Jordan McGillis

ENERGY CROSSROADS

EXPLORING NORTH CAROLINA'S TWO ENERGY FUTURES

locke

JUNE 2021

Energy Crossroads

Exploring North Carolina’s Two Energy Futures

4800 Six Forks Road, Suite 220
Raleigh, NC 27609
(919) 828-3876 | johnlocke.org

v 1.0.0, June 2021

Contents

Executive Summary

North Carolina's Clean Energy Plan, a proposal put together by the Department of Environmental Quality at the behest of Governor Roy Cooper, calls for a 70-percent reduction of greenhouse gas emissions from electricity by 2030 and carbon neutrality by 2050. Duke Energy has submitted Integrated Resource Plans that include pathways to the Clean Energy Plan targets. Duke Energy's Portfolio D most resembles the Clean Energy Plan, deploying wind, solar, and battery storage on an unprecedented scale.

This report assesses North Carolina's existing electricity portfolio, analyzes the changes proposed by Duke Energy's Portfolio D, and compares that scenario to alternatives that utilize nuclear energy and natural gas to achieve emissions reduction rather than the Clean Energy Plan's preferred wind, solar, and battery storage.

The report finds:

- North Carolina has an exemplary record on emissions reduction, driven by its robust electricity generation from nuclear energy and its recent shift to natural gas.
- The Clean Energy Plan is an expensive, wasteful, and risky means of achieving the state's emissions goal, as demonstrated by Duke Energy's cost estimates and by future grid scenario modeling from the Center of the American Experiment.
- Duke Energy would require over $100 billion in present-value revenue to realize the demands of the Clean Energy Plan with Portfolio D.
- Duke Energy's Portfolio D would increase electric bills for North Carolina households by more than $400 each year. North Carolina's industrial electricity customers would face increases of close to $50,000 each year in the scenario, compounding costs for all North Carolinians.
- Achieving the Clean Energy Plan's 2030 emissions goal with Duke Energy's Portfolio D would come at a cost of over $110 per metric ton of reduced carbon dioxide.
- An alternative scenario expanding natural gas's role on the grid would reduce emissions more than 60 percent by 2030 at a cost of just $2.86 per metric ton.
- A scenario expanding nuclear energy's role on the grid using U.S. Energy Information Administration cost assumptions would reduce emissions 70 percent, achieving the Clean Energy Plan target at $79.23 per metric ton, a rate close to 30-percent more affordable than Duke Energy's Portfolio D.
- A scenario deploying a Korean-developed nuclear reactor now in use internationally would reduce emissions 70 percent by 2030 at $39.98 per metric ton, roughly one-third the rate of Duke Energy's Portfolio D.

- Nuclear energy and natural gas are both efficient uses of land, requiring just 0.5 square miles and 2 square miles, respectively, in order to average 1,000 megawatts over the course of a year in North Carolina, compared to 575 square miles for onshore wind power, 265 square miles for offshore wind, and 60 square miles for solar power to provide the same amount of electricity.
- The Clean Energy Plan's reliance on wind, solar, and battery storage entails significant environmental, supply chain, and land-use risks.
- Expanded utilization of nuclear energy and natural gas would provide better pathways to emissions reduction than the wind, solar, and battery storage scenarios preferred by Governor Cooper and the Department of Environmental Quality.

Introduction

Spoiler alert. If people want zero carbon emissions and still want to live in the 21st century, the affordable, reliable, environmentally friendly way to do it is nuclear power. Period. It's that simple. It's that easy. And, yet, it isn't. Why do the climate alarmists who claim we have a short window to resolve the issue make it so difficult to do so?

Here's the dirty little secret of the Big Green industrial complex: This battle isn't about clean air or affordable power. It's about political power to control people. Controversial ecologist Paul Ehrlich said it out loud in the mid-1970s. Ehrlich argued that availability, reliability, and affordability of nuclear power, which we see as benefits, actually represent costs.

He added, "In fact, giving society cheap, abundant energy at this point would be the moral equivalent of giving an idiot child a machine gun."

In spring 1979, several years after Ehrlich made his provocative statements, three events converged. Hollywood released the anti-nuclear movie The China Syndrome. Within 12 days of the release, the United

States experienced a partial reactor meltdown at the Three Mile Island nuclear power plant. This unfortunate coincidence made the movie seem somewhat prophetic. Within weeks of both of those, I had to argue the pro-nuclear energy case in my high school debate class. Since my debate partner defected to the other side, it was just me. While I couldn't convince my partner to be with me, I did convince the class. I've been pro-nuclear ever since.

I'm the opposite of Paul Ehrlich. I believe in the innovative and entrepreneurial spirit of the American people. I believe they will use nuclear energy for good to improve the human condition at home and abroad.

Apparently, North Carolina Governor Roy Cooper is more like my debate partner. He told Congress, "Everything needs to be on the table." However, his Clean Energy Plan defies his congressional testimony. Cooper has set North Carolina's energy table as Ehrlich would. Cooper's plan features unreliable, unaffordable wind, solar, and batteries because they appease his base, Big Green nonprofits, and profiteers.

By our calculations ratepayers and taxpayers will have to invest hundreds of billions of dollars into industrial wind turbines, utility-scale solar, and not-yet-ready for primetime, behemoth-sized batteries for Gov Cooper to realize his renewable goals. Even with all that spending, we would not achieve his goal of lowering emissions.

Wind and solar advocates employ soft terms like "transform" or "transition." A more appropriate word choice is "force." Renewables will force us to change and not for the better. Unless living in the 11th century or on an energy starvation diet is your thing, wind and solar plus giant batteries won't work for our grid, our economy, our businesses, our homes, and our environment. These sources will force you to use significantly less energy whether you want to or not.

This isn't just having to choose between powering your cell phone or your computer or your child's nebulizer. It's wondering whether or not you'll have the power for your child's nebulizer. Gasoline-powered generators may be in everyone's future.

Michael Shellenberger, author of the best-selling Apocalypse Never: Why Environmental Alarmism Hurts Us All, made an astute observation: “curiously, the people who are the most alarmist about the [climate] problems also tend to oppose the obvious solutions.” Shellenberger is a unicorn in the environmental movement. He’s an intellectually honest conservationist who cares deeply about the condition of our planet and the human condition. In his book, he makes the obvious case for opposing renewables while championing nuclear. It’s a great read. I recommend it.

Intellectual honesty is why we are having to prove the obvious. North Carolinians should have their eyes wide open before being thrust into energy poverty and suffering through rolling brown outs or worse — sustained blackouts. Think California on any given day or Texas during a historically brutal winter storm.

As this paper and Shellenberger’s book prove, nuclear is the only way to achieve the goals of lower emissions and affordable, reliable power. Author of our study Jordan McGillis also addresses the huge amounts of land required for wind and solar projects. The demand for land degrades the environment in the name of saving it.

There’s a geopolitical component as well. Renewables shackle us to unfriendly regimes like the Chinese Communist Party in order to get the necessary raw materials to manufacture solar panels and wind turbines.

Our paper isn’t likely to change Roy Cooper’s irresponsible position, but we do hope it impacts yours.

Amy O. Cooke

Amy O. Cooke
CEO, John Locke Foundation

ELECTRICITY IN NORTH CAROLINA

Charting a course for North Carolina's power future requires an understanding of where the state is today and how it arrived here. On this note, one can only be positive and optimistic. North Carolina has a diverse, affordable electricity mix compared with the national averages and its electricity is getting cleaner each year.

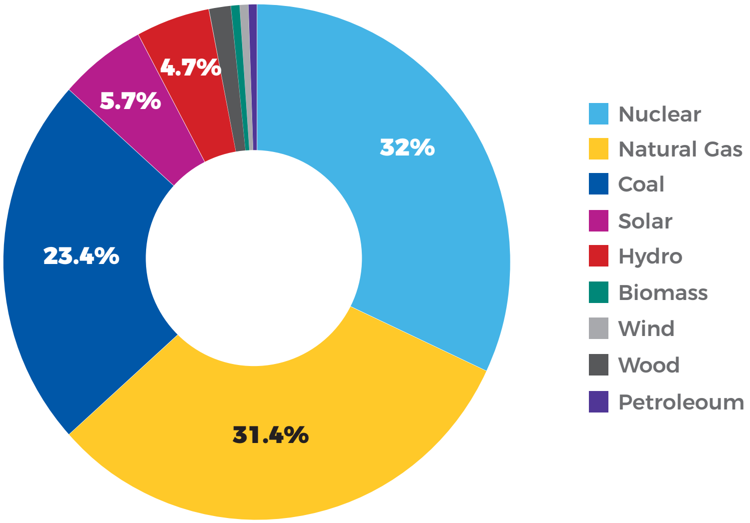
Electricity Mix

In 2019, the most recent year for which the U.S. Energy Information Administration (EIA) offers its full state energy profile, North Carolina's primary source of electricity generation was nuclear energy.[1] The state's electric power industry totaled 131,173,861 megawatt-hours (MWh) for the year.

Nuclear energy provided 32 percent (41,915,605 MWh).

Natural gas provided 31.4 percent (41,146,865 MWh, of which combined cycle was responsible for 34,751406 MWh.)

North Carolina 2019 Electricity Generation by Source



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Coal was the third leading generation source, contributing 23.4 percent (30,672,101 MWh).

Together, those three sources generated 86.7 percent of North Carolina's electricity.

The remaining 16,709,383 MWh came from photovoltaic (PV) solar power, hydroelectric power, wood, petroleum other biomass, and wind.

Solar generated 5.7 percent.

Hydro generated 4.7 percent.

Wood generated 1.4 percent.

Generation from other biomass was 0.5 percent.

Wind generated 0.4 percent

Petroleum and other sources made up the remaining 0.54 percent.

Two of these figures stand out on a national scale. The first is nuclear energy's stellar contribution to North Carolina's electricity needs. According to EIA, North Carolina was sixth among the states in electricity net generation from nuclear power in 2019, producing about 5 percent of the nation's total.

The second noteworthy figure is the electricity generation North Carolina gets from solar energy. In 2019, EIA reports, North Carolina ranked second after California in both the amount of total installed solar power generating capacity at almost 4,700 megawatts (MW) and actual solar generation.

As the North Carolina Department of Environmental Quality (DEQ) notes in its Clean Energy Plan, state and federal renewable energy subsidies, favorable federal Public Utility Regulatory Policy Act conditions, and the state's Renewable Energy and Energy Efficiency Portfolio Standard propelled North Carolina's solar industry. With those advantages, solar's megawatt-hour total jumped from 7,000 in 2010 to 700,000 in 2014 to 7,000,000 in 2019. The Solar Energy Industries Association ranks North Carolina third nationally in its State Solar Spotlight and ranks the state's solar growth projection ninth nationally.[2] Nevertheless, as noted above, solar energy still contributes just a sliver of the state's power. The generation gap looks even more stark when the jobs numbers are highlighted. Solar produces one-sixth of the electricity provided by nuclear and natural gas, but requires double the workers to do so. DEQ's touting of what it calls clean energy jobs in the state reveals a blind spot in this regard.[3]

The changes in the North Carolina electricity and emissions profile over the course of this young century are remarkable and encouraging. In 2007, the state's highest electricity emissions year, North Carolina got the lion's share of its electricity from coal, at over 60 percent.[4] Nuclear, a mainstay of the state's mix, has generated around a third of its power each year, totaling about 40 terawatt-hours annually since 2003.[5]

The big climber has been natural gas. In 2000, natural gas generated less than one percent of North Carolina's power. In the record emissions year, it was still at just 3.4 percent, but five years later in 2012 it jumped to 16.6

percent. Four years after that, in 2016, natural gas surpassed coal generation, contributing 30 percent, compared to the sedimentary rock's 28.6 percent. In the period between 2005 and 2019, Duke Energy retired close to 4 GW of coal resources between North and South Carolina.[6] Because natural gas emits about half as much carbon dioxide per British thermal unit (Btu), the emissions savings of this switch have been profound.[7]

Greenhouse Gas Emissions

In 2017, the state's electricity sector generated 47.3 million metric tons of carbon dioxide (CO_2) according to the U.S. Energy Information Administration, down almost 40 percent from the all-time state high of nearly 80 million metric tons in 2007 and down 12 percent since 1980, when the state population was 42 percent smaller than it is today.[8] [9] As DEQ documented in its 2019 report,[10] between 2005 and 2017 the state's gross greenhouse gas emissions fell 23.7 percent. The leading contributor to this decline was the electricity industry.

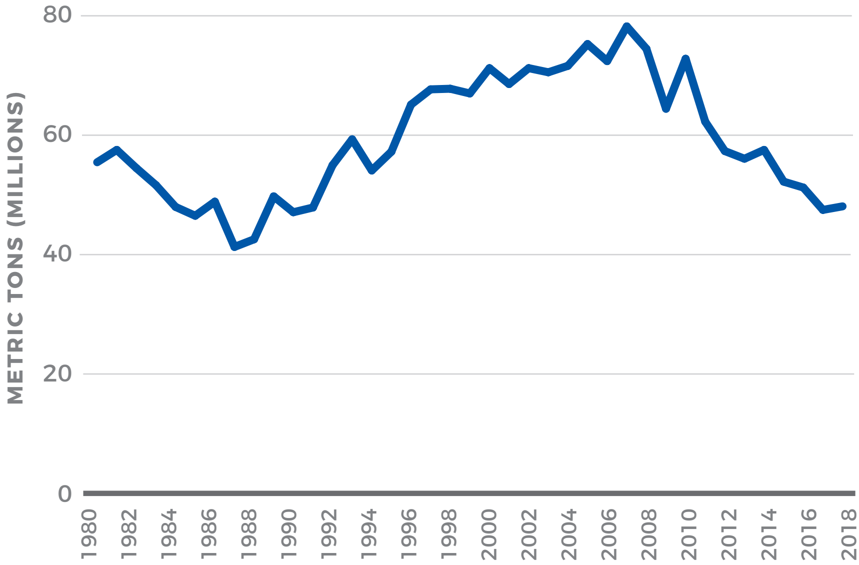
In this respect, North Carolina is representative of the country as a whole. Since the mid-2000s, the proliferation of natural gas from American shale basins has enabled the country to reduce greenhouse gas emissions from electricity by a third.[11]

In 2018, the most recent year from which comprehensive EIA comparison tables are available, North Carolina's electricity emissions total was lower than six smaller population states, Alabama, Indiana, Kentucky, Michigan, Missouri, and West Virginia. North Carolina's total is also 8.8 percent lower than Georgia's, despite Georgia's population being just 1 percent larger.

Per capita, North Carolinians emit about 4.5 metric tons of CO_2 each year by way of electricity, placing North Carolina 30th nationally (i.e., closer to the lowest per capita emissions states than to the highest).

According to the World Resources Institute (WRI), North Carolina is

North Carolina Annual Emissions from Electricity Generation



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

among the nation's leaders in "decoupling" emissions from economic performance, having better-than-average carbon intensity and better-than-average improvement from 2005 to 2017.[12] WRI reports that North Carolina reduced emissions by around a quarter in that period while increasing state GDP by almost a fifth. Only New York and Massachusetts experienced better economic growth with as deep of reductions in emissions.

North Carolina's relatively low per capita electricity emissions and carbon intensity profiles can be attributed to nuclear and natural gas leading its existing electricity mix.

Electricity Rates

As of February 2021, North Carolina customers pay 9.48 cents per kWh

"According to DEQ, the combined capacity of North Carolina's nuclear units was 5,118 MW in 2017. The units had an average capacity factor of 94 percent."

across all end-use sectors, placing it 19th in affordability among the 50 states and the District of Columbia and a full 2 cents below the average of 11.60. Within the South Atlantic region that also includes Delaware, the District of Columbia, Florida, Georgia, Maryland, South Carolina, Virginia, and West Virginia, North Carolina ranks third in all sector end-use affordability, with only Virginia and West Virginia customers paying less per kilowatt-hour (kWh).[13]

Residential customers in North Carolina paid 11.13 cents per kWh in February 2021, the 14th most affordable rate in the country and the second cheapest in the region. With the state average household consumption of electricity around 1,100 kWh per month, this comes out to an average monthly bill of about $123.[14]

Commercial customers paid 9.02 cents per kWh, ranking 10th in the country and second cheapest in the region. Industrial customers paid 6.08 cents per kWh, ranking 11th in the country and again second in the region in affordability.

Energy Jobs

The Energy Future Initiative's 2020 U.S. Energy and Employment Report recorded close to 60,000 workers employed in electric power generation, fuels, transmission, distribution, and energy storage, 1.2 percent of total state employment.[15] Natural gas generation employed 2,800 workers and nuclear generation employed 1,600 workers. 6,600 workers were reported as spending the majority of their time on solar and another 2,300 workers spent some time on solar.

The report logged an additional 88,000 workers in energy efficiency. It should be noted, however, that the energy efficiency designation is dubious in many cases. For example, of the 2.3 million jobs deemed by the report to be in energy efficiency across the nation, 494,000 are in automobile manufacturing and are given the energy efficiency designation because the workers “are contributing to producing vehicles that help achieve” national fuel-economy mandates.

North Carolina’s Power Plants

Nuclear Power Plants

Duke Energy operates five reactors at three nuclear plants in the state: the McGuire Nuclear Station in Mecklenberg County, the Harris Nuclear Plant in Wake County, and the Brunswick Nuclear Plant in Brunswick County. South of the state border, Duke Energy operates Oconee Nuclear Station, Catawba Nuclear Station, and Robinson Nuclear Plant.

The McGuire Nuclear Station, which was commissioned in 1981, has the highest capacity at 2,316 megawatts. The Harris Nuclear Plant, commissioned in 1987, has a capacity of 964 megawatts. The Brunswick Nuclear Plant, commissioned in 1975, has a capacity of 1,870 megawatts.[16] Duke Energy noted in its 2018 Integrated Resource Plan that capacity uprates totaling 56 megawatts are planned for the Brunswick and Harris plants through 2028.

According to DEQ, the combined capacity of North Carolina’s nuclear units was 5,118 MW in 2017. The units had an average capacity factor of 94 percent.[17] The licenses for these plants expire between 2034 and 2046, but Duke Energy is in the process of renewing them.[18]

Natural Gas Power Plants

Duke Energy operates 11 gas-fired generating facilities in North Carolina, ranging from the Asheville Combined Cycle Station in Buncombe County to the Dan River Combined Cycle Station in Rockingham County to the Sutton Combustion Turbine facility in Wilmington. The state's gas-fired facilities offer dispatchable electricity from an array of points across the state.

Duke Energy reports that the Asheville Combined Cycle Station is 75-percent more efficient than the coal plant it replaced.[19]

Interstate pipelines supply the natural gas that North Carolina uses. Since 2015, significant volumes have arrived from the Utica and Marcellus shale plays in the northern Appalachian Basin.

Coal Power Plants and Retirements

Duke Energy operates six coal-fired generating facilities in North Carolina, ranging from the Rogers Energy Complex (Cliffside Steam Station) in Cleveland and Rutherford Counties to the Mayo Plant in Roxboro.

According to S&P Global Market Intelligence, Duke Energy operates about 9,000 MW of coal-fired generation in the Carolinas.[20]

The highest-capacity coal-fired facilities are the Roxboro Steam Plant in Semora, the Belews Creek Steam Station in Stokes County, and the Marshall Steam Station in Catawba County. S&P Global states that these are among Duke Energy's 10 largest operating plants in the region.

The Roxboro Steam Plant has the highest capacity at 2,422 megawatts, followed by the Belews Creek Steam Station, with its 2,240 megawatts, and the Marshall Steam Station with its 2,090 megawatts.

While the Roxboro Steam Plant is a coal-exclusive plant, Marshall and Belews Creek will use both coal and natural gas in 2021.

Duke Energy states it will complete construction this year at Marshall to enable 50 percent natural gas co-firing on units 3 and 4 and up to 40 percent natural gas co-firing on units 1 and 2.

The Belews Creek Steam Station is a two-unit generating facility. In 2020, according to Duke Energy, natural gas was added to the station to allow

40 percent natural gas co-firing on both units.

Duke Energy reports that for every pound of coal displaced with natural gas at Marshall and Belews Creek, sulfur dioxide is reduced by an estimated 99 percent, and carbon dioxide emissions are reduced by about 40 percent per megawatt-hour.

Duke Energy's Integrated Resource Plan scenarios will retire all of its power plants in the Carolinas that "rely exclusively on coal."

Through the first two months of 2021, the McGuire and Brunswick nuclear plants were the highest generators, contributing 3,257,611 MWh and 2,658,263 MWh respectively. The leading natural gas generators were the Smith, Asheville, and Dan River facilities, which generated 1,479,748 MWh, 731,605 MWh, and 727,056 MWh, respectively. The Roxboro Steam Plant generated 1,369,025 MWh in the period, leading coal facilities.[21]

North Carolina's long experience with baseload nuclear power and its copious recent natural gas additions position the state to succeed in its pursuit of reliable, low-carbon electricity.

NORTH CAROLINA ELECTRICITY POLICY

As Locke's Jon Sanders has noted, North Carolina policymakers have pursued a sequence of interventions to move the state's electricity market towards renewable energy, including the Clean Smokestacks Bill in 2002,[22] a 35-percent investment tax credit for renewable energy in 2005,[23] a renewable electricity mandate in 2007,[24] and an 80-percent property tax abatement for solar energy systems in 2008.[25] Those programs were followed in the recently-ended decade by Governor Roy Cooper's Clean Energy Plan.

For the purposes of this paper, the renewable electricity mandate and the Clean Energy Plan are most germane.

Renewable Energy and Energy Efficiency Portfolio Standard

With the passage of Senate Bill 3 in August 2007,[26] North Carolina became the 25th state and the first in the southeastern U.S. to establish

> "North Carolina remains the only state in the region with a renewable electricity mandate. Neighbors Virginia and South Carolina have non-binding goals, but do not have binding standards."

a renewable electricity mandate, i.e., a legally-binding requirement for utilities to provide the state with a certain percentage of electricity from politically-preferred sources.

North Carolina's benchmark renewable energy requirement, codified as N.C. Gen. Stat. § 62-133.8, is known as the Renewable Energy and Energy Efficiency Portfolio Standard (REPS).

REPS went into effect in 2012 and requires investor-owned utilities such as Duke Energy to supply 12.5 percent of retail electricity sales from eligible sources by 2021. Municipal utilities and cooperatives have a slightly lower bar to meet. The sources deemed eligible include solar, wind, small hydro (up to 10 megawatts), geothermal, wave energy, emissions-controlled biomass, landfill gas, and hydrogen derived from renewable sources. Up to a quarter of the requirement can be satisfied through added energy efficiency technologies, including combined heat and power systems.[27] Beginning in 2021, a utility may meet up to 40 percent of the requirements through savings due to implementation of energy efficiency measures. In 2011, demand response was added as a means for utilities to achieve compliance.[28]

In February 2008, the North Carolina Utility Commission (NCUC) adopted final rules to implement REPS in the utility sector.[29] Per NCUC, utilities comply with REPS by generating eligible electricity, purchasing eligible electricity, or purchasing Renewable Energy Certificates, tradable instruments obtained from generation.[30]

North Carolina remains the only state in the region with a renewable electricity mandate. Neighbors Virginia and South Carolina have non-binding goals, but do not have binding standards.[31] Critically from the viewpoint of the utility customer, REPS allows for utilities to recover the costs of adding eligible sources to their supply by passing their costs through to the public.

Executive Order 80

In October 2018, Governor Roy Cooper issued Executive Order 80, a state directive on responding to climate change.[32] The order indicated:

"The State of North Carolina will strive to accomplish the following by 2025:

a. Reduce statewide greenhouse gas emissions to 40% below 2005 levels;

b. Increase the number of registered, zero-emission vehicles ('ZEVs'; individually, 'ZEV') to at least 80,000;

c. Reduce energy consumption per square foot in state-owned buildings by at least 40% from fiscal year 2002-2003 levels."

The order also directed the Department of Environmental Quality to develop a "North Carolina Clean Energy Plan" that "fosters and encourages the utilization of clean energy resources, including energy efficiency, solar, wind, energy storage, and other innovative technologies in the public and private sectors, and the integration of those resources to facilitate the development of a modern and resilient electric grid."

The North Carolina Clean Energy Plan

DEQ executed Governor Cooper's request by delivering the North Carolina Clean Energy Plan (CEP) in October 2019.[33] The purpose of the CEP, stated DEQ upon the documents' release, "is to outline policy and action recommendations that will accomplish these goals." The CEP outlines, in DEQ's words, "what our electricity system should look like in 2030 and what values we must retain moving forward."

"North Carolina is an exemplar of smart carbon reduction and it can be a national leader deep into this century."

With that framing, the CEP puts forth DEQ's policy preferences. The meat of the CEP is DEQ's Detailed Policy and Action Recommendations. DEQ defines in this section three goals:

(1) to reduce electric power sector greenhouse gas emissions by 70 percent from 2005 levels— a baseline of 79.37 million metric tons of carbon dioxide equivalent, according to DEQ's 2019 Greenhouse Gas Inventory—by 2030 and attain carbon neutrality by 2050;

(2) to foster long-term energy affordability for North Carolina's residents and businesses by modernizing regulatory and planning processes;

(3) to accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.

DEQ considers these three cardinal recommendations "critical to the transition to a 21st century regulatory model that incentivizes business decisions that benefit both the utilities and the public in creating an energy system that is clean, affordable, reliable, and equitable," and "central to the transformational shift that is necessary to lay a new foundation for a clean energy future..."

In order to attain these goals, DEQ establishes six strategies:

(1) carbon reduction—which focuses on the development of greenhouse gas mitigation policy designs for the electric power sector;

(2) utility incentives and comprehensive system planning—which address recommendations related to utility compensation methods, regulatory processes, and long-term utility system planning;

(3) grid modernization and resilience—which identify pathways to

modernize the electric grid to support clean energy resources, and ways to establish and maintain grid resilience and flexibility;

(4) clean energy deployment and economic development—which focus on methods to increase customer access to clean energy resources, regulatory processes related to the way clean energy resources are valued, and emerging areas that can create economic opportunities;

(5) equitable access and justice—which address methods to relieve the energy burden on low-income communities, provide job training, and develop a clean energy workforce;

(6) energy efficiency and electrification strategies—which identify approaches to electrify the transportation sector and end-use sectors.

Assuming the risks posed by anthropogenic global warming as described by bodies like the Intergovernmental Panel on Climate Change, the goals that DEQ establishes in the CEP and the broad strategies for achieving them are reasonable. But DEQ and, ultimately as the state's chief executive, Governor Cooper, break from reality when presenting the state with pathways to get there.

DEQ seems fixated on its preferred electricity sources to the exclusion of viable, and, arguably, more dependable sources. The sources towards which DEQ wants to steer the state are wind and solar energy, with copious battery storage.

The word "solar" appears in the main document 158 times, "storage" appears 83 times, "wind" appears 62 times. "Nuclear," as in nuclear energy, North Carolina's leading power source, appears a paltry 14 times in the main document's 146 pages.

DEQ implies its avoidance of nuclear energy was at the direction of Executive Order 80, arguing that "Executive Order 80 (EO 80) and DEQ define clean energy resources to include solar, EE, battery storage, wind, efficient electrification, and other zero-emitting technology options capable of quickly decarbonizing the power sector and modernizing the electric power sector."

In fact, Governor Cooper's executive order did not stipulate that DEQ should form a plan around specific energy sources. The order's language regarding sources was open-ended, encouraging "the utilization of clean energy resources, including energy efficiency, solar, wind, energy storage, and other innovative technologies in the public and private sectors..."

Nuclear energy most certainly qualifies as an innovative technology and as a zero-emitting technology option capable of quickly decarbonizing the power sector.

DEQ released its CEP Supporting Document (CEPSD) in the wake of the CEP announcement.[34] The CEPSD sheds light on the scarce attention nuclear drew in the CEP. DEQ concludes its CEPSD section on nuclear energy by stating, "new generating resources should be identified to replace the [nuclear power plants'] existing capacity and generation even if the NRC extends their licenses (as desired by Duke Energy) for an additional twenty years. It is prudent to now begin looking for a nuclear generation replacement so that we can meet NC's future baseload electric needs."

As this conclusion make clear, DEQ is willfully spurning the electricity source that has provided the state a third of its power for decades, that supplies baseload power without carbon emissions, and that has proven itself at thousands of sites globally.

North Carolina is an exemplar of smart carbon reduction and it can be a national leader deep into this century. It should give policymakers and citizens pause that DEQ includes in its Clean Energy Plan a dozen positive references to California, the state with the nation's highest-profile electricity failures over the past two decades.

North Carolina can do better.

DUKE ENERGY'S INTEGRATED RESOURCE PLANS

North Carolina's investor-owned utilities are required to present the state with periodic comprehensive updates on their plans for providing the state with electricity. These reports are known as Integrated Resource Plans (IRPs) and the body tasked by statute with evaluating them is the NCUC.

NCUC's role, per the Public Utilities Act (G.S. 62),[35] is to provide fair regulation of public utilities in the public interest. Among NCUC's various functions are the aforementioned implementation of REPS and the approval of IRPs.[36] According to NCUC, integrated resource planning examines conservation, energy efficiency, load management, and other demand- and supply-side issues in order to determine the least-cost way of providing electricity.

Duke Energy Progress[37] and Duke Energy Carolinas[38] filed their latest IRPs with NCUC in September 2020. The two subsidiaries of Duke Energy Corporation file separate IRPs with North Carolina and South Carolina, but since they operate as a joint-dispatch system across the state

> "The Duke Energy IRPs consist of six portfolios, each offering a different electricity future for the state through 2035."

line, they are mirror-image documents. For the purposes of this report, the documents will be referred to jointly as "the Duke Energy IRPs," "the Duke IRPs," or, simply, "the IRPs."

The Duke Energy IRPs must be viewed in the context of the electricity policies and the 2019 Clean Energy Plan described above. Duke Energy, in its position as a state-regulated monopoly, largely builds its plans around existing and anticipated policy.

As Duke Energy explains on its website, it "applies three primary objectives of increasingly clean, reliable, and affordable [electricity] to guide its IRP planning process, and considers and compares resource portfolio alternatives to comply with policy objectives." Duke Energy notes in the IRPs, "In North Carolina, Duke Energy is an active participant in the state's Clean Energy Plan stakeholder process, which is evaluating policy pathways to achieve a 70% reduction in greenhouse gas emissions from 2005 levels by 2030 and carbon neutrality for the electric power sector by 2050." While Duke Energy has announced a corporate commitment to achieving net-zero emissions by 2050, in line with Governor Cooper's agenda, it lags slightly behind the state with its corporate commitment to reduce CO_2 emissions 50-percent below 2005 levels by 2030.

The Duke Energy IRPs consist of six portfolios, each offering a different electricity future for the state through 2035. All six scenarios would see Duke Energy achieve its 2030 goal of a 50-percent from baseline CO_2 reduction.

This report will describe each, but pay closest attention to the scenario (Portfolio D) that most clearly reflects the policy preferences of Governor Cooper and DEQ. Duke Energy describes Portfolio D as illustrating a potential pathway to the Clean Energy Plan goal of a 70-percent reduction by 2030 and maps high deployment of wind energy. This report will then present some alternative scenarios that we think would better serve the state.

The six portfolios are designated in the following manner by Duke Energy:

Portfolio A — Base without Carbon Policy

Portfolio B — Base with Carbon Policy

Portfolio C — Earliest Practicable Coal Retirements

Portfolio D — 70-Percent CO_2 Reduction: High Wind

Portfolio E — 70-Percent CO_2 Reduction: High Small Modular Nuclear

Portfolio F — No New Gas Generation

Portfolio A

Portfolio A is the base case without carbon policy, i.e., the scenario operates under current policy assumptions. While readers may intuitively expect that this portfolio would lead to a stalling of emissions reduction, even in the simple base case without carbon policy the current trend continues and emissions drop precipitously. Since 2005, the Duke Energy combined system has reduced its emissions by 38 percent. In the base case without carbon policy, that figure reaches 53 percent by 2030. This context is important to bear in mind when evaluating the costs associated with the incremental emissions reductions in the other portfolios.

Portfolio A meets new load growth by adding more natural gas generation to the electricity mix. It incorporates coal unit retirements based on the most economic selections (see: IRPs Chapter 11), taking 3,200 MW offline by 2029. This portfolio adds 2,000 MW of nameplate capacity solar and solar plus storage throughout the IRP planning horizon. At the end of the IRP period, Duke Energy forecasts that battery storage becomes more economical than combustion turbine natural gas capacity for peaking purposes. That battery storage will come on top of

MAYA REAGAN

Duke Energy, in its position as a state-regulated monopoly, largely builds its plans around existing and anticipated policy.

the additional 140 MW of grid-tied battery storage in the early- to mid-2020s. Overall, Portfolio A adds 5,300 MW of combustion turbine and combined cycle natural gas capacity beginning the winter of 2026 to, in Duke's words, ensure the utility can meet customer load demand.

According to the Combined System Portfolio table on IRP Page 16: Portfolio A results in a 56-percent system CO_2 reduction by 2030, a 53-percent CO_2 reduction by 2035, a present value revenue requirement (PVRR) of $79.8 billion, and transmission investment of $0.9 billion.

PVRR is a proxy for cost to Duke Energy customers.

Duke IRP Portfolio A Results Table

2030 CO_2 Reduction	2035 CO_2 Reduction	Present Value Revenue Requirement ($B)	Estimated Transmission Investment Required ($B)
56%	53%	$79.8	$0.9

Portfolio B

Portfolio B is the base case, but *with* carbon policy. This portfolio, the IRPs explain, assumes the same base planning assumptions as the previous case but is developed with a carbon tax simulation as a proxy for future carbon regulation.

Portfolio B adds 4,300 MW of natural gas capacity, replacing new peaking natural gas generation in favor of base and intermediate load natural gas resources. All differences between Portfolios A and B are attributable to the IRP carbon tax. Because of the added cost assumptions, Portfolio B selects 1,400 MW more of incremental solar plus storage than Portfolio A. This plan also adds 600 MW of onshore wind to 2035. Because wind and solar are intermittent sources of generation, additional storage is needed. This portfolio adds it in the form of 500 MW of standalone, grid-tied battery storage in the early 2030s and 350 MW of storage coupled with solar.

According to the Combined System Portfolio table on IRP Page 16: Portfolio B results in a 59-percent system CO_2 reduction by 2030, a 62 -percent CO_2 reduction by 2035, a PVRR of $82.5 billion, and transmission investment of $1.8 billion.

Duke IRP Portfolio B Results Table

2030 CO_2 Reduction	2035 CO_2 Reduction	Present Value Revenue Requirement ($B)	Estimated Transmission Investment Required ($B)
59%	62%	$82.5	$1.8

Portfolio C

Portfolio C reflects the earliest possible coal retirements. The portfolio bumps up the retirement of Mayo Unit 1 from 2029 in the base cases to 2026 and accelerates the Roxboro units 1 and 2 retirement from 2029 to 2028, meaning they will retire in the same year as Roxboro units 3 and 4.

This plan replaces 3,200 MW of coal capacity with a combination of natural gas, onshore wind, solar, and significant battery storage.

Portfolio C adds 9,600 MW of natural gas capacity and 1,350 MW of onshore wind capacity. Solar additions in this scenario yield a total solar nameplate capacity of 12,400 MW.

As in Portfolio B, it adds 2,200 of incremental battery storage capacity. Portfolio B requires 500 MW of standalone, grid-tied battery storage to be added in the early- and mid-2020s. It does, however, avoid "additional transmission upgrades" by siting replacement gas generation at the Roxboro station.

Duke IRP Portfolio C Results Table

2030 CO_2 Reduction	2035 CO_2 Reduction	Present Value Revenue Requirement ($B)	Estimated Transmission Investment Required ($B)
64%	64%	$84.1	$1.3

Portfolio D

Portfolio D reaches 70-percent CO_2 reduction through high wind usage. It is the scenario that most closely resembles the Clean Energy Plan put forward by Governor Cooper and DEQ and the governor's offshore wind executive order that was delivered in June 2021.[39] In addition to this segment, our report will offer an in-depth analysis of Portfolio D in a following section.

Portfolio D emphasizes offshore wind energy. In order to achieve the emissions goal on time, it also retires coal units at the earliest dates possible, as in Portfolio C. Additionally, Portfolio D uses increased annual solar integration limits.

Portfolio D includes the addition of 5,500 MW of combined offshore and onshore wind, at a roughly even split, and a total of 16,250 MW of nameplate capacity solar energy by 2035. It also utilizes 6,400 MW of incremental natural gas and 4,400 MW of incremental storage—double the total for Portfolios B and C.

The IRPs note that even with assumptions of high energy efficiency, demand response, and the accelerated coal retirements, this scenario “do(es) not get the combined system to 70% CO_2 reductions by 2030.” In order to reach 70 percent, Duke Energy “adds 1,200 MW of offshore wind into the DEP system for the winter peak of 2030.” For reserve capacity reasons, coal units 1 and 2 at Roxboro are left in operation to 2030 when the offshore wind capacity becomes fully operational.

According to the Combined System Portfolio table on IRP Page 16: Portfolio D results in a 70-percent system CO_2 reduction by 2030, a 73-percent CO_2 reduction by 2035, a PVRR of $100.5 billion, and transmission investment of $7.5 billion.

The PVRR in Portfolio D is thus 22-percent more expensive than in Portfolio B (the base case with carbon policy) and 26-percent more expensive than in Portfolio A (the base case without carbon policy).

Duke IRP Portfolio D Results Table

2030 CO_2 Reduction	2035 CO_2 Reduction	Present Value Revenue Requirement ($B)	Estimated Transmission Investment Required ($B)
70%	73%	$100.5	$7.5

Portfolio E

Portfolio E achieves the same 70-percent CO_2 emissions benchmark as Portfolio D, but does so with small modular nuclear reactors (SMRs) emphasized.

The plan also leverages high energy efficiency and demand response expectations and assumes increased renewable integration limits. It retires coal units at the earliest practicable dates.

This scenario uses an addition of 1,350 MW of SMR technology, along with the same 4,400 MW of incremental storage in Portfolio D. It adds slightly less natural gas, at 6,100 MW. Like the above scenario it yields a total nameplate solar capacity of 16,250 MW. It also includes additions of 2,850 MW of onshore wind and a modest addition of 250 MW offshore.

As in Portfolio D, the IRPs note, even with assumptions of high energy efficiency, demand response, and renewables, combined with accelerated coal retirements, this scenario "do(es) not get the combined system to 70% CO_2 reductions by 2030" until a 684-megawatt small modular nuclear reactor is added to the system at the beginning of 2030.

And also as in Portfolio D, the retirements of Roxboro units 1 and 2 are delayed from 2028 to 2030 to maintain planning reserve capacity until the last nuclear addition is operational.

According to the Combined System Portfolio table on IRP Page 16: Portfolio E results in a 71-percent system CO_2 reduction by 2030, a 74-percent CO_2 reduction by 2035, a PVRR of $95.5 billion, and transmission investment of $3.1 billion.

This scenario is about 5-percent more affordable than Portfolio D.

Duke IRP Portfolio E Results Table

2030 CO_2 Reduction	2035 CO_2 Reduction	Present Value Revenue Requirement ($B)	Estimated Transmission Investment Required ($B)
71%	74%	$95.5	$3.1

Portfolio F

Portfolio F presents a scenario in which no natural gas generation is added to the system. The results demonstrate how important new natural gas is to system affordability.

In Portfolio F, coal is retired on the most economic schedule available, rather than the fastest. As coal is retired, energy and capacity needs are met by deploying 4,000 MW of battery storage and 2,500 MW of offshore wind by 2030.

By 2035, this scenario includes 16,400 MW of nameplate solar capacity. It adds 3,150 MW of onshore wind capacity and 2,650 MW of offshore capacity, an additional wind capacity total of 5,800 MW, the highest of any scenario. Unlike Portfolio D, it adds SMR capacity, totaling 700 MW. It also has the highest storage addition of any portfolio at 7,400 MW.

Unsurprisingly, Portfolio F is the most expensive presented.

According to the Combined System Portfolio table on IRP Page 16: Portfolio F results in a 65-percent system CO_2 reduction by 2030, a 73-percent CO_2 reduction by 2050, a PVRR of $108.1 billion, and transmission investment of $8.9 billion.

Duke IRP Portfolio F Results Table

2030 CO_2 Reduction	2035 CO_2 Reduction	Present Value Revenue Requirement ($B)	Estimated Transmission Investment Required ($B)
65%	73%	$108.1	$8.1

IRPs Conclusion

The IRPs give us a peek at six possible electricity futures for the state. As the data show, Portfolio D, the scenario most-closely resembling the preferences of Governor Cooper and DEQ, presents an unconvincing value proposition. It would achieve the desired emissions reduction, but the costs would be calamitous for North Carolinians, with transmission cost forecasts alone exceeding $7 billion and a total PVRR price tag of over $100 billion.

Portfolios A, B, and C demonstrate that continued emissions progress can be achieved without burdening the state with politically-favored, intermittent wind and solar.

Total Cost PVRR Through 2050, Excluding the Explicit Cost of Carbon (2020 USD in Billions)

	MIN	MEDIAN	MAX
BASE PLANNING WITHOUT CARBON POLICY	$31.00	$34.40	$39.90
BASE PLANNING WITH CARBON POLICY	$32.50	$35.70	$41.00
EARLIEST PRACTICABLE COAL RETIREMENTS	$34.50	$37.30	$42.10
70% CO2 REDUCTION: HIGH WIND	$42.40	$44.50	$47.90
70% CO2 REDUCTION: HIGH SMR	$39.60	$41.90	$45.70
NO NEW GAS GENERATION	$49.70	$52.10	$56.00

Total Cost PVRR Through 2050, Including the Explicit Cost of Carbon (2020 USD in Billions)

	MIN	MEDIAN	MAX
BASE PLANNING WITHOUT CARBON POLICY	$32.50	$43.30	$50.60
BASE PLANNING WITH CARBON POLICY	$34.80	$43.50	$49.70
EARLIEST PRACTICABLE COAL RETIREMENTS	$35.90	$44.60	$50.70
70% CO2 REDUCTION: HIGH WIND	$43.10	$49.50	$54.20
70% CO2 REDUCTION: HIGH SMR	$41.00	$47.20	$51.90
NO NEW GAS GENERATION	$51.80	$57.30	$61.30

Portfolio F, a foil installed to show the importance of natural gas, should not overshadow the real threat of Portfolio D. Portfolio D, unlike F, is a realistic and concerning possibility.

Portfolio E shows that even to achieve the 70-percent-by-2030 benchmark, Portfolio D is unnecessary and undesirable. This report will now analyze Portfolio D in more detail and show that there are viable alternatives outside of Duke Energy's six portfolios that would better serve the state.

PUTTING THE CLEAN ENERGY PLAN IN CONTEXT

At the behest of the John Locke Foundation, the Center of the American Experiment (henceforth "the Center") modeled four North Carolina electricity scenarios and four Duke Energy systemwide scenarios to aid in analysis of the Clean Energy Plan and the Duke Energy IRPs.

Because Duke Energy's Portfolio D resembles the Clean Energy Plan, that scenario is the focal point of the Center's analysis, which runs through 2051. In juxtaposition to the costly Portfolio D scenarios for North Carolina and the Duke system, the Center modeled three other North Carolina scenarios and three other Duke system scenarios. The alternative North Carolina and Duke system scenarios share the same basic assumptions. For the sake of simplicity, this report will henceforth focus on the North Carolina scenarios, unless otherwise stated.

The three alternatives to the Portfolio D scenario are:

1. The Natural Gas Scenario, in which new natural gas capacity is added to replace retiring coal instead of a massive investment in wind, solar, and battery storage.

2. The EIA Nuclear Scenario, in which new nuclear capacity is added to replace retiring coal instead of wind, solar, and battery storage.
3. The APR1400 Scenario, in which a particular reactor design, the Korean APR1400, is utilized in North Carolina in the place of the proposed wind, solar, and battery storage.

Each scenario has certain costs and benefits and the following sections will detail the advantages and drawbacks of each.

Portfolio D Scenario

According to the Center's modeling, the Portfolio D Scenario's shift to reliance on wind, solar, and battery storage would foist upon North Carolina ratepayers over $100 billion in additional costs relative to the existing electricity mix by 2051. This increase comprises roughly $57 billion in utility returns, $7 billion in property taxes, and $33 billion in additional generation costs. The modeling shows annual operating expenses from the mid-2030s onward at more than $1.5 billion above current levels.

Costs to Customers

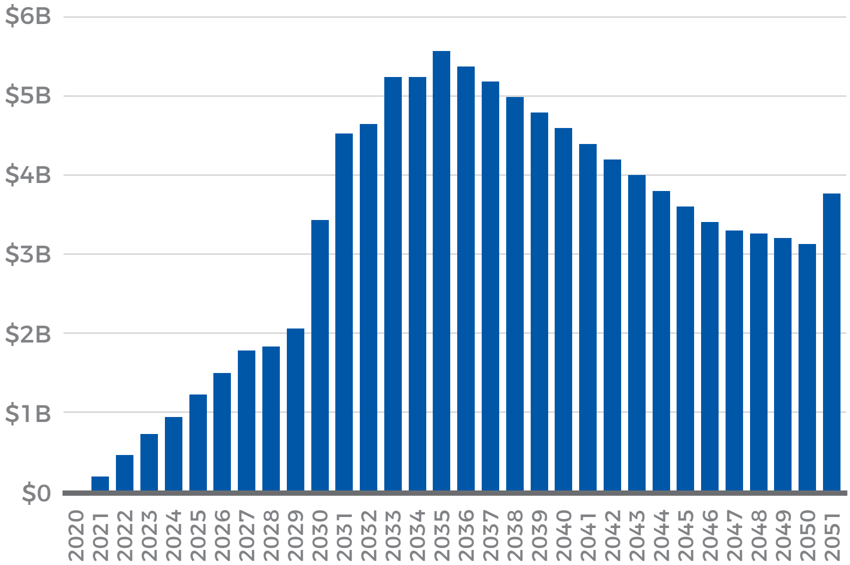
Broken down by rate class, residential customers would see the greatest increase in cents per kWh. Rates for residential customers would climb by nearly 2 cents by the end of the decade, then increase to more than 5 cents per kWh above baseline by the middle of the 2030s.

Residential customers would see costs above baseline of $411 on average from 2020 to 2051. From 2032 to 2051, annual costs would be $522 above baseline.

For commercial customers, rates would climb by about 1.5 cents per kWh by the end of the decade, then increase to 4 cents per kWh above baseline by the middle of the 2030s.

Commercial customers would see costs above baseline of $1,705 per year on average from 2020 to 2051. From 2032 to 2051, costs would be $2,165 above baseline.

Portfolio D Scenario Costs Relative to Baseline by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

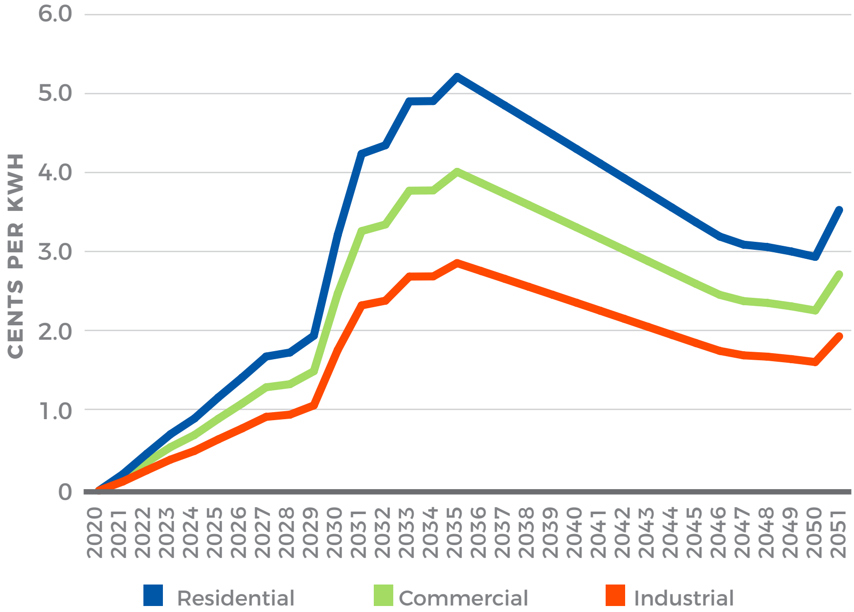
For industrial customers, rates would climb by about 1 cent per kWh by the end of the decade, then increase to about 3 cents per kWh above baseline by the middle of the 2030s.

The rate increases mean industrial customers' annual electricity costs would increase by $48,553 on average from 2020 to 2051. Cost increases would be most dramatic from 2032 to 2051, when average costs would be $61,649 above baseline.

Capacity Mix

The term "capacity mix" denotes the percentages of a system's installed capacity from the various sources of electricity. Capacity mix differs critically from generation mix, which denotes the percentages of a system's actual electricity generation from the various sources. Capacity factor, a key, related concept that will be discussed later in this report, describes a source's generation relative to its capacity.

Portfolio D Scenario Rates Relative to Baseline by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

The initial North Carolina capacity mix in the Center's models includes:

- 31 percent coal
- 18 percent combustion turbine natural gas
- 16 percent nuclear
- 15 percent combined cycle natural gas
- 12 percent utility solar
- 6 percent hydro
- 1 percent onshore wind

The 2051 Portfolio D Scenario capacity mix includes:

- 24 percent utility solar

- 19 percent combustion turbine natural gas
- 16 percent combined cycle natural gas
- 11 percent nuclear
- 9 percent solar plus storage
- 6 percent onshore wind
- 5 percent offshore wind
- 5 percent storage
- 4 percent hydro
- 1 percent community solar

Generation Mix

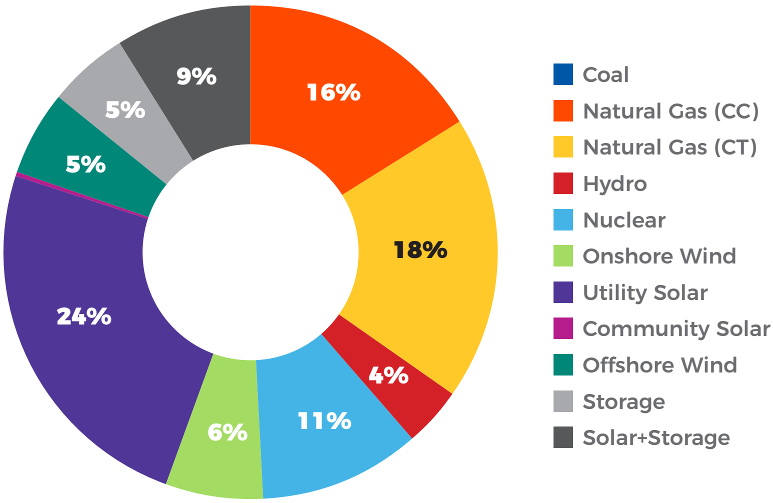
The initial North Carolina generation mix in the Center's models includes:

- 33 percent nuclear
- 27 percent combined cycle natural gas
- 25 percent coal
- 6 percent utility solar
- 5 percent hydro
- 4 percent combustion turbine natural gas

The 2051 Portfolio D Scenario generation mix includes:

- 33 percent nuclear
- 18 percent combined cycle natural gas
- 17 percent utility solar
- 7 percent solar plus storage

Portfolio D Scenario 2051 Capacity Mix



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

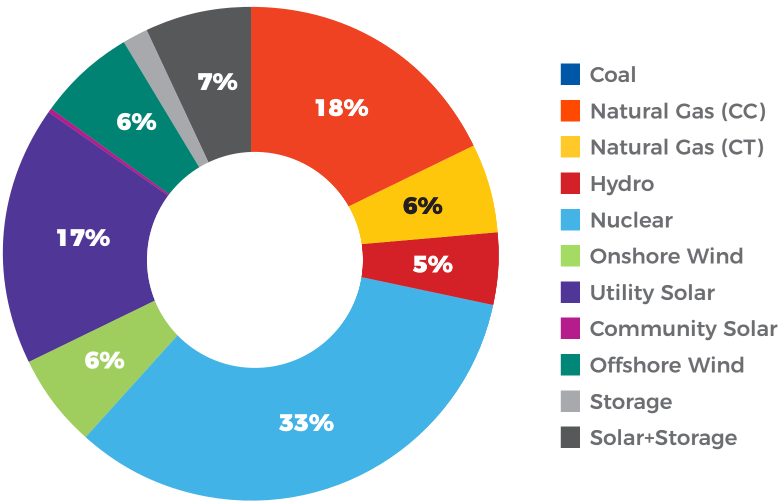
- 6 percent combustion turbine natural gas
- 6 percent offshore wind
- 6 percent onshore wind
- 5 percent hydro
- 2 percent storage

In 2051, nuclear, natural gas, and hydro account for 62 percent of electricity generation. Wind, solar, and storage account for the remaining 38 percent.

Operating Costs by Energy Source

The Center's modeling shows that by 2035 and through 2051, Portfolio D would still rely most heavily for electricity generation on nuclear and

Portfolio D Scenario 2051 Generation Mix



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

natural gas, with nuclear, combined cycle natural gas, combustion turbine natural gas, coal, and hydro generating 100,000,000 MWh as late as 2029 and close to 80,000,000 MWh annually through the remainder of the model period to 2051. The operating costs, however, are skewed towards the intermittent sources and storage.

From 2033 through 2051, onshore wind, utility solar, community solar, offshore wind, storage, and solar plus storage are responsible for more than half of the operating costs, at more than $3 billion each year.

The initial North Carolina costs by source in the Center's models includes:

- 36 percent coal
- 25 percent combined cycle natural gas
- 19 percent nuclear
- 10 percent utility solar

- 8 percent combustion turbine natural gas
- 1 percent hydro
- 1 percent community solar

The 2051 Portfolio D Scenario costs by source include:

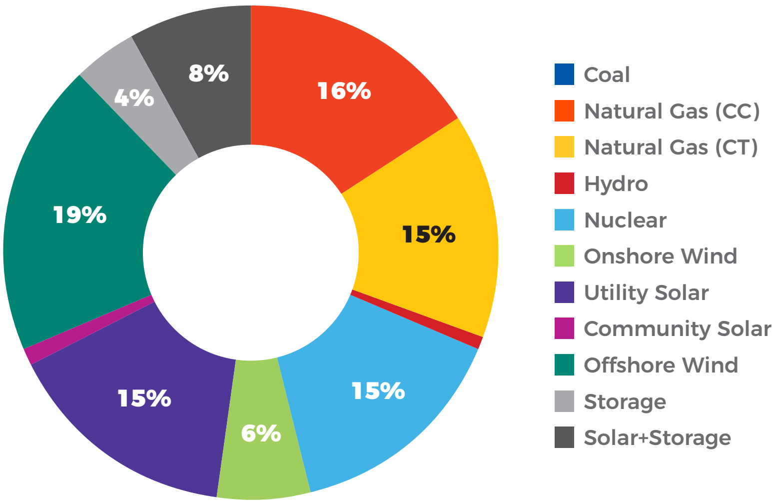
- 19 percent offshore wind
- 16 percent combined cycle natural gas
- 15 percent utility solar
- 15 percent combustion turbine natural gas
- 15 percent nuclear
- 8 percent solar plus storage
- 6 percent onshore wind
- 4 percent storage
- 1 percent community solar
- 1 percent hydro

Together, wind, solar, and storage account for 53 percent of costs in 2051.

To reiterate, wind, solar, and storage cost North Carolina more than half of its electricity operating costs in this scenario, but never account for even 40 percent of the annual electricity generation. Further, it should be noted that the operation of natural gas as backup for the intermittent sources dramatically reduces the efficiency of the resource and inflating costs.

Relatedly, grid utilization—a term that describes the ratio of actual electricity generation to potential generation—in the Center's models for the Portfolio D Scenario would decrease from 44.1 percent to 29.5 percent, meaning ratepayers would be forced to pay for more idle capacity sitting dormant on the grid.

Portfolio D Scenario 2051 Cost Breakdown by Source



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

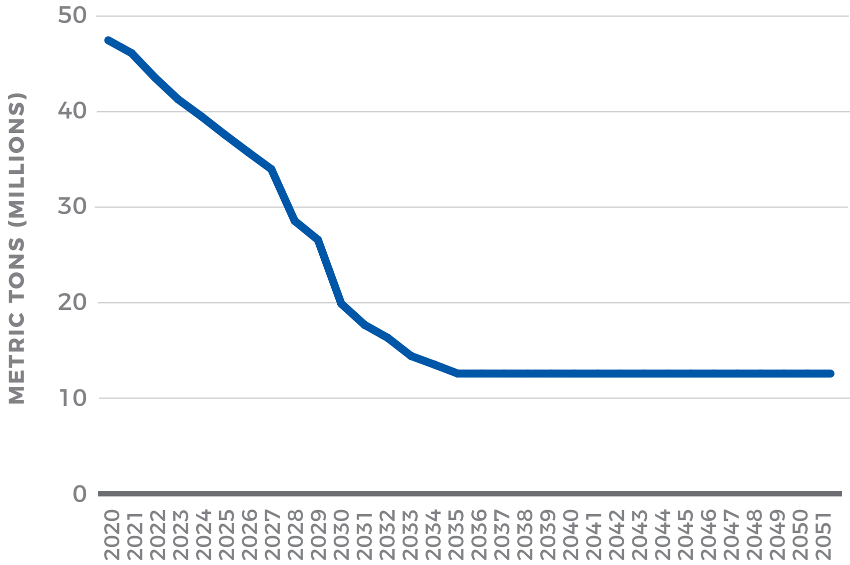
Cost per Metric Ton of CO_2 Reduced

In the Portfolio D Scenario, the state reduces CO_2 emissions to 70 percent below 2005 levels by the 2030 target, but the reductions come at a high cost.

The modeling indicates it will cost North Carolina $111.77 for every metric ton of CO_2 reduction through 2031. Through 2051, it will cost North Carolina $123.86 per metric ton.

Readers should note that this figure soars beyond the federal social cost of carbon in use by the Biden administration at this time of $51.[40] This discrepancy casts doubt on the favorability of Portfolio D on cost-benefit terms. When viewed alongside the JLF alternative scenarios' emissions reduction costs, Portfolio D looks even more dubious. In the Center's North Carolina models, the Portfolio D Scenario performance is poorer than in any other scenario by this measure.

Portfolio D Scenario Emissions by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

Portfolio D Conclusion

Portfolio D, which most reflects Governor Cooper and DEQ's Clean Energy Plan, would be a terrible bargain for the state of North Carolina. The plan would reduce carbon dioxide emissions as intended, but it would come at an unreasonable cost, as demonstrated by the Center's modeling.

Natural Gas Scenario

The first alternative scenario is one in which new natural gas capacity is added instead of wind, solar, and battery storage as in the Portfolio D Scenario.

In the Natural Gas Scenario modeling, 6,400 MW of natural gas is added to the capacity mix instead of the renewable energy additions listed in Duke Energy's IRPs. All 6,400 MW of capacity additions are combined cycle. In the Natural Gas Scenario, the same capacity retirements are made as in the IRPs. This results in a net capacity increase of about 4,250 MW for the state.

This scenario presents extraordinary savings for North Carolina relative to the Portfolio D Scenario. Whereas the Portfolio D Scenario would drive up operating costs to more than $1.5 billion above baseline annually, the Natural Gas Scenario reduces annual operating expenses to $500 million *below* baseline from the early-2030s to the end of the model period and reduces costs overall, even when incorporating property tax expenses, transmission and upgrade expenses, and Duke Energy returns.

Costs to Customers

As a result, ratepayers will see smaller increases in their bills in the Natural Gas Scenario than in the Portfolio D Scenario.

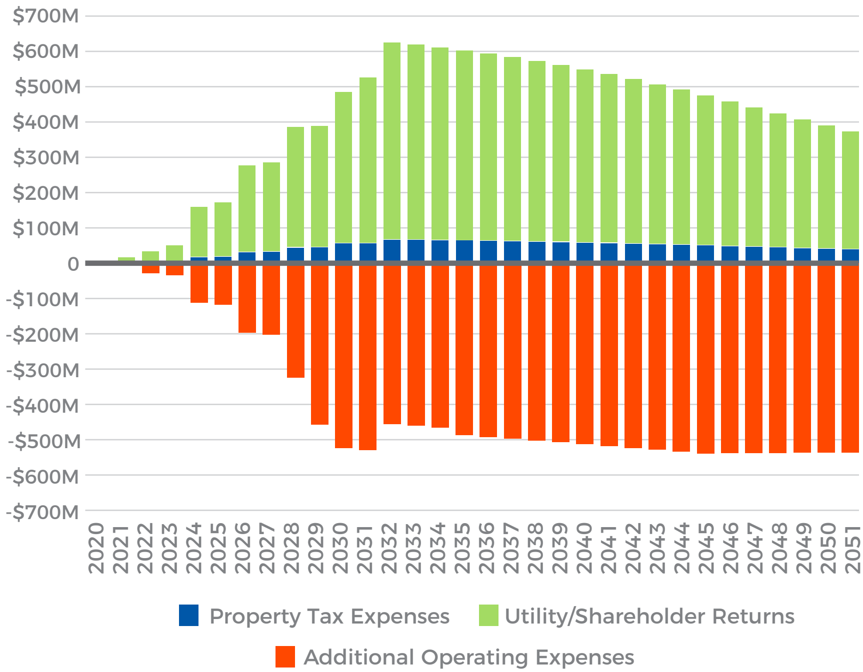
In the Natural Gas Scenario, residential customers will see their rates increase by a fraction of a cent through the first decade, peaking at about 0.15 cents per kWh above baseline in 2032. Rates will then fall on a similarly minute scale, decreasing back to parity with baseline rates by the early-2040s, and continuing to fall until residential rates are about 0.15 cents per kWh below baseline in 2051.

Commercial customers will see their rate follow the same trajectory, peaking at about 0.12 cents per kWh above baseline in 2032, then falling to about 0.12 below baseline in 2051.

The experience will be much the same for industrial customers. Rates will rise to just shy of 0.1 cents per kWh above baseline, then fall steadily to almost 0.1 cents per kWh below baseline in 2051.

Averaged over the entire model period to 2051, in the Natural Gas Scenario residential customers will see annual costs of just $1.38 above

Natural Gas Scenario Costs Relative to Baseline by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

baseline; commercial customers will see annual costs of $5.71 above baseline; and industrial customers will see annual costs of $162.71 above baseline. The Portfolio D Scenario, recall, resulted in residential, commercial, and industrial customers paying $411, $1,705, and $48,553 more each year, respectively.

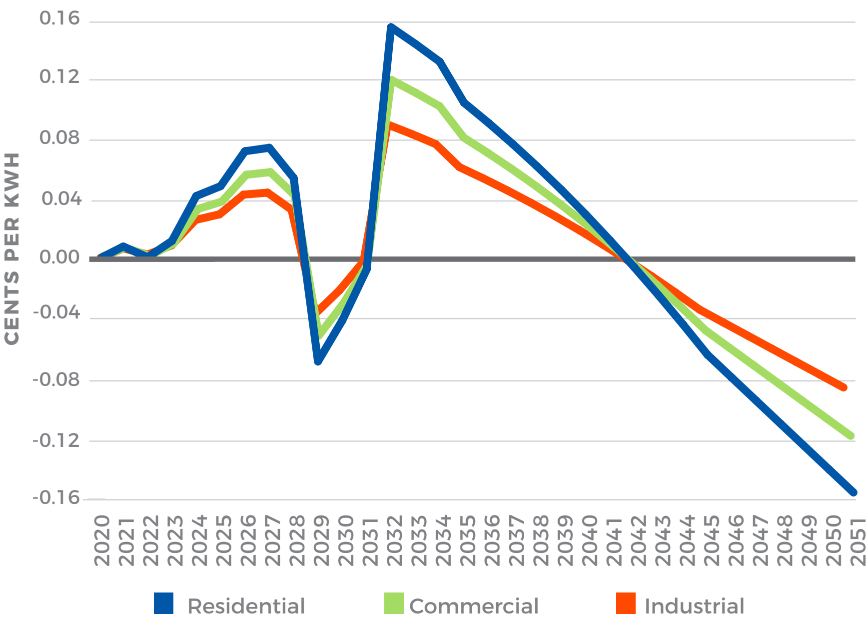
Put another way, the Portfolio D Scenario cost increases would be 300 times higher than those of the Natural Gas Scenario.

Capacity Mix

The initial North Carolina capacity mix in the Center's models includes:

- 31 percent coal

Natural Gas Scenario Rates Relative to Baseline by Year



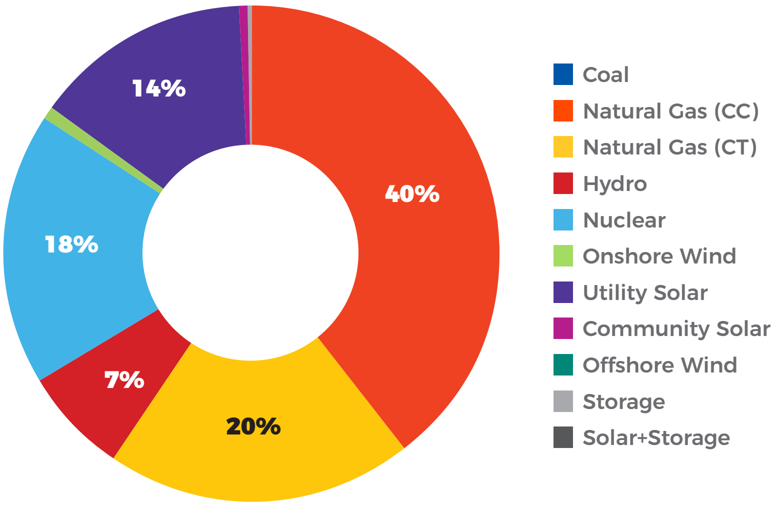
SOURCE: CENTER OF THE AMERICAN EXPERIMENT

- 18 percent combustion turbine natural gas
- 16 percent nuclear
- 15 percent combined cycle natural gas
- 12 percent utility solar
- 6 percent hydro
- 1 percent onshore wind

The 2051 Natural Gas Scenario capacity mix includes:

- 39 percent combine cycle natural gas

Natural Gas Scenario 2051 Capacity Mix



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

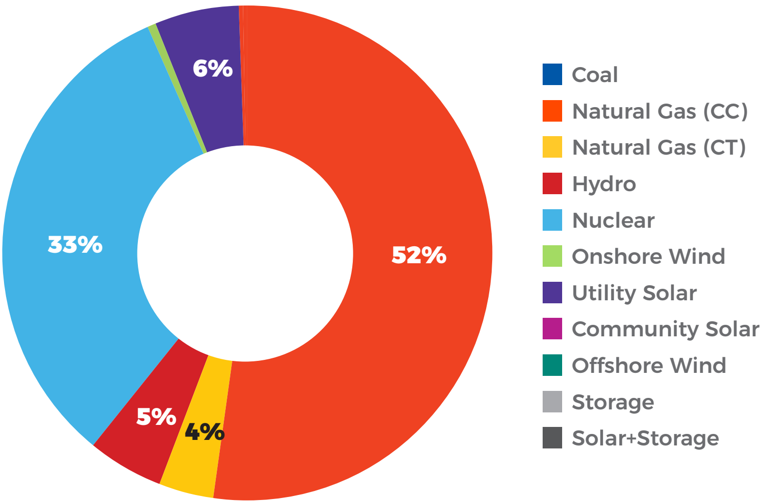
- 20 percent combustion turbine natural gas
- 18 percent nuclear
- 14 percent utility solar
- 7 percent hydro
- 1 percent onshore wind

Generation Mix

The initial North Carolina generation mix in the Center's models includes:

- 33 percent nuclear
- 27 percent combined cycle natural gas
- 25 percent coal

Natural Gas Scenario 2051 Generation Mix



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

- 6 percent utility solar
- 5 percent hydro
- 4 percent combustion turbine natural gas

The 2051 Natural Gas Scenario generation mix includes:

- 52 percent combined cycle natural gas
- 33 percent nuclear
- 6 percent utility solar
- 5 percent hydro
- 4 percent combustion turbine natural gas

Cumulatively, natural gas accounts for 56 percent of generation in this scenario. Gas and nuclear combine to provide 89 percent.

Operating Costs by Energy Source

The initial North Carolina costs by source in the Center's models includes:

- 36 percent coal
- 25 percent combined cycle natural gas
- 19 percent nuclear
- 10 percent utility solar
- 8 percent combustion turbine natural gas
- 1 percent hydro
- 1 percent community solar

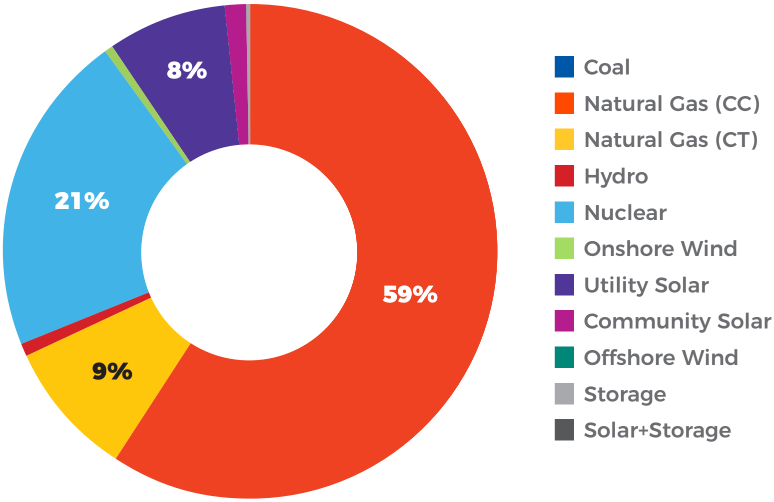
The 2051 Natural Gas Scenario costs by source include:

- 59 percent combined cycle natural gas
- 21 percent nuclear
- 9 percent combustion turbine natural gas
- 8 percent utility solar
- 1 percent offshore wind
- 1 percent community solar
- 1 percent hydro

Unlike in the Portfolio D Scenario, the resources generally produce electricity commensurate with their cost to the system in this scenario. It is worth noting that in the Natural Gas Scenario, combustion turbine natural gas (the higher emitting, higher cost variety) needs to be utilized less than in the Portfolio D Scenario in which it serves as a critical backup for intermittent wind and solar.

Grid utilization in this scenario would increase from 44.1 percent to 50.6 percent. This is primarily the result of retiring the current coal fleet that is operating at low capacity factors.

Natural Gas Scenario 2051 Cost Breakdown by Source



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

Cost per Metric Ton of CO_2 Reduced

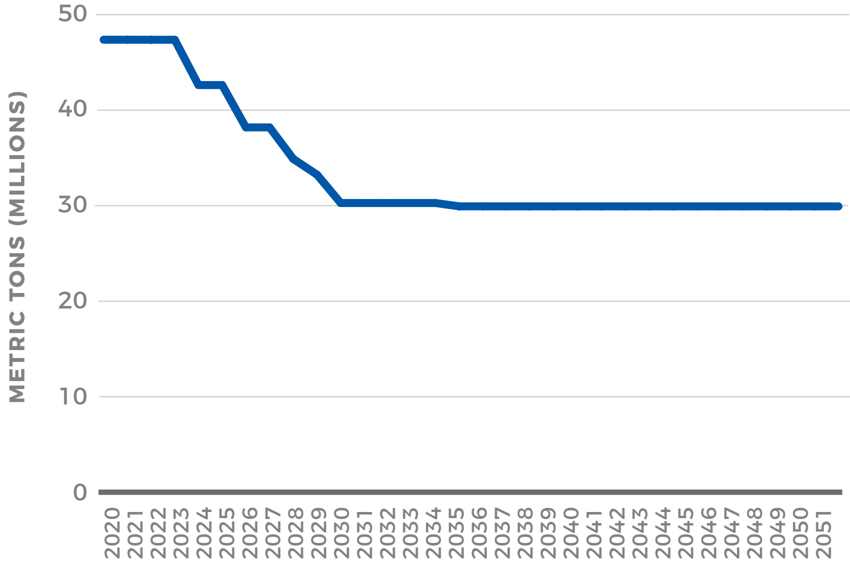
The Natural Gas Scenario provides less in terms of total emissions reduction than the Portfolio D Scenario. Nevertheless, the emissions reductions in this scenario are significant and, importantly for North Carolinians, they are remarkably cost-effective.

The Natural Gas Scenario reduces emissions to almost 20,000,000 metric tons below baseline annually by 2030 and through the remainder of the model period.

The 30,000,000 million metric ton figure that the state would emit from electricity annually from 2030 through 2051 in this scenario is more than 60 percent below 2005's emissions.

The emissions reductions by 2031 would come at a cost of $2.86 to the state per metric ton of CO_2 reduced. Through 2051, the price would be a miniscule 79 cents per metric ton reduced.

Natural Gas Scenario Emissions by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

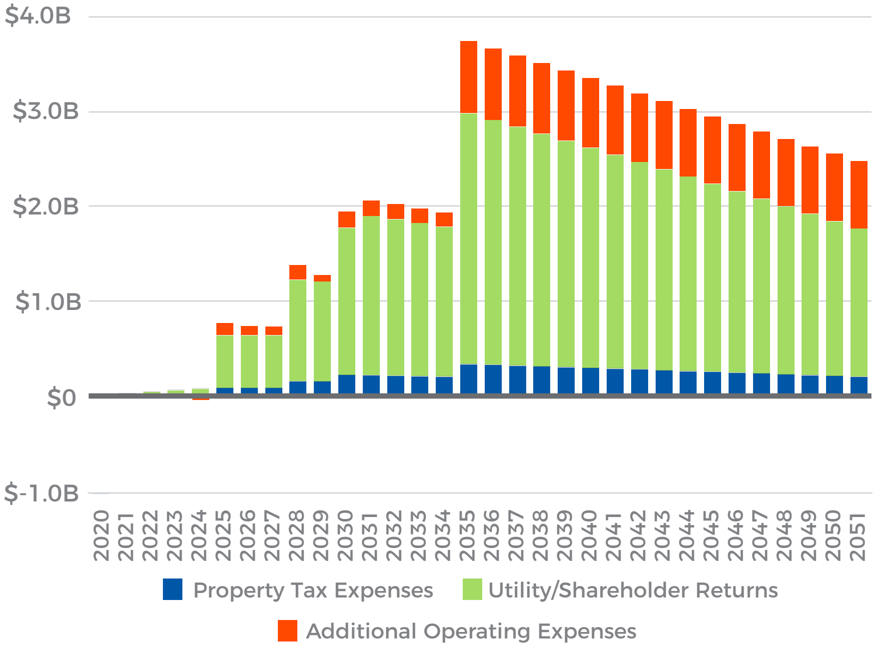
Juxtaposed with the Portfolio D Scenario costs to North Carolina of \$111.77 per metric ton of CO_2 reduction through 2031 and \$123.86 per metric ton through 2051, the Natural Gas Scenario looks attractive. The Portfolio D Scenario results in twice the emissions cut of the Natural Gas Scenario, but would cost 100 times more for each metric ton.

While the Natural Gas Scenario does not reach the Clean Energy Plan target of 70 percent below 2005 emissions levels, per dollar, natural gas additions are more effective at reducing emissions than the wind, solar, and battery storage additions Portfolio D demands.

EIA Nuclear Scenario

The second alternative scenario is one in which the Center modeled new nuclear capacity using U.S. Energy Information Administration

EIA Nuclear Scenario Costs Relative to Baseline by Year



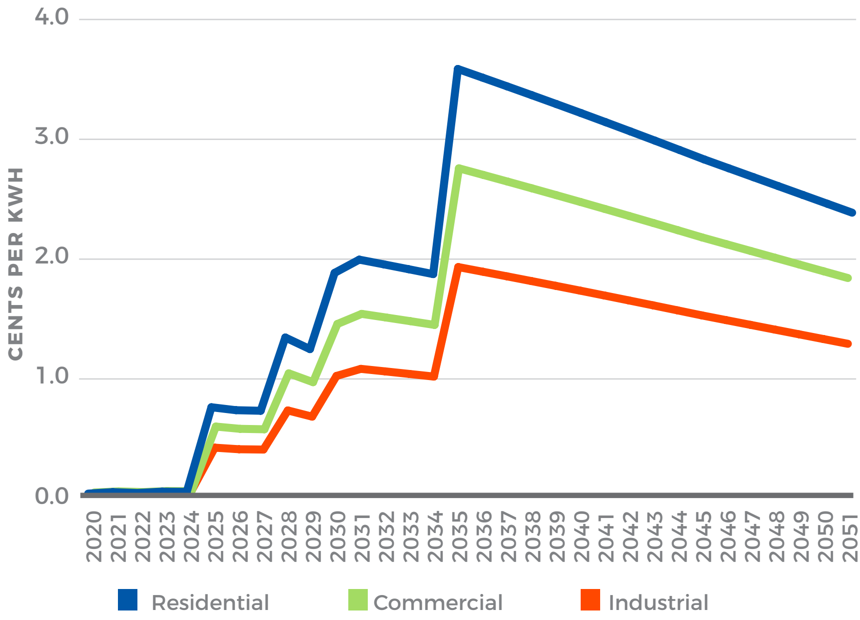
SOURCE: CENTER OF THE AMERICAN EXPERIMENT

assumptions instead of the wind, solar, and storage additions in the Portfolio D Scenario.

These additions come in the form of three 1,000-megawatt nuclear facilities and one 2,000 facility, for a total of 5,000 MW of new nuclear capacity. Additionally, the scenario includes another 1,500 MW of combined cycle natural gas capacity. In this scenario, the same coal retirements were made as in the Portfolio D Scenario. This results in a net capacity increase for North Carolina of about 4,150 MW.

Unlike the Natural Gas Scenario, the EIA Nuclear Scenario aims to achieve emissions reductions on par with the Portfolio D Scenario. The total additional cost to ratepayers of the nuclear scenario for the North Carolina

EIA Nuclear Scenario Rates Relative to Baseline by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

model would be $68 billion through 2051. While that is costly, it is $36.5 billion less expensive than the Portfolio D Scenario.

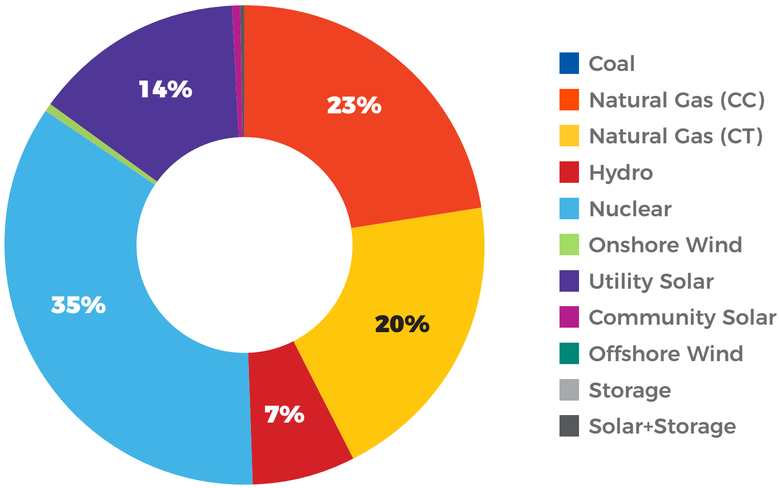
Costs to Customers

The EIA Nuclear Scenario is costlier for customers than the Natural Gas Scenario, but more affordable than the Portfolio D Scenario.

Residential customers will see rates climb to about 3.5 cents per kWh above baseline in this scenario by the mid-2030s, then fall to about 2.5 cents per kWh above baseline by 2051.

Annual costs for residential customers will average $267 above baseline through the model period. That figure is about $140 cheaper than the $411 increase in the Portfolio D Scenario.

EIA Nuclear Scenario 2051 Capacity Mix



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

Commercial customers will see a similar pattern, with rates rising to more than 2.5 cent per kWh above baseline, then falling to 1.8 cents per kWh above baseline by 2051. Annual costs for residential customers will average $1,109 above baseline through the model period. That figure is about $600 cheaper than the $1,705 increase in the Portfolio D Scenario.

Industrial customers' rates will increase to about 2 cents per kWh above baseline in 2035, then fall to about 1.3 cents per kWh above baseline by 2051. Annual costs for industrial customers will average $31,570 above baseline through the model period. That figure is about $17,000 lower than the $48,553 increase in the Portfolio D Scenario.

Capacity Mix

The initial North Carolina capacity mix in the Center's models includes:

- 31 percent coal
- 18 percent combustion turbine natural gas

- 16 percent nuclear
- 15 percent combined cycle natural gas
- 12 percent utility solar
- 6 percent hydro
- 1 percent onshore wind

The 2051 EIA Nuclear Scenario capacity mix includes:

- 35 percent nuclear
- 22 percent combined cycle natural gas
- 20 percent combustion turbine natural gas
- 14 percent utility solar
- 7 percent hydro
- 1 percent onshore wind
- 1 percent community solar

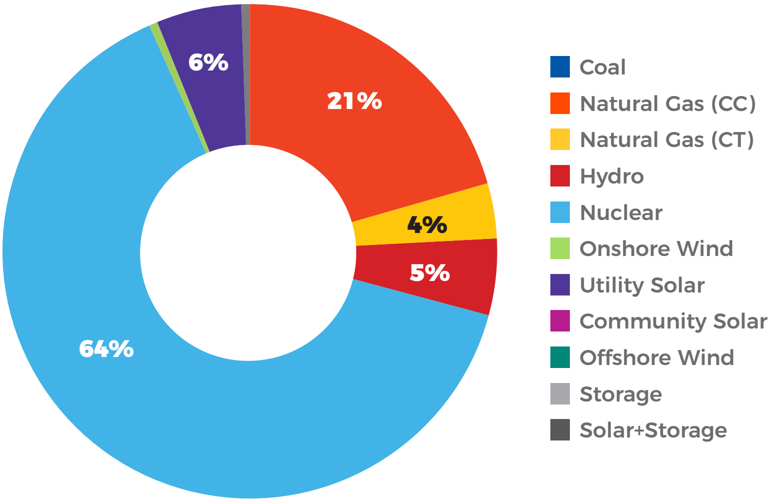
Generation Mix

The initial North Carolina generation mix in the Center's models includes:

- 33 percent nuclear
- 27 percent combined cycle natural gas
- 25 percent coal
- 6 percent utility solar
- 5 percent hydro
- 4 percent combustion turbine natural gas

The 2051 EIA Nuclear Scenario generation mix includes:

EIA Nuclear Scenario 2051 Generation Mix



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

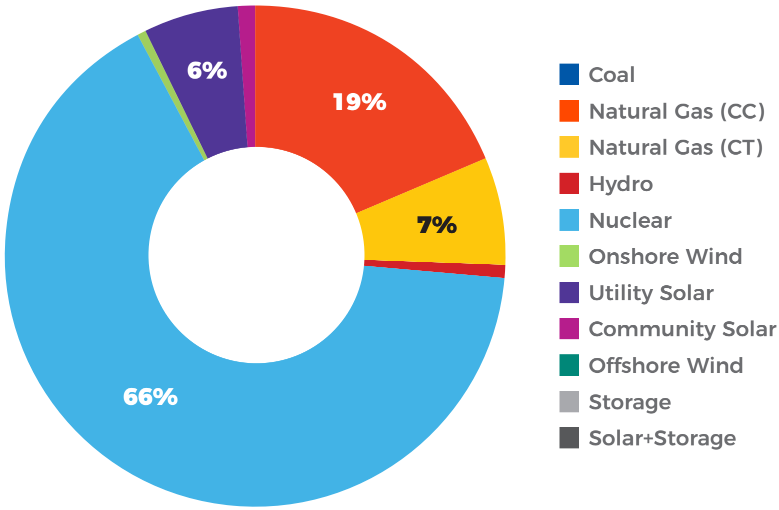
- 64 percent nuclear
- 21 percent combined cycle natural gas
- 6 percent utility solar
- 5 percent hydro
- 4 percent combustion turbine natural gas

Operating Costs by Energy Source

The initial North Carolina costs by source in the Center's models includes:

- 36 percent coal
- 25 percent combined cycle natural gas
- 19 percent nuclear

EIA Nuclear Scenario 2051 Cost Breakdown by Source



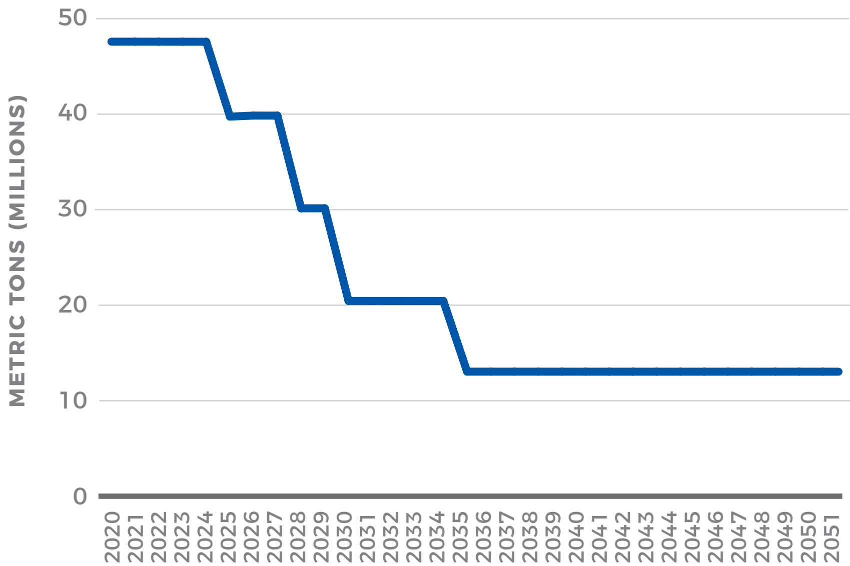
SOURCE: CENTER OF THE AMERICAN EXPERIMENT

- 10 percent utility solar
- 8 percent combustion turbine natural gas
- 1 percent hydro
- 1 percent community solar

The 2051 EIA Nuclear Scenario costs by source include:

- 66 percent nuclear
- 19 percent combined cycle natural gas
- 7 percent combustion turbine natural gas
- 6 percent utility solar
- 1 percent community solar
- 1 percent hydro

EIA Nuclear Scenario Emissions by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

Grid utilization in this scenario would increase from 44.1 percent to 50.4 percent. As in the Natural Gas Scenario, costs are commensurate with generation in this scenario and combustion turbine natural gas is used sparingly, relative to the Portfolio D Scenario in which it is significantly relied upon to back up intermittent wind and solar.

Cost per Metric Ton of CO_2 Reduced

The EIA Nuclear Scenario reduces emissions to the state goal of 70 percent below 2005 figures, and it does so at a lower cost than the Portfolio D.

Modeling for the Portfolio D Scenario revealed a cost per metric ton of CO_2 reduced of $111.77 through 2031 and $123.86 through 2051.

The EIA Nuclear Scenario would only cost $79.53 per metric ton through 2031 and $86.83 through 2051.

This scenario achieves the same emissions reduction at a lower cost to North Carolina.

APR1400 Scenario

The final alternative scenario is one that deploys a specific nuclear reactor, the APR1400.

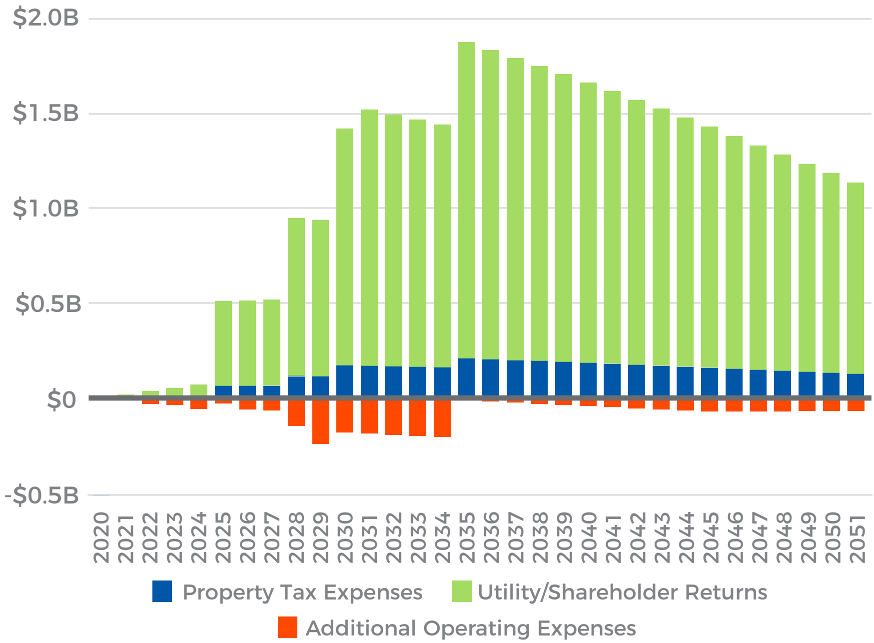
APR1400 is a reactor developed by the Korea Hydro & Nuclear Power Co., Ltd. (KHNP), a subsidiary of the Korea Electric Power Corporation (KEPCO). APR1400, which is shorthand for 1400-megawatt advanced pressurized water nuclear reactor, has demonstrated credibility as a carbon-free, baseload source of electricity in South Korea and has recently begun commercial operation in the United Arab Emirates (UAE) as well.

KHNP submitted a Standard Design Certification Application for APR1400 to the U.S. Nuclear Regulatory Commission (NRC) on December 23, 2014. The NRC issued KHNP design certification for the APR1400 in August 2019.[41]

APR1400 is the first foreign-designed nuclear reactor to receive NRC certification. It joins five other standard reactor designs that have been certified in the United States: General Electric's Advanced Boiling Water Reactor (ABWR); Westinghouse's System 80+, AP600 and AP1000; and GE's Economic Simplified Boiling Water Reactor.

APR1400 was conceived in 1992 and was first put to use at South Korea's Shin-Kori Nuclear Power Plant, with construction beginning in 2008.[42] The first unit, Shin-Kori Unit 3, began commercial operation in 2016. Shin-Kori Unit 4 began commercial operation in 2019.[43] Six other units have been planned or are under construction in South Korea—two more at Shin-Kori and four at Shin-Hanul Nuclear Power Plant.[44] Nuclear energy makes up one-eighth of South Korea's electricity mix, but has faced political challenges in recent years, despite its stellar contribution toward the country's 2050 carbon-neutrality goal.[45]

APR1400 Scenario Costs Relative to Baseline by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

The United Arab Emirates selected APR1400 from among a field of competitors bidding to build nuclear capacity in the Persian Gulf nation in 2009.[46] Construction began on the first unit in 2012 and on three additional units by 2015. The Emirates Nuclear Energy Corporation (ENEC) announced in April 2021 that the first of four planned APR1400 units has begun commercial operations at the Barakah Nuclear Power Plant in the emirate of Abu Dhabi.[47] According to S&P Global, the UAE is the first Gulf Cooperation Council country to generate power from nuclear energy.[48]

In an official statement, ENEC chairman Khaldoon Khalifa Al Mubarak said of the development:

"The UAE set a clear roadmap with solid principles to ensure this project was developed in accordance with the highest international industry standards of safety and quality with full transparency…Our investment in pioneering technologies and the decarbonisation of our electricity production not only advances the UAE's clean energy leadership, but also produces tangible socioeconomic and environmental benefits."[49]

Once all units are operational, they will produce 5.6 GW—enough to meet 25 percent of the UAE's power demand.

Modeling conducted by the Center of the American Experiment shows that APR1400 would provide superb value for the state of North Carolina, as it has for South Korea and the UAE.

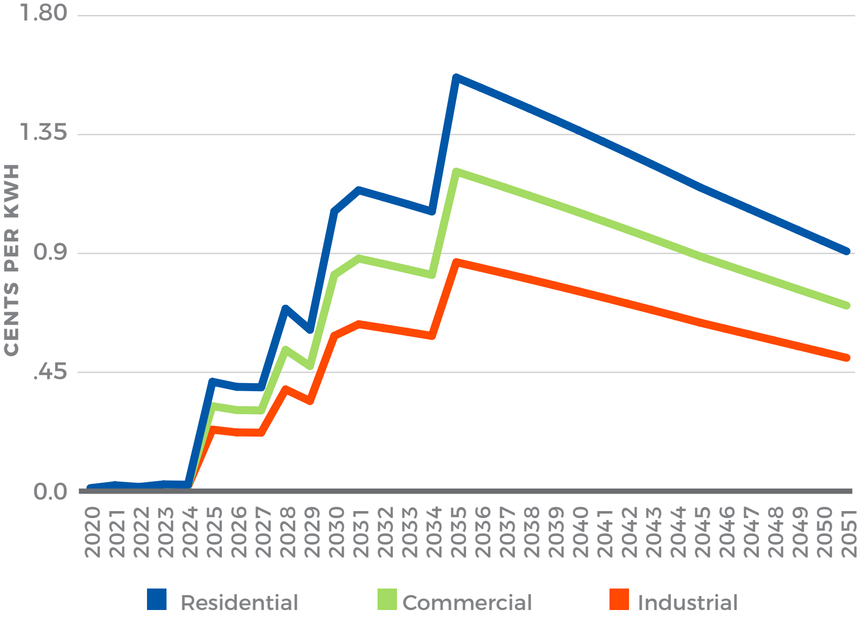
In the Center's modeling, 5,600 MW of APR1400 nuclear capacity replace the renewable energy additions listed in Portfolio D. These additions come in the form of four 1,400-megawatt facilities beginning in 2025. In addition, one 900-megawatt natural gas combined-cycle facility is included. The amount of nuclear capacity was based on reaching a similar carbon-free percentage as Portfolio D. Incidentally, the four facilities mirror what will soon be in commercial operation in the UAE. In the modeled APR1400 scenario, the same capacity retirements were made as were made in Portfolio D, resulting in a net capacity increase of 4,149.7 MW in the North Carolina scenario. Capital costs in this scenario were based on capital costs in the UAE.[50]

The Center finds that the total additional cost to North Carolina in the APR1400 scenario would be $34.4 billion through 2051, compared to the base year. This is the second least expensive scenario from among the Center's North Carolina models and is $70 billion less expensive than Portfolio D.

Costs to Customers

Residential electricity rates in this scenario would increase on average by 1.04 cents per kWh and reach a high of 1.75 cents above the base year rate per kWh in 2035. Commercial rates would increase on average by

APR1400 Scenario Rates Relative to Baseline by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

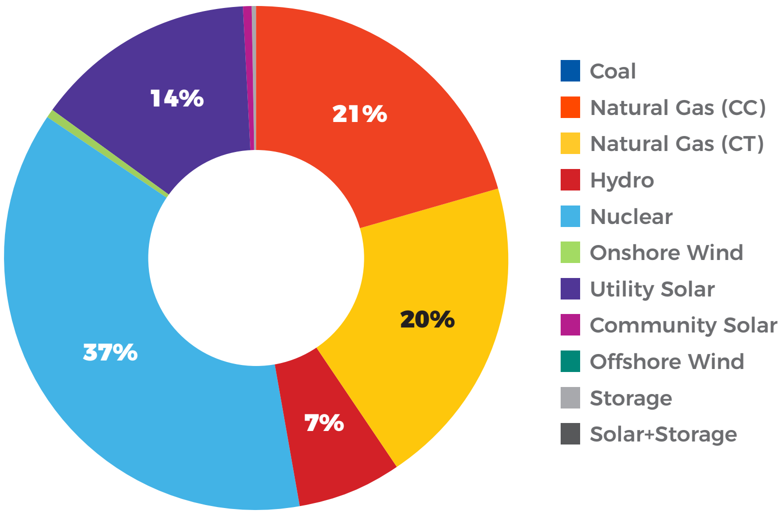
0.81 cents per kWh and reach a high of 1.35 cents above the base year rate per kWh in 2035. Industrial rates would increase on average by 0.58 cents per kWh and reach a high of 0.97 cents above the base year rate per kWh in 2035.

For residential customers, annual electricity costs will be an average of $135.16 higher through 2051 than in the base year. Between 2032 and 2051 costs will be an average of $175.49 higher than in the base year.

For commercial customers, annual electricity costs will be an average of $561.01 higher through 2051 than in the base year. Between 2032 and 2051 costs will be an average of $728.41 higher than in the base year.

For industrial customers, annual electricity costs will be an average of $15,973.78 higher through 2051 than in the base year. Between 2032 and 2051 costs will be an average of $20,739.98 higher than in the base year.

APR1400 Scenario 2051 Capacity Mix



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

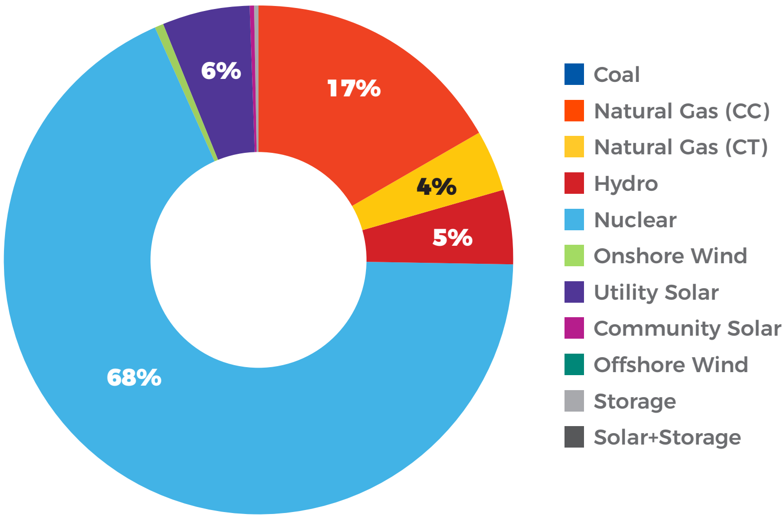
The Portfolio D Scenario, recall, resulted in residential, commercial, and industrial customers paying $411, $1,705, and $48,553 more each year, respectively, meaning the APR1400 Scenario is $275 cheaper for residential customers, $1,040 cheaper for commercial customers, and $32,500 cheaper for industrial customers than the Portfolio D Scenario.

Capacity Mix

The initial North Carolina capacity mix in the Center's models includes:

- 31 percent coal
- 18 percent combustion turbine natural gas
- 16 percent nuclear
- 15 percent combined cycle natural gas

APR1400 Scenario 2051 Generation Mix



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

- 12 percent utility solar
- 6 percent hydro
- 1 percent onshore wind

The 2051 APR1400 Scenario capacity mix includes:

- 37 percent nuclear
- 20 percent combined cycle natural gas
- 20 percent combustion turbine natural gas
- 14 percent utility solar
- 7 percent hydro
- 1 percent onshore wind
- 1 percent community solar

Generation Mix

The initial North Carolina generation mix in the Center's models includes:

- 33 percent nuclear
- 27 percent combined cycle natural gas
- 25 percent coal
- 6 percent utility solar
- 5 percent hydro
- 4 percent combustion turbine natural gas

The 2051 APR1400 Scenario generation mix includes:

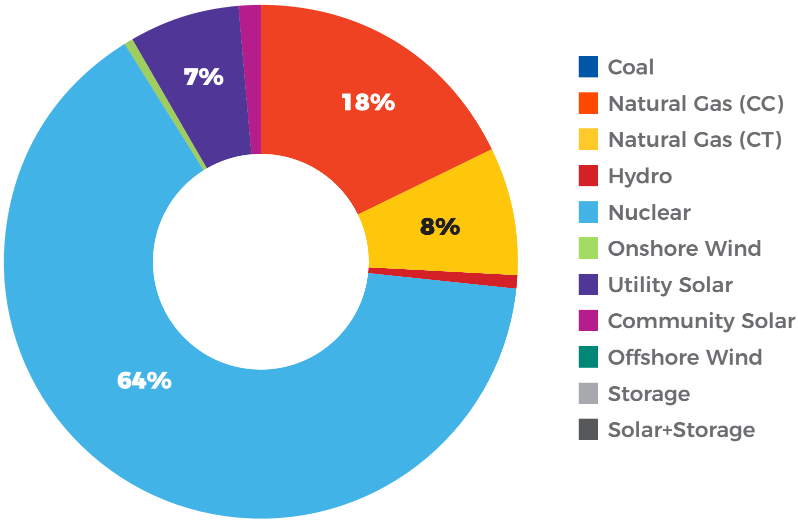
- 68 percent nuclear
- 17 percent combined cycle natural gas
- 6 percent utility solar
- 5 percent hydro
- 4 percent combustion turbine natural gas

Operating Costs by Energy Source

The initial North Carolina costs by source in the Center's models includes:

- 36 percent coal
- 25 percent combined cycle natural gas
- 19 percent nuclear
- 10 percent utility solar
- 8 percent combustion turbine natural gas

APR1400 Scenario 2051 Cost Breakdown by Source



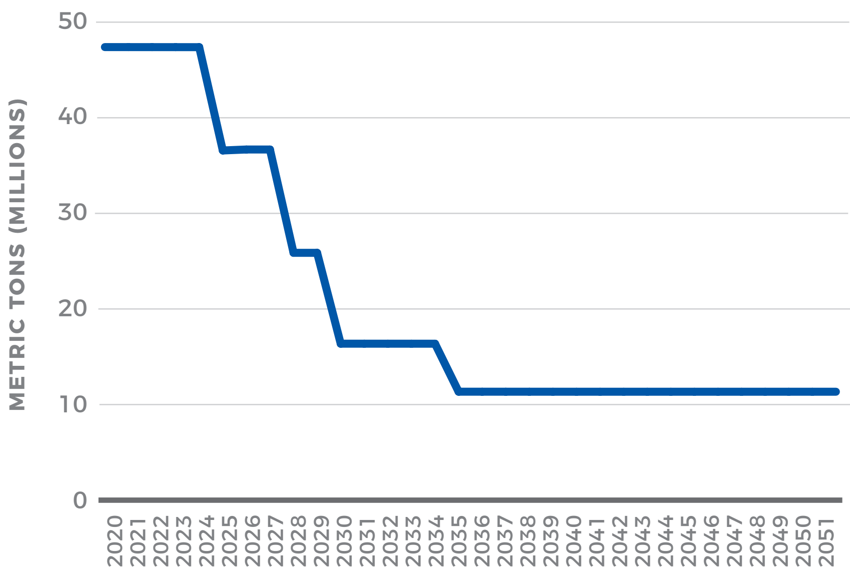
SOURCE: CENTER OF THE AMERICAN EXPERIMENT

- 1 percent hydro
- 1 percent community solar

The 2051 APR1400 Scenario costs by source include:

- 64 percent nuclear
- 18 percent combined cycle natural gas
- 8 percent combustion turbine natural gas
- 7 percent utility solar
- 1 percent onshore wind
- 1 percent community solar
- 1 percent hydro

APR1400 Scenario Emissions by Year



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

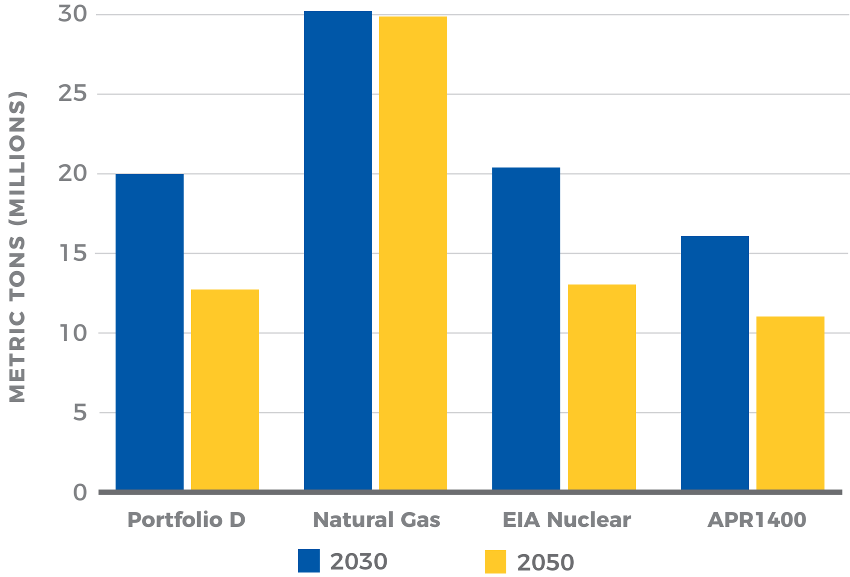
As in the first two alternative scenarios, the APR 1400 Scenario's source costs reflect generation for the most part and the scenario minimizes the use of combustion turbine natural gas. Grid utilization in this scenario would increase from 44.1 percent to 50.4 percent.

Cost per Metric Ton of CO_2 Reduced

The overarching purpose of the Duke Energy IRPs and of this project is to find ways for North Carolina to reduce its contribution to global greenhouse gas concentrations from the electricity sector in a cost-effective way. The results of the Center's modeling provide valuable insights towards this end.

The APR1400 Scenario for North Carolina would result in a carbon-free generation percentage of 79.4 percent. North Carolina would reduce its

Projected 2030 and 2050 CO_2 Emissions by Scenario



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

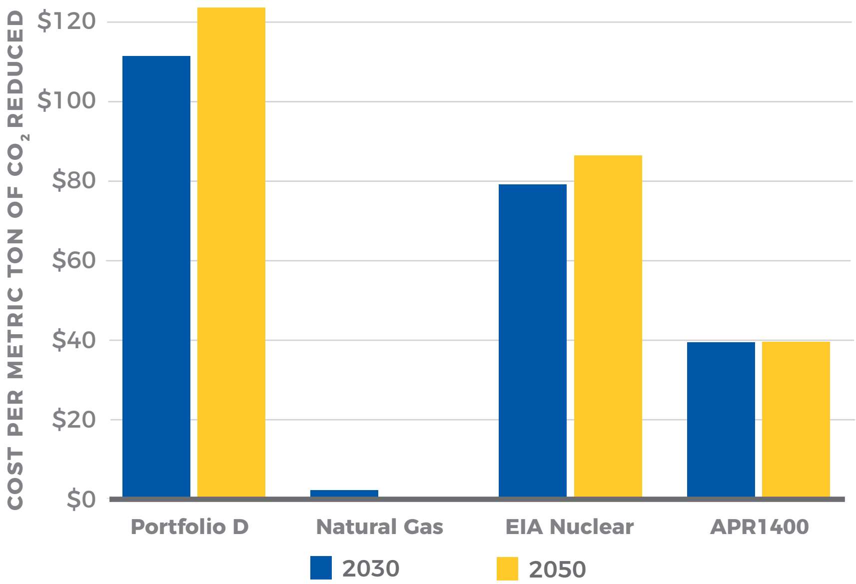
CO_2 emissions from electricity in this scenario by 77 percent by 2035, from nearly 50 million metric tons to slightly above 10 million.

Total CO_2 emissions in this scenario would amount to 668 million metric tons throughout the model, averting 857 million metric tons compared to 2020 emissions and would be the largest CO_2 emissions decrease of any scenario in the North Carolina models.

Critically, in the APR1400 Scenario the cost of reductions is much lower than in the other deep reduction scenarios. The cost per metric ton of CO_2 emissions reduction through 2051 in the APR1400 scenario is $40.11.

That cost is 53 percent less than the $86.83 that it would cost to reduce emissions in the EIA Nuclear Scenario and an astonishing 67 percent less than the whopping $123.86 it would cost to reduce emissions with

Projected 2030 and 2050 CO_2 Emissions Reduction Costs



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

Portfolio D.

To reiterate:

The EIA Nuclear Scenario reduces emissions in 2050 to 12.7 million metric tons at a reduction cost of $86.83 per unit.

The Portfolio D Scenario reduces emissions to 12.7 million metric tons at a reduction cost of $123.86 per unit.

APR1400 reduces emission even lower, to 11 million metric tons, at a reduction cost of just $40.11 per unit.

Of the modeled scenarios, utilizing APR1400 is the most cost-effective route to deep carbon dioxide emissions reduction. As one of 39 states with NRC agreements, North Carolina is positioned to fast-track APR1400 and pursue its emissions goals in a way that holds costs to ratepayers in check and, as the next section will explain, reduces land-use impact.[51]

THE NORTH CAROLINA CLEAN ENERGY PLAN'S HIDDEN COSTS

The shortcomings of wind and solar as key players on an electricity grid are many. At the root of these issues is that wind and solar energy are both intermittent.

Wind and solar generation are at the mercy of weather and the planet's diurnal cycle. Generation from these sources drops when wind and sunlight are uncooperative. As a result, they cannot be relied upon to the extent that baseload electricity from, say, nuclear energy can.

Wind and solar's intermittency stresses the grid. As Duke Energy writes in Chapter 16 of the IRPs, "The utility's control systems continuously ramp central station generating units up or down to meet electric demand of the customers it serves. With the growing contribution of renewable energy sources, which have variable output from minute to minute, this balance becomes increasingly challenging to maintain."

Downstream of this core problem is that wind and solar energy entail significant resource and space demands, both for the installation of capacity and for energy storage in the form of batteries. As noted in the scenario analyses, this problem also necessitates extensive investment in dispatchable backup sources that can generate in a pinch when wind and solar fall off. The leading source for this type of generation is combustion-turbine natural gas. Combustion-turbine gas has a quicker start up time than combined-cycle, but runs less efficiently, emitting more, and thus undermining the ostensible emissions savings of adding wind and solar capacity.

Complicating matters further, the battery supply chain presents a host of environmental and geopolitical risks in its own right. This section will give attention to the concept of capacity factor, to levelized and imposed costs, to environmental and geopolitical risk, and, most extensively, to land use.

As Duke Energy describes, pursuing an electricity scenario compatible with Governor Cooper and DEQ's Clean Energy Plan demands "extensive additional analysis around the siting, permitting, interconnection, system upgrades, supply chain and operational considerations of more significant amounts of intermittent resources and much greater dependence on energy storage on the system."

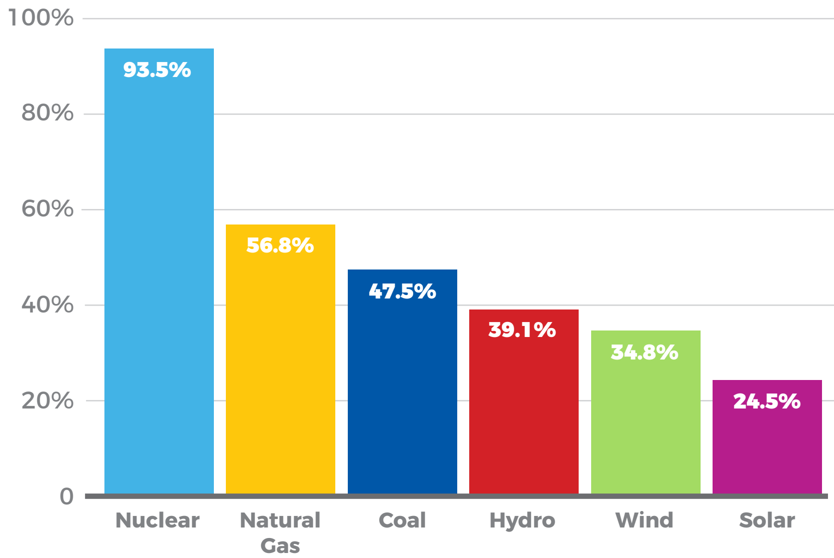
Capacity Factor

Another way of describing wind and solar's intermittency problems is with the concept of capacity factor. In a handy guide to electricity lingo,[52] the U.S. Department of Energy describes the concept in this way:

"Capacity factors allow energy buffs to examine the reliability of various power plants. It basically measures how often a plant is running at maximum power. A plant with a capacity factor of 100% means it's producing power all of the time."

When North Carolinians see the scale of wind and solar additions, it is critical that they appreciate that capacity means something very different for a source like nuclear than it does for wind and solar in terms of actual power production.

Capacity Factor by Source, 2019



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

According to EIA, the capacity factors of the major electricity sources in 2019 were:

- 93.5 percent for nuclear
- 56.8 percent for natural gas
- 47.5 percent for coal
- 39.1 percent for hydro
- 34.8 percent for wind
- 24.5 percent for solar

Wind and solar's low capacity factors mean that a grid needs to invest far more in total capacity than if baseload sources are put at the forefront.

Imposed Costs and the Levelized Cost of Electricity

Another effect of wind and solar additions is that the more reliable sources of electricity are not able to run in their most effective manners, i.e., the intermittency of wind and solar imposes costs on the grid and to electricity ratepayers in the end. When imposed costs are accounted for, the levelized cost of electricity (LCOE) looks quite different.

In 2019, the Institute for Energy Research published a report titled "The Levelized Cost of Electricity from Existing Sources" that examined this issue.[53] Wind and solar, the report's authors explain, increase the LCOE of dispatchable resources by reducing their utilization rates without reducing their fixed costs.

The report estimates the imposed cost brought on by wind energy is about $24 per MWh of wind generation when the cost is modeled against new combined-cycle natural gas generation it might displace. It estimates the imposed cost of solar is about $21 per MWh of solar generation when we modeled against the cost of natural gas generation it might displace.

When these imposed costs are included, the average LCOEs of new wind ($90) and new photovoltaic solar ($88.7) are more than double the average LCOEs of existing combined-cycle natural gas ($36) and nuclear ($33).

To be clear, however, this report uses LCOE values derived from Form 1 filings submitted to the Federal Energy Regulatory Commission (FERC) by Duke Energy Carolinas and Duke Energy Progress. New LCOE values were calculated based on inputs from EIA's electricity market module assumptions in the Annual Energy Outlook 2021. This methodology utilizes North Carolina capacity factors to calculate region-specific LCOE values.[54]

Environmental and Geopolitical Risks

While wind and solar electricity generation do not emit carbon dioxide, they do have environmental effects. Wind, solar, and battery power are

Jiangxi Ganfeng Lithium Co., the world's largest lithium mining company. Lithium-ion batteries, which constitute the majority of grid-scale storage and give plausibility to significant wind and solar penetration, bring with them a host of environmental and geopolitical thorns.

dependent on raw materials, just as baseload power is dependent on raw materials.

Lithium-ion batteries in particular, which constitute the majority of grid-scale storage and give plausibility to significant wind and solar penetration, bring with them a host of environmental and geopolitical thorns.[55] Batteries are resource-intensive goods that depend on extractive practices and a complex, geopolitically-fraught supply chain. Despite their centrality to what have been deemed "clean energy" plans, batteries beget toxic waste that as of yet does not have a recycling solution.

Wind, Solar, and Battery Resource Demands

Solar electricity generation requires a diverse mix of materials. Silica is the principal raw material used to manufacture solar cells. Copper is another major component. According to the U.S. Geological Survey, metals such as cadmium, gallium, germanium, indium, selenium, and tellurium "are recovered as byproducts from the production of other metals and are critical to varying extents for the efficient operation of photovoltaic cells."[56]

Wind turbines, too, are resource-dependent. As an international team of researchers wrote for the journal *One Earth* in July 2020, "there are increasing concerns about conflicts between the supply of rare-earth elements (REs) (mainly neodymium, praseodymium, and dysprosium) and the global expansion of wind power."[57]

A May 2021 report from the International Energy Agency (IEA) analyzed the mineral resource demands of a global shift to wind, solar, and battery storage.[58] IEA presents a sobering picture, finding that per megawatt:

- Offshore wind requires about 8,000kg of copper and 5,000kg of zinc.
- Onshore wind requires about 3,000kg of copper and 5,000kg of zinc.
- Solar requires about 3,000kg of copper and 3,000kg of silicon.
- Nuclear requires less than 2,000kg of copper and less than 6,000kg of minerals total.
- Natural gas requires less than 2,000kg of minerals altogether.

IEA comments broadly that, "(w)hile solar PV plants and wind farms do not require fuels to operate, they generally require more materials than fossil fuel-based counterparts for construction," and adds, "(a)long with hydropower, nuclear is one of the low-carbon technologies with the lowest mineral intensity."

The batteries that would store the energy from wind and solar also, of course, rely on a global mining, refining, and transport network for lithium, nickel, copper, cobalt, graphite, and manganese.[59] Cobalt mining has sparked widespread concern on both environmental and social grounds.[60]

Mining and processing of key minerals for wind, solar, and battery power, come with a host of water-related issues as well. “Mining and mineral processing require large volumes of water for their operations,” IEA notes, “and pose contamination risks through acid mine drainage, wastewater discharge and the disposal of tailings.” Around half of lithium and copper production takes place in areas of high water stress.

The processing of rare-earth elements (REs), similarly, “often generates toxic and radioactive materials,” that “can leak into groundwater, causing major health and safety issues, including fatalities,” IEA determines.

New Energy Geopolitics

According to *Bloomberg New Energy Finance* (BNEF), China controls 80 percent of the world’s raw material refining for lithium-ion batteries, 77 percent of the world’s cell capacity, and 60 percent of the world’s component manufacturing.[61]

In BNEF’s 2020 national rankings, China comes in first in both the raw materials category and the cell and component category. The U.S., meanwhile, ranks 15th in raw materials and 4th in the cell and component category.

The raw material rankings are based on resource availability, mining capacity, and refining capacity. Cell and components are ranked based on the manufacturing capacity of electrolyte salts and solutions, anodes, cathodes, separators, and cells.

James Frith, BNEF’s head of energy storage, describes the current situation as one of Chinese “dominance,” remarking that it is “to be expected given its huge investments and the policies the country has implemented over the past decade. Chinese manufacturers, like CATL, have come from nothing to being world-leading in less than 10 years.”

For China and the United States, additions of wind, solar, and battery storage have different geopolitical consequences. As Paul Kolbe, director

"For 31 of the 35 minerals designated as 'critical' by the Department of the Interior, the U.S. imports more than half of its annual consumption. For 14 of the critical minerals, the U.S. has no production whatsoever."

of the Intelligence Project at Harvard University's Belfer Center for Science and International Affairs, and Mark Finley, fellow in energy and global oil at Rice University's Baker Institute, argued in the February 2021 issue of the Oxford Institute for Energy Studies' quarterly journal, China is the geopolitical winner of a global transition away from oil and gas.[62]

For China, a government-driven focus on batteries and electric vehicles enhances energy security, since the country imports the vast majority of the oil and gas it uses. Wood Mackenzie reports that by 2030 China will import 50 percent of its natural gas supply and 80 percent of its oil supply.[63]

The United States, on the other hand, is the world's largest producer of natural gas, has been a net export of natural gas for four years, and became in 2020 a net annual petroleum exporter for the first time since at least 1949, according to the U.S. Energy Information Administration.[64] [65]

Meghan L. O'Sullivan, professor of international affairs at Harvard University's Kennedy School of Government and director of the Geopolitics of Energy Project, wrote in the same issue of the Oxford energy journal, "In recent years, America found itself in a position to use energy as a means—an instrument—of foreign policy to achieve other, non-energy-related goals, largely due to the unconventional boom which catapulted the United States into the position of being the largest oil and natural gas producer in the world."[66]

Batteries are not a U.S. strength at this time. Reducing barriers to domestic resource extraction would help, but as of 2019, the Department of Energy remarked, "the United States is not a large producer of minerals such as lithium, manganese, cobalt, or graphite—all important components of today's lithium-ion batteries."[67]

For 31 of the 35 minerals designated as "critical" by the Department of the Interior, the U.S. imports more than half of its annual consumption.[68] For 14 of the critical minerals, the U.S. has no production whatsoever.[69]

China holds 37 percent of global rare-earth reserves and was responsible for 63 percent of the world's total production in 2019.[70] As the international research team described in *One Earth*, these minerals are essential for the generation of electricity for wind turbines. "As China cemented its influence over the market, the rest of the world grew increasingly reliant on Beijing's steady supply," Christina Lu wrote for *Foreign Affairs* in the April 2021. "Between 2016 and 2019, the United States imported 80 percent of its rare earths from China."[71]

China's supply-chain primacy leads IEA to include "(d)ominance of China across the value chain from mining to processing and magnet production" among the key challenges of a global shift to wind, solar, and battery power.

Wind, Solar, and Battery Waste

According to IEA, the recycling rates for used copper, aluminum, chromium, zinc, and cobalt are all below 50 percent. For lithium and REs, the recycling rate is below 1 percent. In a 2020 series of posts on the environmental risks of wind, solar, and batteries, the Union of Concerned Scientists (UCS) explained the basic waste challenge we face as volumes of wind turbines, solar panels, and batteries reach the end of their lifespans.[72] While UCS sees the possibility of solutions, it brings attention to the coming tsunami of waste from allegedly-clean energy.

Wind Energy Waste

The most visible environmental problem that arises from wind energy is solid waste. Wind turbine blades, which are now generally longer than 100 feet, are beginning to pile up in landfills.

"Tens of thousands of aging blades are coming down from steel towers around the world," *Bloomberg Green's* Chris Martin wrote in February 2020, "and most have nowhere to go but landfills."[73]

Martin reports that in the United States, 8,000 turbine blades will need to find final resting places by 2024. Europe has over 3,500 blades coming down each year. Because of the rigors blades must withstand during their lifespan, they are not easily crushed, nor are there reasonable avenues to recycling. As of 2020, only three U.S. landfills—located in Lake Mills, Iowa; Sioux Falls, South Dakota; and Casper, Wyoming—accepted blades.

NPR reports that by 2040 the U.S. will generate more than 700,000 tons of wind turbine blade waste,[74] the equivalent of 22,580 discarded Boeing 737s.[75]

Solar Energy Waste

The main pollutants from discarded solar panels are lead, cadmium, and selenium. UCS indicates that while safe waste processing (ideally, material recovery) is possible, processing capacity has not kept pace with deployments of solar panels as there is little incentive to design or install custom processes at municipal waste facilities.

The most prevalent type of panel—crystalline silicon—can be handled in municipal glass, metal, or electronic waste facilities. However, these facilities have limited capacity to extract all the materials and, due to the infrequency of supply of PV panels in need of recycling, little incentive to design or install custom processes.

Battery Waste

According to University of Wisconsin chemistry researcher Robert J. Hamers, "Nickel is dirt cheap. It's pretty good at energy storage. It is also toxic. So is cobalt."[76] The Environmental Protection Agency agrees and classifies lithium-ion batteries as hazardous material.[77]

According to Chemical and Engineering News (CEN), waste from lithium-ion batteries will hit 2 million metric tons per year by 2030, most of which will end up in landfills, with grave potential for soil and groundwater contamination.[78]

Unlike, for example, standard car batteries, lithium-ion battery recycling has not proven economical and, thus, the battery binge has the potential to become a major environmental stressor. The onerous recycling process for lithium-ion batteries is itself resource-intensive and capital-intensive. “Most of the batteries that do get recycled undergo a high-temperature melting-and-extraction, or smelting, process similar to ones used in the mining industry,” CEN explains. A significant portion of the recycling cost arise from “the need to treat the emission of toxic fluorine compounds released during smelting.”

CEN adds that a battery’s environmental cost begins long before it becomes waste. “(M)ining for some battery metals requires processing metal-sulfide ore, which is energy intensive and emits SOx that can lead to acid rain.”

Duke Energy’s Battery Build-Out

The scale of the proposed North Carolina energy storage expansion is difficult to overstate. As Duke Energy writes in the IRPs’ Technology, Policy and Operational Considerations subsection, “For the 70% reduction and No New Gas cases, the unprecedented levels of storage that are required to support significantly higher levels of variable energy resources present increased system risks, given that there is no utility experience for winter peaking utilities in the U.S. or abroad with operational protocols to manage this scale of dependence on short-term energy storage.”

Portfolio F (No New Natural Gas) would involve the most extensive use of battery storage, with incremental additions totaling 7,400 MW, “over six times the amount of large-scale battery storage currently in service in the United States,” according to the IRPs.

This plan would require the commitment of 1,100 acres (1.72 square miles) of land solely to batteries. That's a space, Duke notes, that is larger than 830 football fields.

At 4,400 MW of incremental storage, Portfolio D demands about 60 percent of the sums listed above for Portfolio F. That means over 1 square mile, or about 500 football fields—still a daunting prospect for the state and one it should view with caution.

Land Use

One of the overlooked aspects of the energy and environment discussion is land use. And as the Duke Energy battery figures indicate, it is going to be a major concern for North Carolina.

While resources like coal, natural gas, hydro, and nuclear are scrutinized for their effects on the natural environment, far less scrutiny has been applied to the effects on the natural environment of so-called green energy sources, like biofuels, solar, and wind energy.

Biofuels, while not of the utmost centrality in the North Carolina electricity discourse, are an instructive example of green mythology clouding public understanding of real impact.

Biofuels are made using organic matter from crops like corn, sugarcane, and palm oil. They have been marketed as pro-environmental alternatives to fossil fuels, but come with tremendous environmental downsides. The fundamental problem with biofuels is energy density.

The production of biofuels demands the appropriation of enormous swaths of land because biofuels lack the energy density provided by other energy sources, like nuclear and the liquid fossil fuels they are intended to replace in transportation. In other words, biofuels are inefficient. According to the U.S. Environmental Protection Agency, biofuel development means more land area consumption by agriculture, increased use of polluting inputs, and higher food prices.[79]

Bloomberg Green reports that as of February 2021, around 50 million acres in the U.S. are devoted to growing corn and soy for biofuels, according to U.S. Department of Agriculture statistics.[80] Despite taking up a cumulative acreage larger than the state of Missouri, biofuels provide just 5 percent of U.S transportation fuel by energy content, according to the U.S. Energy Information Administration.[81]

The biofuel problem is even more acute outside of the U.S., where tropical rainforests have fallen prey to the industry's voracious land appetite. In Indonesia a biofuel expansion is underway that officials say will necessitate planting 37 million acres of new palm oil plantations—equivalent to 20 percent of the island of Borneo.[82] To make matters worse, palm oil-derived biodiesel only delivers emissions benefits relative to fossil fuels in very narrow circumstances, meaning a program like Indonesia's may actually be adding to global greenhouse gas concentrations.[83]

The world is waking up to the problems of biofuel adoption,[84] yet wind and solar energy, which present many of the same problems, remain reputationally unscathed.

A grid powered by wind and solar energy would be similarly destructive on the natural environment—a fact highlighted by *Bloomberg Green's* Dave Merrill on April 29, 2021, in an expansive series of graphics giving visual affirmation of the data that shows the inefficiency of wind and solar compared to alternatives.[85]

Merrill's work leverages research presented by Princeton University's Net-Zero America Project in 2020[86] and by Strata Policy, a Utah-based think tank in 2017.[87]

The Strata paper Merrill uses, "The Footprint of Energy: Land Use of U.S. Electricity Production," provides a quantification of area requirements for electricity from coal, natural gas, nuclear, hydro, onshore wind, and solar, using data from 2015. The quantifications include resource production, generation, transportation, transmission, and waste.

Strata finds that natural gas and nuclear energy require about 12 acres per megawatt of electricity; that solar requires 43.5 acres; and that onshore wind requires 70.6 acres. Strata's figures are worth breaking out in detail.

Natural Gas Land Use

- In 2015, natural gas plants in the U.S. produced 1,333,482,000 megawatt-hours of electricity, according to the U.S. Energy Information Administration, 32.7 percent of the nation's total electricity production.
- In 2015, there were 1,740 natural gas power plants in the U.S. with a total generating capacity of 448,529 megawatts.
- In 2015, natural gas had a combined capacity factor of 33.9 percent. Combined cycle, which accounted for the majority of natural gas capacity, had a capacity factor of 55.9 percent.
- According to the Natural Gas Supply Association, the average natural gas plant requires between 20 and 40 acres of land.
- At an assumed mean of 30 acres, natural gas plants required approximately 52,200 acres of land in 2015, or 0.343 acres per megawatt produced.
- In 2015, there were 555,364 producing gas wells in the U.S.
- Multiplying the total well pad land use by the percentage of natural gas used for electricity generation equates to approximately 194,377.4 acres, or 1.28 acres per megawatt produced.
- Extrapolating from statistics in the state of Wisconsin, the land disturbed to source and process sand for hydraulic fracturing was 57,982.186 acres total, or 0.381 acres per megawatt produced.
- Approximately 1.58 million acres of land were required to transmit natural gas by pipeline in 2015, or 10.406 acres per megawatt produced.

- Adding these various points in the supply chain, natural gas in the U.S. used about 12.4 acres per megawatt in 2015.
- If the U.S. were to use natural gas as its only electricity source, it would require 4.68 million acres of land based on 2015 figures, or more than 90 percent of the land area of Massachusetts.

Nuclear Land Use

- In 2015, 61 nuclear power stations with 99 reactors generated 797,178,000 megawatt-hours of electricity, according to the U.S. Energy Information Administration, 19.6 percent of the nation's total electricity production.
- The 59 nuclear sites in the U.S. require an average of 832 acres (1.3 square miles) for every 1,000 MW of installed capacity for a total of 82,030 acres, or 0.901 acres per megawatt.
- In 2015, nuclear had a capacity factor of 92.3 percent.
- U.S. nuclear plant operators purchased 56.6 million pounds of uranium in 2015.
- 94 percent of that uranium was produced outside of the U.S.
- Canada and Australia are the main sources of U.S. uranium imports, combining for 39 percent of total U.S. purchases in 2019 (a figure that includes domestically-sourced uranium). The Central Asian countries of Kazakhstan and Uzbekistan are the second source, combining for 27 percent of U.S. uranium purchases. Russia account for 15 percent. The African countries of Namibia and Niger account for 7 percent combined.[88]
- Approximately 130,000 acres of land were required to produce the percentage of the world supply (42 percent) that the U.S. purchased.
- The land used to produce that uranium divided by total U.S. nuclear energy produced was 1.42 acres per megawatt.

- At 19.6 percent of U.S. electricity, approximately 940,000 acres of land were needed for nuclear electricity transmission.
- In total, U.S. nuclear waste storage requires approximately 6,145 acres, or 0.07 acres per megawatt.
- U.S. nuclear energy required 1.16 million acres of land in 2015, or 12.71 acres per megawatt.
- If the U.S. were to use nuclear as its only electricity source, it would require 4.79 million acres of land based on 2015 figures, or an area roughly the size of New Jersey.

Onshore Wind Land Use

- By the end of 2015, the US had a total installed capacity of 75,714 megawatts, which generated 190,719,000 megawatt-hours.
- Wind energy produces at an average of 32.2 percent capacity.
- According to the National Renewable Energy Laboratory, large wind facilities use between 24.7 and 123.6 acres per megawatt of capacity.
- Wind turbines are one of the largest consumers of neodymium, a rare-earth element.
- According to the Massachusetts Institute of Technology, the average wind turbine uses 171 kilograms of rare earths per megawatt of capacity.
- To mine the neodymium necessary for one megawatt of wind capacity, 0.09 acres of land are directly disturbed.
- Accordingly, the land use total for mining is 0.279 acres per megawatt of wind energy produced.
- At 4.7 percent of the nation’s total electricity production in 2015, approximately 225,600 acres of land were required to transmit wind energy, or 10.36 acres per megawatt.

- Onshore wind's total estimate for land use is 70.64 acres per megawatt of electricity produced.
- According to the estimates in this report, for the U.S. to be powered exclusively by wind power it would require 26.6 million acres of land, an area nearly equivalent to the state of Tennessee.
- This estimate does not factor in the considerable solid waste that comes in the form of discarded turbine blades.

Solar Land Use

- In 2015, solar energy had the worst capacity factor from among the sources evaluated by Strata, at 25.8 percent for photovoltaic solar and 22.1 percent for thermal (concentrated) solar.
- Utility scale solar requires an average of 8.1 acres per megawatt of capacity and thermal solar plants require 10 acres per megawatt of capacity.
- In 2015, distributed solar, or small-scale private generation, produced almost 36 percent of the total solar electricity output.
- Because the majority of utility scale solar power is produced by photovoltaic panels rather than the thermal technology, Strata uses the estimate of 8.1 acres per megawatt of solar capacity or 31.347 acres per megawatt of solar electricity produced.
- To produce one megawatt of photovoltaic solar, 13 tons of solar grade polysilicon is needed, requiring 18.21 tons of silicon metal at the conversion rate of 0.714 from silicon metal to polysilicon.
- Producing one megawatt of photovoltaic solar requires 0.14 acres for the mining of raw quartz.
- At 0.6 percent of the nation's electricity production in 2015, approximately 29,000 acres of land were used to transmit solar energy in 2015, or 10.135 acres per megawatt, not including distributed solar.

- Based on Strata's methodology, solar requires 43.5 acres per megawatt produced.
- Strata estimates that for solar to exclusively power the US it would require 16.4 million acres, an area larger than West Virginia and Rhode Island combined, but notes that there is considerable methodological disagreement on how to make solar estimates.

Princeton's Net-Zero America Project

While Strata's work provides a more granular look at the demands of the various electricity sources, Princeton's Net-Zero America Project provides a view from above, describing just how much land would be required for the United States to reach carbon neutrality under a variety of scenarios.

The E+ scenario "assumes aggressive end-use electrification, but energy-supply options for minimizing total energy-system cost while meeting the goal of net-zero emissions in 2050 are relatively unconstrained." The E+RE+ scenario "assumes the electrification level of E+, but is supply-side constrained to be 100% renewable by 2050, with no new nuclear plants built, and no underground carbon storage by 2050." Three mixed scenarios are also evaluated.

The Princeton results are jaw-dropping.

The cumulative total wind and solar farm area in the E+RE+ scenario by 2050 is approximately 246,400,000 acres, or 385,000 square miles, as the authors describe it.

That's an area roughly the size of Arkansas, Iowa, Kansas, Missouri, Nebraska, Oklahoma, and West Virginia combined—or seven North Carolinas.

In this scenario, wind accounts for the overwhelming majority of the area needed, at 94 percent. The southeast would be most impacted by solar arrays, which require exclusive use of 90 percent of the area on which they are sited. In the southeast, Princeton expects that "forested

Land Mass Required to Exclusively Power the United States by Each Energy Source

	Land Mass Required (Acres)	U.S. State of Equivalent Land Mass
Natural Gas	4.68 million	Massachusetts
Nuclear	4.79 million	New Jersey
Solar	16.4 million	Tennessee
Wind	26.6 million	West Virginia

SOURCE: STRATA POLICY

lands make up the largest directly impacted land cover type," echoing the biofuel disaster in Indonesia.

The study provides estimates for land use in each state, finding that Texas bears the highest total burden, with 26,000 square miles turned over to wind and solar energy. As a percentage of state land, Iowa would be impacted most, needing to devote 37 percent of its territory to the net-zero energy buildout.

In addition to onshore wind, this plan would require offshore wind farms to span entire Atlantic Coast, using 25,000 square miles, an area larger than West Virginia.

The Transmission Challenge

A challenge embedded in the land use issue is that wind and solar energy tends to be generated far from population centers and in widely dispersed locations, necessitating unprecedented expansion of electricity transmission capacity.

"The most difficult land-use challenge in any scenario," Bloomberg's Merrill writes, "may be building transmission lines…Transmission line capacity would need to more than triple under the high-renewable scenario laid out by the Princeton researchers. Without it, many new wind and solar projects would be stranded."

According to Princeton's study, the U.S. will need to quintuple transmission capacity in the next thirty years. In the E+RE+ with base siting scenario, electricity transmission will require a capital investment of $3.7 trillion—about 16 percent of the country's 2019 gross domestic product.

The Duke Energy Carolinas and Duke Energy Progress power delivery systems currently consist of about 180,000 miles of distribution lines and close to 20,000 miles of transmission lines spanning the two states. As part of the IRPs, Duke Energy "conducted a high-level assessment to identify the number of transmission projects and estimated costs associated with increasing import capability into the DEP/DEC area transmission systems from all neighboring transmission regions as well as from offshore wind."

The assessments considered the necessary new construction and upgrades needed to increase import capability by 5 GW and 10 GW respectively.

The 5 GW scenario would require on the Duke Energy transmission systems:

- 4 new 500 kilovolt (kV) lines
- 3 new 230 kV lines
- 2 new 500/230 kV substations
- 4 new 300 static volt-ampere reactive compensators (SVCs)
- several reconductor and lower-class voltage upgrades
- The estimated costs for the associated transmission projects are between $4B and $5B.

The 10 GW import scenario would require on the DEP/DEC transmission systems:

- 7 new 500 kilovolt (kV) lines
- 4 new 230 kV lines
- 3 new 500/230 kV substations
- 4 new 300 static volt-ampere reactive compensators (SVCs)
- several reconductor and lower-class voltage upgrades

The estimated costs for the associated transmission projects are between $8B and $10B.

The IRPs add, "Importantly, actual upgrade costs may vary significantly when the specific projects to enable the requested incremental import capability need are identified through detailed Transmission Planning studies. Equally significant, these estimates exclude the cost of neighboring third-parties' transmission system upgrades…"

The IRPs also note risks of delays that can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource. Loss of local ancillary benefits that are inherent with on-system resources, curtailment due to transmission constraints in neighboring areas, and transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.

Transmission from offshore wind, the main differentiator of Portfolio D, is particularly challenging. According to Eco Rhode Island, the transmission line connecting the Block Island project (the first offshore wind site in the U.S.) to Rhode Island's shore has been prone to exposure as a result of shifting sands and storms.[89]

National Grid, Rhode Island's primary electric utility, owns the high-voltage power line from Block Island to the coast and says it will spend $30 million for its share of the reconstruction. According to a National Grid spokesperson, "While exact bill impacts won't be available for some time, we don't anticipate major fluctuations to those charges with these needed repairs."

> **"Astronomical costs and physical risks aside, a plan like Portfolio D is likely to encounter fierce legal, political, and social opposition at the local level."**

Ørsted, the Danish company that owns the 12-inch transmission cable from the offshore wind site to Block Island, does not have the ability to pass costs on to utility customers and will covers its repairs from its own budget.[90]

Astronomical costs and physical risks aside, a plan like Portfolio D is likely to encounter fierce legal, political, and social opposition at the local level.

An April 2021 paper by energy analyst Robert Bryce, "Not In Our Backyard," documents what Bryce describes as "the binding constraint" on plans like Duke's Portfolio D.[91] "(R)ural politicians and landowners across the U.S.," Bryce writes, "are fighting against the encroachment of large-scale renewable energy projects."

According to Princeton, wind energy projects have "large spatial extent and significant visual impact" on the surrounding area and "will require broad-based and sustained support from communities across much of the nation."

Bryce shows that sustained support is unlikely.

From New England to the Pacific coast and everywhere in between, local spats abound over issues like noise and health impacts, reduction of property values, wildlife mortality, and despoliation of viewsheds. Bryce describes protests, lawsuits, and local bans in Maine, Vermont, New York, Pennsylvania, Indiana, Minnesota, North Dakota, and California, the common theme of which is that the people who live in the regions expected to become wind and solar generation hubs want little part of it.

This challenge for wind and solar has not only arisen in the U.S., but in Europe as well.

"Murmurings of protests against wind farms here and there over the years have turned into a roar," Julia Zilles, a political analyst at Germany's University of Göttingen, told *Bloomberg Green*. "Partly it's a problem of provincial sensibilities vs. big-city politics: Locals feel that policymakers just don't care what they think."[92]

An example Bryce cites pertaining to transmission is the long-anticipated, never-constructed transmission system to connect New York City to Canadian hydropower. Since the 1980s, numerous proposals have been made for a 1,000-megawatt high-voltage transmission line through the Hudson Valley only to wither away. Recently, New York politicians such as Bill de Blasio have said they support the construction of the proposed Champlain Hudson Power Express, a $2.2 billion project that could finally make good on the promise of using Canadian hydropower in New York. But the project still has not moved forward.[93]

Carving up rural and coastal America to build new electricity lines is easy to model but hard to accomplish. By forcing new construction onto local communities, the U.S. federal government and state governments risk catalyzing an American version of the yellow vests movement that has disrupted French energy plans since 2018.[94]

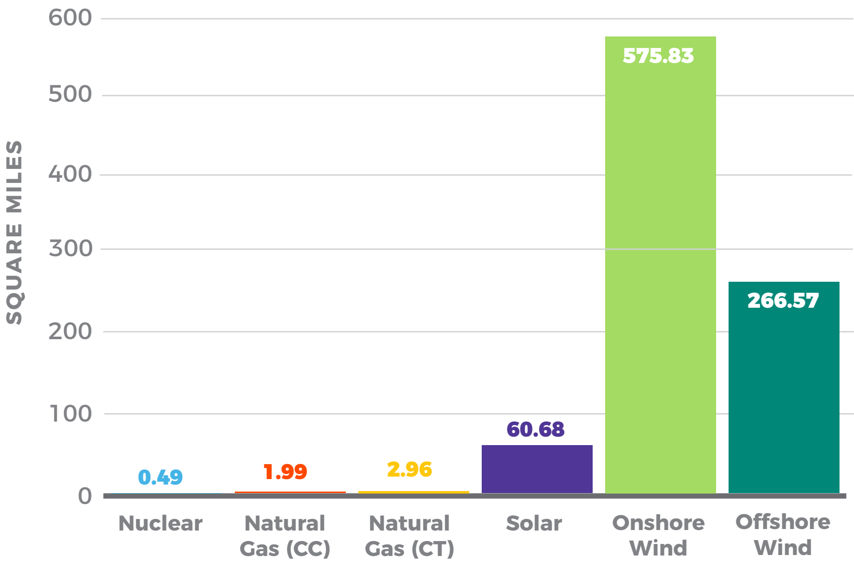
North Carolina Land Use Modeling

Modeling provided for the John Locke Foundation by the Center of the American Experiment estimates that for North Carolinians, the land-cost of wind is even higher than the estimates from Strata would suggest.

The Center finds that to average 1,000 megawatts throughout the course of a year in North Carolina:

- Nuclear would require 0.5 square miles (less than 350 acres).
- Natural gas combined cycle would require 2 square miles (less than 1,300 acres).
- Natural gas combustion turbine would require 3 square miles (less than 2,000 acres).

North Carolina Land-Use Requirement for 1,000 MW by Source



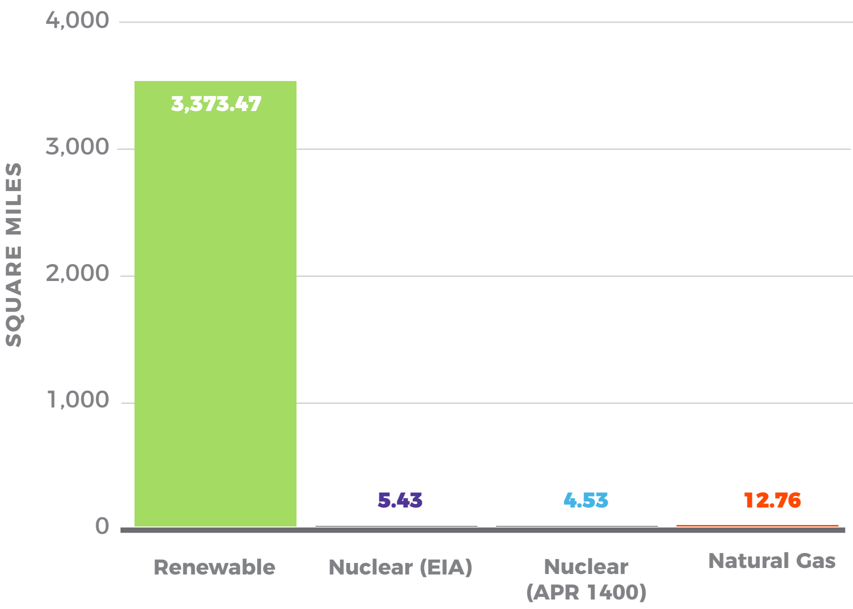
SOURCE: CENTER OF THE AMERICAN EXPERIMENT

- Solar would require 61 square miles (almost 40,000 acres).
- Offshore wind would require 267 square miles (over 170,000 acres), or close to 2 times the area of Raleigh.
- Onshore wind would require 576 square miles (over 365,000 acres), an area larger than all of Mecklenburg County.

According to the Center's methodology, to meet North Carolina's total electricity needs:

- The APR1400 Scenario would require 4.5 square miles (about 2,900 acres).
- The EIA Nuclear Scenario would require 5.4 square miles (about 3,500 acres).

North Carolina Land-Use Requirement by Scenario



SOURCE: CENTER OF THE AMERICAN EXPERIMENT

- The Natural Gas Scenario would require 13 square miles (about 8,300 acres).
- The Portfolio D Scenario would require 3,373 square miles (over 2 million acres), an area larger than the three biggest counties in the state combined.

The land use problem for wind and solar will become more prevalent in the coming years as more states begin large-scale buildouts. An additional consideration that lessens the quantitative case against wind is that wind energy does not require exclusive use of the area on which turbines are sited. Farming and ranching can often coexist in the same space. With that said, wind turbines' verticality presents yet more conflict.

"A sound electricity framework would attempt to maximize a system's affordability and reliability while minimizing the disruption it causes and risks it imposes on ecosystems and communities."

According to the U.S. Energy Information Administration, since 2012, the average height of wind turbines installed in the United States has been about 280 feet. New developments in offshore wind will send blades higher than ever. MHI Vestas Offshore Wind's V164 has a hub height of 344 feet and a blade tip maximum height of over 600 feet.[95] With its 80-meter blades, the turbine's sweep area is larger than that of the London Eye.

Vestas' latest prototype will be over 850-feet tall, making it 200 feet taller than St. Louis's Gateway Arch and 300 feet taller than the Washington Monument.[96]

As has been widely documented, wind turbines are serious threats to avian life, killing hundreds of thousands of birds and bats each year in the United States. According to the U.S. Fish and Wildlife Service (FWS), the most comprehensive estimates show that bird deaths from turbine collisions are between 140,000 and 500,000 birds per year.[97]

As wind energy capacity increases, FWS states, statistical models predict that bird deaths resulting from collisions with turbines could reach 1.4 million annually. In terms of raw numbers, songbirds are the most common victims. Hawks, eagles, and falcons are also especially vulnerable to wind turbines due to their flight behaviors.

Yet another point against wind in the environmental and social columns is the scramble for balsa wood it has sparked in South America.[98]

Balsa wood is a light-weight, stiff wood that is an ideal core material for wind turbine blades. The National Renewable Energy Laboratory, *The Economist* reports, has calculated that the 100-meter blades that are now making their way to the marketplace require 150 cubic meters (5,300 cubic feet) of balsa wood. The primary global source of balsa wood is Ecuador.

According to *The Economist*, the global demand surge for wind turbines driven by government policy has created an illegal wood rush, with loggers invading land reserved for indigenous populations and denuding riverside plots with cut-and-float raids.

The Economist writes that indigenous groups such as the Waorani Nation of Ecuador "are still vulnerable to exploitation" and have been enticed to log balsa with payment of liquor and marijuana. The boom has fueled drug abuse and violence, the magazine reports, with Gilberto Nenquimo, the president of the Waorani Nation of Ecuador, saying that his brother-in-law "was murdered with a chainsaw in a dispute over balsa."

The May 2021 IEA report similarly remarks, "(c)hanges in land use can result in the displacement of communities and the loss of habitats that are home to endangered species."

Wood Mackenzie forecasts that the share of synthetic alternatives to balsa will increase from 20 percent in 2018 to more than 55 percent by 2023, spelling the end of the Ecuadorean balsa boom.

A final area worthy of mention is the contentious debate surrounding the health effects of wind turbine noise, particularly low-frequency sound and infrasound, on human beings. Wind advocates point out that low-frequency sound and infrasound are commonly encountered in daily life. A 2018 paper in the journal *Trends in Hearing*, however, finds that there are open questions relating to the measurement and propagation of wind turbine noise and "its encoding by the central nervous system" for which we do not have "a good scientific understanding."[99] The authors call for "a more complete characterization and modeling of the sound generated" by individual wind turbines and the large aggregations that the modern wind facility comprises.

Hidden Costs Conclusion

As the John Locke Foundation hopes is made clear by this section, hidden social, environmental, economic, and land-use costs are not merely areas for future work, but issues of grave import today as the political framework is being set for the state's energy future.

A sound electricity framework would attempt to maximize a system's affordability and reliability while minimizing the disruption it causes and risks it imposes on ecosystems and communities. The weight of the evidence suggests that nuclear energy and natural gas provide electricity in a manner consistent with that framework. Wind and solar do not.

As Bloomberg's Merrill concludes, "if the U.S. wants a carbon-free economy by 2050 using the least amount of land, it will need to rely far less on wind and solar and instead build hundreds of nuclear plants and natural gas plants…"

While Duke's Portfolio D portends disaster, the Natural Gas Scenario, the EIA Nuclear Scenario, and the APR1400 Scenario would provide North Carolina with affordable, reliable electricity while also respecting the key considerations discussed above.

LESSONS FROM ELSEWHERE

America's two largest states by population, California and Texas, have followed electricity paths that North Carolinians may find of interest and that provide a degree of instruction.

Texas

In February 2021, Texas experienced historic power outages. In the aftermath, pundits generally responded by blaming the energy sources that their biases inclined them against. That is, proponents for fossil fuels pointed a finger at wind's poor performance and advocates for a renewable energy transition blamed natural gas for not meeting expectations.

The first point that must be understood in the Texas situation, however, is that the historic blackouts were, at root, the result of an historic weather event. Texas was extraordinarily cold for a weeklong period relative to its norms. This had a multitude of effects including record winter electricity demand driven by home heating needs and a major disruption

> **"Proponents for fossil fuels pointed a finger at wind's poor performance and advocates for a renewable energy transition blamed natural gas for not meeting expectations."**

of electricity supply due to the system's under-preparedness for the extended period of cold.

As temperatures were setting records, sources of electricity ranging from wind, to natural gas, to nuclear were rendered less effective than needed because they were not designed to withstand such an extended chill. According to the state's grid operator, ERCOT, 46.8 percent of generation "was forced out at the highest point due to the impacts of various extreme weather conditions."[100] At the peak, demand climbed to over 69,000 MW,[101] compared to ERCOT's seasonal demand peak forecast of 58,000 MW.[102]

Further, Texas has its own interconnection that severely limits electricity imports and a unique market structure that does not have the backstops in place that are standard elsewhere. In that sense, the Texas experience was anomalous.

Nevertheless, there are some points worth considering for a state like North Carolina.

One point is that, as has been stressed in earlier sections of this report, wind operates at a lower capacity factor than natural gas and nuclear, typically around 40 percent in Texas.[103] For 2020 on the whole, wind generated 23 percent of ERCOT's electricity.[104] During the winter weather event, wind was expected to generate less than that typical standard, but in fact it did not meet even the lowered bar.

On February 15, at the height of the crisis, wind provided 73,395 MWh, or 6 percent of the region's daily generation mix according to EIA tracking statistics.[105] Natural gas, meanwhile, provided 759,708 MWh, or 65 percent.

In other words, natural gas generated ten times the power wind generated, despite having just 66 percent more installed capacity in ERCOT territory.

The International Energy Agency made this comparison concisely.

“Gasfired generation has a rated winter capacity of 55 GW but output dropped to 31 GW on 15 February due to issues throughout the supply chain – freezing wellheads, pipeline derates and generator equipment failures all contributed. Wind generation was about half of its 6.1 GW seasonal rating.”[106]

“In Texas,” IEA concluded, “while the shortfall in the gas system was critical, coal and nuclear plants also experienced outages, and wind generators significantly underperformed expectations.”

Renewables advocates will highlight that gas underperformed relative to expectations. There is an aspect of truth to that claim and it does highlight a risk natural-gas reliance poses. The risk this crisis highlights regarding natural gas is that it uses on-time delivery of fuel. Nuclear energy and coal, on the other hand, are stored on-site and thus can be trusted in a wider range of situations. That said, natural gas still provided an abundance of electricity during the Texas freeze, particularly when held up against the paltry wind generation total.

California

A better example of the risks North Carolina faces is California. California, like North Carolina, has historically used nuclear for a significant portion of its electricity. It is much further along, however, in purging of nuclear from its mix.

In 1996, nuclear was responsible for 29.7 percent of California’s utility generation, with the 2,500 MW San Onofre nuclear facility and 2,100 MW Diablo Canyon nuclear facility being the leading generators.[107]

"As of January 2021, California's average retail price of electricity for the residential sector of 21.43 cents per kWh is close to double that of neighboring Arizona."

But California has since turned against nuclear. By 2014, after the retirement of San Onofre, California's electricity generation mix looked quite different. It was still, however, strongly anchored by dispatchable sources.

In 2014, natural gas generated 61.3 percent. Nuclear generated 8.6 percent. Wind and solar combined to generate 11.9 percent.[108]

Over the ensuing years California began utilizing intermittent electricity sources *en masse* to meet it emissions reduction goals. According to a Wood Mackenzie's Wade Schauer, California has taken 5 GW of dispatchable capacity offline since 2018, replacing it with only 2,200 MW of comparable capacity.[109]

By 2019, the most recent year for which a full account is available, the mix had begun to skew more heavily towards intermittent sources. That year, natural gas generated 43 percent of California electricity. Nuclear generated 8.1 percent. Wind and solar combined to generate 21 percent.[110]

Distressingly, California policymakers have determined the state's lone remaining nuclear power plant, Diablo Canyon, will be taken offline beginning in 2024.[111]

State policy will make California increasingly dependent on wind, solar, and battery storage, instead of reliable baseload nuclear.

According to California's grid operator, CAISO, electricity shortfalls, as have been seen in recent years, are bound to become more prevalent due to this shift. CAISO's concerns center upon the imposition intermittent sources, especially solar, place upon dispatchable sources that are called upon to ramp up to meet demand late in the day as the sun sets and the wind dies down—a problem the Institute for Energy Research explicates in its paper, The Solar Value Cliff.[112] This will occur despite California having added the largest battery storage system in the U.S.[113]

California is already highly reliant upon imports from neighboring states during times of high load, and is becoming more so as local generation is retired. But CAISO warns that its neighbors have their own challenges and cannot be counted on to bail California out.

As of January 2021, California's average retail price of electricity for the residential sector of 21.43 cents per kWh is close to double that of neighboring Arizona (11.70 cents per kWh), Nevada (11.53 cents per kWh), and Oregon (11.06 cents per kWh).[114]

Germany

Germany provides another interesting example. Germany's *energiewende* (energy transition) is the country's plan to reduce greenhouse gas emissions by 80 percent by 2050, to use renewable energy for 80 percent of electricity, and simultaneously to phase out Germany's nuclear power.

After 20 years, the results are sobering. Reuters reported in March 2021 that an internal audit yet to be published as of this writing has found that the *energiewende* "has proven too costly and underestimated the risks to supply."[115]

Energy researcher Vaclav Smil wrote in November 2020 for the Institute of Electrical and Electronics Engineers' Spectrum publication, "In 2000, 6.6 percent of Germany's electricity came from renewable sources; in 2019, the share reached 41.1 percent. In 2000, Germany had an installed capacity of 121 gigawatts and it generated 577 terawatt-hours, which is 54 percent as much as it theoretically could have done (that is, 54 percent was its capacity factor). In 2019, the country produced just 5 percent more (607 TWh), but its installed capacity was 80 percent higher (218.1 GW) because it now had two generating systems. The new system, using intermittent power from wind and solar, accounted for 110 GW, nearly 50 percent of all installed capacity in 2019, but operated with a capacity factor of just 20 percent."[116]

Put another way, Germany has built copious volumes of wind and solar capacity but is suffering from the inherent flaws of those resources. From 2000 to 2019, the average residential rate of electricity in Germany doubled, reaching about 34 cents per kWh (put into USD terms).

The worse is yet to come, though. According to Reuters, the *energiewende* audit foretells a "looming energy supply shortfall as utilities prepare to turn off the last of their nuclear reactors and the government spurs a pullout from coal." With its goal of ending nuclear reliance and its turn to wind solar, Germany's *energiewende* is a plan North Carolina should keep its eyes on.

THE NUCLEAR OPPORTUNITY

As of 2021, Duke Energy provides approximately 50 percent of its power across its service area in the Carolinas with carbon-free nuclear generation. With nuclear energy and the supplanting of coal by natural gas, North Carolina has become a national leader in productivity relative to emissions. To reiterate a point made earlier, only two states have outpaced North Carolina in the race to "decouple" economic growth from emissions growth.

The state has an opportunity to build on this success by exploring an expansion of nuclear's role rather than the elimination of it recommended by the DEQ's Clean Energy Plan.

Duke Energy's IRPs shows one path for a nuclear buildout, Portfolio E.

Among the options Duke presents that will achieve the 70-percent CO_2 emissions reduction, Portfolio E outshines its competitor, Portfolio D.

By leveraging advances in small modular nuclear technology, Portfolio E would slash emissions at a 5-percent discount relative to Portfolio D's heavy reliance on high-cost offshore wind.

MAYA REAGAN

North Carolina has an opportunity to build on past success by exploring an expansion of nuclear's role rather than the elimination of it recommended by the DEQ's Clean Energy Plan.

There is reason for optimism on the small modular nuclear front, based on developments made at the Idaho and Oak Ridge (TN) National Laboratories on new nuclear designs.

Small modular reactors have the potential to be even more efficient than the already impressive existing nuclear fleet. To achieve a nameplate capacity of 720 MWe, the developer NuScale claims its small modular reactor would require just 35 acres, compared to traditional plants that might take up close to 600 acres to reach the same capacity.[117] Smaller reactors can be deployed in places that could not support larger reactors, including remote and isolated areas, and areas with less access to the water necessary to cool larger reactors.[118] Another advantage of SMRs is that they would decentralize risk from nefarious activities, such as the May 2021 cyberattack on the operator of the Colonial Pipeline.[119] SMRs, which can be sited below ground, also present a minimized physical target.[120]

Duke Energy is an active participant in these developments, "working with private and public sectors to drive research, development and demonstration of additional advanced reactor technologies under the DOE's Advanced Reactor Demonstration Program," according to the IRPs.

The problem with this approach is that the pace of development does not necessarily match the state's expectations. The costs remain far above the costs of larger reactors and the timelines are still long. The first NuScale reactor, for example, is not expected to begin operation until 2029.[121]

Resultantly, extending the lifespan of Duke Energy's existing fleet is essential. Duke plans to achieve an extension via the Nuclear Regulatory Commission's Subsequent License Renewal (SLR) process. SLR is permission to extended operation from 60 years to 80 years.[122]

NRC has to date complete three SLR application reviews, renewing the licenses in both cases. The first case involved Units 3 and 4 at the Turkey Point Nuclear Generating Station, a NextEra Energy facility in South Florida.[123] The Turkey Point application was received in January 2018 and NRC issued license renewal in December 2019. The second application came from Peach Bottom Atomic Power Station in July 2018.[124] NRC issues license renewal for Units 2 and 3 at the Pennsylvania facility in March 2020.

NRC most recently completed its review of the SLR application for Surry Units 1 and 2 (Virginia), issuing the renewal in May 2021.[125] Two applications currently with NRC are Point Beach Units 1 and 2 (Wisconsin)[126] and North Anna Units 1 and 2 (Virginia).[127]

Duke announced in September 2019 its intent to pursue SLR for all eleven nuclear units in the operating fleet and has begun the process for Oconee Nuclear Station's Units 1, 2, and 3.

Along with the perpetuation of existing generation, building new baseload nuclear facilities along the lines discussed in the EIA Nuclear Scenario section and the APR1400 Scenario section would be wise.

The IRPs indicate Duke Energy is considering doing so, stating, "the Company will continue to monitor and analyze key developments on factors impacting the potential need for, and viability of, future new baseload nuclear generation. Such factors include further developments on the Vogtle project and other new reactor projects worldwide, progress on existing unit relicensing efforts, nuclear technology developments, and changes in fuel prices and carbon policy."

Nuclear is a proven, effective source of electricity for the state of North Carolina. Any pathway the state chooses to pursue a low-emission economy should put nuclear energy at the forefront.

CONCLUSION

This report analyzes the Clean Energy Plan put forward by the Department of Environmental Quality and Governor Roy Cooper, finding that its costs and hidden risks far exceed those of alternative plans capable of achieving the same emissions-reduction goals. Rather than investing in redundant, intermittent power, the state would benefit from a recognition and continuation of the nuclear and natural gas strategy that has thus far yielded success.

To recapitulate:

The Clean Energy Plan jeopardizes the reliability and affordability of North Carolina's electricity. Pursuing the Clean Energy Plan via Duke Energy's Portfolio D would cause a direct cost increase of more than $400 annually for each North Carolina household.

North Carolina is a national leader in productivity relative to emissions and has an opportunity to accelerate its growth by building on its record of success using nuclear energy and natural gas.

The Clean Energy Plan's narrow focus on intermittent energy sources obscures the emissions-reduction success that has already been demonstrated and can be amplified by a nuclear energy expansion.

A future electricity scenario expanding natural gas's role on the grid would reduce emissions to 60-percent below North Carolina's peak at a rate of less than $3 per metric ton of carbon dioxide, providing the best pound-for-pound emissions-cutting choice.

A scenario expanding nuclear energy's role on the grid using U.S. Energy Information Administration cost assumptions would reduce emissions as deeply as Portfolio D at about 70 percent of Portfolio D's cost.

A scenario deploying APR1400 would reduce emissions lower than even Portfolio D and would do so at just 35-percent of Portfolio D's cost per metric ton.

Nuclear energy and natural gas are both efficient uses of land, requiring just 0.5 square miles and 2 square miles, respectively, to average 1,000 megawatts over the course of a year in North Carolina, compared to 575 square miles for onshore wind power, 265 square miles for offshore wind, and 60 square miles for solar power to provide the same amount of electricity.

The Clean Energy Plan's reliance on wind, solar, and battery storage entails significant environmental, supply chain, and land-use risks.

Nuclear energy and natural gas provide North Carolina with reliable, cost-effective pathways to achieve its emissions-reduction goals.

APPENDIX

The Center of the American Experiment conducted eight future electricity grid scenarios for the John Locke Foundation. Four scenarios are based on the Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) system and four scenarios are based on only North Carolina. Each set includes a scenario based on Portfolio D from the Integrated Resource Plans filed by Duke Energy Progress and Duke Energy Carolinas; a scenario based on adding natural gas capacity to replace retiring coal facilities without renewable additions; a scenario based on adding a combination of nuclear capacity and combined-cycle natural gas with U.S. Energy Information Administration-designated capital costs instead of renewables to achieve similar carbon-free percentages to Portfolio D; and one scenario based on adding a combination of Korean APR1400 nuclear capacity and combined-cycle natural gas instead of renewable to achieve similar carbon-free percentages.

The assumptions, which vary from scenario to scenario, are listed below.

North Carolina Scenarios vs. Duke Energy Scenarios

Center of the American Experiment included Duke Energy scenarios for analysis along with North Carolina scenarios. Duke Energy accounts for the vast majority of electricity sales in North Carolina, but not all. To determine the impact of renewable energy on electricity prices and emissions in the entire state of North Carolina, we extrapolated the findings from the Duke scenarios to match the electricity demand for the rest of North Carolina electricity consumers. The author has relied primarily on the North Carolina scenarios and has distinguished between the two sets when necessary.

North Carolina

Annual capacity additions were based on extrapolating Portfolio B annual additions to match Portfolio D total additions. With the exception of natural gas capacity additions—which were attributed to North Carolina to replace retiring coal facilities in the state—additions were then split between North Carolina and South Carolina based on Duke Energy's revenue share between the two states. Finally, the rest of North Carolina electricity providers were assumed to match Duke Energy's renewable energy additions. Total capacity additions amounted to 27,086.4 MW while total capacity retirements were 10,649.7 MW—equating to a net increase of 16,436.7 MW. Capacity additions include 20,608.6 MW of wind, solar, and storage facilities, as well as 6,400 MW of natural gas.

Duke Energy

Annual capacity additions were based on Portfolio B annual capacity additions (listed on Page 105 of DEC's IRP and Page 107 of DEP's IRP) and extrapolated to match capacity additions listed for Portfolio D (on Page 16 of DEC's IRP and Page 17 of DEP's IRP). Capacity retirements were based on the "Earliest Practicable" coal retirement schedule listed on Page 175 of DEC's IRP and Page 174 of DEP's IRP. Total capacity additions for this scenario amounted to 26,876 MW while total capacity retirements were 11,529.5 MW—equating to a net increase of 15,346.5 MW. Capacity additions include 20,399 MW of wind, solar, and storage facilities, as well as 6,400 MW of natural gas.

Portfolio D Scenario

For both the Duke Energy and North Carolina scenario, $7.5 billion in transmission costs were included. Duke Energy's Portfolio D was used because it is more aggressive, in terms of greenhouse gas emissions reductions, than Portfolios A-C, but is not as unrealistic as Scenario F, which would allow no new natural gas plants to be built. Scenario D is also the most similar to the proposals put forward by North Carolina Governor Roy Cooper.

Natural Gas Scenario

In both natural gas scenarios, renewable energy additions listed in Duke Energy's Portfolio D were excluded and only 6,400 MW of natural gas additions were included. All 6,400 MW of capacity additions were combined-cycle. The same capacity retirements were made in both scenarios as was made in Scenario D for North Carolina and Duke Energy, equating to a net capacity increase of 4,249.7 MW in the North Carolina scenario and 5,129.5 MW in the Duke Energy scenario.

EIA Nuclear Scenario

In both EIA reference case nuclear scenarios, 5,000 MW of new nuclear capacity are modeled in the place of renewable energy additions listed in Portfolio D. These additions come in the form of three 1,000 MW facilities and one 2,000 MW facility beginning in 2025. In addition, 1,500 MW of combined-cycle natural gas additions are included in this scenario. The amount of nuclear capacity was determined by reaching similar carbon-free percentages as Portfolio D. The same capacity retirements were made in both scenarios as was made in Portfolio D for North Carolina and Duke Energy, equating to a net capacity increase of 4,149.7 MW in the North Carolina scenario and 5,029.5 MW in the Duke Energy scenario.

APR1400 Scenario

In both APR1400 scenarios, 5,600 MW of APR1400 nuclear capacity are modeled in the place of renewable energy additions listed in Portfolio D. These additions come in the form of four 1,400 MW facilities beginning in 2025. In addition, one 900 MW combined-cycle facility is included. The amount of nuclear capacity was based on reaching a similar carbon-free percentage as Scenario D. The same capacity retirements were made in both scenarios as was made in Scenario D for North Carolina and Duke Energy, equating to a net capacity increase of 4,149.7 MW in the North Carolina scenario and 5,029.5 MW in the Duke Energy scenario.

Financial Lifespans

Natural gas facilities, both combined-cycle and combustion-turbine, were attributed financial lives of 30 years. Onshore and offshore wind facilities operated through 20-year financial lifespans. Solar, both stand-alone and plus storage, received financial lifespans of 25 years. Storage facilities were attributed 20-year lifespans. Nuclear facilities operated through 40-year lifespans. These assumptions were applied in all scenarios.

Repowering

All existing renewable energy facilities were repowered and kept online in every scenario. Wind facilities were repowered after 20 years for both onshore and offshore, and solar facilities were repowered after 25 years. Storage facilities were not repowered. These assumptions were applied in all scenarios. These assumptions were applied in all scenarios.

Capital Costs

With the exception of APR1400 nuclear facilities, all overnight capital costs were derived from EIA's assumptions to the Annual Electricity Outlook of 2021.[128] APR1400 capital costs were based on facilities built in United Arab Emirates.[129]

Levelized Cost of Electricity

Existing levelized cost of electricity (LCOE) values were derived from Form 1 filings submitted to the Federal Energy Regulatory Commission (FERC) by Duke Energy Carolinas and Duke Energy Progress.[130] New LCOE values were taken from EIA's LCOE report of 2021.[131]

Existing Capacity and Capacity Factors

Existing generating capacity in the North Carolina group was based on

EIA's State Electricity Profile of North Carolina.[132] Existing generating capacity for the Duke Energy group was based on FERC Form 1 filings submitted by Duke Energy Carolinas and Duke Energy Progress.[133]

Coal Retirements

Every scenario assumes that all coal capacity is retired from the system by 2035.

CO_2 Emissions per Megawatt-hour (MWh)

CO_2 Emissions per MWh were derived from the EIA State Electricity Profile of North Carolina.[134]

Capital Structure

The capital structure for every scenario was 53-percent equity with a 9.6-percent return and 47-percent debt with a 4.7-percent return.

Timeframe

Each scenario begins in 2020 and ends in 2051.

Nuclear Land-Use Assumptions

Land use assumptions for nuclear power are based of the area for the McGuire Nuclear Station.

2316 MW,[135] 700 acres,[136] and 96.6 percent capacity factor.[137]

Combined-Cycle Natural Gas Land-Use Assumptions

Land use assumptions for combined-cycle natural gas are taken from the Asheville Combined Cycle Station, which houses a 560 MW facility on 700 acres.[138]

Combustion-Turbine Natural Gas Land-Use Assumptions

Land use assumptions for combustion-turbine natural gas are taken from the Lincoln Combustion Project, a 402 MW facility sitting on 746 acres of land.[139]

Solar Land-Use Assumptions

Solar land use assumptions are based on 8 acres per MW of installed capacity, based on the density of the Wilkes Solar LLC development.[140] The Center believe this is a defensible midpoint between a range of estimates. A Decommissioning Cost Estimate Study by Duke Energy Progress shows a land-use value of 11 acres per MW of installed capacity.[141] A study conducted by the NC Sustainable Energy Association (NCSEA) and the NC Department of Agriculture and Consumer Services estimated a land use of 5.78 acres of land per MW of installed capacity.[142] A capacity factor of 20.6 percent was used, reflecting the statewide total for solar installations found in the 2019 EIA state data profile for North Carolina.[143]

Onshore Wind Land-Use Assumptions

Land use assumptions for wind are based on the Desert Wind project in North Carolina. The plant has an installed capacity of 208 MW sits on 22,000 acres of land.[144] The capacity factor of 28.7 percent was obtained from Lawrence Berkeley Laboratory's Wind Project-Level performance displays.[145]

Offshore Wind Land-Use Assumptions

Land use assumptions and capacity factors are based on the Hornsea 1 project off the coast of the UK. The project was used because it is one of the largest offshore wind facilities in the world. The project spans 157 square miles, or roughly 100,500 acres, and has an installed capacity of 1218 MW.[146] A capacity factor of 48.4 percent is used, reflecting its 2020 generation.[147]

Limitations

Like all analyses, this analysis has limitations. The most important limitation to this analysis is that it is not an hour-by-hour analysis of estimated electricity demand, also referred to as “load,” versus the estimated supply on the grid. To do this, the Center would need accurate forecast data on demand, and realistic supply data for each fuel type at each hour. This is complicated by the fact that offshore wind is a relative unknown in the United States, and North Carolina has only one onshore wind facility, which provides little insight as to the wind resources in the state. As a result, the Center estimated the electricity generation of these sources based on annual production assumptions. This means our analysis likely underestimates the amount of installed capacity needed to meet the peak demand for electricity on a grid that is increasingly powered by intermittent electricity supplies.

Endnotes

1 U.S. Energy Information Administration, "North Carolina Electricity Profile 2019," Accessed May 7, 2021, https://www.eia.gov/electricity/state/NorthCarolina/

2 Solar Energy Industries Association, "State Solar Spotlight: North Carolina," May 6, 2021, https://www.seia.org/sites/default/files/2021-05/North Carolina.pdf

3 North Carolina Department of Environmental Quality, "North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System," October 2019, https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf

4 U.S. Energy Information Administration, "Energy-Related CO2 Emission Data Tables (Fuel specific emission tables by state 2018)," Accessed May 7, 2021, https://www.eia.gov/environment/emissions/state/

5 Center for the New Energy Economy, "State Brief: North Carolina," Colorado State University, July 2020, https://cnee.colostate.edu/wp-content/uploads/2020/07/State-Brief_NC_July-2020.pdf

6 Duke Energy Progress, "Duke Energy Progress Integrated Resource Plan 2020 Biennial Report," September 2020,https://www.duke-energy.com/_/media/pdfs/our-company/irp/202296/dep-2020-irp-full-plan.pdf?la=en

7 U.S. Energy Information Administration, "North Carolina Electricity Profile 2019," See: Full Data Tables 1-16.

8 U.S. Census Bureau, "QuickFacts: North Carolina," Accessed May 12, 2021, https://www.census.gov/quickfacts/fact/table/NC/PST045219

9 U.S. Census Bureau, "General Population Characteristics: North Carolina," Accessed May 12, 2021, https://www2.census.gov/library/publications/decennial/1980/volume-1/north-carolina/1980a_ncabc-02.pdf

10 North Carolina Department of Environmental Quality, "Greenhouse Gas Inventory," Accessed May 7, 2021, https://deq.nc.gov/energy-climate/climate-change/greenhouse-gas-inventory

11 U.S. Environmental Protection Agency, "Greenhouse Gas Inventory Data Explorer," Accessed May 5, 2021, https://cfpub.epa.gov/ghgdata/inventoryexplorer/#electricitygeneration/entiresector/allgas/select/all

12 Devashree Saha and Joel Jaeger, "Ranking 41 US States Decoupling Emissions and GDP Growth," World Resources Institute, July 28, 2020,

https://www.wri.org/insights/ranking-41-us-states-decoupling-emissions-and-gdp-growth

13 U.S. Energy Information Administration, "Electric Power Monthy (Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector)," Accessed May 5, 2021, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

14 U.S. Energy Information Administration, "2019 Average Monthly Bill - Residential," Accessed May 5, 2021, https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf

15 Environmental Entrepreneurs, "North Carolina Energy and Employment — 2020," August 2020, https://static1.squarespace.com/static/5a98cf80ec4eb7c5cd928c61/t/5e781597e08d1b666d1f294b/1584928153130/NorthCarolina-2020.pdf

16 Duke Energy, "Power Plants," Accessed May 5, 2021,https://www.duke-energy.com/Our-Company/About-Us/Power-Plants

17 North Carolina Department of Environmental Quality, "North Carolina Clean Energy Plan, Supporting Document Part 2, Energy Resources," October 2019,https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/2.-Energy-Resources-FINAL.pdf

18 David Dalton, "Duke Energy Preparing For Licence Renewals At Entire Fleet Of 11 Nuclear Plants," NucNet, February 4, 2021,https://www.nucnet.org/news/duke-energy-preparing-for-licence-renewals-at-entire-fleet-of-11-nuclear-plants-2-4-2021

19 Duke Energy, "Duke Energy Progress customers receiving 560 megawatts of cleaner energy from new natural gas power plant in North Carolina," July 22, 2020, https://news.duke-energy.com/releases/duke-energy-progress-customers-receiving-560-megawatts-of-cleaner-energy-from-new-natural-gas-power-plant-in-north-carolina

20 Darren Sweeney and Krizka Danielle Del Rosario, "Duke Energy considers retiring 9,000 MW of coal, adding vast amounts of storage," S&P Global Market Intelligence, September 29, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/duke-energy-considers-retiring-9-000-mw-of-coal-adding-vast-amounts-of-storage-60476894

21 U.S. Energy Information Administration, "Form EIA-923 detailed data with previous form data (EIA-906/920)," Accessed May 7, 2021, https://www.eia.gov/electricity/data/eia923/

22 Kamen Nikolaev and Roy Cordato, "The Clean Smokestacks Bill: A Retrospective," John Locke Foundation, March 4, 2010, https://www.johnlocke.org/research/the-clean-smokestacks-bill-a-retrospective/

23 Jon Sanders, "The steep price of extending the sunset on a special-interest tax credit," John Locke Foundation, September 3, 2015, https://www.johnlocke.org/update/the-steep-price-of-extending-the-sunset-on-a-special-interest-tax-credit/

24 Jon Sanders, "Power to the People: End SB 3 with its expensive, regressive renewable energy portfolio standard," John Locke Foundation, March 27, 2013, https://www.johnlocke.org/research/power-to-the-people-end-sb-3-with-its-expensive-regressive-renewable-energy-portfolio-standard/

25 Jon Sanders, "Detailing renewable energy's dependency on government goodies," John Locke Foundation, April 17, 2017, https://lockerroom.johnlocke.org/2017/04/17/detailing-renewable-energys-dependency-on-government-goodies/

26 Session Law 2007-397, Senate Bill 3, § 62-2, https://www.ncleg.net/Sessions/2007/Bills/Senate/PDF/S3v6.pdf

27 Database of State Incentives for Renewables & Efficiency, "Renewable Energy and Energy Efficiency Portfolio Standard - Program Overview," Accessed May 7, 2021, https://programs.dsireusa.org/system/program/detail/2660/renewable-energy-and-energy-efficiency-portfolio-standard

28 North Carolina Sustainable Energy Association, "A Citizen's Guide: North Carolina Renewable Energy & Energy Efficiency Portfolio Standard," 2012, https://energync.org/wp-content/uploads/2017/03/Citizens_Guide_NC_REPS.pdf

29 North Carolina Utility Commission, "Docket No. E-100, Sub 113," 2007, http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=6e5009d5-491e-4d3e-8ce0-9ff6fe493cdd

30 Sam Watson, "Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission, October 21, 2008, https://www.epa.gov/sites/production/files/2016-03/documents/renewable_energy_and_energy_efficiency_portfolio_standard_in_north_carolina.pdf

31 U.S. Energy Information Administration, "Renewable energy explained: Portfolio standards," Accessed May 7, 2021, https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php

32 Office of Governor Roy Cooper, Executive Order No. 80, October 29, 2018, https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20

Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf

33 North Carolina Department of Environmental Quality, "North Carolina Clean Energy Plan."

34 North Carolina Department of Environmental Quality, "North Carolina Clean Energy Plan, Supporting Document Part 2, Energy Resources."

35 § 62-2(b), https://www.ncleg.net/enactedlegislation/statutes/html/bychapter/chapter_62.html

36 North Carolina Utilities Commission, "2020 Report - Volume LI," January 4, 2021, https://www.ncuc.net/statbook/2020report.pdf

37 Duke Energy Progress, "Duke Energy Progress Integrated Resource Plan 2020 Biennial Report."

38 Duke Energy Carolinas, "Duke Energy Carolinas Integrated Resource Plan 2020 Biennial Report," https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/irp/202296/dec-2020-irp-full-plan.pdf?la=en&rev=f907071cc4dc4651b25ab93ca6f3d8f0

39 Office of Governor Roy Cooper, Executive Order No. 218, June 9, 2021, https://governor.nc.gov/news/governor-cooper-commits-offshore-wind-power-north-carolina-creates-jobs-transitioning-clean

40 Rachel Cleetus, "The Social Cost of Carbon Gets an Interim Update from the Biden Administration," Union of Concerned Scientists, March 2, 2021, https://blog.ucsusa.org/rachel-cleetus/the-social-cost-of-carbon-gets-an-interim-update-from-the-biden-administration

41 U.S. Nuclear Regulatory Commission, "Issued Design Certification – Advanced Power Reactor 1400 (APR1400)," Accessed May 1, 2021, https://www.nrc.gov/reactors/new-reactors/design-cert/apr1400.html

42 World Nuclear News, "First Korean APR-1400 enters commercial operation," December 20, 2016, https://web.archive.org/web/20170824051337/http:/www.world-nuclear-news.org/NN-First-Korean-APR-1400-enters-commercial-operation-2012164.html

43 World Nuclear News, "Second APR-1400 unit starts commercial operation," September 2, 2019, https://www.world-nuclear-news.org/Articles/Second-APR-1400-unit-starts-commercial-operation

44 KEPCO E&C, "APR1400," Accessed May 1, 2021, https://www.kepco-enc.com/eng/contents.do?key=1533.

45 World Nuclear News, “Design work suspended for new Shin Hanul units,” May 26, 2017, https://www.world-nuclear-news.org/NN-KHNP-design-work-suspended-for-new-Shin-Hanul-units-2605174.html

46 World Nuclear News, “UAE picks Korea as nuclear partner,” December 29, 2009, https://www.world-nuclear-news.org/NN_UAE_picks_Korea_as_nuclear_partner_2812091.html

47 Power Technology, “Barakah nuclear plant’s first unit begins operations,” April 7, 2021, https://www.power-technology.com/news/barakah-plant-first-unit/

48 Dania Saadi, “Interview: UAE’s Abu Dhabi to produce 1/3 of power from clean energy in 4 years,” S&P Global Platts, September 13, 2020, https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/091320-interview-uaes-abu-dhabi-to-produce-13-of-power-from-clean-energy-in-4-years

49 Power Technology, “Barakah nuclear plant’s first unit begins operations.”

50 Science Council for Global Initiatives, “The Cost of Nuclear Power,” Accessed May 1, 2021, http://www.thesciencecouncil.com/index.php/dr-barry-brook/175-the-cost-of-nuclear-power#:~:text=Korea%20has%20focused%20attention%20on,turnkey%20cost%20of%20%243%2C643%2FkW

51 U.S. Nuclear Regulatory Commission, “Agreement State Program,” Accessed May 1, 2021, https://www.nrc.gov/about-nrc/state-tribal/agreement-states.html

52 Office of Nuclear Energy, “What is Generation Capacity?” U.S. Department of Energy, May 1, 2020, https://www.energy.gov/ne/articles/what-generation-capacity

53 Thomas F. Stacy and George S. Taylor, “The Levelized Cost of Electricity from Existing Generation Resources,” Institute for Energy Research, June 2019, https://www.instituteforenergyresearch.org/wp-content/uploads/2019/06/IER_LCOE2019Final-.pdf

54 U.S. Energy Information Administration, “Levelized Costs of New Generation Resources,” Annual Energy Outlook 2021, February 2021, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

55 James Gignac, “Cracking the Code on Recycling Energy Storage Batteries,” Union of Concerned Scientists, October 30, 2020, https://blog.ucsusa.org/james-gignac/recycling-energy-storage-batteries

56 Donald I. Bleiwas, “Byproduct Mineral Commodities Used for the

Production of Photovoltaic Cells," U.S. Geological Survey, 2010, https://pubs.usgs.gov/circ/1365/Circ1365.pdf

57 Jiashuo Li et al, "Critical Rare-Earth Elements Mismatch Global Wind-Power Ambitions," One Earth Volume 3 Issue 1 pp 116-125, July 24, 2020, https://www.sciencedirect.com/science/article/pii/S2590332220302980

58 International Energy Agency, "The Role of Critical Minerals in Clean Energy Transitions," May 2021, https://iea.blob.core.windows.net/assets/24d5dfbb-a77a-4647-abcc-667867207f74/TheRoleofCriticalMineralsinCleanEnergyTransitions.pdf

59 Amit Katwala, "The spiralling environmental cost of our lithium battery addiction," Wired, May 8, 2018, https://www.wired.co.uk/article/lithium-batteries-environment-impact

60 Todd C. Frankel, Michael Robinson Chavez, and Jorge Ribas, "Mobile Power, Human Toll: The Cobalt Pipeline," Washington Post, September 30, 2016, https://www.washingtonpost.com/graphics/business/batteries/congo-cobalt-mining-for-lithium-ion-battery/

61 Bloomberg New Energy Finance, "China Dominates the Lithium-ion Battery Supply Chain, but Europe is on the Rise," September 16, 2020, https://about.bnef.com/blog/china-dominates-the-lithium-ion-battery-supply-chain-but-europe-is-on-the-rise/

62 Paul Kolbe and Mark Finley, "Winners and losers in an uneven energy transition," Oxford Energy Forum Issue 126, pages 41-44, February 2021, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2021/02/OEF-126.pdf

63 Wood Mackenzie, "China's green ambitions can complement energy security and economic goals," March 18, 2021, https://www.woodmac.com/press-releases/chinas-green-ambitions-can-complement-energy-security-and-economic-goals/

64 International Energy Agency, "Natural Gas Information: Overview," July 2020, https://www.iea.org/reports/natural-gas-information-overview

65 U.S. Energy Information Administration, "Oil and petroleum products explained: Oil imports and exports," Accessed June 16, 2021, https://www.eia.gov/energyexplained/oil-and-petroleum-products/imports-and-exports.php

66 Meghan L. O'Sullivan, "The energy transition and the enduring role of energy in US foreign policy," Oxford Energy Forum Issue 126, pages 36-

39, February 2021, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2021/02/OEF-126.pdf

67 Office of Energy Efficiency and Renewable Energy, "Advancing U.S. Battery Manufacturing and a Domestic Critical Minerals Supply Chains," U.S. Department of Energy, October 4, 2019, https://www.energy.gov/eere/articles/advancing-us-battery-manufacturing-and-domestic-critical-minerals-supply-chains

68 U.S. Department of the Interior, "Final List of Critical Minerals 2018," May 18, 2018, https://www.federalregister.gov/documents/2018/05/18/2018-10667/final-list-of-critical-minerals-2018

69 Joyce A. Ober, "Mineral commodity summaries 2018," U.S. Geological Survey, 2018, https://pubs.er.usgs.gov/publication/70194932

70 Congressional Research Service, "An Overview of Rare Earth Elements and Related Issues for Congress," November 24, 2020, https://crsreports.congress.gov/product/pdf/R/R46618

71 Christina Lu, "Why Rare Earths Are the Key to Just About Everything," Foreign Policy, April 22, 2021, https://foreignpolicy.com/2021/04/22/rare-earths-china-us-greenland-geopolitics/

72 James Gignac, "Cracking the Code on Recycling Energy Storage Batteries."

73 Chris Martin, "Wind Turbine Blades Can't Be Recycled, So They're Piling Up in Landfills," Bloomberg Green, February 5, 2020, https://www.bloomberg.com/news/features/2020-02-05/wind-turbine-blades-can-t-be-recycled-so-they-re-piling-up-in-landfills

74 Christina Stella, "Unfurling The Waste Problem Caused By Wind Energy," National Public Radio, September 10, 2019, https://www.npr.org/2019/09/10/759376113/unfurling-the-waste-problem-caused-by-wind-energy

75 Boeing Company, "737: Airplane Characteristics for Airport Planning," Accessed May 16, 2021, http://www.boeing.com/assets/pdf/commercial/airports/acaps/737.pdf

76 Terry Devitt, "Lithium battery component found to harm key soil microorganism," University of Wisconsin, February 4, 2016, https://news.wisc.edu/lithium-battery-catalyst-found-to-harm-key-soil-microorganism/#:~:text=The%20material%20at%20the%20heart,the%20journal%20Chemistry%20of%20Materials

77 U.S. Environmental Protection Agency, "Used Lithium-Ion Batteries,"

Accessed May 16, 2021, https://www.epa.gov/recycle/used-lithium-ion-batteries#:~:text=Lithium%20batteries%20are%20hazardous%20materials,CFR%20Parts%20171%E2%80%93180).&text=Hazard%20communication%20requirements%20are%20found,in%2049%20CFR%20section%20173.185

78 Mitch Jacoby, "It's time to get serious about recycling lithium-ion batteries," Chemical & Engineering News, July 14, 2019, https://cen.acs.org/materials/energy-storage/time-serious-recycling-lithium/97/i28

79 U.S. Environmental Protection Agency, "Economics of Biofuels," Accessed May 17, 2021, https://www.epa.gov/environmental-economics/economics-biofuels#:~:text=Regarding%20non%2DGHG%20environmental%20impacts,deplete%20aquifers%20(NRC%202011)

80 Dave Merrill, "The U.S. Will Need a Lot of Land for a Zero-Carbon Economy," Bloomberg Green, April 29, 2021, https://www.bloomberg.com/graphics/2021-energy-land-use-economy/

81 U.S. Energy Information Administration, "Use of energy explained," Accessed May 8, 2021, https://www.eia.gov/energyexplained/use-of-energy/transportation.php

82 Hans Nicholas Jong, "Indonesia's biofuel bid threatens more deforestation for oil palm plantations," Mongabay, December 21, 2020, https://news.mongabay.com/2020/12/indonesia-biofuel-deforestation-oil-palm-plantation-b30/

83 Ana Meijide et al, "Measured greenhouse gas budgets challenge emission savings from palm-oil biodiesel," Nature Communications 11 1089, February 27, 2020, https://www.nature.com/articles/s41467-020-14852-6

84 Mario Loyola, "Stop the Ethanol Madness," The Atlantic, November 23, 2019, https://www.theatlantic.com/ideas/archive/2019/11/ethanol-has-forsaken-us/602191/

85 Dave Merrill, "The U.S. Will Need a Lot of Land for a Zero-Carbon Economy."

86 Eric Larson et al, "Net-Zero America: Potential Pathways, Infrastructure, and Impacts," Princeton University, December 15, 2020, https://netzeroamerica.princeton.edu/the-report

87 Landon Stevens, "The Footprint of Energy: Land Use of U.S. Electricity Production," Strata Policy, June 2017, https://www.strata.org/pdf/2017/footprints-full.pdf

88 U.S. Energy Information Administration, "Nuclear explained: Where

our uranium comes from," Accessed June 2, 2021, https://www.eia.gov/energyexplained/nuclear/where-our-uranium-comes-from.php

89 Tim Faulkner, "Offshore Wind Cable Exposed at Block Island Beach," Eco RI News, May 24, 2019, https://www.ecori.org/renewable-energy/2019/5/24/wind-farm-power-cables-exosed-at-block-island-beach

90 Tim Faulkner, "Ratepayers On Hook for Portion of Block Island Wind Farm Cable Mess," Eco RI News, September 14, 2020, https://www.ecori.org/renewable-energy/2020/9/14/ratepayers-on-the-hook-for-portion-of-block-island-wind-farm-cable-mess

91 Robert Bryce, "Not In Our Backyard: Rural America is fighting back against large-scale renewable energy projects," Center of the American Experiment, April 2021, https://files.americanexperiment.org/wp-content/uploads/2021/04/Not-in-Our-Backyard-Robert-Bryce.pdf

92 Jess Shankleman and Lars Paulsson, "As Wind Power Grows in Europe, So Does Resistance From Locals," Bloomberg Green, June 19, 2020, https://www.bloomberg.com/news/articles/2020-06-19/wind-power-and-turbines-are-facing-pushback-from-europe-s-locals

93 Sarah Smith, "Hydro-Québec and Transmission Developers to deliver renewable energy to New York," Energy Global, May 13, 2021, https://www.energyglobal.com/other-renewables/13052021/hydro-qubec-and-transmission-developers-to-deliver-renewable-energy-to-new-york/

94 The Economist, "What, and who, are France's 'gilets jaunes'?," November 27, 2018, https://www.economist.com/the-economist-explains/2018/11/27/what-and-who-are-frances-gilets-jaunes

95 MHI Vestas Offshore Wind, "MHI Vestas Launches the First 10 MW Wind Turbine in History," September 25, 2018, https://mhivestasoffshore.com/mhi-vestas-launches-the-first-10-mw-wind-turbine-in-history/

96 The Maritime Executive, "New World's Largest Wind Turbine as Offshore Wind Scale-Up Continues," February 11, 2021, https://www.maritime-executive.com/article/new-world-s-largest-wind-turbine-as-offshore-wind-scale-up-continues

97 U.S. Fish & Wildlife Service, "Wind Turbines," Accessed May 14, 2021, https://www.fws.gov/birds/bird-enthusiasts/threats-to-birds/collisions/wind-turbines.php

98 The Economist, "The wind-power boom set off a scramble for balsa wood in Ecuador," January 30, 2021, https://www.economist.com/the-

americas/2021/01/30/the-wind-power-boom-set-off-a-scramble-for-balsa-wood-in-ecuador

99 Simon Carlile, John L. Davy, David Hillman, and Kym Burgemeister, "A Review of the Possible Perceptual and Physiological Effects of Wind Turbine Noise," Trends in Hearing, August 7, 2018, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC6081752/

100 Bill Magness, "Review of February 2021 Extreme Cold Weather Event — ERCOT Presentation," ERCOT, February 25, 2021, http://www.ercot.com/content/wcm/lists/226271/Texas_Legislature_Hearings_2-25-2021.pdf

101 Official ERCOT Twitter account, @ERCOT_ISO, February 14, 2021, https://twitter.com/ERCOT_ISO/status/1361142665140711427

102 Robert Walton, "Texas grid operator braces for record electric demand, warns generators to prepare," Utility Dive, February 12, 2021, https://www.utilitydive.com/news/texas-grid-operator-braces-for-record-electric-demand-warns-generators-to/595005/

103 U.S. Energy Information Administration, "Wind is a growing part of the electricity mix in Texas," October 15, 2020,https://www.eia.gov/todayinenergy/detail.php?id=45476#:~:text=In%20April%202019%2C%20wind%20generators,United%20States%20as%20a%20whole

104 ERCOT, "Generation," Accessed May 20, 2021, http://www.ercot.com/gridinfo/generation

105 U.S. Energy Information Administration, "Hourly Electric Grid Monitor: Texas (TEX) region daily generation mix 2/15/2021, Central Time," Accessed May 28, 2021, https://www.eia.gov/electricity/gridmonitor/expanded-view/custom/pending/RegionBaEnergymix-8bb69ca2-613b-492c-b4bf-548b26e252f0/edit

106 Keith Everhart and Gergely Molnar, "Severe power cuts in Texas highlight energy security risks related to extreme weather events," International Energy Agency, February 18, 2021, https://www.iea.org/commentaries/severe-power-cuts-in-texas-highlight-energy-security-risks-related-to-extreme-weather-events

107 U.S. Energy Information Administration, "State Electricity Profiles," February 1999, https://www.eia.gov/electricity/state/archive/062996.pdf

108 California Energy Commission, "2014 Total Electricity System Power," Accessed May 18, 2021, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2019-total-system-electric-generation/2014

109 Jeff St. John, "California's Shift From Natural Gas to Solar Is Playing a Role in Rolling Blackouts," Greentech Media, August 17, 2020, https://www.greentechmedia.com/articles/read/how-californias-shift-from-natural-gas-to-solar-is-playing-a-role-in-rolling-blackouts

110 California Energy Commission, "2019 Total System Electric Generation," Accessed May 18, 2021, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2019-total-system-electric-generation

111 Kavya Balaraman, "California's last nuclear plant is poised to shut down. What happens next?" Utility Dive, March 23, 2021, https://www.utilitydive.com/news/californias-last-nuclear-plant-is-poised-to-shut-down-what-happens-next/596970/

112 Institute for Energy Research, "The Solar Value Cliff: The Diminishing Value of Solar Power," August 2017, https://instituteforenergyresearch.org/wp-content/uploads/2017/08/The-Solar-Value-Cliff-August-21.pdf

113 California ISO, "Largest battery storage system in US connects to California ISO grid," July 13, 2020, http://www.caiso.com/Documents/LargestBatteryStorageSysteminUSConnectstoCaliforniaISOGrid.pdf

114 U.S. Energy Information Administration, "Rankings: Average Retail Price of Electricity to Residential Sector, February 2021 (cents/kWh)."

115 Markus Wacket, "Germany's energy drive criticised over expense, risks," Reuters, March 30, 2021, https://www.reuters.com/article/germany-energy-audit-idUSL8N2LS2RC

116 Vaclav Smil, "Germany's Energiewende, 20 Years Later," IEEE Spectrum, November 25, 2020, https://spectrum.ieee.org/energy/renewables/germanys-energiewende-20-years-later

117 NuScale, "Cost-Competitive Energy," Accessed March 31, 2021, https://www.nuscalepower.com/newsletter/nucleus-spring-2019/cost-competitive-energy#:~:text=A%20proposed%20720%20MWe%20NuScale,would%20require%20nearly%20600%20acres

118 Office of Nuclear Energy, "4 Key Benefits of Advanced Small Modular Reactors," U.S. Department of Energy, May 28, 2020, https://www.energy.gov/ne/articles/4-key-benefits-advanced-small-modular-reactors

119 David E. Sanger, Clifford Krauss, and Nicole Perlroth, "Cyberattack Forces a Shutdown of a Top U.S. Pipeline," New York Times, May 8, 2021,https://www.nytimes.com/2021/05/08/us/politics/cyberattack-colonial-pipeline.html

120 Office of Nuclear Energy, "Benefits of Small Modular Reactors (SMRs)," U.S. Department of Energy, Accessed March 31, 2021, https://www.energy.gov/ne/benefits-small-modular-reactors-smrs

121 Office of Nuclear Energy, "NRC Approves First U.S. Small Modular Reactor Design," U.S. Department of Energy, September 2, 2020, https://www.energy.gov/ne/articles/nrc-approves-first-us-small-modular-reactor-design

122 U.S. Nuclear Regulatory Commission, "Status of Subsequent License Renewal Applications," Accessed May 18, 2021, https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html

123 U.S. Nuclear Regulatory Commission, "Turkey Point Nuclear Plant, Units 3 & 4 – Subsequent License Renewal Application," Accessed May 18, 2021, https://www.nrc.gov/reactors/operating/licensing/renewal/applications/turkey-point-subsequent.html

124 U.S. Nuclear Regulatory Commission, "Peach Bottom Atomic Power Station, Units 2 & 3 – Subsequent License Renewal Application," Accessed May 18, 2021, https://www.nrc.gov/reactors/operating/licensing/renewal/applications/peach-bottom-subsequent.html

125 U.S. Nuclear Regulatory Commission, "Surry, Units 1 and 2 – Subsequent License Renewal Application," Accessed May 18, 2021, https://www.nrc.gov/reactors/operating/licensing/renewal/applications/surry-subsequent.html

126 U.S. Nuclear Regulatory Commission, "Point Beach Nuclear Plant, Units 1 & 2 – Subsequent License Renewal Application," Accessed May 18, 2021, https://www.nrc.gov/reactors/operating/licensing/renewal/applications/point-beach-subsequent.html

127 U.S. Nuclear Regulatory Commission, "North Anna, Units 1 and 2 – Subsequent License Renewal Application," Accessed May 18, 2021, https://www.nrc.gov/reactors/operating/licensing/renewal/applications/north-anna-1-2-subsequent.html

128 U.S. Energy Information Administration, "Electricity Market Module," February 2021, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf

129 Science Council for Global Initiatives, "The Cost of Nuclear Power."

130 Federal Energy Regulatory Commission, "Form 1 - Electric Utility Annual Report."

131 U.S. Energy Information Administration, "Levelized Costs of New Generation Resources."

132 U.S. Energy Information Administration, "North Carolina Electricity Profile 2019."

133 Federal Energy Regulatory Commission, "Form 1 - Electric Utility Annual Report."

134 U.S. Energy Information Administration, "North Carolina Electricity Profile 2019."

135 Ibid.

136 U.S. Nuclear Regulatory Commission, "Applicant's Environmental Report Operating License Renewal Stage [McGuire Nuclear Station],", Accessed June 4, 2021, https://www.nrc.gov/reactors/operating/licensing/renewal/applications/mcguire-catawba/duke-env-m.pdf

137 U.S. Energy Information Administration, "North Carolina Electricity Profile 2019."

138 John Boyle, "Duke Energy officially retires coal units at Lake Julian," Asheville Citizen Times, January 30, 2020, https://www.citizen-times.com/story/news/local/2020/01/30/duke-energy-retires-coal-units-lake-julian/4619923002/

139 Duke Energy, "Lincoln Combustion Turbine Station Expansion," Accessed May 28, 2021, https://www.duke-energy.com/our-company/about-us/new-generation/natural-gas/lincoln-ct-expansion

140 Jule Hubbard, "$85M solar farm planned on 600 acres," Wilkes Journal-Patriot, November 18, 2020, https://www.journalpatriot.com/news/85m-solar-farm-planned-on-600-acres/article_8c18fb03-fb1b-5948-a9db-64dc2e1c9890.html

141 Duke Energy Progress, "Decommissioning Cost Estimate Study Project No. 95525," April 19, 2017, https://dms.psc.sc.gov/Attachments/Matter/1857c756-b264-49a6-bca7-9283b59fc0cf

142 NC Sustainable Energy Association, "Land Use Analysis of NC Solar Installation," Accessed May 28, 2021, https://energync.org/wp-content/uploads/2017/03/Solar_Land_Use_Analysis_Results.pdf

143 U.S. Energy Information Administration, "North Carolina Electricity Profile 2019."

144 Avangrid, "Amazon Wind Farm North Carolina — Desert Wind," Accessed May 28, 2021, https://www.avangrid.com/wps/wcm/connect/1ef8bf38-251d-4969-b66f-d7bbf91a9e62/2017-1654-AR-AWFNC-Desert+Wind+fact+sheet-111017.pdf?MOD=AJPERES

&CACHEID=ROOTWORKSPACE-1ef8bf38-251d-4969-b66f-d7bbf91a9e62-l-Tb7px#:~:text=The%20Amazon%20Wind%20Farm%20North,commercial%20operation%20in%20early%202017.

145 Lawrence Berkeley National Laboratory, “Wind Power Performance,” Accessed May 28, 2021, https://emp.lbl.gov/wind-power-performance

146 British Broadcasting Corporation, “First power from world’s biggest offshore wind farm,” February 15, 2019, https://www.bbc.com/news/uk-england-humber-47214591

147 Andrew Z.P. Smith, “UK offshore wind capacity factors,” Energy Numbers, March 1, 2021, https://energynumbers.info/uk-offshore-wind-capacity-factors

About the Author

Jordan McGillis is deputy director of policy at the Institute for Energy Research. He is the author of the 2019 IER white paper "The Case Against a Carbon Tax" and the 2018 IER white paper "The Solar Value Cliff." McGillis is a regular contributor to *National Review* and to *The American Spectator*. His work on energy has appeared in numerous other publications as well, including the *Houston Chronicle* and the *Albuquerque Journal*.

FOR MORE INFORMATION, CONTACT

Brian Balfour

Senior Vice President of Research

John Locke Foundation

bbalfour@lockehq.org

919-828-3876

locke
THE JOHN LOCKE FOUNDATION

Our History

The John Locke Foundation was created in 1990 as an independent, nonprofit think tank that would work "for truth, for freedom, for the future of North Carolina." The Foundation is named for John Locke (1632-1704), an English philosopher whose writings inspired Thomas Jefferson and the other Founders. The John Locke Foundation is a 501(c)(3) research institute and is funded by thousands of individuals, foundations and corporations. The Foundation does not accept government funds or contributions to influence its work or the outcomes of its research.

Our Vision

The John Locke Foundation envisions a North Carolina of responsible citizens, strong families, and successful communities committed to individual liberty and limited, constitutional government.

Our Mission

The John Locke Foundation employs research, journalism, and outreach programs to transform government through competition, innovation, personal freedom, and personal responsibility. Locke seeks a better balance between the public sector and private institutions of family, faith, community, and enterprise.

THE JOHN LOCKE FOUNDATION

4800 Six Forks Rd., #220
Raleigh, NC 27609
919-828-3876
johnlocke.org

johnlockefoundation   @johnlockenc

John Locke Foundation   johnlockefoundation1   johnlockefoundation