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

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AUTHORS

Rachel Wilson
Spencer Fields
Patrick Knight
Ed McGee
Wendy Ong
Nidhi R. Santen, PhD
Thomas Vitolo, PhD
Elizabeth A. Stanton, PhD

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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Executive Summary

The Southern Environmental Law Center and Appalachian Mountain Advocates retained Synapse Energy Economics, Inc. (Synapse) to determine whether proposed new interstate pipelines that would deliver natural gas from West Virginia to Virginia and the Carolinas are necessary to maintain adequate gas supply to the region. Two new interstate pipelines have been proposed to transport natural gas from the Marcellus Shale into Virginia and the Carolinas:

1) Atlantic Coast Pipeline (proposed by Dominion Pipeline, Duke Energy, Piedmont Natural Gas, and AGL Resources); and

2) Mountain Valley Pipeline (proposed by EQT Midstream Partners, NextEra US Gas Assets, WGL Midstream, and Vega Midstream MVP).

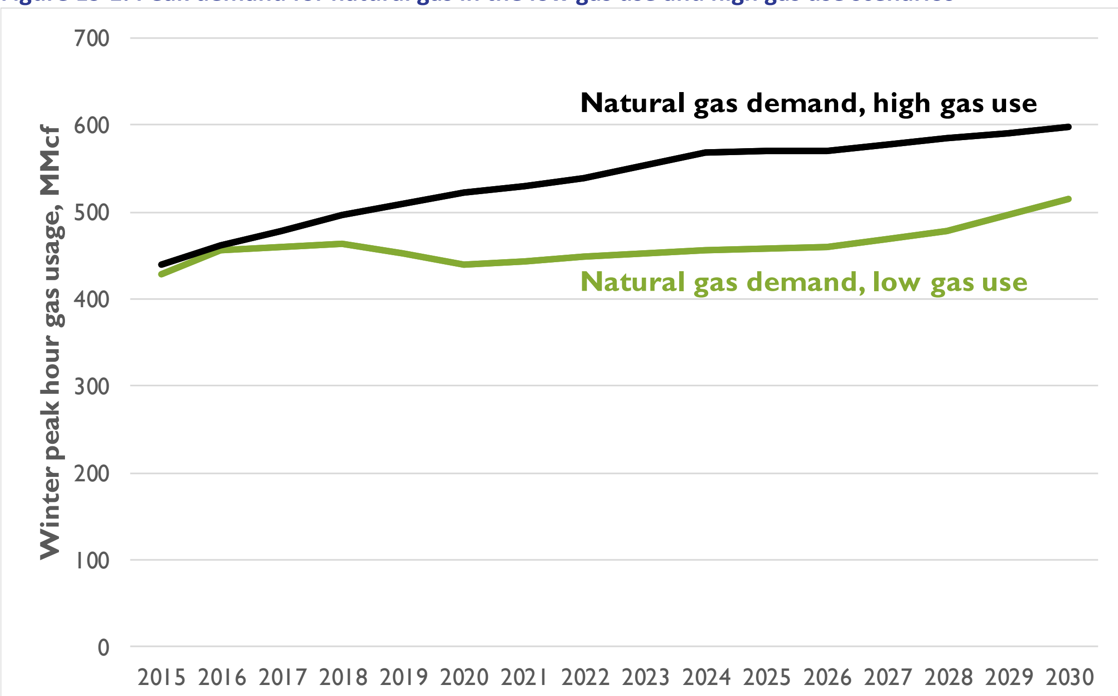
In their proposals, the developers of these projects assert that subscription rates for pipeline capacity demonstrate the need for additional natural gas in the target region, but they fail to compare the region's existing natural gas supply capacity to its expected future peak demand for natural gas. We undertake that comparison in this report. In the analysis presented here Synapse finds that, in fact, given existing pipeline capacity, existing natural gas storage, the expected reversal of the direction of flow on the existing Transco pipeline, and the expected upgrade of an existing Columbia pipeline, the supply capacity of the Virginia-Carolinas region's existing natural gas infrastructure is more than sufficient to meet expected future peak demand. This result raises significant questions about the need for additional investment in new interstate natural gas pipelines in the region and, more generally, the utility of pipeline subscription rates as justification for these projects.

Future demand for natural gas

Synapse developed low and high scenarios of future natural gas use for the study region, defined as Virginia, North Carolina, and South Carolina, to identify the expected range of likely demand for natural gas. Both low and high scenarios comply with the U.S. Environmental Protection Agency's limits for carbon dioxide emissions under the Clean Air Act. These limits consist of two separate regulations under Section 111(b) (Carbon Pollution Standards), which establishes federal standards for new, modified, and reconstructed power plants, and Section 111(d) (Clean Power Plan), which establishes state-based standards for existing power plants. While the demand for energy services is the same in each scenario, the low gas use scenario assumes greater energy efficiency savings and a more rapid build out of renewable generating facilities while the high gas use scenario assumes a greater number of retirements of coal-fired generating units and the use of new and existing natural gas-fired generators to meet emission goals.

In the high gas use scenario, renewable capacity and savings from energy efficiency in each state are determined by individual Renewable Portfolio Standards and Energy Efficiency Resource Standards. North Carolina is the only state in our study region with a Renewable Portfolio Standard, so its renewable capacity increases to meet its targets. Otherwise, renewable capacity and energy efficiency savings remain relatively constant in the high gas use scenario throughout the study period. Natural gas is used to meet Clean Power Plan targets, thus representing the outer bound of likely future natural gas demand. For both scenarios, Synapse estimated the highest combined electric and non-electric natural gas demand in any hour of the year in order to compare this "peak hour" value to the region's anticipated supply capacity of natural gas. If the region's natural gas infrastructure can supply sufficient gas during the peak hour of greatest demand, then there should be no obstacle to supplying gas during the rest of the year. Figure ES-1 shows the peak demand for natural gas in each year during the study period for the low gas use and high gas use scenarios.

Figure ES-1. Peak demand for natural gas in the low gas use and high gas use scenarios



Future natural gas supply capacity

In Virginia and the Carolinas, peak demand for natural gas is satisfied by the combination of several different types of supply capacity, notably:

- **Existing pipelines:** The existing pipelines belonging to Transco, Cove Point, Columbia Gas Transmission, Dominion Transmission, Southern Natural Gas, South Carolina PL Corporation, East Tennessee Natural Gas, Nora Transmission, and Bluefield Gas have the capacity to supply just over 300 MMcf per hour into the study region.

- **Reported natural gas storage:** Storage is an essential part of every natural gas supply system and plays a critical role in meeting peak demand. Reported liquefied natural gas (LNG) and underground natural gas storage in the region has the capacity to supply 71 MMcf per hour. Not all owners of natural gas infrastructure are required to report storage capacity, so the region's maximum or actual natural gas storage is not known.

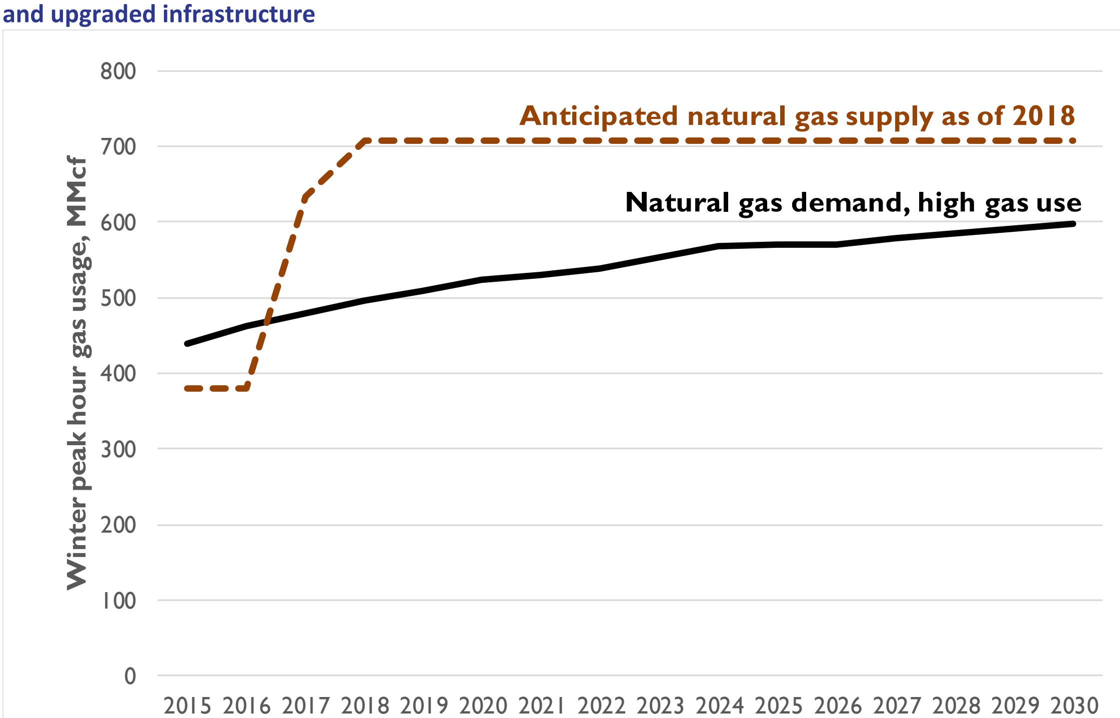
The "reported" storage value used in this analysis is, therefore, a conservative assumption and, indeed, is lower than the minimum amount of regional storage that existed in 2015 (that is, the difference between pipeline capacity and peak hour demand).

- **Expected reversals and upgrades of existing pipelines:** The reversal of the Transco Mainline pipeline as part of the Atlantic Sunrise project has been proposed before the Federal Energy Regulatory Commission (FERC) and is expected to add the capacity to supply 254 MMcf per hour to the study region in 2017 (changing the export of 127 MMcf to an import of 127 MMcf, for a net change of 254 MMcf). The WB Xpress project, an upgrade to an existing pipeline proposed by Columbia Gas, would add an additional 73 MMcf per hour to the region beginning in 2018.

Result: Natural gas supply capacity exceeds peak demand

Figure ES-2 compares maximum expected natural gas demand (peak-hour demand in our high gas scenario) in years 2015 through 2030 to anticipated natural gas supply capacity on existing and upgraded infrastructure, including existing pipelines, reported storage, the 2017 reversal of the Transco Mainline pipeline, and the 2018 WB Xpress project. (Note that reported supply capacity is lower than actual peak hour demand in 2015 and 2016: In all likelihood, the gap in capacity to serve actual peak was supplied by natural gas storage facilities that are not reported in publicly available data sources.)

Figure ES-2. Maximum peak hour natural gas demand compared to anticipated natural gas supply on existing and upgraded infrastructure



For Virginia and the Carolinas, the anticipated natural gas supply capacity on existing and upgraded infrastructure is sufficient to meet maximum natural gas demand from 2017 through 2030: Additional interstate natural gas pipelines, like the Atlantic Coast and Mountain Valley projects, are not needed to keep the lights on, homes and businesses heated, and existing and new industrial facilities in production. This assessment of sufficient supply capacity includes only reported storage capacity, ignoring the existence of additional unreported storage capacity demonstrated by recent years' peak hour demand.

Assessing the need for pipeline investment

Interstate transmission pipeline infrastructure serving Virginia and the Carolinas is part of an interconnected system that includes pipeline and storage capacity both inside and outside of the region. Considering each new pipeline proposal as an isolated project ignores important alternatives that would increase regional natural gas supply capacity and avoid the adverse impacts on communities or the environment that can result from new construction. Alternatives to new pipeline construction include:

- Projects that reverse the flow of the Transco pipeline will lead to a significant increase in natural gas capacity in the Virginia and Carolinas region, and make new interstate transmission infrastructure (e.g., the proposed Atlantic Coast Pipeline and the Mountain Valley Pipeline) unnecessary to serve the market in Virginia and the Carolinas. Reversal of the Transco pipeline is one component of the proposed Atlantic Sunrise project.
- Investment in additional storage facilities may be a more cost-effective solution to boosting natural gas supply capacity in those few hours of the year where concerns exist regarding supply constraints.
- New or accelerated measures for gas energy efficiency, electricity energy efficiency, demand response (programs that pay large electric consumers to shift demand off of peak hours), and investment in renewable generating resources are critical tools to lower both annual and peak demand for natural gas.

To safeguard public interests, a determination of need for new pipeline infrastructure requires a detailed, integrated analysis of natural gas supply capacity and demand for the region as a whole.

1. INTRODUCTION

Two new interstate pipelines have been proposed to transport natural gas from West Virginia into Virginia and the Carolinas: 1) Atlantic Coast Pipeline (proposed by Dominion Pipeline, Duke Energy, Piedmont Natural Gas, and AGL Resources); and 2) Mountain Valley Pipeline (proposed by EQT Midstream Partners, NextEra US Gas Assets, WGL Midstream, and Vega Midstream MVP).[1] The developers of both projects assert that these pipelines are necessary to meet regional energy demand now and in the future.

Interstate transmission pipeline infrastructure serving Virginia and the Carolinas is part of an interconnected system that includes natural gas pipeline and storage capacity both inside and outside of the region. For a pipeline developer to establish that a new interstate pipeline is necessary, it would need to demonstrate that existing natural gas capacity in Virginia and the Carolinas region is not sufficient to provide enough gas to meet the demand over the course of a year or—more importantly—in the peak winter hour. For such a demonstration to be defensible, it would be necessary to base estimates of future capacity and demand of natural gas on detailed modeling of both the non-electric and electric sectors. If there were evidence of a capacity shortage in the model, it would likely present itself through higher natural gas prices and resulting higher electricity prices and/or through modeled results showing curtailment of natural gas-fired generators.

The developers of the Atlantic Coast and Mountain Valley proposal development projects assert that these pipelines are necessary to meet regional energy demand. Synapse conducted an independent examination of the validity of these statements by analyzing public documents relating to the proposed and existing natural gas infrastructure, and performing a modeling analysis of projected natural gas demand. We conducted our analysis in four steps:

- Estimation of winter peak non-electric demand in our study region
- Development of two scenarios of demand for natural gas in the electric sector and low, reference, and high sensitivity assumptions regarding the price of natural gas
- Assessment of future natural gas supply in our study region
- Analysis of balance between natural gas capacity and demand during the winter peak hour

Section 2 of this report provides an overview of the ways in which pipeline developers have assessed the need for their projects in the filings submitted to the Federal Energy Regulatory Commission. It then describes our own estimates of future peak demand for natural gas.

[1] Note that a third pipeline, the Appalachian Connector Pipeline, has also been proposed by the Williams Company but the necessary application and supporting materials have not yet been filed with the Federal Energy Regulatory Commission.

Section 3 describes existing natural gas capacity infrastructure and anticipated future supply.

Section 4 compares existing and projected natural gas supply with natural gas demand during the winter peak for each modeled year.

Finally, three appendices present detailed modeling assumptions and results:

- Appendix A presents the methodology used to estimate non-electric demand.
- Appendix B presents the methodology used to estimate demand from the electric sector.
- Appendix C presents the methodology used to develop the estimates of winter peak natural gas use in the ReEDS model.

2. FUTURE DEMAND FOR NATURAL GAS

A determination of need for incremental pipeline capacity in the Virginia-Carolinas region requires a projection of future demand for natural gas from non-electric (residential, commercial, and industrial) and electric end uses. Residential and commercial use of natural gas is primarily for space and water heating and thus peaks annually in the winter when temperatures are lower. Industrial use often stays consistent from month to month. Regional use of natural gas for electric generation has historically been summer peaking; however, a slight decline in summer gas use in the past year, combined with an increase in winter gas demand, has resulted in similar gas consumption levels in the electric sector for both summer and winter peaks. As a result, when we combine the non-electric and electric uses for natural gas, we find that the "ultimate system peak," or hour of maximum natural gas demand, occurs in the winter. In order to ensure adequate supply to consumers, local distribution companies must be able to procure enough natural gas to reliably meet this ultimate system peak.

In their filings with the Federal Energy Regulatory Commission (FERC), pipeline developers must demonstrate that a market need exists for each of the proposed new pipelines, which should include detailed forecasts of expected end-use demand in the region. However, as described below, the developers' assessments of need rely primarily on Energy Information Administration (EIA), the statistical and analytical agency within the United States Department of Energy, projections of growth in natural gas used for electric generation.

2.1. Pipeline Developer Assessment of Need

The developers of the new natural gas pipelines proposed to run through Virginia and the Carolinas assert that their projects are necessary to meet future energy needs. Under Section 7(c) of the Natural Gas Act of 1938, FERC has jurisdiction over pipeline infrastructure and is authorized to issue certificates of "public convenience and necessity" for "the construction or extension of any facilities...for the transportation in interstate commerce of natural gas." FERC's decision to grant or deny a pipeline certificate is based upon a determination of whether the pipeline project would be in the public interest. The agency accounts for several factors, including a project's potential impact on pipeline competition, the possibility of overbuilding, subsidization by existing customers, potential environmental impacts, avoidance of the unnecessary use of eminent domain, and other considerations. This determination relies heavily on a demonstrated market need for the proposed new pipeline. FERC requires assessments of the need for new natural gas supply in the study region. Those assessments, which reside in the *Resource Report 1* documents filed by the developers, are summarized below.

Atlantic Coast Pipeline

The developers of the Atlantic Coast Pipeline attribute the need for the pipeline largely to their expectation of growth in future electric demand from natural gas generation. The developers cite data from EIA and the U.S. Census Bureau, stating that natural gas demand for all uses in Virginia and North Carolina has grown by 37 and 50 percent, respectively, between 2008 and 2012.[2] The pipeline's developers claim that "demand for natural gas in Virginia and North Carolina is expected to increase in coming decades due to a combination of population growth and displacement of coal-fired electric power generation."[3] They use the U.S. Census Bureau prediction that between 2000 and 2030, Virginia's population will grow by 2.7 million residents and North Carolina's by 4.2 million residents.[4] They also state that coal plant retirements and low natural gas prices will cause natural gas to surpass coal as the most common fuel for electric power generation in the region by 2035.[5]

The Atlantic Coast Pipeline developers commissioned a study from ICF International showing a scenario in which between 2019 and 2038 approximately 9,900 megawatts (MW) of coal and nuclear generating capacity in Virginia and North Carolina will retire, while the region builds 20,200 MW of new natural gas capacity. As a result, ICF predicts that demand for natural gas for electric power generation in the two states will "grow 6.3 percent annually between 2014 and 2035, increasing from 1 Bcf/d (billion cubic feet per day) to 3.7 Bcf/d."[6]

In April 2014, Duke Energy and Piedmont issued a request for proposals in North Carolina for incremental pipeline transportation service, citing their "existing and future natural gas generation requirements, core load growth, and system reliability and diversity goals."[7] Virginia Power Services Energy Corp, Inc. issued a similar request to serve Virginia. These companies contracted for

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[2] 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. Available online at: https://www.dom.com/library/domcom/pdfs/gas-transmission/atlantic-coast-pipeline/acp-shp-rr1-1.pdf.

[3] Ibid.

[4] Ibid.

[5] Ibid.

[6] Ibid, page 1-5.

[7] Ibid, page 1-5.

transportation service on the Atlantic Coast Pipeline, along with other companies in the region. According to the pipeline's developers, "over 90 percent of the new pipeline system's capacity has been contracted for in binding precedent agreements with major utilities and local distribution companies…(and) (t)he ACP [Atlantic Coast Pipeline] is not designed to export natural gas overseas; this is not a component of the purpose and need of the ACP."[8]

Mountain Valley Pipeline

The assessment of need from the developers of the Mountain Valley Pipeline has fewer details, though they also base their needs assessment on their expectation of growth in electric power generation from natural gas. Developers state that the EIA predicts total U.S. natural gas consumption will increase from 25.6 trillion cubic feet in 2012 to 31.6 trillion cubic feet in 2040, with much of this increase in demand coming from the electric sector.[9] Developers also state that "the increased demand for natural gas is expected to be especially high in the southeastern United States, as coal-fired generation plants convert to or are replaced by natural gas fired generation plants. The infrastructure design of the Project is expected to benefit these regions by connecting the production supply to the market demand."[10] Finally, according to the developers, "MVP [Mountain Valley Pipeline] may also support additional uses of natural gas in south central West Virginia and southwest Virginia by providing an open access pipeline that can facilitate interconnects and subsequent economic development associated with having access to affordable gas supplies, as these areas currently have limited interstate pipeline capacity."[11]The Mountain Valley Pipeline reports that it has secured 20-year commitments for firm transportation capacity for its full capacity, though the amount of gas that will be contracted for has not been reported at this time.[12]

Summary

The assessment of need from the developers of these proposed pipelines rely entirely on the expectation that there will be significant growth in regional natural gas use for electric power generation over the next 20 years. Developers expect that the Atlantic Coast Pipeline and Mountain Valley Pipeline will primarily (1) serve new natural gas-fired electric generating units constructed to replace retiring coal units or (2) meet growing electric demand in Virginia and North Carolina. Both pipeline developers rely on projections of electric demand and infrastructure additions from the EIA; however, the EIA has

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[8] Ibid, page 1-7.

[9] Mountain Valley Pipeline Project. 2015. *Resource Report 1 – General Project Description.* Prepared for Docket No. PF-15-3. Available online at: http://www.mountainvalleypipeline.info/current-news.

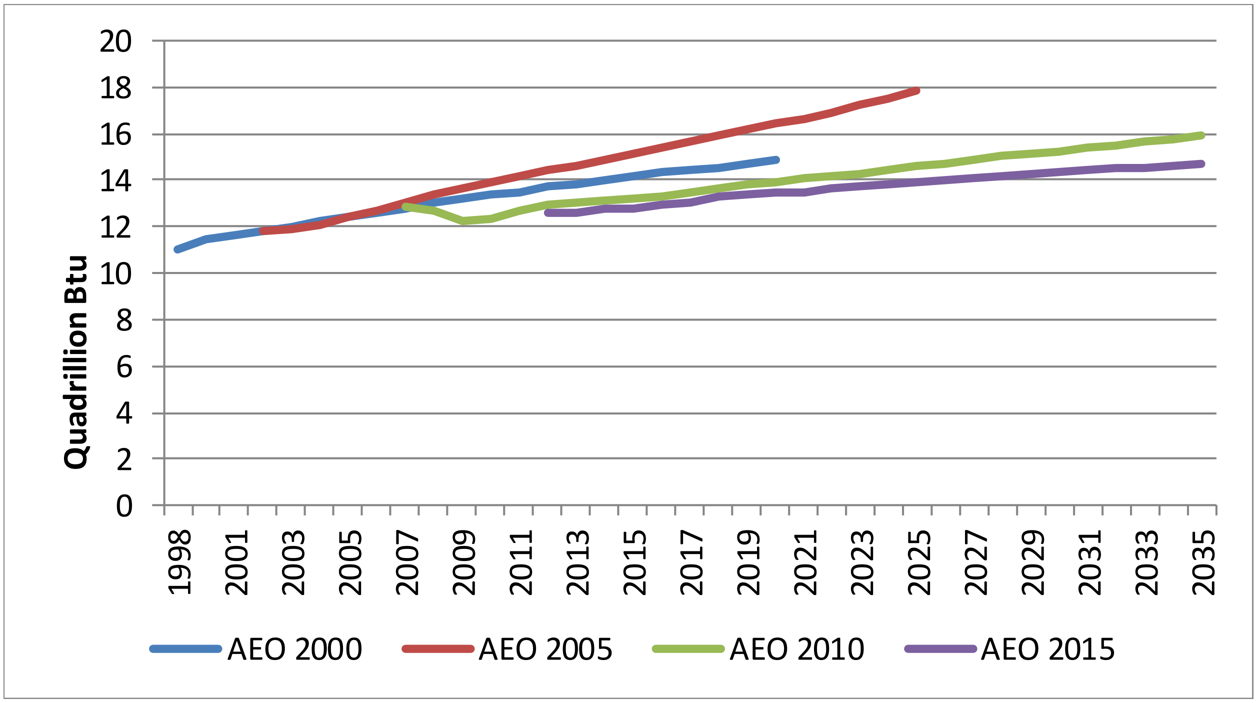
[10] Ibid.

[11] Ibid.

[12] Business Wire. 2016. *Mountain Valley Pipeline Secures New Shipper Commitment with Con Edison.* Available online at: http://www.businesswire.com/news/home/20160122005701/en/Mountain-Valley-Pipeline-Secures-Shipper-Commitment-Con

revised its forecasts of electricity consumption steadily downward over the last 15 years, as shown in Figure 1.

Figure 1. Historic EIA forecasts of electricity consumption, as published in the Annual Energy Outlook (AEO)



Pipeline developers also rely on subscription rates as a demonstration of need for new pipeline capacity. However, many of the customers that have contracted for capacity on these proposed pipelines are affiliates or subsidiaries of the pipeline owners, and are regulated utilities that pass pipeline costs to consumers through rates.

Of the two proposed pipeline developers that have filed an assessment of need, only the Atlantic Coast Pipeline developer did a modeling study to quantify the projected increase in natural gas demand. Neither developer assessed current and projected pipeline and storage capacity in the region to determine whether it is adequate to meet a projected increase in natural gas demand.

Pipeline Economics

Insufficient capacity to meet expected future natural gas demand is not the only reason that may explain proposals to develop new natural gas pipelines. Reasons for private investors to advance proposals for new natural gas supply infrastructure also include:

- **A secure return on investment:** Guaranteed—or otherwise very secure—avenues for returns on investments in natural gas pipelines are possible if utilities receive legislative, utility commission, or FERC approval to recover pipeline expenditures from gas or electric customers. These returns are, at time, higher than those for other investment opportunities.

- **Market benefits from lower or higher natural gas prices:** Large corporations with diverse holdings may take actions that depress or inflate the price of natural gas. These actions may have complex benefits in other related markets such as providing a stimulus for additional fuel switching to natural gas.
- **Commitment to the future of natural gas:** For corporations with both deep and wide-spread investments in the future of natural gas, actions to further entrench public energy infrastructure in this fuel may have long-run benefits unrelated to meeting current or near-future demand.
- **Interplay between market competitors**: Companies that have the development of natural gas pipelines as a core business area may propose pipelines early—before their competitors—as part of a long-run strategy to protect their market share.
- **Overseas exports:** The expected rapid expansion of U.S. exports of liquefied natural gas (LNG) over the next five to ten years will require sufficient infrastructure to deliver natural gas to existing and proposed LNG terminals. Pipeline developers that are confident that demand for U.S. LNG exports is on the rise have an additional motivation to expand their ownership interests in natural gas supply infrastructure.

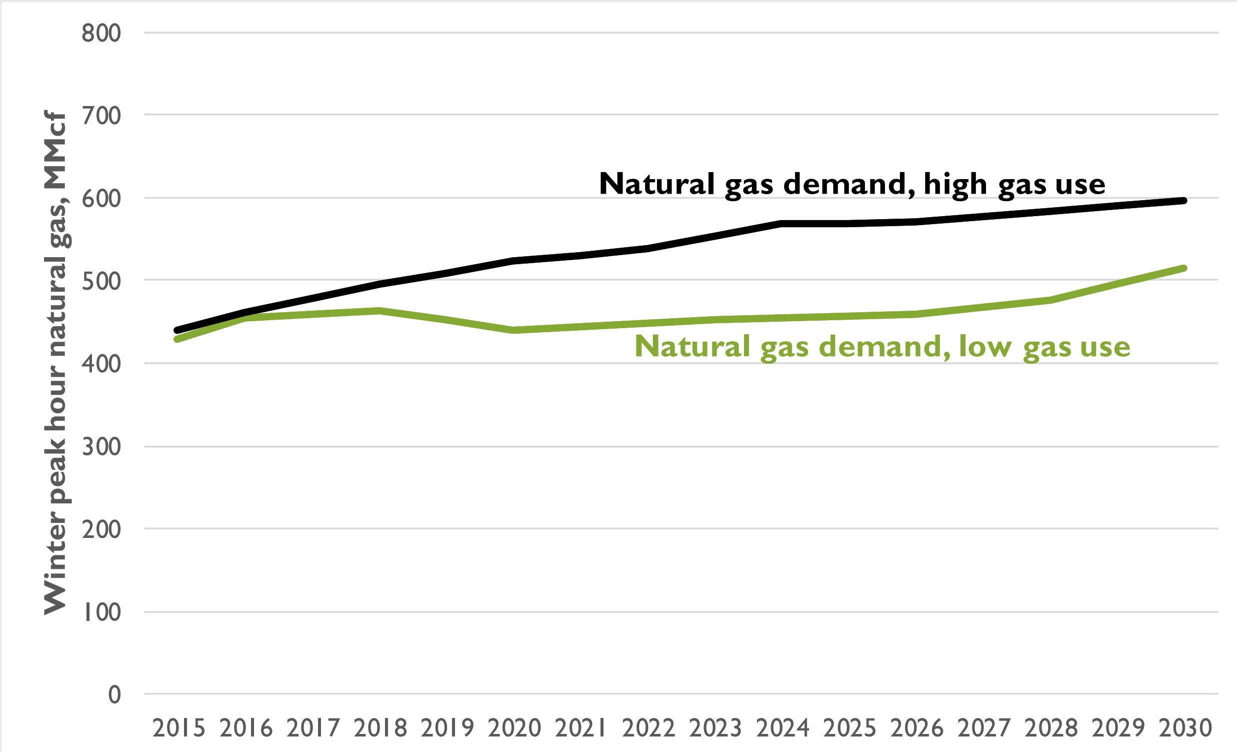
2.2. Estimates of Peak Demand for Natural Gas

Synapse projected peak demand for natural gas in Virginia and the Carolinas from 2015 to 2030. This projection had two components: non-electric natural gas demand and demand for natural gas from the electric sector. Forecasts of non-electric demand for natural gas reflect demand projections from natural gas suppliers in the Virginia-Carolinas region under a single scenario, commonly referred to as the "design-day" forecast. However, demand for natural gas from the electric sector is highly dependent upon the compliance pathway that each state decides to pursue to meet its individual reduction targets for emissions of carbon dioxide (CO_2) as established under the Clean Air Act's regulation of new and existing power plants.

We estimated peak natural gas demand under two scenarios: (1) a low gas use scenario that assumes compliance with the Clean Air Act through greater energy efficiency savings and a more rapid build out of renewable generating facilities; and (2) a high gas use scenario that assumes increased use of natural gas for electric power generation (thus representing the maximum expected gas use in the region). As described in more detail in Appendix A, we relied primarily on filings from natural gas distribution companies with the public utility commissions in their respective states as the basis for our forecast of non-electric natural gas use. For the electric sector, we used the National Renewable Laboratory's Regional Energy Deployment System (ReEDS model) to simulate electric system dispatch in the Eastern Interconnection and provide the forecasted volume of peak natural gas use under our high gas use and low gas use scenarios.

We then combined the forecast of peak non-electric demand with the forecasts of electric sector natural gas demand under both the high gas use and low gas use scenarios, as shown in Figure 2.

Figure 2. Combined peak demand for natural gas (non-electric and electric) in the low gas use and high gas use scenarios



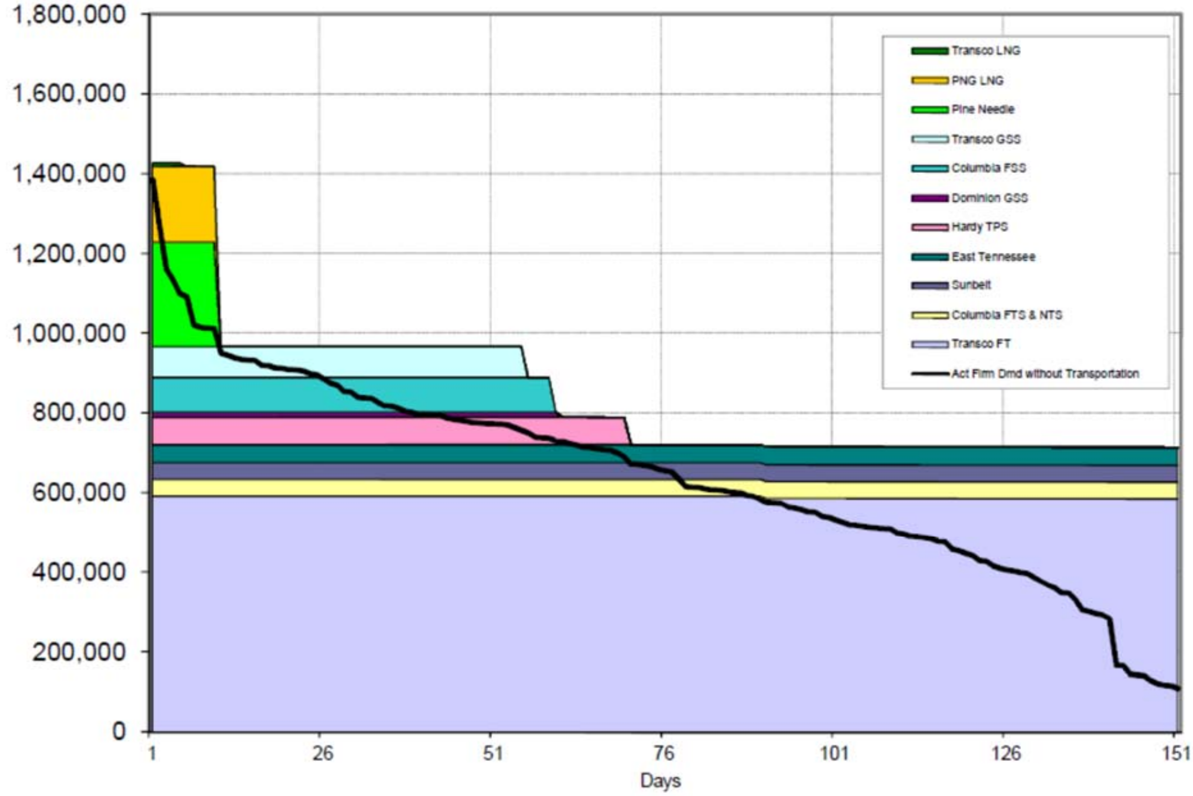
As shown in Figure 2, total demand for natural gas is higher in the high gas use scenario when companies rely on gas-fired generators to meet Clean Air Act goals. Demand in the peak hour reaches 597 MMcf in 2030 in this scenario, which reflects the maximum possible gas use in the region during the study period, compared to a peak-hour demand of 515 MMcf in the scenario that relies upon increased additions of renewable energy and energy efficiency in order to meet emissions reduction targets for CO_2.

3. Anticipated Natural Gas Supply on Existing and Upgraded Infrastructure

A determination of need for additional incremental pipeline capacity in the Virginia-Carolinas region also requires an inventory of existing natural gas infrastructure and planned upgrades and modifications to that infrastructure and an assessment of whether or not that supply flow is adequate to meet projected demand. The forms of natural gas capacity infrastructure considered in this analysis include existing pipeline capacity, existing storage, and future reversals and expansions of existing pipelines that would bring additional natural gas into the Virginia-Carolinas region. Inter- and intrastate natural gas pipelines transport gas from producing areas to both local distribution companies and directly to large consumers like electric power plants. These natural gas supplies typically help regions meet baseload (that is, average or everyday) natural gas demand, while storage resources contribute to meeting peak demand. Natural gas can be stored underground in aquifers, salt caverns, and depleted oil and gas fields, as well as aboveground in tanks that allow storage in liquid form.

Figure 3 gives an example graphical representation of the relationship between natural gas demand and natural gas supply infrastructure. The graph shows the forecasted winter demand for natural gas in 2015 and the supply available in the region from Piedmont Natural Gas, a distributor of natural gas in North and South Carolina, to meet that demand. The black line represents natural gas demand, and the colored rectangles represent the various types of capacity infrastructure used to meet demand on a given day. The graph shows pipeline capacity at the bottom of the stack, with the Transco, Columbia, Sunbelt, and East Tennessee pipelines providing natural gas in each of the 151 days shown on the graph. Base storage capacity is shown in the middle of the graph, and is represented by the Hardy storage facility as well as the storage services available on the Dominion, Columbia and Transco systems. Finally, the top tier of the graph shows available LNG storage, which is used to meet demand on a small number of peak winter days, and includes the Pine Needle, PNG LNG, and Transco LNG facilities. Note that in 2015 the Piedmont Natural Gas territory—as is common throughout the Virginia-Carolinas region—requires natural gas storage facilities in order to adequately supply natural gas on approximately 50 percent of winter days.

Figure 3. Piedmont Natural Gas 2015 design winter supply and demand – total Carolinas



Source: Piedmont Natural Gas. Testimony and Exhibits of Michelle R. Mendoza before the Public Service Commission of South Carolina. Docket No. 2015-4-G. June 3, 2015.

Synapse reviewed available information on existing pipelines in Virginia and the Carolinas in order to determine the capacity of the region's current natural gas infrastructure. Existing natural gas capacity comprises:

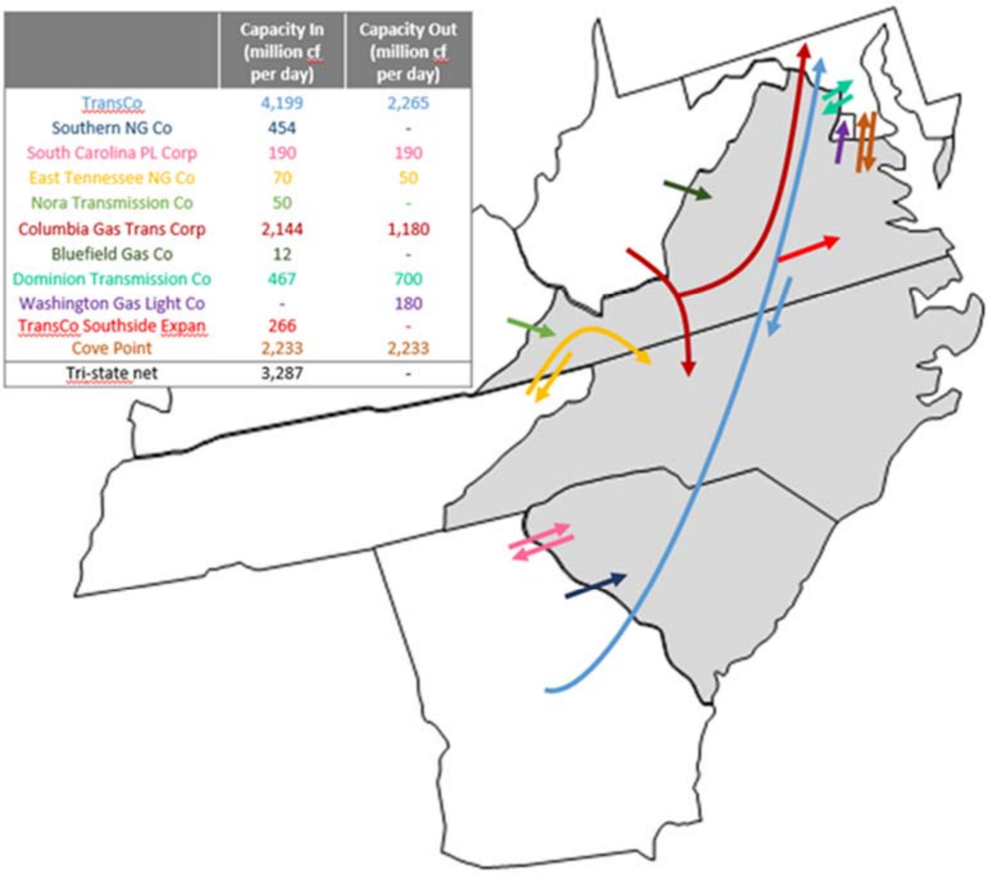
- existing pipeline capacity in the three-state region of Virginia, North Carolina, and South Carolina; and
- existing storage capacity within the region.

The following sections describe the region's existing and projected natural gas infrastructure in more detail.

3.1. Existing Pipelines

To estimate existing capacity in this analysis, we considered "historical in-flow," which limits the capacity to the pipeline inflow that existed in 2014, less any contracts out of the region. It is important to note that not all natural gas that originates in or passes through the region is meant for local use. We exclude gas under contract for capacity outside of the region from our estimation of the volume of gas available to contribute to in-region capacity. Figure 4 shows the existing pipelines currently in place in the region, along with a table detailing the current in-flow and out-flow capacity of these pipelines according to EIA data from 2014.

Figure 4. Currently existing natural gas supply capacity into and out of the Virginia-Carolinas three-state region



	Capacity In (million cf per day)	Capacity Out (million cf per day)
TransCo	4,199	2,265
Southern NG Co	454	-
South Carolina PL Corp	190	190
East Tennessee NG Co	70	50
Nora Transmission Co	50	-
Columbia Gas Trans Corp	2,144	1,180
Bluefield Gas Co	12	-
Dominion Transmission Co	467	700
Washington Gas Light Co	-	180
TransCo Southside Expan	266	-
Cove Point	2,233	2,233
Tri-state net	3,287	-

Source: Synapse analysis based on data from EIA. U.S. state-to-state capacity. December 2014. Available at: http://www.eia.gov/naturalgas/pipelines/EIA-StatetoStateCapacity.xls.
Note: Locations of pipelines are approximate and are not meant to portray the exact pipeline locations.

Note that the Williams Company placed the Transco Virginia Southside Expansion project into service in September 2015.[13] The 2014 EIA data shown in Figure 4 does not include that project, and Synapse added it to our estimate of the existing total pipeline capacity.

Figure 4 above shows the net capacity from existing pipelines in MMcf per day. In order to calculate the capacity from existing pipelines in the peak hour, we employ the industry standard assumption that 5.6

[13] Williams Company. 2015. "Williams' Transco Completes Virginia Southside Expansion." September 1. Available online at: http://investor.williams.com/press-release/williams/williams-transco-completes-virginia-southside-expansion

percent of daily gas demand occurs in the peak hour.[14] Estimated natural gas capacity available from existing pipelines during the peak hour is approximately 309 MMcf for the duration of the analysis period.

3.2. Natural Gas Storage

While natural gas pipeline capacity is used to meet baseload (average day-to-day) demand for natural gas, gas storage facilities play an essential role in meeting peak demand. As a standard, continual practice, natural gas is injected into these storage facilities during periods of low gas demand and withdrawn during peak periods. Peak send-out capacity in the Virginia-Carolinas region must provide sufficient volumes of natural gas to meet demand on even the coldest winter day. To do so requires a combination of pipeline and storage capacity resources.

Natural gas can be stored in several ways:

- **Underground reservoirs** are the primary form of natural gas storage, and consist of depleted oil and gas reservoirs, aquifers, and salt caverns. Suppliers can draw from these underground facilities to meet base demand or demand during peak periods.
- **Aboveground facilities,** such as LNG storage tanks, serve primarily during periods of peak demand and offer several advantages over underground facilities. LNG storage occupies less space than underground facilities, as they store natural gas in liquid form. For this reason, they tend to be in closer proximity to end-use markets and can often provide higher levels of deliverability on short notice.
- **"Line packing,"** in which natural gas is stored temporarily in existing pipelines by packing additional gas volumes into pipelines, provides additional natural gas during peak demand periods.

Owners and operators of natural gas storage facilities tend to be: 1) interstate and intrastate pipeline companies, which use storage to meet the demand of end-use customers; 2) local gas distribution companies, which use gas from storage to serve customers directly; and 3) independent storage service providers. Government authorities do not require all owners and operators of natural gas infrastructure to report their storage capacity, so we do not know the region's maximum or actual natural gas storage. We collected the Pipeline and Hazardous Materials Safety Administration's partial data on LNG facilities in the Virginia-Carolinas region, as well as EIA's data on the region's underground storage facilities. Together, these values make up the "reported" storage value used in this analysis. The hourly capacity contribution of reported storage is estimated to be 71 MMcf per hour and is shown in Table 1, below.

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[14] Levitan & Associates, Inc. 2015. Gas-Electric System Interface Study Target 2 Report: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems. Prepared for the Eastern Interconnection Planning Collaborative. p.82. Available online at: http://nebula.wsimg.com/c1a27fe57283e35da35df90f71a63f7a?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

Table 1. Storage capacity of LNG and underground facilities with deliverability to the Virginia-Carolinas region

Company Name	Facility Type	Facility Name	State	Total Daily Capacity (MMcf)	Hourly capacity (MMcf)
Columbia Gas of Virginia Inc	LNG	Lynchburg LNG	VA	6	0.3
Columbia Gas Transmission, LLC	LNG	Chesapeake LNG	VA	120	5.0
Greenville Utilities Commission	LNG	LNG Plant	NC	24	1.0
Piedmont Natural Gas Co Inc	LNG	Bentonville LNG	NC	180	7.5
Piedmont Natural Gas Co Inc	LNG	Huntersville LNG	NC	200	8.3
Public Service Co of North Carolina	LNG	PSNC Energy LNG	NC	110	4.6
Roanoke Gas Co	LNG	LNG Facility	VA	30	1.3
South Carolina Electric & Gas Co	LNG	Salley LNG	SC	90	3.8
South Carolina Electric & Gas Co	LNG	Bushy Park LNG	SC	60	2.5
Pine Needle Operating Company, LLC	LNG	Pine Needle LNG	NC	400	16.7
Columbia Gas/Piedmont Natural Gas	Underground	Hardy	WV	170.9	7.1
Spectra Energy	Underground	Early Grove	VA	20	0.8
Spectra Energy	Underground	Saltville	VA	300	12.5
	Total			1,710.9	71.3

Sources: (a) Pipeline and Hazardous Materials Safety Administration. Distribution, Transmission & Gathering, LNG, and Liquid Annual Data. Liquefied Natural Gas (LNG) Annual Data – 2010 to present. Available at http://phmsa.dot.gov/pipeline/library/data-stats/distribution-transmission-and-gathering-lng-and-liquid-annual-data; (b) US EIA. Natural Gas Annual Respondent Query System (EIA-191 Data through 2015). Available at http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7

The estimate of 71 MMcf per hour from storage is a conservative assumption. The Hardy storage facility in West Virginia is included in this estimate because publicly available documentation demonstrates that distribution companies in the Virginia-Carolinas region contract for storage with this facility. In addition, EIA data show the existence of an additional 149 MMcf/hour of active natural gas storage in West Virginia that we did not include in our estimate due to lack of evidence that this storage was contractually available to local distributors in our study area.

3.3. Planned Reversals and Expansions of Existing Pipelines

The major interstate pipelines continue to announce new expansion projects aimed at delivering gas from the Marcellus area to reach anticipated markets. Of the many proposals submitted to FERC that would affect markets across the United States, several propose large-scale expansion projects intended to deliver natural gas to the Virginia-Carolinas region.

The largest of these is Transco's Atlantic Sunrise project, which would reverse the flow of the Transco pipeline and allow the company to provide 1,675 MMcf per day of incremental firm transportation capacity for natural gas from northern Pennsylvania through our study region, terminating in Alabama. The expected in-service date for the project is July 1, 2017.[15] Transco in-flows and out-flows were

[15] Transcontinental Gas Pipe Line Company, LLC. 2015. *Resource Report No. 1: General Project Description*. Prepared for Atlantic Sunrise Project Docket No. CP15-138. Available online at: http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20150331-5153

included in our calculations of existing pipeline capacity. We assume that with the reversal of the Transco pipeline, the out-flows would be eliminated, and there would be a corresponding increase of in-flows, resulting in a net gain of 254 MMcf per hour of peak capacity from the Atlantic Sunrise project.

NiSource's Columbia Gas Transmission Company (TCO) has announced a number of new pipeline expansion projects including its WB Xpress project, designed to send additional shale gas supplies (about 1.3 Bcf per day) east from the Marcellus to West Virginia, Virginia, and the Cove Point LNG facility in Maryland. The WB XPress project would replace about 26 miles of existing TCO pipeline with a new line of the same diameter. Increased flows would result from the use of higher pressures that the new line would carry. The project, which the company anticipates being in-service in 2018, would add approximately 73 MMcf per hour of peak capacity.

4. Natural Gas Supply Exceeds Demand

Figure 5 compares our modeled maximum expected natural gas demand (peak-hour demand in our scenario of high gas use) in years 2015 through 2030 to future natural gas infrastructure, including existing pipeline capacity, reported storage, the expected 2017 reversal of the Transco Mainline pipeline, and the expected 2018 WB Xpress project. (Note that reported capacity is lower than actual peak hour demand in 2015 and 2016. In all likelihood, the gap in capacity to serve actual peak was supplied by natural gas storage facilities that are not reported in publicly available data sources and/or by some portion of the 149 MMcf/hour of active storage located in West Virginia.)

The region's anticipated natural gas supply on existing and upgraded infrastructure is sufficient to meet maximum natural gas demand from 2017 through 2030. Additional interstate natural gas pipelines, like the Atlantic Coast Pipeline and the Mountain Valley Pipeline, are not needed to keep the lights on, homes and businesses heated, and industrial facilities in production. This assessment of sufficient capacity includes only reported storage capacity, ignoring the existence of additional unreported storage capacity demonstrated by recent years' peak hour demand.

Figure 5. Peak hour natural gas demand under scenarios of low and high natural gas use compared to anticipated natural gas supply on existing and upgraded infrastructure

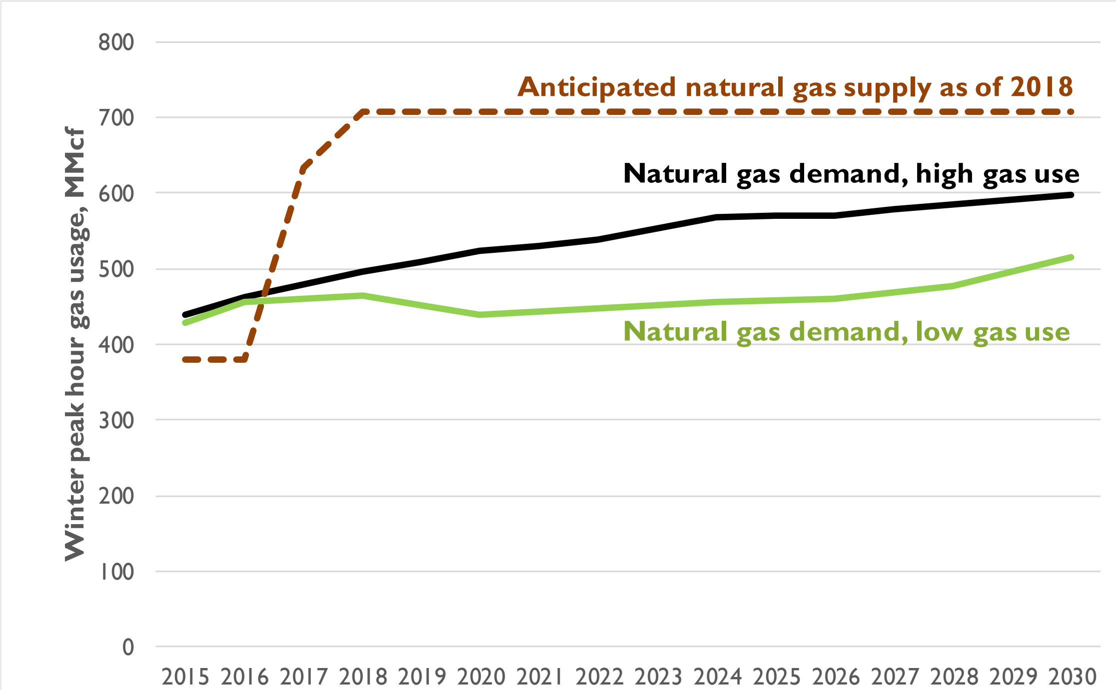


Figure 5 shows an excess of natural gas supply under a scenario of maximum natural gas demand. The policy pathway chosen by states for compliance with Clean Power Plan emissions reduction targets has a significant impact on the magnitude of this excess supply capacity, as shown in Figure 7. Under the high natural gas use scenario, where Clean Power Plan compliance is achieved primarily through the addition of new natural gas combined-cycle power plants, peak demand for natural gas climbs steadily throughout the study period and results in excess natural gas supply of approximately 100 MMcf per hour in 2030. In contrast, the low gas use scenario, which minimizes the addition of new NGCC generators and instead relies on new installations of renewable energy capacity and savings through efficiency measures, results in surplus supply of almost 200 MMcf per hour.

Projected future natural gas demand depends greatly on the policies pursued by each of the states in this analysis. While non-electric natural gas demand remains fairly constant during our analysis period, natural gas demand from the electric sector rises significantly over time in a scenario of high natural gas use, where the states pursue Clean Power Plan compliance through the use of new natural gas generating capacity. If states choose to pursue additional energy efficiency and renewable energy capacity under a scenario of low gas use, combined natural gas demand rises much more slowly over time and results in an even greater capacity surplus in 2030.

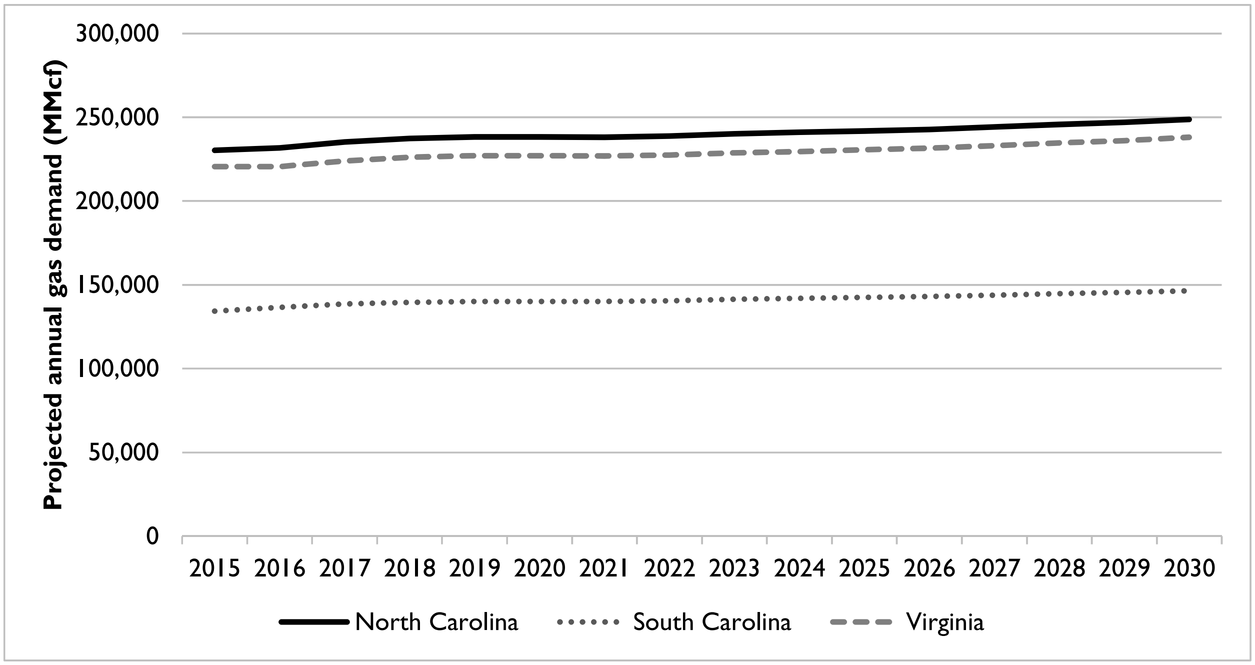
Appendix A: Non-Electric Demand Methodology and Data Sources

As an input to our modeling, we calculated projected demand for natural gas in Virginia and the Carolinas from 2015 to 2030.[16] This projection had two components: non-electric natural gas demand and demand for natural gas from the electric sector. As described below, we relied primarily on EIA data for the former and we used the Regional Energy Deployment System (ReEDS model) to calculate the latter. We projected natural gas demand for two different time periods, first calculating annual natural gas demand, and next making a projection of winter peak demand—the amount of natural gas consumed in both sectors at the hour of maximum demand. This section describes the methodology and data sources used to forecast non-electric natural gas demand, while Appendix B provides further detail on the methodology and data sources used to estimate natural gas demand from the electric sector.

Synapse based its forecast of non-electric natural gas demand for the states included in the analysis—North Carolina, South Carolina, and Virginia—on data from EIA's 2015 Annual Energy Outlook (AEO). EIA publishes data on forecasted natural gas demand in the residential, commercial, industrial, and transportation sectors for the South Atlantic Region of the United States through 2040. We took the historical natural gas consumption rates by state and by sector and applied them to the forecasted regional natural gas demand in order to arrive at a forecast of annual non-electric demand for each of the three states in our analysis. These results are shown in Figure A-1.

[16] U.S. Energy Information Administration. 2015. *Annual Energy Outlook*.

Figure A-1. Projected annual non-electric natural gas demand

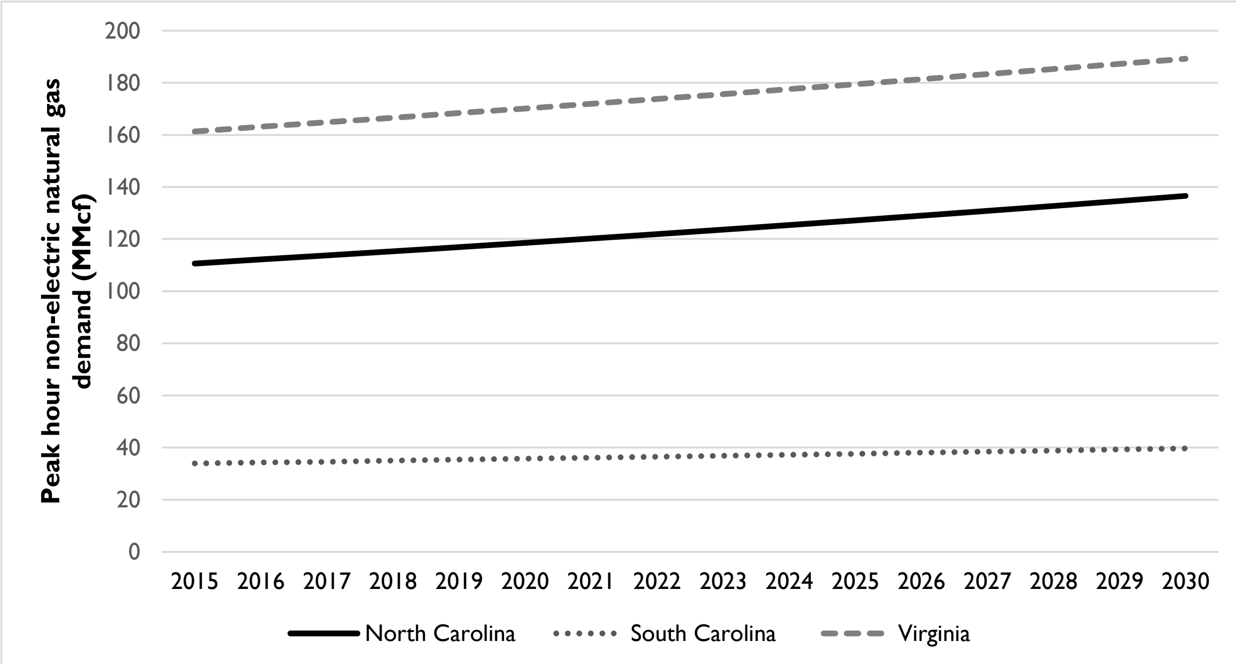


Source: EIA 2015 Annual Energy Outlook.

Second, projected non-electric winter peak demand was calculated using filings with state public utilities commissions from the 13 gas distribution companies located within the three states in this analysis. We reviewed filings from each local distribution company for the most recent year to determine the companies' "design day" natural gas requirements—the volume of gas needed to meet customer demand on the coldest winter day—and then summed the results across the distribution companies to arrive at design day totals for each of the three states. Companies typically presented results for the next one to five years in the future. Based on these results, we calculated compound annual growth rates for each company and applied them to future years to generate a forecast through 2030. In order to arrive at peak hour requirements from the design day, we assumed that the volume used in the peak hour of the design day represents 5.6 percent of the total design day volume.[17] Those projections of non-electric winter peak demand are shown in Figure A-2. Projected peak hour non-electric natural gas demand In the peak hour, non-electric natural gas requirements rise gradually throughout the modeled period, beginning at 306 MMcf in 2015 and rising to 366 MMcf in 2030.

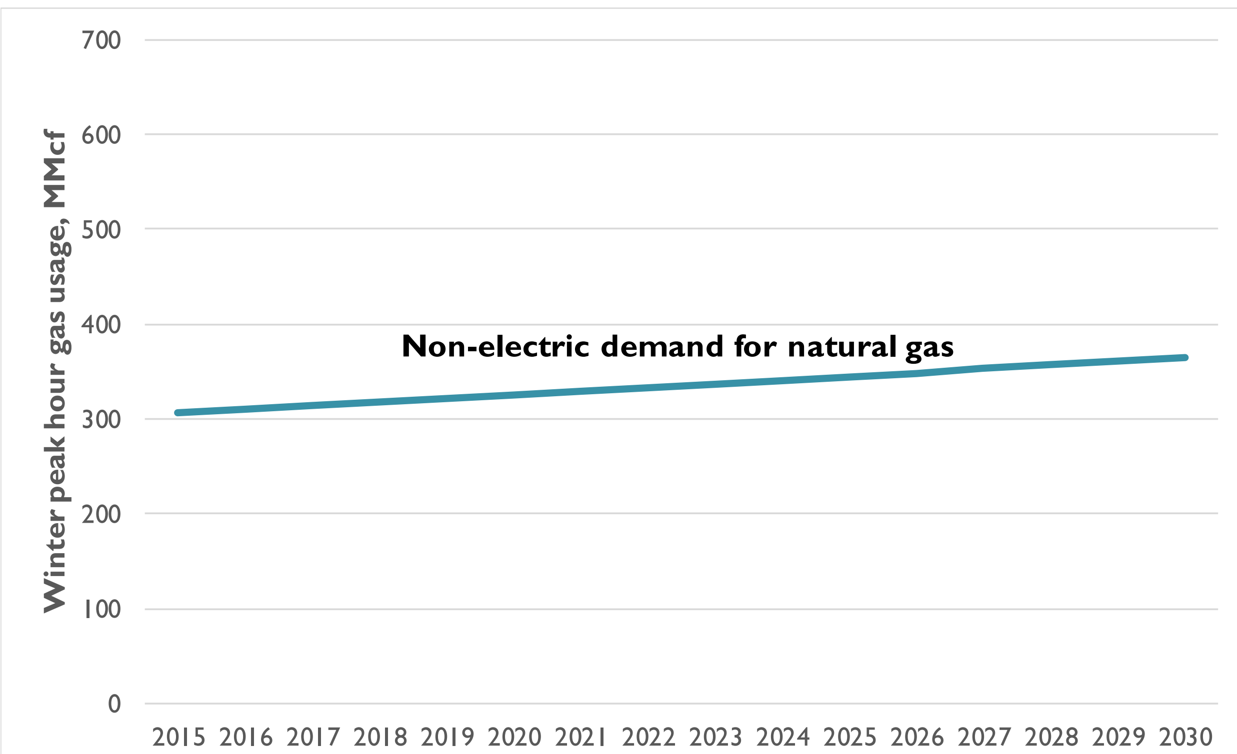
[17] Levitan & Associates, Inc. 2015. Gas-Electric System Interface Study Target 2 Report: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems. Prepared for the Eastern Interconnection Planning Collaborative. p.82. Available online at: http://nebula.wsimg.com/c1a27fe57283e35da35df90f71a63f7a?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

Figure A-2. Projected peak hour non-electric natural gas demand



Source: Data were taken from filings made with state public utilities commissions by gas distribution companies

Figure A-3. Peak-hour non-electric demand for natural gas in Virginia and the Carolinas



These methodologies resulted in forecasts for both annual and peak non-electric natural gas demand. Demand from the electric sector was derived from electric sector modeling, and is described in the next section.

APPENDIX B: ELECTRIC DEMAND METHODOLOGY AND DATA SOURCES

Electric sector modeling scenarios of low and high natural gas use were designed to comply with the U.S. Environmental Protection Agency's limits for carbon dioxide emissions under Sections 111(b) and 111(d) of the Clean Air Act, released on August 3, 2015. Section 111(b) (the Carbon Pollution Standards) sets emissions limits for new fossil-fueled power plants that commenced construction after January 8, 2014, or units that were modified or reconstructed as of June 18, 2014. Separate standards exist for coal- and natural gas-fired units, but each reflects the degree of emission limitation that EPA believes represents the best system of emission reduction (BSER) for each type of unit. The standard for new and reconstructed natural gas that is operating under baseload conditions is 1,000 pounds of CO2 per MWh on a gross-output basis, while non-baseload units must meet a clean fuels input-based standard. Standards for coal-fired plants depend on whether the unit is new, reconstructed, or modified. New coal-fired power plants must meet a standard of 1,400 pounds of CO2 per MWh-gross; reconstructed units must meet a standard of either 1,800 or 2,000 pounds of CO2 per MWh-gross, depending on their heat input; and the standards for modified facilities are plant specific and are consistent with best annual historical performance.

Section 111(d) (the Clean Power Plan) aims to reduce emissions of carbon dioxide (CO_2) from existing fossil fuel-fired power plants by approximately 30 percent below 2005 levels by 2030. Each state's approach to compliance with the proposed Clean Power Plan—its choice of what new resources to build and how much to run existing fossil-fuel generators—will have a critical role in determining how much electric-sector natural gas is needed in future years. In order to meet the emission reduction goals set by EPA, states must develop plans that will reduce their average CO_2 emission rate at affected generating units from a 2012 baseline rate to a lower state-specific target rate by 2030. In its proposed Clean Power Plan, EPA offers each state the flexibility to choose either mass- or rate-based targets for compliance.

We conducted modeling of electric sector demand in two steps. First, we developed two scenarios of Clean Power Plan compliance: (1) a scenario of high natural gas use that complies with emissions reduction targets through the use of new natural gas generators, and (2) a scenario of low natural gas use that relies on energy efficiency and installations of new renewable energy capacity to meet targets. We then screened them using Synapse's own Clean Power Plan Planning Tool (CP3T), which allows users to design future energy scenarios for Clean Power Plan compliance, to examine the various compliance pathways available to a state, and quantify the costs associated with those pathways.

The second step was to input these scenarios into the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) model, which dispatches the electric generators in the Eastern Interconnect in order to meet electric demand and provides annual values of natural gas use from the electric sector over our study period. ReEDS is a deterministic optimization model that provides a detailed representation of the electricity generation and transmission systems in the contiguous United States. It draws many of its assumptions from EIA's 2014 AEO. There are 356 resource supply regions in ReEDS, which are grouped into four tiers of larger regional groupings: balancing areas, reserve sharing groups, North American Electric Reliability Council (NERC) regions, and interconnects. States are also represented in such a way that state policies can be depicted accurately. ReEDS contains 17 annual "time-slices," representing the various ways that electricity loads are met throughout each day and year using all major generator types. One of these 17 time slices is representative of a summer peak—a collection of the highest 40 non-consecutive hours in the summer season, represented by a single "superpeak" time slice. The purpose of this analysis, however, was to evaluate the natural gas requirements for the winter peak hour, which is not represented by any of ReEDS 17 time slices. Synapse performed custom modifications to the underlying ReEDS code to add a winter superpeak time slice, which represents the single hour between the winter months of November and February in which electricity demand is at its highest. For more information on the winter peak modifications made to ReEDS, see Appendix C.

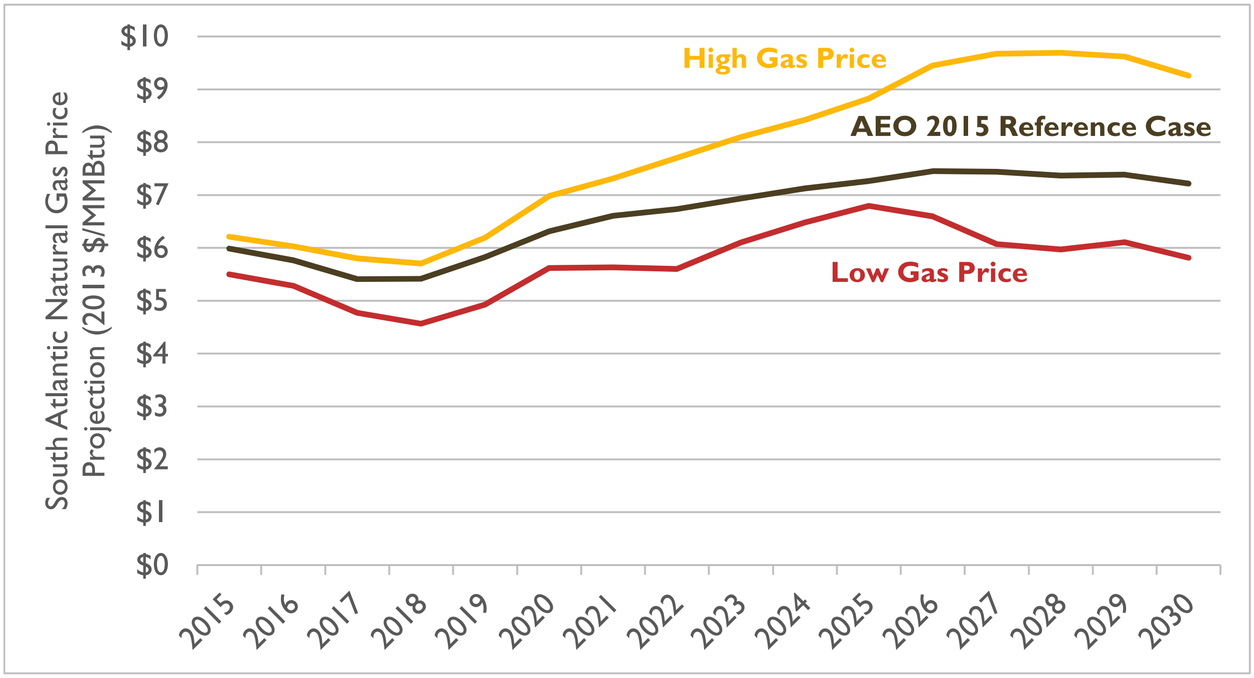
We began our modeling under a set of input assumptions for forecasting future retail sales of electricity, distributed solar PV adoption, natural gas prices, non-coal unit retirements, and announced unit additions through 2020. Future retail sales are based on EIA AEO data. Distributed solar PV adoption rates come from the SunShot 50 trajectory, which is the NREL trajectory that assumes that the cost of solar is reduced by 50 percent by 2020 and then remains constant—a conservative assumption. Natural gas prices used by the model are the regional forecasts from EIA's AEO. Announced unit retirements and additions were included in the modeling based on announcements from electric utilities in the study region.

We then had to develop two different scenarios of natural gas use in the Virginia-Carolinas region that met mass-based Clean Power Plan emission targets without significant over compliance. Mass-based targets were selected for modeling accuracy, and we assumed the new source complement in order to avoid emissions leakage to new power plants. This required the use of the CP3T and ReEDS models in combination. Electric sector capacity build-outs under the two different scenarios—one of which added significant amounts of new NGCC capacity to yield the highest likely estimate of natural gas demand, and one of which relied on new renewable capacity and energy efficiency—were first tested in CP3T for compliance. If those build-outs were found to achieve compliance within CP3T, which does not account for the electricity market interactions between states in the Eastern Interconnect, those values were then input into the ReEDS model, which does capture those market interactions. This ensures that interactions between states are adequately captured in terms of electricity imports and exports from one state to another. The outputs from the resulting ReEDS runs were then input back into CP3T in order to check for CPP compliance. Several iterations of CP3T/ReEDS modeling were required before we arrived at the capacity build-outs for the high gas use scenario (the addition of new NGCC generators) and for the low gas use scenario (the addition of renewable energy and energy efficiency) that would allow compliance with the emission targets established by the Clean Power Plan.

Natural gas price sensitivities

Synapse modeled each of the three scenarios described above with a mid-level, Reference Case natural gas price forecast and evaluated sensitivity cases that examined the effects of natural gas use in the electricity sector under high and low natural gas price forecasts. The mid-level natural gas price forecast was taken from the EIA's AEO 2015 South Atlantic Reference Case. Because the sensitivity case forecasts are only published biannually, the low natural gas price sensitivity forecast was determined by multiplying the Reference Case forecast by the ratio of the High Oil and Gas Resource Case[18] to the regional Reference Case found in AEO 2014. Similarly, the high natural gas price sensitivity forecast was determined by multiplying the Reference Case forecast by the ratio of the Low Oil and Gas Resource Case to the regional Reference Case found in AEO 2014. Those natural gas prices are shown in Figure C-1, below.

Figure C-1. Projection of natural gas prices in South Atlantic region



Synapse input the combinations of scenarios/sensitivities into the ReEDS model, which dispatched the future electric system to meet forecasted electricity demand throughout the analysis period. After running the various scenarios through the ReEDS model, Synapse exported the volume of natural gas, in million cubic feet (MMcf), used for electricity generation in each of the states in the analysis. These data were exported into an Excel spreadsheet both on an annual basis and at the hour of peak demand in each year, from 2015 to 2030, for each modeling scenario. Synapse combined this information with the non-electric demand for natural gas to analyze the need for additional pipeline capacity.

[18] The High Oil and Gas Resource Case assumes large volumes of available oil and natural gas resources, leading to lower prices for oil and gas. Conversely, the Low Oil and Gas Resource Case assumes limited available oil and natural gas resources, leading to higher prices.

APPENDIX C: WINTER PEAK MODELING

NREL's ReEDS model is a national-scale long-range generation capacity expansion planning model with the process of economic dispatch represented through seventeen "time slices" that make up the entire year. NREL chose time slices to appropriately represent times of the year (season) and times of the day when electricity power system operations are expected to be (approximately) similar. For reliability planning purposes, peak demand must be represented; ReEDS does this by collecting the highest 40 non-consecutive hours in the summer season, and representing them with a single "superpeak" time slice, H17. The other sixteen time slices original to ReEDS are shown in Table C-1.

While the summer superpeak is well represented in ReEDS, the winter peak is not. In the original version of the model, each time slice for winter (H9 – H12) is represented as the average load (GW) across all hours encompassed in the time slice. Although this is a very common methodology to keep long-range capacity planning models tractable, the equivalent of a winter season "superpeak" is missed, which in some areas can be significantly different than the average loads represented by the current wintertime slices.

The purpose of the changes Synapse made to the ReEDS model is to represent this winter superpeak for modeling gas-demand in the West Virginia, Virginia, North Carolina, and South Carolina (WV-VA-NC-SC) region. Synapse decided to implement the new winter superpeak using a single peak hour from November – February in the four-state WV-VA-NC-SC region. Below are the steps taken to develop the new one-hour winter superpeak version of the NREL ReEDS model, as well as a snapshot of results from a validation of the model.

Table C-1. Original ReEDS time slice definitions

Time Slice	Hours	season	time of day
H1	736	summer	10PM-6AM
H2	644	summer	6AM-1PM
H3	328	summer	1PM-5PM
H4	460	summer	5PM-10PM
H5	488	fall	10PM-6AM
H6	427	fall	6AM-1PM
H7	244	fall	1PM-5PM
H8	305	fall	5PM-10PM
H9	960	winter	10PM-6AM
H10	840	winter	6AM-1PM
H11	480	winter	1PM-5PM
H12	600	winter	5PM-10PM
H13	736	spring	10PM-6AM
H14	644	spring	6AM-1PM
H15	368	spring	1PM-5PM
H16	460	spring	5PM-10PM
H17	40	summer	superpeak
	8,760 (total)		

Source: NREL ReEDS Model.

Methodology

Step 1. Review ReEDS code, input tables, and time slice dependent equations

The first step in developing the capability of ReEDS to model a single-hour winter peak was to understand the structure of the underlying GAMS code, how the inputs interact with the code, and—most importantly—where the electricity demand and time period definitions are represented within the equations of the model. Synapse reviewed each GAMS file and all worksheets in the Excel workbook used to modify inputs to understand how "hard-coded" the time slice definitions were in the model and whether they would adapt to changes in the input Excel file. The programming code was also reviewed to ensure that optimizing dispatch over a single hour, where multiple hours used to be aggregated, would not cause instability in the mathematical algorithm itself. Synapse determined that as long as we left the "H17" summer superpeak intact (which was hard-coded in many places in the model), we could make all but one modification[19] to represent the single hour in the ReEDS Excel input file. The NREL

[19]The single modification made in the actual GAMS code involved adding the new winter superpeak to a set of time slices ReEDS represents as "not peak." GAMS reserve margin calculations exclude these extraordinary peaks, so per NREL's

ReEDS model development team[20] confirmed that no stability issues or other model infractions would result from representing a single-hour dispatch in the ReEDS dispatch algorithm.

Step 2. Determine new time slice designations

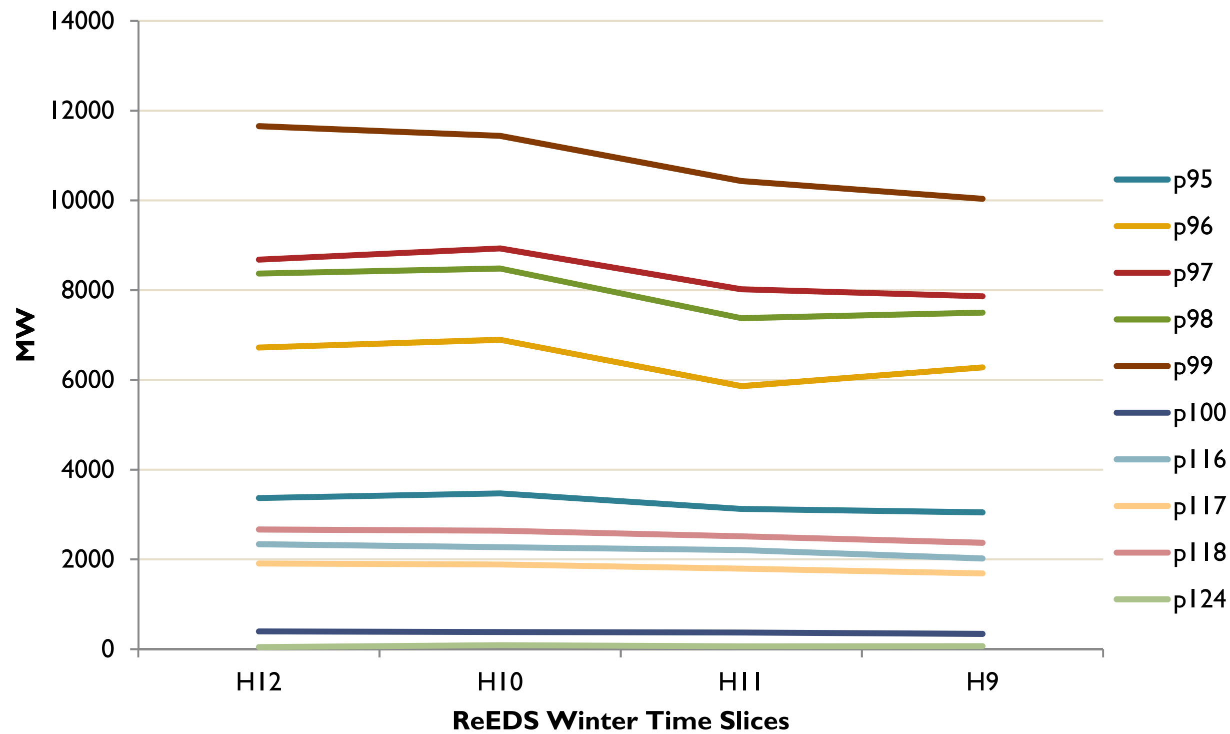
Synapse repurposed an existing time slice to represent the single highest one-hour period during the winter (November, December, January, and February in ReEDS), and used another time slice to "absorb" the remaining hours. Using an existing time slice to represent the single hour (rather than adding an 18th time slice) prevented the need for any major modifications to the underlying GAMS code or run the off-line GIS-based meteorological models that NREL runs to inform several different inputs for each of the time slices.

We used the two time slices in the winter months that had the most similar levels of demand (on balance, across all power control areas [PCA], in our region of interest). Figure C-1 below shows the levels of demand by time slice and PCA for WV-VA-NC-SC in the model. Table C-2 provides the percentage differences between the possible pairs of time slices, showing the high level of similarity between the H10 and H12 slice for most of the PCAs, and the average difference across PCAs by time slice weighted by the level of demand in each PCA. As the table shows, the H10 and H12 slices are by far the most similar with respect to level of demand.

suggestion, the new winter peak time slice (described in more detail in the following steps) was also excluded from the reserve planning margin calculation.

[20] NREL, 2015. Personal communication with Stuart Cohen, June 4, 2015.

Figure C-1. Average winter loads by time slice for WV-VA-NC-SC PCAs in ReEDS



Source: NREL ReEDS Model.

Table C-2. Percent difference in demand levels for pairs of winter season time slices

Time Slice Pair	p95	p96	p97	p98	p99	p100	p116	p117	p118	P124[21]	Weighted Average % Difference
H12-H10	3%	3%	3%	1%	2%	3%	3%	1%	1%	91%	2%
H12-H11	7%	13%	8%	12%	10%	6%	6%	6%	6%	35%	10%
H12-H9	10%	7%	9%	10%	14%	14%	14%	12%	11%	43%	11%
H10-H11	10%	15%	10%	13%	9%	3%	3%	5%	5%	30%	10%
H10-H9	14%	10%	14%	13%	14%	13%	13%	12%	11%	33%	13%
H11-H9	2%	7%	2%	2%	4%	8%	9%	6%	6%	6%	22%

Source: NREL ReEDS Model.

For the slice with the lesser number of hours (H12—winter evening, 600 hours), the duration was decreased to 1 hour, and for the slice with the greater number of hours (H10—winter morning, 840 hours), the duration was increased to 1439 hours = 840 + 600 – 1. The determination of the actual new

[21] Note that p124 is a very low demand PCA, with an average load of 68 MW compared to 346 and 1705 MW as the next lowest PCA average loads.

(peak) demand level to use for the new H12 one-hour slice is described below. The demand for the new H10 slice is now represented as the average load for all hours it includes.[22] The new time slice designations are shown in Table C-3.

Table C-3. New ReEDS time slice definitions to represent a one-hour winter peak demand

Time Slice	Hours	Season	Time of Day
H1	736	summer	10PM-6AM
H2	644	summer	6AM-1PM
H3	328	summer	1PM-5PM
H4	460	summer	5PM-10PM
H5	488	fall	10PM-6AM
H6	427	fall	6AM-1PM
H7	244	fall	1PM-5PM
H8	305	fall	5PM-10PM
H9	960	winter	10PM-6AM
H10	1439	winter	6AM-1PM & 5PM-10PM
H11	480	winter	1PM-5PM
H12	1	winter	1 hour peak
H13	736	spring	10PM-6AM
H14	644	spring	6AM-1PM
H15	368	spring	1PM-5PM
H16	460	spring	5PM-10PM
H17	40	summer	superpeak
	8,760 (total)		

Step 3. Determine demand levels for winter peak time slice

Once we developed the new time slice designations, Synapse assigned actual demand levels to the single highest demand hour in the ReEDS winter season.

Focusing on the WV-VA-NC-SC region, we performed an analysis on the original ReEDS 2010 hourly demand dataset to determine the single hour across the four-state region that had the highest level of demand November 1 through February 28 (ReEDS winter designation).[23] Each state contains multiple

[22] The NREL ReEDS model developers supplied us with the underlying 8,760 hours data it used to develop the original 17 time slices, along with the scripts they used to summarize average loads. This enabled us to make a good estimate of the new average load for the H10 elongated time slice. Note: ReEDS runs on 8760 ABB (Ventyx) data; NREL was able to provide this data due to our existing license with ABB. Synapse received prior approval from ABB to receive this data.

[23] ReEDS uses 2010 demand data as its reference year.

transmission zones,[24] so finding a coincident peak hour across each individually was not possible.[25] However, when aggregated to the state level, a single hour could be determined. The hour we used to represent the winter peak demand was December 15 at 8:00AM. Table C-4 shows the new winter peak demand levels at this hour for each PCA in the four-state area of interest, and the original H12 average time slice demand level for comparison.

Table C-4. New winter peak demand level in the WV-VA-NC-SC area represented in ReEDS

State	PCA	1-HR Winter Peak *(MW)*	Original H12 Slice *(MW)*
SC	p95	4,988	3,369
SC	p96	10,488	6,723
NC	p97	12,769	8,681
NC	p98	12,696	8,371
VA	p99	16,069	11,654
VA	p100	483	394
WV	p116	2,842	2,339
WV	p117	2,393	1,908
VA	p118	3,342	2,667
VA	p124	46	46

We found the 8:00 AM hour on December 15 to be:

- The maximum winter demand hour for each individual state (VA, SC, NC), when demand for a state is defined as the sum of demands across all transmission zones in that state.
- The maximum winter demand hour for the four-state region as a whole (inclusive of WV), when demand for the four-state region as a whole is defined as the sum of demands across all transmission zones encompassed across all four states.
- Consistent with a "sensible" winter peak—a morning hour later in the winter.
- The maximum winter demand hour, when demand is defined as the sum of demands across all transmission zones in the four-state region, from the set of hours that contain at least one absolute winter peak for a single transmission zone in the four-state region. This hour is the *actual* single hour winter peak transmission zone 304 in VA.
- The same hour determined from a simple optimization that minimizes the sum of errors between the hour chosen and the other transmission regions' absolute winter peak loads. This essentially means that while the hour we chose to model as the winter peak demand does not

[24] Each PCA is made up of multiple transmission zones; the original ReEDS hourly demand data is organized by the underlying transmission zones.

[25] While many transmission zones within the four-state area had the *exact* same hour timestamp for their winter peak, some did not. This result is not unexpected given the system-level detail represented in the ReEDS model, and the reality of operations of the electric power system. While the system is highly interconnected, the highest demand in one location will not necessarily occur when demand is highest in another location.

represent the absolute winter peak across all transmission zones, it minimizes the disruption to the original dataset.

Note that while Synapse used the WV-VA-NC-SC region to identify the single hour to represent the peak demand, the ReEDS model ran on the broader Eastern Interconnect region for this WV-VA pipeline analysis. To ensure that a coincident winter peak was represented throughout the Eastern Interconnect, Synapse represented the winter peak demand using this same December 15 8:00AM hour for all PCAs represented in the ReEDS model.

Finally, other demand-related planning parameters were also adjusted as a result of shifting the duration of the time slices from the original model. Lk1, which defines the ratio between average annual load and peak load, and Lk2, which defines the level of variation in demand within a time slice (for the new H12 slice this value is 0 as there is no variation in the single-hour value), were re-calculated using the NREL-provided demand-by-PCA data and R script (ReEDS_load.R).

Step 4. Adjust renewables time slice-dependent capacity and other adjustment factors

ReEDS represents renewable Concentrated Solar Power, PV (central and distributed), and wind using capacity factors and capacity factor adjustments by time slice for each PCA. These factors are developed offline in other models, and pulled into ReEDS hardcoded in the input spreadsheet.

Because these values are time slice dependent, we needed to adjust the H10 winter morning time slice to account for the respective capacity factor for the hours of the H12 winter evening time slice it was “absorbing.” The approach used to account for this was to take a weighted average of these factors based on the hours the new time slice H10 represents from each of the original time slices: 840 hours of the original H10 time slice and 599 hours of the original H12 time slice.

For example, the original H10 and H12 capacity factors (CF) for central station PV for p95, a PCA in South Carolina, were 0.25463 and 0.01908, respectively. The new H10 capacity factor is:

0.15658 = 0.25463*(840/1439) + 0.01908*(599/1439), *or*

New H10 CF = Original H12 CF * (# Hours in Original H12 Slice/# Hours in New H12 Slice) + Original H10 CF*(# Hours in Original H10 Slice/# Hours in New H10 Slice)

The original H12 capacity factor was left intact; using the average capacity factor was the best assumption without re-running the offline meteorological models to calculate the new one-hour capacity factor. Note that while the example above is pulled from a PCA in the four-state region of interest for the current project, for consistency this method was applied to all PCAs represented in ReEDS.

Step 5. Adjust Canadian import factors

ReEDS represents imports from Canada using annual imports, allocating them across the 17 time slices via a seasonal and diurnal assignment factor. Appropriately representing imports for the new set of time slices, where one slice consists of a single hour, required adjusting the fraction of imports that occur in the new winter peak H12 time slice. Imports for H12 were scaled from the original 600 hours to a single hour (1/600th), and the remaining fraction of imports was reassigned to the new elongated H10 slice. This original and new import factors are shown below (Table C-5).

Table C-5. Canadian import factors by time slice in ReEDS

Time Slice	Adjusted CA Import Factor	Original CA Import Factor
H1	0.0516	0.0516
H2	0.0954	0.0954
H3	0.0448	0.0448
H4	0.0612	0.0612
H5	0.0398	0.0398
H6	0.0299	0.0299
H7	0.0490	0.0490
H8	0.0522	0.0522
H9	0.0498	0.0498
H10	0.1835	0.1050
H11	0.0629	0.0629
H12	0.0001	0.0786
H13	0.0521	0.0521
H14	0.1000	0.1000
H15	0.0634	0.0634
H16	0.0589	0.0589
H17	0.0055	0.0055
Sum	1.0000	1.0000

Model Validation: Comparison of Results

A comparison of results between ReEDS with the single-hour winter peak represented and the original time slice formulation shows excellent consistency in total generation, capacity, coal and gas usage, and emissions (all differences are well below 1 percent, see Table C-6).[26] Figure C-2 and Figure C-3 show generation (MW) by time slice for the original and reformulated models, and Figure C-2 highlights the dramatically increased production from combined-cycle and combustion-turbine units in the new H12 time slice. The combination of the consistency in total generation, fuel usage, and emissions, with the

[26] Results shown are based on "Eastern Interconnect-only" ReEDS runs. This is the setting this WV-VA pipeline analysis project uses for its ReEDS modeling.

higher production from natural gas units in the new H12 one-hour time slice shows that the peak winter demand is properly captured.

Table C-6. Comparison of results for key variables between the original ReEDS model and the version with a single-hour winter peak represented

	2010	2012	2014	2016	2018	2020
Capacity (GW)						
Original ReEDS	737.33	755.14	740.61	728.29	738.67	739.52
1HR Winter Peak ReEDS	737.78	755.59	741.06	730.62	741.11	741.63
% Difference	*0.061%*	*0.060%*	*0.061%*	*0.320%*	*0.330%*	*0.285%*
Generation (TWh)						
Original ReEDS	2,937	2,838	2,849	2,941	3,010	3,041
1HR Winter Peak ReEDS	2,937	2,838	2,849	2,941	3,010	3,042
% Difference	*-0.001%*	*-0.001%*	*-0.007%*	*-0.003%*	*0.000%*	*0.027%*
Coal Usage						
Original ReEDS	15.62	12.54	13.33	12.98	13.56	13.42
1HR Winter Peak ReEDS	15.62	12.54	13.32	12.95	13.51	13.43
% Difference	*0.000%*	*0.000%*	*-0.075%*	*-0.231%*	*-0.369%*	*0.075%*
Gas Usage						
Original ReEDS	4.24	5.11	4.49	5.01	4.84	5.05
1HR Winter Peak ReEDS	4.25	5.11	4.49	4.98	4.87	5.02
% Difference	*0.236%*	*0.000%*	*0.000%*	*-0.599%*	*0.620%*	*-0.594%*
CO2 Emissions						
Original ReEDS	1.68	1.44	1.48	1.48	1.52	1.52
1HR Winter Peak ReEDS	1.68	1.44	1.48	1.47	1.52	1.52
% Difference	*0.000%*	*0.000%*	*0.000%*	*-0.676%*	*0.000%*	*0.000%*

Figure C-2. Generation by technology by time slice—Original ReEDS formulation

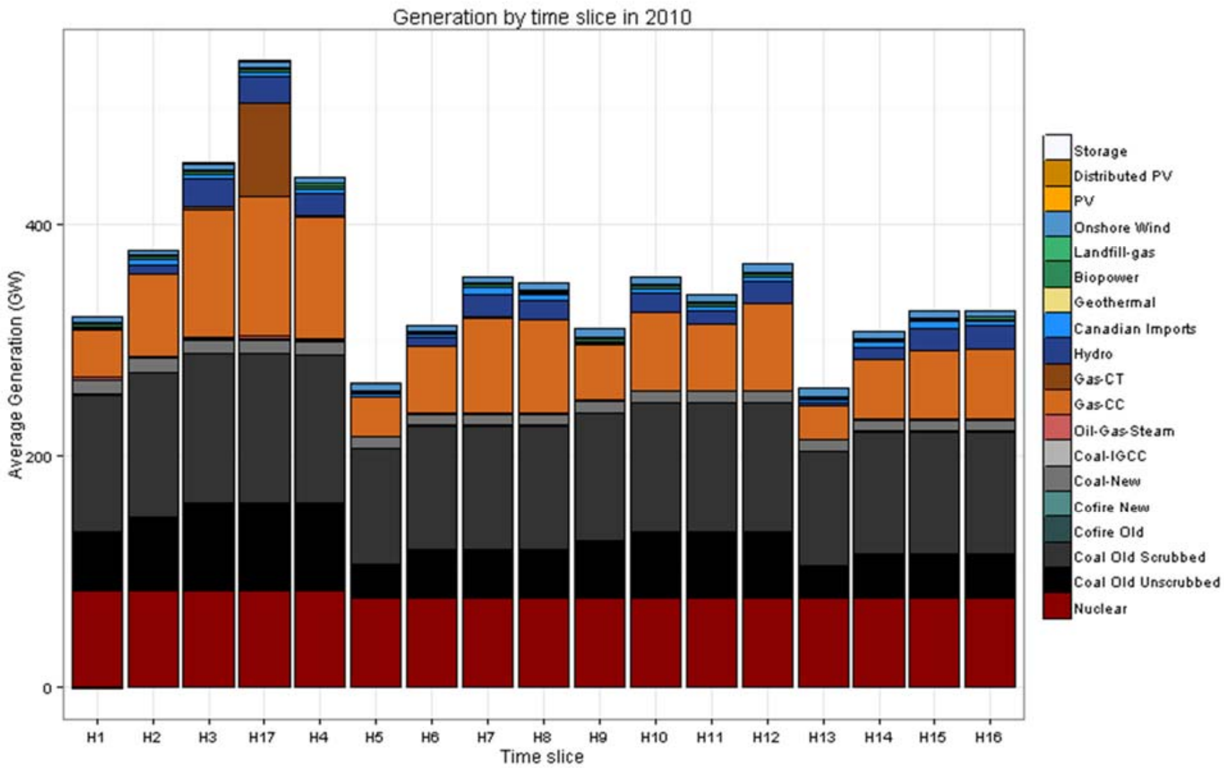


Figure C-3. Generation by technology by time slice—ReEDS with a one-hour Winter Peak (H12)