Obsolete Atlantic Coast Pipeline Has Nothing to Deliver

An examination of the dramatic shifts in the energy, policy, and economic landscape in Virginia and North Carolina since 2017 shows there is little need for new gas generation

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EXECUTIVE SUMMARY

The energy landscape in Virginia and North Carolina has changed dramatically since the Atlantic Coast Pipeline (ACP) was first proposed in 2014 and since FERC issued its final Environmental Impact Statement rejecting alternatives to the pipeline in 2017. Recent legislative and executive actions in Virginia and North Carolina, respectively, are leading to a new clean energy future for the utilities operating in the region. To meet state and corporate targets for reducing carbon dioxide (CO_2) emissions, Dominion Energy, Duke Energy Carolinas (DEC), and Duke Energy Progress (DEP)—with DEC and DEP being referred to collectively here as "Duke Energy"—will need to retire existing coal units, avoid building new gas plants, and build or procure greater amounts of renewable energy and battery storage resources.

Both Dominion's and Duke's 2018 and 2019 long-term integrated resource plans (IRPs) are inconsistent with the clean energy future mapped out by policymakers in Virginia and regulators in North Carolina. The IRPs relied heavily on fossil fuels, with the utilities proposing to continue operation of a sizable portion of their coal fleets and to add a substantial amount of new gas generation in future years. Dominion's 2018 IRP, for example, called for 3,664 megawatts (MW) of new gas combustion turbines by 2033. Dominion's 2019 IRP Update, which included a lower baseline projection of electricity use as well as additional energy efficiency, lowered the total number of new gas units; however, the plan still called for between 1,455 MW and 2,425 MW of new combustion turbines by 2026.[1] The combined 2018 IRPs for Duke Energy planned gas additions totaling 9,000 MW,[2] while the 2019 IRP Updates increased that number to 12,000 MW of new gas resources.[3] In Dominion's recent 2020 IRP, however, the utility was required to model the effect of Virginia's new energy legislation on its fossil generation resources. Now it is planning for maximum new gas of only 970 MW, in stark contrast to resource plans from previous years. Duke's 2020 IRPs will be filed in September 2020 and must include scenarios that meet the new North Carolina emissions targets, as well as Duke Energy's own carbon reduction goals.

The dramatic changes in planned new gas plants in Virginia and the Carolinas require a similar reevaluation of the need for the infrastructure that could supply the fuel for these plants. The interstate Atlantic Coast Pipeline (ACP) was proposed in 2014 to transport gas from West Virginia into Virginia and the Carolinas. At the time they announced the project, original owners Dominion Energy, Duke Energy, Piedmont Natural Gas, and AGL Resources[4] asserted that the pipeline was necessary to supply existing

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[1] Dominion Energy. 2019 Integrated Resource Plan Update. Page 12.

[2] DEC and DEP. 2018. Integrated Resource Plans.

[3] DEC and DEP. 2019. Integrated Resource Plan Updates.

[4] ACP ownership has changed since the project was proposed in 2014. Today, Dominion Energy and Duke Energy are the two project owners.

and new gas generation being constructed in the electric sector.[5] However, in addition to policy actions at the state level, industry trends of flat demand for electricity and falling prices for alternative, zero-emissions technologies have caused utilities across the country to forego plans to construct new gas plants. Instead, these utilities are building an energy future that relies on energy efficiency, demand-side management, wind, solar, and battery storage resources.

On behalf of the Southern Environmental Law Center, Synapse assessed the projected demand for new gas used for electric generation, estimating the "maximum demand for new gas" on a peak winter day in Dominion's and Duke's service territories. We examined public IRPs, new policies in Virginia and North Carolina that will lower CO_2 emissions in the electric sector, and public documents related to the utilities' internal emission reduction goals. We used that data to build spreadsheet models to assess maximum future gas demand on a winter peak day.

The results show three key points:

> Projections of electricity demand have fallen since the 2012 to 2014 period when the ACP was conceptualized, and demand projections are much lower today than they were almost a decade ago.

First, Dominion's and Duke's projections of electricity demand have fallen since the 2012 to 2014 period when the ACP was conceptualized, and demand projections are much lower today than they were almost a decade ago.[6] Dominion's summer peak demand forecast for the year 2021 is 14 percent lower in its 2020 IRP than in its 2012 IRP. Duke Energy's combined summer peak demand forecast is 9 percent lower in its 2019 IRP Updates for the year 2021 than was forecast in the 2012 IRPs. The impacts of the ongoing COVID-19 pandemic will lead to a further decrease in demand growth in Duke and Dominion's service territories, with effects that could be long-lasting, depending on the rate at which the U.S. economy recovers. Utility demand forecasts drive decisions around generation resource acquisitions, meaning that if forecasted demand does not materialize, a utility will have overbuilt relative to its actual need, and its customers will ultimately pay for unneeded infrastructure.

Second, recent policy measures and economic trends dictate that any need for new generating technologies in Virginia and North Carolina should be met with a combination of demand-side measures and renewable and storage technologies. Executive and legislative actions in both states call for reductions in the volume of CO_2 emissions coming from the power sector. Virginia's Clean Economy Act mandates that Dominion close its fossil units by 2045 and requires zero emissions by 2050, while North Carolina's goal of net-zero emissions by 2050 would allow some level of emissions provided they were

[5] Natural Resource Group. 2015. Draft Resource Report 1: General Project Description. Prepared for Atlantic Coast Pipeline, LLC Docket No. PF15-6-000 and Dominion Transmission, Inc. Docket No PF15-5-000. Page 1-7. Available at: https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=13991031.

[6] "Demand" refers to total customer demand for electricity which utilities are expected to supply. Utilities forecast both peak demand (MW) and annual energy (MWh or GWh). Peak demand represents the highest amount of electricity used in a single hour, while annual energy is the total electricity demand over a year period.

offset by reductions in other sectors. Pricing trends for wind, solar, and battery storage resources have declined dramatically over the last decade to the point where these technologies currently outcompete new gas-fired combustion turbine units. These clean energy technologies will soon be less expensive to build and operate than new combined cycle units. For example, since 2014, the mean wind cost has fallen by 30 percent, while the mean solar cost has dropped by 50 percent. Costs for lithium-ion batteries have fallen 76 percent between 2012 and the first half of 2019.

We calculate that the potential maximum demand for new gas is so low as to render the ACP a "stranded asset."

Third, we calculate that the potential maximum demand for new gas is so low as to render the ACP a "stranded asset." If built, the ACP would be unneeded and obsolete the moment it went online, subjecting the utilities who have contracted for gas shipped on the pipeline to the risk that regulators may not allow them to recover the cost of those contracts. The transport capacity of the ACP is 1.5 billion cubic feet (Bcf) of gas per day. Between 2020 and 2030, Dominion's maximum gas consumption from new gas-fired resources on a winter peak day represents approximately 0.7 percent of the total capacity of the pipeline. The maximum gas consumption from new gas-fired resources by Duke Energy is no more than 9 percent of the capacity of the ACP on a peak winter day. As CO_2 emissions requirements/targets become more stringent beyond 2030, the utilities will need to use even less gas in order to comply.

Thus, this minimal amount of additional gas demand on winter peak days in Dominion's and Duke's service territories does not support the construction of a massive new intrastate gas pipeline. Pipeline capacity into North Carolina has already increased by 2 Bcf/day since 2014, absent the operation of the ACP. Pipeline capacity could increase by an additional 0.675 Bcf per day in 2020–2021 as a result of two pipeline expansion projects. Dominion and Duke have not demonstrated that they could not contract for firm capacity on any of these existing or potential pipelines if necessary.

Our analysis demonstrates that the need for new gas-fired generating resources originally anticipated by Duke and Dominion has not and will not materialize, thus negating the utilities' claimed need for the ACP.

1. INTRODUCTION

The interstate Atlantic Coast Pipeline (ACP) was proposed in 2014 to transport gas from West Virginia into Virginia and the Carolinas. Original project owners Dominion Pipeline, Duke Energy, Piedmont Natural Gas, and AGL Resources asserted that the pipeline was necessary to meet regional energy demand both at the time and in the future. In its original application to the Federal Energy Regulatory Commission (FERC), the developers' assessments of need relied primarily on growth projections for gas used in electric generation published by the Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. The current contracts on the ACP, which account for 86 percent of the proposed pipeline's capacity, are with subsidiaries of Duke and Dominion.[7]

The ACP developers commissioned a study from ICF International in 2015 showing a scenario in which, between 2019 and 2038, approximately 9,900 MW of coal and nuclear generating capacity in Virginia and North Carolina would retire, while the region would build 20,200 MW of new natural gas capacity. As a result, ICF predicted that demand for natural gas for electric power generation in the two states would "grow 6.3 percent annually between 2014 and 2035, increasing from 1 Bcf/d (billion cubic feet per day) to 3.7 Bcf/d."[8]

To assess the current projected demand for new gas for electric generation, Synapse examined public integrated resource plans (IRPs) for Duke and Dominion, new policies in Virginia and North Carolina that will lower carbon dioxide (CO_2) emissions in the electric sector, and public documents related to the companies' internal emission reduction goals. We used spreadsheet analysis to examine gas demand during a winter peak day in both Duke and Dominion's service territories. We also examined the effects that the COVID-19 pandemic might have on future demand projections, although we used the utilities' most recent demand projections as the basis for our calculations of future new gas demand, given the uncertainty associated with future electricity demand.

In Section 2, we describe the demand forecasts from Duke and Dominion that were presented in each utility's IRPs between 2014 and 2019. Section 3 presents four scenarios of adjustments to future electric demand that may result due to the current COVID-19 pandemic. Declining cost trends associated with renewable and storage technologies are presented in Section 4. Recent legislation and executive actions that mandate increasing penetrations of renewable generation and declining CO_2 emissions from fossil fueled generators are described in Section 5. In Section 6, we apply these requirements to Duke and Dominion's forecasted peak demand, as presented in their IRPs, to determine the maximum amount of

[7] Atlantic Coast Pipeline. Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates. Before the Federal Energy Regulatory Commission. September 18, 2015.

[8] ICF International. 2015. *The Economic Impacts of the Atlantic Coast Pipeline*. Available at: https://www.abralliance.org/wp-content/uploads/2015/09/Economic_Impacts-ACP_ICFI_study_for_Dominion_2-9-15.pdf.

new gas capacity that could be added to each utility system. We then examine the single peak winter day and estimate generation associated with each fuel type. We differentiate between generation from existing gas units (which already contract for fuel on existing pipelines) and new gas units (which may or may not require additional interstate gas supplies). Finally, in Section 7 we discuss the stranded asset risk associated with new gas infrastructure. We provide a detailed description of our methodology in Appendix A.

2. Historical Demand Forecasts Were Overstated

Electric sector demand has been flat across the United States for the past decade as heavy industries have increasingly been moved overseas, savings from energy efficiency measures have risen, and a larger number of customers generate their own power on site. Demand projections from several utilities in the Southeast region mirror these national trends:

1) In its 2019 IRP, the Tennessee Valley Authority stated that its electric system demand is expected to be flat, or even declining slightly, over the next 10 years.[9]

2) Santee Cooper's 2018 IRP states that the utility's existing portfolio is capable of serving its energy and capacity needs at least until 2032, as average annual energy growth over the forecast period is less than 0.2 percent and average annual growth in winter peak demand is 0.5 percent.[10]

3) Appalachian Power Company projects that residential and commercial demand will decline in future years, and industrial demand will increase slightly over the same period.[11]

In contrast, three of the region's remaining large utilities—Dominion, Duke Carolinas, and Duke Progress—continue to project larger increases in peak demand and annual energy use in their service territories. These demand forecasts drive decisions around generation resource acquisitions, meaning that if forecasted demand does not materialize, a utility has overbuilt relative to its actual need, and its customers ultimately bear this burden. A study done by the Rocky Mountain Institute (RMI) shows that planners have, on average, over-forecast electricity demand by one percentage point for each year of their forecast for at least the last decade, meaning that demand forecasts are more than 10 percent too

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[9] Tennessee Valley Authority. 2019. Integrated Resource Plan. Page 1-4. Available at: https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/default-document-library/site-content/environment/environmental-stewardship/irp/2019-documents/tva-2019-integrated-resource-plan-volume-i-final-resource-plan.pdf?sfvrsn=44251e0a_4.

[10] Santee Cooper. 2018. Integrated Resource Plan. Page 4. Available at: http://www.energy.sc.gov/files/view/Santee percent20Cooper_IRP_2018_FINAL.pdf.

[11] Appalachian Power Company. 2019. Integrated Resource Plan. Pages 17 and 19. Available at: https://rga.lis.virginia.gov/Published/2019/RD227/PDF.

high at the end of a 10 year period. [12] Mark Dyson, Principal at RMI, said: "Because 10+ year forecasts drive investment decisions for 30-year assets, this over-forecasting has led to the present situation of extremely high reserve margins across much of the U.S., costing captive utility customers billions each year."[13] If indeed demand growth in a utility area remains relatively flat, an over-forecast of electric demand can mean that assets are built that may never be used at all.[14] These assets tend to be new gas combined cycle units and combustion turbines.

The following sections examine the historical demand forecasts of Dominion and Duke in more detail.

2.1. Dominion

Figure 2, below, shows that weather-normalized demand in Dominion's service territory have been flat, consistent with the experience of other electric utilities, and yet the PJM demand forecasts since 2010 continued to predict future demand growth.[15]

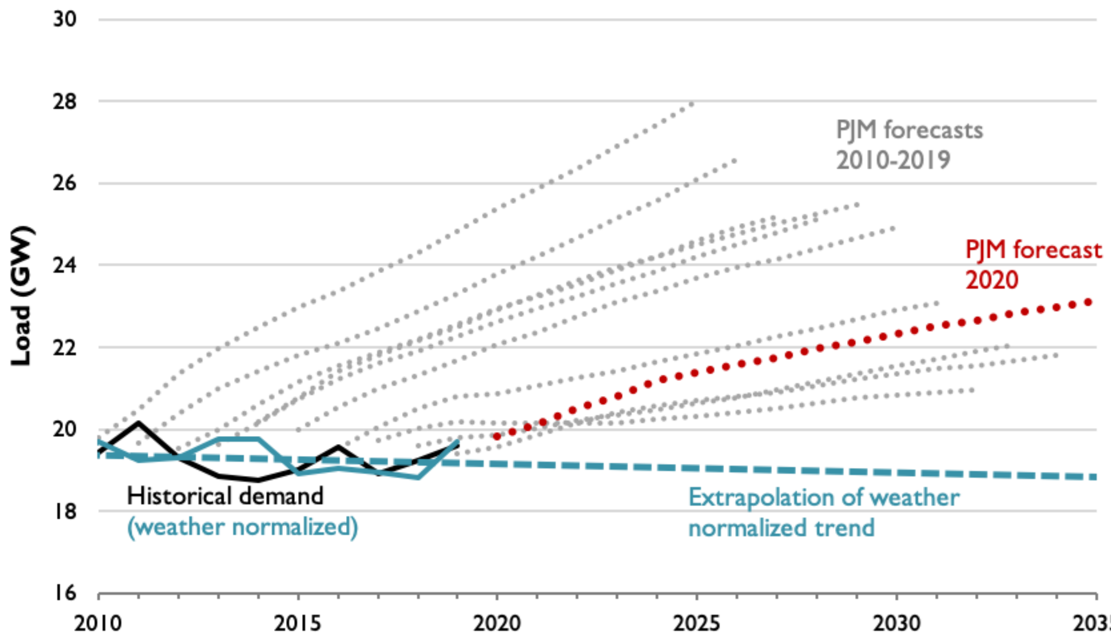
[12] Rocky Mountain Institute. 2017. *The Billion-Dollar Costs of Forecasting Electricity Demand.* Available at: https://rmi.org/billion-dollar-costs-forecasting-electricity-demand/.

[13] Utility Dive. 2019. *Dominion suspends plan to add 1.5 GW of peaking capacity as Virginia faces gas glut*. Available at: https://www.utilitydive.com/news/dominion-suspends-plan-to-add-15-gw-of-peaking-capacity-as-virginia-faces/568489/.

[14] Rocky Mountain Institute. 2017. *The Billion-Dollar Costs of Forecasting Electricity Demand.* Available at: https://rmi.org/billion-dollar-costs-forecasting-electricity-demand/.

[15] PJM is the regional transmission operator (RTO) responsible for managing the competitive wholesale electricity market in 13 states, including the Virginia and the portion of North Carolina served by Dominion, and the District of Columbia. The RTO dispatches power plants across the region, subject to transmission constraints, such that costs are minimized and also undergoes a regional planning process to ensure reliability of the electric grid.

Figure 1. Actual versus forecasted peak demand in the PJM-DOM zone

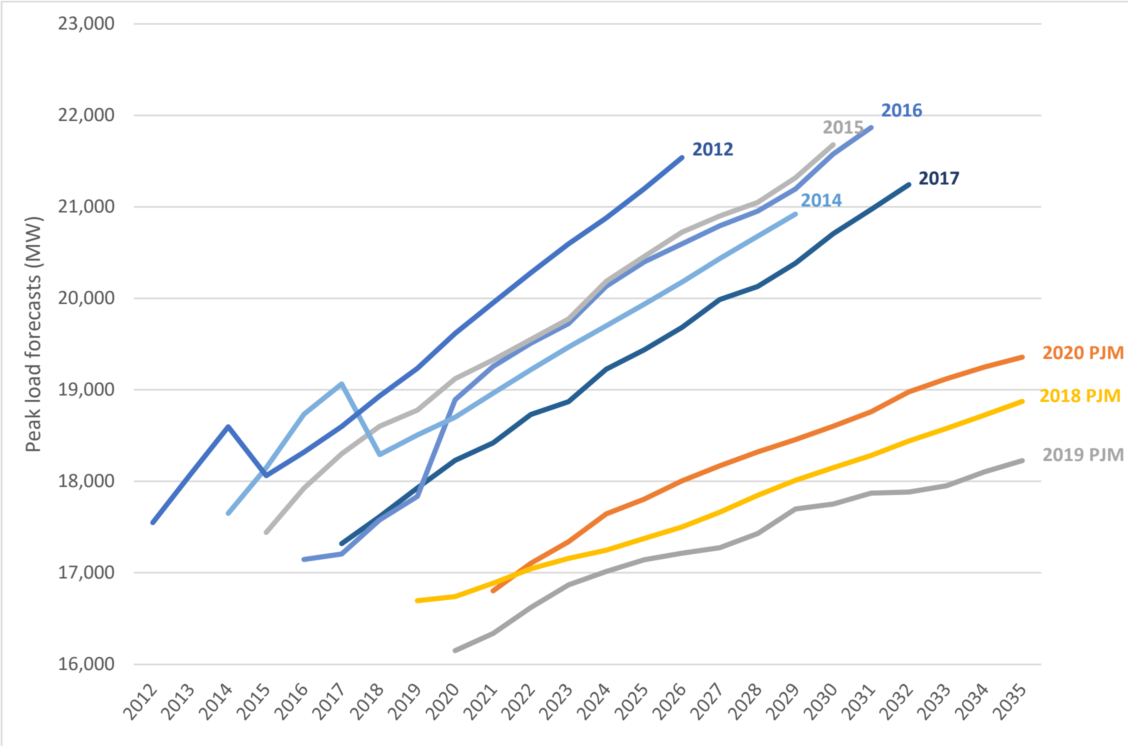


Source: Synapse Energy Economics. 2020. Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line. Prepared for National Parks Conservation Association.

Dominion's own internal demand forecasts have historically been even higher than those from PJM. Figure 2 shows Dominion's peak demand forecasts from its IRPs between 2012 and 2020.[16]

[16] The SCC directed Dominion to use the Dominion Zone PJM coincident (summer) peak load forecast, finding it appropriate because PJM establishes Dominion's capacity obligation based on the company's contribution to PJM's coincident peak, and also because capacity is available to Dominion for purchase from the PJM market during times of Dominion's non-coincident peak.

Figure 2. Historical peak demand projections (summer) in Dominion's service territory



The forecasts from 2012 to 2017 are Dominion's own internal forecasts, adjusted by the company for energy efficiency and demand response. In December 2018, the Virginia State Corporation Commission (SCC) rejected Dominion Energy Virginia's 2018 IRP, finding that the "record…reflects that the load forecasts contained in the Company's past IRPs have been consistently overstated, particularly in years since 2012, with high growth expectations despite generally flat actual results each year."[17] Because "the Commission has considerable doubt regarding the accuracy and reasonableness of the Company's load forecast for use to predict future energy and peak load requirements,"[18] Dominion was ordered to refile its 2018 IRP and to rely on the PJM demand forecast rather than its own internal forecast.[19] The SCC noted this difference in its 2018 Order, stating that "for the past several years, the Company has

[17] Commonwealth of Virginia State Corporation Commission. 2018. In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code §56-597 *et seq*. Order. Case No. PUR-2018-00065. Available at: https://scc.virginia.gov/docketsearch/DOCS/4d5g01!.PDF.

[18] Commonwealth of Virginia State Corporation Commission. 2018. In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code §56-597 *et seq*. Order. Case No. PUR-2018-00065. Available at: https://scc.virginia.gov/docketsearch/DOCS/4d5g01!.PDF.

[19] Load forecast is synonymous with demand forecast.

generally lowered its expected base year forecast with each subsequent IRP, while maintaining a similar slope for its long term forecast."[20]

The forecasts shown in Figure 2 for 2018 to 2020 are therefore PJM's forecasts for the DOM zone, adjusted by the company to represent only the Dominion load serving entity (LSE). These more recent forecasts that use the PJM forecast as a starting point are much lower than those used by Dominion in earlier years. In 2012, for example, Dominion forecasted that peak summer demand in 2021 would be 19,617 MW. In 2020, the forecast for 2021 is 16,802 MW—a difference of almost 3,000 MW.

In December 2019, S&P Global published an analysis concluding that Dominion is using its forecasts of electricity demand to justify building unnecessary new gas capacity that is paid for by customers without providing a corresponding benefit.[21] The authors of the study find that Dominion is retiring existing gas units well before the end of their service lives at the same time it is adding new units, and passing along the costs of these plants to customers.[22]

2.2. Duke

Duke's demand forecasts have been similarly criticized by various parties as being overstated. In a 2017 Order approving Duke's 2016 IRPs, North Carolina regulators accepted Duke's demand forecasts but noted that they share the concerns raised by the state consumer advocate agency about the forecasting methods and those raised by some intervenors that the demand forecast "may be higher than reasonably justified."[23] Analysis of the forecasts of DEC and DEP combined summer and winter peaks from IRPs between 2012 and 2019[24] show that the forecast in 2012 was the highest of any of the following years. This is particularly important because the initial plans for the ACP were formulated during the 2012 IRP horizon and were announced in 2014 prior to completion of the IRPs in that year.

As shown in Figure 3, the summer peak demand forecast for DEC and DEP follows a similar pattern to Dominion. The starting point for each subsequent demand forecast sits below that of the prior year. The 2012 peak summer forecast was the highest of all years analyzed. The 2012 forecast for 2027 is more than 4,000 MW higher than the 2019 forecast for that same year.

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[20] Commonwealth of Virginia State Corporation Commission. 2018. In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code §56-597 *et seq*. Order. Case No. PUR-2018-00065. Available at: https://scc.virginia.gov/docketsearch/DOCS/4d5g01!.PDF.

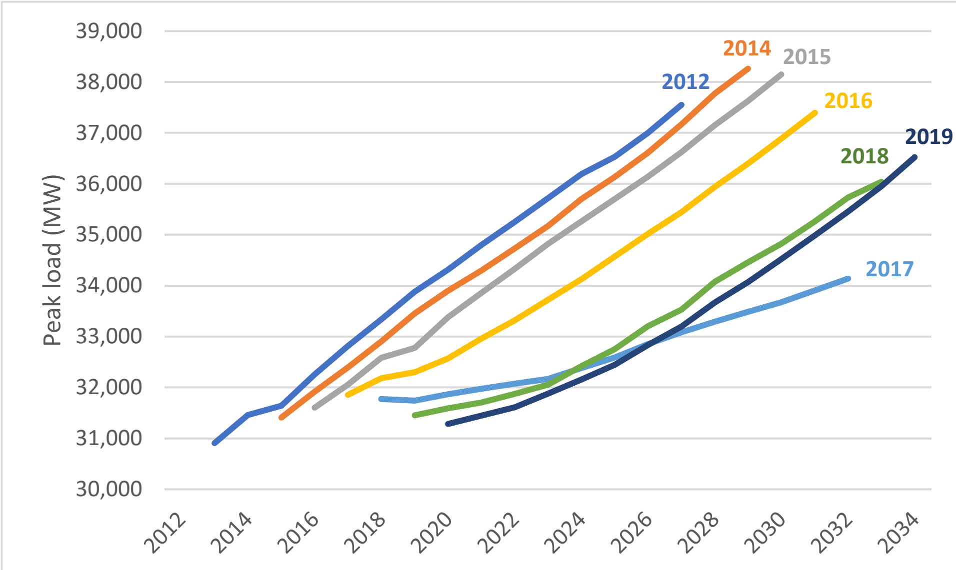
[21] S&P Global. 2019. *Overpowered: In Virginia, Dominion faces challenges to its reign*. Available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/54171542.

[22] S&P Global. 2019. *Overpowered: In Virginia, Dominion faces challenges to its reign*. Available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/54171542.

[23] State of North Carolina Utilities Commission. 2017. *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans*. Docket No. E-100, SUB 147. Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=8f9184ca-b96d-45a4-8bc2-31beb0de95ce.

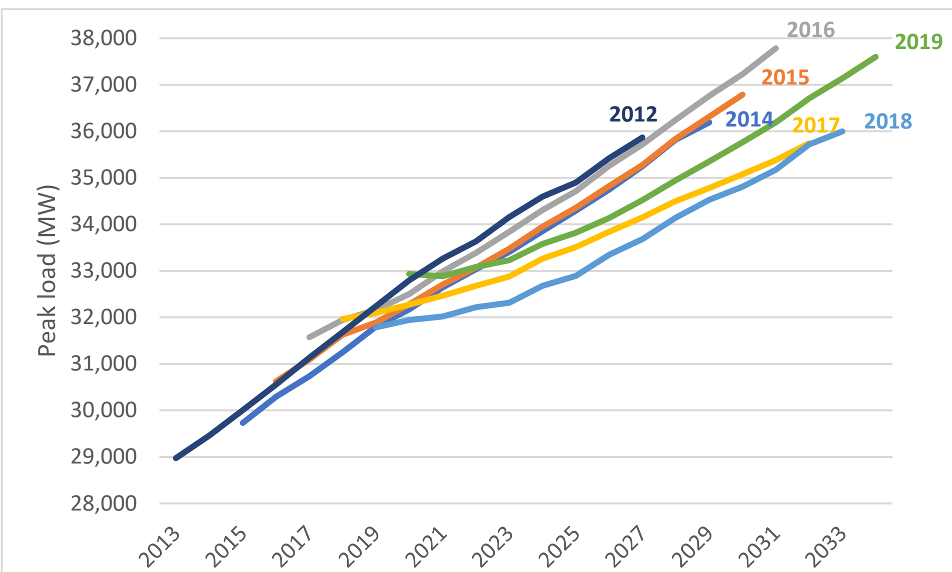
[24] The 2020 Integrated Resource Plans for DEC and DEP are anticipated in September 2020.

Figure 3. Combined historical peak demand projections (summer) for DEC and DEP



Duke has emphasized its recent shift from a summer peaking system to a winter peaking system as a driver behind the need for new gas-fired generating capacity and thus the ACP. The combined winter peak forecast for both utilities is shown in Figure 4. Again, the peak forecast from 2012 is the highest of all the forecasts shown, and the forecast from the 2019 IRP sits below each of the forecasts from the 2012 to 2016 IRPs.

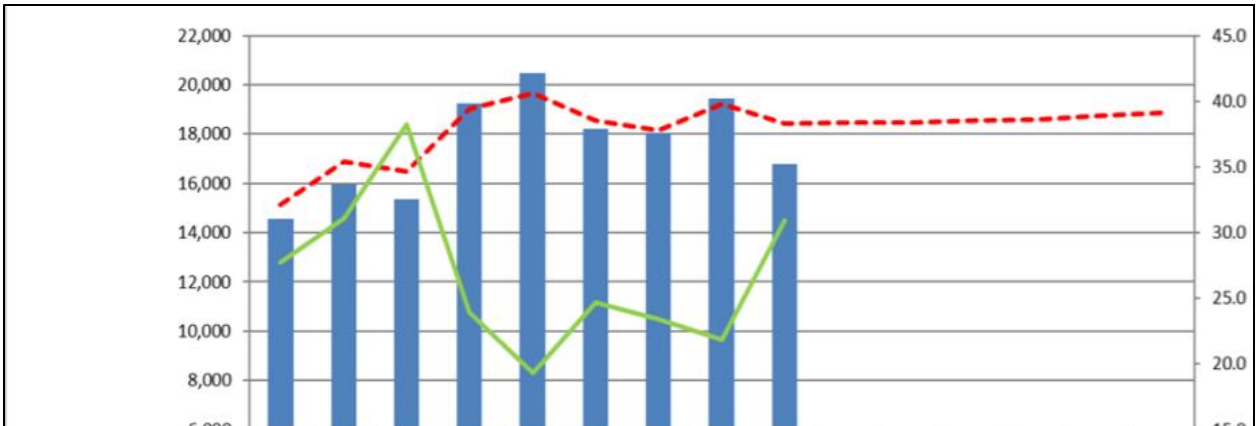
Figure 4. Combined historical peak demand projections (winter) for DEC and DEP



In 2014, the combined winter forecast for the year 2027 was 35,865 MW. The 2019 forecast for the same year was 34,518 MW—a difference of just over 1,300 MW.

The weather normalized historical winter peaks for DEC and DEP have been relatively flat since 2014 and forecasts indicate they are expected to remain flat, as shown in Figure 5 and Figure 6. Both Figures show increased peak demand in 2015 and 2018, which occurred during polar vortex events in those years.

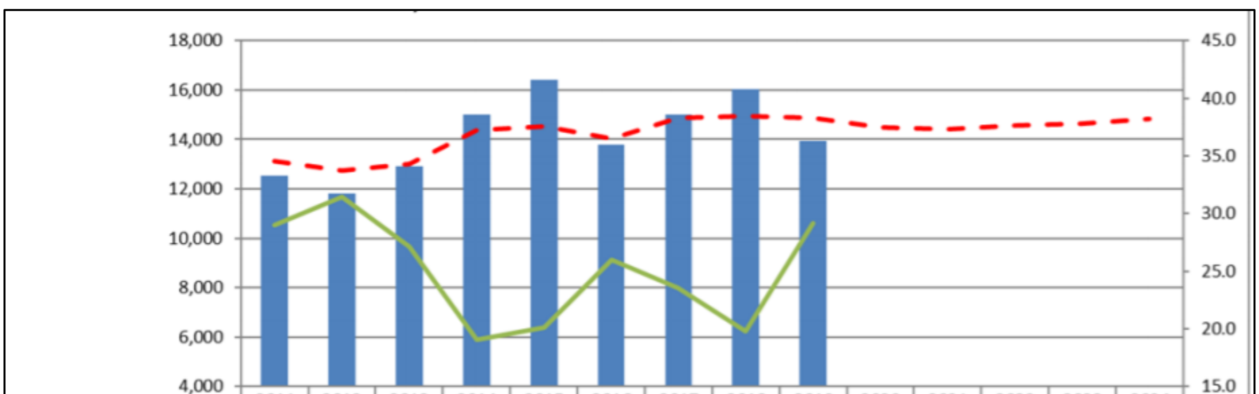
Figure 5. DEC actual, weather normal, and forecasted winter peaks



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	14,561	15,962	15,363	19,232	20,455	18,213	18,069	19,436	16,782						
WN Peak/Forecast	15,141	16,875	16,500	19,040	19,674	18,544	18,162	19,204	18,426	18,460	18,449	18,530	18,580	18,737	18,852
Temp	27.7	31.1	38.3	23.9	19.4	24.7	23.4	21.9	30.9						

Source: DEC 2019 IRP Update.

Figure 6. DEP actual, weather normal, and forecasted winter peaks



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Actual	12,522	11,826	12,897	14,993	16,429	13,801	15,020	16,016	13,942					
WN Peak/Forecast	13,107	12,760	12,994	14,374	14,519	14,026	14,857	14,967	14,858	14,473	14,434	14,557	14,649	14,843
Temp	29.0	31.5	27.1	19.1	20.1	26.0	23.5	19.8	29.2					

Source: DEP 2019 IRP Update.

In advocating for the development of the Atlantic Coast Pipeline, both Duke and Dominion have cited their winter peak forecasts as the driver of the need for new gas capacity. The shift to resource planning focused on meeting winter peak demand is a recent one for these utilities, which have spent decades planning for, and acquiring resources for, a summer peak. Demand-side management measures, which include energy efficiency and demand response, have been built for summer peak since their inception. The 2019 DEC IRP Update includes only 469 MW of DSM in the winter compared to 1,108 MW of DSM in the summer.[25] The 2019 DEP IRP Update lists 478 MW of winter DSM compared to 917 MW in the summer.[26] DEC acknowledged its own lack of effort regarding implementation of winter DSM programs during the recent hearing before the North Carolina Utilities Commission seeking recovery for DSM and energy efficiency costs, stating "historically, the Company has not recognized winter at coincident peak savings associated with demand response programs."[27] Rather than build new gas to meet winter peak demand, Duke and Dominion should build winter DSM programs to reduce those winter peaks—a solution which would result in cost-savings to customers.

3. Effects of COVID-19 Will Lower Future Demand

Recent impacts from COVID-19 include lowered electricity use across the United States, as grid operators around the country are reporting declines in demand and a shifting in load shapes.[28,29] Even the most accurate forecast of energy demand that was created prior to the pandemic is likely overstated due a slowdown in economic activity brought upon by COVID-19.

Analysis from the 2008 recession demonstrated a correlation between unemployment and electricity demand, showing that "…electricity use fell the most in those parts of the country that subsequent data would confirm had experienced the sharpest fall in employment."[30] Using simple linear models, we found a positive and statistically significant link between generation and employment by state for Virginia, South Carolina, and North Carolina from 1990–2018.[31] A more detailed description of the methodology is found in Appendix A.

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[25] Duke Energy Carolinas. 2019. Integrated Resource Plan Update. Pages 52-53.

[26] Dominion. 2020. Integrated Resource Plan. Page 177.

[27] North Carolina Utilities Commission. June 9, 2020. In the Matter of: Application of Duke Energy Carolinas, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C.G.S. 62-133.9 and Commission Rule R8-69. Hearing Transcript. Volume 2. Page 137, lines 4-6.

[28] A load shape specifies the seasonal and hourly variation in energy consumption.

[29] Utility Dive. March 23, 2020. *Utilities beginning to see the load impacts of COVID-19 as economic shutdown widens.* Available at: https://www.utilitydive.com/news/utilities-are-beginning-to-see-the-load-impacts-of-covid-19-as-economic-sh/574632/

[30] Bui, Quoctrung and Justin Wolfers. April 8, 2020. *Another Way to See the Recession: Power Usage is Way Down*. New York Times. Available at: https://www.nytimes.com/interactive/2020/04/08/upshot/electricity-usage-predict-coronavirus-recession.html

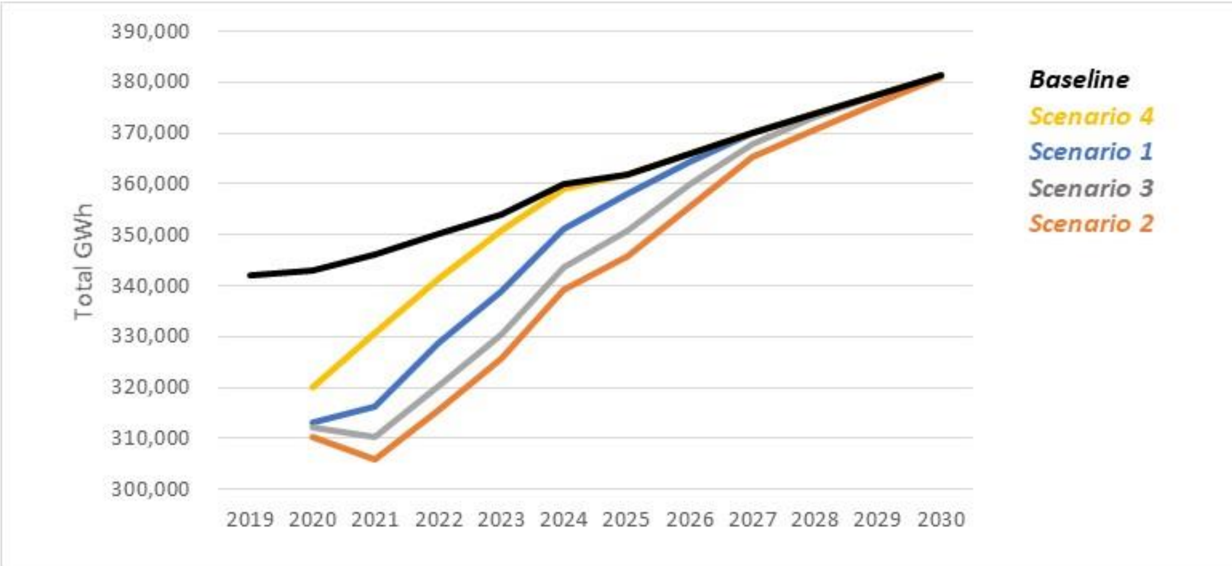
[31] Total generation from EIA Net Generation by State, https://www.eia.gov/electricity/data/state/. Employment data from the U.S. Bureau of Labor Statistics, Local Area Unemployment Statistics, https://data.bls.gov/PDQWeb/la.

State-wide unemployment has spiked dramatically in the months since the initial COVID-19 outbreak, and these effects are likely to persist for years. There is much uncertainty around the timing and severity of unemployment numbers going forward, and so we created four different employment schedules based on the unemployment percentage of total labor force:

- **Scenario 1:** Unemployment decreases to 9.5 percent by the end of 2021 followed by an increase consistent with historical rates of employment gain from January 2010 through February 2020.
- **Scenario 2:** Constant unemployment of 14.7 percent through the end of 2020, followed by an increase in employment described above.
- **Scenario 3:** Used Great Recession of 2008 as a model. Found the number of months between record high unemployment to the return to low unemployment recorded just before the high. The difference between current record high (14.7 percent) and the lows recorded just before the high was distributed across the number of months it took to recover in 2008. Historical recovery ranged from 69–102 months across our three states.
- **Scenario 4:** Three phase recovery starting with a 1 percent decrease in unemployment through August 2020 followed by a decrease of .4 percent through April 2021. Post-April 2021 employment increases at the historical rate.
- **Baseline**: Carried pre-COVID low unemployment rate forward.

We used employment estimates in our regression equations to calculate forecasted generation in each scenario. All scenarios show a dramatic drop in April to our assumed high unemployment rate of 14.7 percent, followed by varying degrees and timing of recovery (Figure 7). If we assumed employment remained constant at pre-COVID levels, our adjustments show a range of demand decreases from 7–10 percent in aggregate between the Carolinas and Virginia in 2020. By 2024 our forecasts range from 0–6 percent below our baseline assumption. While the most dramatic demand reduction coincides with current unemployment spikes, even under the most positive assumption, recovery will take many years.

Figure 7. Total aggregate generation impacts from COVID-19 employment scenarios



Duke noted during a meeting of its shareholders that it was expecting a moderate decline in demand to continue throughout the year, particularly in the commercial and industrial sectors.[32] COVID-19 will almost certainly lower the demand forecast for both Duke and Dominion and could delay the need for new resources, depending on the speed of economic recovery.

4. Declines in Renewable Costs Have Made Them More Competitive as Replacement Resources

The cost of clean energy generation technologies has fallen dramatically over the previous decade, such that the levelized cost of energy (LCOE) is competitive with new gas-fired resources.[33] Lazard's *Levelized Cost of Energy—Version 13.0* shows that the levelized costs for wind are now 70 percent lower than the costs in 2009 with a 10-year compound annual rate of decline of 11 percent per year.[34] Similarly, for solar, Lazard shows an even more drastic cost decline—levelized costs are now 89 percent lower than

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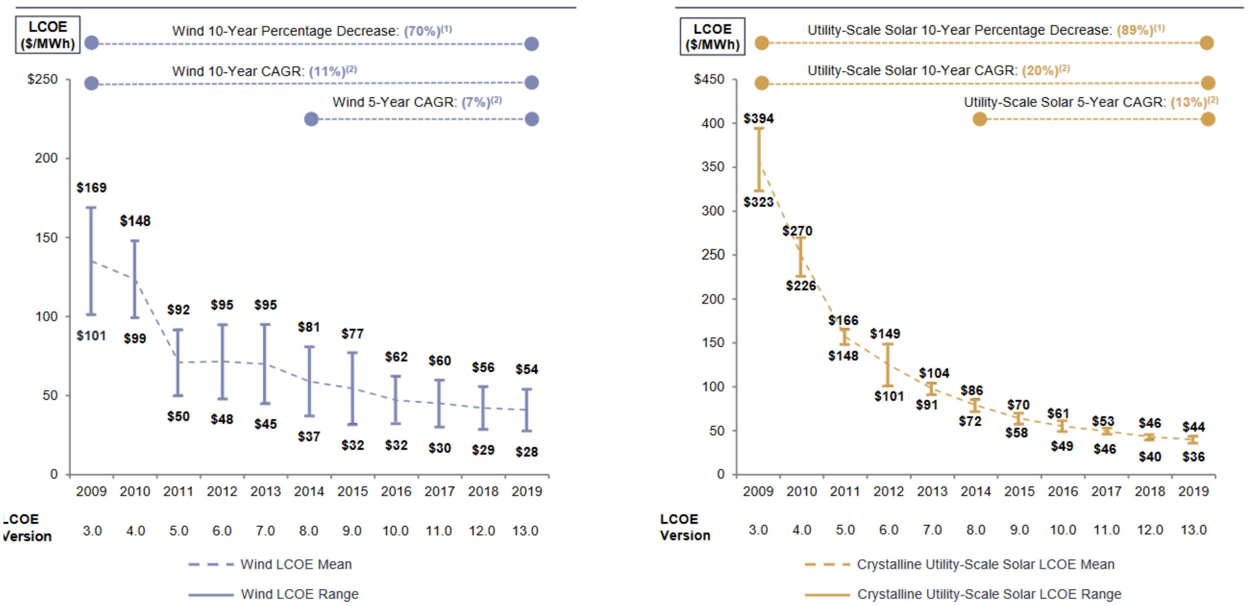
[32] Utility Dive. 2020. *Duke CEO decries 'assault' on natural gas as shareholders, others blast company's resource plans.* Available at: https://www.utilitydive.com/news/duke-ceo-decries-assault-on-natural-gas-as-shareholders-others-blast-com/577815/.

[33] The LCOE metric does not include any transmission and distribution costs associated with the addition of new resources. Those costs are often site-specific and should be considered on a case-by-case basis. Transmission and distribution costs are not resource-specific and may apply to new gas additions as well as to renewable resources.

[34] Lazard. 2019. *Levelized Cost of Energy Analysis—Version 13.0.* Available at: https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

the costs in 2009 with a 10-year compound annual rate of decline of 20 percent per year.[35,36] Since 2014, when the ACP was proposed, the mean wind cost has fallen by 30 percent, while the mean solar cost has dropped by 50 percent. These trends are shown in Figure 8.

Figure 8. Historical costs for unsubsidized wind (left) and solar (right) technologies



Source: Lazard. 2019. Levelized Cost of Energy Analysis—Version 13.0. Available at: https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

The U.S. National Renewable Energy Laboratory (NREL) conducts a renewables benchmark study that shows similar results: from 2010 to 2018, the LCOE of utility-scale solar photovoltaic (PV) declined 80–82 percent. [37] In addition, NREL's study indicates declines in both residential and commercial solar, with commercial solar costs falling by 72 percent and residential solar costs falling by 71 percent over the period. The primary drivers behind these cost declines are a drop in hardware costs, though there have also been declines in a labor and soft costs.[38]

For battery storage technologies, *Lazard's Levelized Cost of Storage—Version 4.0* states that there have been high cost declines for battery storage resources across most use cases and technologies, and that

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[35]Lazard. 2019. *Levelized Cost of Energy Analysis—Version 13.0.* Available at: https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

[36] These are unsubsidized cost declines, not accounting for the Investment Tax credits (ITC) and Production Tax credits (PTC).

[37] NREL. 2018. *US Solar Photovoltaic System Cost Benchmark: Q1 2018.* Available at: https://www.nrel.gov/docs/fy19osti/72399.pdf.

[38] NREL. 2018. *US Solar Photovoltaic System Cost Benchmark: Q1 2018.* Available at: https://www.nrel.gov/docs/fy19osti/72399.pdf.

"sustained cost declines have exceeded expectations for lithium-ion technologies," specifically.[39] Bloomberg New Energy Finance (BNEF) analyzed historical battery storage costs, finding that costs for lithium-ion batteries have fallen 76 percent between 2012 and the first half of 2019.[40] BNEF noted this was its most striking finding when looking at historical cost trends for both renewable and storage technologies.

These price declines for renewable and storage technologies have made paired projects viable and cost-effective replacement options for gas technologies. For example, Florida Power & Light is building the Manatee Energy Storage Center, which is a 409 MW storage system (the world's largest) that will replace two existing gas units. An existing solar plant will charge the battery, and the resulting savings to customers are expected to total $100 million.[41] Prices are expected to continue to decline in the coming years, and these declines will increase the competitiveness of renewable and storage resources with gas combustion turbines and combined cycle units. The Gemini Solar + Battery Storage Project in Nevada couples 690 MW of solar PV with 380 MW of battery storage and will go into service in 2023 at a levelized price of $25/MWh.[42]

Unlike new gas generation infrastructure, renewable and battery storage technologies can be procured incrementally to meet demand, meaning that a smaller number of MW of resources can be built or acquired on a more frequent basis. Gas additions tend to be larger and "lumpier," and the addition of large gas plants in a single year can result in oversupply situations in subsequent years. Large, lumpy additions may also result in stranded assets, discussed in Section 7.

5. Legislative and Executive Actions on Clean Energy Are Reducing Demand for New Gas Generation

Following the proposal for the ACP in 2014, actions at the state and corporate level have established targets for both increases in penetration of renewable energy generation and reductions in greenhouse gas emissions. More recently, there have been a number of states and utilities that have committed to "net-zero" GHG emissions targets, consistent with the recommendation from the United Nations that

[39] Lazard. 2018. *Levelized Cost of Storage Analysis—Version 4.0*. Available at: https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

[40] Utility Dive. 2019. *Electricity costs from battery storage down 76 percent since 2012: BNEF.* Available at: https://www.utilitydive.com/news/electricity-costs-from-battery-storage-down-76-since-2012-bnef/551337/.

[41] Parnell, John. 2019. *FPL to replace aging gas power plants with the world's largest battery.* Forbes. Available at: https://www.forbes.com/sites/johnparnell/2019/03/31/fpl-to-replace-aging-gas-power-plants-with-the-worlds-largest-battery/#640ab4812ebb.

[42] S&P Global. 2020. *Falling US solar-plus-storage prices start to level as batteries supersize*. Available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/falling-us-solar-plus-storage-prices-start-to-level-as-batteries-supersize-56971432.

emissions will need to reach net-zero by 2050 in order to avoid the worst of the impacts from climate change.[43] At the state level, North Carolina has committed to a net-zero emissions goal by 2050, as have Dominion and Duke at the corporate level. The Commonwealth of Virginia has an even more ambitious goal of zero emissions.[44] Those actions are described in more detail below.

5.1. Virginia

Dominion has already begun to prepare for a new energy future because of both state-level mandates and internal company commitments. Recent actions by Virginia's legislative and executive branches have called for increases in energy efficiency and renewable energy, as well as corresponding decreases in emissions of greenhouse gases in the power sector. Virginia's General Assembly enacted Senate Bill 966, the Grid Transformation and Security Act (GTSA) in March 2018. This legislation called for 5,000 MW of utility-operated solar and wind resources by 2028, an additional 500 MW of rooftop solar resources, and $870 million in proposed investment by Dominion Energy in energy efficiency programs.

In September 2019, Virginia Governor Ralph Northam signed Executive Order (EO) Number 43, which tasked the Department of Mines, Minerals and Energy, in consultation with other state agencies, to develop a plan that sources 30 percent of Virginia's electricity from renewables by 2030 and 100 percent from carbon-free sources by 2050. The Order notes that, in the past, Virginia's electric grid has consisted of conventional infrastructure and large, centralized power stations, but goes on to acknowledge that a more modern electric grid will incorporate increasing amounts of renewable energy technologies and distributed energy resources.[45]

The Virginia Clean Economy Act of 2020 (VCEA) codified the plans established by EO 43, increasing the level of renewables beyond those included in the GTSA. The VCEA stands on four key pillars: (1) mandatory retirement of Dominion and Appalachian Power's entire carbon-emitting generation fleet by 2045 (with interim targets for specific units) as well as an expanded cap and trade program that applies to all in-state power plants—regardless of owner or fuel type—that will eliminate carbon emissions by 2050; (2) a mandatory energy efficiency resource standard; (3) a six-fold increase in net metering; and (4) a mandatory renewable portfolio standard to spur investment in utility-scale solar, offshore wind, and energy storage. By 2050, Virginia's entire generation fleet will be carbon-free.

Dominion's 2020 IRP, filed on May 1, 2020, is the first plan put forth by the utility that complies with these new requirements. Prior to filing the IRP, Dominion requested relief from certain regulatory

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[43] Intergovernmental Panel on Climate Change. 2018. *Special Report: Global Warming of 1.5°C.* Available at: https://www.ipcc.ch/sr15/.

[44] A number of large utility customers in Duke and Dominion's service territories have net-zero emissions goals and/or are targeting 100 percent renewable energy by 2050 or earlier. These customers include Microsoft, Google, Amazon and Amazon Web Services, Salesforce, LinkedIn, Equinix, QTS Data Centers, and Adobe, among others.

[45] Commonwealth of Virginia, Office of the Governor. 2019. Executive Order Number 43. Available at: https://www.governor.virginia.gov/media/governorvirginiagov/executive-actions/EO-43-Expanding-Access-to-Clean-Energy-and-Growing-the-Clean-Energy-Jobs-of-the-Future.pdf.

requirements related to gas generation, noting that "significant build-out of natural gas generation facilities is not currently viable."[46] In contrast to the 2019 IRP, which called for 2,445 MW of new gas capacity by 2045,[47] Dominion's 2020 IRP includes 970 MW of new combustion turbines, but these are merely placeholders for some yet-to-be-determined resource to ensure adequate system reliability.[48] A comparison of the planned resource additions between the 2014 and 2020 IRPs is shown in Table 1.

Table 1. Comparison of Dominion's planned resource additions in the 2014 and 2020 IRPs

Resource	2014 IRP (MW Nameplate)	2020 IRP (MW Nameplate)
New combined cycle	1,566	
New combustion turbine	457	970
Solar	559	15,680
Onshore wind	247	
Offshore wind	12	5,112
Nuclear	1,453	
Battery storage		2,414

Additions of solar, offshore wind, and battery storage have increased dramatically since 2014. Planned gas additions increased after the 2014 IRP, with Dominion planning for as many as 3,664 MW of new gas in 2018. The current 970 MW of new "placeholder" gas additions thus represent the minimum amount of gas that has been planned by Dominion since at least 2014.

This reduction in the planned number of gas units also reflects Dominion's corporate goal, announced on February 11, 2020, of net-zero emissions by 2050.[49] This was an update to the company's prior carbon emission reduction goals of 55 percent by 2030 and 80 percent by 2050, relative to 2005 levels.[50]

5.2. North Carolina

In October 2018, North Carolina Governor Roy Cooper signed Executive Order No. 80, which declared the state's support for the 2015 Paris Agreement and set the goal to reduce statewide greenhouse gas

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[46] Virginia Electric and Power Company's Motion for Relief from Certain Requirements Contained in Prior Commission Orders and for Limited Waiver of Rule 150. March 24, 2020. Case No. PUR-2020-00035.

[47] Dominion. 2019. IRP. Page 4.

[48] Dominion. 2020. IRP. Page 5.

[49] Dominion Energy. 2020. *Dominion Energy Sets New Goal of Net Zero Emissions by 2050.* Available at: https://news.dominionenergy.com/2020-02-11-Dominion-Energy-Sets-New-Goal-of-Net-Zero-Emissions-by-2050.

[50] Dominion Energy. 2019. *Investor day ESG session.* Available at: https://s2.q4cdn.com/510812146/files/doc_presentations/2019/03/2019-03-25-DE-IR-investor-meeting-ESG-session_vF.pdf.

emissions to 40 percent below 2005 levels by 2025.[51] The North Carolina Department of Environmental Quality (DEQ) was also tasked with developing a Clean Energy Plan that utilizes clean energy resources and other innovative technologies.

The Clean Energy Plan was developed over a 10-month period with input from more than 160 stakeholder groups and was presented in 2019.[52] The Plan establishes the goal to reduce emissions from the electric sector by 70 percent below 2005 levels by 2030 and achieve carbon neutrality by 2050.[53] Electric sector modeling performed during the development of the Clean Energy Plan indicates that North Carolina cannot achieve its emissions reduction goal without transitioning away from fossil-fueled power plants in favor of cleaner energy sources.[54] Duke's planned gas capacity additions are described in the Clean Energy Plan, with DEQ noting that the "business as usual" approach will not allow the state to achieve its emissions reduction goal from the power sector unless the additional generation need is met by clean energy sources.[55] The North Carolina Utilities Commission, upon approving the DEC and DEP 2018 IRPs, required the utilities to model scenarios in which they achieve the goals set by Executive Order No. 80.[56] State regulators will be responsible for approving Duke's requests to add new gas capacity, and they will need to consider decarbonization goals, declining costs for renewable technologies, and changing market dynamics—all of which contribute to the risk of new gas capacity becoming a stranded asset. A discussion of stranded asset risk is presented in Section 7. Utility requests for new gas capacity will likely be scrutinized more carefully than in the past, given these new considerations, before being given approval by state regulators.

A comparison of Duke Energy's planned resources in the 2014 IRPs and 2019 IRP Updates is shown in Table 2. Planned solar has increased from 0 MW to 4,791; however, this is only one-third of the solar resource planned by Dominion, which has lower projected demand than Duke. Planned combined cycle additions are very similar, but there is an increase of more than 5,000 MW of planned combustion turbines. Notably, there are only 581 MW of planned battery storage in the 2019 IRP updates. As shown in Section 4, a combination of renewables plus battery storage would meet energy and capacity needs at a lower cost to consumers than would new combustion turbines.

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[51] State of North Carolina. 2018. Executive Order No. 80. Available at: https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf.

[52] North Carolina Department of Environmental Quality. 2019. *Clean Energy Plan*. Page 11. Available at: https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[53] North Carolina Department of Environmental Quality. 2019. *North Carolina Clean Energy Plan*. Page 12. Available at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[54] North Carolina Department of Environmental Quality. 2019. *North Carolina Clean Energy Plan*. Page 59. Available at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[55] North Carolina Department of Environmental Quality. 2019. *North Carolina Clean Energy Plan*. Page 25. Available at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[56] State of North Carolina Utilities Commission. 2019. *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans*. Docket No. E-100, SUB 157. Available at: https://cleanenergy.org/wp-content/uploads/NCUC-2018-IRP-Order-E-100-Sub-157.pdf.

Table 2. Comparison of Duke Energy's planned resources in the 2014 IRP and 2019 IRP Update

Resource	2014 IRP (MW Nameplate)	2019 IRP (MW Nameplate)
New combined cycle	4,441	4,583
New combustion turbine	2,190	7,520
Solar		4,791
Battery storage		581
Nuclear	2,373	71
CHP		15
Pumped storage		260

Duke Energy's 2020 IRPs are expected in September 2020, and the company has yet to do an IRP that accounts for the Clean Energy Plan goals. Duke's corporate carbon reduction goal is less stringent than the Clean Energy Plan in the near term. In 2017, Duke Energy announced its goal to reduce carbon emissions 40 percent below 2005 levels by 2030. In 2019, the company acknowledged the effect of declining costs for renewables and storage and accelerated its reduction goal to at least 50 percent by 2030, and net-zero by 2050.[57]

6. PROJECTED ELECTRIC SECTOR GAS DEMAND

To show that there is a need for the ACP, project developers would need to demonstrate that existing gas capacity in the region is insufficient to provide enough gas to meet the demand during the winter peak day.[58] In this section, we project the volume of additional natural gas Duke and Dominion might require on that winter peak day between 2020 and 2030. The methodology is different for the two utilities, given the goals of each state. This analysis assumes compliance with the renewable and CO_2 reduction targets of the states in which these utilities operate and with any company-wide emissions reductions goals.

6.1. Dominion

First, we developed an annual projection of resource capacity for each year from 2020 to 2030 to align with the Virginia Clean Economy Act (VCEA). To calculate the future natural gas demand for the electric sector in Dominion's VA service territory, we used the following assumptions:

[57] Duke Energy. 2019. *Duke Energy aims to achieve net-zero carbon emissions by 2050.* Press Release. Available at: https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.

[58] The maximum volume of gas demand from non-electric and electric end-uses occurs in the winter in the Southeast. Residential and commercial use of gas is primarily for space and water heating, peaking in the winter when temperatures are lower. In the electric sector, summer gas use has declined in the last several years while winter gas demand has increased. When we combined the non-electric and electric uses for gas, we find that the "ultimate system peak" occurs in the winter.

- Dominion builds new solar, wind, and storage capacity according to its Alternative Plan B from its 2020 IRP.[59] Within the IRP, Dominion commits to build 2,556 MW of offshore wind by 2030. Dominion does not make any commitment to building onshore wind in the study period. The utility commits to adding 10,700 MW of (utility-owned, power purchase agreements, and non-utility generators) by 2030, according to its Alternative Plan B.

- Dominion retires Possum Point 5 in 2021, Yorktown 3 and Chesterfield 5 and 6 in 2023, and Clover 1 and 2 in 2025, according to the Dominion's Alternative Plan B (which complies with the VCEA).

- Dominion retires Rosemary (oil) in 2027 and its three biomass units in 2028, according to the Dominion's Alternative Plan B (which complies with the VCEA).

- All hydro, gas, and nuclear units are held constant through the study period. However, according to Dominion's Alternative Plan B, the utility may need to build two 485 MW natural gas CT units in 2023 and 2024 (total of 970 MW) to meet reliability needs, although the IRP includes these units merely as placeholders to address a hypothetical, but currently incomplete, reliability concern.

According to Dominion's Alternative Plan B, the utility asserts that it may need to build two 485 MW natural gas CT units in 2023 and 2024 (total of 970 MW) to meet reliability needs. We do not assess the validity of this claim but assume for the sake of this analysis that it represents the maximum amount of new gas capacity that Dominion could add to its system between now and 2050. In reality, Dominion's IRP does not really propose new combustion turbine units (CTs); the IRP merely included the CTs "as a placeholder to address probable system reliability issues . . . ."[60] The model did not actually select these CTs; they were forced resources, and the modeling shows that within 10 years, these CTs operate at only 0.3 percent capacity factor.[61]

Generation on the winter peak day is informed by Dominion's reported "Energy Generation by Type for Plan B (GWh)" in its 2020 IRP.[62] We assume that no energy is generated for the purposes of filling storage on the winter peak day, and that coal and gas combined cycle units operate according to historical seasonal patterns. The 970 MW of new combustion turbines are assumed to dispatch last in the stack and operate at capacity factors up to 5 percent when necessary. If any energy shortfalls still exist after dispatching Dominion's generating units, we fill in the remaining gap with imports from PJM.[63]

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[59] See Page 28 of Dominion's 2020 IRP: https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2020-va-integrated-resource-plan.pdf?modified=20200501191108.

[60] Dominion. 2020. Integrated Resource Plan. Page 5.

[61] Dominion. 2020. Integrated Resource Plan. Appendix 5D.

[62] Dominion. 2020. Integrated Resource Plan. Appendix 5G.

[63] Total purchased power from PJM is taken from Appendix 5G of the 2020 IRP and distributed across the winter hours.

The Synapse analysis shows that the new gas units contribute a maximum of 49 MW in any given hour during the peak winter day. Between 2023 and 2030, the years with the highest usage of the new gas units during the peak winter day are 2024 through 2028, during which 0.014 Bcf of natural gas are consumed during the peak winter day. By 2030, the new gas demand on the peak winter day drops to 0.011 Bcf of natural gas per day. Furthermore, all gas generation in Dominion's service territory falls in the last three years of the analysis period.

The transport capacity of the ACP is 1.5 Bcf of gas per day. The maximum consumption of additional gas by Dominion represents approximately 0.9 percent of the total capacity of the pipeline, declining to 0.7 percent by 2030.[64] This minimal amount of additional gas demand on winter peak days in Dominion's service territory does not support the construction of a new gas pipeline.

6.2. Duke

Duke's most recent 2019 IRP Updates called for the addition of 9,000 MW of new gas capacity. Duke's plans to build new gas power plants, and its slow progress on clean energy investments, are not only untenable in light of state policies, they threaten the company's own corporate carbon-reduction goals. Indeed, the company's shareholders raised these concerns forcefully during the shareholder meeting in May 2020.[65] Duke has yet to present an IRP for DEC or DEP that complies with the targets in the North Carolina Clean Energy Plan and it is unclear how either utility's projected capacity build-out might change when incorporating those goals. Our spreadsheet model builds such a plan, applying the NC requirements to the units sited in that state, and Duke's corporate goals to the units sited in South Carolina.

Our analysis of Duke's potential future additional natural gas demand begins with the company's planned generation mix for 2030 (taken from its *2020 Climate Report*), in which the company states that all coal units in the Carolinas are retired by 2030.[66]

Next, we compare the estimated annual emissions of that future generation mix to the maximum allowable emissions for 2030, according to the North Carolina target (70 percent emissions reduction relative to 2005 levels by 2030) and Duke's company-wide goal to reach 50 percent emissions reduction (relative to 2005 levels) by 2030.

Assuming a linear decrease in emissions between 2018 and 2030, our analysis finds that Duke's emissions cannot exceed 22.3 million metric tonnes (MMT) of CO_2 in 2030 to meet both the North

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[64] The ACP offers firm transportation services for gas. Dominion's combustion turbines do not rely on firm transportation contracts. However, we assume for the sake of estimating a maximum potential for new gas in Virginia that the ACP could supply any new gas units built by Dominion.

[65] Utility Dive. 2020. *Duke CEO decries 'assault' on natural gas as shareholders, others blast company's resource plans.* Available at: https://www.utilitydive.com/news/duke-ceo-decries-assault-on-natural-gas-as-shareholders-others-blast-com/577815/.

[66] Duke Energy. 2020. Achieving a Net Zero Carbon Future. Available at: https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en.

Carolina and corporate targets. However, Duke's planned generation mix for 2030 yields 45.4 MMT of CO_2 emissions, vastly exceeding their emissions limit for that year. The generation mix projected in Duke's *2020 Climate Report* does not meet North Carolina's emission reduction goal.

Under a scenario in which Duke reduces its coal generation to zero in 2030 and utilizes as much gas as it can to meet emissions targets, the company can generate 33 percent of its total electricity requirement with gas and remain compliant. The maximum amount of generation from gas is approximately 54,400 GWh in 2030, of which 10,900 GWh comes from new gas resources.[67] Given Duke's projections for annual energy demand, the utility finds itself energy short during the 2020–2030 analysis period, and thus we assume that these new gas units will be combined cycle units. Assuming a 70 percent capacity factor for a combined cycle unit, the 10,900 GWh of additional gas generation in 2030 equates to 1,800 MW of new combined cycle capacity. This results in a daily gas demand of 0.14 Bcf per day, or approximately 9 percent of the capacity of the ACP.

Pipeline capacity inflow into North Carolina has increased by more than 2 Bcf/day since 2014, as shown in Table 3.

Table 3. Capacity into North Carolina, by pipeline (Bcf/day)

Pipeline	State	2014	2015	2016	2017	2018	2019
Columbia Gas Trans Corp	VA	0.04	0.04	0.04	0.04	0.04	0.04
East Tennessee Nat Gas Co	VA	0.57	0.57	0.57	0.57	0.57	0.57
Transcontinental Gas P L Co	VA	0.42	1.49	1.49	1.94	2.51	2.51
Transcontinental Gas P L Co	SC	4.01	4.01	4.01	4.01	4.01	4.01
Total		**5.03**	**6.10**	**6.10**	**6.55**	**7.13**	**7.13**

Source: US EIA. 2020. EIA-StatetoStateCapacity.xlsx. Available at: https://www.eia.gov/naturalgas/data.php#pipelines.

Additionally, Transco's Southeastern Expansion project will deliver an additional 0.3 Bcf/day to markets in the Mid-Atlantic and Southeast. The project began construction in August 2019 and is scheduled to enter service in November 2020.[68] The MVP Southgate project, if built and placed into service, will deliver 0.375 Bcf/day to new delivery points in central North Carolina with a target in-service date of 2021.[69] Duke has not demonstrated that it could not contract for firm capacity on any of these existing or potential pipelines to supply any potential incremental need for gas: the ACP, with its capacity of 1.5 Bcf/day, is therefore unnecessary.

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[67] We arrive at this value by subtracting existing gas generation in each year from total expected demand. We apply Duke's assumed annual demand growth factor of 0.46 percent to Duke's 2020 demand requirement of 155,790 GWh to calculate total demand in each year. Existing gas generation is calculated by applying historical annual capacity factors (70 percent for combined cycle, 4 percent for gas turbine, and 31 percent for steam turbine) to Duke's projected natural gas capacity. This includes conversions of coal units into co-fired units expected between 2020 and 2026.

[68] *Transcontinental Gas Pipeline Co., LLC*, 169 FERC ¶ 61,051, at ¶¶ 1, 7 (2019).

[69] Appl. of Mountain Valley Pipeline, LLC at 2, 9, Dkt. No. CP19-14 (Nov. 6, 2018) (eLibrary No. 20181106-5159).

7. NEW GAS INFRASTRUCTURE CARRIES STRANDED ASSET RISK

Many utilities across the country, including Duke and Dominion, have constructed new gas plants in order to replace retiring coal and take advantage of historically low gas prices, despite the flat electricity demand described in Section 2 and the declining renewable energy costs discussed in Section 4.[70] However, recent trends show that it can be cheaper today to build new renewable-plus-storage units than to build ***new*** gas units. Forecasts suggest that in the future, it will be cheaper to build new renewable-plus-storage units than to continue operating ***existing*** gas units.[71] Renewables-plus-storage already outcompete gas-fired combustion turbines for peaking capacity. For example, the Manatee Energy Storage Center, a 409 MW storage system (the world's largest) that will replace two existing gas units, is currently under construction by Florida Power and Light. The battery will be charged by an existing solar plant, and the utility projects that the resulting savings to customers will total $100 million.[72] Renewables-plus-storage are rapidly approaching the price point at which they will be able to outcompete gas combined cycle units. This means that new gas units, and some existing units, are likely to become stranded assets.

A stranded asset is one that no longer has value or produces income. It is important to consider stranded asset risk for new gas units because the costs to construct them are usually recovered by utilities from their customers over many decades. If conditions in the electric sector cause a new or existing gas unit to no longer be used and useful, either the company's customers or its shareholders will be burdened with the costs of a non-performing unit for the remainder of its depreciable life. Such conditions might include cost declines associated with renewables and storage, a declining cap on CO_2 emissions, or both.

According to an extensive, nationwide analysis by RMI completed in Fall 2019, the likelihood that a new gas combined cycle unit will become a stranded asset is increasing over time and will jump dramatically starting in 2029. As shown in Figure 9, by 2035, nearly all currently proposed gas capacity will have operating costs higher than new renewable and storage resources due to expected price declines in these technologies. "The clear implication is that utilities or investors that move ahead with proposed plants face significant financial risk; consumer savings and/or market competition will dictate that the

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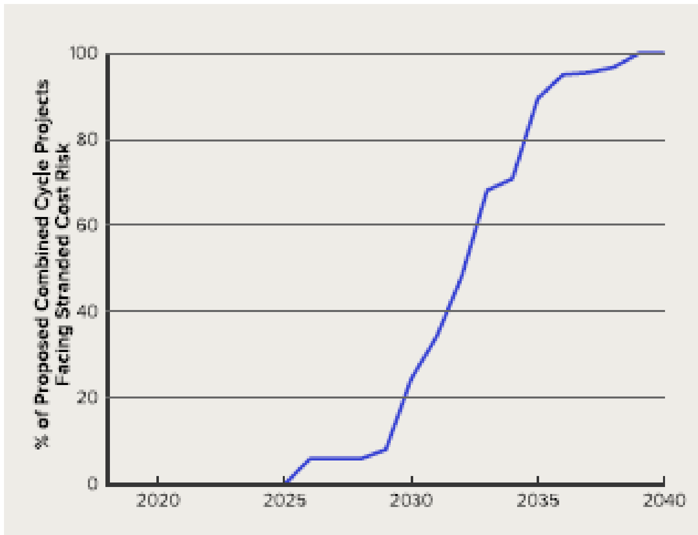
[70] S&P Global. 2019. *Overpowered: Why a US gas-building spree continues despite electricity glut.* Available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/overpowered-why-a-us-gas-building-spree-continues-despite-electricity-glut-54188928.

[71] Rocky Mountain Institute. 2019. *The Growing Market for Clean Energy Portfolios.*

[72] Parnell, J. 2019. "FPL to replace aging gas power plants with the world's largest battery." *Forbes*. Available at: https://www.forbes.com/sites/johnparnell/2019/03/31/fpl-to-replace-aging-gas-power-plants-with-the-worlds-largest-battery/#640ab4812ebb.

plants be shut down while book life remains. In short, combined-cycle investors face significant stranded asset risk."[73]

Figure 9. Percent of proposed combined-cycle units facing stranded asset risk, 2020–2040



Source: Rocky Mountain Institute. 2019. The Growing Market for Clean Energy Portfolios. Page 35.

By 2040, RMI's analysis shows that all the combined cycle gas units currently proposed in the United States will become stranded assets. These findings are in line with an analysis by BNEF. Authors of that study describe two tipping points relative to LCOE costs of different technologies. The first is when the cost of new wind and solar crosses the cost of new-build coal and gas, with the finding that "well situated and equipped wind farms and solar parks are already as cheap as, or cheaper than, fossil fuel alternatives, almost everywhere."[74] The second tipping point occurs when electricity from wind and solar become less expensive than operating existing coal or gas plants, which BNEF finds is likely to happen in the mid- to late-2020s.[75]

State regulators have already begun to cite stranded asset risk as one of the main reasons why they have rejected construction of new gas units and the purchase of existing gas units:

- In March 2018 the Arizona Corporation Commission rejected the IRPs of the state's utilities due to their reliance on gas units and the associated risk of stranded assets. The

[73] Exhibit RW-5. Rocky Mountain Institute. 2019. *The Growing Market for Clean Energy Portfolios.* Page 35.

[74] Bloomberg New Energy Finance. 2018. *Power System Will Dance to Tune of Wind, Solar, Batteries*. Available at: https://about.bnef.com/blog/henbest-power-system-will-dance-tune-wind-solar-batteries/.

[75] Bloomberg New Energy Finance. 2018. *Power System Will Dance to Tune of Wind, Solar, Batteries*. Available at: https://about.bnef.com/blog/henbest-power-system-will-dance-tune-wind-solar-batteries/.

Commission placed a nine-month moratorium on new gas units larger than 150 MW while the utilities modeled scenarios with high penetrations of renewables and storage.[76] That moratorium was then extended for an additional six months.[77]

- In April 2019 the Indiana Utility Regulatory Commission (IURC) rejected an 850 MW gas plant proposed by Vectren, citing concerns that the plant could become a stranded asset as cost of renewables declines and customer demand changes. The IURC directed Vectren to evaluate alternatives to a large, centralized generating station.[78]
- In October 2019 the Minnesota Public Utilities Commission rejected a proposal from Xcel Energy to purchase the 720 MW Mankato combined-cycle gas plant due to stranded asset concerns if the plant were to close early due to the decline in renewable and storage costs.[79]

New combined cycle units need large lead times to construct and there is no way for a utility to scale the asset down if expected demand does not materialize. The alternative to these plants is smaller, more modular resources that avoid the stranded asset risk presented by these new gas units. Electricity demand can be met incrementally with solar, battery storage, and energy efficiency in quantities that match near-term need and allow for customers to benefit from resource cost declines.

If new gas-fired resources pose a stranded asset risk, new pipeline capacity constructed to supply these generators are also subject to this risk. The maximum gas consumption from new gas resources in Dominion and Duke's service territories is less than 10 percent of the ACP's capacity in 2030. Emissions reduction requirements and targets in Virginia and North Carolina, respectively, will become more stringent through 2050, meaning that the utilities will use even less gas if they plan to comply. Given this low utilization, the ACP would be unneeded and obsolete the moment it went online, subjecting the utilities who have contracted for gas shipped on the pipeline to the risk that regulators may not allow them to recover the cost of those contracts.

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[76] Utility Dive. March 15, 2018. *Arizona regulators move to place gas plant moratorium on utilities.* Available at: https://www.utilitydive.com/news/arizona-regulators-move-to-place-gas-plant-moratorium-on-utilities/519176/.

[77] Utility Dive. February 11, 2019. *Arizona extends gas plant moratorium, punts on PURPA reforms.* Available at: https://www.utilitydive.com/news/arizona-extends-gas-plant-moratorium-punts-on-purpa-reforms/548072/.

[78] Utility Dive. April 25, 2019. *Indiana regulators reject Vectren gas plant over stranded asset concerns.* Available at: https://www.utilitydive.com/news/indiana-regulators-reject-vectren-gas-plant-over-stranded-asset-concerns/553456/.

[79] Utility Dive. October 1, 2019. *Minnesota rejects Xcel's 720 MW Mankato gas plant purchase over stranded asset concerns.* Available at: https://www.utilitydive.com/news/minnesota-rejects-xcels-720-mw-mankato-gas-plant-purchase-over-stranded-as/564029/.

8. CONCLUSIONS

Our analysis demonstrates that the need for new gas capacity anticipated by Duke and Dominion in the 2012 to 2014 planning period, when the Atlantic Coast Pipeline proposal was in the early stages of development, has not and will not materialize. By the same token, changes in the policy landscape, declines in projected demand growth, and continued declines in price for renewables and battery storage have been pronounced since 2017 when the final Environmental Impact Statement for the ACP was issued by FERC. Projections of demand by the companies have historically been overstated and actual demand has grown at a much lower rate than forecasted by the utilities. The impacts of the ongoing COVID-19 pandemic will lead to a further decrease in demand growth in Duke and Dominion's service territories, with effects that could be long-lasting, depending on the rate at which the U.S. economy recovers.

Recent policy measures and economic trends dictate that any need for new generating technologies in Virginia and North Carolina should be met with a combination of demand-side measures and renewable and storage technologies. Executive and legislative actions in both states call for reductions in the volume of CO_2 emissions coming from the power sector. Virginia's Clean Economy Act sets a target of zero emissions by 2050, while North Carolina's net-zero target would allow some level of emissions providing they were offset by reductions in other sectors. Pricing trends for wind, solar, and battery storage resources have declined dramatically over the last decade, to the point where these technologies currently outcompete new gas-fired combustion turbine units, and will soon be less expensive to build and operate than new combined cycle units.

New gas resources have long been a major part of Duke's and Dominion's future resource plans, but they no longer have a large role to play in the companies' portfolios. The utilities cannot rely on new gas generation to meet the emissions goals in their states and at the corporate level. Further, continuing to suggest that they can creates an undue burden on Duke and Dominion ratepayers. Any future gas units constructed in Virginia and North Carolina face sizable stranded asset risk, as does the Atlantic Coast Pipeline.

Appendix A. Methodology

Effects of COVID-19 in the Demand Forecast

Using total employment as a proxy for economic activity, Synapse predicted that the overall health of the economic system would be positively correlated with total energy demand. As COVID-19 slows down the economy, we would expect a reduction in electric demand. Using simple linear models, we found the relationship between total generation and total employment by state for Virginia, South Carolina, and North Carolina between 1990 and 2018.[80] Our models confirmed our prediction, showing a positive link between employment and total generation in each state. Table 4 shows the statistically significant results of the regressions.

Table 4. Generation as a function of employment regression results

	Significance	R Square	Intercept	Employment Coefficient
North Carolina	$3.46*10^{\wedge-10}$	.77	-3,922,084	30.28
South Carolina	$4.31*10^{\wedge-6}$	.55	1,919,373	46.79
Virginia	$1.25*10^{\wedge-7}$	.6508	-16,113,815	24.31

Unemployment has spiked dramatically over the past few months, with likely lasting effects over the coming years. While there is uncertainty around the timing and severity of unemployment going forward, it is highly likely it will remain high in the near to long term. To address this uncertainty, we created four different employment schedules based on the unemployment percentage of total labor force. To do this we first extrapolated the total labor force by state, using the historical average growth rate looking back to 1976. We then came up with four unemployment scenarios based on the unemployment percentage of labor force under varying degrees of severity. Both the total amount of unemployment and the rate at which employment grows is varied. Each scenario assumed a high unemployment rate of 14.7 percent in April according to the national average from the Bureau of Labor Statistics (BLS). In all scenarios this rate decreases over time at varying rates. While the national unemployment rate may not match state unemployment rates, we have decided to make this assumption for simplicity. We have also assumed that unemployment has already reached its high.

- **Scenario 1:** Unemployment decrease to 9.5 percent by the end of 2021 followed by a decrease consistent with historical rates of employment gain between January 2010-February 2020.
- **Scenario 2:** Constant unemployment of 14.7 through the end of 2020, followed by an increase in employment described above.

[80] Total generation from EIA Net Generation by State, https://www.eia.gov/electricity/data/state/. Employment data from the U.S. Bureau of Labor Statistics, Local Area Unemployment Statistics, https://data.bls.gov/PDQWeb/la.

- **Scenario 3:** Used Great Recession of 2008 as a model. Found the number of months between record high unemployment to the return to low unemployment recorded just before the high. The difference between current record high (14.7 percent) and the lows recorded just before the high was distributed across the number of months it took to recover in 2008. Historical recovery ranged from 69–102 months across our three states.
- **Scenario 4:** Three phase recovery starting with a 1 percent decrease in unemployment through August 2020 followed by a decrease of .4 percent through April 2021. Post April 2021 employment increases at the historical rate.
- **Baseline**: Carried pre-COVID low unemployment rate forward.

From each scenario, we used employment estimates in our regression equations to calculate a forecasted generation. Each scenario shows a dramatic drop in April to our assumed high unemployment rate of 14.7 percent, followed by varying degrees and timing of recovery (Figure 7). If we assumed employment remained constant at pre-COVID levels, our adjustments show a range of demand decreases between 7 and 10 percent in aggregate between the Carolinas and Virginia in 2020. By 2024 our forecasts range from 0–6 percent below our baseline assumption. While the most dramatic demand reduction coincides with current unemployment spikes, even under the most positive assumption, recovery will take many years.

Forecasting Electric Sector Gas Demand

Synapse estimated generation on the winter peak day in Dominion's service territory from 2020 through 2030 using a spreadsheet model and applying the following assumptions to our annual capacity projections described in Section 6:

- We apply hourly winter capacity factors for solar and wind resources in Dominion's service territory to our annual solar and wind capacity projections. The hourly capacity factors are derived from the Horizons Energy National Database.

- We apply annual capacity factors for nuclear (92 percent), hydroelectric (35 percent), and oil (2 percent) resources to our annual capacity projections for each resource type.

- For coal resources, we apply the January 2020 average hourly capacity factor of Dominion's coal units to our calculated projected capacity for each resource type. The average hourly capacity factor was calculated using data from the U.S. Energy Information Administration's Form EIA-923.[81]

- For existing gas resources, we apply the January 2020 average hourly generation (taken from the U.S. Energy Information Administration's Form EIA-923) to the entire study period, as none of the units are expected to retire.

In our winter peak day analysis, we identified an energy shortfall during all hours of the winter peak day through 2023. Once excess generation begins in 2024, we spread all excess generation into later hours,

[81] U.S. Energy Information Administration. Form EIA-923, Available at: https://www.eia.gov/electricity/data/eia923/.

assuming the energy is stored using a battery technology with a round-trip efficiency of about 85 percent.[82] Next, we identify which hours of the peak day from 2020–2030 will require additional generation from the new gas units proposed by Dominion in its Alternative Plan B. If any energy shortfalls still exist after applying the generation from the two gas CT units (assuming a capacity factor of 20 percent), we fill in the remaining gap with imports from PJM.

Our analysis shows that the new gas units can lead to a maximum generation of 194 MW in any given hour, which equates to 2,253 mcf of gas per hour. The gas units are run during about 61 percent of the hours in the peak day of the time period from 2023–2030. The highest usage of the new gas units during the peak winter day takes place in 2024, during which 49,558 mcf of natural gas are consumed per day. In years following 2026, renewables begin to remove the need for the additional gas units.

Our analysis of Duke's potential future additional natural gas demand begins with the company's planned generation mix for 2030 (taken from its 2020 Climate Report). Duke's planned company-wide generation mix for 2030 is 42 percent gas, 11 percent coal, and 47 percent non-emitting resources.[83]

Next, we compare the estimated annual emissions of that future generation mix to the maximum allowable emissions for 2030, according to the North Carolina legislation (70 percent emissions reduction relative to 2005 levels by 2030) and Duke's company-wide goal to reach 50 percent emissions reduction (relative to 2005 levels) by 2030. Below are the key assumptions from our emissions reduction analysis:

- To calculate 2005 emissions for both Duke Energy Progress and Duke Energy Carolinas, we multiplied their 2005 fossil generation (taken from the U.S. Energy Information Administration's Form EIA-923) by their units' respective emissions factors (taken from the EIA).[84] For combined cycle gas units, we use a generation-weighted emissions factor for the two turbine types.
- The 2005 emissions were separated by state (North Carolina and South Carolina) to apply different emissions reduction targets. For North Carolina we apply the state mandate; for South Carolina we apply the Duke Energy company goal.
- We assume a linear decrease in emissions between 2018 and 2030.

[82] U.S. Department of Energy and Hydrowires. July 2019. Energy Storage Technology and Cost Characterization Report. See Table ES.1 of: https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf.

[83] Duke Energy. 2020. Achieving a Net Zero Carbon Future. Available at: https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en.

[84] U.S. EIA. Available at: https://www.eia.gov/tools/faqs/faq.php?id=73&t=11.