



U.S. DEPARTMENT OF ENERGY

Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector

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Executive Summary

The natural gas sector in the United States has been fundamentally transformed by technological advancements in horizontal drilling and hydraulic fracturing that have enabled the economic extraction of natural gas from shale formations. This breakthrough has, in turn, unlocked new, geographically diverse natural gas resources that are unprecedented in size.

The availability of abundant, low-cost natural gas has increased demand for natural gas from multiple end-use sectors. In the electric power sector, which is currently the largest consumer of natural gas in the United States, the record-low natural gas prices during the month of April 2012 drove generation from natural gas to virtually match that of coal. While coal has regained some of its market share because of gradually rising natural gas prices, the combination of favorable economics and the lower conventional air pollution and greenhouse gas emissions associated with natural gas relative to other fossil fuels is likely to contribute to expanded use of natural gas in the electric power sector in the future.

However, increased use of natural gas in the electric power sector also presents some potential challenges. Unlike other fossil fuels, natural gas cannot typically be stored on-site and must be delivered as it is consumed. Because adequate natural gas infrastructure is a key component of electric system reliability in many regions, it is important to understand the implications of greater natural gas demand for the infrastructure required to deliver natural gas to end users, including electric generators.

The purpose of this study is to understand the potential infrastructure needs of the U.S. interstate natural gas pipeline transmission system under several future natural gas demand scenarios. Specifically, three scenarios were developed: a reference scenario and two scenarios with increased electric sector natural gas demand. Both increased demand scenarios—an Intermediate Demand Case and a High Demand Case—are based on a simple, illustrative national carbon policy applied to the electric power sector (not based on any real or proposed policy) that drives increased electric sector natural gas use. The Intermediate and High Demand Cases differ only in their underlying assumptions about coal-fired power plant retirements. In particular, the High Demand Case, which assumes greater coal-fired power plant retirements, is intended to be an upper-bound test case on natural gas consumption in the electric power sector.¹

To perform this analysis, the U.S. Department of Energy commissioned Deloitte MarketPoint to examine these scenarios in its North American Integrated Model (NAIM), which simultaneously models the electric power and the natural gas sectors.

¹ For a more detailed description of the scenarios considered in this analysis, see Section 2.3 Description of Scenarios.

The key findings of this analysis are the following:

Key Finding 1: Diverse sources of natural gas supply and demand will reduce the need for additional interstate natural gas pipeline infrastructure. The combination of a geographic shift in regional natural gas production—largely due to the expanded production of natural gas from shale formations—and growth in natural gas demand is projected to require expanded natural gas pipeline capacity. However, the rate of pipeline capacity expansion in the scenarios considered by this analysis is lower than the historical rate of natural gas pipeline capacity expansion. Pipeline capacity additions in the cases considered here are projected to be 38–42 billion cubic feet per day (Bcf/d) between 2015 and 2030. In comparison, between 1998 and 2013, nearly 127 Bcf/d of pipeline capacity was added in the United States. Because projected natural gas production and demand are geographically diverse, the need for additional interstate natural gas pipeline infrastructure is lower than would be expected if the increased production or demand were concentrated in a particular region. Furthermore, recent pipeline capacity additions that were placed in service between 2007 and the present in order to realign the U.S. natural gas transmission system with changing supply and demand conditions driven by increases in shale gas production are likely to reduce the need for future pipeline infrastructure.

Key Finding 2: Higher utilization of existing interstate natural gas pipeline infrastructure will reduce the need for new pipelines. The U.S. pipeline system is not fully utilized because flow patterns have evolved with changes in supply and demand. Increased demand for natural gas in the scenarios considered by this analysis does not lead to larger increases in pipeline capacity because, in some regions, available existing pipeline capacity is projected to be used before expanding existing pipelines or building new capacity. Given the cost of building new pipelines, finding alternative routes that utilize available existing pipeline capacity is often less costly than expanding pipeline capacity. While seasonality of demand requires pipelines to accommodate peak natural gas demand, the incremental demand from new base load natural gas generation in the scenarios considered in this analysis tends to be relatively uniform across the year. It is easier to accommodate this relatively uniform incremental natural gas demand on existing pipelines than it would be to accommodate demand that coincides more strongly with peak demand.

Key Finding 3: Incremental interstate natural gas pipeline infrastructure needs in a future with an illustrative national carbon policy are projected to be modest relative to the Reference Case. While a future carbon policy may significantly increase natural gas demand from the electric power sector, the projected incremental increase in natural gas pipeline capacity additions is modest relative to the Reference Case. In the Intermediate Demand Case, an incremental 1.4 Bcf/d (about 4% of total Reference Case capacity additions of 38 Bcf/d) of additional pipeline capacity above Reference Case levels is projected to be built. Similarly, in the High Demand Case, an incremental 3.9 Bcf/d (10% of total Reference Case capacity additions of 38 Bcf/d) of additional pipeline capacity above Reference Case levels is projected to be built. These relatively modest incremental additions follow from the system characteristics described previously and from the pipeline infrastructure attributes of the sources of incremental natural gas supply across the cases.

Key Finding 4: While there are constraints to siting new interstate natural gas pipeline infrastructure, the projected pipeline capacity additions in this study are lower than past additions that have accommodated such constraints. Siting energy infrastructure in the United States is a complex, multi-jurisdictional, and multidimensional process, with no two projects facing the same set of issues. While these barriers present potential challenges to expanding U.S. natural gas infrastructure, the Federal Energy Regulatory Commission (FERC) has authorities to facilitate siting of natural gas pipeline infrastructure. Similarly, while there are a number of institutional and other barriers to siting infrastructure and coordinating the natural gas and electric systems, there are multiple processes underway to address these issues. In addition, the projected pipeline capacity additions in this study (ranging from 38 to 42 Bcf/d across the cases from 2015 to 2030) are lower than past additions (127 Bcf/d of pipeline capacity was added from 1998 to 2013) that have accommodated siting constraints. However, if siting energy infrastructure becomes more or less challenging in the future, the level of effort needed to site the pipeline capacity additions projected in this analysis could increase or decrease.

1. Introduction

1.1 Purpose of This Study

Over the past decade, natural gas production in the United States has undergone a revolution. The combination of hydraulic fracturing and horizontal drilling technology has allowed economic access to enormous quantities of natural gas from shale formations. As a result, in 2013, the United States became the world's largest producer of hydrocarbons.² This development has had and will likely continue to have significant consequences for the broader economy. The impact of abundant, low-cost natural gas is particularly important in the electric power sector. During the month of April 2012, electricity generation from natural gas-fired plants virtually matched generation from coal-fired plants.³ While coal has regained some of its market share because of gradually rising natural gas prices, growth in natural gas generation is projected to continue in the future.⁴

Increased use of natural gas in electric generation presents some potential challenges. While coal can typically be stored on-site at power plants, natural gas must be delivered as it is used.⁵ Because adequate natural gas infrastructure is a key component of electric system reliability in many regions, it is important to understand the implications of greater natural gas demand for the infrastructure required to deliver natural gas to end users, including electric generators.

The United States has more than 217,000 miles of interstate natural gas pipelines to deliver natural gas from producing regions to end users.⁶ However, the continued development of natural gas from shale formations, which tend to be situated outside of traditional natural gas producing regions, will require new pipeline infrastructure and/or the repurposing of existing infrastructure.

The purpose of this study is to understand the potential infrastructure needs of the natural gas pipeline system under several future natural gas demand scenarios. Specifically, three scenarios were developed: a reference scenario and two scenarios with increased electric sector natural gas demand. Both increased demand scenarios—an Intermediate Demand Case and a High Demand Case—apply a simple, illustrative carbon policy to the U.S. electric power sector (not based on any real or proposed policy) that drives increased electric sector natural gas use. These cases differ only in their underlying

² U.S. Energy Information Administration, "Total Oil Supply (Thousand Barrels Per Day)," International Energy Statistics, <http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=5&pid=53&aid=1>; U.S. Energy Information Administration, "Dry Natural Gas Production (Billion Cubic Feet)," International Energy Statistics, accessed September 24, 2014, <http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=3&pid=26&aid=1>.

³ U.S. Energy Information Administration, "Net generation for United States, monthly," Electricity Data Browser, accessed September 24, 2014, <http://www.eia.gov/electricity/data/browser/#/topic/0?agg=0,1,2&fuel=pe&geo=g&sec=g&freq=M&start=200701&end=201204&charted=3-5-7-9-11>.

⁴ U.S. Energy Information Administration, "Table 8. Electricity Supply, Disposition, Prices, and Emissions," *Annual Energy Outlook 2014*, May 7, 2014, accessed September 24, 2014, http://www.eia.gov/forecasts/aeo/excel/aeotab_8.xlsx.

⁵ Some natural gas power plants also have the ability to operate on alternatives to pipeline-delivered natural gas, such as fuel oil and local stores of liquefied natural gas (LNG) or liquefied petroleum gas (LPG). In addition, note that potential deliverability challenges for coal have also been documented. For example, see: U.S. Energy Information Administration, "Coal stockpiles at coal-fired power plants smaller than in recent years," *Today in Energy*, November 6, 2014, accessed November 12, 2014, <http://www.eia.gov/todayinenergy/detail.cfm?id=18711>.

⁶ U.S. Energy Information Administration, "Estimated Natural Gas Pipeline Mileage in the Lower 48 States, Close of 2008," accessed October 23, 2014, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/mileage.html.

assumptions about coal-fired power plant retirements. In particular, the High Demand Case, which assumes greater coal-fired power plant retirements, is intended to be an upper-bound test case on natural gas consumption in the electric power sector.

1.2 Recent Developments in the U.S. Natural Gas Sector

The United States has an extensive natural gas infrastructure that efficiently produces, stores, and transports natural gas from producing fields to end users. The United States is the largest consumer of natural gas in the world, and with the recent growth in shale gas production, the United States is also now the world's largest natural gas producer.⁷ As shown in Figure 1, pipelines originate in supply regions and transport natural gas to major market regions as well as to smaller markets throughout the country. While most pipelines are relatively short (several hundred miles or less), some major transmission pipelines stretch over a thousand miles. For example, the Transcontinental (Transco) pipeline, connecting Texas and Louisiana supplies to Mid-Atlantic markets, and the Rockies Express (REX) pipeline, connecting Colorado and Wyoming supplies to Ohio and eastern markets, are both about 1,700 miles long.

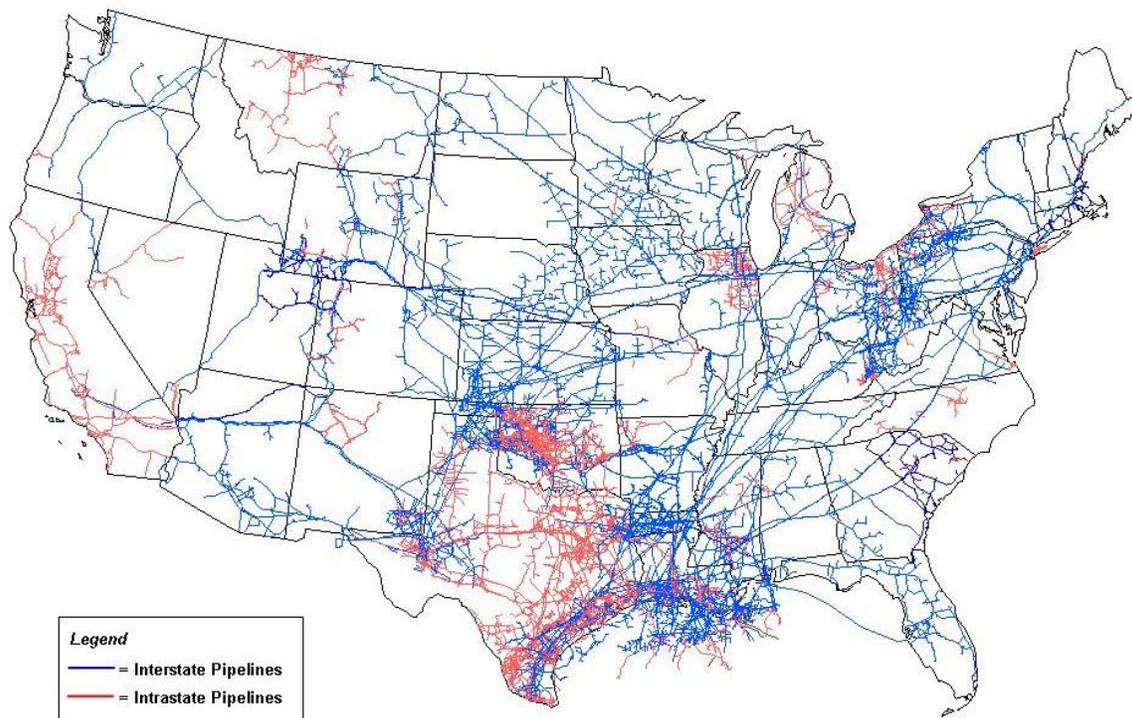


Figure 1: U.S. Natural Gas Pipeline System⁸

Because pipelines are not moved once they are built, new pipelines or modifications to existing pipelines are required when production in a supply basin grows and reaches pipeline takeaway capacity constraints out of the region, or when demand in a market area grows to exceed the pipeline system

⁷ U.S. Energy Information Administration, "Dry Natural Gas Production (Billion Cubic Feet)," International Energy Statistics, accessed September 24, 2014, <http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=3&pid=26&aid=1>.

⁸ U.S. Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System.

capacity to deliver into the region. For example, during the previous decade, rapid growth in Rockies natural gas production gave rise to the REX pipeline, which transports natural gas produced in the region to markets in the East. Similarly, rapid natural gas demand growth in Florida prompted construction of the Gulfstream pipeline and numerous expansions of the Florida Gas Transmission pipeline so that natural gas produced in the Gulf region could be delivered to consumers in Florida.

The most prolific shale gas basin in the United States is the Marcellus, with the prime fields located in Pennsylvania and West Virginia. The growth in Marcellus shale gas production has had a major impact on the flow of natural gas throughout the United States. Natural gas that was once imported from other states into eastern markets has been increasingly displaced by Marcellus production. While pipeline capacity connecting Marcellus producing fields to either natural gas markets or interconnections to existing pipelines has been added, some natural gas production has yet to be connected, because pipeline takeaway capacity is still limited.

1.3 Economics of Natural Gas Transmission

New natural gas pipeline development is driven by market supply and demand, which expresses itself in the form of basis differential, or the difference in natural gas prices between two locations or “hubs.” Basis differentials provide an incentive for prospective pipeline shippers (the party that wants to transport natural gas) to request that a pipeline company (the party that develops and/or owns the pipeline, often referred to as the “operator”) construct new pipeline capacity and enter into long-term contracts for firm pipeline transportation service sufficient to enable the pipeline operator to proceed with the project.⁹ Effectively, such an agreement enables the operator to have confidence that a significant share of the project’s development, construction, financing, and operating costs will be recoverable from shippers. Once a new natural gas pipeline is constructed, the shipper can rely on its contract for firm transportation service to capture the resulting basis differential.¹⁰ Basis differentials, and how the captured revenues compare to the cost of constructing pipelines, largely determine how much and in which locations pipeline capacity is likely to be added.¹¹

⁹ Shippers may be gas marketers or other entities, such as local distribution companies that contract for transportation service in order to gain access to supply to serve retail customers. Also, pipeline operators typically do not own upstream natural gas assets but instead generate revenue by offering pipeline capacity to shippers. In 1992, the Federal Energy Regulatory Commission issued Order Number 636, “Restructuring of Interstate Natural Gas Pipeline Services (Final Rule).” Order Number 636 fundamentally altered the manner in which pipeline operators conducted business by requiring pipeline companies to sell natural gas transportation, storage, and other services separately (often referred to as “unbundling”), and enabled all participants in the U.S. natural gas market to buy, sell, or trade natural gas with any other market participant. For more details, see <http://www.ferc.gov/legal/maj-ord-reg/land-docs/restruct.asp>. Note also that natural gas may be contracted on a firm, or uninterruptible, basis. Firm transportation service is backed by an agreement that typically binds both parties to the agreement to either deliver or receive the quantity of natural gas specified in the agreement. Firm service has priority over interruptible service and cannot be curtailed during periods of high demand.

¹⁰ Note also that while requests for firm transportation service by shippers effectively drive new pipeline expansion, these shippers may make available transportation service to others in the secondary or resale markets once the pipeline is fully constructed and operating.

¹¹ Changes in other sectors, such as electricity, may further change the supply and demand conditions within natural gas markets. These changes may, in turn, affect basis differentials and the resulting incentives for natural gas pipeline infrastructure development.

The cost of constructing pipelines can be significant. For example, the 1,698-mile-long REX pipeline, which has a capacity of 1.8 billion cubic feet per day (Bcf/d), cost approximately \$5 billion to construct.¹² In order for the economics of the pipeline to be favorable, the natural gas flowing through the pipeline must generate sufficient revenue over its operating lifetime to justify the upfront capital investment.

Revenue and/or cost recovery for pipeline shippers depends on the demand for natural gas, which is highly seasonal, particularly in the East. Moreover, pipeline shippers sometimes capture high value for short durations, often during peak periods, when increased demand, coupled with transmission constraints, causes basis differentials to rise. For example, the “polar vortex,” which occurred during the winter of 2013–2014 and plunged the Mid-Atlantic, Northeast, and Southeast into a deep freeze, highlights how pipeline transmission constraints can cause price spikes in transmission-constrained markets. In fact, even during normal years in regions served by limited pipeline capacity, significant transmission constraints can last for weeks. However, while price spikes and temporary transmission constraints associated with extreme weather events can have significant impacts on natural gas consumers, a price spike may or may not provide sufficient revenue to justify additional infrastructure investment.

1.4 Institutional Considerations

Siting energy infrastructure in the United States is a complex, multi-jurisdictional, and multidimensional process, with no two projects facing the same set of issues. While these barriers present potential challenges to expanding U.S. natural gas infrastructure, the Federal Energy Regulatory Commission (FERC) has authorities to facilitate siting of natural gas pipeline infrastructure. Specifically, under the Natural Gas Act (NGA), FERC has authority to regulate the interstate transmission and certain sales for resale of natural gas.¹³ Central to resolving siting and cost allocation issues, FERC also possesses authority to grant the right of eminent domain for the construction of pipelines, and under Section 7 of the NGA, FERC can issue a certificate of public convenience and necessity to allow pipeline operators to recover expenses associated with pipeline construction and operation.

The combination of technical change, fundamental economic drivers, and related institutional considerations explain the history of pipeline capacity additions in the United States. Figure 2 depicts total U.S. pipeline capacity additions and construction expenditures by year in which pipelines were or are expected to be placed in service.¹⁴ There has been significant investment in new interstate pipeline capacity over the last 18 years for which data are available, with more than 133 Bcf/d of capacity additions and \$65 billion in capital expenditures. The pipeline expenditures in Figure 2 do not follow a smooth path over time; major projects, such as the REX pipeline, which placed sections of the pipeline into service in 2008 and 2009, result in total expenditures for a particular year that exceed the long-run

¹² Scott Parker, “Natural Gas Pipelines,” Kinder Morgan Energy Partners, L.P., accessed September 24, 2014, http://www.kindermorgan.com/content/docs/2008_Analysts_Conf_02_Natural_Gas_Pipelines.pdf.

¹³ U.S. Energy Information Administration, “Natural Gas Act of 1938,” accessed September 24, 2014, http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1938.html.

¹⁴ The data in Figure 2 reflect both the capacity and cost associated with constructing new pipelines as well as adding capacity to existing pipelines. In addition, the data account for the capacity and cost associated with reversing flows in existing pipelines.

average. Recent growth in natural gas production from shale formations has spurred new growth in pipeline construction because many large shale deposits are located outside of regions with a history of pipeline construction and therefore lack the associated infrastructure. As such, the majority of expenditures for pipelines placed in service from 2010 through 2013 were for projects designed to transport shale gas.

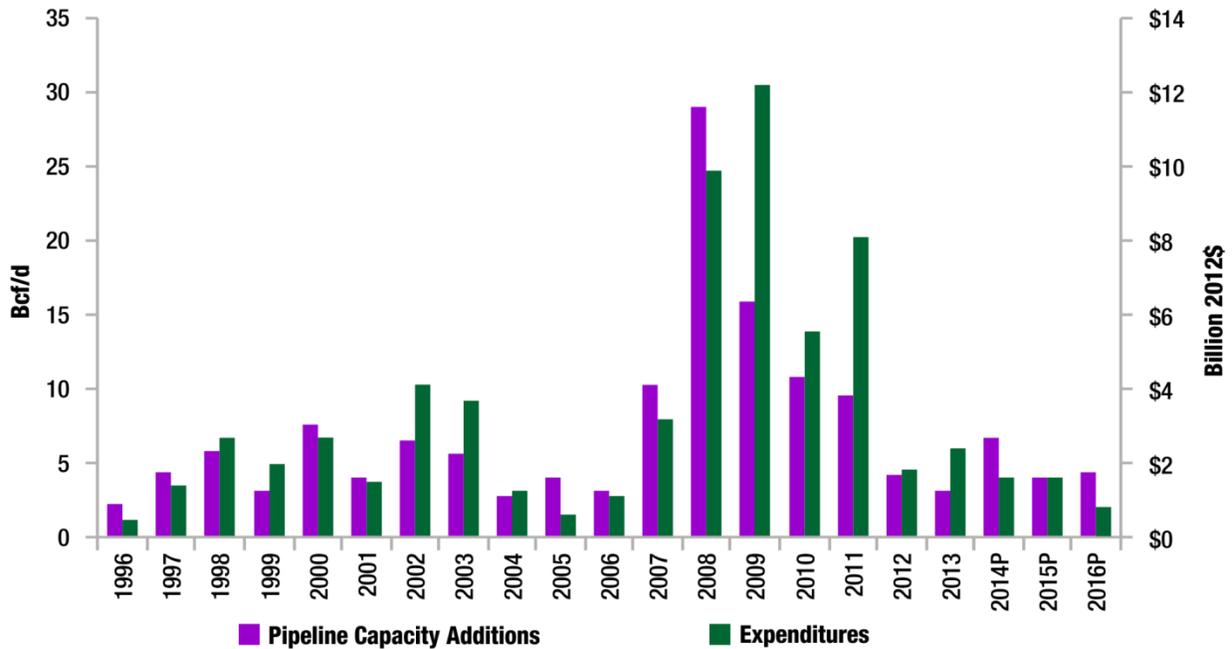


Figure 2: Interstate Pipeline Capacity Additions and Capital Expenditures by Year in Service¹⁵

¹⁵ U.S. Energy Information Administration, "U.S. natural gas pipeline projects," July 1, 2014, accessed September 24, 2014, <http://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xls>. Years 2014–2016 are additions reported as planned.

2. Model Description, Limitations, and Scenarios

2.1 Model Description

This study uses the Deloitte MarketPoint North American Integrated Model (NAIM) to analyze the interaction between electric power and natural gas markets in North America.¹⁶ NAIM includes detailed and comprehensive electricity and natural gas market models. Each sectoral model includes disaggregated representations of supply, infrastructure, and demand by geographic region within North America. These two sectoral models are then integrated both geographically and temporally to produce a comprehensive and self-consistent set of results across both markets.

NAIM applies microeconomic theory to solve for market-clearing prices and quantities simultaneously across multiple markets, multiple commodities, and multiple time steps. It performs fundamental market analysis of supply and demand within each region and their dynamic interactions. The model uses monthly time steps over a 30-year time horizon, but the electricity model further disaggregates the monthly time steps to more accurately represent load duration curves in each region.

On the natural gas side of NAIM, the model represents natural gas producer decisions regarding the timing and quantity of reserves to add, given producers' resource endowments, the cost to bring production online, and anticipated forward prices. Within the model, there are about 40 natural gas supply regions in the United States. The model uses depletable resource economics to compute a resource production schedule that maximizes profit, given endogenously projected wellhead prices. Under this approach, today's drilling affects tomorrow's natural gas prices and, conversely, expectations about tomorrow's natural gas prices affect today's drilling.

NAIM also represents the existing interstate pipeline system by pipeline segment. The model builds additional pipeline capacity when it is economic, given the computed supply-demand dynamics as well as infrastructure constraints and costs. Specifically, the model builds pipeline capacity if the basis differential across a new pipeline would be large enough to cover pipeline variable costs and recovery of upfront capital costs for expansion, while providing a sufficient rate of return. That is, the volume of natural gas flows over time must deliver sufficient after-tax margins to justify the cost of expansion.

The model input that determines the cost of expansion is the overnight capital cost.¹⁷ Estimates of capital cost are derived from the cost of actual pipeline projects. For example, a 1 Bcf/d pipeline expansion that costs \$500 million would have a capital cost of \$1.37 per million cubic feet (Mcf) of

¹⁶ For more details on the Deloitte MarketPoint North American Integrated Model, see: Deloitte MarketPoint, *Deloitte MarketPoint*, 2011, http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/us_er_marketpoint_marketbuilder011411.PDF. The results are solely for informational purposes and are not intended to be predictions of events or future outcomes. Deloitte MarketPoint is not, by means of this publication, rendering accounting, business, financial, investment, legal, tax, or other professional advice or services to any person. Deloitte MarketPoint shall not be responsible for any loss sustained by any person who uses or relies on this publication.

¹⁷ The overnight capital cost is the cost at which a unit could be constructed, assuming that the entire process from planning through completion could be accomplished in a single day. It does not include related financing costs (cost of capital) and does not reflect potential changes in cost over the actual period during which the capacity would be constructed.

annual transmission capacity. The cost of each additional Mcf of expansion for a specific pipeline segment is assumed to be constant in the model.¹⁸

To represent natural gas demand for the residential, commercial and industrial sectors, the model applies growth rates by sector and region derived from the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2014* (AEO 2014) Reference Case to historical state-level demand data. Demand for natural gas from these sectors is assumed to be responsive to changes in natural gas prices over time. Demand for natural gas from the electric power sector is determined endogenously by NAIM, which computes fuel use based on competition between different types of power generation.

More specifically, on the electricity side of NAIM, the model contains a representation of the North American electricity system, including electric generation assets, bulk transmission between regions, and load patterns. NAIM projects prices, generation mix, associated fuel use, and environmental emissions for North American power markets. The geographic scope encompasses all areas under the jurisdiction of the North American Electric Reliability Corporation (NERC), which includes portions of Canada and Northern Baja Mexico, as well as all of the lower 48 United States.¹⁹ Within NAIM there are a total of 76 electricity balancing regions.

Electric generating capacity additions are largely endogenous, with some planned and other capacity additions specified exogenously, while all capacity retirements are specified exogenously. NAIM uses technology cost and performance assumptions similar to those assumed in EIA's AEO 2014 Reference Case. Electric transmission capacity additions are specified exogenously, and NAIM's total electric load projection is based on the AEO 2014 Reference Case.²⁰

Finally, the representation of inter-commodity linkages allows the model to project how an illustrative national carbon policy might affect each regional electricity market, which in turn affects the natural gas market. Integrating the markets for natural gas and electricity within the model is important because future U.S. natural gas demand growth is projected to be largely driven by the electric power sector.

2.2 Modeling Limitations

This analysis assumes rational economic behavior with perfect foresight, but a variety of barriers may lead to outcomes that differ from those projected by this analysis. Real-world markets may overbuild or underbuild infrastructure in anticipation of future demand and prices. For example, by 2006, FERC had received 43 applications to construct new U.S. liquefied natural gas (LNG) import terminals, and a total of 11 facilities were ultimately built in anticipation of a large increase in LNG imports that never

¹⁸ The model also accounts for the costs associated with adding capacity to existing pipelines through expansions and looping (adding a new pipeline running parallel to an existing pipeline). In addition, the model accounts for the costs associated with reversing flows in existing pipelines. For example, in June 2014, a portion of the Rockies Express Pipeline, which was originally constructed to bring natural gas from the Rocky Mountain region to eastern markets, was reconfigured to allow natural gas produced in the Marcellus and Utica shale basins to be transported to midwestern markets. See U.S. Energy Information Administration, "First westbound natural gas flows begin on Rockies Express Pipeline," *Today in Energy*, June 18, 2014, accessed October 22, 2014, <http://www.eia.gov/todayinenergy/detail.cfm?id=16751>.

¹⁹ For details, see Appendix A.1 Map of Electric Power Sector Natural Gas Demand Regions.

²⁰ U.S. Energy Information Administration, "Market Trends: Electricity demand," *Annual Energy Outlook 2014*, May 7, 2014, accessed October 1, 2014, http://www.eia.gov/forecasts/aeo/MT_electric.cfm. Total electric generation in NAIM is, on average, approximately 0.8% lower than AEO 2014 Reference Case levels over the projection period.

materialized.²¹ The approach taken in this study does not try to anticipate suboptimal actions. While real-world markets do not always perfectly align supply and demand, it is difficult to determine a credible way to anticipate potential future market disequilibrium.

In addition, interstate pipeline capacity additions in the model are presumed to use the most efficient routing, regardless of ownership. Full access to pipeline segments is assumed for both the utilization of existing capacity and future capacity additions. As such, the model is limited in its ability to account for the potential cost of barriers facing many interstate natural gas pipeline projects, including siting and permitting challenges as well as cost allocation and cost recovery issues.²²

As discussed later in this report, the amount of new interstate natural gas pipeline capacity projected in the scenarios considered in this analysis between 2015 and 2030 (38–42 Bcf/d) is considerably lower than the amount of new capacity added for the historical period between 1998 and 2013 (127 Bcf/d). Because this historical capacity was constructed in a market and regulatory environment prone to the siting, permitting, and cost recovery issues described previously, it is reasonable to conclude that a smaller amount of total capacity (such as that projected in the Reference Case, Intermediate Demand Case, and High Demand Case) could be constructed in the future in a similar market and regulatory environment. However, if siting energy infrastructure becomes more or less challenging in the future, the level of effort needed to site the pipeline capacity additions projected in this analysis could increase or decrease.

Moreover, in the near term, all three scenarios in this analysis project relatively modest interstate pipeline capacity additions (2.2–2.7 Bcf/d annually between 2015 and 2020). Increased production from shale and other geographically diverse sources of natural gas as well as geographic diversity in the sources of natural gas demand have significantly reduced the need for additional construction of interstate natural gas pipeline infrastructure. Projected near-term pipeline capacity additions are smaller than the annual average additions over the last five years for which data are available (8.8 Bcf/d annually between 2009 and 2013) and also smaller than the average annual capacity additions reported

²¹ Bipartisan Policy Center, National Commission on Energy Policy, *Siting Critical Energy Infrastructure: An Overview of Needs and Challenges*, June 2006, 33, http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/Siting%20Critical%20Energy%20Infrastructure_448851db5fa7d.pdf; Federal Energy Regulatory Commission, “Existing FERC Jurisdictional LNG Import/Export Terminals,” April 19, 2012, accessed October 23, 2014, <http://www.ferc.gov/industries/gas/indus-act/lng/exist-term.asp>.

²² Independent system operators (ISOs), state governments, and FERC are actively working to improve natural gas system deliverability and reliability in organized electricity markets. Policy changes underway include modifications to ISO forward capacity market incentives to better align resource performance and flexibility, FERC’s proposed reforms to improve the coordination and scheduling of natural gas pipeline capacity with electricity markets, and a New England States Committee on Electricity (NESCOE, an organization comprising representatives appointed by six New England governors) proposal to expand natural gas pipeline capacity and electric transmission capacity in New England. Selected examples include: FERC, “Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities,” Notice of Proposed Rulemaking, March 20, 2014, <http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-1.pdf>; NESCOE, “New England Governors’ Commitment to Regional Cooperation on Energy Infrastructure Issues,” December 6, 2013, http://nescoe.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf; PJM Interconnection, “PJM Capacity Performance Updated Proposal,” October 7, 2014, <http://pjm.com/~media/documents/reports/20141007-pjm-capacity-performance-proposal.ashx>; and ISO New England, “Potential Changes in the Forward Capacity Market (FCM) in New England,” October 20, 2014, http://www.iso-ne.com/static-assets/documents/2014/11/03_fcm101_oct_2014_potential_fcm_changes.pdf.

as planned for the years 2014–2016 by EIA (5.1 Bcf/d annually).²³ Taken together, these comparisons suggest that the rate of near-term and medium-term pipeline capacity expansion projected by this analysis is consistent with the rate of both historical and planned capacity expansion.

Projections in this study are also limited by the spatial and temporal resolution of the model. The monthly time resolution in the model may not identify interstate pipeline constraints that reflect peak demand days or shorter time intervals. Moreover, these projections will not capture most future *intrastate* pipeline capacity additions (as opposed to *interstate* pipeline capacity additions). Increased natural gas demand will likely also require new, smaller pipelines (known as laterals) to connect new electric power sector generation. Laterals are difficult to represent because they depend on the precise locations of any new electric generating capacity that is built. Similarly, the model represents the pipeline gathering system as part of an integrated natural gas gathering and processing system within each basin, so natural gas gathering pipeline additions are not explicitly modeled. However, these limitations are not likely to affect the conclusions about interstate natural gas pipeline infrastructure.

Finally, the model computes optimal natural gas storage dispatch based on projected monthly prices and storage operating parameters. The model does not endogenously determine future storage capacity, and storage capacity is held constant in the model.²⁴ This study also does not address how greater natural gas demand may affect the need for high-deliverability storage, which becomes important at time scales shorter than the monthly time resolution of the model, and is often used by natural gas electric power generators. However, none of these assumptions is likely to affect the conclusions about interstate natural gas pipeline infrastructure. In fact, the lack of natural gas storage additions in this study could place more pressure on the natural gas transmission system than would be the case if storage expansion were explicitly represented, consistent with the intention to create an upper-bound test case.

2.3 Description of Scenarios

In order to analyze the potential impact of increased demand from the electric power sector, this report examines three scenarios: a “Reference Case” with no national carbon policy, an “Intermediate Demand Case” with an illustrative national carbon policy applied to the electric power sector, and a “High Demand Case” with an illustrative national carbon policy applied to the electric power sector and accelerated coal-fired power plant retirements. The cases are described in Figure 3.

²³ Planned projects include projects that have been publicly announced, projects that have applied for or have received FERC approval, and projects that are under construction.

²⁴ Total U.S. natural gas underground storage capacity grew at an average annual rate of 1.2% from 2008 to 2013. See: U.S. Energy Information Administration, “U.S. Total Underground Natural Gas Storage Capacity,” September 30, 2014, accessed October 9, 2014, <http://www.eia.gov/dnav/ng/hist/n5290us2a.htm>.

Case Name	Case Description
1. Reference Case	Reference Case with no national carbon policy
2. Intermediate Demand Case	Nationally uniform carbon policy (illustrative) applied to the Reference Case
3. High Demand Case	Nationally uniform carbon policy (illustrative) applied to the Reference Case, with accelerated coal-fired power plant retirements

Figure 3: Cases Analyzed

The Reference Case does not include an illustrative national carbon policy, but it does include existing state renewable energy portfolio standards as well as regional greenhouse gas emissions policies, such as the Regional Greenhouse Gas Initiative (RGGI) in the Northeast and Mid-Atlantic and the California Global Warming Solutions Act (AB32).²⁵ In the Reference Case, approximately 25 gigawatts (GW) of coal capacity are retired after 2014. These retirements have been publicly announced and are imposed exogenously in the model.

In the increased demand cases, an illustrative carbon policy was applied nationally beginning in the year 2020 at a price of about \$32 (2012\$) per metric ton of CO₂, increasing at a rate of 5% per year in real terms. This pathway matches EIA’s AEO 2014 \$25 Carbon Price side case from 2020 onwards. This illustrative national carbon policy is not intended to represent any actual or proposed policy, but instead is used as a means to drive growth in electric power sector natural gas demand, and consequently in natural gas infrastructure.

In the Intermediate Demand Case, coal-fired power plant retirements are assumed to follow the trajectory in the Reference Case. In other words, no additional retirements beyond those already announced occur. However, in such a policy scenario, coal-fired power plants for which no announcements have been made to date could in fact retire prior to 2030, which in turn would require additional generation from other sources, including natural gas.

To analyze this, a High Demand Case was also modeled. In this case, all coal-fired power plants that lacked scrubber-type emissions controls as of the first quarter of 2014 are assumed to retire in 2017. This assumption results in an incremental reduction of 104 GW of coal-fired capacity beyond the 25 GW of capacity that retires in the Reference and Intermediate Demand Cases. Just as some units that have not yet publicly announced a decision to retire may in fact eventually retire, it is likely that some uncontrolled units will be economic to retrofit and will continue to operate after 2017.

This analysis focuses specifically on the sensitivity of the interstate natural gas pipeline infrastructure to varying levels of electric power sector natural gas demand. Additional scenarios would be needed to characterize a broader range of possible natural gas futures. For example, future work might consider alternative natural gas supply assumptions (such as the size of the natural gas resource base or the rate of technology advances that affect drilling cost and/or drilling productivity) that could result in natural

²⁵ Existing federal production tax credits and investment tax credits for renewable energy sources are assumed to be expired in all of the cases considered in this analysis.

gas supply that is higher or lower than Reference Case levels. Similarly, future work might consider scenarios in which energy efficiency or conservation is significantly deployed to meet end-user demand, or scenarios with alternative assumptions about future industrial or transportation natural gas demand.

3. Model Results

3.1 Natural Gas Demand

In the Reference Case, total U.S. natural gas demand is projected to grow steadily and reach about 76 Bcf/d by 2030, an 18% increase from 2015 levels.²⁶ Reference Case demand in 2030 is close to EIA’s AEO 2014 Reference Case level of approximately 80 Bcf/d.²⁷ Figure 4 shows natural gas demand by sector in the Reference Case.

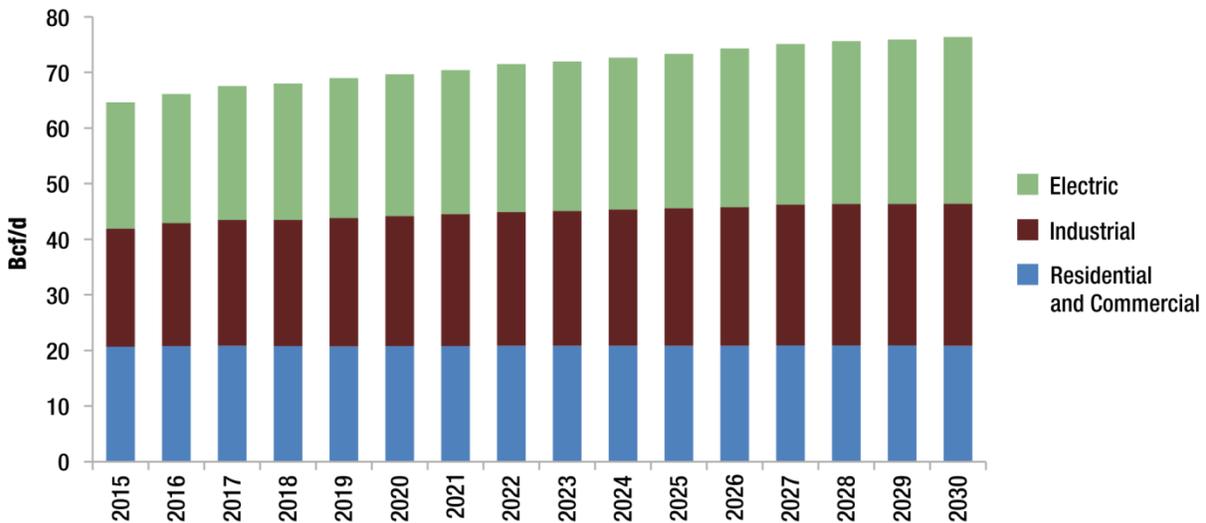


Figure 4: Reference Case Total U.S. Natural Gas Demand by Sector, 2015 to 2030

One of the implications of increased natural gas production from shale formations is that the United States is now an attractive source of LNG for global buyers. The Reference Case projects about 5.1 Bcf/d of U.S. LNG exports by 2020.²⁸ The volume of U.S. LNG exports in the model is determined by Deloitte MarketPoint’s World Gas Model, which computes the competitiveness of U.S. LNG exports in global markets based on projections of the domestic price of natural gas, the cost of building LNG liquefaction terminals, the cost of transportation and liquefaction, and the price and demand for natural gas in foreign markets.²⁹ Given these conditions, the model determines whether the capital investment would be recovered. The model’s estimate of LNG export volumes is based purely on underlying economics

²⁶ The model output presented in Figure 4 does not include natural gas used at the production site, volumes used in processing, pipeline use and losses, or natural gas exports.

²⁷ U.S. Energy Information Administration, “Table 13. Natural Gas Supply, Disposition, and Prices,” *Annual Energy Outlook 2014*, May 7, 2014, accessed September 24, 2014, http://www.eia.gov/forecasts/aeo/excel/aeotab_13.xlsx.

²⁸ For comparison, the U.S. Energy Information Administration’s *Annual Energy Outlook 2014* projects 5.7 Bcf/d of LNG exports by 2020. See: U.S. Energy Information Administration, “Table 134. Natural Gas Imports and Exports,” *Annual Energy Outlook 2014*, May 7, 2014, accessed September 29, 2014, http://www.eia.gov/forecasts/aeo/supplement/suptab_134.xlsx.

²⁹ For more details on the Deloitte MarketPoint World Gas Model, see: Deloitte MarketPoint, *Deloitte MarketPoint*, http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/us_er_marketpoint_marketbuilder011411.PDF.

and does not capture purchase decisions of LNG consumers who are willing to pay above market prices in order to diversify their LNG acquisition portfolios.³⁰

In general, under an illustrative national carbon policy, a shift away from more carbon-intensive generation such as coal to lower-carbon generation such as natural gas and to zero-carbon options such as nuclear, renewables, and energy efficiency would be expected. Because this study examines the impacts of an illustrative national carbon policy on the natural gas pipeline system, this section will focus on the impact of these two scenarios on electric power sector natural gas demand. See Appendix B. Electric Power Sector Results for additional electric power sector results.

Figure 5 compares electric power sector natural gas demand across the cases. In the Intermediate Demand Case, electric power sector natural gas demand increases by about 7.5 Bcf/d (about 25%) in 2030 relative to the Reference Case. In the High Demand Case, electric power sector natural gas demand increases by about 14 Bcf/d (about 46%) in 2030 relative to the Reference Case.³¹

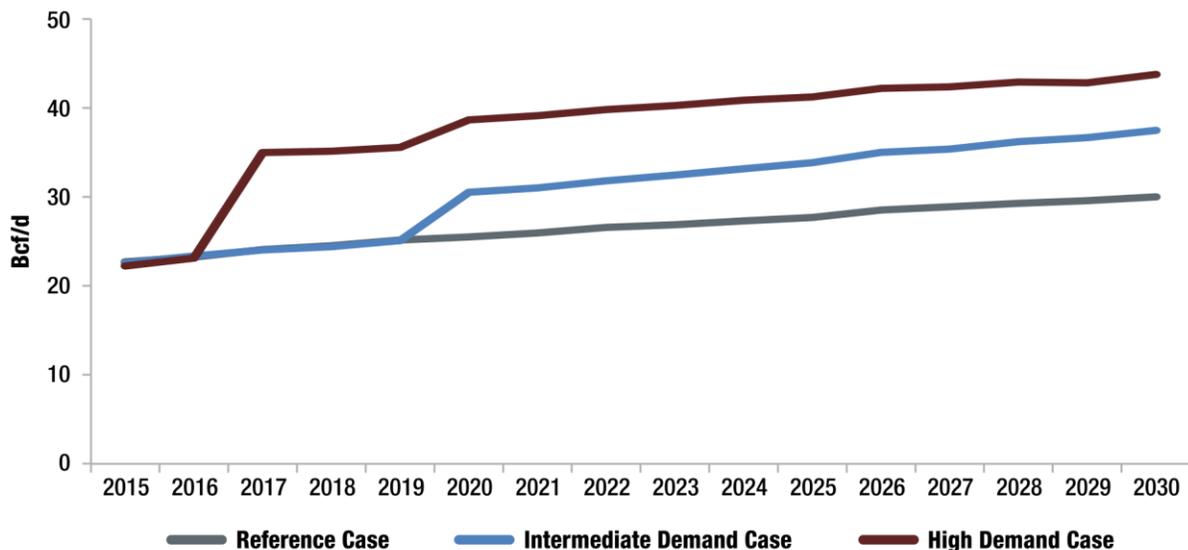


Figure 5: Electric Power Sector Natural Gas Demand across the Cases, 2015 to 2030

Figure 6 shows electric power sector natural gas demand by region in the Reference Case (for a description of regions, see Appendix A.1 Map of Electric Power Sector Natural Gas Demand Regions).

³⁰ In order to test the sensitivity to alternative assumptions about U.S. LNG export volumes, an additional case was run with approximately 10 Bcf/d of LNG exports by 2022. The pipeline capacity additions projected in this case are not significantly different from those projected in the Reference Case.

³¹ These increases are equivalent to 10% and 18%, respectively, of total natural gas demand in 2030 in the Reference Case.

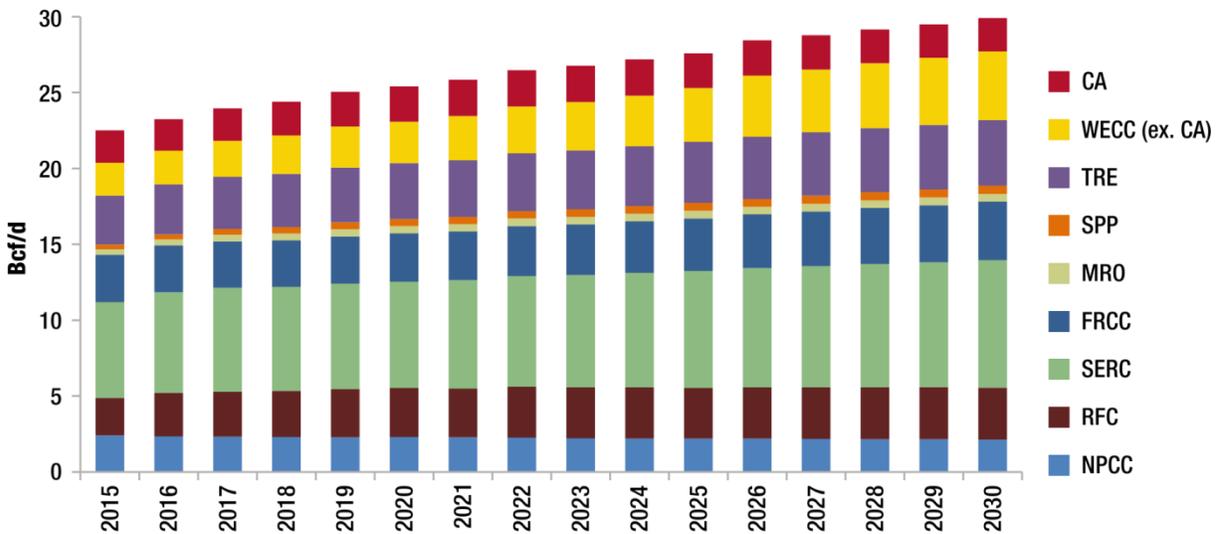


Figure 6: Reference Case Electric Power Sector Natural Gas Demand by Region, 2015 to 2030

The incremental change in electric power sector natural gas demand between the Intermediate Demand Case and the Reference Case is shown in Figure 7. Positive values are increases relative to the Reference Case, while negative values are decreases. The electric power sector natural gas demand results are consistent with the electric power sector generation results presented in Appendix B. Electric Power Sector Results. Nearly all regions see an increase in electric power sector natural gas demand once the illustrative national carbon policy is applied in 2020, as natural gas-fired generation replaces generation from coal-fired units. However, regions in which coal-fired generation is replaced with a greater amount of renewable power, such as MRO and SPP, do not demand as much incremental natural gas as other regions.

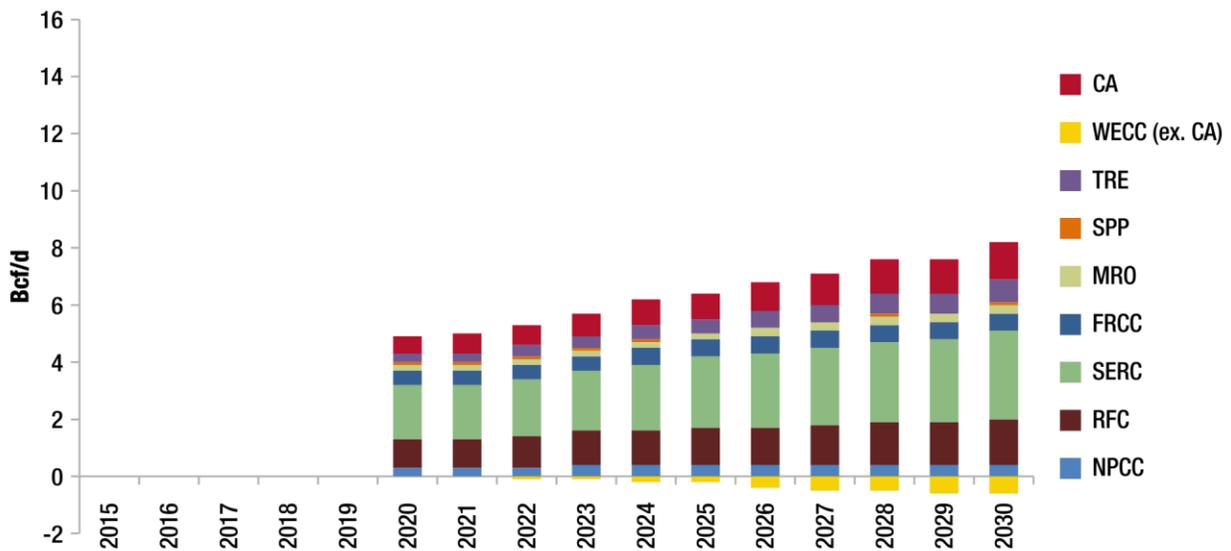


Figure 7: Intermediate Demand Case Electric Power Sector Natural Gas Demand Relative to the Reference Case, 2015 to 2030

Figure 8 shows the change in electric power sector natural gas demand in the High Demand Case relative to the Reference Case. In this modeling framework, the greater number of coal plant retirements assumed in this scenario results in greater natural gas-fired generation and, in turn, greater natural gas demand in the electric power sector. This increase in natural gas demand also begins earlier, reflecting the assumption about the timing of coal-fired power plant retirements.

In the WECC (excluding CA) region, power sector natural gas demand declines in the Intermediate Demand Case (Figure 7) but increases in the High Demand Case (Figure 8) relative to the Reference Case. In the Reference Case, WECC (excluding CA) exports electricity to California. However, the application of the illustrative national carbon policy in the Intermediate Demand Case increases the costs to operate fossil generation in the WECC (excluding CA) region. In light of these higher costs, the WECC (excluding CA) region exports less electricity to California, and fossil generation—and, in turn, power sector natural gas demand—in the WECC (excluding CA) region declines relative to the Reference Case (Figure 7). Natural gas power generation increases in California to replace decreasing imports of power from the WECC (excluding CA) region. The greater number of coal-fired power plant retirements assumed in the High Demand Case requires replacement energy to be made up by natural gas-fired generation in the WECC (excluding CA) region. This effect works in the opposite direction as the prior one, resulting in greater WECC (excluding CA) power sector natural gas demand in the High Demand Case relative to the Reference Case (Figure 8).

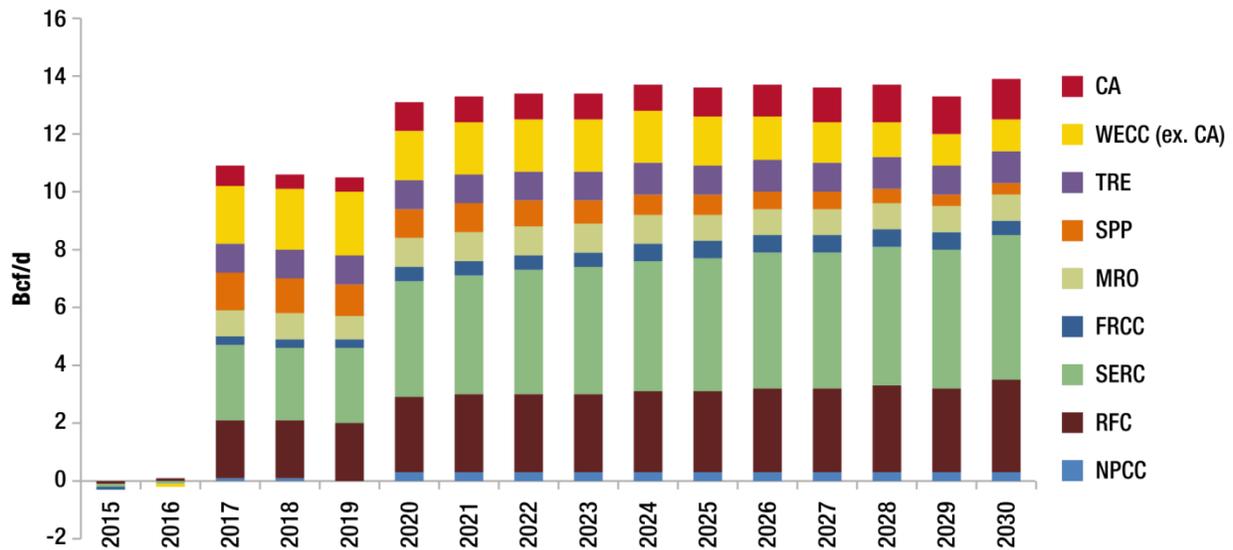


Figure 8: High Demand Case Electric Power Sector Natural Gas Demand Relative to the Reference Case, 2015 to 2030

3.2 Natural Gas Supply

Growing demand for natural gas leads to a significant increase in the supply of natural gas. In the Reference Case, total natural gas production is projected to grow by 37% from 2015 to 2030, increasing from approximately 71 Bcf/d in 2015 to nearly 98 Bcf/d in 2030 (Figure 9).³² Reference Case natural gas supply in 2030 is comparable to EIA’s AEO 2014 Reference Case level of approximately 94 Bcf/d.³³ The Reference Case projection also shows a continued increase in shale gas production over the projection period. With the most significant contribution coming from the Marcellus basin, total U.S. shale gas production is projected to reach about 70 Bcf/d by 2030 and to become the dominant source of U.S. natural gas supply (for a description of the production regions, see Appendix A.2 Map of Lower 48 States Shale Plays).

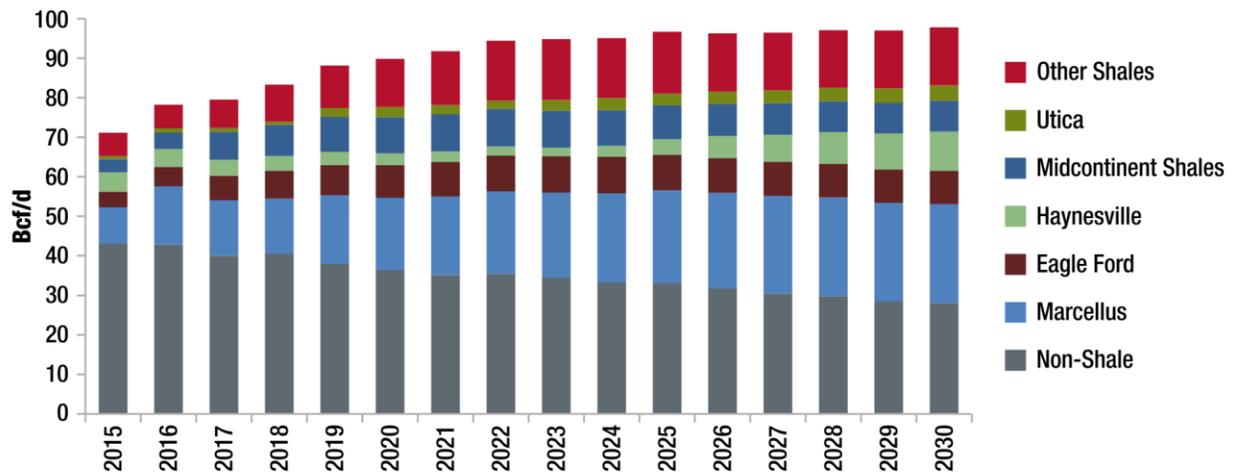


Figure 9: Reference Case Natural Gas Production by Production Region, 2015 to 2030

In response to the increased use of natural gas for power generation in the Intermediate and High Demand Cases, U.S. natural gas production is projected to increase by 6%–10% over Reference Case levels in 2030. The majority of production is projected to come from shale gas basins, as shown in Figure 10. The remainder, totaling 38% of total natural gas supply in both the Intermediate Demand Case and the High Demand Case, includes conventional natural gas, offshore natural gas, associated gas, coalbed methane, and tight gas.³⁴ Just as in the Reference Case, shale gas production in the Intermediate Demand Case is spread across multiple regions. While the volumes of natural gas supplied are larger in the High Demand Case, the geographic distribution of that supply is similar.

³² In any given year, natural gas production is greater than natural gas demand plus net exports because of fuel used or lost in all stages of natural gas production, transmission, distribution, and storage.

³³ U.S. Energy Information Administration, “Table 13. Natural Gas Supply, Disposition, and Prices,” *Annual Energy Outlook 2014*, May 7, 2014, accessed September 24, 2014, http://www.eia.gov/forecasts/aeo/excel/aeotab_13.xlsx.

³⁴ “Tight gas” is natural gas found in low-permeability sandstones and carbonate reservoirs. The rock layers that hold the natural gas are very dense, preventing easy flow of natural gas.

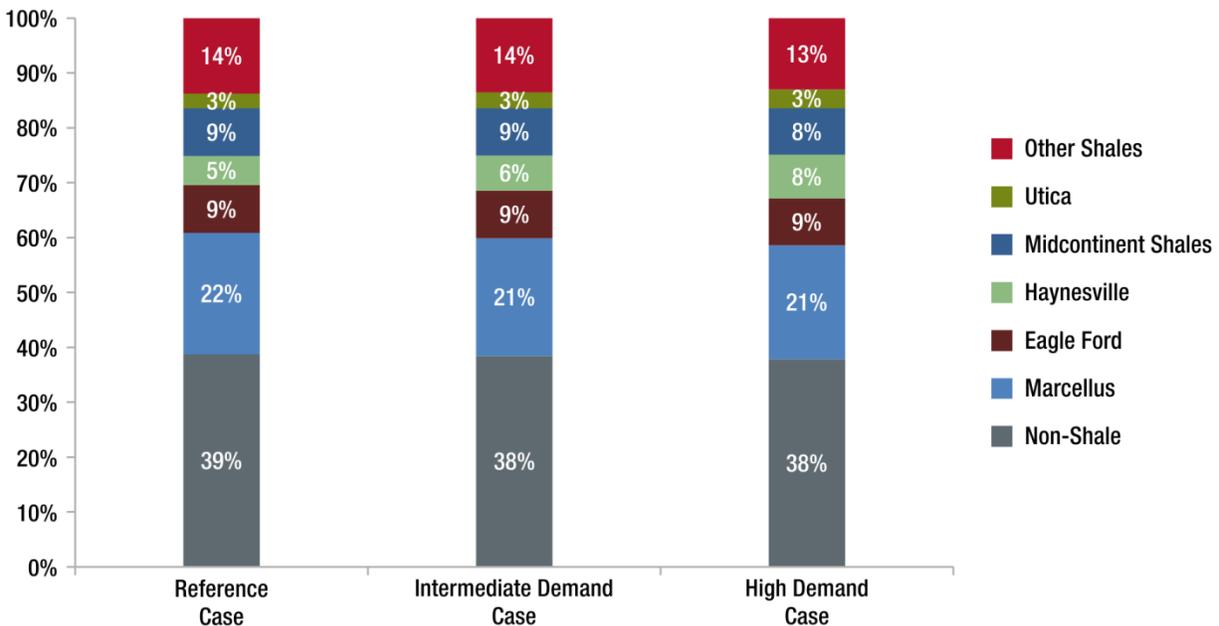


Figure 10: Share of Total Natural Gas Production from Different Production Basins across the Cases, 2015 to 2030

Interestingly, while the Marcellus region is the largest source of shale gas production in the Reference Case, it is not the largest incremental source, relative to the Reference Case, of projected future natural gas production in the Intermediate and High Demand Cases. Instead, the largest source of incremental shale gas production in these cases is the Haynesville basin, which is situated in East Texas and Northwest Louisiana. This result follows from the underlying resource economics of the shale plays represented in the model. As the lowest-cost Marcellus resources are depleted over the course of the Reference Case projection, only higher-cost Marcellus supplies remain available for incremental production in the increased demand cases. Incremental Marcellus production is also likely to require additional infrastructure to bring production to market, diminishing the attractiveness of Marcellus production relative to other basins. In addition, the Haynesville is well positioned to supply natural gas to southern electricity markets, which account for a significant share of the increase in demand from the U.S. electric power sector in the Intermediate and High Demand Cases (Figure 7 and Figure 8).

3.3 Natural Gas Prices

The United States is estimated to hold about 2,400 trillion cubic feet (Tcf) of technically recoverable natural gas in shale formations, equivalent to approximately 100 years of supply at present levels of demand.³⁵ The large shale gas resource potential has effectively made the long-run natural gas supply curve more elastic, and as a result, long-run natural gas demand changes are less likely to result in major price impacts.

³⁵ U.S. Energy Information Administration, "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States," June 13, 2013, accessed September 24, 2014, <http://www.eia.gov/analysis/studies/worldshalegas/>.

In the Reference Case, U.S. natural gas prices are among the lowest compared to other industrialized countries throughout the forecast period. Figure 11 shows historical prices through 2010 as well as the projected price at Henry Hub in the Reference Case.³⁶ Advancements in the technology used to produce natural gas from shale formations, coupled with the global recession, caused natural gas prices to fall sharply from 2009 to 2012. In the Reference Case, natural gas prices slowly rebound and rise throughout the projection period at levels that are sufficient to incentivize production from marginal sources of natural gas supply. Henry Hub natural gas prices in the Reference Case are similar to prices in EIA’s AEO 2014 Reference Case. In 2030, Reference Case Henry Hub prices are projected to be \$6.16/million British thermal units (MMBtu), while EIA’s AEO 2014 Reference Case prices are projected to be \$6.03/MMBtu.³⁷

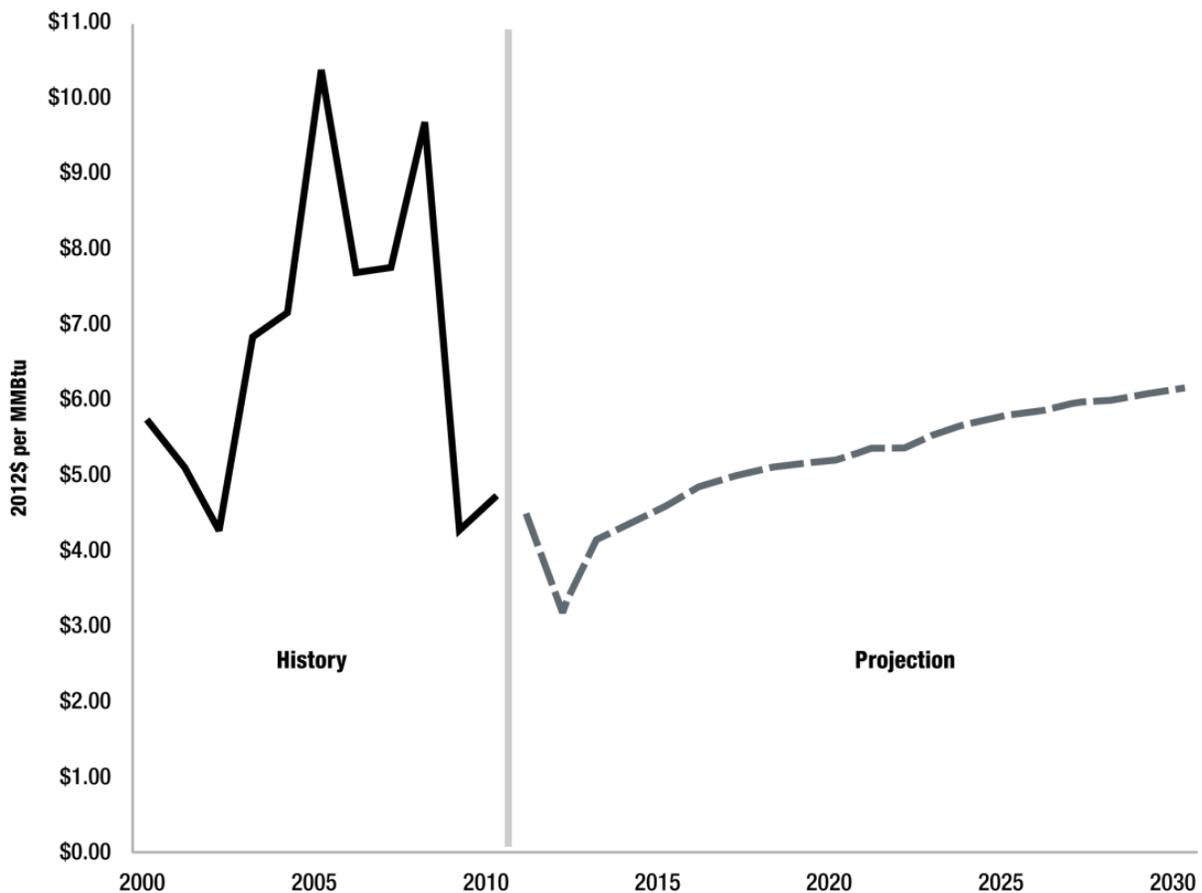


Figure 11: Historical and Projected Henry Hub Natural Gas Prices in the Reference Case, 2000 to 2030³⁸

³⁶ The projection begins in 2011 in order to calibrate the model.

³⁷ U.S. Energy Information Administration, “Figure MT-40: Annual average Henry Hub spot natural gas prices in the Reference case, 1990–2040,” *Annual Energy Outlook 2014*, May 7, 2014, accessed September 25, 2014, http://www.eia.gov/forecasts/aeo/excel/figmt40_data.xls.

³⁸ Source for historical Henry Hub prices: U.S. Energy Information Administration, “Henry Hub Natural Gas Spot Price,” September 17, 2014, accessed September 24, 2014, <http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm>.

Figure 12 shows average prices from 2015 to 2030 across the cases for selected major regional natural gas markets and hubs. In the Intermediate Demand Case, growing demand for natural gas results in an average increase in Henry Hub prices of \$0.19/MMBtu (or about 4%) from 2015 to 2030 relative to the Reference Case. In the High Demand Case, the average increase in Henry Hub prices is about \$0.53/MMBtu (or about 10%) from 2015 to 2030 relative to the Reference Case. The largest price impact in these cases is in Massachusetts, which is far downstream in regional pipeline flows.

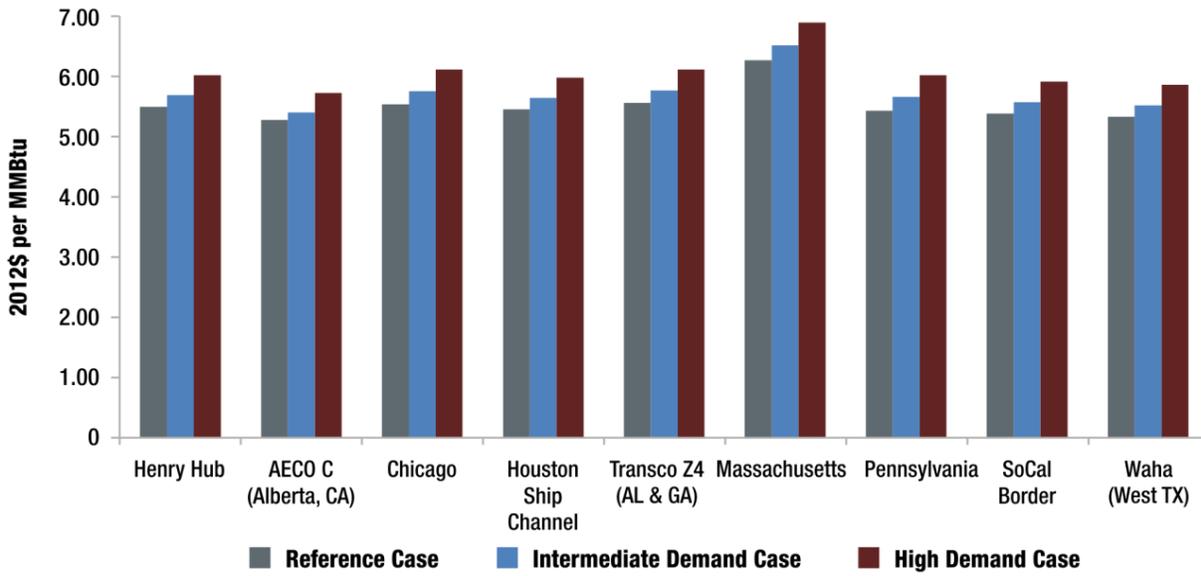


Figure 12: Average Natural Gas Prices by Location across the Cases, 2015 to 2030

3.4 Natural Gas Transmission

Reference Case

In the Reference Case, the combination of a geographic shift in regional natural gas production—largely due to the expanded development of natural gas from shale formations—and growth in natural gas demand is projected to require more interstate natural gas pipeline capacity.

Figure 13 shows the historical and planned capacity additions from 1996 to 2016, along with the projected pipeline capacity additions between 2015 and 2030 in the Reference Case. Pipeline capacity additions in the Reference Case are projected to be 38 Bcf/d between 2015 and 2030. In comparison, between 1998 and 2013, nearly 127 Bcf/d of pipeline capacity was added in the United States. Continued integration of shale gas production from the Marcellus basin, which is the largest producing basin in the Reference Case projection, is a key driver of future pipeline capacity additions in the Reference Case. Shale gas produced from the Marcellus is both lower in cost and situated geographically closer to end-user demand in the eastern United States. As a result, more than half of the 38 Bcf/d of interstate pipeline capacity additions in the Reference Case are associated with further integrating Marcellus natural gas production into U.S. natural gas markets.

Even with the significance of the Marcellus, projected natural gas production and demand are geographically diverse, so the need for additional interstate natural gas pipeline infrastructure is lower than would be

expected if the increased production or demand were concentrated in a particular region. Furthermore, pipeline capacity additions that were placed in service between 2007 and the present in order to realign the U.S. natural gas transmission system with changing supply and demand conditions driven by increases in shale gas production are projected to reduce the need for future pipeline infrastructure.

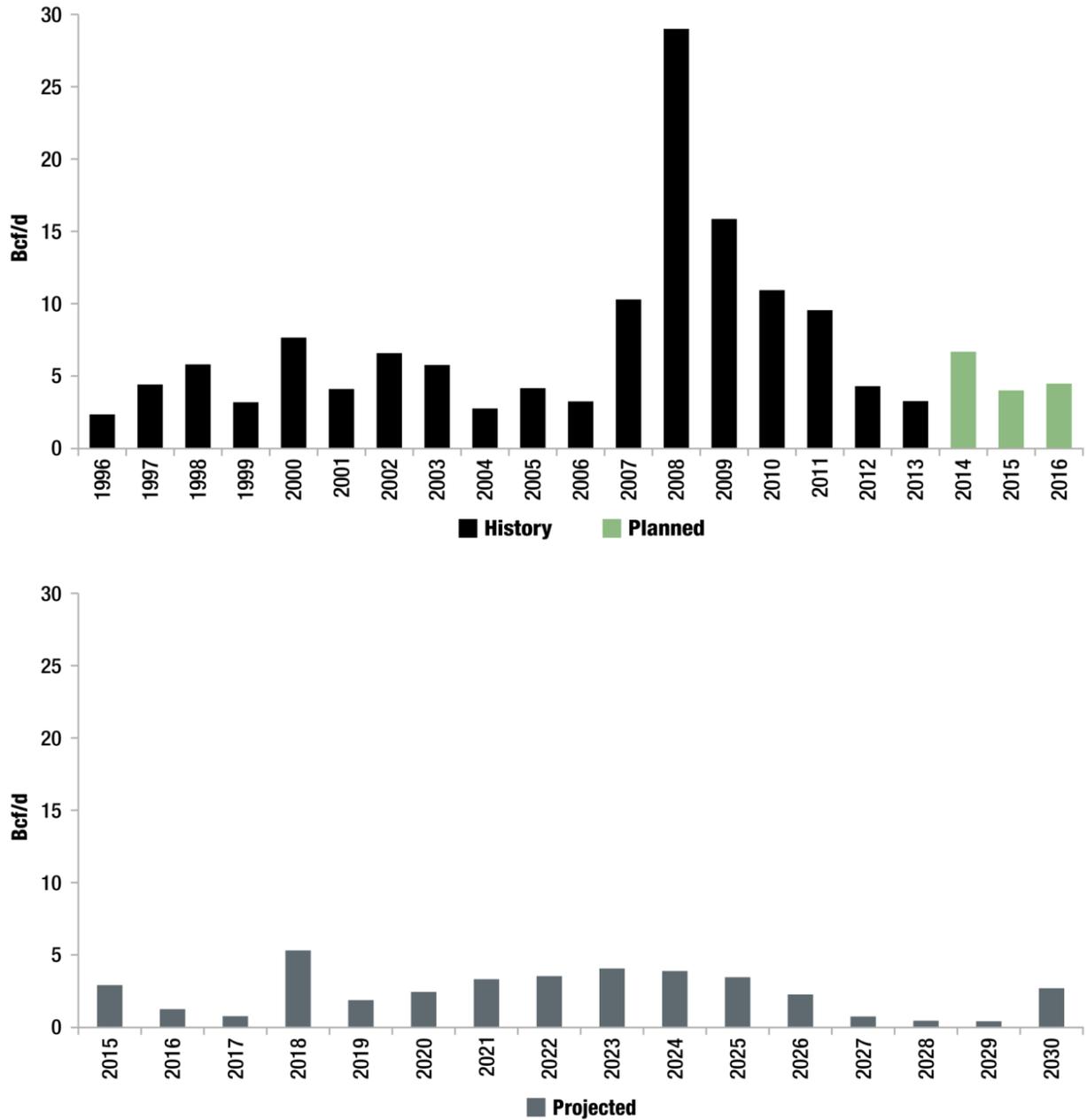


Figure 13: Historical, Planned, and Projected U.S. Interstate Pipeline Capacity Additions, 1996 to 2030³⁹

³⁹ Source for historical and planned additions: U.S. Energy Information Administration, "Natural Gas Pipeline Projects from 1996 to Present," July 7, 2014, accessed September 24, 2014, <http://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xls>. The Deloitte MarketPoint projection for years 2015 through 2018 includes both planned and economic expansion.

Another reason that pipeline capacity additions in the Reference Case are not greater is that, in many regions, existing pipeline capacity is not fully utilized during many parts of the year. Average capacity utilization between 1998 and 2013 was 54%.⁴⁰ For comparison, projected pipeline utilization for the top 200 pipeline segments by projected flow volume in the Reference Case in 2030 is 57%.⁴¹ Given the cost of building new pipelines, finding alternative routes utilizing available capacity on existing pipelines is often less costly than expanding pipeline capacity.⁴² This response is more likely when incremental natural gas demand does not strongly coincide with peak natural gas demand, which is true in the Reference Case, because the incremental demand is largely driven by increases in base load natural gas generation in the electric power sector.

Figure 14 shows the regional distribution of projected pipeline capacity additions between 2015 and 2030 (for more detail on the regions, see Appendix A.3 Map of Natural Gas Pipeline Expansion Regions). In the Marcellus, growth in natural gas production is projected to require additional expansion of pipeline takeaway capacity from the region. In total, an estimated 8.4 Bcf/d of additional pipeline capacity will be needed to integrate Marcellus production with regional markets and interstate pipelines (shown as “Within Marcellus” in Figure 14). Growing Marcellus natural gas production is projected to dominate the Mid-Atlantic natural gas market. Not only will natural gas from the Marcellus displace flows from other regions, but it will also be exported to other parts of the country. A portion of the growth in Marcellus natural gas production is projected to serve northeastern markets and will require 3.2 Bcf/d of incremental pipeline capacity (shown as “Mid-Atlantic to North” in Figure 14).⁴³

⁴⁰ Calculation based on data from the following sources: U.S. Energy Information Administration, “U.S. State-to-State capacity,” January 16, 2014, accessed November 13, 2014, <http://www.eia.gov/naturalgas/pipelines/EIA-StatetoStateCapacity.xls>; U.S. Energy Information Administration, “International & Interstate Movements of Natural Gas by State,” October 31, 2014, accessed November 13, 2014, http://www.eia.gov/dnav/ng/ng_move_ist_a2dcu_nus_a.htm.

⁴¹ This value represents annual average utilization for the top 200 segments in the model. Projected pipeline utilization in any given region or at any given time may be higher or lower than the average values reported here, depending on seasonal patterns of natural gas demand and regional natural gas system characteristics. In addition, annual pipeline utilization will be well below 100% for most pipelines because of the seasonality of natural gas flows. A pipeline might operate near full capacity during peak seasons but will operate at much lower levels during off-peak seasons.

⁴² As discussed in Section 1.3 Economics of Natural Gas Transmission, pipeline expansions are driven by basis differential, which means that new pipelines may be constructed even when existing capacity is available to perform the same transportation service, provided that the anticipated revenue can justify the investment and operating costs.

⁴³ The construction of a planned 1.7 Bcf/d expansion to the Transco Pipeline, which will serve markets in the Northeast, is exogenously specified to be in service in 2018 in the model.

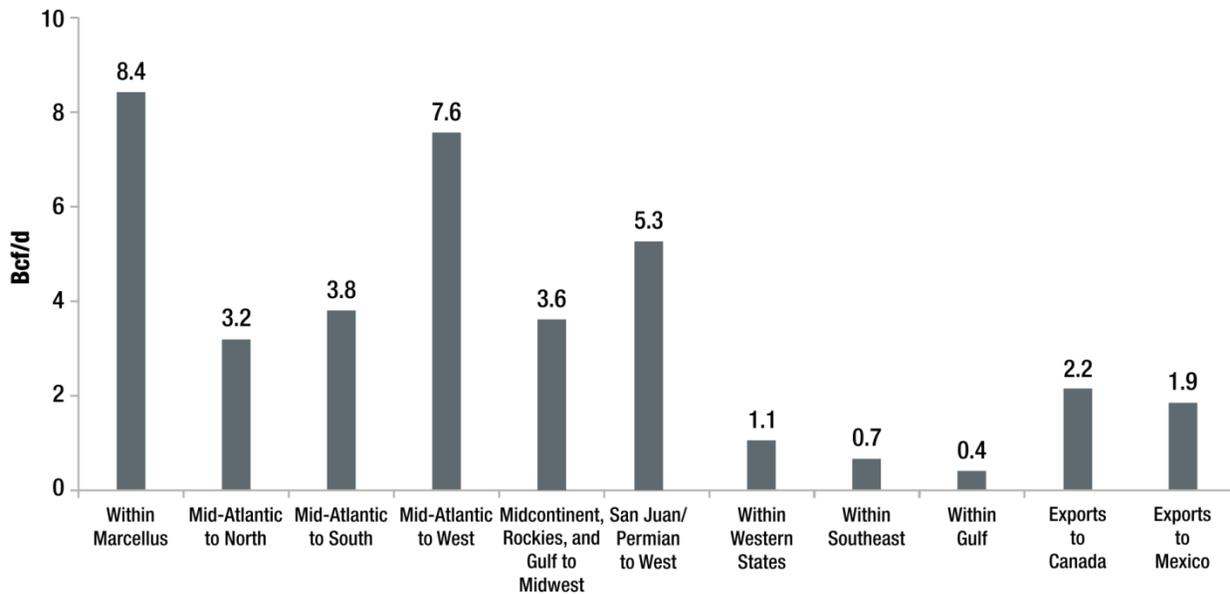


Figure 14: Projected Interstate Pipeline Capacity Additions in the Reference Case, 2015 to 2030

Growth in the Marcellus and in the Utica is also projected to reverse flows that historically have come from west and south of the region. In the Reference Case, the model projects 4.4 Bcf/d will reverse flow from Ohio to Indiana (included within the total for “Mid-Atlantic to West” in Figure 14). Other expansions are projected to increase flows from Pennsylvania and West Virginia to Ohio, bringing total Mid-Atlantic to West expansion to 7.6 Bcf/d. Flow reversal is also projected southward out of the Marcellus to serve markets in the Southeast. Pipelines that currently bring natural gas from the Gulf region to the north are projected to reverse flow so that Marcellus production can serve the Virginia and Carolinas markets (included within the total for “Mid-Atlantic to South” in Figure 14). As a result of the projected expansions, Virginia is almost completely served by Marcellus production. However, pipeline reversals do not go any farther south beyond the Carolinas because Gulf production is able to maintain hold of southern markets.

In addition, Midcontinent, Rockies, and Gulf production, which is largely displaced from eastern markets, is increasingly transported to the Midwest and is projected to require 3.6 Bcf/d of capacity (shown as “Midcontinent, Rockies, and Gulf to Midwest” in Figure 14). The greater quantity of natural gas from the Midcontinent, Rockies, and Gulf region, as well as from the Marcellus and Utica, that serves midwestern markets, in turn, leads to a greater amount of natural gas that is available for export to Canada. As a result, export pipelines from the Midwest to Canada are projected to expand by 2.2 Bcf/d (shown as “Exports to Canada” in Figure 14).⁴⁴ Finally, as production increases in the San Juan and Permian basins,

⁴⁴ The model assumes Canadian natural gas demand will grow to 5.5 Tcf (approximately 15 Bcf/d) by 2030, compared to 4.3 Tcf (about 12 Bcf/d) as estimated in the U.S. Energy Information Administration’s *International Energy Outlook 2013* for the same period. Deloitte MarketPoint’s Canadian demand projections are in line with estimates from the Canadian National Energy Board. See: U.S. Energy Information Administration, “Table A6. World natural gas consumption by region, Reference case, 2009-2040,” *International Energy Outlook 2013*, July 25, 2013, accessed September 24, 2014, http://www.eia.gov/forecasts/archive/ieo13/excel/ieotab_6.xls; Canadian National Energy Board, “Energy Demand: Reference

more pipeline capacity is projected to be added to allow natural gas produced in the Rockies and in the Permian basin to increase its share of California and western markets (shown as “San Juan/Permian to West” in Figure 14).

Intermediate and High Demand Cases

In the Intermediate Demand Case, electric power sector natural gas demand increases by 7.5 Bcf/d in 2030 compared to the Reference Case. This is a 25% increase relative to Reference Case electric power sector natural gas demand and a 10% increase relative to total Reference Case natural gas demand. The impact on natural gas production is lower, at 6.1 Bcf/d (6%) over Reference Case levels in 2030. Higher U.S. natural gas demand results in lower U.S. pipeline exports to Canada, which in turn reduces the need for additional U.S. natural gas production.⁴⁵ Moreover, only a relatively modest 1.4 Bcf/d (about 4% of the total Reference Case capacity additions of 38 Bcf/d) of additional pipeline capacity beyond Reference Case levels is projected to be built by 2030. As in the Reference Case, because incremental natural gas production and demand are broadly distributed, and because utilization of some existing pipelines can be increased, the need for additional natural gas infrastructure is reduced.⁴⁶

In the High Demand Case, electric power sector natural gas demand is projected to increase by about 14 Bcf/d over Reference Case levels in 2030. This is a 46% increase relative to Reference Case electric power sector natural gas demand and an 18% increase relative to total Reference Case natural gas demand. This increase in demand results in a 10 Bcf/d (10%) increase in U.S. natural gas production relative to the Reference Case in 2030. Just as in the Intermediate Demand Case, reductions in natural gas pipeline exports account for the difference between natural gas production and demand. With the increase in natural gas demand in the High Demand Case, an incremental 3.9 Bcf/d (approximately 10% of the total Reference Case capacity additions of 38 Bcf/d) of additional pipeline capacity above Reference Case levels is projected to be built by 2030. Just as in the Reference and Intermediate Demand Cases, the wide geographic distribution of both natural gas production and demand and the ability to increase utilization of some existing pipelines reduce the need for additional interstate natural gas pipeline infrastructure. Projected pipeline utilization for the top 200 pipeline segments by projected flow volume in the model in 2030 rises to 60% in the Intermediate Demand Case and 61% in the High Demand Case, compared to 57% in the Reference Case.

Finally, to further understand the reasons for the modest incremental infrastructure needs in the Intermediate and High Demand Cases, it is necessary to consider the incremental sources of supply in

Case – Canada,” *Canada's Energy Future 2013: Supply and Demand Projections to 2035*, November 11, 2013, accessed September 24, 2014, <http://www.neb-one.gc.ca/nrg/ntgrtd/ft/2013/ppndcs/pxndsdmnd-eng.html>.

⁴⁵ In the Intermediate and High Demand Cases, U.S. LNG export levels are unchanged from the Reference Case level of 5.1 Bcf/d. In order to test the sensitivity to alternative assumptions about U.S. LNG export volumes, an additional case was run that coupled the High Demand Case assumptions with approximately 10 Bcf/d of LNG exports by 2022. The total pipeline capacity additions projected in this case are not significantly different from those projected in the High Demand Case.

⁴⁶ Just as in the Reference Case, incremental demand in the increased demand cases largely follows from increases in natural gas-fired electric power generation primarily designed to serve base load electricity demand. As a result, incremental natural gas demand in these cases is relatively uniform over the course of a year, compared to total natural gas demand in the Reference Case, which exhibits a stronger seasonal pattern. It is easier to accommodate this relatively uniform incremental natural gas demand on existing pipelines than it would be to accommodate demand that coincided more strongly with peak demand.

these cases relative to the Reference Case. As discussed previously, while the Marcellus is the largest source of shale gas production in the Reference Case, driving more than half of the total pipeline capacity additions in the Reference Case, the Haynesville basin is the largest source of incremental shale gas supply in the Intermediate and High Demand Cases, relative to the Reference Case. Compared to the Marcellus, increased production of shale gas in the Haynesville basin requires little or no additional interstate pipeline capacity in order to access markets, because the region has a history of natural gas production and is already well served by interstate natural gas pipelines. However, even if the incremental natural gas supply in the Intermediate or High Demand Cases were to come from another basin with a history of natural gas production, the additional infrastructure requirements would be unlikely to affect the conclusions about infrastructure needs relative to historical experience.

Figure 15, which compares the incremental regional pipeline capacity additions in the Intermediate and High Demand Cases to those in the Reference Case, demonstrates that the regional incremental capacity additions (and subtractions) are comparatively small, relative to the level of capacity additions in the Reference Case (shown in gray). However, there are some modest changes in regional capacity additions between the cases.

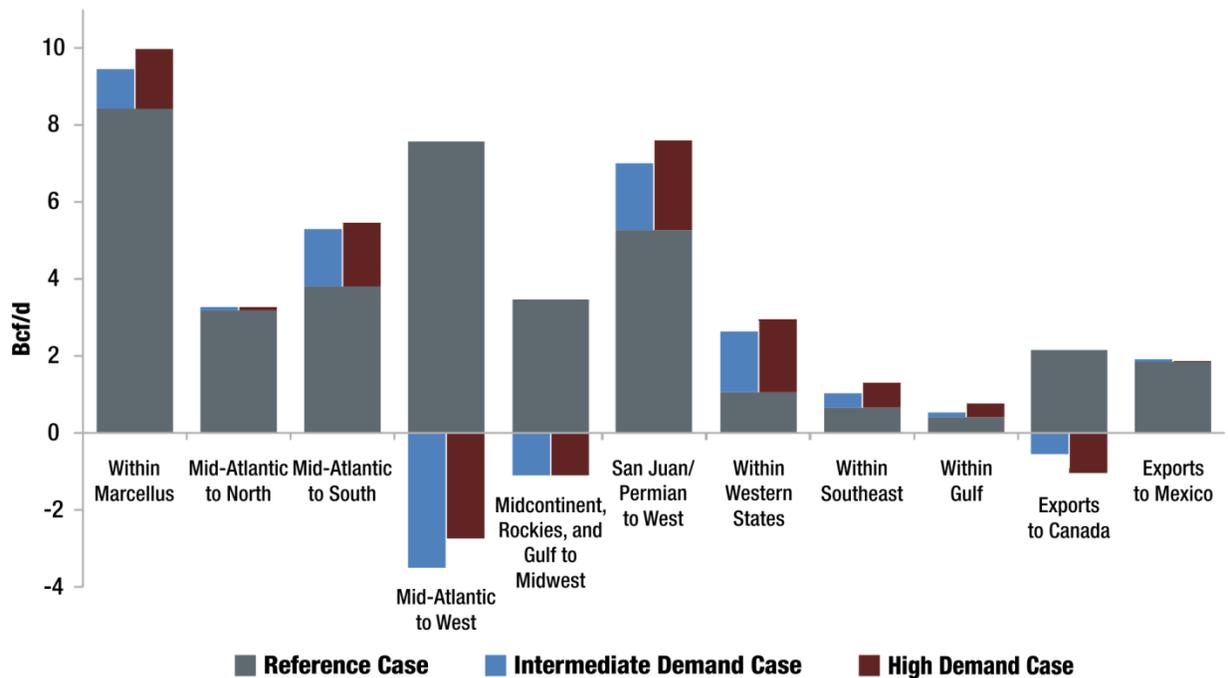


Figure 15: Incremental Interstate Pipeline Capacity Additions in the Intermediate Demand (blue) and High Demand (red) Cases Compared to the Reference Case (gray), 2015 to 2030⁴⁷

In both increased demand cases, greater natural gas demand within the Mid-Atlantic and southeastern regions results in regionally produced natural gas remaining within the region or being sent to

⁴⁷ The gray bars are identical to Figure 14, which shows Reference Case pipeline capacity additions between 2015 and 2030. The blue and red bars show the incremental changes in additions relative to the Reference Case over the same period in the Intermediate Demand and High Demand Cases, respectively. Total additions in these cases over the period can therefore be found by summing the gray and blue and gray and red bars, respectively.

southeastern markets (shown as “Within Marcellus” and “Mid-Atlantic to South” in Figure 15). Furthermore, in both increased demand cases, the demand for natural gas in midwestern markets (and the resulting tendency to send natural gas westward) is lower than the demand in the Mid-Atlantic (and the resulting tendency to use such supplies within the region), so the 7.6 Bcf/d of projected capacity expansions in the Reference Case (shown as “Mid-Atlantic to West” in Figure 15) is reduced by 3.5 Bcf/d in the Intermediate Demand Case and by 2.9 Bcf/d in the High Demand Case. Given the increased demand for natural gas in the Southeast, the tendency to send natural gas northward to midwestern markets is lower than the tendency to use Gulf production in the Southeast, so fewer pipeline capacity expansions are projected into the Midwest from the Gulf in the Intermediate and High Demand Cases than in the Reference Case (shown as “Midcontinent, Rockies, and Gulf to Midwest” in Figure 15).

In both increased demand cases, more pipeline capacity additions are projected relative to Reference Case levels within the West as well as westward from the San Juan and Permian basins to meet growing demand for natural gas in California and western markets (shown as “Within Western States” and “San Juan/Permian to West” in Figure 15). While there are not any coal-fired power plants to displace in California, natural gas demand increases because of reduced imports of electricity and the resulting higher utilization of in-state natural gas-fired power plants.

Finally, compared to the Reference Case, which projects 2.2 Bcf/d of pipeline capacity additions to support U.S. exports to Canada, the Intermediate Demand Case projects 0.5 Bcf/d fewer capacity additions, while the High Demand Case projects 1.0 Bcf/d fewer capacity additions (shown as “Exports to Canada” in Figure 15). These reductions in export volumes follow from the increasing demand for natural gas in the United States relative to Canada, driven by the growing demand from the U.S. electric power sector.

3.5 Expenditures on Natural Gas Transmission Infrastructure

The projected capital expenditures required to construct, expand, and modify interstate pipeline infrastructure described in the previous section are shown in Figure 16. Total capital expenditures on pipeline capacity expansion in the Reference Case are projected to be about \$42 billion between 2015 and 2030. In comparison, between 1998 and 2013, pipeline capacity expenditures totaled more than \$63 billion.⁴⁸ In the Intermediate Demand Case, the incremental capital expenditures are projected to be about \$0.6 billion, 1.3% higher than the Reference Case, and in the High Demand Case, the incremental capital expenditures are projected to be about \$2.8 billion, 6.5% higher than the Reference Case.⁴⁹

⁴⁸ While projected costs are lower than historical costs (over a similar time period), the difference in expenditures is not as large as the difference in pipeline capacity additions between history and the model projection. The distance associated with the pipeline capacity additions in the model projection is comparable to (but lower than) the distance associated with historical pipeline capacity additions. Because project costs reflect, in part, the distance associated with new pipelines, the projected expenditures are closer to (but still lower than) historical expenditures.

⁴⁹ As noted previously, the model does not include the cost of expanding natural gas gathering and processing systems. As such, the projected capacity expansions are limited to the granularity of the pipeline system representation in the model. Because demand is mostly represented at the state level, intrastate pipeline capacity is only partially represented in the model.

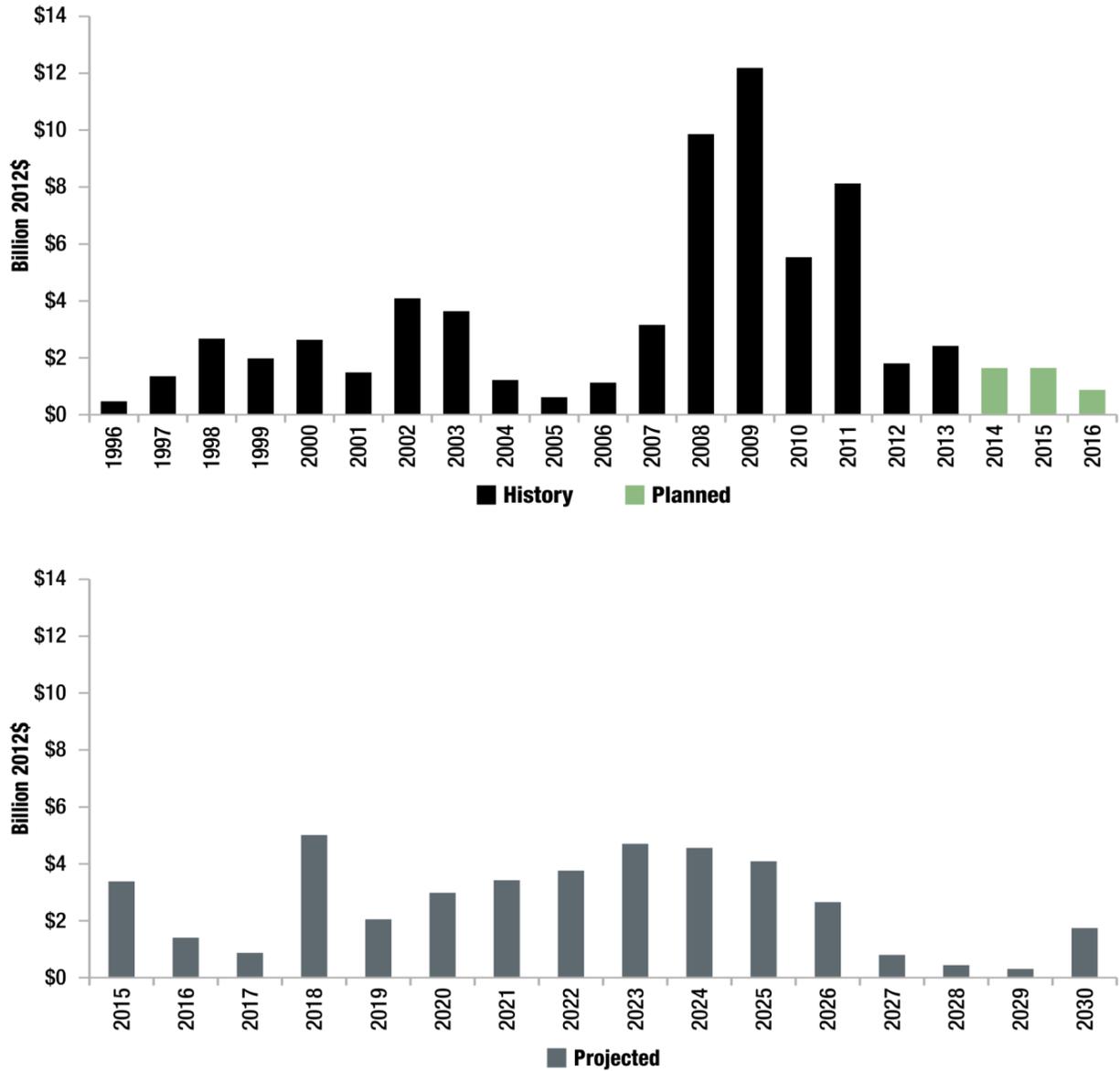


Figure 16: Historical, Planned, and Projected Capital Expenditures on U.S. Interstate Pipeline Capacity, 1996 to 2030⁵⁰

⁵⁰ Source for historical and planned additions: U.S. Energy Information Administration, "Natural Gas Pipeline Projects from 1996 to Present," July 7, 2014, accessed September 24, 2014, <http://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xls>. The Deloitte MarketPoint projection for years 2015 through 2018 includes both planned and economic expansion.

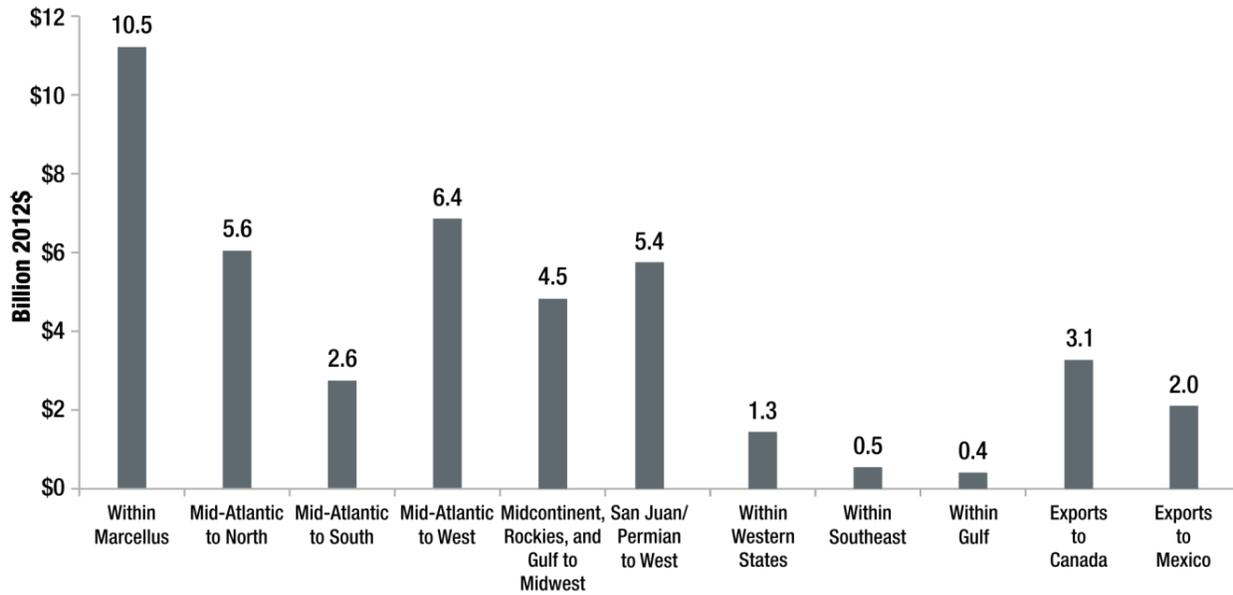


Figure 17: Projected Capital Expenditures on U.S. Interstate Pipeline Capacity in the Reference Case, 2015 to 2030

Projected regional pipeline capital expenditures are displayed in Figure 17. The largest interstate pipeline capital expenditures in the Reference Case are projected to be in the Marcellus to construct pipeline takeaway capacity. In the Intermediate and High Demand Cases (Figure 18), expenditures to expand Marcellus takeaway capacity and to transport natural gas southward increase relative to the Reference Case. Furthermore, in these cases, expenditures to transport Marcellus production westward and Midcontinent, Rockies, and Gulf production northward decline relative to the Reference Case, consistent with the changes in pipeline capacity additions between the cases (Figure 15). Finally, in both cases, expenditures to bring Rockies and southwestern natural gas into and around California increase compared to Reference Case levels (shown as “Within Western States” and “San Juan/Permian to West” in Figure 18), also consistent with the changes in pipeline capacity additions between the cases.

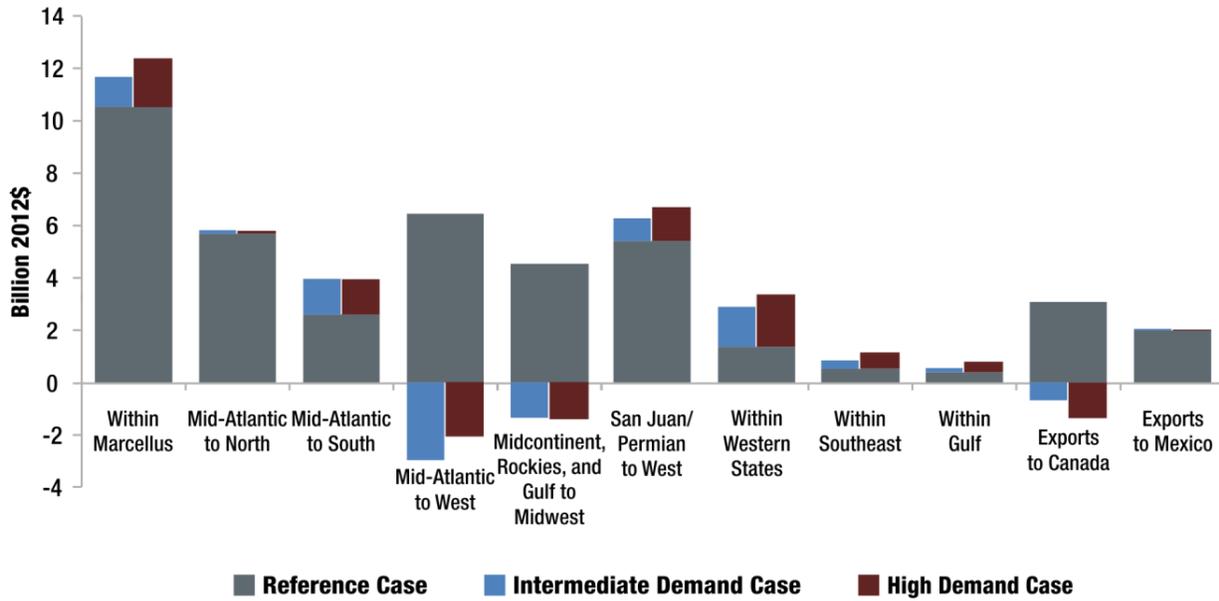


Figure 18: Incremental Projected Pipeline Capital Expenditures in the Intermediate Demand (blue) and High Demand (red) Cases Compared to the Reference Case (gray), 2015 to 2030⁵¹

⁵¹ The gray bars are identical to Figure 17, which shows Reference Case pipeline capital expenditures between 2015 and 2030. The blue and red bars show the incremental changes in expenditures relative to the Reference Case over the same period in the Intermediate Demand and High Demand Cases, respectively. Total expenditures in these cases over the period can therefore be found by summing the gray and blue and gray and red bars, respectively.

4. Conclusion

This study concludes that, under scenarios in which natural gas demand from the electric power sector increases, the incremental increase in interstate natural gas pipeline expansion and associated investment is modest, relative to historical capacity additions. The projected rate of interstate pipeline capacity expansion in the scenarios considered in this analysis is lower than the rate of historical capacity additions over the past 15 years and is consistent with information currently available on planned capacity additions over the next 3 years. In the scenarios considered here, 38–42 Bcf/d of new and expanded interstate pipeline capacity is projected to be constructed between 2015 and 2030, compared to nearly 127 Bcf/d of pipeline capacity added in the United States between 1998 and 2013.

Similarly, capital expenditures on new interstate pipelines in the scenarios considered here are projected to be significantly less than the capital expenditures associated with infrastructure expansion over the last 15 years. The scenarios in this analysis project \$42 billion to \$45 billion in capital expenditures on new, expanded, and modified interstate pipeline capacity between 2015 and 2030, while pipeline capacity expenditures totaled more than \$63 billion between 1998 and 2013.

The results of this study are consistent with a recent report prepared by ICF International for the Interstate Natural Gas Association of America (INGAA) Foundation.⁵² Average annual expenditures on interstate natural gas pipeline infrastructure range from \$2.6 billion to \$2.8 billion across the cases considered in this analysis between 2015 and 2030. The INGAA study, which utilizes a different set of input assumptions and projection methodologies, projects annual expenditures that range between \$2.7 billion and \$4.0 billion across the cases considered in its analysis.⁵³

Two primary factors mitigate the need for additional interstate natural gas pipeline infrastructure and related capital expenditures in these scenarios. First, the growth in both natural gas demand from electricity generation and natural gas production is broadly distributed rather than geographically concentrated, reducing potential interstate pipeline capacity constraints as well as the need for new interstate pipelines. Second, increasing utilization of capacity that is not fully utilized in existing interstate natural gas pipelines, re-routing natural gas flows, and expanding existing pipeline capacity are potentially lower-cost alternatives to building new infrastructure and can accommodate a significant increase in natural gas flows.⁵⁴

While the conclusions about interstate pipeline additions and capital expenditures are likely to be robust to a range of alternative assumptions, additional research could further inform discussions about natural gas infrastructure needs and related natural gas system issues. Such research might consider representation of shorter time intervals (such as peak days or peak hours), the role of seasonal and high-

⁵² Interstate Natural Gas Association of America Foundation, Inc., “North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance,” March 17, 2014, accessed November 4, 2014, <http://www.ingaa.org/Foundation/Foundation-Reports/2035Report.aspx>.

⁵³ *Ibid.*, p. 26.

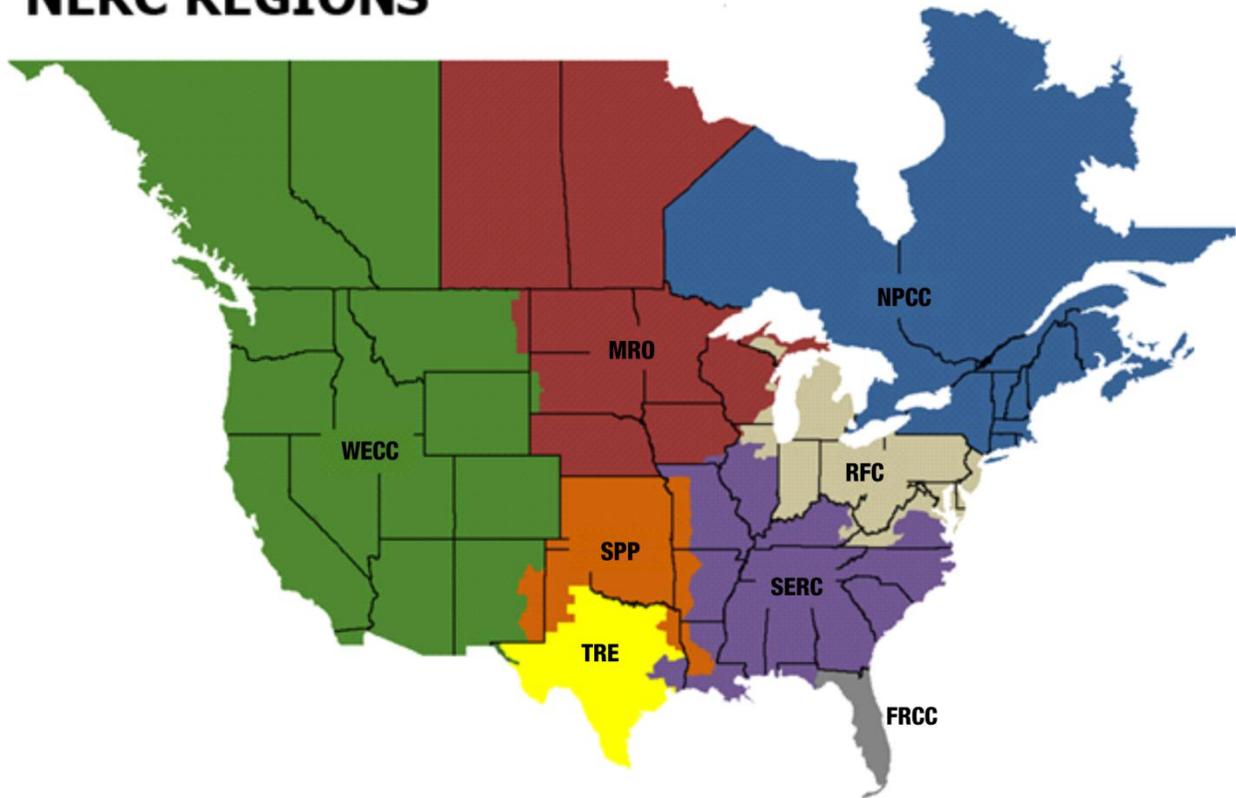
⁵⁴ As discussed in Section 1.3 Economics of Natural Gas Transmission, pipeline expansions are driven by basis differential, which means that new pipelines may be constructed even when existing capacity is available to perform the same transportation service, provided that the anticipated revenue can justify the investment and operating costs.

deliverability natural gas storage, and more granular regional and local segmentation of natural gas markets to pinpoint areas where future investment may be needed. In addition, a variety of other supply and demand cases might be considered, including cases that represent alternative industrial demand, transportation demand, or export futures, as well as alternative natural gas supply assumptions.

Appendix A. Additional Figures

Appendix A.1 Map of Electric Power Sector Natural Gas Demand Regions

NERC REGIONS

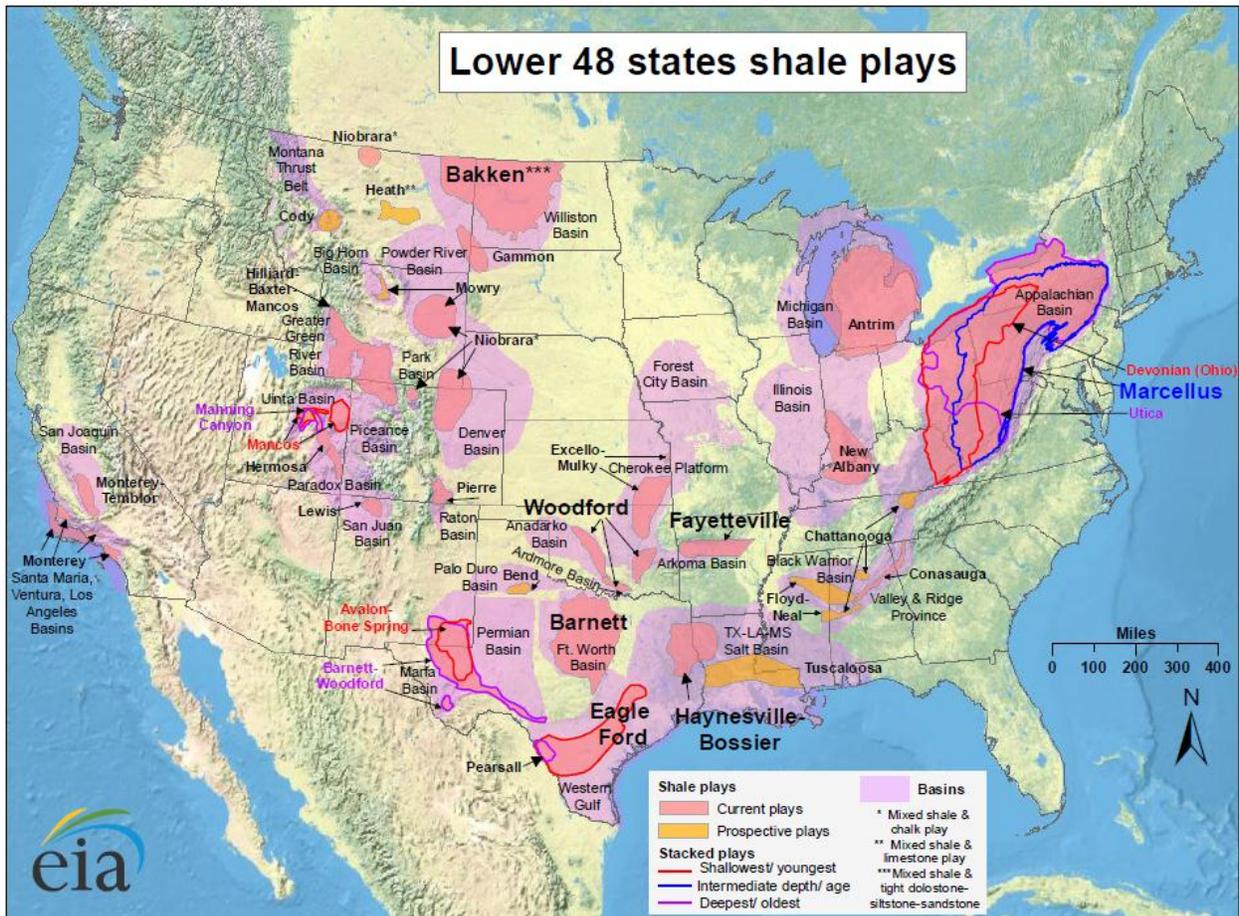


Region Abbreviation	Definition
FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Figure 19: Map of North American Electric Reliability Corporation (NERC) Regions⁵⁵

⁵⁵ North American Electric Reliability Corporation, “NERC Regions Map,” accessed October 22, 2014, http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Interconnections_Color_072512.jpg.

Appendix A.2 Map of Lower 48 States Shale Plays



Model Region	Producing Region
Non-Shale	All conventional, associated, offshore, tight, and coalbed methane production
Eagle Ford	Eagle Ford shale basin
Haynesville	Haynesville shale basin
Marcellus	Marcellus shale basin
Midcontinent Shales	Fayetteville, Woodford, and Arkoma shale basins
Utica	Utica shale basin
Other Shales	Barnett, Permian, Niobrara, and all other shale basins

Figure 20: Map of Lower 48 States Shale Plays⁵⁶

⁵⁶ U.S. Energy Information Administration, "Lower 48 states shale plays," May 9, 2011, accessed October 22, 2014, http://www.eia.gov/oil_gas/rpd/shale_gas.pdf.

Appendix A.3 Map of Natural Gas Pipeline Expansion Regions

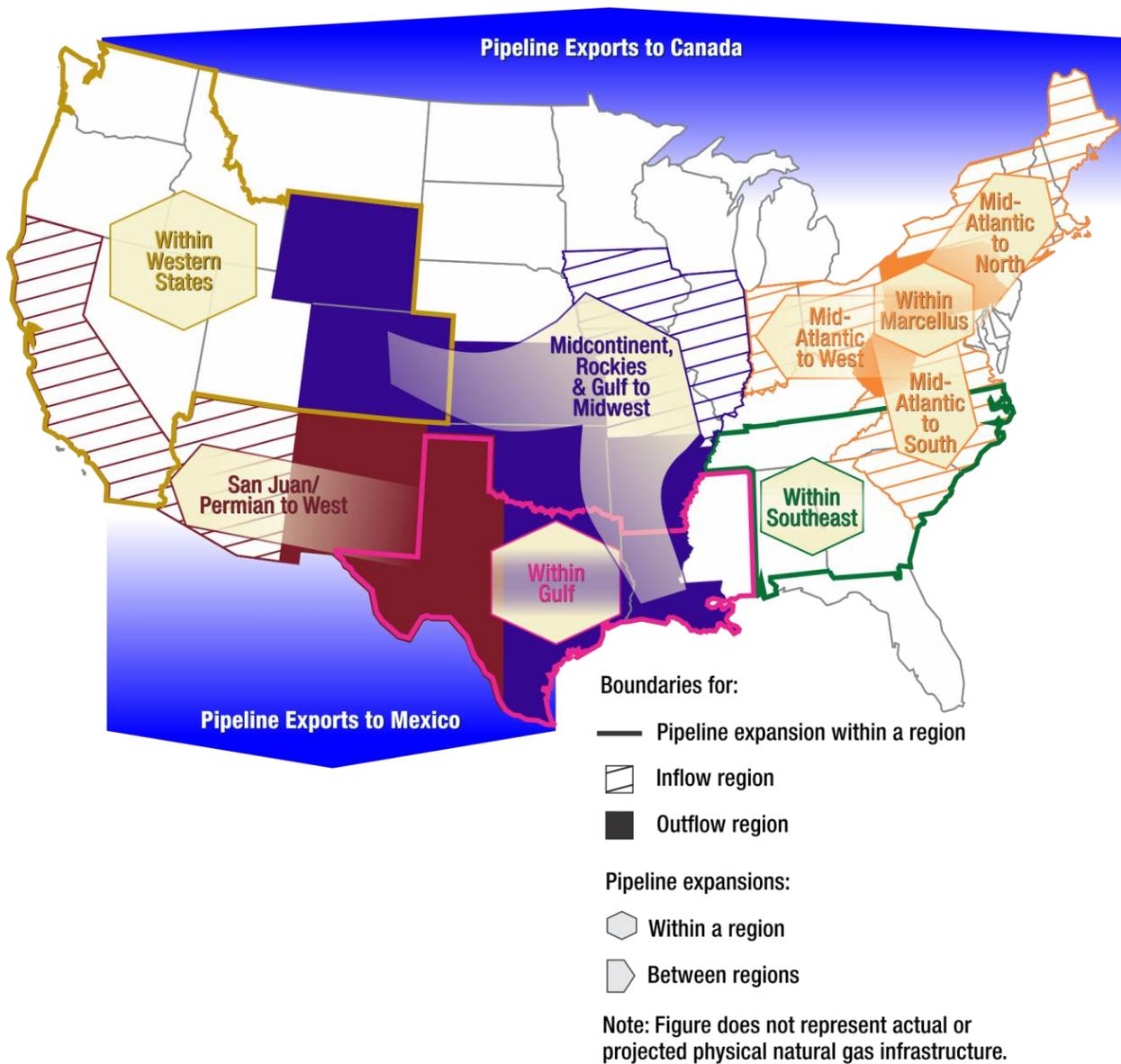


Figure 21: Map of Natural Gas Pipeline Expansion Regions⁵⁷

⁵⁷ Regions that are not included in this figure are not projected to have pipeline capacity additions. Pipeline capacity additions from the Bakken region are not reported with the regional pipeline expansion results, because Bakken region wet natural gas production is represented in the model as natural gas liquids processing that is delivered to the Chicago market via the Alliance Pipeline. LNG exports are also not reported with the regional pipeline expansion results.

Appendix B. Electric Power Sector Results

Figure 22 shows the projected generation by fuel in the Reference Case. In this case, the majority of electricity generation is supplied by coal- and natural gas-fired generation, along with generation from nuclear and renewable energy sources. Coal-fired generation decreases by 2% from 2015 to 2030, while natural gas-fired generation increases substantially, by approximately 33% over the same period. Non-hydro renewable generation grows by approximately 76% between 2015 and 2030, but the absolute increase is slightly less than half of the increase from natural gas-fired sources.

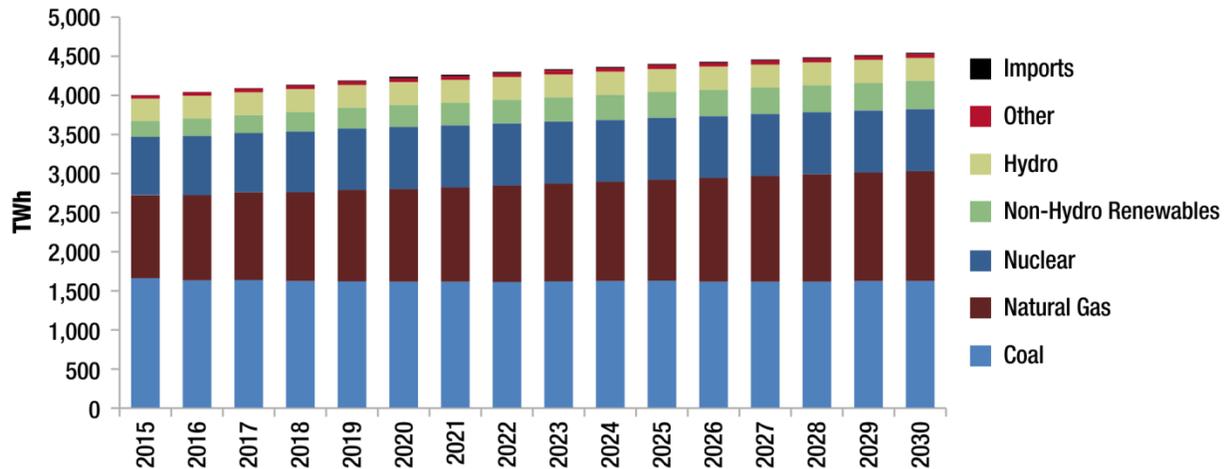


Figure 22: Electric Sector Generation by Fuel in the Reference Case, 2015 to 2030⁵⁸

Regional natural gas-fired generation is shown in Figure 23. While the WECC (excluding CA) region is expected to experience the largest relative increase in natural gas-fired generation during the forecast period (a 106% increase and absolute growth of 112 terawatt-hours [TWh]), the Southeast (SERC and FRCC) is expected to see the largest absolute increase in natural gas-fired generation (a 31% increase and absolute growth of 137 TWh).⁵⁹ Part of the increase in natural gas-fired generation in these regions stems from a decrease in coal-fired capacity; both WECC (excluding CA) and the Southeast (i.e., SERC and FRCC) have large coal-fired fleets with a significant number of announced retirements.

⁵⁸ The label “Imports” represents U.S. imports of electricity generated in Canada.

⁵⁹ For a map of the regions mentioned here, see Appendix A.1 Map of Electric Power Sector Natural Gas Demand Regions.

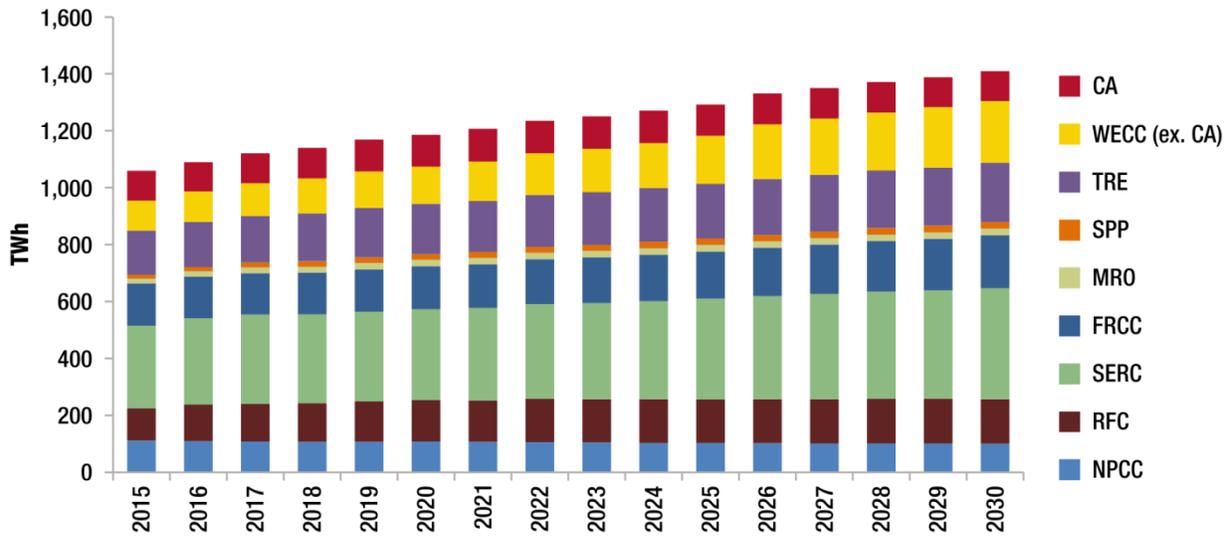


Figure 23: Natural Gas-Fired Generation by Region in the Reference Case, 2015 to 2030

Figure 24 shows the shift in generation in the Intermediate and High Demand Cases relative to the Reference Case. The dominant source of replacement generation for coal in both cases is natural gas-fired generation. Non-hydro renewables make up the balance, with a small contribution from cross-border imports from Canada (shown as “Imports”).

In the High Demand Case, all coal-fired power plants that lacked scrubber-type emissions controls as of the first quarter of 2014 (the most recent data that were available prior to publication of this report) are assumed to retire in 2017. Consequently, the electric power sector responds in two steps: first, in 2017, when the coal-fired capacity is retired, and then again in 2020, when the illustrative national carbon policy begins to affect dispatch. The reduction in coal-fired capacity assumed in the High Demand Case drives a larger shift from coal to natural gas, renewables, and imports.

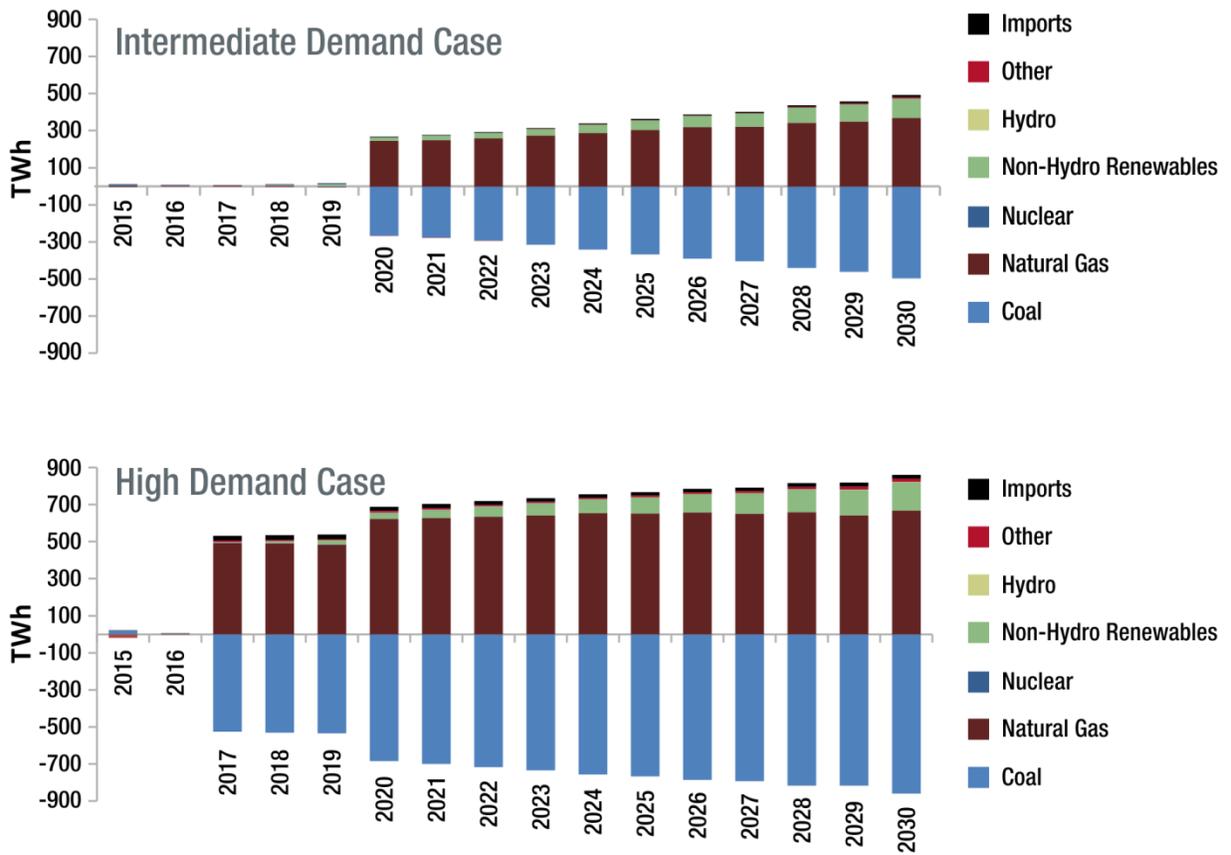


Figure 24: Change in Generation in the Intermediate Demand and High Demand Cases Relative to the Reference Case, 2015 to 2030⁶⁰

⁶⁰ The label "Imports" represents U.S. imports of electricity generated in Canada.

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