

An analysis of the need for the Atlantic Coast Pipeline Extension to Hampton Roads, Virginia

Prepared for Mothers Out Front

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Executive Summary

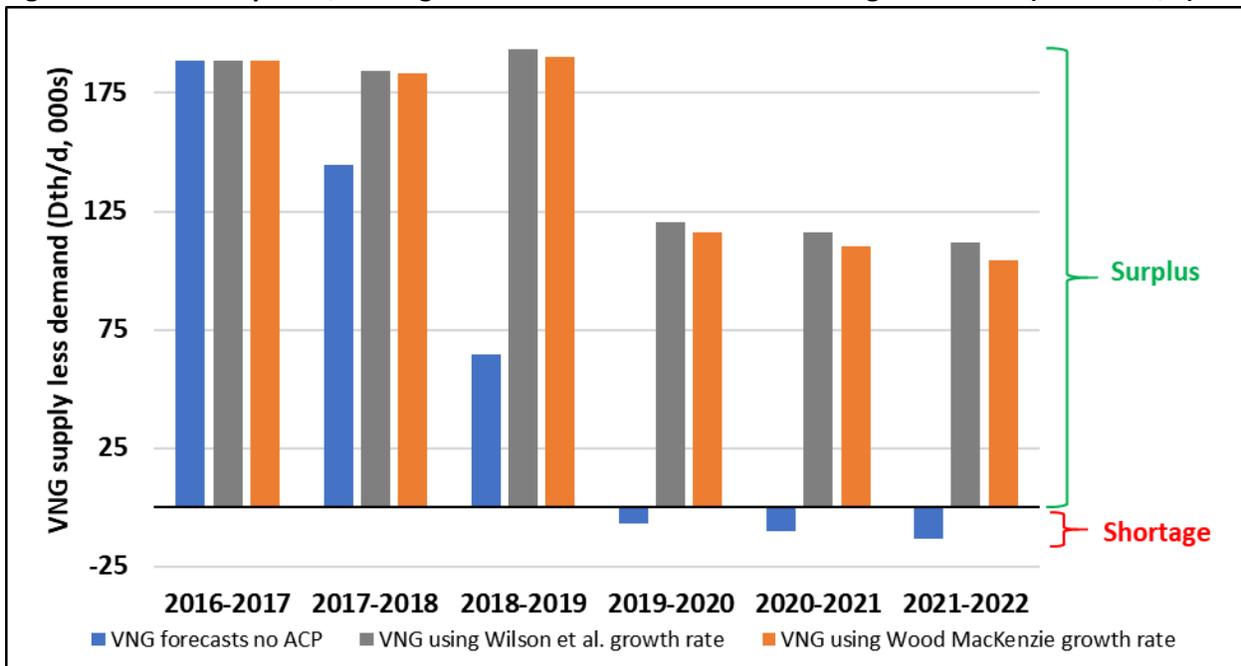
With the fate of the Atlantic Coast Pipeline (ACP) uncertain, questions have been raised regarding the impact of the ACP’s cancellation on gas supplies in the Hampton Roads area of Virginia. This Applied Economics Clinic white paper seeks to answer the question: Is Hampton Roads electric or gas supply at risk without increased supply from a new pipeline? Based on our analysis, we conclude:

- Virginia Natural Gas (VNG) has substantially overstated its annual peak demand growth forecasts. When more modest forecasts are applied, VNG has ample gas pipeline capacity to meet peak demand for the next five years or more.
- If gas supply constraints were to develop, nonetheless, in the Hampton Roads area, there would be no effect on the area’s electricity supply.
- It does not appear that involuntary curtailment of the area’s industrial users has resulted in gas supply constraints in the Hampton Roads area. In 2017, VNG reported to regulators that “no interruptions occurred on annual peak days during the last ten years.”

Forecast of gas shortage relies on inflated demand projections

VNG growth forecasts are overstated when compared with other recent industry forecasts for the Southeast. VNG predicts very high—7.4 percent per year—growth in its peak gas demand over the next five years (see Figure ES-1). In contrast, Woods McKenzie, consultants for the Mountain Valley Pipeline, reported that gas use by industrial, commercial, and residential gas customers in the Southeast for the period 2016 –2030 would only grow at 1.6 percent per year, well below VNG’s prediction. Another non-industry study forecasted 1.2 percent per year growth for these same users in this region.

Figure ES-1: VNG surpluses/shortages no ACP with alternative demand growth rates (1000s Dth/d)



Only VNG’s own projection of very high growth in peak gas demand results in gas supply shortages and a need for additional supply capacity in the Hampton Roads area. Any annual peak gas demand rate of 6.8 percent or less does not result in a shortage, and applying growth rates from non-industry forecasts results in a substantial available surplus for VNG.

No evidence of impact of Hampton Roads gas supply on its electric supply

During the approval process for the ACP, Dominion has not provided evidence of how its peak electric demand reflects greater need for gas at peak times of need in the Hampton Roads area. In fact, PJM, the regional electricity provider, has ample generation capacity on summer peak days.

Little evidence for risk of gas curtailment

Dominion’s claims that recent industrial curtailments in the Hampton Roads area point to a need for the Atlantic Coast Pipeline are undercut by VNG’s own reports of low numbers of rare curtailments. For its last rate case, VNG was asked to provide detailed data on the number of curtailments on peak day for the last ten years (2009-2017). VNG “responded that no interruptions occurred on annual peak days during the last ten years”¹ and noted also that during the last five years, VNG’s customers “have enjoyed and utilized the VNG transmission and distribution system to meet their energy needs 99.9% of the time.”² Dominion’s statement in its 2018 Climate Report that industrial curtailment in Hampton Roads is common is contradicted by VNG data provided to VA SCC.³ Finally, industrial users may have voluntarily elected to have their gas supply interrupted as part of an interruptible rate system in which large customers elect to be subject to gas interruption in exchange for lower rates. This is a standard industry practice.

Non-pipeline alternatives may be available at similar or lower costs

If gas supply capacity were of concern in the Hampton Roads area—and it does not appear that this is the case—potential shortages should be filled by the least cost resource or set of resources with the goal of minimizing customer costs. “Peak shaving” alternatives to pipeline include biofuels, building electrification (the use of heat pumps instead of gas heating), electric battery storage, gas energy efficiency, gas demand response, interruptible rates, and liquefied natural gas storage. Gas energy efficiency is less expensive than the lower end of expected ACP Hampton Roads costs, and building electrification costs match the lowest end of ACP Hampton Roads cost estimates.

¹ VA SCC. PUE-2016-00143. August 2017. *Application of Virginia Natural Gas for a general rate increase and for authority to revise the terms and conditions applicable to natural gas service. Direct testimony of Glenn A. Watkins on behalf of the Office of the Attorney General Division of Consumer Counsel.* Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/4%40vq01!.PDF>. p.9.

² Ibid.p.9.

³ Ibid.p.8.

1. Introduction

The Atlantic Coast Pipeline (ACP) is a proposed gas pipeline that would extend for about 600 miles from West Virginia to Virginia and North Carolina. If built, the ACP would provide up to 1.5 million dekatherms per day (Dth/d) of gas and would be constructed, owned and operated by four companies: Dominion Energy, Inc., Duke Energy Corporation, Piedmont Natural Gas Co., Inc., and AGL Resources, Inc.⁴

The project includes a lateral pipeline (ACP Hampton Roads or Chesapeake lateral extension) of about 80 miles that would extend from Northampton County, North Carolina to Chesapeake in the Hampton Roads area in Virginia (AP-3 in Figure 1). ACP Hampton Roads would deliver gas to Virginia Electric and Power Company (Dominion), and to Virginia Natural Gas, Inc. (VNG) in the city of Chesapeake.⁵

Figure 1: ACP Hampton Roads (AP-3)



Source: Reproduced from FERC Docket CP15-554-000. September 2015. *Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates. Exhibit F.* Submitted by Atlantic Coast Pipeline, LLC. Available at: <https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13990931>

⁴ FERC Docket CP15-554-000. September 2015. *Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates.* Submitted by Atlantic Coast Pipeline, LLC. Available at: <https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13990931>

⁵ Ibid.

VNG is a gas distribution company serving about 300,000 customers in southeastern Virginia.⁶ VNG contracted 75,000 Dth/d of gas capacity to be delivered at Chesapeake in Hampton Roads, Virginia through the ACP Hampton Roads.⁷ Dominion, a subsidiary of Dominion Energy, Inc., is an electric utility company with headquarters in Richmond, Virginia, serving about 2.5 million electric customers in Virginia and North Carolina.⁸ Dominion contracted for 300,000 Dth/d of gas capacity in the ACP, and the right to obtain half of that amount (150,000 Dth/d) also delivered at Chesapeake. While Dominion holds the right to get gas delivered at Chesapeake, the Company could get its full capacity of 300,000 Dth/d at any other delivery point on the ACP to which it holds rights, including Randolph County, West Virginia, Buckingham County, Virginia, Brunswick County, Virginia and Greensville County, Virginia.

The facts that appear in this case study do not include any benefits that may accrue from extra Hampton Roads capacity due to the Southside Connector Pipeline project and, to the extent that project has a net effect, it appears that it would further ameliorate any shortages that could present themselves in the unlikely scenario of a shortage.

2. Analysis of peak demand forecasts

VNG's demand for gas on peak

Virginia gas utilities are not required to file an Integrated Resource Plan (IRP) with the state utility commission but must file a "Gas Utility Five-Year Forecast" to report design day and design winter requirement expectations for the next five years.⁹ The Commonwealth of Virginia State Corporation Commission (VA SCC) requires that this filing provide a summary of the demand forecast model and main assumptions used to develop the utility's forecasts.¹⁰

VNG's latest five-year forecast, filed with the Commission in November 2018,¹¹ projected that design-day requirements for the heating season will increase from 342,000 Dth/d in 2016-2017 (the last year of historical data in the forecasts) to 489,000 Dth/d in 2021-2022 (see Figure 2; these projections were not

⁶ Virginia Natural Gas: About Us. Available at: <https://www.virginianaturalgas.com/about-us>

⁷ FERC Docket CP15-554-000. September 2015. *Resource Report 1: General Project Description*. Submitted by Atlantic Coast Pipeline, LLC and Dominion Transmission, Inc. Available at: <https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=13991031>

⁸ Commonwealth of Virginia State Corporation Commission (VA SCC) Case No. PUR-2018-00065, and North Carolina Utilities Commission Docket No. E-100, Sub 157. May 1, 2018. *Virginia Electric and Power Company's Report of Its Integrated Resource Plan Before the Virginia State Corporation Commission and North Carolina Utilities Commission*. Submitted by Dominion Energy. Available at: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf>

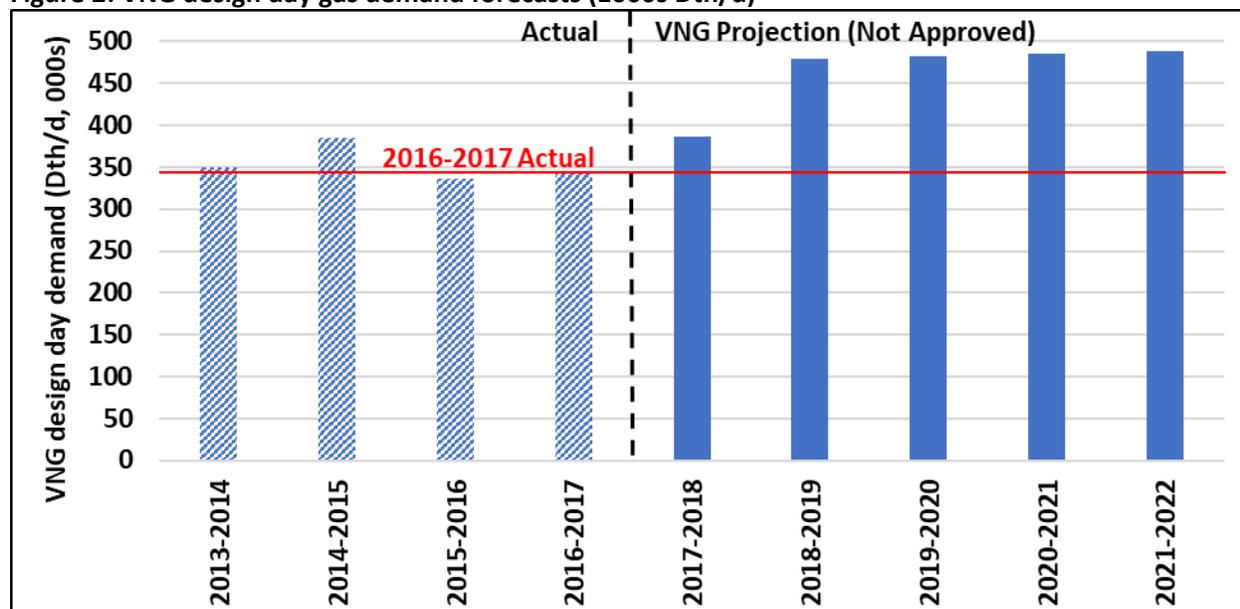
⁹ VA SCC. 2016. *Gas Utility Five-Year Forecast Information Requirements*. Available at: <https://www.scc.virginia.gov/pur/docs/forecast.pdf>

¹⁰ *Ibid.* p.1.

¹¹ VNG. November 2018. *Gas Utility Five-Year Forecast for Virginia Natural Gas*. Filed with VA SCC.

recommended by SCC staff as discussed below).¹² This represents an increase of 146,000 Dth/d in design-day requirements in five years (a 43 percent increase during this period). In contrast, historical data show that VNG’s design-day demand has remained relatively stable, falling slightly from 350,000 Dth/d in 2013-2014 to 342,000 Dth/d in 2016-2017.

Figure 2: VNG design day gas demand forecasts (1000s Dth/d)



Data source: VNG, Inc. November 2018. *Gas Utility Five-Year Forecast for Virginia Natural Gas*. Filed with VA SCC.

Description of forecast assumptions and methods

In its last rate increase application in March 2017,¹³ VNG explains that it forecasted its number of customers using the actual number of customers as of September 30, 2016 as a baseline, seasonal factors, and expected growth. VNG explained that a “working group of personnel from the marketing, engineering, and regulatory departments collaborate to develop the monthly growth (or decline) forecast as part of the Company’s budget process.”¹⁴

VNG forecasts gas consumption for residential and non-residential firm customers by estimating an average use per customer using a regression model that includes heating degree days and economic

¹² VNG’s heating season corresponds to the period November 1 through March 31.

¹³ VA SCC Case No. PUE-2016-00143. March 2017. *Application of Virginia Natural Gas for a general rate increase and for authority to revise the terms and conditions applicable to natural gas service*. Direct testimony of David M. Meiselman on behalf of Virginia Natural Gas, Inc. Submitted by VNG. Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/3%237501!.PDF>

¹⁴ Ibid. p.14.

variables for Virginia.¹⁵ For other customers, including delivery and natural gas vehicles service customers, VNG's application forecasts individual customer consumption and then aggregates the total. To forecast customer-level consumption, "VNG reviews historical monthly consumption data from the test year period (October 1, 2015 through September 30, 2016) with input from the marketing department, and corrects for future changes in demand resulting from customer expansions and contractions and one-time, extraordinary events such as re-tooling, strikes and storms."¹⁶ This means that gas consumption for these customers is projected based entirely on VNG staff's judgment and opinion regarding historical trends and future outlook.

In testimony responding to VNG's rate increase application, VA SCC staff criticized the Company's econometric forecasts and proposed the use of the linear regression model that Staff had used in both VNG's 2011 rate case¹⁷ and in the rate case applications of other Virginia gas utilities.¹⁸ In its testimony, Staff justifies its recommendation by stating that "Staff believes its method is appropriate because it produces replicable and verifiable results, is consistent with the regression models used by other gas utilities in Virginia, and is consistent with the model used by VNG itself in its tariffed [weather normalization adjustment] mechanism."¹⁹ The Commission adopted Staff's recommended methodology when approving a settlement agreed to by VNG and the parties to the case.

External peak demand forecasts

Recent external forecasts of peak gas demand in the greater region are substantially lower than VNG's own forecasts, which average 7.4 percent per year from 2017 to 2021. Wilson et al. project an annual rate of growth of 1.2 percent for peak demand for the Virginia and Carolinas region,²⁰ and Wood Mackenzie projects an annual rate of growth of 1.6 percent for the Southeast region (see Figure 3).²¹

¹⁵ The Company's rate increase application states that "a non-parametric, cubic spline technique can more precisely account for changes in relative heat sensitivity during shoulder months." Ibid. p.14.

¹⁶ Ibid. p.15.

¹⁷ VA SCC Case No. PUE-2016-00143. August 2017. *Application of Virginia Natural Gas for a general rate increase and for authority to revise the terms and conditions applicable to natural gas service. Direct testimony of Estaña M. Davis.* Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/3h9401!.PDF>

¹⁸ Other Virginia gas companies that use linear regression include Roanoke Gas Company, Atmos Energy Corporation, Southwestern Virginia Gas Company, Washington Gas Light Company, and Appalachian Natural Gas Distribution Company.

¹⁹ VA SCC Case No. PUE-2016-00143. August 2017. *Application of Virginia Natural Gas for a general rate increase and for authority to revise the terms and conditions applicable to natural gas service. Direct testimony of Estaña M. Davis.* Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/3h9401!.PDF.p.7>.

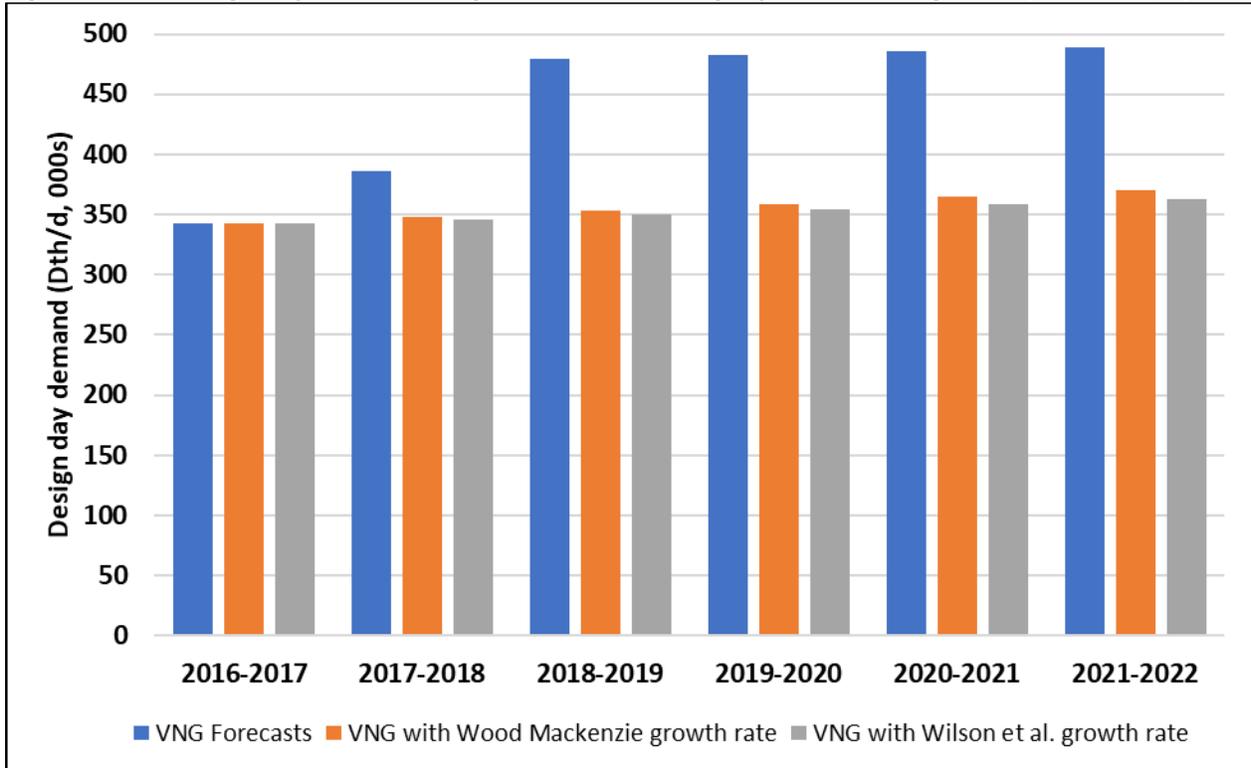
²⁰ Rachel Wilson et al. *Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? An examination of the need for additional pipeline capacity into Virginia and Carolinas.* Prepared for Southern Environmental Law Center and Appalachian Mountain Advocates. September 2016. Available at: https://www.southernenvironment.org/uploads/words_docs/2016_09_12_Synapse_Report_-_Are_the_ACP_and_MVP_Necessary_FINAL.PDF

²¹ Wood Mackenzie, Inc. *Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project.* January 2016. FERC Docket No. CP16-10-000, in: Motion to Answer and Answer of Mountain Valley



VNG’s own forecasts of its design-day requirements are higher than forecasts made by outside experts and inconsistent with historical design-day requirements.

Figure 3: VNG design day demand using other forecasts of gas peak demand growth (1000s Dth/d)



Note: 2016-2017 is VNG’s actual design day demand, while data from 2017-2018 are projections based on VNG’s forecasts, Wood MacKenzie rate of growth and Wilson et el. rate of growth. Data sources: VNG. November 2018. *Gas Utility Five-Year Forecast for Virginia Natural Gas*. Filed with VA SCC. Wood Mackenzie, Inc. *Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project*. January 2016. FERC Docket No. CP16-10-000, in: Motion to Answer and Answer of Mountain Valley Pipeline, LLC to Comments on the Draft Environmental Impact Statement. Exhibit A. Rachel Wilson et al. 2016. *Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? An examination of the need for additional pipeline capacity into Virginia and Carolinas*.

Dominion’s demand for gas on coincident peak

Dominion peak electric demand is not the same thing as it need for gas supply coincident with the gas system peak—the relevant measure of Dominion’s impact on gas capacity constraints and the usefulness of ACP Hampton Roads in relieving any constraints that may exist. Only 37 percent of Dominion’s peak capacity is served by gas and our review revealed no evidence that electric and gas

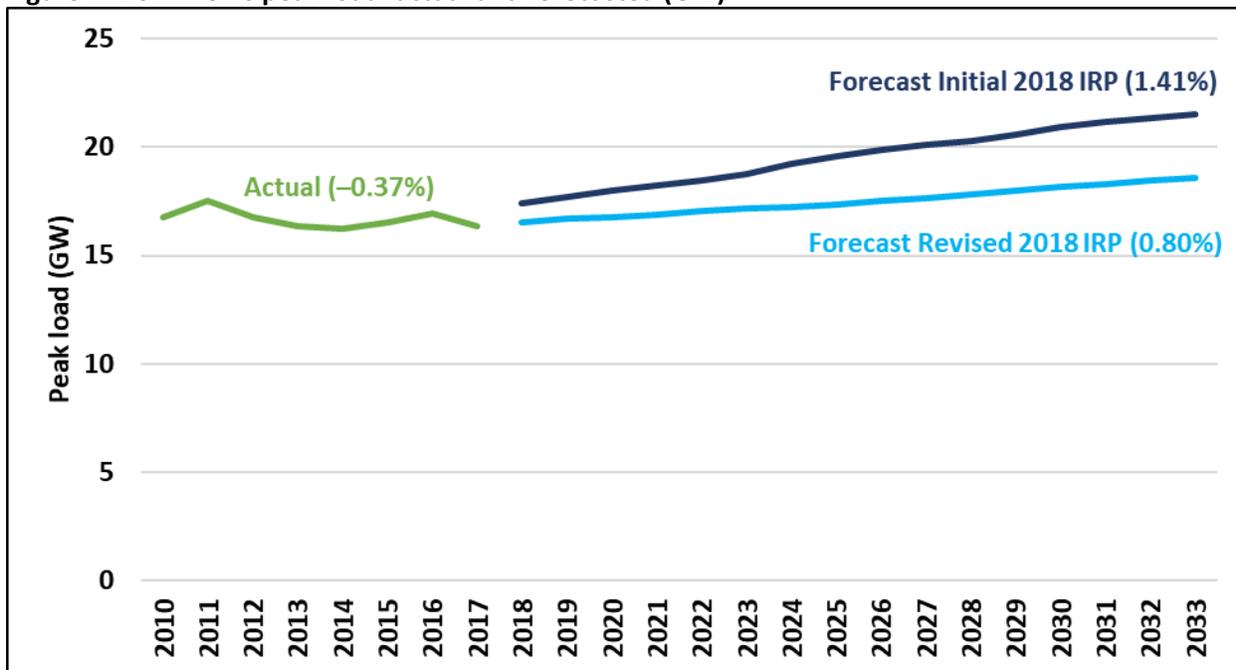
Pipeline, LLC to Comments on the Draft Environmental Impact Statement. Exhibit A. Available at: <https://www.mountainvalleypipeline.info/~media/Sites/MVP/News-Info/Files/1/MVP%20Answer%20to%20Comments%20on%20DEIS.ashx>

peaks coincide: Dominion’s customer needs peak in summer and its capacity requirements reflect this higher level; Dominion’s winter capacity needs are lower and include not only space heating demand (which would likely coincide with gas peak demand) but also industrial, commercial and residential electric use not related to space heating.

Dominion’s overestimate of peak electric demand

Dominion expects its summer peak electric demand to grow. In its 2018 IRP filed with VA SCC in May 2018,²² Dominion presented summer peak load forecasts from 2018 until 2033 rising at an average annual rate of 1.4 percent (see dark blue line in Figure 4).

Figure 4: Dominion’s peak load: actual and forecasted (GW)



Note: Average annual growth rates in parentheses. Data source: Dominion 2013, 2015-2018 IRPs and Revised 2018 IRP. Available at: 2018 IRP: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf>. 2017 IRP: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2017-irp.pdf?la=en>. 2016 IRP: <https://www.nrc.gov/docs/ML1627/ML16271A535.pdf>. 2015 IRP: <http://www.scc.virginia.gov/docketsearch#caseDocs/134454>. 2013 IRP: <http://www.scc.virginia.gov/docketsearch#caseDocs/132549>. Revised 2018 IRP: <http://www.scc.virginia.gov/docketsearch/DOCS/4f0801!.PDF>

²² VA SCC Case No. PUR-2018-00065, and North Carolina Utilities Commission Docket No. E-100, Sub 157. May 1, 2018. *Virginia Electric and Power Company’s Report of Its Integrated Resource Plan Before the Virginia State Corporation Commission and North Carolina Utilities Commission*. Submitted by Dominion Energy. Available at: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf>

The VA SCC reviewed Dominion’s IRP and issued an order concluding “that the Company has failed to establish that its 2018 IRP, as currently filed, is reasonable and in the public interest.”²³ In its order, the Commission required Dominion to correct and refile its 2018 IRP.

The Commission determined that Dominion’s peak load forecasts were too high. In its order, VA SCC explained that “alternative load forecasts were presented by Staff and respondents for the Commission’s consideration, each of which supported, to varying degrees, lower peak load and energy sales forecasts compared to the Company.”²⁴ In addition, the Commission pointed out that Dominion’s load forecasts in its previous IRPs have been consistently overstated since 2012. For these reasons “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”²⁵ and ordered Dominion to use Dominion Zone PJM coincident peak load forecasts.

On March 7, 2019, Dominion filed amendments to its 2018 IRP in response to the VA SCC order. In its new forecasts, Dominion assumes that peak load will increase at a lower annual rate of 0.8 percent, consistent with PJM forecasts (see “Forecast Revised 2018 IRP” in light blue in Figure 4 above).

Electric demand forecasts

Dominion forecasts its peak load demand in two steps. First, it uses an econometric model to forecast monthly sales by type of customer: residential, commercial, industrial, public authority, street and traffic lighting, and wholesale customers and other load serving entities in the Dominion Energy Zone (DOM Zone). For each of these types of customers, Dominion estimates a regression model that includes variables such as income, employment, unemployment rate, Virginia gross state product, electric prices, gas prices, and weather variables (the exact variables included in each equation vary by type of customer). In the second step, Dominion uses the monthly sales forecasts from step 1 to model peak load for each hour of the day in the DOM Zone, and forecasts monthly and seasonal peaks by simulating hourly demand using projected economic conditions.²⁶

Several recent external forecasts for electric peak load either for Dominion or for the Southeast region are available, all projecting a lower rate of growth in peak load compared to the 1.4 percent annual growth used in Dominion’s initial 2018 IRP (see Figure 4 above). Wilson projects an annual rate of growth of Dominion’s peak load of 0.6 percent,²⁷ while Wood Mackenzie projects that electric peak load

²³ VA SCC Case No. PUR-2018-00065. December 7, 2018. *Order*. Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/4d5g01!.PDF>. pp. 2-3.

²⁴ *Ibid.* p.6.

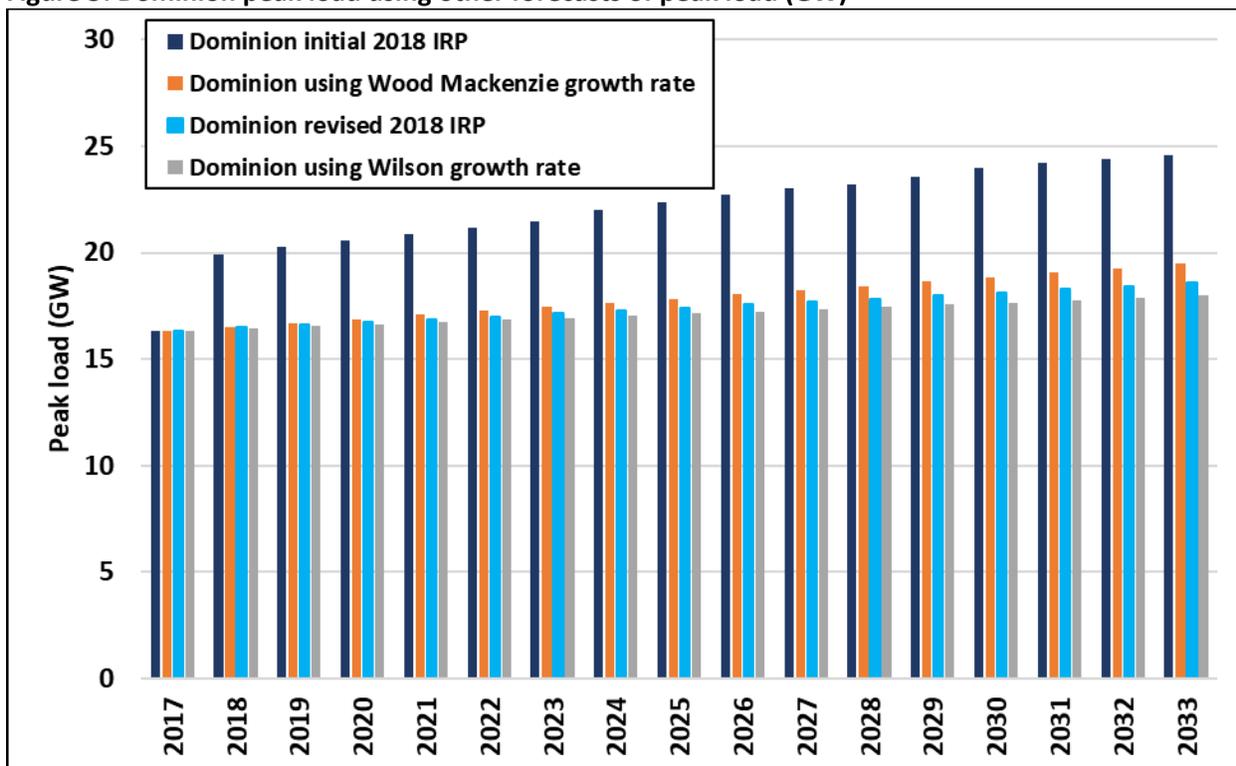
²⁵ *Ibid.* p.7.

²⁶ *Ibid.* p.16.

²⁷ VA SCC Case No. PUR-2018-00065. August 2018. *Direct testimony of James F. Wilson on behalf of Environmental Respondents*. Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/3n5m01!.PDF>.

in the Southeast region will increase by 1.1 percent per year (see Figure 5). Dominion’s revised IRP, based on PJM’s load forecast, expects peak load to grow 0.8 percent per year.

Figure 5: Dominion peak load using other forecasts of peak load (GW)



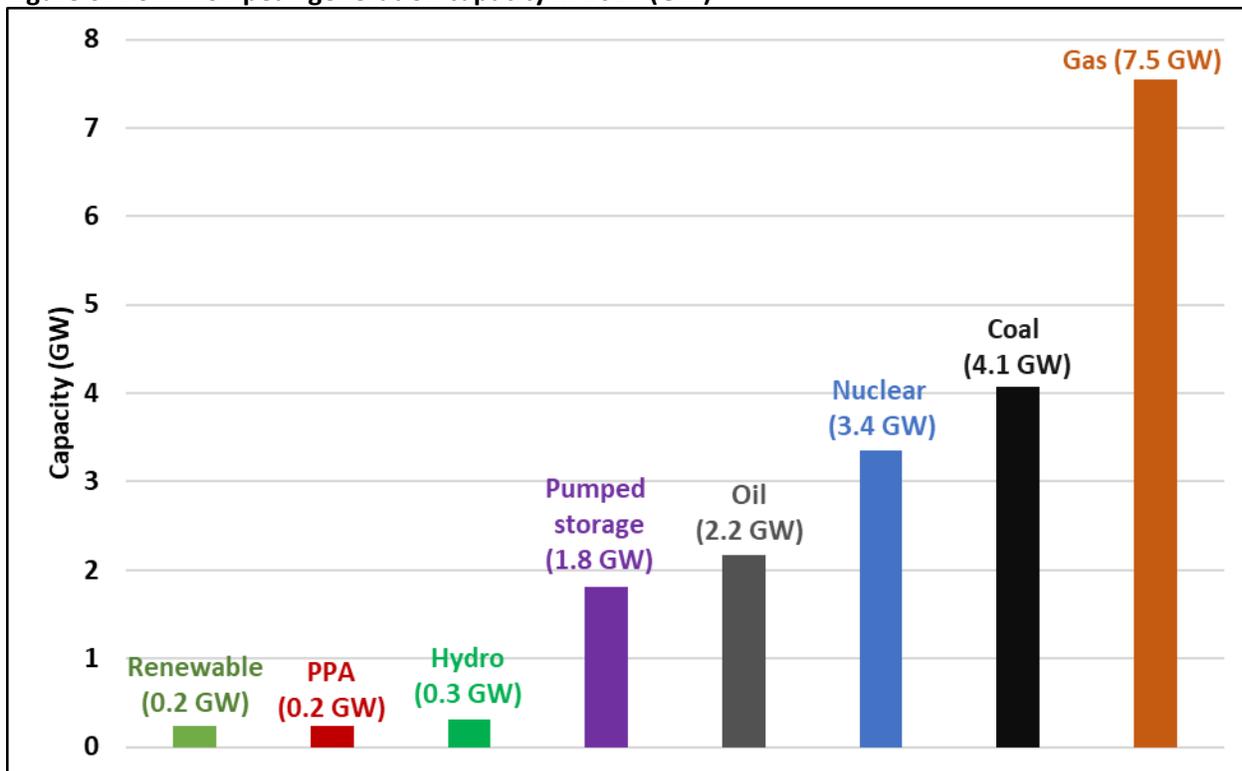
Note: Data for 2017 is actual peak load, while data from 2018 are based on forecasts using four different rates of growth: Dominion Initial 2018 IRP rate of growth, Wood Mackenzie rate of growth, Dominion revised 2018 IRP rate of growth, and Wilson rate of growth. Data source: *Dominion 2018 IRP*. Available at: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf>. Wood Mackenzie, Inc. *Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project*. Available at: <https://www.mountainvalleypipeline.info/~media/Sites/MVP/News-Info/Files/1/MVP%20Answer%20to%20Comments%20on%20DEIS.ashx>. *Dominion Revised 2018 IRP*. Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/4f0801!.PDF>. VA SSC Case No. PUR-2018-00065. August 2018. *Direct testimony of James F. Wilson on behalf of Environmental Respondents*. Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/3n5m01!.PDF>.

Dominion’s own summer peak load forecasts are higher than other recent forecasts for peak load in the Southeast region (see Figure 5), and higher than historical peak demand for Dominion (see Figure 4). Dominion’s summer peak is an input to the relevant measure of Dominion’s impact on gas capacity constraints but it is not the measure itself. Only a measure of Dominion’s need for gas supply coincident with the gas system peak can determine the impact of electric demand on gas capacity constraints.

Existing electric generating capacity

Currently, Dominion has about 20 GW of summer generation capacity. Gas dominates Dominion’s generation capacity (7.5 GW), followed by coal (4.1 GW), nuclear (3.4 GW) and oil (2.2 GW) (see Figure 6).

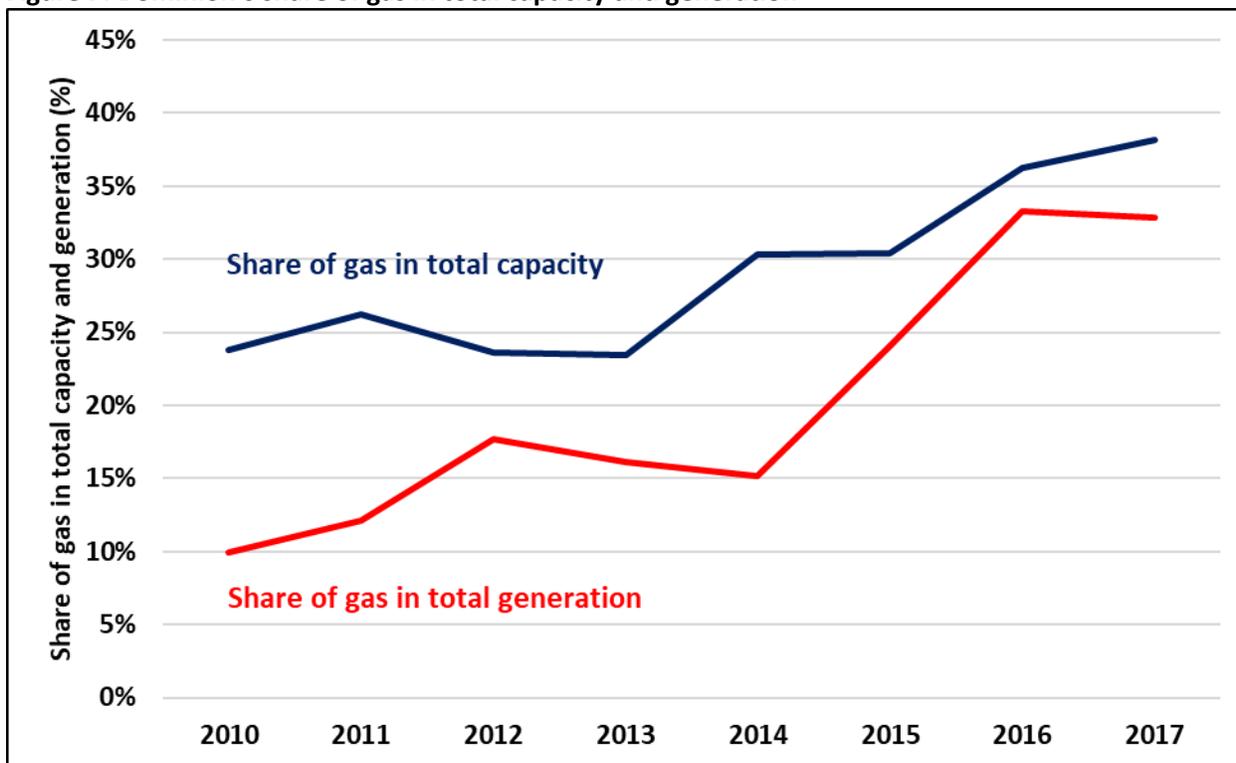
Figure 6: Dominion peak generation capacity in 2017 (GW)



Note: PPP is generation capacity from power purchase agreements (fossil fuels and renewable generation that Dominion buys from non-utility generators). Data source: VA SCC Case No. PUR-2018-00065, and North Carolina Utilities Commission Docket No. E-100, Sub 157. May 1, 2018. *Virginia Electric and Power Company’s Report of Its Integrated Resource Plan Before the Virginia State Corporation Commission and North Carolina Utilities Commission*. Submitted by Dominion Energy. Appendix 3F. Available at: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf>

Dominion’s reliance on gas for capacity and generation has increased during the last decade: the share of gas in total capacity (GW of capacity to generate) rose from 24 percent in 2010 to 38 percent in 2017, while the share of gas in total generation (GWh of electricity generated) increased from 10 percent to 33 percent during the same period (see Figure 7).

Figure 7: Dominion’s share of gas in total capacity and generation



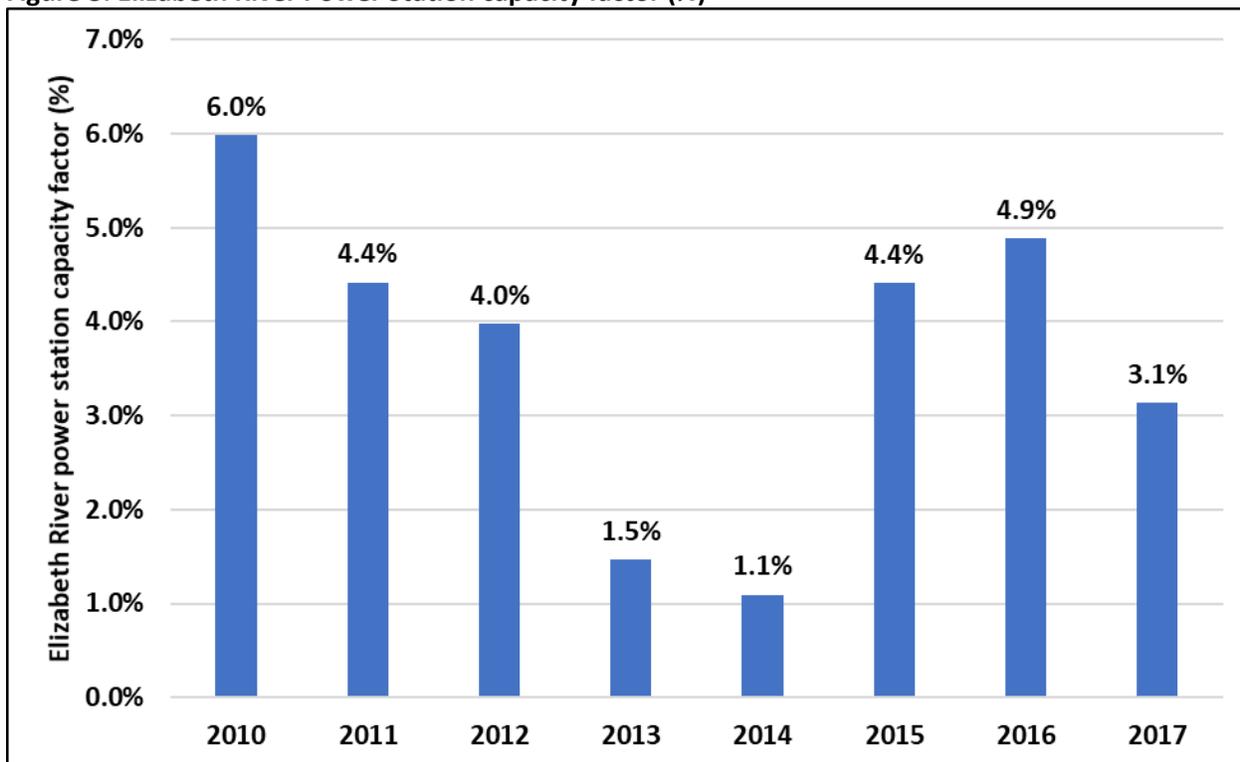
Data source: *Dominion 2013, 2015-2018 IRPs and Revised 2018 IRP*. Available at: 2018 IRP: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf>. 2017 IRP: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2017-irp.pdf?la=en>. 2016 IRP: <https://www.nrc.gov/docs/ML1627/ML16271A535.pdf>. 2015 IRP: <http://www.scc.virginia.gov/docketsearch#caseDocs/134454>. 2013 IRP: <http://www.scc.virginia.gov/docketsearch#caseDocs/132549>. Revised 2018 IRP: <http://www.scc.virginia.gov/docketsearch/DOCS/4f0801!.PDF>

Currently, Dominion’s use of gas in the Chesapeake area is limited. The Company has one gas-powered generation station in the area, the Elizabeth River Power Station, which has three combustion turbine (CT) peak generation units with a combined summer capacity of 0.35 GW,²⁸ accounting for less than 1.8 percent of Dominion’s total installed capacity. Elizabeth River’s functions as a peaker unit (operating only in times of the highest electric demand) and its capacity factor has stayed between 1 and 6 percent of total potential generation over the past eight years (see Figure 8). In 2017, for example, Elizabeth River Power Station generated almost 96 GWh at a capacity factor of 3.1 percent, which accounted for

²⁸ VA SCC Case No. PUR-2018-00065, and North Carolina Utilities Commission Docket No. E-100, Sub 157. May 1, 2018. *Virginia Electric and Power Company’s Report of Its Integrated Resource Plan Before the Virginia State Corporation Commission and North Carolina Utilities Commission. Appendix 3A*. Submitted by Dominion Energy. Available at: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf>

only 0.1 percent of Dominion’s total generation in that year; its peak months of operation in 2017 were July, August and June, respectively.

Figure 8: Elizabeth River Power Station capacity factor (%)



Source data: EIA. *Net generation Elizabeth River Power Station Series ID: ELEC.PLANT.GEN.52087-ALL-ALL.A megawatthours*. Available at: <https://www.eia.gov/opendata/qb.php?category=5107&sdid=ELEC.PLANT.GEN.52087-ALL-ALL.A>

Future additions to electric generating capacity

In its 2018 IRP, Dominion examines five alternative resource plans. As in its previous three IRPs, Dominion does not identify or recommend a “preferred plan.” The plans considered by Dominion are:²⁹

- **Plan A: No CO₂ tax.** No new regulations or restrictions on power station carbon emissions. This plan is used as the baseline to compare the other four plans.
- **Plan B: Virginia Regional Greenhouse Gas Initiative (Unlimited Imports).** Implementation of Virginia Department of Environmental Quality regulations from January 2018. Dominion

²⁹ VA SCC Case No. PUR-2018-00065, and North Carolina Utilities Commission Docket No. E-100, Sub 157. May 1, 2018. *Virginia Electric and Power Company’s Report of Its Integrated Resource Plan Before the Virginia State Corporation Commission and North Carolina Utilities Commission*. Submitted by Dominion Energy. Available at: <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf>



assumes that compliance will be achieved through the use of more carbon intensive out-of-state energy and generating capacity.

- **Plan C: Regional Greenhouse Gas Initiative (RGGI) (Unlimited Imports).** Assumes Virginia becomes a full member of RGGI. Compliance with RGGI is met through the use of more carbon intensive out-of-state energy and capacity.
- **Plan D: RGGI (Limited Imports).** Assumes Virginia becomes a full member of RGGI. Compliance with RGGI is met through generation built in Virginia and limited imports of more carbon-intensive power.
- **Plan E: Federal CO₂ Program.** Assumes that Virginia does not implement any CO₂ reduction program, but also assumes that federal CO₂ legislation imposes restrictions beginning in 2026.

In each of these alternative resource plans, Dominion expects to:

- Add more solar and wind generation capacity
- Extend nuclear energy contracts
- Potentially retire older oil, coal and gas generation units, but the Company has not made a final decision about these retirements.
- Add 5.25 GW of gas generation capacity,³⁰ a 70 percent increase in gas generation between 2017 and 2033. About 30 percent of the additional gas generation capacity will be combined cycle (CC) and 70 percent will be CT.

Four out of the five Dominion alternative resource plans add still more gas capacity (in addition to the 5.25 GW).³¹

- **Plan A:** 0.46 GW in CT capacity.
- **Plans B and C:** 1.61 GW of CT capacity.
- **Plan D:** 0.56 GW of CT capacity, and 1.06 GW in CC capacity.

Dominion is currently building the Greenville County Power Station, a gas CC in Greenville/Brunswick County, Virginia with a 1.6 GW capacity.³² This station is now operational using the Transco pipeline, and while it may be served by the ACP and does not require the ACP Hampton Roads lateral for its gas supply.

Dominion's IRP does not provide locations for any of the additional gas capacity called for in its resource plans and does not in any way suggest that this new capacity will be located in the Hampton Roads area. The Company has not announced plans to build a new power station in the Chesapeake area or along the route of ACP Hampton Roads.

³⁰ Ibid. p.4.

³¹ Ibid. pp.4-5.

³² Ibid. Appendix 3K.

Dominion's need for gas on coincident gas system peak

Dominion expects its summer peak demand to grow over time, but provides no reason to think that this growth will increase the need for Elizabeth River energy generation at summer peak or, more relevantly, at the coincident gas system peak during winter heating season. While Dominion expects to add more CT capacity in the next years, it has given no indication that new CTs will be built in the Hampton Roads area.

3. Sufficiency of future supply capacity

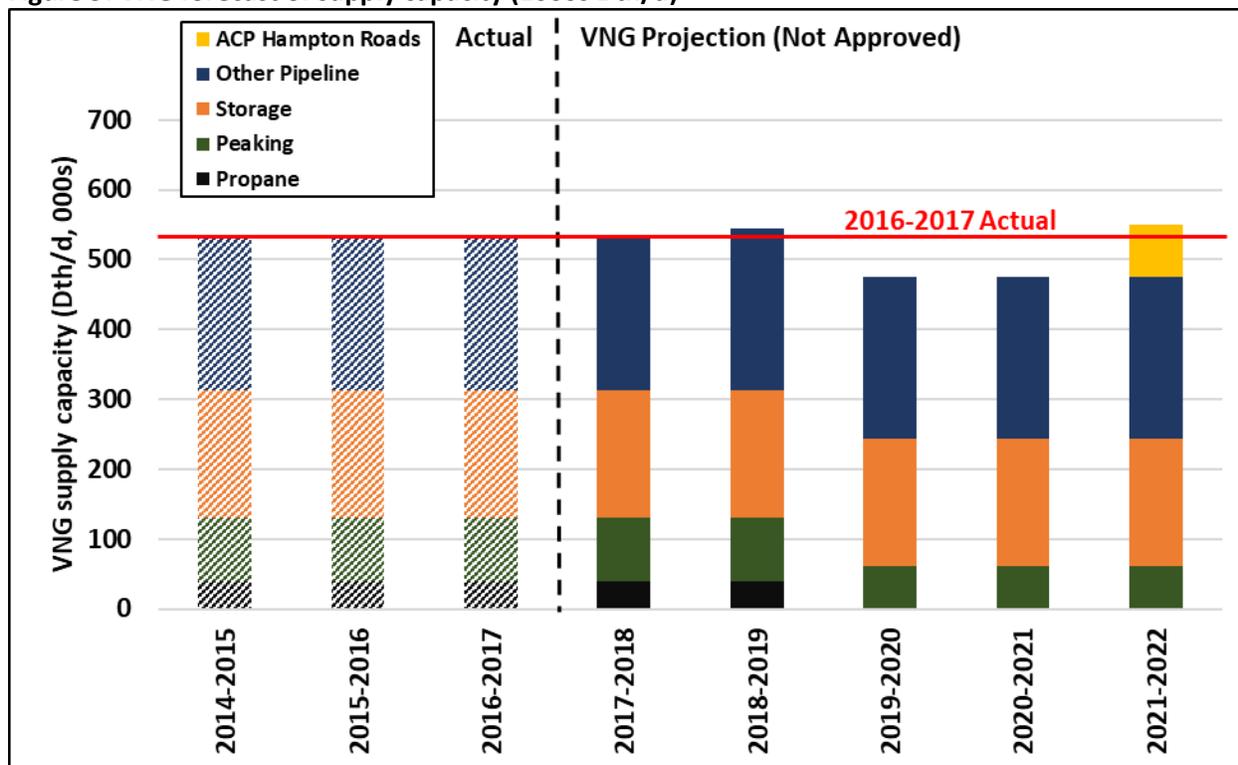
Only VNG's own projections of very high (7.4 percent per year) growth in peak gas demand over the next five years result in gas supply shortages and a need for additional supply capacity. Any annual peak gas demand rate of 6.8 percent or less does not result in a shortage, and alternative forecasts for the region range from 1.2 to 1.6 percent annual growth. Dominion has not provided any evidence of how its peak electric demand reflects greater need for gas in the Hampton Roads area on coincident gas system peak. Dominion's claims the recent industrial curtailments in the region point to a need for new pipeline capacity is undercut by VNG's own reports of low number of rare curtailments that might be better categorized as employment of an interruptible rate system in which large customers elect to be subject to gas interruption in exchange for lower rates. Due to the scant public record it is difficult to discern the nature or cause of any Chesapeake area curtailments.

VNG's gas supply capacity

In 2016-2017, the last year for which historical data are available, VNG had a gas supply capacity of 531,000 Dth/d (see Figure 9). Contracted capacity on pipelines accounts for about 41 percent of VNG supply capacity, storage for 34 percent, and peaking capacity and propane for 25 percent. VNG forecasts suggest that the Company expects its supply capacity to increase to 544,000 Dth/d in 2017-2018 due an new pipeline capacity, and then fall to 475,000 Dth/d in 2019-2020 due to reductions in peaking and propane capacity (see Figure 9). Adding VNG's contracted capacity of 75,000 Dth/d in ACP Hampton Roads would raise VNG's supply to 550,000 Dth/d in 2020-2021.³³

³³ The final project description of the ACP stated that VNG had committed to shipping 155,000 Dth/d (Atlantic Coast Pipeline, LLC and Dominion Transmission, INC. 2015. *Resource Report 1: General Project Description*. p.1-11. Available at: <https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=13991031>). The application to build the ACP filed with FERC, however, stated that "VNG originally contracted for 75,000 Dt/day, and later in 2015 entered into an amendment to add an additional 80,000 Dt/day of capacity. VNG has an option, however, to provide Atlantic notice on or before June 30, 2016, to "turn back" this incremental capacity" (FERC Docket CP15-554-000. September 2015. *Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates*. Submitted by Atlantic Coast Pipeline, LLC. p.12 footnote 10. Available at: <https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13990931>) Since VNG projects a capacity of 75,000

Figure 9: VNG forecast of supply capacity (1000s Dth/d)



Data source: VNG. 2018. *Gas Utility Five-Year Forecast*.

VNG expects that design day demand will increase faster than supply, and will surpass supply capacity in 2019-2020. Based on VNG’s own projections of design-day demand and expected supply capacity, VNG would experience a shortage of 7,000 Dth/d (or 1.3 percent of capacity) starting in 2019-2020. Adding the ACP Hampton roads capacity in 2021-2022, would produce a surplus of 61,000 Dth/d.

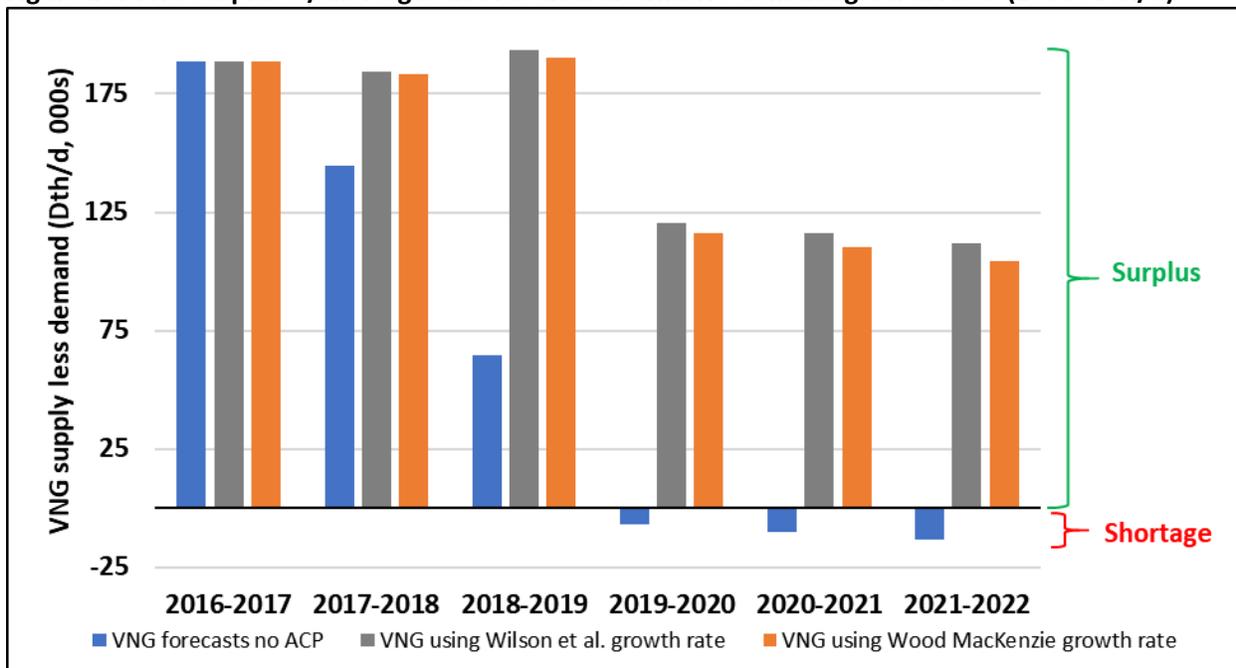
Using Wilson et al. forecasted rate of growth of peak demand of 1.2 percent for the Virginia and the Carolinas region³⁴ or Wood Mackenzie rate of growth of 1.6 percent for the Southeast, VNG would experience surpluses of more than 100,000 Dth/d until 2021-2022, the end of the forecasting period

Dth/d in the ACP in its last forecasts, this analysis assumes that VNG turned back the additional 80,000 Dth/d of capacity.

³⁴ Rachel Wilson et al. *Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? An examination of the need for additional pipeline capacity into Virginia and Carolinas*. Prepared for Southern Environmental Law Center and Appalachian Mountain Advocates. September 2016. Available at: https://www.southernenvironment.org/uploads/words_docs/2016_09_12_Synapse_Report_-_Are_the_ACP_and_MVP_Necessary_FINAL.PDF

(see Figure 10).^{35,36} VNG instead projects a very small shortage, a result which depends on their assumed rate of growth of design day demand of 7.4 percent per year, which is higher than other projected rates for the region. Any growth rate lower than 6.8 percent, results in surplus gas supply capacity for VNG during the entire forecasting period without adding ACP Hampton Roads or any other additional capacity.

Figure 10: VNG surpluses/shortages no ACP with alternative demand growth rates (1000s Dth/d)



Data sources: VNG. 2018. *Gas Utility Five-Year Forecast*. Rachel Wilson et al. *Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? An examination of the need for additional pipeline capacity into Virginia and Carolinas*. September 2016. Wood Mackenzie, Inc. *Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project*. January 2016. FERC Docket No. CP16-10-000, in: Motion to Answer and Answer of Mountain Valley Pipeline, LLC to Comments on the Draft Environmental Impact Statement. Exhibit A.

Reliability and industrial curtailment

If supply capacity is not enough to meet peak demand, utilities may cut off or “curtail” service to some of their customers. Although AEC’s analysis has not revealed evidence of past supply shortages, Dominion presented arguments supporting the need for the Hampton Roads extension of the ACP. In its

³⁵ Wood Mackenzie, Inc. *Southeast U.S. Natural Gas Market Demand in Support of the Mountain Valley Pipeline Project*. January 2016. FERC Docket No. CP16-10-000, in: Motion to Answer and Answer of Mountain Valley Pipeline, LLC to Comments on the Draft Environmental Impact Statement. Exhibit A. Available at: <https://www.mountainvalleypipeline.info/~media/Sites/MVP/News-Info/Files/1/MVP%20Answer%20to%20Comments%20on%20DEIS.ashx>

³⁶ Wood MacKenzie defines the Southeast region as: Alabama, Florida, Georgia, North Carolina, South Carolina, Tennessee, Virginia and West Virginia.

2018 *Climate Report*, Dominion argues that increasing reliability is one of the most important goals of the ACP, stating that “(i)n recent winters, Virginia and North Carolina utility customers have faced significant fuel cost spikes due to pipeline capacity constraints in the region”.³⁷ In that same report, Dominion suggests that these capacity constraints are particularly important in Hampton Roads, where “during cold weather, large customers periodically have natural gas service curtailed as a matter of routine”.³⁸

For its last rate case, VNG was asked to provide detailed data on the number of curtailments on peak day for the last ten years (2009-2017). VNG “responded that no interruptions occurred on annual peak days during the last ten years”³⁹ and noted also that during the last five years, VNG’s customers “have enjoyed and utilized the VNG transmission and distribution system to meet their energy needs 99.9% of the time.”⁴⁰ Dominion’s statement that industrial curtailment in Hampton Roads is common is not supported by VNG data provided to VA SCC.⁴¹

One exception happened in 2015, when VNG curtailed interruptible customers from February 19 at 12:00 AM until February 21 at 10:00 AM.^{42,43} VNG stated that “(t)he interruption order was issued due to average daily temperatures being extremely low causing demand to be near design day levels.”⁴⁴

News reports quoting Dominion and VNG representatives suggest that VNG curtailed 11 industrial customers during January of 2018 as a result of very cold weather.^{45,46} Other reports, however, indicate that these industrial customers choose to be subject to gas delivery interruption in exchange for lower rates. In an interview published in *The Roanoke Times*, Thomas Hadwin, a former executive for electric

³⁷ Dominion Energy. November 2018. *Climate Report*. Available at: <https://www.dominionenergy.com/library/domcom/media/community/environment/reports-performance/2018-dominion-energy-climate-report.pdf?la=en>, p.7.

³⁸ Ibid.p.7.

³⁹ VA SCC. PUE-2016-00143. August 2017. *Application of Virginia Natural Gas for a general rate increase and for authority to revise the terms and conditions applicable to natural gas service. Direct testimony of Glenn A. Watkins on behalf of the Office of the Attorney General Division of Consumer Counsel*. Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/4%40vq01!.PDF>, p.9.

⁴⁰ Ibid.p.9.

⁴¹ Ibid.p.8.

⁴² During February 2015, the East of the United States experienced record or near-record cold temperatures. Source: NOAA National Centers for Environmental Information. *State of the Climate: Synoptic Discussion for February 2015*. Retrieved on May 16, 2019. Available from: <https://www.ncdc.noaa.gov/sotc/synoptic/201502>

⁴³ Cited on: VA SCC. PUE-2016-00143. August 2017. *Application of Virginia Natural Gas for a general rate increase and for authority to revise the terms and conditions applicable to natural gas service. Direct testimony of Glenn A. Watkins on behalf of the Office of the Attorney General Division of Consumer Counsel*. Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/4%40vq01!.PDF>

⁴⁴ Ibid.p.8

⁴⁵ Bacon, J. January 10, 2018. “Polar Vortex II Brings Gas Curtailments, Price Spikes.” *Bacon’s Rebellion*. Available at: <https://www.baconsrebellion.com/wp/polar-vortex-ii/>

⁴⁶ Zullo, R. 2018. “Does recent cold snap underscore or undercut need for Atlantic Coast Pipeline?” *Richmond Times-Dispatch*. n.p. Available at: https://www.richmond.com/business/does-recent-cold-snap-underscore-or-undercut-need-for-atlantic/article_49ee68f7-3f38-5b00-8f7d-acc4d5eef41a.html

and gas utilities, explained that, “What really happened was that 10 industrial customers of VNG volunteered to cut back on some of their gas usage in exchange for lower rates. This voluntary curtailment involved 90 fewer industrial customers than during the polar vortex in 2013-2014.”⁴⁷

4. Alternatives to pipelines

Evidence of a need for the ACP Hampton Roads lateral rests on VNG’s expectation of rapid growth in peak gas demand that is not supported by other forecasts for the region and Dominion’s claims of gas customer curtailment during severe winter weather, which, by VNG’s account appears to be rare, minimal, and managed by their interruptible rate program. If, nonetheless, supply capacity is of concern in the Hampton Roads area, potential shortages should be filled by the least cost resource or set of resources with the goal of minimizing customer costs.

This section investigates whether VNG proposed investment in ACP Hampton Roads is the least cost alternative to meet future peak demand or whether, instead, other demand or supply side measures can meet this potential need at a lower expense. According to Dominion, the ACP project will cost between \$7.0 and \$7.5 billion⁴⁸ excluding financing costs.⁴⁹ Interest payments, taxes and expenses in operation and maintenance are likely to add another \$4.5 billion to the total cost of the ACP assuming a 40-year lifetime.⁵⁰ The cost of building ACP Hampton Roads is about 10 percent of the total cost of building the ACP project,⁵¹ or \$1.2 billion. Over a 40-year lifetime, the annualized cost of ACP Hampton Roads is \$30 million.

⁴⁷ T. Hadwin. February 7, 2018. “No, cold wave doesn't show need for pipeline.” The Roanoke Times. Available at: https://www.roanoke.com/opinion/commentary/hadwin-no-cold-wave-doesn-t-show-need-for-pipeline/article_48beeea8-a70a-5499-ba51-186f3b3e79fe.html

⁴⁸ Nominal dollars. Dominion Energy, News Release: Dominion Energy Announces Fourth-Quarter and Full-Year 2018 Earnings, Provides Atlantic Coast Pipeline Update. Available at: <https://news.dominionenergy.com/2019-02-01-Dominion-Energy-Announces-Fourth-Quarter-and-Full-Year-2018-Earnings-Provides-Atlantic-Coast-Pipeline-Update>

⁴⁹ The Supply Header pipeline is a 37.5-mile that would bring gas to the top of the ACP. See Dominion Energy. Supply Header Project. Available at: <https://www.dominionenergy.com/company/natural-gas-projects/supply-header-project>

⁵⁰ Data on O&M, taxes and interests are available for the first three years of the project. O&M expenses for the following years is increased at a rate of 2.5 percent per year, taxes are calculated as 1 percent of the value of the pipeline minus depreciation, and interests are calculated using an interest rate of 6.8 percent assuming that 50 percent of the project is financed with debt. Inflation is assumed to be 2 percent per year. Dominion assumes a depreciation rate of 2.5 percent, which implies a 40 year expected project lifetime.

⁵¹ In its application to build the ACP project, ACP LLC estimated that the total cost of the project would be about \$5.1 billion. The Hampton Roads spur of the ACP consists of a 79-mile pipeline, a compressor station in Northampton County, North Carolina and the new Elizabeth River metering and regulating station in Chesapeake, Virginia. Together, the estimated cost was about \$527 million, which represents a little over 10 percent of the total cost of the ACP project. Source: FERC Docket No. CP15-554-000. September 2015. *Abbreviated application for a*

Given a total contracted capacity in ACP Hampton Roads of 225,000 Dth/d, available every day throughout the year, its cost per unit of capacity is approximately \$1.60 to \$1.86 per Dth on peak. Comparison to non-pipeline alternatives presented in this section shows gas energy efficiency measures with lower costs and building electrification costs as roughly equivalent to the lower end of the ACP Hampton Roads expected cost range.

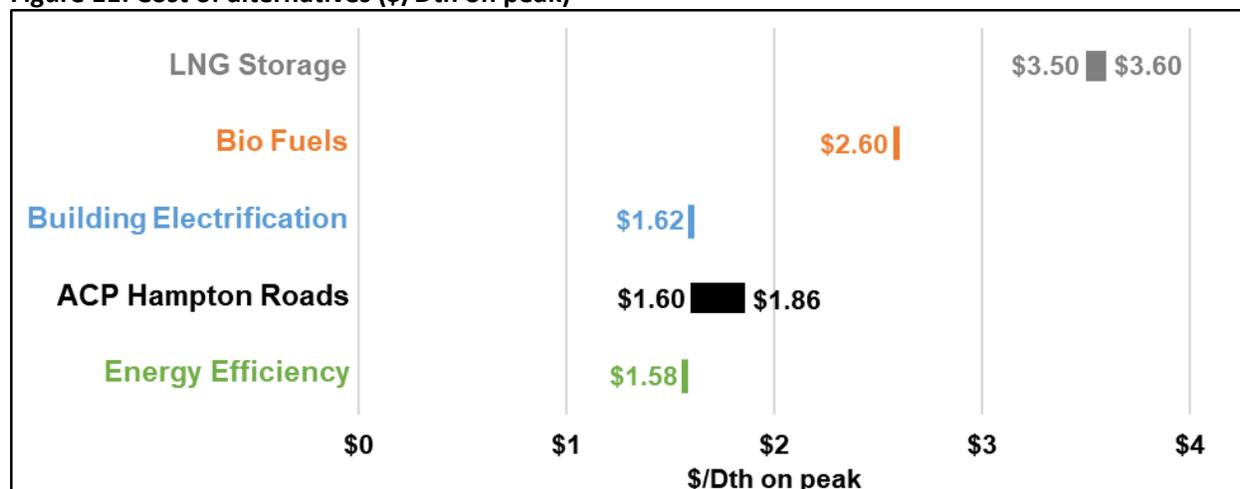
Non-pipeline “peak shaving” alternatives

Potential peak gas demand shortages can be addressed through new pipeline capacity, as proposed by Dominion and VNG, or by supply- or demand-side pipeline alternatives. Minimizing customer costs requires a cost comparison of all potential strategies—and our review has revealed no such comparison made available by ACP Hampton Roads, VNG, or Dominion.

We compare costs in terms of a “dollars per Dth on peak” measure, the calculation of which varies somewhat from resource to resource. The intent of this measure is to provide a cost per unit of supply capacity on peak: for some measures this capacity is available every day of the year, waiting to be used; for other measures, the capacity is made available at times of peak need. The estimation techniques used here are preliminary and offered with the goal of opening a dialogue regarding how best to value gas savings on peak. Specific calculation methods are discussed below.

“Peak shaving” alternatives to pipeline include liquefied natural gas (LNG) storage, biofuels, building electrification (the use of heat pumps instead of gas heating), and gas energy efficiency (all shown in Figure 11), as well as several measures that prove harder to assign costs on peak: gas demand response, interruptible rates, and electric battery storage.

Figure 11: Cost of alternatives (\$/Dth on peak)



certificate of public convenience and necessity and blanket certificates. Submitted by Atlantic Coast Pipeline, LLC. Available at: <https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=13990931>

As is discussed in more detail below, the gas energy efficiency cost estimate of \$1.58 per Dth on peak is the least expensive peak shortage reduction strategy, is less expensive than the lower end of expected ACP Hampton Roads costs, and is likely an overestimate. Building electrification Dth costs on peak are at the lowest end of ACP Hampton Roads cost estimates, and bio fuels and LNG storage are more expensive than the pipeline alternative.

LNG storage

Perhaps the most common gas peak shaving measure currently in use, LNG storage and vaporization reduces potential supply shortfalls and the need for pipeline investment by allowing gas utilities to liquify gas (or to purchase liquefied gas) to store during non-peak times and vaporize LNG for use during peak periods.

A 2015 study calculated the costs of LNG storage and processing capacity for New England (not including the cost of the gas itself or LNG shipping costs) at \$3.50 to \$3.60 per Dth on peak, and suggested an additional factor of 15 percent (not included in Figure 11) be added to this estimate to account for gas used to power the processing facility.⁵²

Bio fuels

Gas capacity supplied through local renewable bio fuels (landfill gas, dairy digester gas, wastewater treatment, municipal solid waste) may provide a limited source of energy on peak without need for additional pipeline infrastructure.

In September 2018, Consolidated Edison Company of New York (ConEd) filed a request for approval of non-pipeline alternatives with the New York Public Service Commission, which included costs for bio fuel strategies.⁵³ Assuming a 20-year life and 8 percent weighted average cost of capital, AEC calculated Dth costs on peak for each of the alternative resources for which ConEd presented costs. ConEd estimated the cost of its bio fuel alternatives at \$2.60 per Dth on peak.

Building electrification

Replacing gas space and water heating with electric heat pumps—a process sometimes called “building electrification”—can shave peak demand for gas, reducing potential supply shortfalls. Switching from gas heating to electric heat pumps greatly reduces the total amount of gas needed for heating, including

⁵² Hibbard, P.J. & Aubuchon, C.P. 2015. Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas. Analysis Group, Inc. Available at:

<https://www.mass.gov/files/documents/2016/11/pe/reros-study-final.pdf>

⁵³ ConEd. September 28, 2018. *Petition of Consolidated Edison Company of New York, Inc.’s Request for Approval of Non-Pipeline Solutions Portfolio in the Smart Solutions for Natural Gas Customers Program*. New York Public Service Commission Case 17-G-0606. Available at:

<http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A7C3D0CD-E2B3-4B42-807C-82B553AE63F9}>

gas used to produce the electricity that runs heat pumps. To generate 1 MMBtu of energy a gas furnace requires 11 therms of gas.⁵⁴ Heating the same 1 MMBtu of energy using an electric heat pump requires 90 kWh of electricity;⁵⁵ on average, Dominion burns 2.35 therms of gas to produce this electricity. In the Dominion territory, switching from gas to electric heat pump heating results in a 77 percent reduction in the amount of gas consumed per household. Note that electric capacity in the PJM area is in excess of reserves required for reliability purposes and this surplus is expected to continue for more than a decade.⁵⁶

A recent AEC report found that the cost of installing and operating a heat pump in Massachusetts is \$36 per year higher than installing a new gas furnace and central AC system.⁵⁷ ConEd's petition for approval of non-pipeline alternatives provide a cost of a heat pump program equivalent to \$1.62 per Dth on peak.

Energy efficiency

Gas energy efficiency and other demand-side programs serve as an alternative to pipeline investments by reducing customer demand and, therefore, reducing any potential shortfall between supply and demand. Energy efficiency programs reduce the amount of gas needed to provide the same level of energy and heating and can be a cheap and effective way to reduce peak demand. Energy efficiency programs that are specifically targeted at peak usage increase the potential to shave gas system peaks.

Electric energy efficiency programs place a specific value on avoided costs on peak, usually calculated at the avoided capacity cost in dollars per megawatt. While gas energy efficiency programs typically do not, to date, include an explicit avoided capacity cost, ConEd's petition for approval of non-pipeline alternatives provides a cost of a gas energy efficiency program equivalent to \$1.58 per Dth on peak.

It is important to note that this is the direct cost to the utility of administering a gas energy efficiency program. It is not a net cost that includes the benefits of gas energy efficiency, including avoided gas use, avoided water use, and positive health impacts and other non-energy benefits. Gas energy efficiency programs are operated all over the United States based on estimates of their net costs (which do not typically include a dollar value for peak shaving benefits) as "all cost effective", or having benefits equal to or greater than their costs. ConEd's gas energy efficiency program cost is very likely an overestimate. The cost of gas energy efficiency is calculated in many states as net negative: that is, each unit of energy efficiency confers benefits that are greater than its costs.

⁵⁴ Assuming an Annual Fuel Utilization Efficiency (AFUE) of 95 percent.

⁵⁵ This assumes a heat pump with a Heating Seasonal Performance Factor (HSPF) of 11.

⁵⁶ PJM Staff. 2018. *2018 PJM Reserve Requirement Study: 11-year Planning Horizon*. Available at: <https://www.pjm.com/-/media/committees-groups/committees/pc/20181011/20181011-item-06b-2018-pjm-reserve-requirement-study-draft.ashx>

⁵⁷ Lopez, R., Comings, T., Stanton, E. & Tavares, E. 2019. *Home Heat Pumps in Massachusetts*. Applied Economics Clinic. Available at: <https://aeclinic.org/publicationpages/2019/5/29/home-heat-pumps-in-massachusetts>

Gas demand response

Gas demand response programs are another demand-side measure that can shave peak demand and reduce potential supply shortfalls. Demand response programs provide incentives to customers to reduce their energy usage during peak times, which can reduce aggregate peak demand. A recent study by Brattle found that gas demand response programs can reduce the need in infrastructure and provide cost savings.⁵⁸ A pilot study for Massachusetts found that using smart thermostats can reduce winter peak demand by 3.5 percent, equivalent to almost 180,000 therms over the course of the winter season.⁵⁹ A winter demand response program by Southern California Gas Company produced a 3.7 percent reduction in gas usage during three days in January 2017, equivalent to about 800 therms of gas savings in three days.⁶⁰ Cost information for gas demand response was not sufficient to allow estimation on a Dth on peak basis.

Interruptible rates

Interruptible rates, used widely by gas utilities around the country, provide an incentive similar to demand response. Currently, for smaller commercial or industrial customers, VNG interruptible delivery rate is \$0.05 per therm (with fixed monthly charge included),⁶¹ while the rate for firm service for commercial and industrial customers is \$0.75 per therm (with fixed monthly charge included)—a difference of \$0.70 per therm.⁶² ⁶³ Our preliminary review of interruptible rates for gas utilities in Montana, North Dakota, Oregon, Pennsylvania, South Dakota, Washington and Wyoming found a difference between interruptible and non-interruptible rates for small commercial customers ranging

⁵⁸ Weiss, J., Levine, S., Sergici, S., Thapa A. & Grausz, L. 2018. *Demand response for natural gas distribution: opportunities and challenges*. The Brattle Group. Available at:

https://brattlefiles.blob.core.windows.net/files/13929_demand_response_for_natural_gas_distribution.pdf

⁵⁹ Massachusetts Department of Energy Resources. July 2015. *Nest seasonal savings. Impact evaluation*. Available at: <https://www.mccleanenergy.org/wp-content/uploads/2016/08/MCE-AL-17-E-Seasonal-Savings-Pilot.pdf>

⁶⁰ Schellenberg, J., Savage, A. & Ciccone, A. 2017. *SoCalGas® 2016-2017 Winter Demand Response Load Impact Evaluation*. Nexant, Inc. Available at: http://www.calmac.org/publications/SoCalGas_2016-2017_Winter_DR_Load_Impact_Evaluation.pdf

⁶¹ This is calculated as the monthly charge to interruptible customers in VGN's Schedule 9 that use less than 50,000 Mcf, expressed as \$/Mcf, plus the rate per Mcf, and then converted to \$/th. VNG's current rates (May 2019) are available at: <https://www.virginianaturalgas.com/-/media/Files/VNG/Rates-Tariff/2019/May%202019%20Website%20Rsates.xlsx>

⁶² This is calculated as the monthly charge to C&I customers in VGN's Schedule 2C that use 500 Ccf, expressed as \$/Ccf assuming they use this full amount, plus the rate per Ccf, and then converted to \$/th. VNG's current rates (May 2019) are available at: <https://www.virginianaturalgas.com/-/media/Files/VNG/Rates-Tariff/2019/May%202019%20Website%20Rsates.xlsx>

⁶³ VA SCC. PUE-2016-00143. March 2018. *Schedule of rates and charges*. Available at: <http://www.scc.virginia.gov/docketsearch/DOCS/3jsc01!.PDF>



from \$0.07 to \$0.46 per therm.⁶⁴ Cost information for interruptible rates was not sufficient to allow estimation on a Dth on peak basis.

Electric battery storage

Electric battery storage could reduce electric peak, thus easing constraints at the coincident peak between electric and gas. The same could be said of all electric peak shaving measures, especially those related to reducing electric heating demand because that occurs on the coincident peak.

A study for North Carolina found that residential battery storage in combination with a rooftop solar is not cost-effective under current electric rates.⁶⁵ The study considered Lithium ion batteries with 4-hour duration and a lifetime of 10 years. Since the price of these batteries is expected to decrease over time, the study finds that by 2030, residential battery storage may be cost effective.

⁶⁴ Interruptible rates were taken from various utility websites where interruptible and non-interruptible rates for commercial customers were made available. Montana, North Dakota, South Dakota, Wyoming: Montana-Dakota Utilities: <https://www.montana-dakota.com/rates-services/rates-tariffs/>. Oregon and Washington: Cascade Natural Gas: <https://www.cngc.com/rates-services/rates-tariffs/>. Pennsylvania: Philadelphia Gas Works: <https://www.pgworks.com/uploads/media/PGWGasServiceTariff.pdf>.

⁶⁵ NC State Energy Storage Team. 2018. *Energy storage options for North Carolina*. Available at: <https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2019/02/NC-Storage-Study-FINAL.pdf>