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The Vanishing Need for the Atlantic Coast Pipeline

Growing Risk That the Pipeline Will Not Be Able to Recover Costs From Ratepayers

Executive Summary

The Atlantic Coast Pipeline (ACP) is a 600-mile, 42-inch natural gas pipeline currently under construction to bring natural gas from northern West Virginia to Virginia and North Carolina. The project is being built by a joint venture of Dominion (48%), Duke Energy (47%), and Southern Company (5%). Its construction was approved by the Federal Energy Regulatory Commission in October 2017.

The project was originally projected to cost $5.1 billion.[1] Cost overruns to date have raised the cost of the project by about 30% to $6.5 to $7 billion, excluding financing costs[2]. But cost overruns are not the only challenge faced by the project.

The biggest threat to the project's profitability may come if and when the project is ever completed. The demand outlook for gas has changed dramatically since the project's inception and much of the project's original justification has evaporated. Indications are that the project's affiliated utility customers may struggle to convince state regulators to pass the full cost of pipeline transportation agreements through to utility customers. Indeed, the project does not represent good value to the ratepayer.

This briefing discusses the considerable headwinds faced by the Atlantic Coast Pipeline. Key findings include:

- Six companies, all of whom are regulated utility affiliates of the pipeline's sponsors, have contracted for 96% of the pipeline's capacity.
- Atlantic Coast Pipeline, LLC will recover the costs of the pipeline through rates charged to the pipeline's customers. Given that the vast majority are

[1] Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, p. 2.
[2] S. Layag, Dominion raises Atlantic Coast-related cost estimate by $500M, citing snags," S&P Global Market Intelligence, November 1, 2018.

regulated utilities, these costs will have to be approved by state utility regulators in Virginia and North Carolina.

- Electric utility subsidiaries of Duke and Dominion in Virginia and North Carolina have contracted for 68% of the pipeline's capacity. Yet, the argument by these utilities that they need new natural gas pipeline capacity has been significantly weakened since the ACP was first proposed.

- In its most recent long-term Integrated Resource Plan (IRP), four out of five of Dominion's modelled scenarios show no increase in natural gas consumption from 2019 through 2033.

- Dominion's 2018 IRP was rejected by Virginia state regulators, in part for overstating projections of future electricity demand. This implies that future natural gas consumption will likely be even less than forecasted in the IRP.

- The most recent IRPs of Duke Energy Progress and Duke Energy Carolinas show that previously planned natural gas plants have been delayed further into the future. We also find that Duke also has a history of overstating its forecast of electricity demand.

- Over the next decade, it is likely that the demand for natural gas in Virginia and North Carolina will be further eroded as renewable energy and storage technologies continue to rapidly decline in price.

We recommend several questions investors could be asking management in order to obtain a clearer view of the project's value.

The Atlantic Coast Pipeline Proposes to Recover Costs From Ratepayers of Affiliate Companies

The pipeline is owned by Dominion (48%), Duke Energy (47%), and Southern Company (5%), which together formed Atlantic Coast Pipeline LLC (ACP-LLC). These project owners intend for the upfront capital cost of building the project, currently estimated at $6.5 to $7 billion, to be recovered through transportation rates from the companies that contract with ACP-LLC to ship natural gas on the pipeline. Ninety-six percent of the capacity on the pipeline was contracted when the pipeline was first proposed to FERC. Following Dominion's acquisition of SCANA, all of these transportation contracts are with regulated utility companies affiliated with the three ACP-LLC partners, as shown in Table 1.

Table 1: Six Companies, All of Whom Are Regulated Utility Affiliates of the Pipeline's Sponsors, Have Contracted for 96% of the Pipeline's Capacity

Natural Gas Shipper Company	Parent Company of Shipper	Amount of Capacity Contracted (Dth/day)	Percent of Total Pipeline Capacity
Virginia Power Services, Inc.	Dominion	300,000	20%
Duke Energy Progress, Inc.	Duke Energy	452,750	30%
Duke Energy Carolinas, LLC	Duke Energy	272,250	18%
Piedmont Natural Gas Company, Inc.	Duke Energy	160,000	11%
Public Service Company of North Carolina, Inc.	Dominion	100,000	7%
Virginia Natural Gas, Inc.	Southern Company	155,000	10%

These companies are regulated utilities in Virginia and North Carolina, which means that their rates must be approved by the Virginia State Corporation Commission and North Carolina Utilities Commission, respectively. Costs that are not approved cannot be recovered through customer rates. In the case of the Atlantic Coast Pipeline, the utilities would seek to recover the cost of the pipeline once these utilities start shipping gas on the pipeline.

In its order approving the Atlantic Coast Pipeline, the Federal Energy Regulatory Commission specifically declined to comment on whether the contracts (known as precedent agreements) that regulated utilities had entered into with affiliates to ship gas on the pipeline were prudent, noting that "state utility regulators must approve any expenditures by state regulated utilities… [A]ny attempt by the Commission to look behind the precedent agreements in this proceeding might infringe upon the role of state regulators in determining the prudency of expenditures by the utilities that they regulate... Should they elect to construct the projects before affirmative action by the state regulators, the applicants will be at risk of not being able to recover some, or any, of their costs."[3,4]

We review recent forecasts for electricity generation and natural gas consumption by Duke and Dominion's electric utilities (Virginia Power, Duke Energy Progress and Duke Energy Carolinas), which together have reserved 68% of the Atlantic Coast Pipeline's capacity.[5] We find that the argument by these utilities that they need new natural gas pipeline capacity has been significantly weakened in the last couple of years, with implications for the likelihood of recovering pipeline costs from ratepayers.

Updated Company Forecasts Show Reduced Demand for Natural Gas Over Previous Projections

The Atlantic Coast pipeline was predicated on rapidly growing natural gas demand in Virginia and North Carolina. In its original application to the Federal Energy Regulatory Commission, the pipeline joint venture cited an ICF International study forecasting that "demand for natural gas for power generation in Virginia and North Carolina is expected to grow 6.3 percent annually between 2014 and 2035."[6] The specific volumes of natural gas to be delivered to various end user utilities is reflected in Table 1, above.

In just the past few years, the case for the Atlantic Coast pipeline has become much weaker, in terms of the outlook for natural gas power generation in Virginia and

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[3] Federal Energy Regulatory Commission, Docket No. CP15-554, "Order Issuing Certificates," October 13, 2017, 60. We also note that, although the North Carolina Utilities Commission approved Duke Energy Carolinas and Duke Energy Piedmont's decision to enter into precedent agreements to ship gas on the Atlantic Coast Pipeline, the Commission's order "for ratemaking purposes … do[es] not constitute approval of the amount of compensation paid pursuant to the Agreements." (North Carolina Utilities Commission, Docket No. E-2 Sub 1052, "Order accepting affiliate agreements, allowing payment thereunder and granting limited waiver of code of conduct," October 29, 2014.)

[4] In a dissenting opinion, Commissioner LaFleur noted, "it is appropriate for the Commission to consider as a policy matter whether evidence other than precedent agreements should play a larger role in our evaluation regarding the economic need for a proposed pipeline project. I believe that evidence of the specific end use of the delivered gas within the context of regional needs is relevant evidence that should be considered as part of our overall needs determination." (Federal Energy Regulatory Commission, Docket No. CP15-554, Dissenting Opinion of Commissioner LaFleur, October 13, 2017, page 4.

[5] In addition to these three electric utilities, Piedmont Natural Gas announced that approximately half of its contracted natural gas capacity would be used for resale to electric utilities within its service territory, which includes Dominion, Duke and several electric cooperatives. (See: Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, p. 7; and Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, p. 1-12).

[6] Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, p. 1-6.

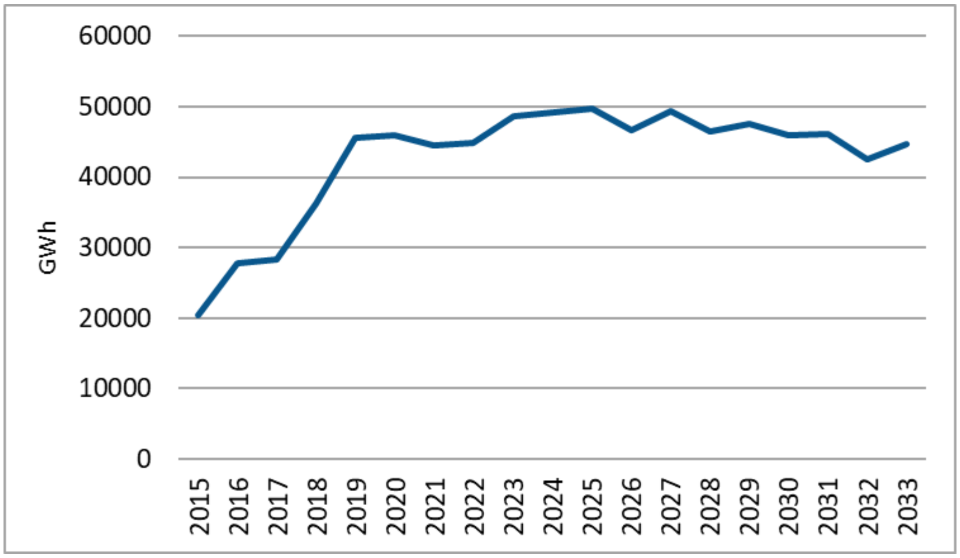
North Carolina. In this section, we look specifically at Duke Energy Carolinas, Duke Energy Progress, and Dominion Virginia Power, which together contracted for 68% of the gas to be shipped on the Atlantic Coast Pipeline.

Dominion's Most Recent Integrated Resource Plan Shows 2033 Natural Gas Consumption Maintained at 2019 Levels

In the case of Dominion Virginia Power, the need for new natural gas has completely evaporated. Virginia Power has recently constructed a new natural gas combined cycle plant at Brunswick and another at Greensville. According to documents filed with the State Corporation Commission, Brunswick and Greensville are receiving natural gas from the Transco pipeline.[7] After the Greensville natural gas plant enters service in 2019, Virginia Power's natural gas consumption is likely to remain flat to slightly declining over the next 15 years, according to Virginia Power's most recent long-term Integrated Resource Plan. At the same time, the plan notes the increasing competitiveness of renewable energy and shows significant growth in renewable energy generation over the next fifteen years. In the plan, Dominion lays out what it considers to be five plausible future scenarios for meeting future electricity demand through 2033. The plan provides annual natural gas consumption figures for only one of its five scenarios, shown in Figure 1. In that scenario, natural gas consumption in 2033 is actually lower than in 2019. Based on the information provided for the other four scenarios, we estimate that only one of those four scenarios shows a significant (16%) increase in natural gas consumption by 2033 relative to 2019. In other words, **in four out of its five plausible future scenarios, Dominion's 2018 Integrated Resource Plan models natural gas consumption in 2033 as equal to or slightly lower than 2019 natural gas consumption**.

[7] Dominion represented to the Virginia State Corporation Commission that the Brunswick plant would have a contract for firm natural gas supply from Transcontinental Gas Pipe Line Company ("Transco"), which was to construct nearly 100 miles of new pipeline to the plant. (State Corporation Commission of Virginia, Case No. PUE-2012-00128, "Application of Virginia Electric and Power Company for approval and certification of the proposed Brunswick County Power Station electric generation and related transmission facilities under §§56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider BW, under § 56-585.1 A 6 of the Code of Virginia," November 2, 2012.). Similarly, Dominion represented that the Greensville Plant "will be fueled using 250,000 Dth per day of natural gas with reliable firm transportation provided by Transcontinental Gas Pipe Line Company, LLC" though it also noted that Greensville "will also have access to" the Atlantic Coast pipeline. (State Corporation Commission of Virginia, Case No. PUE-2015-00075, "Application of Virginia Electric and Power Company for approval and certification of the proposed Greensville County Power Station and related transmission facilities pursuant to §§56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider GV, pursuant to § 56-585.1 A 6 of the Code of Virginia," July 1, 2015.) While there may be some reliability benefit to Dominion to having multiple pipelines serving the same plants, as suggested by FERC's final order approving the ACP (at p. 27-28), no economic evaluation of the cost-benefit trade-off of this alleged reliability improvement has ever been provided.

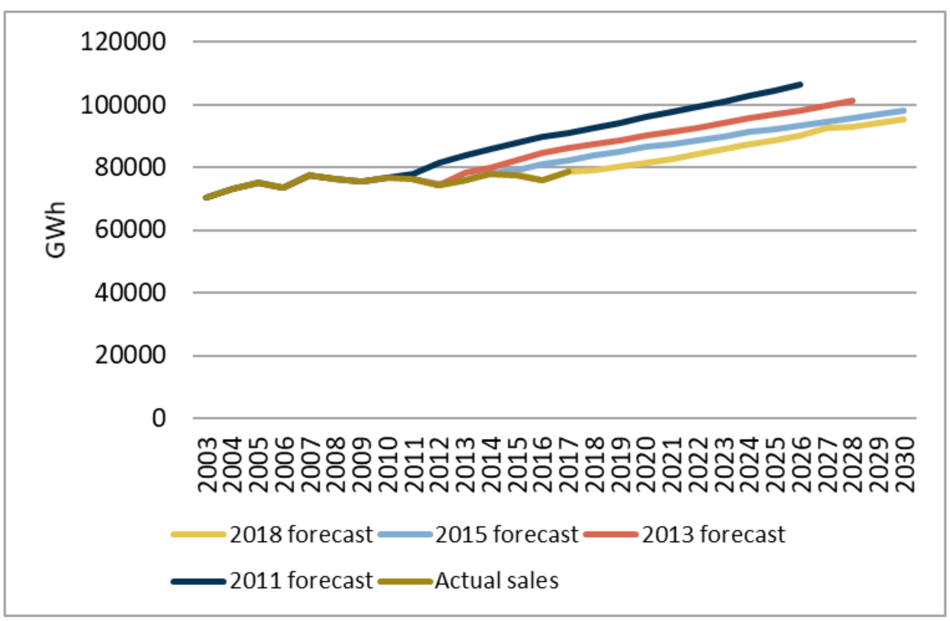
Figure 1: Dominion Virginia Power's Actual and Forecasted Power Generation From Natural Gas, 2015 Through 2033



Source: Dominion Virginia Electric and Power Company's 2018 Integrated Resource Plan, Appendix 3G.

Dominion's need for natural gas in 2033 will be even lower if Dominion's forecasted growth in electricity sales does not materialize, as appears likely. As shown by Figure 2, Dominion has consistently predicted growing electricity demand, while actual electricity demand has remained essentially flat since 2007.

Figure 2: Dominion Virginia Power's Actual and Forecasted Electricity Sales Show a Consistent Pattern of Overstating Forecasts

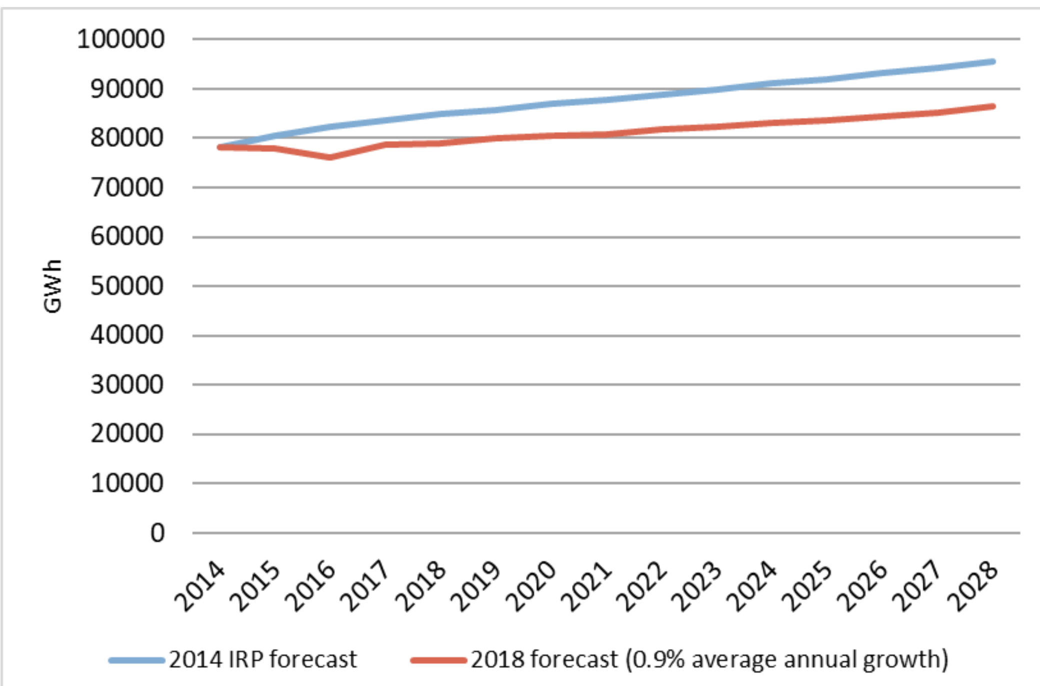


Source: Dominion Virginia Electric and Power Company's 2011, 2013, 2015 and 2018 Integrated Resource Plans.

For the first time ever, the Virginia State Corporation Commission rejected Dominion's Integrated Resource Plan in 2018. Among other issues, the Commission noted its "considerable doubt regarding the accuracy and reasonableness of the Company's load forecast." The Commission cited the inaccuracy of Dominion's forecasts in the recent past, as well as the fact that PJM – the regional transmission organization – forecasts load growth for Dominion's region of only 0.9% per year, compared to Dominion's forecast growth of 1.4% per year.[8]

Figure 3 compares Dominion's load forecast from 2014 (the year in which the Atlantic Coast Pipeline was first proposed) with a forecast based on PJM's assumption of 0.9% per year load growth. By 2028, the last year of the 2014 forecast, the difference between the forecast equates to 6550 GWh. For comparison, this is about 60% of the expected generation of the Greensville power plant currently under construction.

Figure 3: Revised Forecast of Dominion's Load Growth (Based on PJM Assumptions) Is Significantly Lower Than Dominion's Forecast When ACP Was First Proposed



Source: Dominion Virginia Electric and Power Company's 2014 Integrated Resource Plan, and IEEFA calculation based on PJM Load Forecast Report (January 2018).

Thus, assumptions about load growth have significant implications on the demand for new energy resources. It is likely that Dominion's rejected 2018 Integrated Resource Plan continues to overstate future electricity demand. Yet, even so, the majority of the scenarios in Dominion's IRP do not indicate any significant growth in

[8] Virginia State Corporation Commission, Order, Case No. PUR-2018-00065, December 7, 2018, p. 6-7.

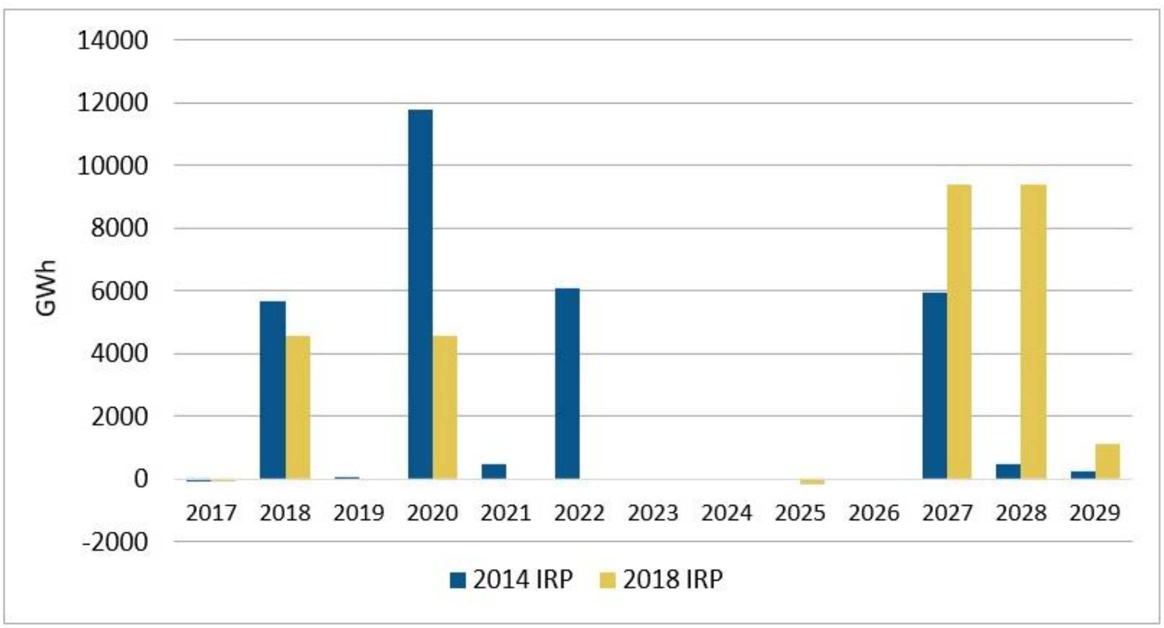
natural gas power generation after the construction of the Greensville gas plant, which is served with gas from the Transco pipeline.

Duke's Lower Forecasts for Electricity Demand Have Resulted in Significant Delays in New Natural Gas Plant Construction

The case for Duke Energy's demand for natural gas from the Atlantic Coast pipeline has also weakened substantially since the project was proposed in 2014.

Duke's most recent Integrated Resource Plans show that the demand for new natural gas power plants has been significantly delayed.[9] Figure 4 shows the proposed net additions and retirements of new natural gas plants in Duke's 2014 Integrated Resource Plan (the year that the Atlantic Coast Pipeline was announced) versus its most recent 2018 Integrated Resource Plan.[10] Major natural gas capacity additions that were initially projected to occur in 2020-2022 are now projected for 2027-2028.

Figure 4: Projected Natural Gas Generation Additions (Net of Retirements) for Duke Energy Progress and Duke Energy Carolinas in 2014 and 2018 Forecasts



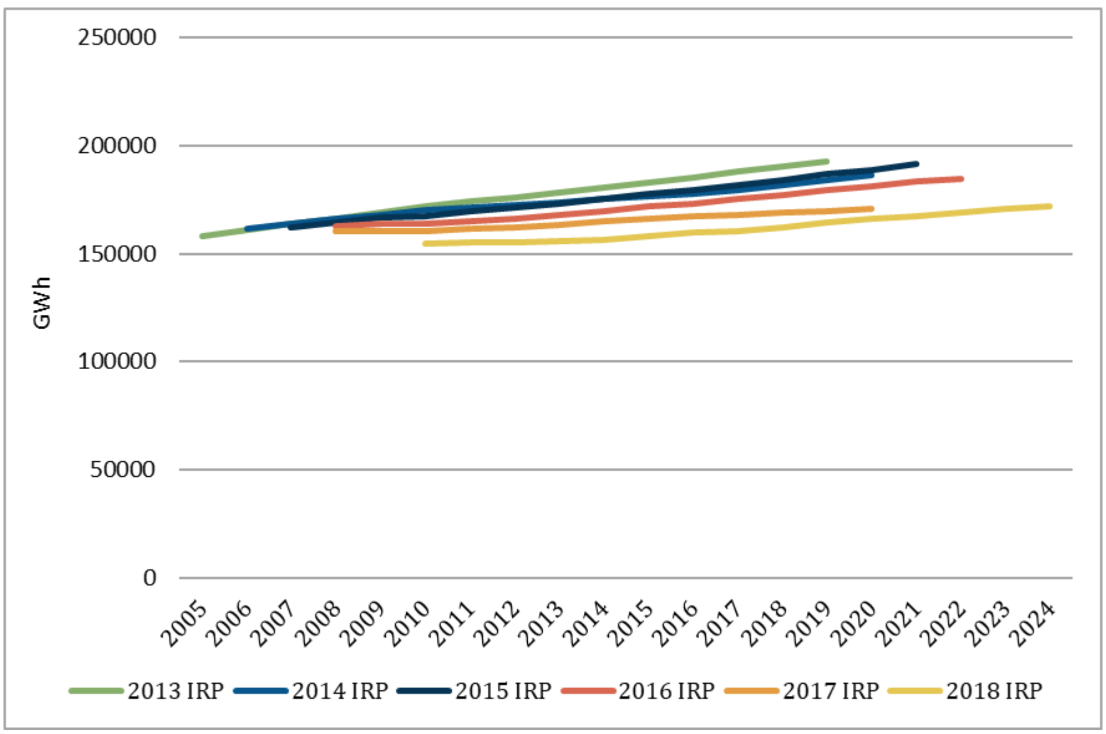
Source: Duke Energy Progress and Duke Energy Carolinas 2014 Integrated Resource Plans and 2018 Integrated Resource Plans.

[9] Unlike Dominion, Duke's Integrated Resource Plans do not provide an annual forecast of natural gas power generation.
[10] Figure 4 assumes an 80% capacity factor for natural gas combined cycle power plants and a 7% capacity factor for natural gas combustion turbines.

The delay in the buildout of these projects appears to be driven by Duke's downward revision of its load forecast, as shown in Figure 5. Like Dominion, Duke had forecasted growing electricity sales in 2014, whereas actual sales have been relatively flat. The difference in Duke's 2014 and 2018 load forecasts amounts to 20,356 GWh by 2029. As can be seen from Figure 4, this is more than the total amount of electricity that would have been generated from the new natural gas plants that Duke originally intended to construct in 2020 and 2022. This amount of electricity, if entirely generated from natural gas, equates to 54% of the natural gas capacity that Duke has reserved on the Atlantic Coast Pipeline.[11]

Duke's 2018 load forecast projects electricity demand growing at 0.7% per year through 2033. As shown from Figure 5, Duke's sales have been relatively flat for the last five years. Indeed, Duke's most recent 2018 sales forecast starts from a lower level than its 2013 sales forecast.

Figure 5: Load Growth for Duke Energy Progress and Duke Energy Carolinas Has Failed to Materialize as Projected



Source: Duke Energy Progress and Duke Energy Carolinas 2013, 2014, 2015, 2016, 2017 and 2018 Integrated Resource Plans.

[11] This calculation assumes a heat rate of 7000 BTU/kWh for natural gas power plants.

While Duke still plans significant new natural gas capacity additions in the late 2020s, the further into the future these projects are pushed the more speculative they become. In particular, Duke's history of overstating its load forecast should raise concerns for investors that these plants will not materialize at the scale currently projected.

The Outlook for New Natural Gas Combined Cycle Capacity Is Challenging

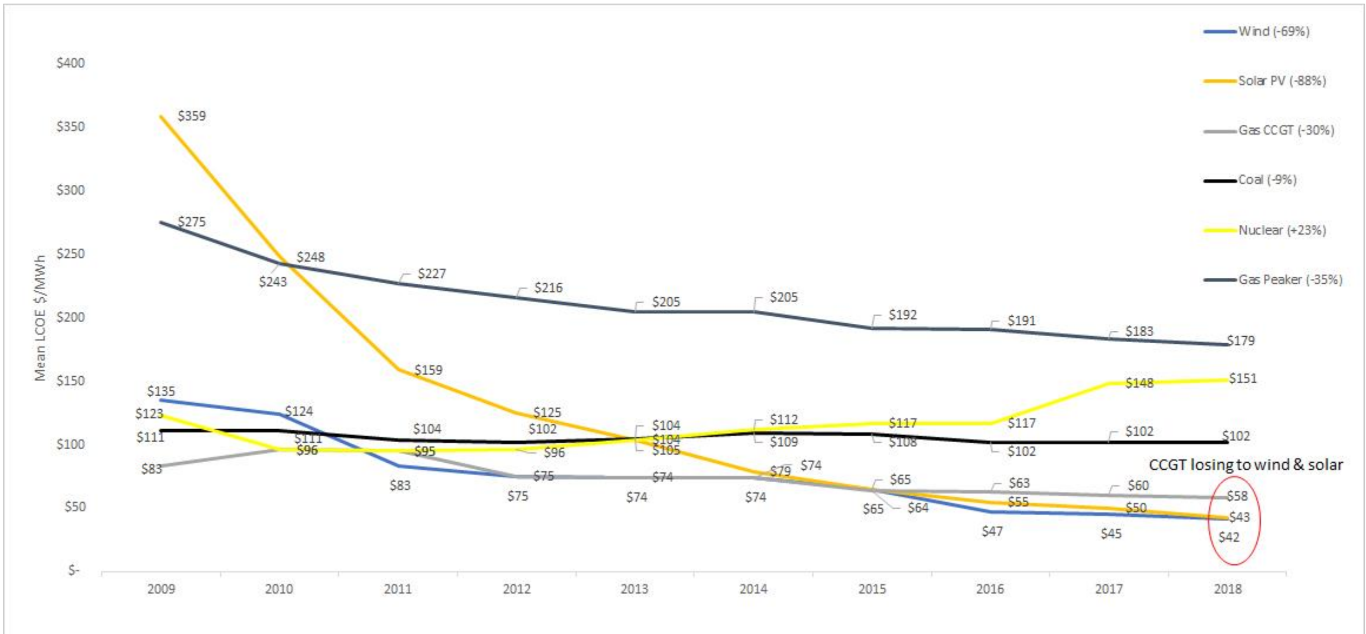
Duke's expectation that it will build new natural gas combined cycle (CCGT) capacity in the late 2020s appears to ignore the decreasing competitiveness of this form of generation amid the remarkable cost reductions and technological advances of renewable energy. Recent analyses of the Levelized Cost of Electricity (LCOE) for a range of generation technologies shows utility-scale wind and solar already competitive with CCGT in many markets. In November 2018, Bloomberg New Energy Finance declared that, "(s)*olar and/or onshore wind are now the cheapest source of new bulk power in all major economies except Japan*."[12]

The combination of battery storage with wind and/or solar plants is already competitive in some markets with traditional dispatchable power sources such as CCGT. The fact that rapidly evolving technology is triggering frequent changes in the outlook for power generation should increase caution around a multi-billion gas pipeline with no clear short- or medium-term market justification. Assuming that something will come along in the long-term is not a strategy for such a substantial investment.

Figure 6 shows the Lazard analysis of mean unsubsidized LCOE values since 2009. Wind and solar have been competitive with CCGT since 2015 and further cost declines have placed their mean cost below CCGT for the past two years despite decreases in CCGT costs.

[12] Tifenn Brandily, '2H 2018 LCOE, Update, Global Levelized cost of generation, capacity and flexibility', Bloomberg New Energy Finance, November 19, 2018 at p.5

Figure 6: Global Mean Unsubsidized Levelized Costs of Energy Show Natural Gas Combined Cycle Plants Losing to Wind and Solar



Source: Lazard's Levelized Cost of Energy Analysis, Version 12.0, 2018.

The Lazard chart shows a global mean. In Figure 7 below, LCOE analysis for the United States provided by Bloomberg New Energy Finance (BNEF) is shown. BNEF groups generation technologies into three categories: Bulk, Dispatchable and Flexible. This recognizes the differing functions of available generation technologies. While CCGT is dispatchable, it is not flexible as it takes a long time to ramp up to full capacity. These comparisons show that today, wind and solar are the cheapest form of bulk generation and can already compete with CCGT for dispatchable generation when combined with onsite storage. Standalone battery storage can compete in some cases with gas-fired flexible generation.[13]

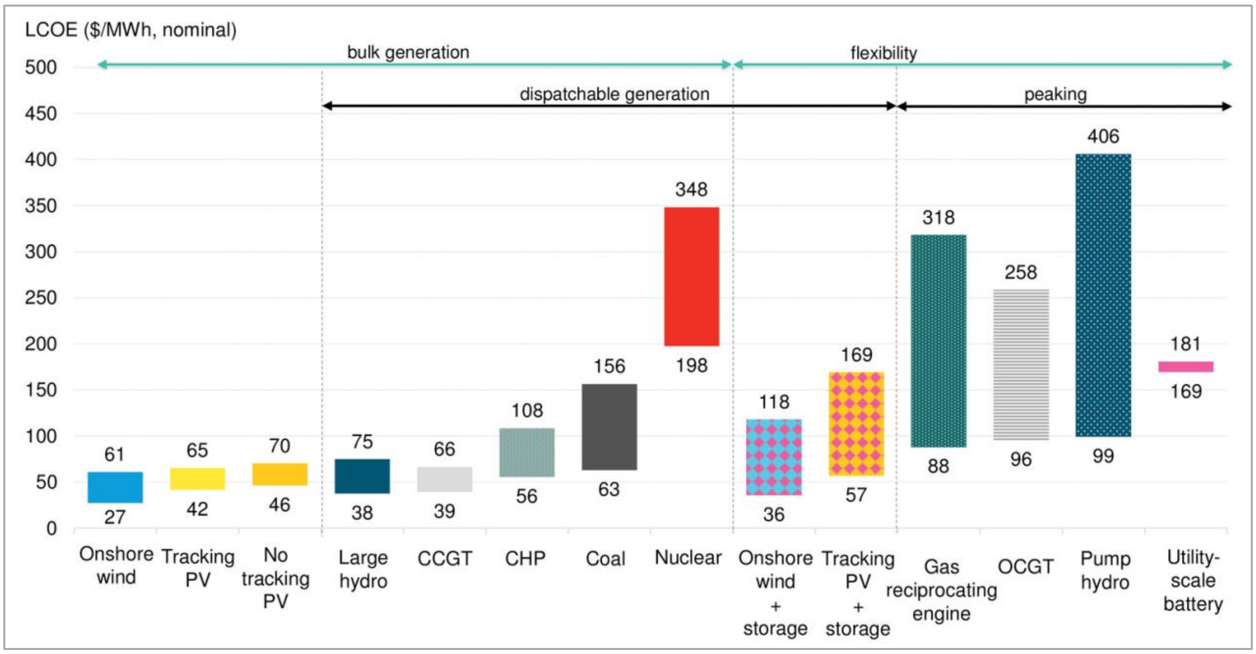
Over the next decade, the cost of batteries is projected to mirror the substantial cost declines recently achieved by wind and solar, while those generation technologies will also achieve further cost reductions. As mature technologies, gas-fired generation of all types will face stagnant technology costs while a major component of operational costs – fuel – is only likely to rise.

The fracking boom has sunk U.S. gas costs to the lowest in the world and that has made gas-fired generation more competitive than in most markets globally. However, as production plateaus over the next decade and exports rise, further cost reductions are unlikely. BNEF notes in its latest LCOE report that U.S. gas prices only need to rise a little above today's level to undermine the economics of running CCGT plants:

[13] Open cycle gas turbine (OCGT) and gas reciprocating engines.

> *"In most locations in the U.S. today, onshore wind without subsidy outcompetes CCGT plants supplied by cheap shale gas as a source of new bulk generation. If the gas price rises above $3/MMBtu, new and existing CCGTs run the risk of becoming rapidly undercut by new solar and wind. This means fewer run-hours and a stronger case for technologies such as gas peakers and batteries that thrive at lower capacity factors."*[14]

Figure 7: Wind and Solar With Storage Are Competitive With Natural Gas Combined Cycle Generation in the United States



Source: Bloomberg New Energy Finance, Nov. 2018.[15]

These trends, partially acknowledged by the growing role of renewable energy and storage resources in the long-term plans of the ACP-LLC partners, are reasons for skepticism around the future of a gas pipeline project that does not have a single independent committed customer. The most recent long-term resource plans of both Dominion Virginia Power, Duke Energy Carolinas and Duke Energy Progress do not show the rapid demand growth for natural gas power generation that the Atlantic Coast Pipeline was originally premised on. These utilities have revised downward their load forecasts and delayed or cancelled plans for new natural gas power plants.

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[14] Tifenn Brandily, "2H 2018 LCOE Update, Global: Levelized cost of generation, capacity and flexibility". November 19, 2018. P.5. BloombergNEF. Available by subscription only.
[15] Tifenn Brandily, Op. Cit. P.73

Conclusion and Recommended Questions

Recent long-term plans filed by the Virginia and North Carolina regulated electric utilities that are contracted for 68% of the capacity of the Atlantic Coast Pipeline show that the case for growing natural gas demand by these utilities has substantially eroded since the project was first proposed. Both Duke and Dominion have a history of overstating their forecasts of electricity demand. And even under these inflated forecasts, previous plans for new natural gas capacity have been delayed or cancelled in recent years.

Ultimately it is the State Corporation Commission of Virginia and the North Carolina Utilities Commission that are responsible for approving the inclusion of natural gas pipeline transportation costs in electric rates. If the capacity that these utilities have reserved on the Atlantic Coast pipeline is significantly underutilized, as appears likely, investors in the Atlantic Coast pipeline run the risk that state regulators will not approve full inclusion of pipeline costs in electric rates.

We recommend that investors ask hard questions of the ACP-LLC joint venture partners:

- What is the risk that state regulators will disapprove, or partially disapprove, recovery of project costs from ratepayers?
- Does the Virginia State Corporation Commission's rejection of Dominion's 2018 Integrated Resource Plan and its order that Dominion develop a revised load forecast change the perception of the risk that the SCC will not fully approve the pass-through of ACP project costs in rates?
- Without rate recovery, or with partial rate recovery, does the project still make sense?

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