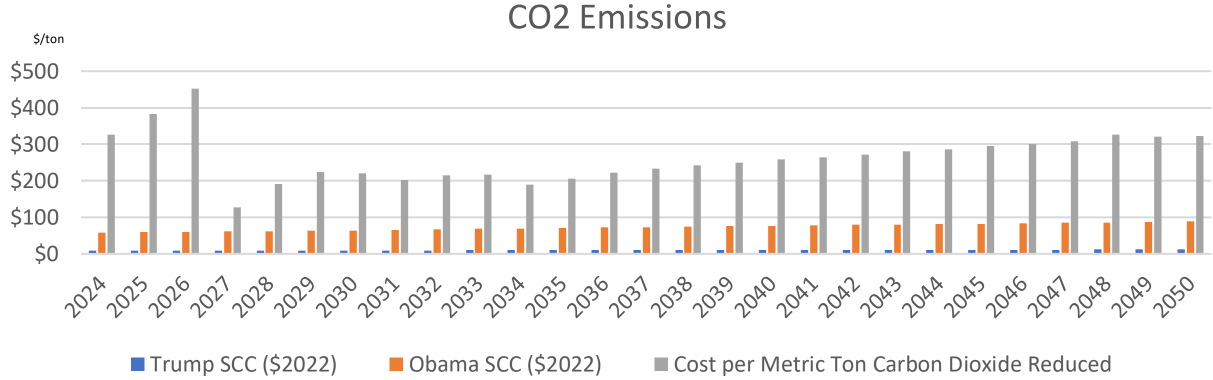
Also, as discussed in "Analysis of Portfolio 1," the cost of using hydrogen, $716 per MWh, is substantially higher than that of natural gas, $300 per MWh (see Figure 11).

Emissions Reductions

Through 2050, North Carolina would see total CO_2 reductions of 626 million metric tons compared with 2020 levels. It would be an average CO_2 emission reduction of 21.6 million metric tons per year through 2050.

The average cost of reducing CO_2 emissions would be $259 per metric ton reduced through 2050. This cost is exorbitant even when compared against Social Cost of Carbon (SCC) values estimated by both the

Figure 22. P2 Obama Social Cost of Carbon vs. Cost of Reducing CO2 Emissions



Obama and Trump administrations. In fact, the cost of CO_2 reductions resulting from building offshore wind facilities exceeds SCC estimates from both administrations every single year (see Figure 22).

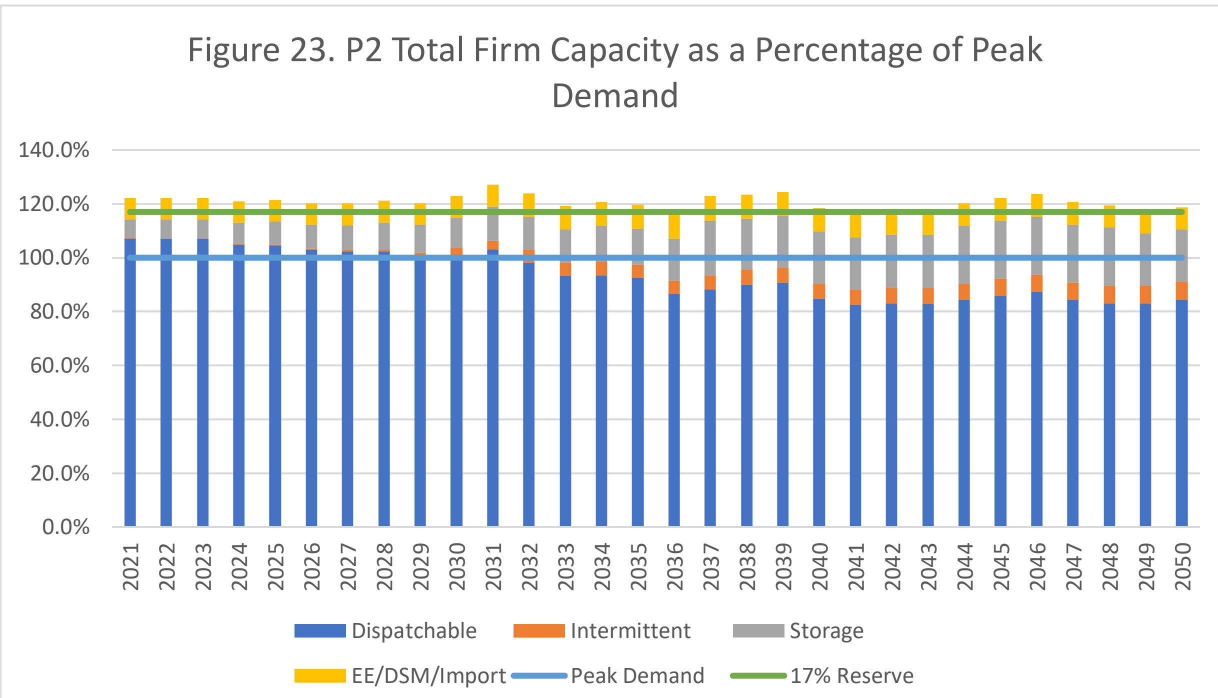
Reliability

This analysis evaluated reliability of Scenario 2 on an *annual* and *hourly* basis.

Figure 23 shows Duke's planned reliable capacity compared with peak winter load. Winter values are shown because it is when electricity demand is highest. Wind and solar effective load-carrying capacities produced by Duke are used for this analysis.

Alarmingly, Duke plans to rely upon the accredited capacity of wind and solar, storage, and LMRS to meet net load after 2032. Such reliance would be irresponsible because, as we learned in California and Texas, accredited capacities for wind and solar generation are not guaranteed, and an overreliance on these technologies could result in capacity shortfalls.

The amount of fuel-based dispatchable capacity used to meet Duke's reserve margin is dwindling



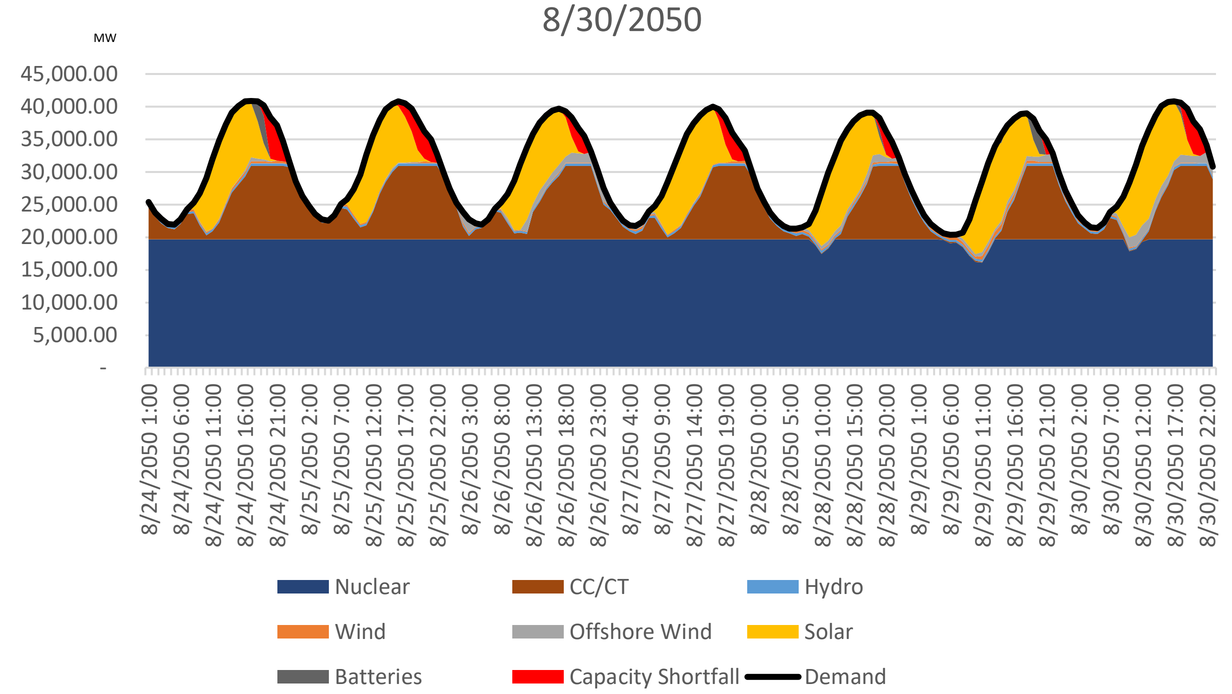
because maintaining an adequate safety net with wind and solar is extremely expensive due to their lower accredited capacity. For example, Duke anticipates capacity values for stand-alone solar will eventually be as little as 1 or 2 percent during peak demand periods, which occur in Duke's system during winter months.[26]

The *hourly* reliability of this scenario (Figure 24) was evaluated comparing real-time hourly load for Duke Energy Progress and Duke Energy Carolinas for estimated hourly generation from all resource types for every hour of the year.[27]

[26] Carolinas Carbon Plan, "Quantitative Analysis."
[27] See Appendix, "Reliability."

This model utilizes hourly load shape and generation data from EIA's electric grid monitor to obtain hourly demand data, peak load, and capacity factors for onshore wind and solar.[28] For offshore wind capacity factors, the data are utilized power data for offshore wind in Eastern North Carolina from the SAM database for the National Renewable Energy Laboratory.[29] These were the best representations of hourly wind and solar resources for North Carolina. Nuclear, with the addition of more flexible SMR technologies, natural gas/hydrogen power plants, and storage facilities are used as peaking resources for intermittent power. Excess wind, solar, and nuclear power are allowed to charge storage facilities when room is available to store additional energy. The model also assumes no power loss from charge to discharge.

Figure 24. P2 Hourly Load Shape, Capacity Shortfalls: 8/24/2050-8/30/2050



Using this metric, we have identified 31 hours in this scenario where there is insufficient capacity available to meet electricity demand.

The maximum capacity shortfall in this scenario was found to be 6,328 MW. This shortfall may be sufficient to trigger load shedding if adequate demand-side resources are not available.

[28] Hourly Electric Grid Monitor, U.S. EIA, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

[29] SAM, NREL, https://sam.nrel.gov.

Analysis of Portfolio 3

Scenario Overview: Portfolio 3 (P3): "70 percent by 2034 SMR" — Portfolio 3 would target the achievement of 70 percent CO2 emissions reductions by 2034 with new nuclear. It is the only portfolio that does not include the deployment of offshore wind. By extending the 70 percent interim target timeframe to 2034, this portfolio would allow the first new nuclear unit (285 MW SMR), deployed in 2032, to contribute toward achieving the 70 percent interim target.

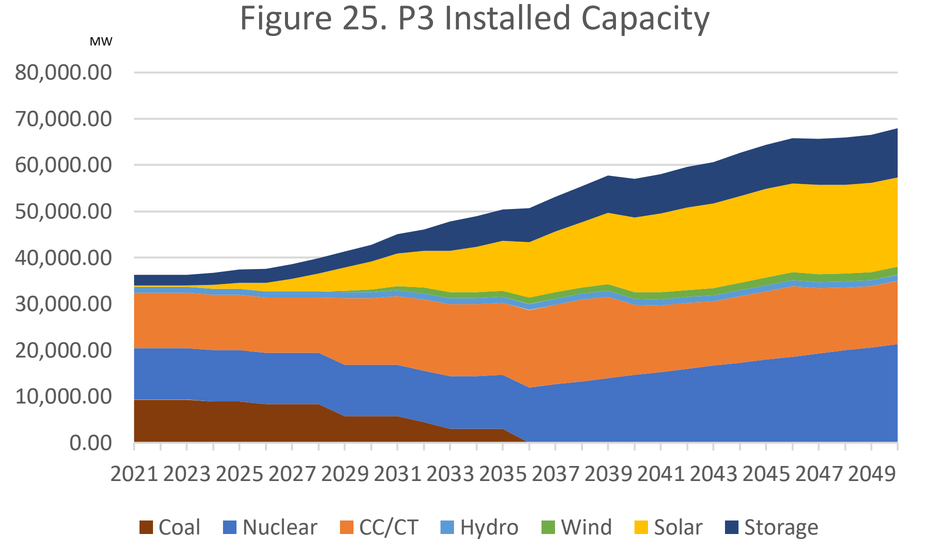
P3 would extend the timeframe for achieving the 70 percent interim target relative to P1 and P2, allowing additional time for deployment of solar, wind, battery, pumped storage hydro, and grid edge resources to contribute to meeting the interim target. P3 plans for the same coal unit retirement schedule as Portfolios 1 and 2, except for Roxboro Units 3-4 (1,409 MW) which are retired by 2034 in this portfolio.

By 2035, P3 would retire 6,300 MW of coal and add 10,500 MW of solar, 1,200 MW of onshore wind, 2,500 MW of battery storage, 2,400 MW of natural gas/hydrogen combined cycle, 1,200 MW of natural gas/hydrogen combustion turbine, 600 MW of nuclear, and 1,700 MW of pumped storage.

By 2050, P3 would retire 9,300 MW of coal and add 19,000 MW of solar, 1,800 MW of onshore wind, 6,400 MW of battery storage, 2,400 MW of combined cycle natural gas/hydrogen, 7,500 MW of combustion turbine natural gas/hydrogen, 10,200 MW of nuclear, and 1,700 MW of pumped storage.

Under P3, the amount of installed capacity on North Carolina's electric grid would increase from 36.3 GW in 2021 to 50.4 GW by 2035 and increase to 68 GW by 2050, representing a near doubling of the amount of installed capacity on Duke Energy's electric system (see Figure 25).

Figure 25. P3 Installed Capacity



Cost

P3 would cost $141.7 billion through 2050, much of which would occur after 2035.

The two largest sources of expenses consist of $83.6 billion in utility returns and $42.6 billion in additional generation costs, while $4 billion in transmission expenses and $11.4 billion in property tax expenses are also included.

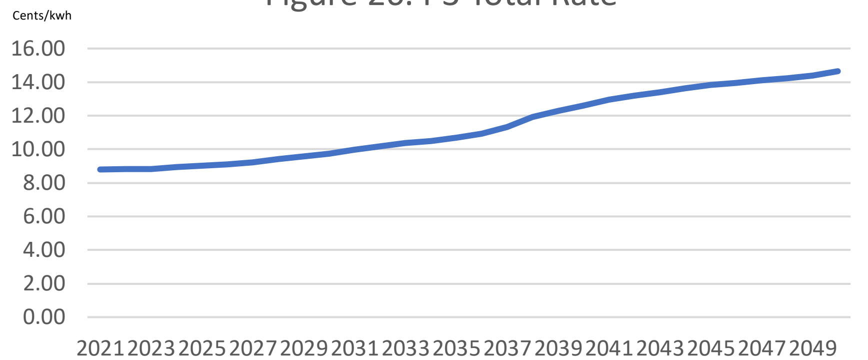
Ratepayer Impact

This resource plan would increase the cost of electricity substantially for each customer rate class.

Total

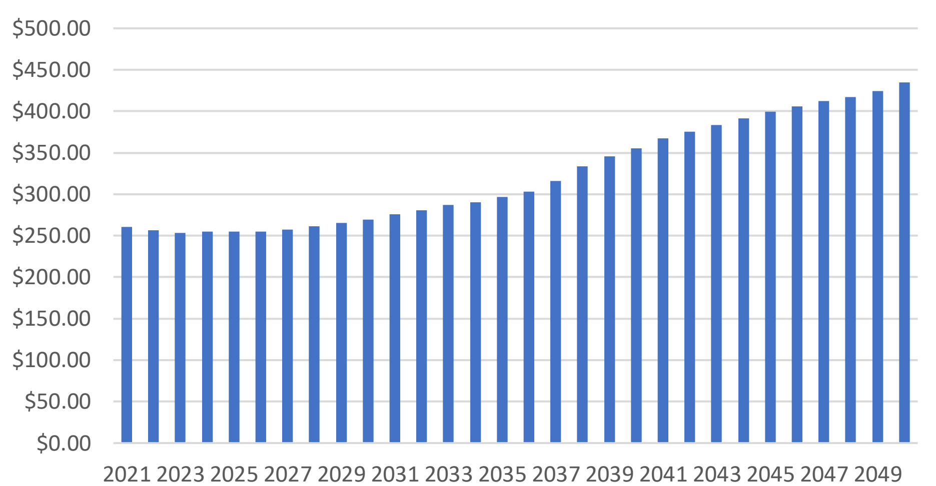
The graph below shows the projected annual cost increase in total electricity prices from 2021 through 2050. Rates would increase by 2.03 cents/kWh in 2035 and 6.17 cents/kWh by 2050.

Figure 26. P3 Total Rate



Rising rates would increase average monthly electric bills by $36.28 in 2035 and $174.29 in 2050, which you can see in the graph below.

Figure 27. P3 Total Bills

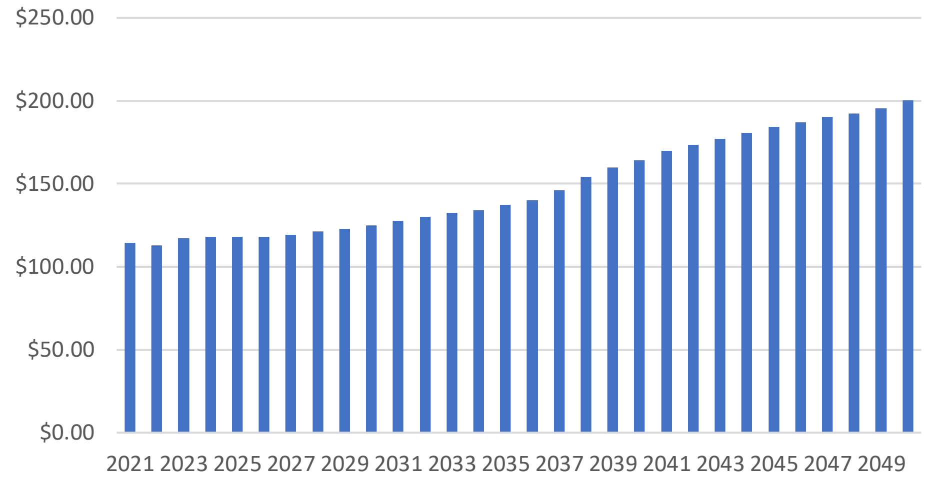


Residential

Residential rates would increase by 2.54 cents/kWh in 2035 and 7.72 cents/kWh by 2050.

Rising rates would increase average monthly electric bills by $22.88 in 2035 and $86.04 in 2050, which you can see in the graph below.

Figure 28. P3 Residential Monthly Bills

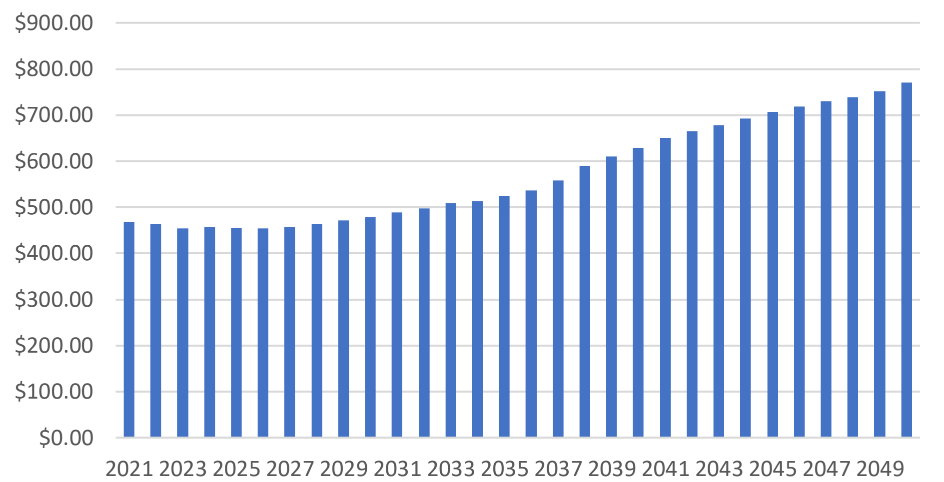


Commercial

Commercial rates would increase by 1.94 cents/kWh in 2035 and 5.87 cents/kWh by 2050.

Rising rates would increase average monthly electric bills by $56.44 in 2035 and $301.89 in 2050, which

Figure 29. P3 Commercial Monthly Bills

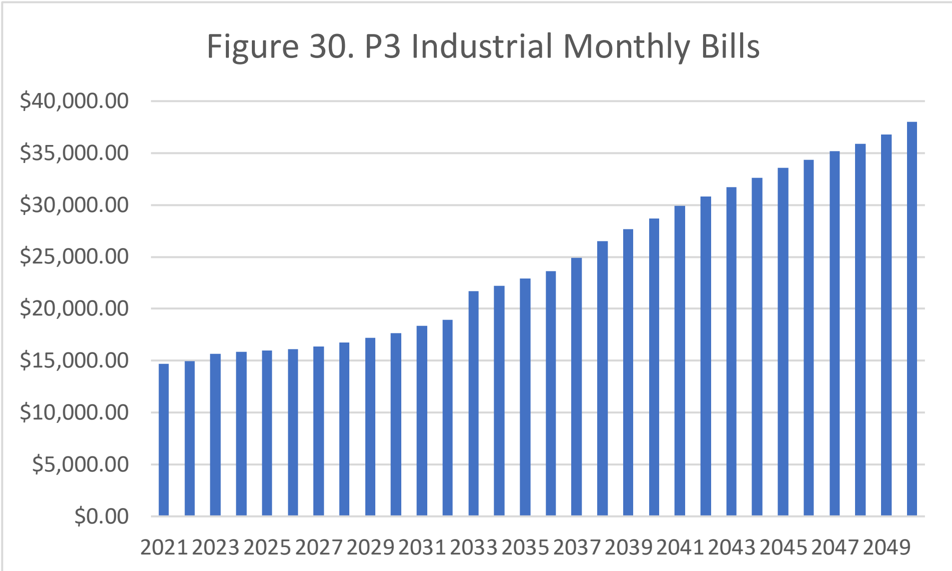


you can see in the graph.

Industrial

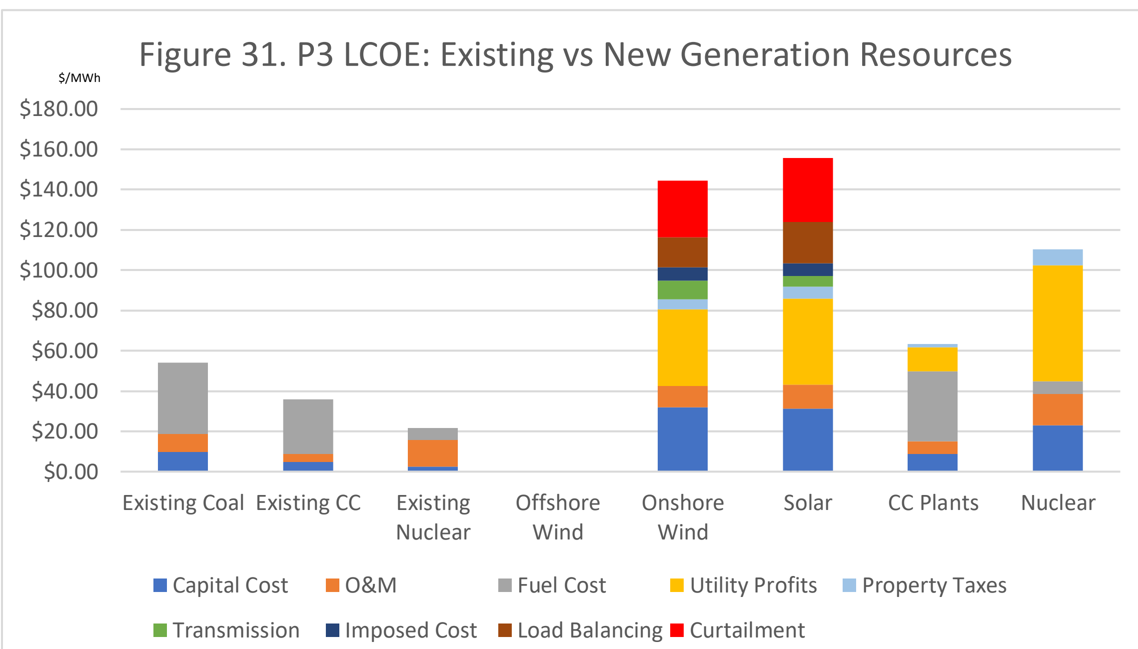
Industrial rates would increase by 1.34 cents/kWh in 2035 and 4.21 cents/kWh by 2050.

Rising rates would increase average monthly electric bills by $8,201.24 in 2035 and $23,280.99 in 2050, which you can see in the graph below.



The Levelized Cost of Energy for Each Resource Type

Costs are higher for wind and solar facilities because, unlike with traditional fossil fuel plants and nuclear plants, grids powered with large concentrations of intermittent wind and solar projects require much more transmission than systems consisting largely of dispatchable power systems.[30]

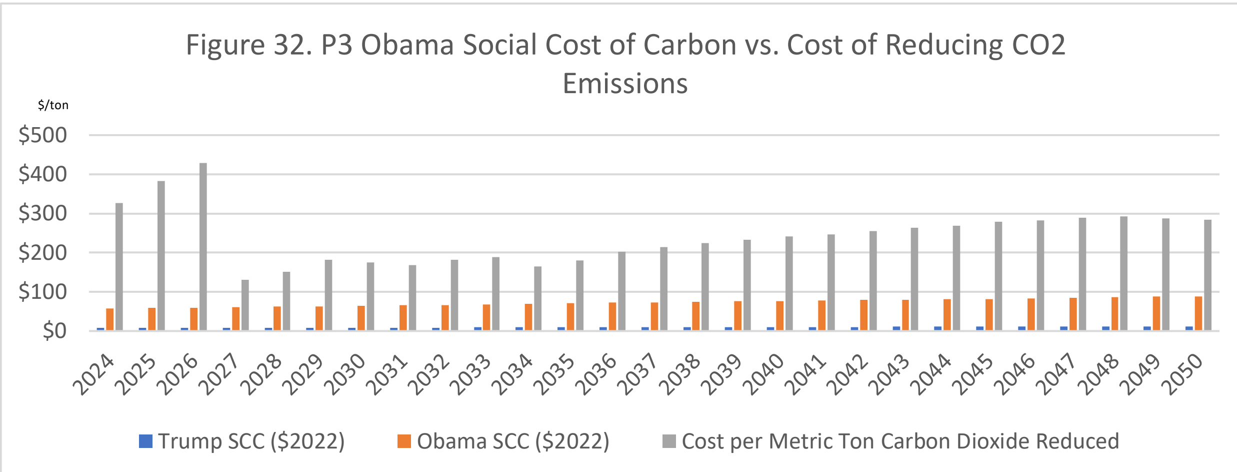


[30] See Appendix, "Factors Affecting the 'All-In' Levelized Cost of Renewables."

Also, as discussed in "Analysis of Portfolio 1," the cost of using hydrogen, $716 per MWh, is substantially higher than that of natural gas, $300 per MWh (see Figure 11).

Emissions Reductions

Through 2050, North Carolina would see total CO_2 reductions of 592 million metric tons compared with 2020 levels. It would be an average CO_2 emission reduction of 20.4 million metric tons per year through 2050.

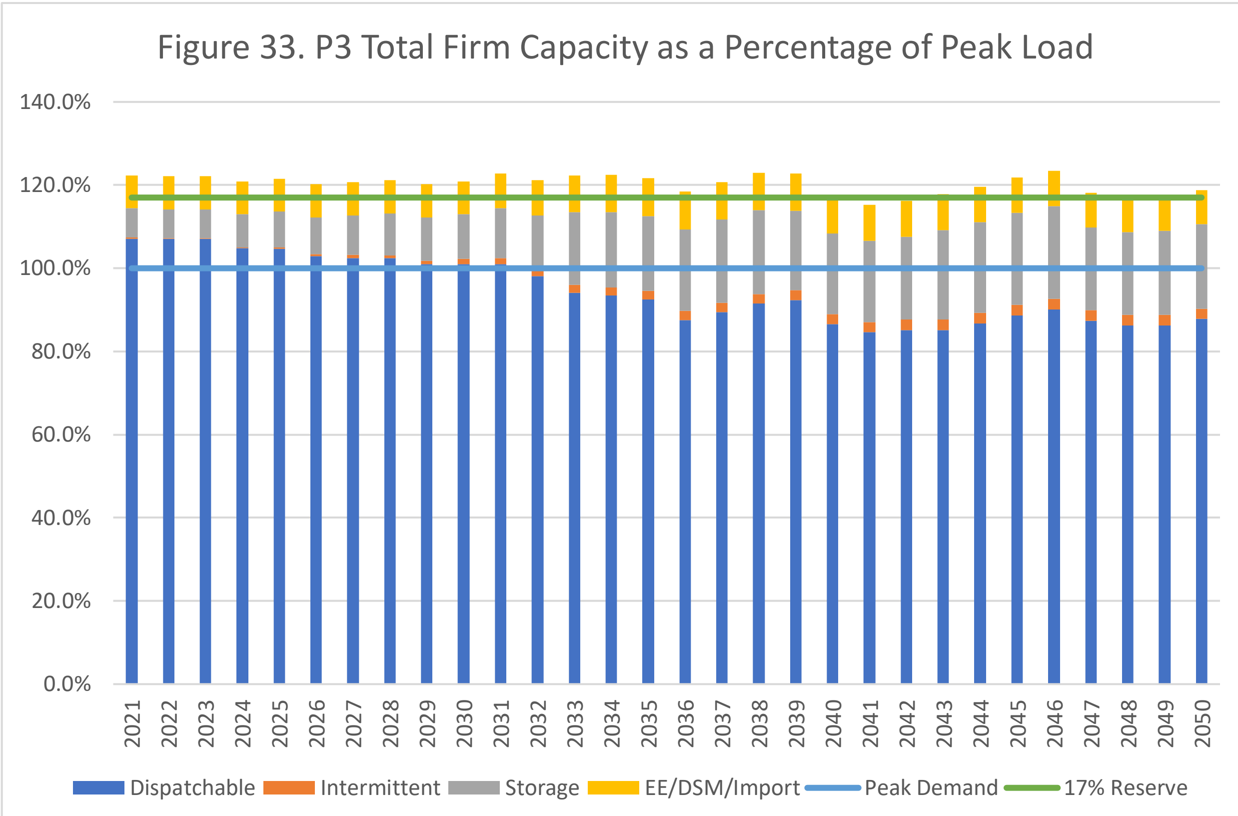


The average cost of reducing CO_2 emissions would be $253 per metric ton reduced through 2050. This cost is exorbitant even when compared against Social Cost of Carbon (SCC) values estimated by both the Obama and Trump administrations. In fact, the cost of CO_2 reductions would exceed SCC estimates from both administrations every single year (see Figure 32).

Reliability

This analysis evaluated reliability of P3 on an *annual* and *hourly* basis.

Figure 33 shows Duke's planned reliable capacity compared with peak winter load. Winter values are shown because it is when electricity demand is highest. Wind and solar effective load-carrying capacities produced by Duke are used for this analysis.



Alarmingly, Duke plans to rely upon wind and solar accredited capacities, storage facilities, and demand side management (DSM) to meet net load after 2032.

The amount of fuel-based dispatchable capacity used to meet Duke's reserve margin is dwindling because it is relying on nonfirm generation, DSM, and storage. For example, Duke anticipates capacity values for stand-alone solar will eventually be as little as 1 or 2 percent during peak demand periods, which occur in Duke's system during winter months.[31]

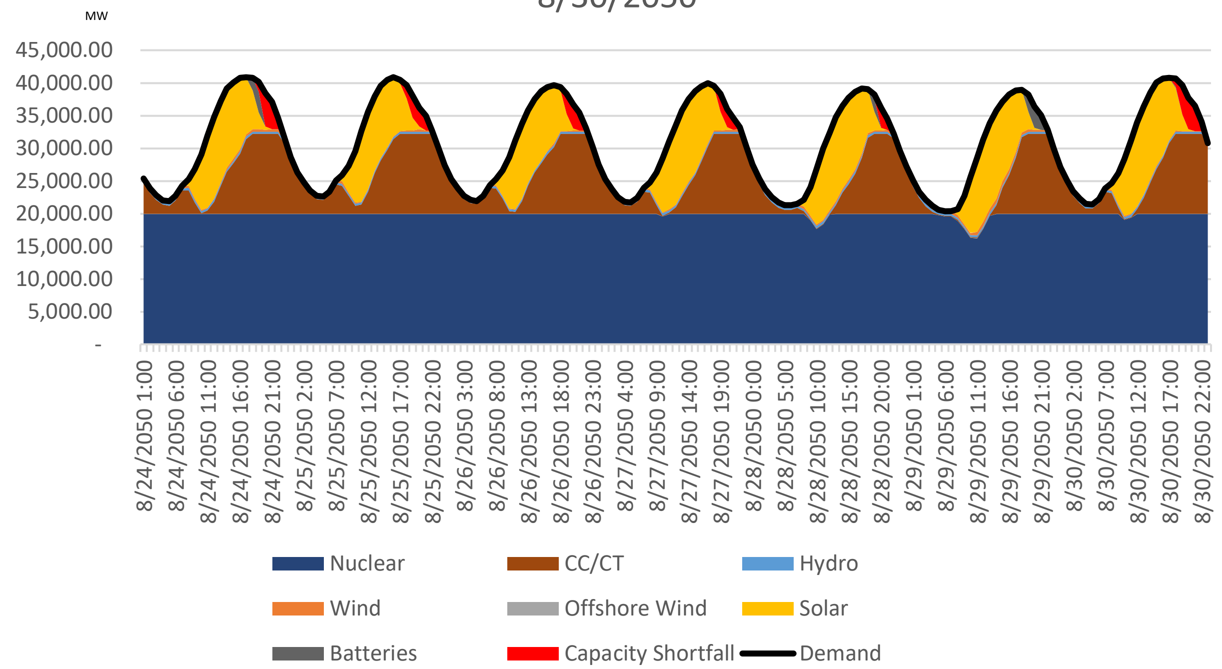
The *hourly* reliability of this scenario (Figure 34) was evaluated comparing real-time hourly load for Duke Energy Progress and Duke Energy Carolinas for estimated hourly generation from all resource types for every hour of the year.[32]

[31] Carolinas Carbon Plan, "Quantitative Analysis."

[32] See Appendix, "Reliability."

This model utilizes hourly load shape and generation data from EIA's electric grid monitor to obtain hourly demand data, peak load, and capacity factors for onshore wind and solar.[33] For offshore wind capacity factors, the data are utilized power data for offshore wind in Eastern North Carolina from the SAM database for the National Renewable Energy Laboratory.[34] These were the best representations of hourly wind and solar resources for North Carolina. Nuclear, with the addition of more flexible SMR technologies, natural gas/hydrogen power plants, and storage facilities are used as peaking resources for intermittent power. Excess wind, solar, and nuclear power are allowed to charge storage facilities when room is available to store additional energy. The model also assumes no power loss from charge to discharge.

Figure 34. P3 Hourly Load Shape, Capacity Shortfalls: 8/24/2050-8/30/2050



Using this metric, we have identified 32 hours in this scenario where there is insufficient capacity available to meet electricity demand.

The maximum capacity shortfall in this scenario was found to be 5,054 MW. This shortfall may be sufficient to trigger load shedding if adequate demand-side resources and energy imports are not available.

[33] Hourly Electric Grid Monitor, U.S. EIA, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

[34] SAM, NREL, https://sam.nrel.gov.

Analysis of Portfolio 4

Scenario Overview: Portfolio 4 (P4): "70 percent by 2034 OSW+SMR" — P4 would deploy both offshore wind and new nuclear resources to achieve the 70 percent interim target by 2034. To meet this target, 285 MW (one unit) of nuclear SMR and 800 MW (one 800 MW block) of offshore wind would be added in the early 2030s. The extended timeframe would allow for greater contributions from grid edge resources, as well as additional time to build out required solar, onshore wind, battery, and pumped storage hydro capacity.

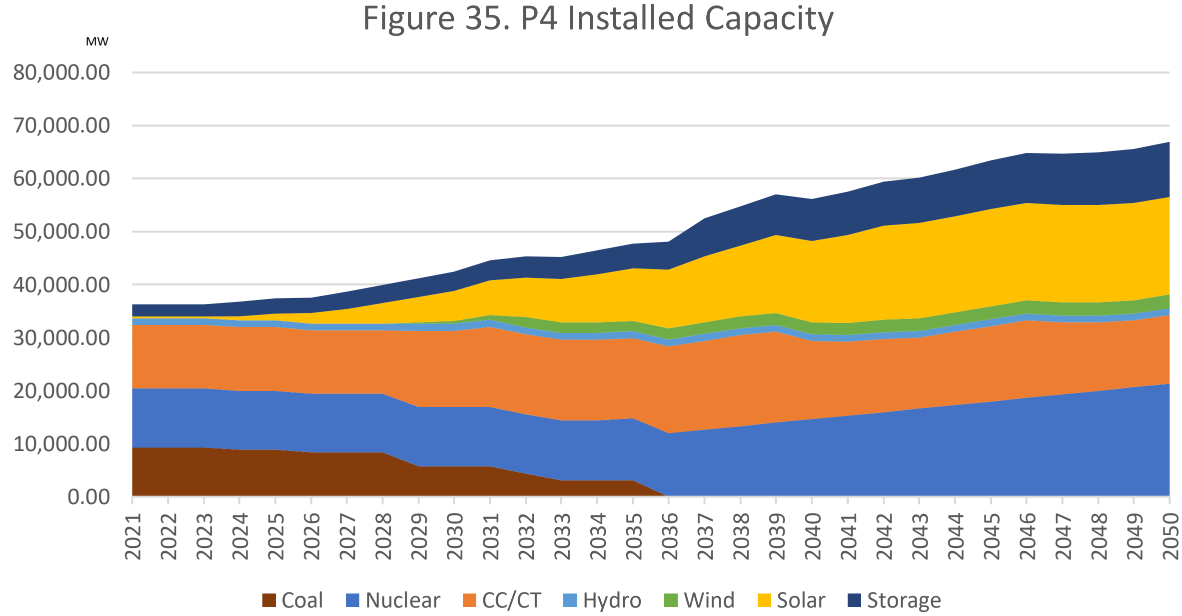
P4 plans for the same coal unit retirement schedule as P1 and P2, except for Roxboro Units 3-4 (1,409 MW) which are retired by 2034 in this Portfolio.

By 2035, P4 would retire 6,300 MW of coal and add 9,500 MW of solar, 1,200 MW of onshore wind, 800 MW of offshore wind, 2,100 MW of battery storage, 2,400 MW of combined cycle natural gas/hydrogen, 1,200 MW of combustion turbine natural gas/hydrogen, 600 MW of nuclear, and 1,700 MW of pumped storage.

By 2050, P4 would retire 9,300 MW of coal and add 18,100 MW of solar, 1,800 MW of onshore wind, 800 MW of offshore wind, 6,100 MW of battery storage, 2,400 MW of combined cycle natural gas/hydrogen, 6,800 MW of combustion turbine natural gas/hydrogen, 10,200 MW of nuclear, and 1,700 MW of pumped storage.

Under P4, the amount of installed capacity on North Carolina's electric grid would increase from 36.3 GW in 2021 to 47.7 GW by 2035 and increase to 66.9 GW by 2050, representing a near doubling of the amount of installed capacity on Duke Energy's electric system (see Figure 35).

Figure 35. P4 Installed Capacity



Cost

P4 would cost $146.2 billion through 2050, much of which would occur after 2035.

The two largest sources of expenses consist of $85.2 billion in utility returns and $45.4 billion in additional generation costs, while $4 billion in transmission expenses and $11.6 billion in property tax expenses are also included.

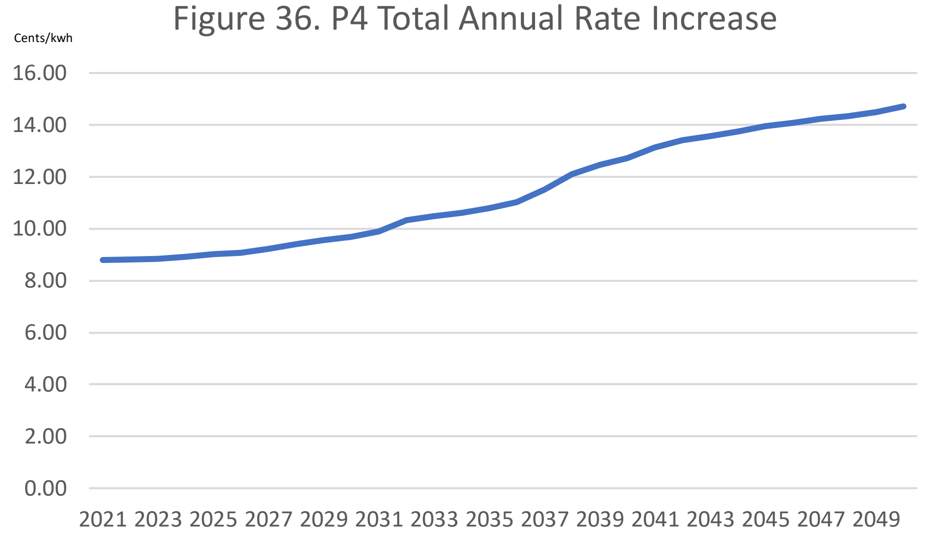
Ratepayer Impact

This resource plan would increase the cost of electricity substantially for each customer rate class.

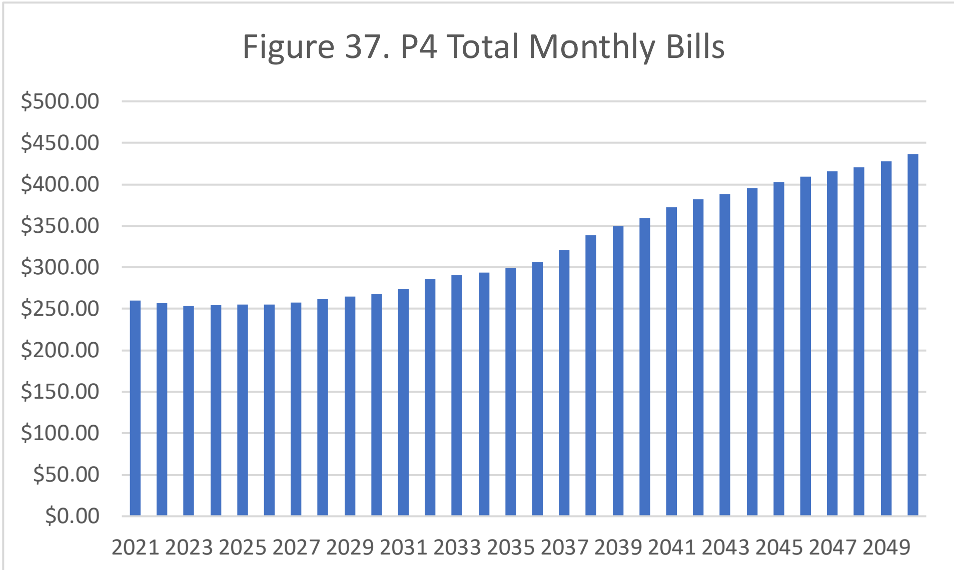
Total

The graph below shows the projected annual cost increase in total electricity prices from 2021 through 2050. Rates would increase by 2.13 cents/kWh in 2035 and 6.24 cents/kWh by 2050.

Figure 36. P4 Total Annual Rate Increase



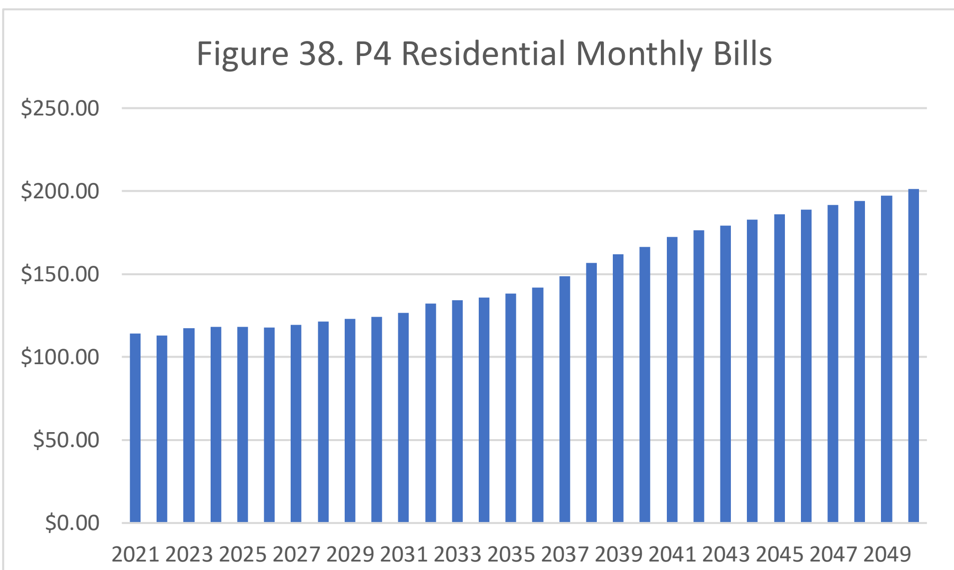
Rising rates would increase average monthly electric bills by $38.97 in 2035 and $176.29 in 2050, which you can see in the graph below.



Residential

Residential rates would increase by 2.67 cents/kWh in 2035 and 7.81 cents/kWh by 2050.

Rising rates would increase average monthly electric bills by $24.13 in 2035 and $86.96 in 2050, which you can see in the graph below.

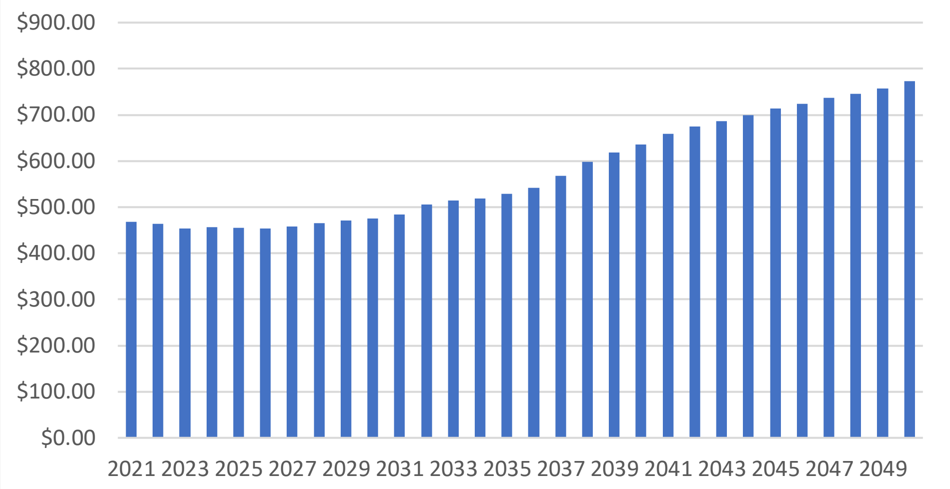


Commercial

Commercial rates would increase by 2.03 cents/kWh in 2035 and 5.94 cents/kWh by 2050.

Rising rates would increase average monthly electric bills by $61.21 in 2035 and $305.42 in 2050, which you can see in the graph below.

Figure 39. P4 Commercial Monthly Bills

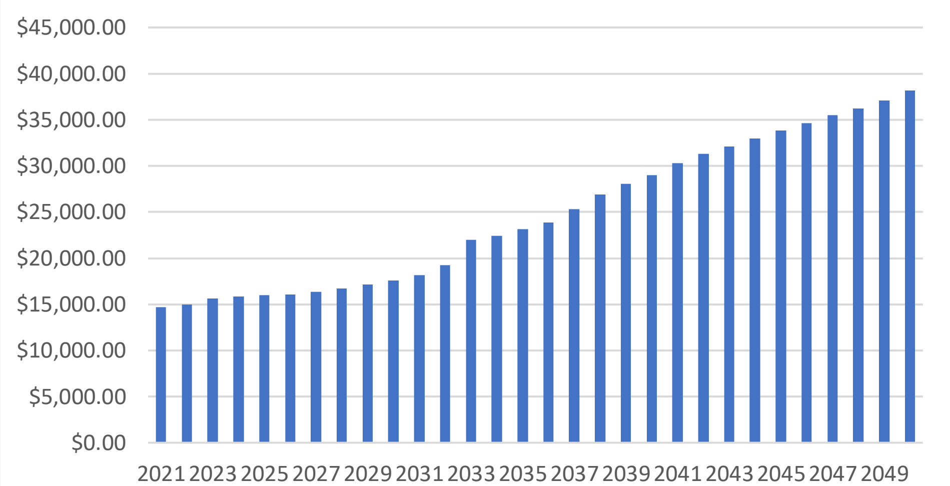


Industrial

Industrial rates would increase by 1.45 cents/kWh in 2035 and 4.26 cents/kWh by 2050.

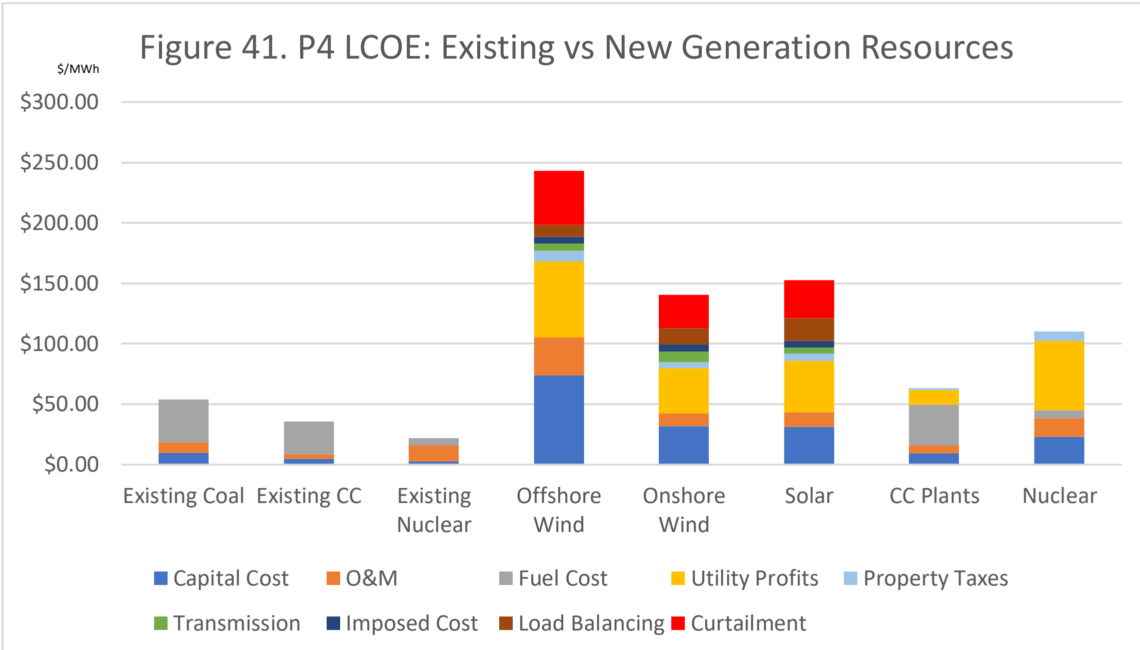
Rising rates would increase average monthly electric bills by $8,409.46 in 2035 and $23,455.61 in 2050, which you can see in the graph below.

Figure 40. P4 Industrial Monthly Bills



The Levelized Cost of Energy for Each Resource Type

Costs are higher for wind and solar facilities because, unlike with traditional fossil fuel plants and nuclear plants, grids powered with large concentrations of intermittent wind and solar projects require much more transmission than systems consisting largely of dispatchable power systems.[35]



Also, as discussed in "Analysis of Portfolio 1," the cost of using hydrogen, $716 per MWh, is substantially higher than that of natural gas, $300 per MWh (see Figure 11).

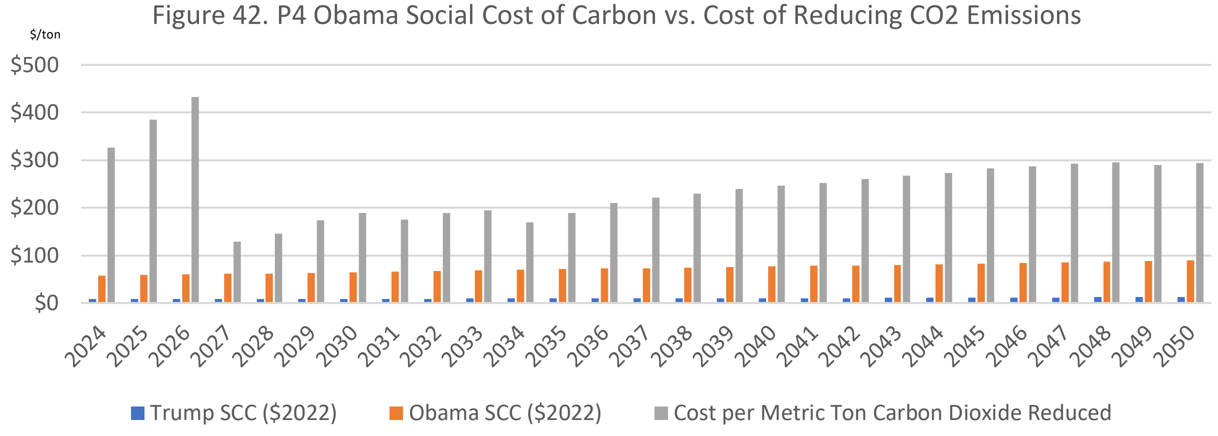
Emissions Reductions

Through 2050, North Carolina would see total CO_2 reductions of 599 million metric tons compared to 2021 levels. It would be an average CO_2 emission reduction of 20.7 million metric tons per year through 2050.

[35] See Appendix, "Factors Affecting the 'All-In' Levelized Cost of Renewables."

The average cost of reducing CO_2 emissions would be $257 per metric ton reduced through 2050. This cost is exorbitant even when compared against Social Cost of Carbon (SCC) values estimated by both the Obama and Trump administrations. In fact, the cost of CO_2 reductions would exceed SCC estimates from both administrations every single year (See Figure 42).

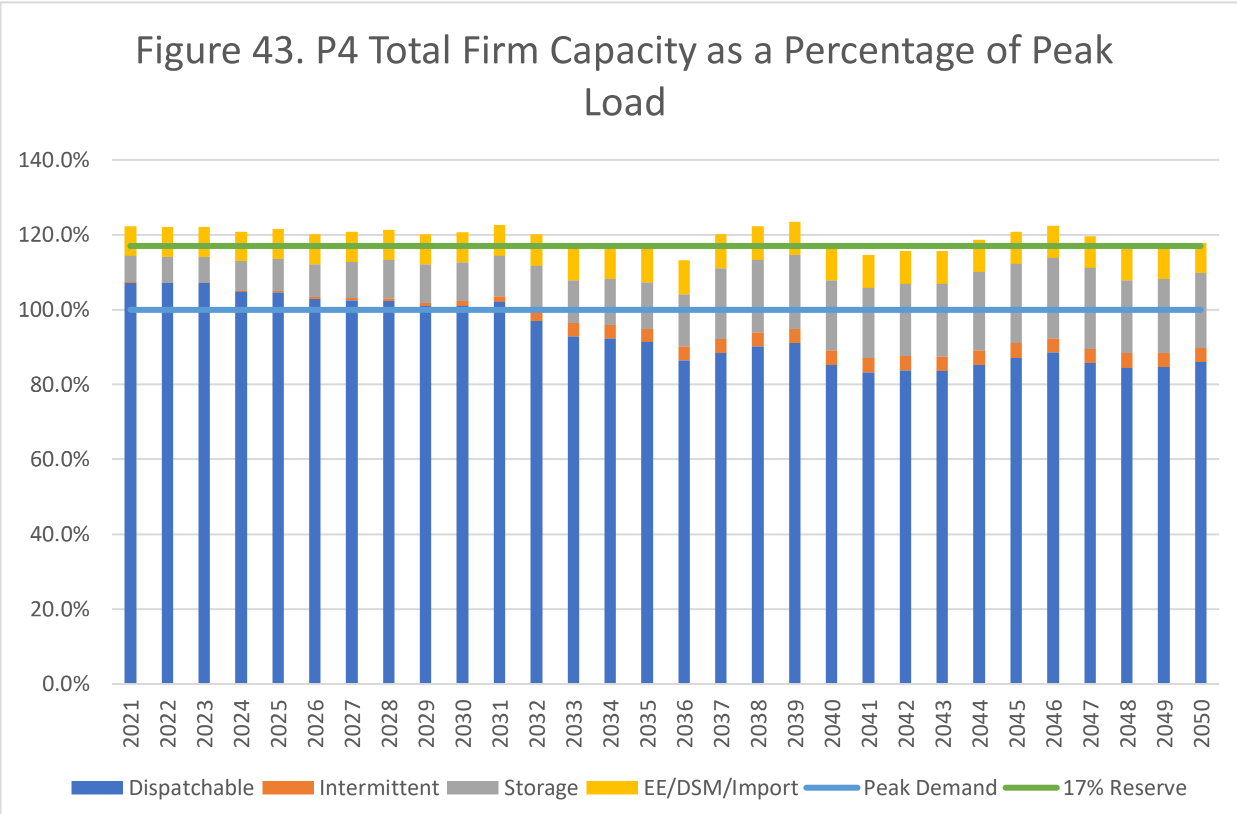
Figure 42. P4 Obama Social Cost of Carbon vs. Cost of Reducing CO2 Emissions



Reliability

This analysis evaluated reliability of P4 on an *annual* and *hourly* basis.

Figure 43 shows Duke's planned reliable capacity compared to peak winter load. Winter values are shown because it is when electricity demand is highest. Wind and solar effective load-carrying capacities produced by Duke are used for this analysis.



Alarmingly, Duke plans to rely upon accredited wind and solar capacities, storage, and DSMs to meet net load beginning in 2032.

The amount of fuel-based dispatchable capacity used to meet Duke's reserve margin is dwindling because it is relying on nonfirm generation, DSM, and storage. For example, Duke anticipates capacity values for stand-alone solar will eventually be as little as 1 or 2 percent during peak demand periods, which occur in Duke's system during winter months.[36]

The *hourly* reliability of this scenario (Figure 44) was evaluated comparing real-time hourly load for Duke Energy Progress and Duke Energy Carolinas for estimated hourly generation from all resource types for every hour of the year.[37]

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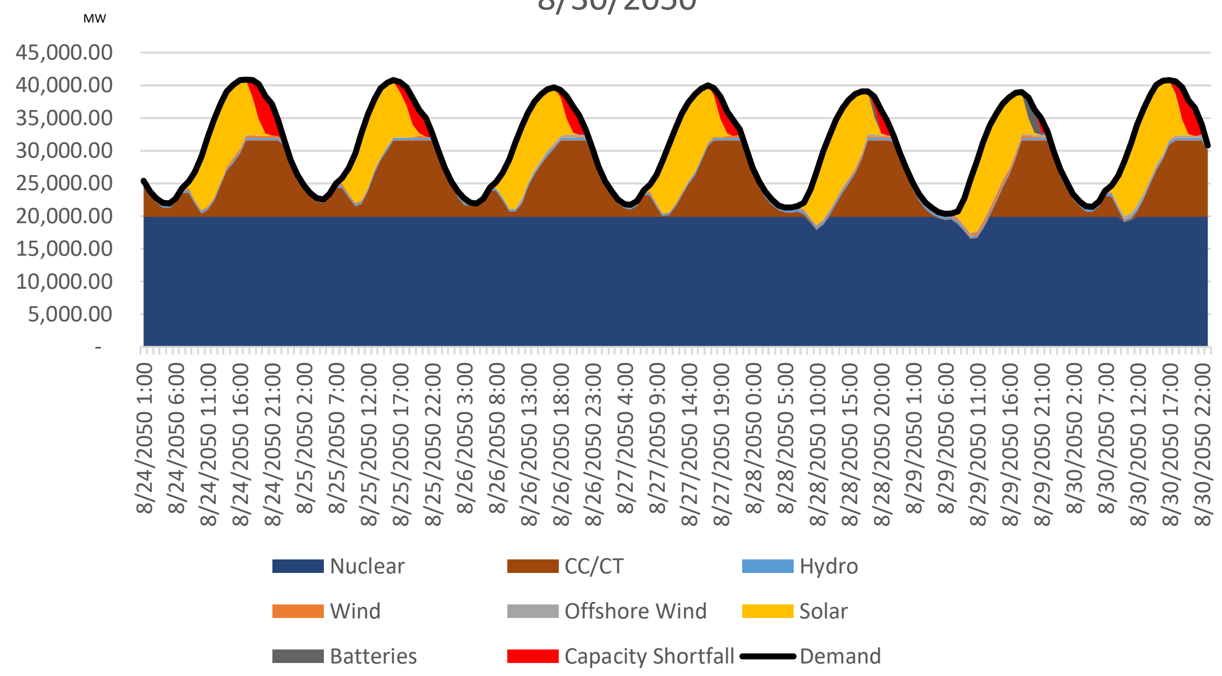
[36] Carolinas Carbon Plan, "Quantitative Analysis."

[37] See Appendix, "Reliability."

This model utilizes hourly load shape and generation data from EIA's electric grid monitor to obtain hourly demand data, peak load, and capacity factors for onshore wind and solar.[38] For offshore wind capacity factors, the data are utilized power data for offshore wind in Eastern North Carolina from the SAM database for the National Renewable Energy Laboratory.[39] These were the best representations of hourly wind and solar resources for North Carolina. Nuclear, with the addition of more flexible SMR technologies, natural gas/hydrogen power plants, and storage facilities are used as peaking resources for intermittent power. Excess wind, solar, and nuclear power are allowed to charge storage facilities when room is available to store additional energy. The model also assumes no power loss from charge to discharge.

Figure 44. P4 Hourly Load Shape, Capacity Shortfalls: 8/24/2050-8/30/2050



Using this metric, we have identified 41 hours in this scenario where there is insufficient capacity available to meet electricity demand.

The maximum capacity shortfall in this scenario was found to be 5,698 MW. This shortfall may be sufficient to trigger load shedding if adequate demand-side resources are not available.

[38] Hourly Electric Grid Monitor, U.S. EIA, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

[39] SAM, NREL, https://sam.nrel.gov.

Analysis of the Least Cost Decarbonization Scenario

Scenario Overview: American Experiment's analysis has concluded that none of the four scenarios proposed by Duke is truly a least-cost, reliable scenario for decarbonization. We are proposing an alternative scenario called the Least Cost Decarbonization scenario (LCD) to achieve similar rates of decarbonization at a lower cost, utilizing more reliable generators.

This portfolio is predicated on the flexibility and discretion provided to the Commission in HB 951 to determine the optimal timing and resource mix to achieve the least-cost path to HB 951's CO_2 emissions reduction targets.

To this effect, the LCD would utilize existing coal plants to mitigate rising natural gas prices and keep these units online until the mid-2030s, when new nuclear power plants would be brought online to replace them. This strategy is consistent with the letter — *and* the spirit — of HB 951, which seeks to optimize low costs and reliability by providing flexibility on the timeline for coal unit retirements.[40]

This approach would also minimize fuel supply risks for natural gas, which could be constrained by a lack of pipeline capacity.

While this scenario would not meet the 70 percent reduction in CO_2 emissions by 2030, relative to a 2005 baseline, HB 951 specifies that the Commission may approve a Carbon Plan that achieves the target after the specified dates "in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical or other factors beyond the control of the electric public utility, or in the event necessary to maintain the adequacy and reliability of the existing grid."

Cost

The LCD Scenario would cost $107.9 billion through 2050, much of which would occur after 2035.

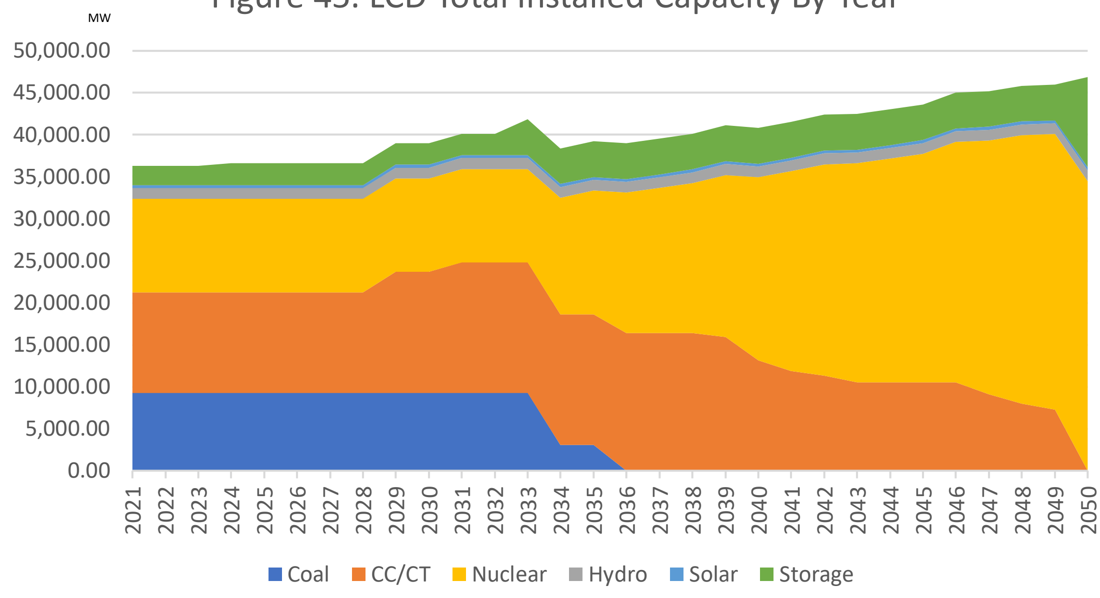
The two largest sources of expenses consist of $74.6 billion in utility returns and $22.5 billion in additional generation costs, while $673 million in transmission expenses and $10.2 billion in property tax expenses are also included.

Under the LCD scenario, the amount of installed capacity on North Carolina's electric grid would increase from 36.3 GW in 2021 to 39.2 GW by 2035 and increase to 46.8 GW by 2050, representing an increase of over 10 GW of the amount of installed capacity on the North Carolina electric system (see Figure 45). In contrast, the four Duke scenarios would all nearly double the amount of installed capacity by 2050.

[40] Carolinas Carbon Plan, "Executive Summary."

Nuclear power, pumped storage, batteries, and natural gas facilities would be the only additions made in this scenario, and coal and natural gas would be phased out by 2050 to comply with the law.

Figure 45. LCD Total Installed Capacity By Year



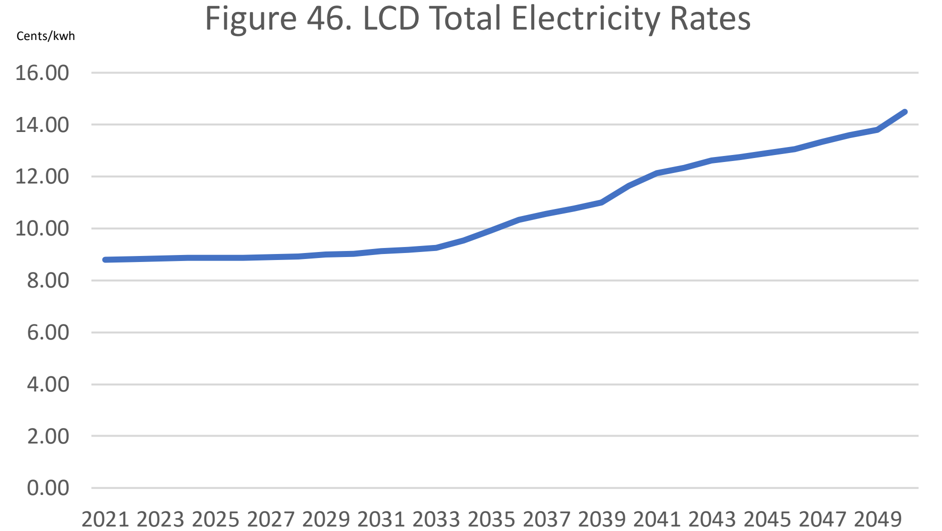
Ratepayer Impact

This resource plan would increase the cost of electricity substantially for each customer rate class.

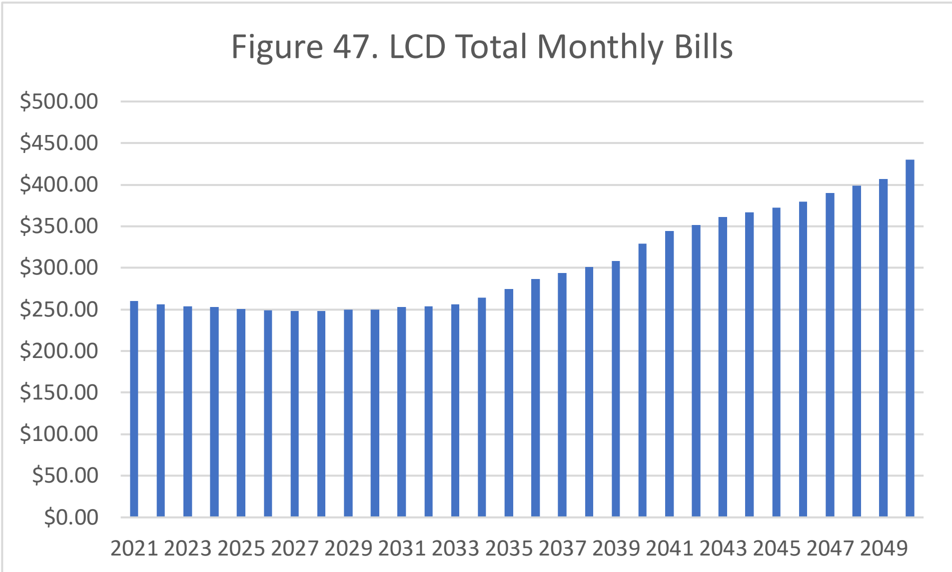
Total

The graph below shows the projected annual cost increase in total electricity prices from 2021 through 2050. Rates would increase by 1.54 cents/kWh in 2035 and 5.89 cents/kWh by 2050.

Figure 46. LCD Total Electricity Rates



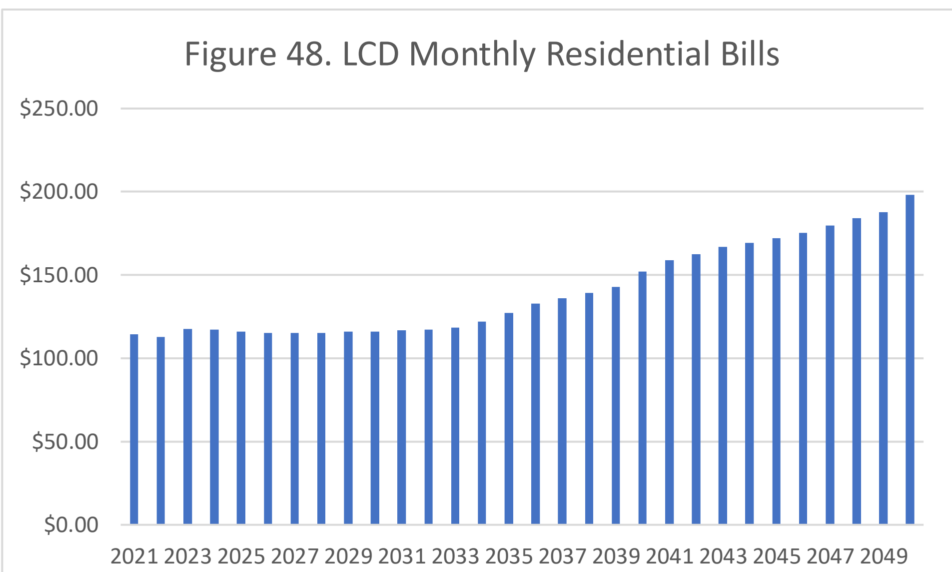
Rising rates would increase average monthly electric bills by $14.76 in 2035 and $169.82 in 2050, which you can see in the graph below.



Residential

The graph below shows the projected annual cost increase in residential electricity prices from 2021 through 2050. Rates would increase by 1.92 cents/kWh in 2035 and 7.36 cents/kWh by 2050.

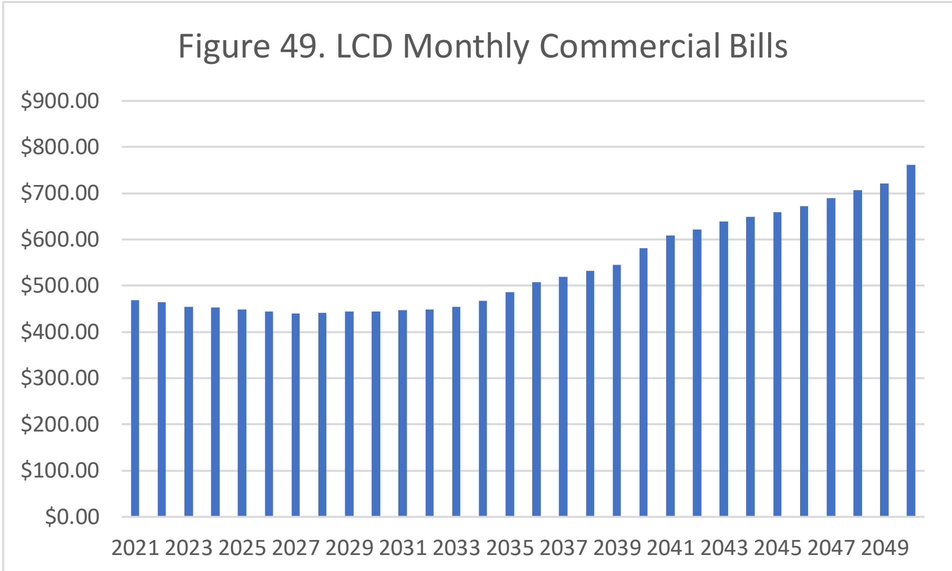
Rising rates would increase average monthly electric bills by $12.93 in 2035 and $83.98 in 2050, which you can see in the graph below.



Commercial

The graph below shows the projected annual cost increase in commercial electricity prices from 2021 through 2050. Rates would increase by 1.46 cents/kWh in 2035 and 5.60 cents/kWh by 2050.

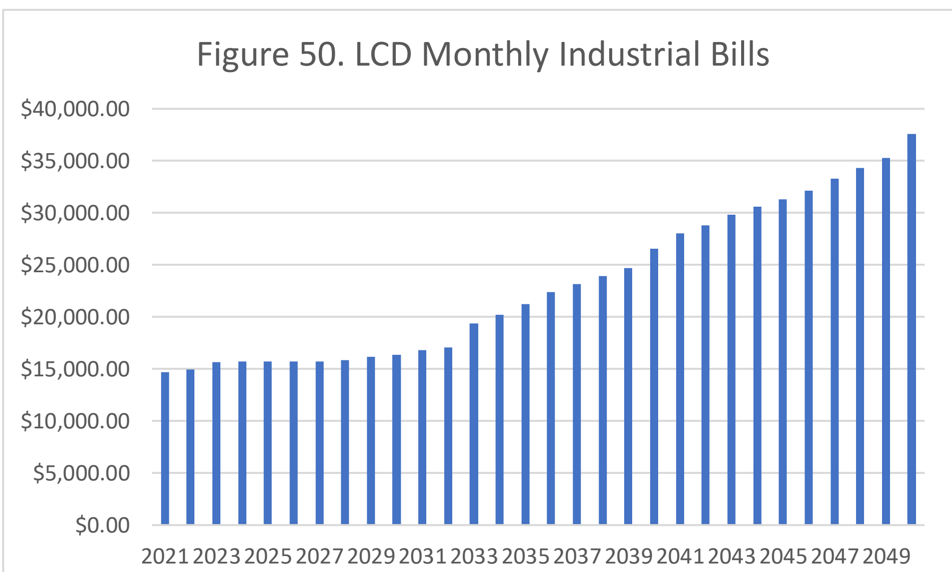
Rising rates would increase average monthly electric bills by $18.37 in 2035 and $293.96 in 2050, which you can see in the graph below.



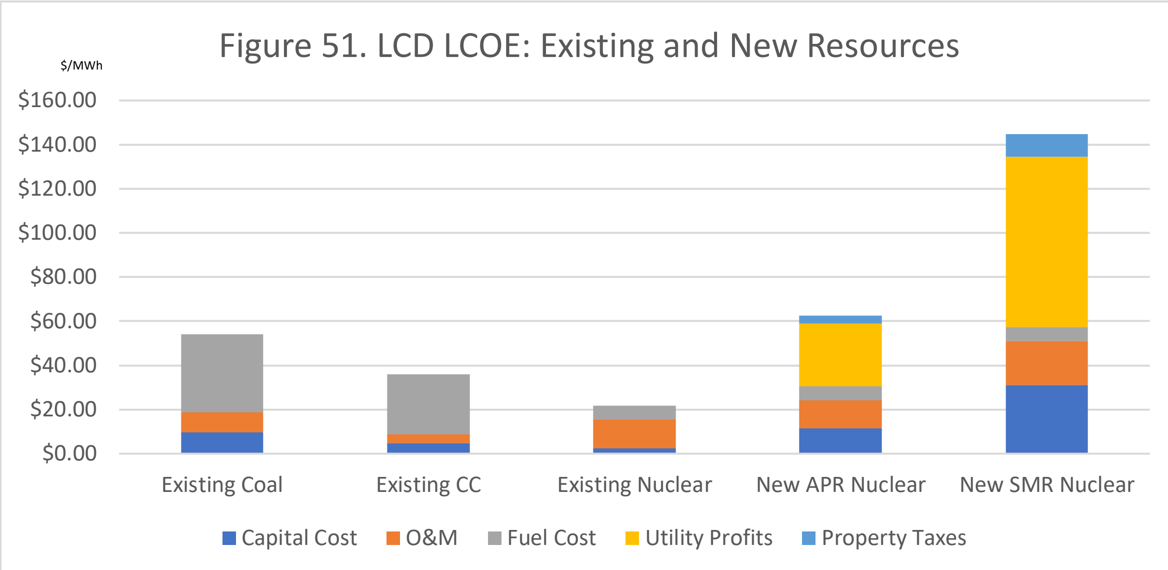
Industrial

The graph below shows the projected annual cost increase in industrial electricity prices from 2021 through 2050. Rates would increase by 1.05 cents/kWh in 2035 and 4.02 cents/kWh by 2050.

Rising rates would increase average monthly electric bills by $6,537.99 in 2035 and $22,890.02 in 2050, which you can see in the graph below.



The Levelized Cost of Energy for Each Resource Type

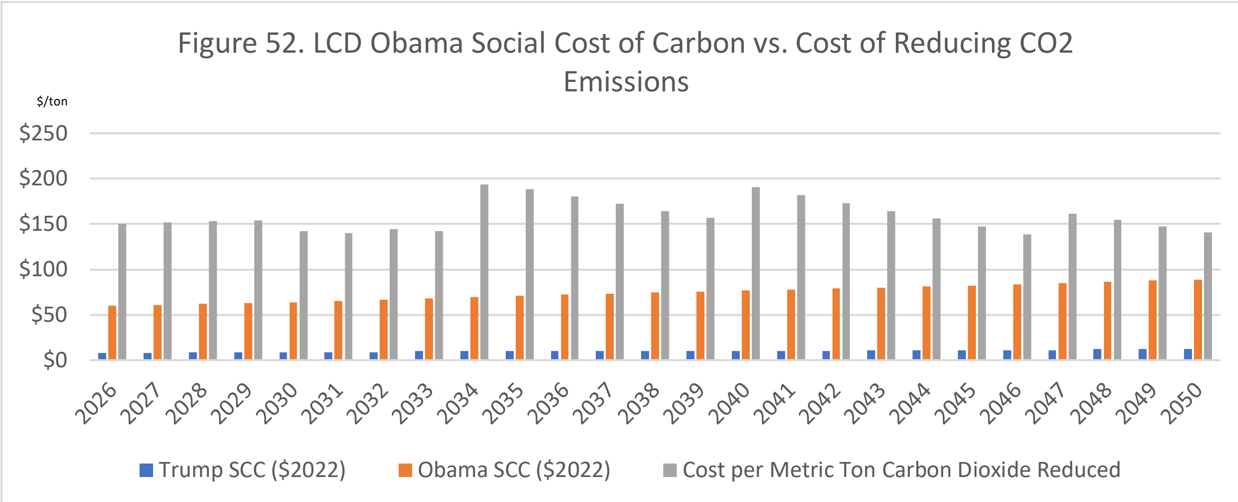


For the LCD scenario, the two primary power plants added to the grid would be APR 1400 and SMR nuclear technologies. SMR power plants are used more for ramping needs, and as such the cost per MWh would increase over time as the plants are utilized less frequently. APR 1400 power plants, however, would be maintained primarily as baseload facilities.

Emissions Reductions

Through 2050, North Carolina would see total CO_2 reductions of 584 million metric tons compared to 2020 levels. It would be an average CO_2 emission reduction of 20.1 million metric tons per year through 2050.

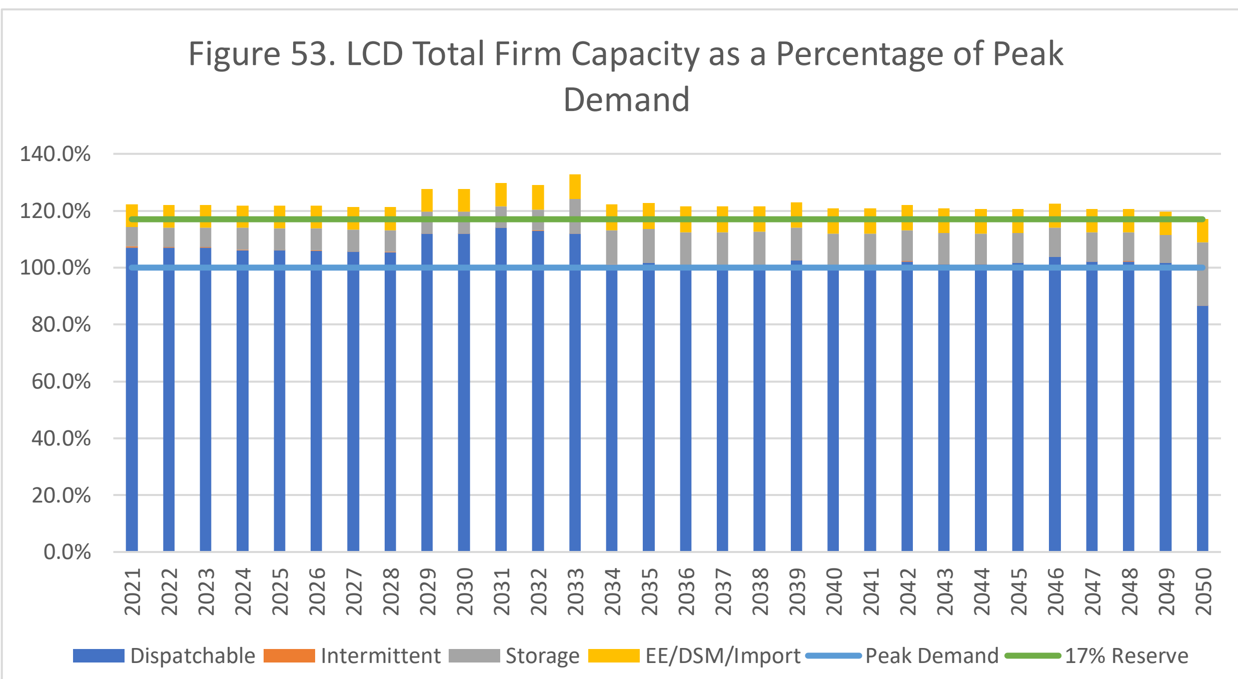
The average cost of reducing CO_2 emissions would be $185 per metric ton reduced through 2050. This cost is very high even when compared against Social Cost of Carbon (SCC) values estimated by both the Obama and Trump administrations. In fact, the cost of CO_2 reductions would exceed SCC estimates from both administrations every single year (see Figure 52).



Reliability

This analysis evaluated reliability of the LCD on an *annual* and *hourly* basis.

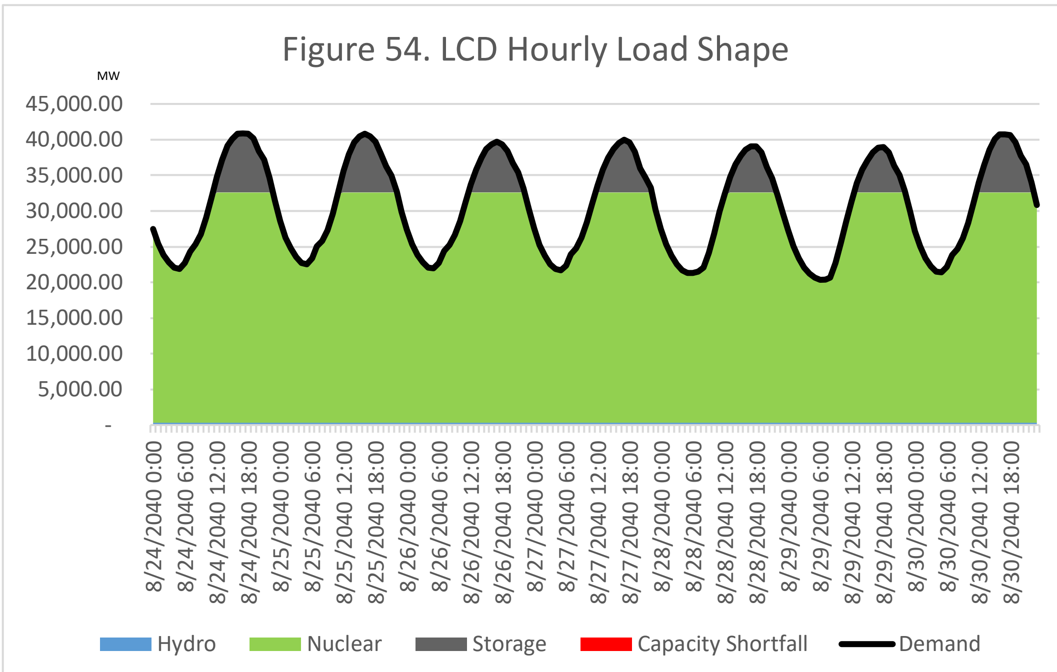
Figure 53 shows the planned reliable capacity compared to peak winter load. Winter values are shown because it is when electricity demand is highest.



In the LCD scenario, there is enough firm dispatchable capacity to meet peak demand in every year but 2050, where adequate storage capacity would provide the needed power. These storage devices are charged using reliable nuclear power plants, ensuring the storage resources would be available when needed most.

The *hourly* reliability of this scenario (Figure 54) was evaluated comparing real-time hourly load for Duke Energy Progress and Duke Energy Carolinas for estimated hourly generation from all resource types for every hour of the year.[41]

As you can see, during the same stretch that every Duke Energy scenario shows a capacity shortfall for at least six out of seven days, which could potentially lead to load-shedding events or blackouts, the LCD scenario maintains reliability through a mixture of nuclear power and storage.



[41] See Appendix, "Reliability."

Conclusion

As this report demonstrates, none of the four portfolios that comprise Duke's Carolinas Carbon Plan fulfill the "least-cost path … to achieve compliance with the authorized carbon reduction goals" set forth in HB 951. Nor do any of them "maintain or improve upon the adequacy and reliability of the existing grid." Each of the portfolios would greatly increase electricity costs on North Carolina consumers, greatly increase the amount of installed capacity well beyond expected population increases would warrant, and result in a less efficient, less reliable grid for our troubles.

Each of the scenarios discussed would cause substantial increases in electricity costs for North Carolina families and businesses, but a portfolio that focuses on building reliable, dispatchable power plants would decarbonize at the lowest possible cost.

Furthermore, nuclear power plants, which can last for up to 80 years, would provide lower-cost electricity in the future as they depreciate and repay initial capital costs. That is not the case for wind and solar assets that only last 20 and 25 years, respectively. They would necessitate a constant "build and rebuild" treadmill of capital expenditures that virtually guarantee ratepayers never have low-cost electricity after capital costs are recouped.

Duke's Carbon Plans are predicated on large capital expenditures for wind and solar and rely on optimistic hydrogen cost assumptions that are not reflective of the current state of the technology. For this reason, more study is needed by stakeholders through a thorough public information process.

The results of this study raise significant questions about the impact of the Carolinas Carbon Plan. Inability to comply with HB 951 means the plan certainly cannot comply with the least-cost, adequate, and reliable service state law rightly considers so important for North Carolinians. It also means the Commission — and the General Assembly — should seek more analysis.

This issue is simply too important for North Carolina families, businesses, schools, churches, governments, and the economy. We need more eyes on the matter, and more time considering it from all angles. Given the magnitude of the costs under consideration, commissioners, legislators, and the public should give the Duke Carbon Plans and related issues a thorough vetting. We owe it to North Carolinians to get this right.

Appendix

1. Capacity additions

Capacity additions for each of the scenarios in Duke's Carbon Plan are based on the capacity additions and retirements Tables E-61 through E-71, found in Appendix E, "Quantitative Analysis."[42]

2. Reliability

The annual reliability of the grid was evaluated for each scenario by comparing the projected winter peak load with the unforced capacity (UCAP) on the grid. For our analysis, we used Duke's capacity values by tranche. However, we are skeptical that onshore and offshore wind values will be as high as the values projected by Duke.

The hourly reliability of each scenario was measured by comparing real-time hourly load for Duke Energy Progress and Duke Energy Carolinas for the year 2021. Load shape data and hourly wind and solar generation were obtained from EIA Form 930.[43]

Duke's load growth assumptions are used to extrapolate load shape through each of the subsequent modeled years. Hourly solar generation data was divided by installed capacity to get the hourly capacity factor. For offshore wind, National Renewable Energy Lab data were used.[44]

3. Factors Affecting the "All-In" Levelized Cost of Renewables

All power plants, regardless of fuel type, have upfront capital costs to repay, require transmission lines, pay property taxes, and, in areas with government-approved monopoly utilities, earn profits for electric companies. However, the intermittency of wind and solar results in a situation where these expenses are greater on electric grids utilizing high levels of renewables compared with grids with more dispatchable generators.

Additionally, the intermittency of wind and solar impose unique expenses on the electric grid that are not imposed by dispatchable generators. These costs include the imposed cost on existing generators, load-balancing costs, and the costs associated with overbuilding and curtailing wind and solar generators to reduce the need for battery storage while at the same time preventing the grid from becoming overloaded.

Capital Costs

Power plants must repay the money spent to construct the facility. However, electric grids with high penetrations of intermittent wind and solar have higher capital costs to repay than grids centered around dispatchable generators because the unreliability of wind and solar means these grids must have more installed capacity to remain reliable.

[42] Carolinas Carbon Plan, "Quantitative Analysis."
[43] Hourly Electric Grid Monitor, " About the EIA-930 data," U.S. EIA, https://www.eia.gov/electricity/gridmonitor/about.
[44] SAM, NREL, https://sam.nrel.gov.

Transmission Costs

Executing the Carbon Plan would require a transformation of the Duke Energy Carolinas, LLC and Duke Energy Progress, LLC transmission system in the near term and the long term to interconnect the unprecedented amounts of new supply-side resources needed to retire significant amounts of coal-fired generation and achieve the carbon emissions reductions targets.

The Carbon Plan would require significant investment in the transmission system on an aggressive timeline to interconnect the significant amounts of incremental new solar, solar plus storage, stand-alone storage, wind, small modular reactors, and new natural gas generation resources identified as needed in the Carbon Plan and reliably to retire the coal units that currently support the grid.[45]

Duke's Carbon Plan provides transmission costs assumptions for each of its four Scenarios which are used to make these LCOE calculations. In the LCD scenario, however, transmission expenses are minimized by building new nuclear facilities near existing coal infrastructure.

Utility Profits

Because investor-owned utilities (IOUs) such as DEC and DEP are regulated monopolies in North Carolina, they are not allowed to make a profit on the electricity they sell. Instead, they are guaranteed a 9.6 percent profit, or rate-of-return on equity, when they spend money on capital assets such as power plants, transmission lines, and even new corporate offices, if the North Carolina Utilities Commission deems these expenses to be in the public interest.

Utility profits are bolstered significantly by provisions in HB 951, which require that any new generation facilities or other resources selected by the Commission in order to achieve the CO_2 emissions reduction goals for electric public utilities must be owned and recovered on a cost-of-service basis by the applicable electric public utility, except in the case of energy efficiency measures and demand-side management, for which existing law applies, and in the case of solar generation, which is to be allocated according to the specified percentages.

Property Taxes

Property taxes are a cost of doing business for every type of power plant. However, due to significant overbuilding of wind and solar, the need for more transmission lines, and "backup" natural gas facilities or battery storage, transitioning to renewable energy uniquely increases property tax costs for utility companies — and thus ratepayers — because there is much more property to tax.

Intermittency Costs Specific to Wind and Solar

Because intermittent renewables are unreliable, they impose unique costs on the electric grid that are not imposed by reliable, dispatchable power sources. American Experiment has

[45] Duke Energy, Carolinas Carbon Plan, "Appendix P. Transmission System Planning and Grid Transformation," https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/carolinas-carbon-plan/supplemental/appendix-p.pdf?la=en&rev=f9cda767bc2d4c55a100771b314689f2.

identified three separate costs — imposed costs, load-balancing costs, and overbuilding and curtailment costs — and detailed them below.

- Imposed Costs

  Imposed costs occur when reliable power plants are forced to reduce their production to make room for intermittent renewable generation on the grid.[46] As the utilization rate of the reliable power plant falls, its LCOE increases because it is spreading its fixed costs over fewer megawatt-hours (MWh) of generation.

- Load-Balancing Costs

  Load-balancing costs stem from the need to provide reliable electricity when the wind is not blowing or the sun is not shining, either with backup natural gas facilities or battery storage.

  We calculate load-balancing costs by determining the total cost of building and operating new natural gas or battery storage facilities to meet electricity demand during the time horizon studied in our models. These costs are then attributed to the LCOE values of wind and solar by dividing the cost of load balancing by the generation of new wind and solar facilities (capacity-weighted).

  Attributing load-balancing costs to wind and solar allows for a more equal comparison of the expenses incurred to meet electricity demand between nondispatchable energy sources, which require backup generation to maintain reliability, and dispatchable energy sources like coal, natural gas, and nuclear facilities that do not require backup generation.

- Overbuilding and Curtailment Costs

  The cost of battery storage for meeting electricity demand is prohibitively high, so many wind and solar advocates argue that it is better to overbuild renewables, often by a factor of five to eight compared with the dispatchable thermal capacity on the grid, to meet peak demand during periods of low wind and solar output. These intermittent resources would then be curtailed when wind and solar output improves.

  As wind and solar penetration increase, a greater portion of their output will be curtailed for each additional unit of capacity installed.[47]

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[46] It should be noted that the imposed cost in this report differs from the Institute for Energy Research report that discusses this topic. The main difference is that IER uses new natural gas facilities to measure the imposed cost, whereas the imposed cost in this report is placed on existing thermal generators (any that need to lower production and spread fixed costs over fewer sales but remain on the grid to “backup” wind and solar generation). New facilities used to “firm up” wind and solar capacity are accounted for through the load-balancing cost below.

[47] Dev Millstein et al., “Solar and Wind Grid System Value in the United States: The Effect of Transmission, Congestion, Generation Profiles, and Curtailment," *Joule,* Volume 5, Issue 7, July 21, 2021, pp. 1749–1775, https://www.sciencedirect.com/science/article/pii/S2542435121002440.

This "overbuilding" and curtailing vastly increases the amount of installed capacity needed on the grid to meet electricity demand during periods of low wind and solar output. The subsequent curtailment during periods of high wind and solar availability effectively lowers the capacity factor of all wind and solar facilities, which greatly increases the cost per MWh produced.

Assessing these costs and attributing them to wind and solar facilities is critical to understanding the cost of using these intermittent resources to meet electricity demand.