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OFFICE OF FOSSIL ENERGY

Natural Gas and Electric Interdependencies Case Study: Near-Term Infrastructure Needs in PJM

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Disclaimer

Prepared by:

National Energy Technology Laboratory (NETL)

Justin M. Adder

Thomas J. Tarka, P.E.

Strategic Energy Analysis & Planning Division

Energy Sector Planning and Analysis (ESPA)

Booz Allen Hamilton, Inc.

WorleyParsons Group, Inc.

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
Bcf	Billion cubic feet (natural gas)
Bcf/d	Billion cubic feet per day (natural gas)
BRA	Base residual auction
Btu	British thermal unit
DOE	Department of Energy
EIA	Energy Information Administration
ESPA	Energy Sector Planning and Analysis
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GW	Giga-watt electric
HEDD	High Electric Demand Day
HHV	Higher heating value
IHS CERA	IHS Cambridge Energy Research Associates
I.D.	Inside diameter
in	Inches
kWh	Kilo-watt hour electric
LDC	Local distribution company
MATS	Mercury and Air Toxics Standards
mi	Mile
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British thermal units
MMcf	Million cubic feet (natural gas)
MW	Mega-watt electric
MWh	Mega-watt hour electric
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NGCT	Natural gas-fired combustion turbines
NOx	Nitrous oxide
NOPR	Notice of proposed rulemaking
NSPS	New Source Performance Standards
NYISO	New York Independent System Operator
O&M	Operation and maintenance
PJM	PJM Interconnection, LLC
REX	Rockies Express
RPS	Renewable Portfolio Standards
RTEP	Regional Transmission Expansion Planning
RTO	Regional Transmission Organization
SCED	Security constrained economic dispatch
SERC	SERC Reliability Corporation
TWh	Tera-watt hour electric
U.S.	United States

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Executive Summary

Market and regulatory forces are driving an increase in the use of natural gas (NG) for electricity generation in the United States. This is driving an increase in natural gas consumption, the construction of new natural gas-fired generation, and the increased utilization of existing natural gas-fired generation. Historically, however, the vast majority of natural gas power generation has not served as baseload power or operated at sustained, high capacity factors, but instead has provided generation to meet seasonal or daily peak loads. Therefore, this expansion in natural gas's role in power generation represents a transition which will require additional infrastructure and may present unanticipated challenges or costs.

This report examines the scope and scale of the transition about to occur in the next five to ten years, in terms of electrical generating capacity, increased demand for natural gas, and infrastructure needs. Both current and forecasted planned-certain electrical generating capacity[1] mix and the current and forecasted natural gas infrastructure are evaluated to understand the potential risk areas with the shift from coal to gas. The PJM Interconnection, LLC (PJM) was selected as a case study because of the relatively large number of coal plant retirements and increasing reliance on natural gas-fired power plants within PJM's footprint.

It was found that in 2014, natural gas pipeline infrastructure was sufficient to meet current delivery needs, with spare capacity existing at the majority of natural gas delivery points in the PJM region. However, the shift in generating capacity towards both existing and new natural gas-fired generation, coupled with an increase in electricity imports from other Regional Transmission Organizations (RTOs) will require additional infrastructure in the near term. Notably, more than 6,000 miles of electrical transmission lines and 3,000 miles of natural gas pipelines are planned to go into service over the next five years.

New electrical generating capacity – beyond that which is currently accounted for as planned-certain – is projected to be necessary starting in 2020 in order to meet peak demand. This will likely require additional transmission and pipeline infrastructure beyond what is planned, and timing considerations associated with the construction and permitting of such projects create the potential for short-term increases in pipeline congestion.

Key findings of this report include:

- The PJM region is expected experience a net loss in generating capacity of 15 GW, or 7 percent, from 2007 to 2020. New capacity added during this period will almost solely be natural gas-fired units.
- Natural gas generating capacity will increase from 28 percent of PJM's total generating capacity mix to 35 percent, slightly exceeding total coal-fired generating capacity. Most of this capacity will be located near existing natural gas infrastructure.

[1] "Certain" capacity includes generating units listed within the Active Generation Queue that are permitted and under construction. Speculative generating units in the Active Generation Queue are omitted due to their uncertain nature. These units include generating units that are proposed approval pending or under feasibility study. Certain capacity includes two types of capacity, existing and planned. Existing-certain capacity is that which has completed construction, but is not yet delivering power to the electric grid. Planned-certain capacity is that which is currently under construction. Throughout this report, unless otherwise noted, certain capacity is considered to be the aggregate of existing and planned-certain capacity.

- After 2020, additional generating capacity will be required to meet peak electricity demand, with a total of 14 GW to be required by 2025.
- A security-constrained economic dispatch model shows that the gas delivery requirements will increase 133 percent between 2014 and 2025, or an average of 8 percent per year, to meet future power generation needs. A number of factors might push this demand higher, e.g. if less efficient combustion turbines are built instead of combined cycle units due to timing issues, or, if the aforementioned capacity required after 2020 consists of natural gas-fired units.
- PJM is expected to become more heavily reliant upon power transmission imports from surrounding regions, increasing by a factor of eight from 1.3 GW in 2014/2015 to 10.6 GW in 2025/2026, peaking at 14.2 GW in 2023/2024.
- Currently, there are approximately 3,000 miles of new, mostly large, natural gas pipelines and 6,000 miles of transmission lines planned for the PJM region.
- Working natural gas storage is clustered in the central PJM region and has increased in recent years due to equipment upgrades and optimization at existing sites, growing by 4.2 percent since 2005 with the daily capacity deliverable from storage increasing by 7.8 percent. Significant growth in storage capacity is not anticipated in the near term as no new natural gas storage sites are planned.

1 Introduction

The electric grid is currently undergoing a significant shift as market and regulatory forces are driving a transition of the electric generating fleet from one whose primary fuel source is coal to one fueled by natural gas (NG).[2]

This has elicited little cause for concern from certain sectors, based on the widely held view that natural gas supplies will remain plentiful and inexpensive in the near term due to new, unconventional (shale) gas development.[3] Historically, however, the vast majority of natural gas power generation has not served as baseload power or operated at sustained, high capacity factors, but instead has provided generation to meet seasonal or daily peak loads. Therefore, this expansion in natural gas's role in power generation represents a transition which will require additional infrastructure and may present unanticipated challenges or costs. Taken together, these challenges present real risks of both higher energy costs – impacting the Nation's economy and the consumer – and reliability of the electric grid as natural gas becomes a more dominant fuel.

The goal of this report is to examine the scope and scale of the transition about to occur in the next five to ten years, in terms of plant retirements, capacity additions, and infrastructure needs. Because the impact of this shift will affect regions differently based on their generating capacity profile, it was necessary to focus on a single region and use that as a case study. This case study was then developed with the goal of answering the following questions:

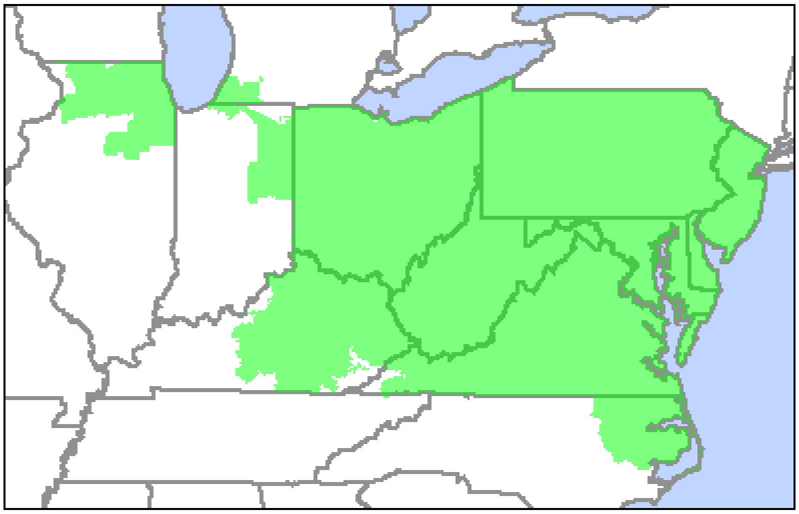
- How much capacity is being retired?
- Is there enough new natural gas generating capacity to meet the need?
- What are the plans for new natural gas-fired capacity and natural gas infrastructure?
- What is the existing or proposed natural gas storage in the area?
- How do the natural gas/electrical systems perform during peak demand days?

PJM Interconnection, LLC (PJM) was selected because of the relatively large number of coal plant retirements and increasing reliance on natural gas-fired power plants within PJM's footprint. The PJM region encompasses a significant portion of the Eastern United States (U.S.), stretching from coastal areas of the Mid-Atlantic through the Ohio Valley and into the Chicago metropolitan area, (as shown in Exhibit 1-1, using Ventyx (1)). This region also includes the Marcellus and Utica shale formations, which are currently being developed as significant new sources of natural gas.

[2] The market and regulatory forces driving this shift are myriad. From a market perspective, sustained low natural gas prices resulting from new shale plays, relatively low electricity demand over the last five years, anemic capacity markets, and – until recently – mild winters are all factors. From a regulatory perspective, new environmental regulations such as the Mercury and Air Toxics Standards (MATS), and proposed regulations such as the New Source Performance Standards (NSPS) and other greenhouse gas (GHG) reduction initiatives are leading to coal retirements and increasing uncertainty in coal's role in the power sector. State and regional regulations such as state Renewable Portfolio Standards (RPS) are also placing pressure on coal. The uncertainty and current market forces all serve to drive utilities to natural gas generation, especially for capacity additions based on the relatively low capital requirements for such units. (32)

[3] The vast majority of energy analysts remain bullish on natural gas supply from unconventional production. There are those who believe the resource base is either over-estimated, more costly to develop than anticipated, or that the market fundaments remain shaky. Two recent examples of the latter are a recent article in Nature and a report from the International Energy Association. (32)

Exhibit 1-1 Map of the PJM RTO



1.1 Scope

This report provides the framework needed to determine the scope of issues facing the PJM region as it goes through this fleet transition. Some of this information may change over time as issues mature and industry discussions occur.

Specifically, this report will examine the following information regarding the PJM region:

- Current and forecasted power capacity mix
- Ability of forecasted capacity to meet forecasted peak loads, North-American Electricity Reliability Corporation (NERC) planning reserve threshold requirements, and PJM planning requirements
- Natural gas distribution infrastructure network and how it aligns with the locations of planned new natural gas power generating plants
- Location of natural gas storage facilities
- Barriers to increased natural gas-fired capacity

The data in this report is structured so that historical and near-term infrastructure information is provided through 2020, while forecasted information is projected through 2025. Historical and near-term infrastructure is considered through 2020 because this encompasses the typical development and regulatory periods for both (a) electric generating capacity and transmission, and (b) natural gas infrastructure, and these projects, therefore, have a high probability of being placed into service. Such projects are described as "planned-certain" throughout this document. Infrastructure with expected in-service dates beyond 2020 is considered highly speculative and, therefore, is not included.

Forecasts were performed through 2025 to encompass the 10-year planning horizon typically used by power system operators and to determine trends in utilization and potential needs beyond the near-term. An electric load growth rate of 1.8 percent annually was used for the duration of the study period, based on forecasts by IHS Cambridge Energy Research Associates (IHS CERA).[4] Near-term fuel prices through December 2015 were based on the U.S. Energy Information Administration's (EIA) Short-Term Energy Outlook (2), while long-term prices were based on the EIA's 2014 Annual Energy Outlook (AEO). (3)

There are a number of issues which are beyond the scope of this work. This report does not examine (a) risks surrounding the performance of the existing fleet – most notably whether the existing NG and coal fleet can operate at high capacity factors for sustained, multi-year periods, (b) impacts of other regulatory drivers which might result in additional coal retirements and therefore increased natural gas usage, (c) price impacts due to natural gas volatility, infrastructure upgrades, or other factors.

Also omitted are challenges which could make expanded natural gas usage in power generation a more significant transition than might be expected. These challenges include lack of significant onsite fuel storage, historically volatile prices, competition with home heating during winter months, and supply contract structures which have been traditionally focused on natural gas use as a peaking or opportunity fuel.[5]

Lastly, natural gas market structures were excluded from this analysis due to the transition that is taking place in the natural gas and electricity marketplace. The Federal Energy Regulatory Commission (FERC) has recently released a notice of proposed rulemaking (NOPR) to better coordinate the scheduling of natural gas and electricity markets in light of increased reliance on natural gas for electric generation, as well as to provide additional flexibility to all shippers on interstate natural gas pipelines. (4) Finally, contracts for electricity providers to obtain natural gas were excluded from this report. There are multiple ways that natural gas contracts are structured and information on types of contracts and parties involved are not publicly available.

2 PJM Capacity Changes and Requirements

The manner in which the capacity mix is transitioning from coal to natural gas, and how these changes could impact PJM's ability to operate reliably was examined, in order to understand the change in capacity composition. This was done by examining what, if any, capacity additions (over those units which are already considered planned-certain additions) would be required to meet NERC planning reserve threshold requirements and forecasted peak loads. Electricity imports from other Regional Transmission Organizations (RTO) were also examined, particularly in light of PJM's limiting imports to no more than 6,500 MW (or 6.5 GW) beginning with the recent 2017/18 base residual auction (BRA) as a means of limiting both risk and reliance on imports.

[4] It is important to note that the IHS growth rate is significantly higher than the growth rate utilized by PJM in the development of their 2014 and 2015 Load Forecast Reports. (29) The growth rates utilized by PJM in their forecast reports were 1.0% annually for summer peak through 2025 and 0.9% annually for winter peak through 2025 and were developed following the process defined in PJM Manual 19: Load Forecasting and Analysis. (30)

[5] Unlike traditional baseload power plants, such as coal and nuclear, which are capable of long-term operation due to onsite fuel storage or long duration fuel life, very few natural gas power plants have NG stored onsite. Some plants are equipped to use a secondary fuel, usually a petroleum-derived liquid fuel like heating oil or diesel. For those NG plants with onsite storage, many of these plants have secondary fuel availability for multiple-day operation at full load, however, these plants represent only a fraction of the total natural gas-fired fleet.

It was found that:

- PJM will be required to add new capacity (beyond what is planned-certain) by 2016 in order to meet NERC reserve requirements, and by 2020 in order meet peak demand;
- Starting in 2015/2016, PJM will become increasingly dependent on imports, exceeding the self-imposed 6,500 MW import limit in the BRA, by increasing levels from 33 to over 100 percent;
- Capacity additions required to meet peak demand will be significant. The 14.2 GW of new capacity required is slightly more than the total capacity additions of 12.1 GW between 2007 and 2020, but will occur over a much shorter time span;
- If PJM limits imports to 6,500 MW, the need for additional new capacity will be accelerated.

These findings and the modeling methodology utilized to reach them are described below.

2.1 Changes in Capacity and Generation Mix

Based on announced generating capacity retirements and planned-certain capacity additions from 2014 to 2020, PJM will add a significant amount of natural gas-fired capacity, while retiring a significant amount of coal-fired capacity, as shown in Exhibit 2-1. (1) By 2020, over 13 GW of coal-fired capacity is expected to be retired in PJM, which will be replaced, in part, by 6.6 GW of natural gas-fired capacity as a result of regulatory and market pressures over the period shown.

Exhibit 2-1 PJM natural gas-fired and coal-fired capacity change 2014 to 2020

Capacity	New (GW)	Retired (GW)	Net Change (GW)
Natural Gas-fired Capacity	10.74	4.13	6.60
Coal-fired Capacity	0.53	13.55	-13.03

Of the 4.13 GW of natural gas-fired retirements within the PJM footprint, 2.67 GW are located within New Jersey and are occurring in response to that state's High Electric Demand Day (HEDD) environmental rules and requirements, which become effective May 1, 2015, and require combustion or steam units within the state to meet specified NOx emissions rates.[6] These emissions rates primarily affect peaking units that are infrequently dispatched and fueled mostly by natural gas and petroleum.

PJM generating capacity is forecasted to decrease through 2020 with natural gas-fired capacity increasing and coal-fired capacity decreasing on a percentage basis (Exhibit 2-2, Exhibit 2-3). Although the capacity shift from coal to natural gas is equal on a categorical percentage basis,

[6]Under New Jersey's HEDD Rule, the allowable emissions rate for natural gas or petroleum-fired combustion turbines and boilers ("steam units") is 1.0 lb NOx/MWh while for petroleum-fired units the limit is 1.6 lb NOx/MWh. New units can be fitted with Low-NOx combustion systems which allow them to meet this standard. (22)

the quantities of capacity in question are significantly different on a net basis, with retiring coal outnumbering new natural gas by more than 2-to-1 (Exhibit 2-4) since the inception of the PJM capacity market in 2007. (1)

Exhibit 2-2 New PJM capacity (2007-2020) [19.83 GW][7]

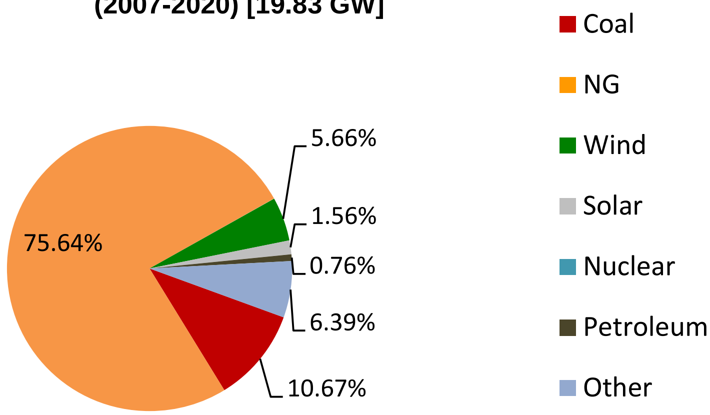


Exhibit 2-3 Retiring capacity (2007-2020) [32.48 GW][8]

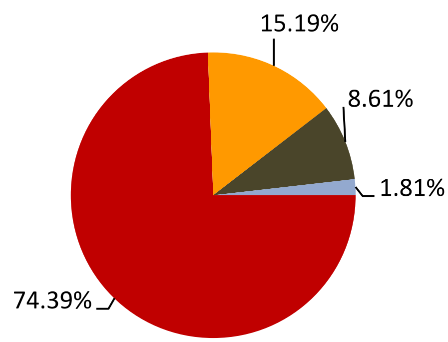


Exhibit 2-4 Cumulative change (GW) of the capacity mix for 2007-2020 period

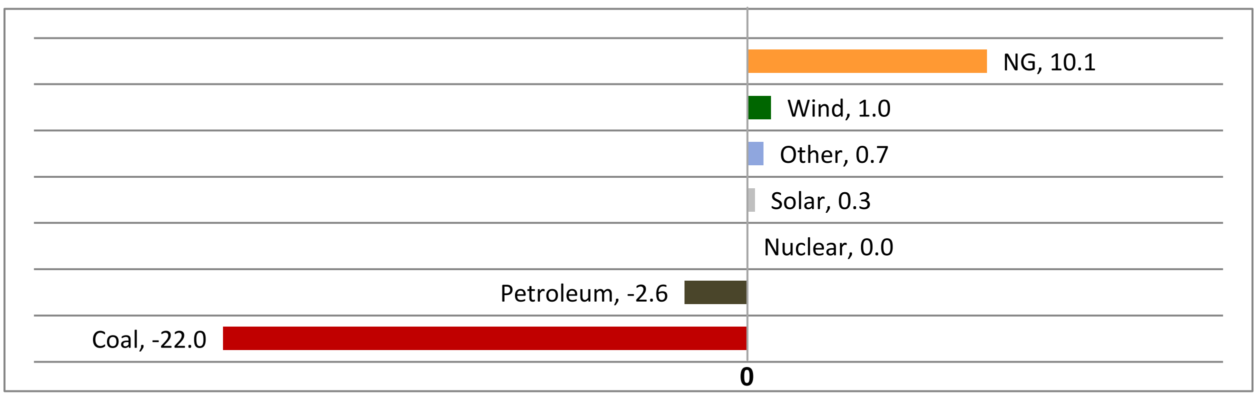


Exhibit 2-5 illustrates the changing capacity mix, from 2007 through 2020. While installed coal capacity remains steady at 83 GW from 2007 through 2011 – despite poor economic conditions and reduced revenues – a large drop off occurs by 2015, with nearly 20 GW of capacity retiring. (1)

This drop in coal-fired capacity and increase in gas-fired capacity represents the changing regulatory environment and the low cost of natural gas. Between 2007 and 2011, the mix was relatively stable due to poor economic conditions, major environmental regulations that had not been issued or implemented, and natural gas prices that were still elevated above current levels. In recent years (2012 onwards), utilities have been faced with the dilemma of installing pollution

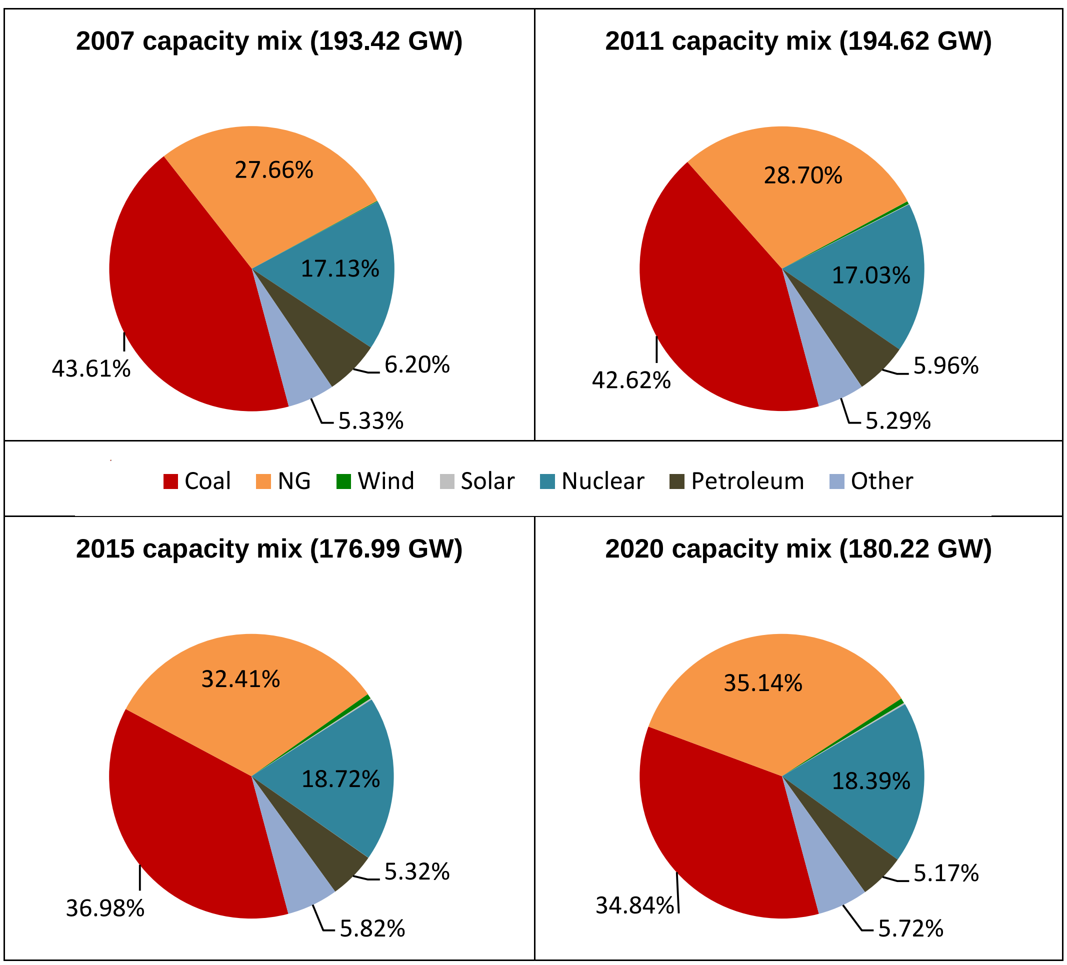
[7] Other new capacity includes the addition of hydro (0.2 GW), biomass (0.4 GW), gases (0.3 GW), geothermal (0.0 GW), and other small renewables (0.3 GW).

[8] Other retiring capacity includes the retirement of hydro (0.0 GW), biomass (0.1 GW), gases (0.1 GW), geothermal (0.0 GW), and other small renewables (0.5 GW).

controls on aging coal-fired generators or retiring them. The drop-off in capacity represents an economic choice to retire many units, based on factors such as sustained and forecasted low natural gas prices, uncertainty regarding the impact of proposed regulations, continued anemic electricity demand, and potentially higher operating costs.

It is important to note that despite retirements and a drop in generation nationally, generation from coal in PJM has remained relatively stable since 2009 and is projected to remain so. After a drop-off of 16 percent between 2008 and 2009, generation in PJM has declined only 1.8 percent from 2009 to 2013. By contrast, generation from coal has declined by 21 percent nationally between 2007 and 2013, with annual declines of 12 and 13 percent from 2008 to 2009, and 2011 to 2012 (respectively) driving the reduction, offset by rebounds of 5 percent in 2010 and 2013. Looking forward, the EIA projects generation from coal to remain mostly flat between 2014 and 2040, increasing by less than one percent over the period, with generation in PJM mirroring that based on coal capacity additions. (3)

Exhibit 2-5 PJM fleet capacity profile (%) for 2007-2020 period[9,10]



[9] Capacity values are normalized to the PJM footprint on January 1, 2015. Areas not yet in the RTO in 2007 and 2011 are considered as part of the RTO for this analysis to give an even comparison across each of the profiled years.

[10] Capacity in service on December 31 for each profiled year.

2.2 Capacity Requirements and Transmission Flows

PJM will suffer a net loss of nearly 15 GW of generating capacity from 2007 by 2020, equivalent to 7 percent of its total 2007 capacity. To evaluate if the remaining capacity would be sufficient to maintain PJM's ability to operate reliably, a security-constrained economic dispatch (SCED) model was developed and run using Ventyx's PROMOD 11.1. This model was utilized to determine if and when capacity shortfalls would occur, impacting PJM's ability to meet NERC planning reserve requirements and historical peak loads.

Prior to evaluating shortfall capacity, the model dispatched electricity imports (transmission from surrounding areas) based on physical system operating limitations. Consequently, PJM becomes more reliant on imports – exceeding self-imposed limitations – prior to a shortfall being predicted. This is discussed in more detail in the following section.

Although PJM will suffer a net loss of nearly 15 GW of generating capacity from 2011 to 2020, sufficient generating capacity will be online to meet peak demand through 2019 as indicated in Exhibit 2-6. (5) Beginning in 2020, however, additional capacity will be required to meet peak demand. Incrementally, the additional capacity will sum to nearly 14.2 GW by 2025 or 0.2 GW less than the net change from 2011 to 2020, deployed in half the time.

PJM will be required to add new capacity starting in 2016 in order to meet NERC reliability planning threshold requirements, as indicated in Exhibit 2-7. (5)[11] Through 2025, this capacity totals nearly 27 GW, which is in addition to the capacity needed to meet peak demand. Meeting the NERC planning threshold requirements for 2016 may prove difficult, or result in lower-efficiency natural gas combustion turbines being deployed. These units require as little as six months to deploy, compared to the 16-30 month construction times for the more efficient natural gas combined cycle plants. (6) (7)

[11] The NERC minimum planning reserve requirements for PJM are 15.9% through 2017 and 15.6% beyond.

Exhibit 2-6 Required additional capacity to meet peak hour demand 2014 to 2020

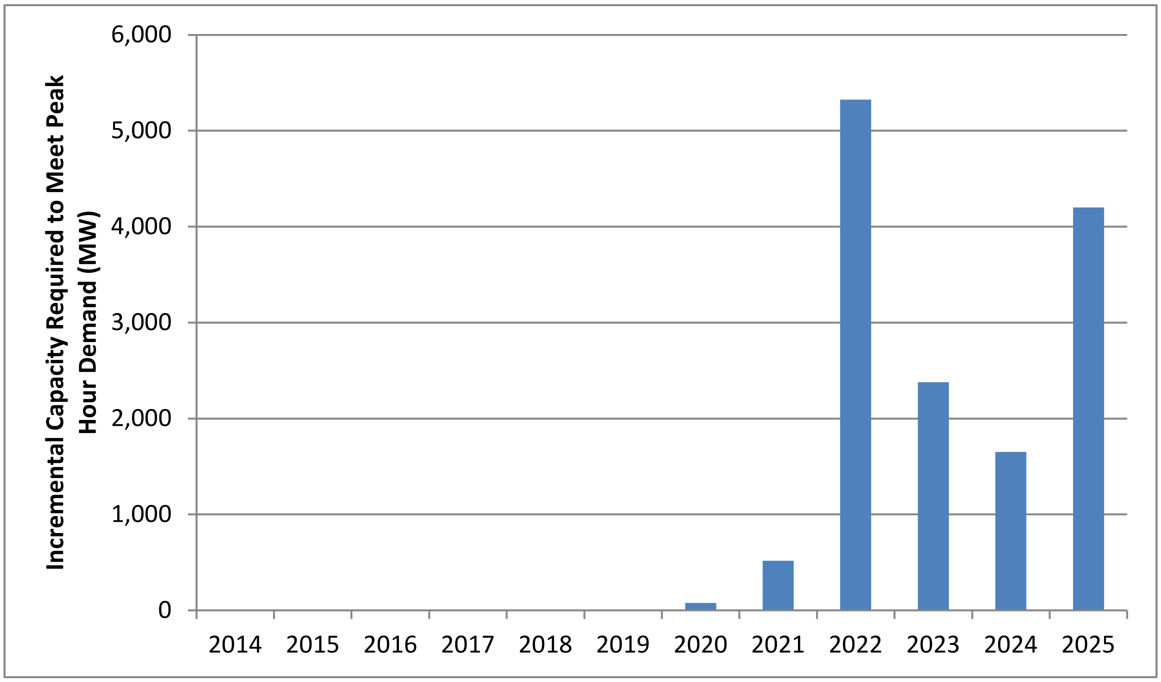
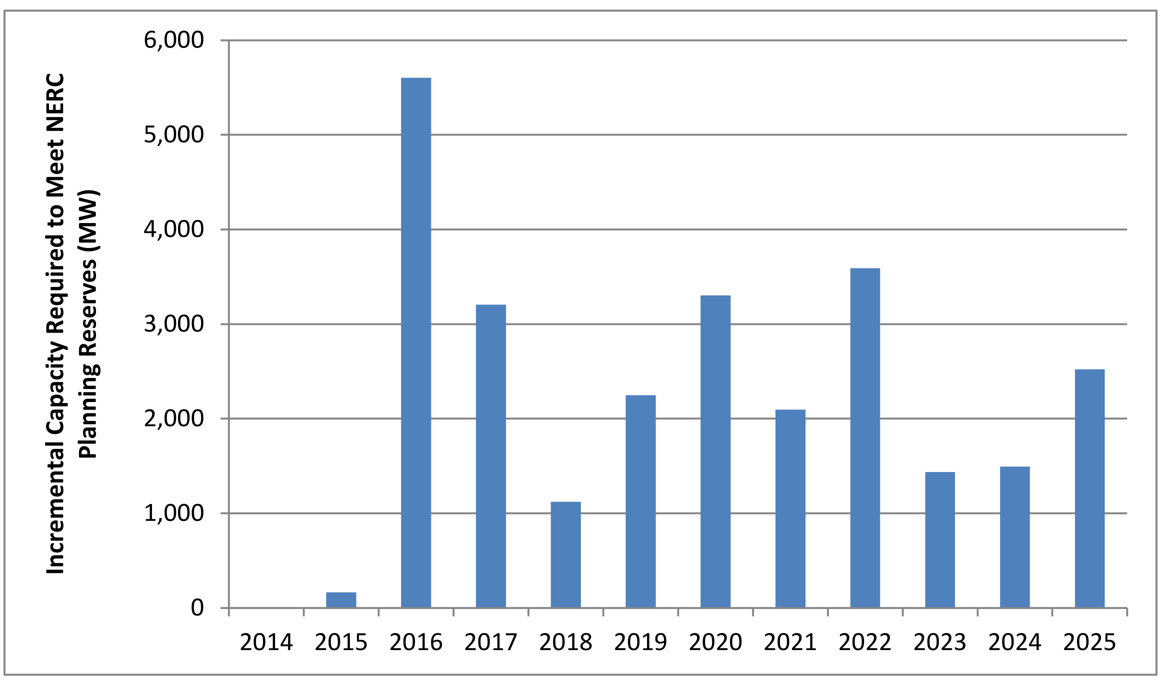


Exhibit 2-7 Required additional capacity to meet NERC planning reserve requirements



2.3 Dispatch Modeling and Transmission Flows

To determine the incremental shortfall values, a SCED model was developed and run using Ventyx's PROMOD 11.1, following, where relevant, the guidance set forth in the PJM Market Efficiency Modeling Practices. (8)[12] The model considered retiring and existing units along with planned-certain units.[13] Units that have announced retirement dates in the future were considered to be existing and operating until their retirement date, e.g., a plant with a retirement date in 2016 is considered operating for 2014 and 2015. The model also included an anticipated load growth rate of 1.8 percent annually for the duration of the study period, which was based on forecasts by IHS CERA. Additionally, near-term fuel prices through December 2015 were based on the EIA's Short-Term Energy Outlook (2), while long-term prices were based on the EIA's 2014 AEO. (3)

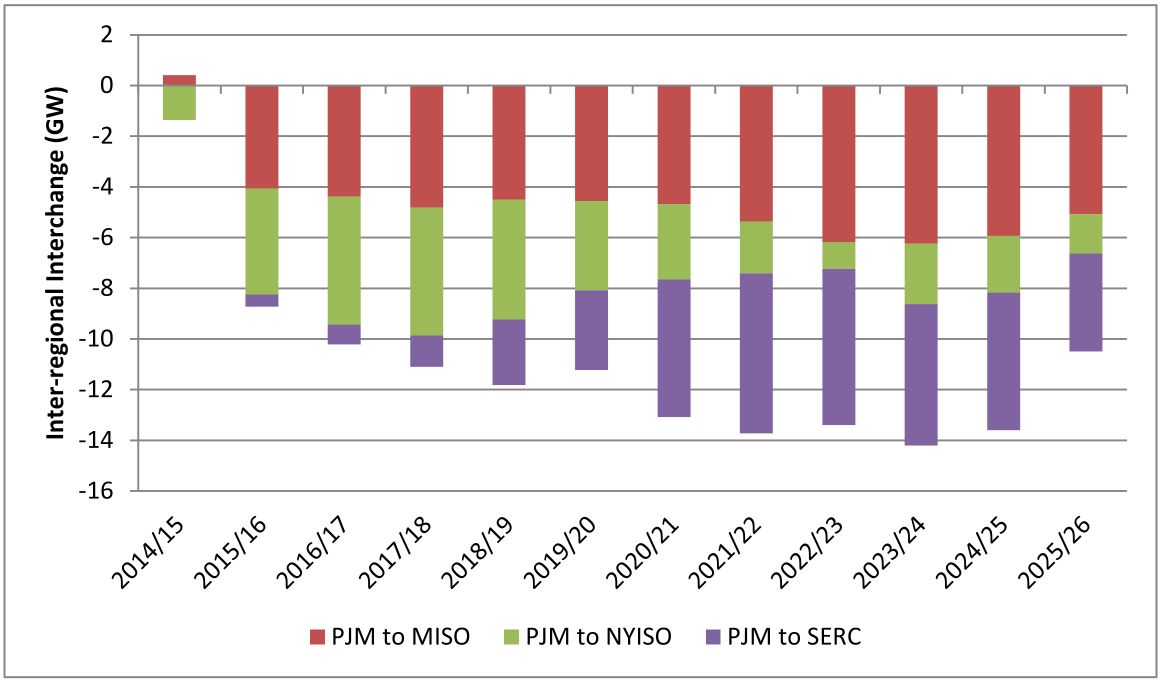
Prior to dispatching the incremental peak demand shortfall capacity, the model dispatched transmission imports from surrounding areas to the level that generating capacity was available and deliverable.[14] Results of the model indicate that PJM will increasingly rely on transmission imports to meet peak demand as indicated in Exhibit 2-8. (5) The transmission results of the model consider the inter-area interchange limits as defined by the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group. (9) These limits, however, are based on physical system conditions and do not account for reductions placed on the system by operators or regulatory requirements. For example, PJM has placed an artificial 6,500 MW capacity import limit on its system for the 2017/18 BRA market year in an effort to reduce the risk that cleared imports may be curtailed by transmission system operators outside of PJM. (10) As Exhibit 2-8 shows, at its peak hour during the 2017/18 capacity year, PJM will exceed this import limit by roughly 75 percent, or 5,000 MW (5 GW) to meet demand based on existing and planned-certain capacity that will be in service. It should be noted that, in Exhibit 2-8, positive interchange represents exports from PJM, while negative interchange represents imports to PJM.

[12] PROMOD 11.1 is a security constrained economic dispatch modeling program that utilizes known power system information to identify the most economic utilization of the power system. PROMOD inputs include power plant characteristics for each grid-connected unit, including heat rates, operation and maintenance (O&M) and fuel costs, interconnection location, and load profiles for each power system balancing area.

[13] "Certain" capacity includes generating units listed within the Active Generation Queue that are permitted and under construction. Speculative generating units in the Active Generation Queue are omitted due to their uncertain nature. These units include generating units that are proposed approval pending or under feasibility study. Certain capacity includes two types of capacity, existing and planned. Existing-certain capacity is that which has completed construction, but is not yet delivering power to the electric grid. Planned-certain capacity is that which is currently under construction. Throughout this report, unless otherwise noted, certain capacity is considered to be the aggregate of existing- and planned-certain capacity.

[14] It is critical to note that the dispatched shortfall capacity did not exist within the model, but was created by the model to balance load and generation. In reality, peak demand shortfall capacity may represent speculative capacity that will be certain and in service by 2020, but is not included in the current model because it is has not reached certainty.

Exhibit 2-8 PJM peak hour transmission flows[15]



3 Natural Gas Demand for Electricity Generation in PJM

Having explored the shift in PJM's capacity fleet mix from coal to natural gas above, this section examines the shift in generating capacity from primarily coal-fired generators to an even split between coal- and natural gas-fired generating capacity, and how much power sector natural gas demand may grow as a result. This shift is being driven by aging baseload capacity, significant quantities of coal capacity retirements (Exhibit 3-1) market and regulatory uncertainty, and sustained, low local natural gas prices due to increased unconventional natural gas development (Exhibit 3-2). (11) (1)

As the exhibits show, these upward pressures for increased natural gas-fired electric generation in PJM are likely to continue through the near future, and in fact may actually be understated. The existing baseload fleet is aging (Exhibit 3-3) and significant evidence points to the inability of aging coal units to operate at the relatively high capacity factors expected in this report, due to age-based degradation. (12) (13)[16]

[15] Positive interchange represents exports from PJM, while negative interchange represents imports to PJM.

[16] NETL is currently investigating whether aging natural gas combined cycle (NGCC) units may similarly be affected by age-based degradation of availability, potentially at an earlier age than coal plants. Such an affect appears to be plausible based on (a) units operating at annual capacity factors well below 70 percent even at historically low gas prices, and (b) known degradation issues associated with NGCC units based on both the design of older units and their historic operation as peaking or load-following units, and the associated mechanical degradation associated with cycling in such a manner. (1) (33)

Exhibit 3-1 Announced capacity retirements through May 2014

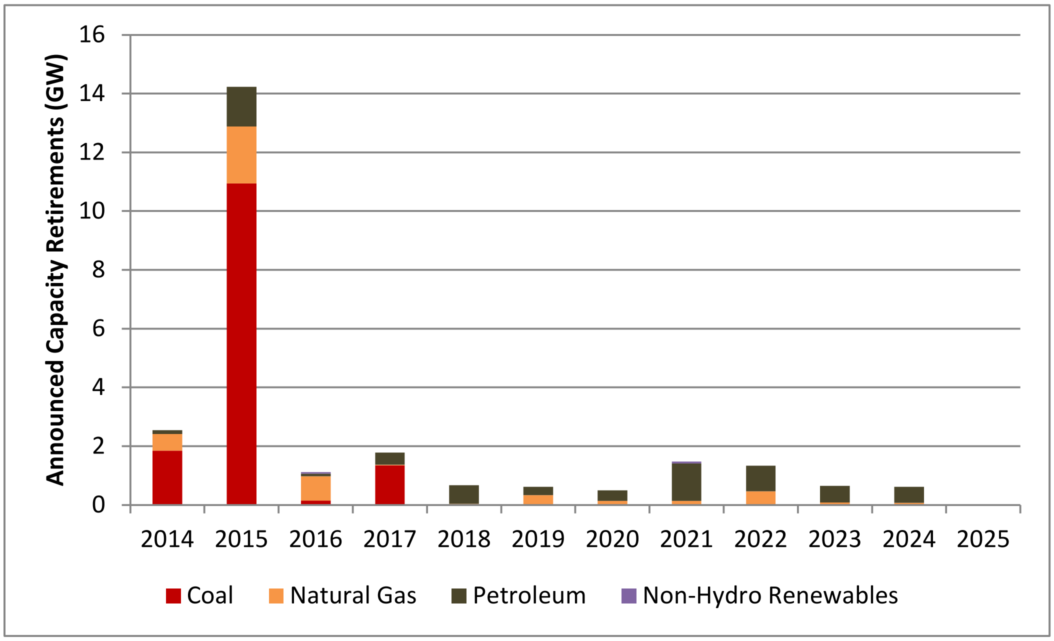
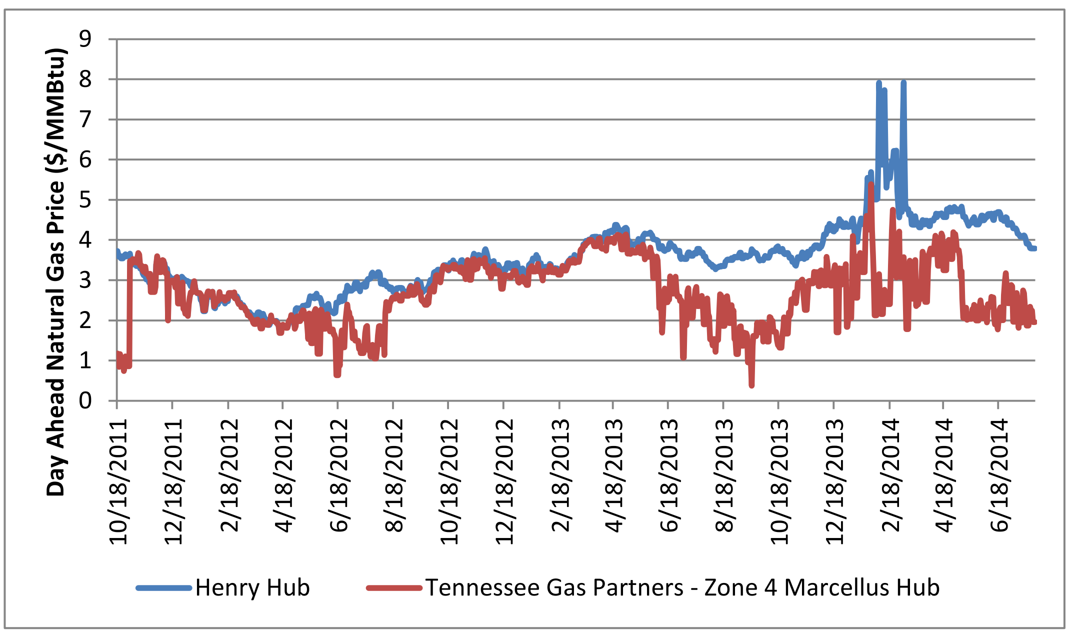
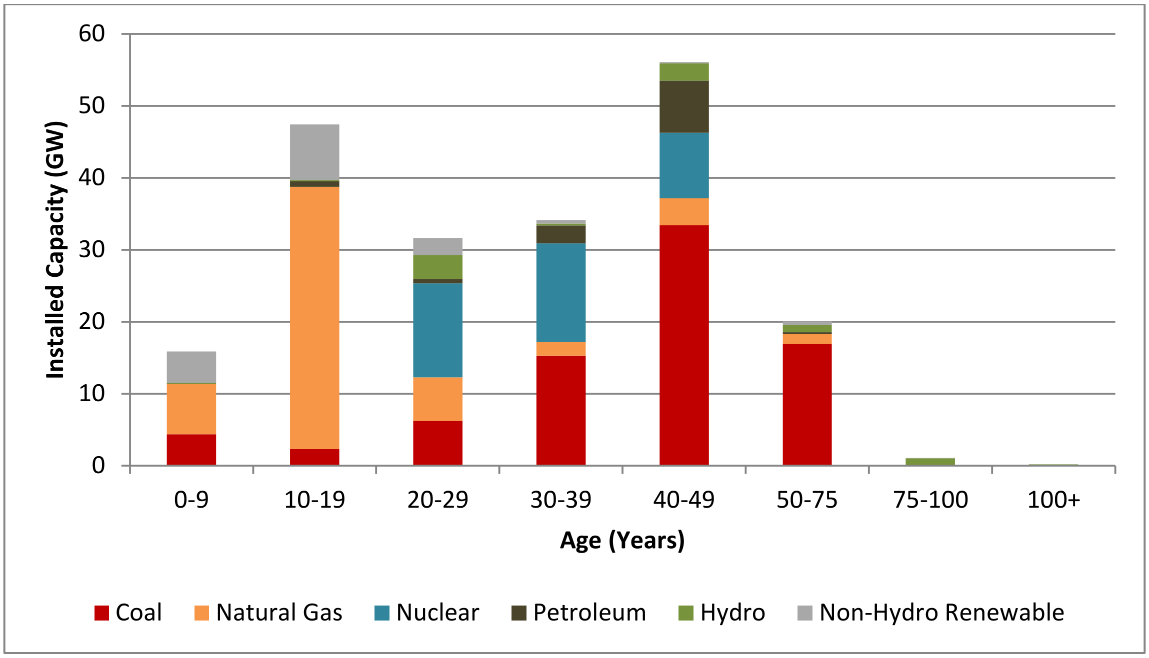


Exhibit 3-2 Henry and Marcellus Hub[17] day ahead prices (2011-2014)



[17] The Henry Hub is the principal pricing point for North American natural gas future contracts traded on the New York Mercantile Exchange. It is located in Erath, Louisiana, and is the junction point for nine interstate and four intrastate pipelines and is capable of a daily natural gas throughput of 1.8 Bcf. (26) The Tennessee Gas Partners – Zone 4 Marcellus Hub is a pricing point located in Northeastern Pennsylvania, between Compressor Station 315 in Tioga County, PA, and Compressor Station 321 in Susquehanna County, PA, that is used for future contracts specifically related to Marcellus Shale play production. (27)

Exhibit 3-3 PJM capacity by age



3.1 Growth in Natural Gas Generation

The SCED model described in Section 2.3 was used to simulate the impacts of market forces and capacity changes on the power system. As expected, natural gas-fired electric power generation in PJM is expected to increase dramatically, increasing 133 percent between 2014 and 2025 as shown in Exhibit 3-4, or an average of 8 percent per year. Incrementally, the largest increases in generation from certain and existing natural gas-fired capacity will occur in 2015 and 2016, as shown in Exhibit 3-5. (5) This is a direct impact of retirements that are scheduled to occur in late 2014 and late 2015. Beyond 2018, growth in incremental gas-fired capacity generation is primarily driven by expected load growth based upon the IHS CERA projection modeled in PROMOD.

As mentioned above, this rate of natural gas consumption growth could be understated based on other factors such as age-based availability degradation, additional retirements, or increased dispatch of natural gas units in response to regulatory forces.

Exhibit 3-4 PJM natural gas-fired generation 2014-2025

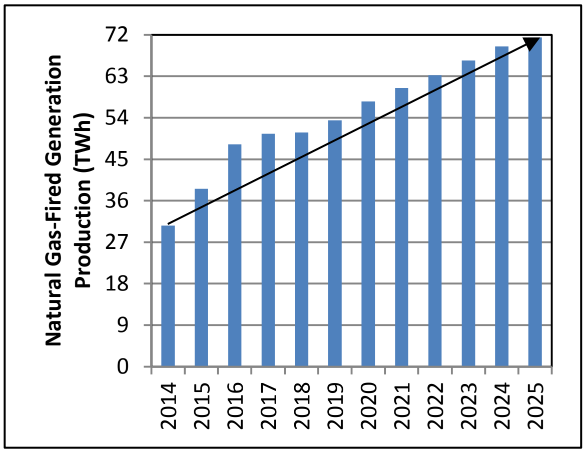
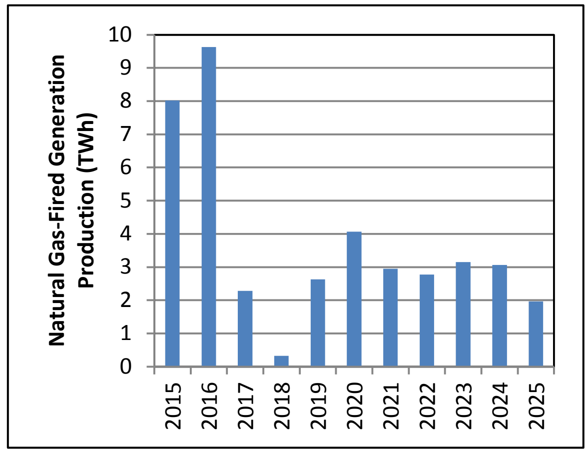


Exhibit 3-5 Forecasted incremental changes in PJM gas-fired electricity generation



3.2 Projected Incremental Natural Gas Demand

As part of the simulation process, PROMOD also calculates the amount of fuel required to produce the equivalent amount of electricity. In this simulation, however, PROMOD determined that there would be a capacity shortfall to meet the NERC planning reserve requirements beginning in 2016[18] and to meet peak demand beginning in 2020, as demand would exceed certain and operating capacity. It was assumed, during the post-processing of the model results, that these shortfalls would be serviced by natural gas-fired capacity that will enter service, but has not yet moved beyond speculative status.[19] The fuel needs for these additional proxy generators was determined through approximation[20] and represents the additional natural gas required to meet these shortfalls.

Exhibit 3-6 shows the combined, incremental natural gas infrastructure requirements for existing capacity and the two shortfall quantities needed to meet peak demand and the NERC reference margins. (5) The shortfall requirements represent how much excess pipeline and infrastructure capacity will be required in order to meet peak demand or utilize available reserve capacity, respectively. As shown, demand is expected to increase by just over one Bcf per day from 2013 to 2025, requiring a headroom of two-thirds a Bcf per day for peak demand and reserve

[18] The NERC planning reserve requirement for PJM is 15.9% prior to 2017, and 15.6% after. These percentages are calculated using the NERC planning reserve formula, Reserve = (Installed Capacity – Net Internal Demand) / Net Internal Demand, where Net Internal Demand is the peak system demand less controllable, dispatchable capacity demand response.

[19] For the purposes of this study, all replacement capacity was assumed to come in the form of NGCC units as opposed to natural gas-fired combustion turbines (NGCT). This assumption is optimistic, given the short construction lead times which may be required or other factors such as the need for NGCTs in order to meet fast, flexible, or low-capital cost criteria. Deploying combustion turbines as a portion of the shortfall capacity would increase the incremental natural gas usage requirement based on their lower efficiency (~41% HHV compared to 61+% for NGCC). (31)

[20] Multiple sources, including the National Petroleum Council (36), and NETL (28), in discussions with WorleyParsons, estimated that the average heat rate of new natural gas-fired capacity ranges from 6,300 to 7,000 Btu/kWh. The proxy gas analysis assumed a median value of 6,700 Btu/kWh. Additionally, PROMOD simulations for existing natural gas-fired capacity signaled an incremental capacity factor increase of nearly 10 percent from 2014 through 2025, reaching an annual average of 24.6% by 2025. From this, it was assumed that the incremental capacity needed to cover the shortfalls would operate at a nominal 10 percent capacity factor. Multiplying these values by the annual amount of shortfall capacity reveals the proxy gas requirements to serve shortfall capacity.

requirement usage. Natural gas demand is expected to grow rapidly through 2016, at about 8 percent annually as the simulation indicates natural gas-fired units are more frequently dispatched to replace retiring coal- and petroleum-fired units. After 2016, however, power sector natural gas demand growth will level off at around 5 percent annually through 2025, even when including proxy capacity fuel requirements.

Incrementally, however, the largest yearly increases in power sector gas demand occur after 2022 with most of the incremental electrical demand increases being met by proxy natural gas-fired capacity (Exhibit 3-7). (5) Gas demand could also be higher if transmission interchange limits drive the construction of more natural gas-fired capacity within PJM or if GHG emissions reduction strategies result in the increased dispatch of gas generators.

Exhibit 3-6 PJM daily natural gas requirement for electricity generation

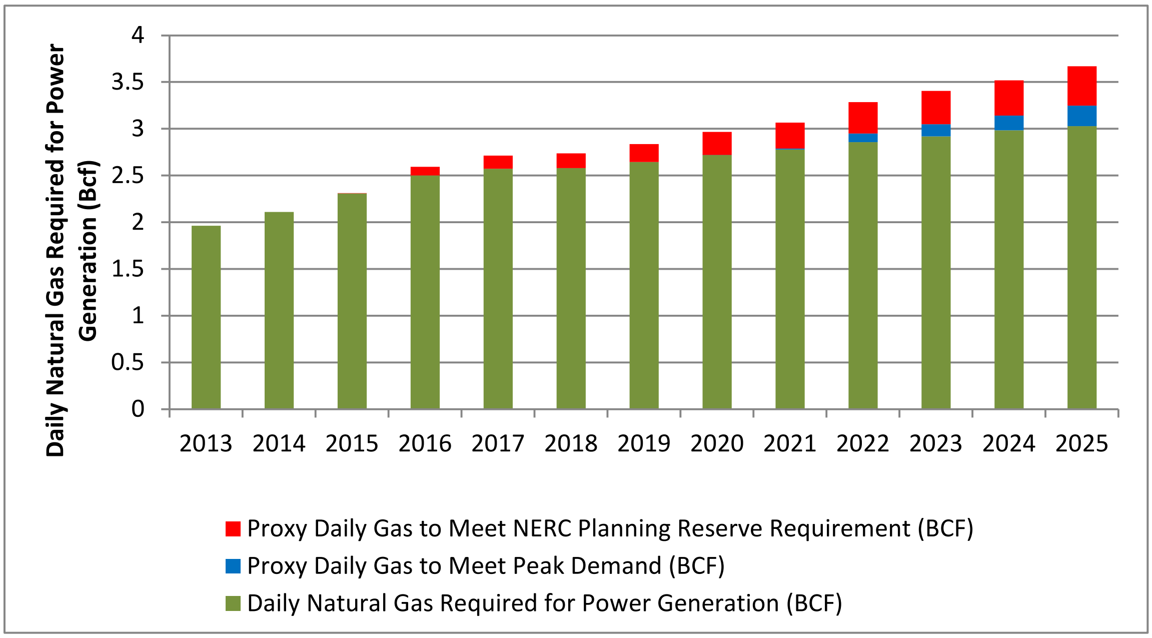
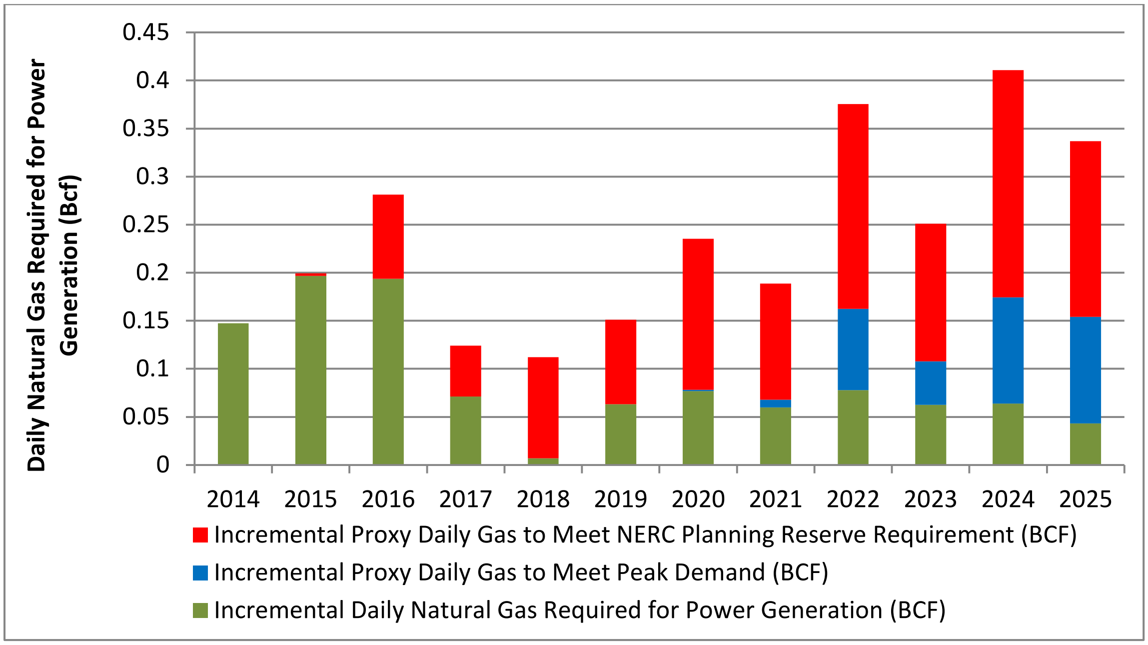


Exhibit 3-7 Incremental daily natural gas requirement for electricity generation in PJM



4 Matching NG Infrastructure and Demand in the PJM Region

In this section, existing and planned natural gas infrastructure is evaluated and examined to determine how it aligns with existing and certain demand points. It was found that overall PJM appears to be well situated to take advantage of new natural gas resources: there is an existing pipeline network, existing trunk-lines are not over-subscribed, and major unconventional natural gas sources, such as the Marcellus and Utica shale formations, lie within its borders. Furthermore, additional infrastructure is being built, both to develop unconventional gas resources and to add intra- and inter-state pipeline capacity.

The one unknown regarding this infrastructure assessment is the type of delivery contracts that can be obtained for natural gas generation. Historically, only local distribution companies (LDC) sign "firm" contracts of natural gas delivery, while natural gas-fired electricity generation predominantly sign interruptible contracts for delivery for financial reasons: these contracts result in lower prices for natural gas, and natural gas prices drive the economics of natural-gas generation.[21] Furthermore, even firm contracts may be interruptible, such as the case where the firm contract is with an LDC or only for a portion of the pipeline, but not the entire transportation leg. For example, in the case of a firm contract on an LDC, priority may be given to natural gas delivery for home heating or human needs over power generation in the case of emergency or extreme demand. (14) The result may be that despite pipeline capacity being available, generators may not be able to obtain natural gas when they need it to generate power. These situations are the exception rather than the rule, as even in times of extreme demand – e.g. the extreme cold event January of 2014 – firm delivery contracts were met. It does, however, illustrate the complexities of natural gas delivery markets and contracts. This issue – the complex

[21] This is in comparison to other baseload power generation types such as coal and nuclear, where plant capital costs dominate the sale price of electricity.

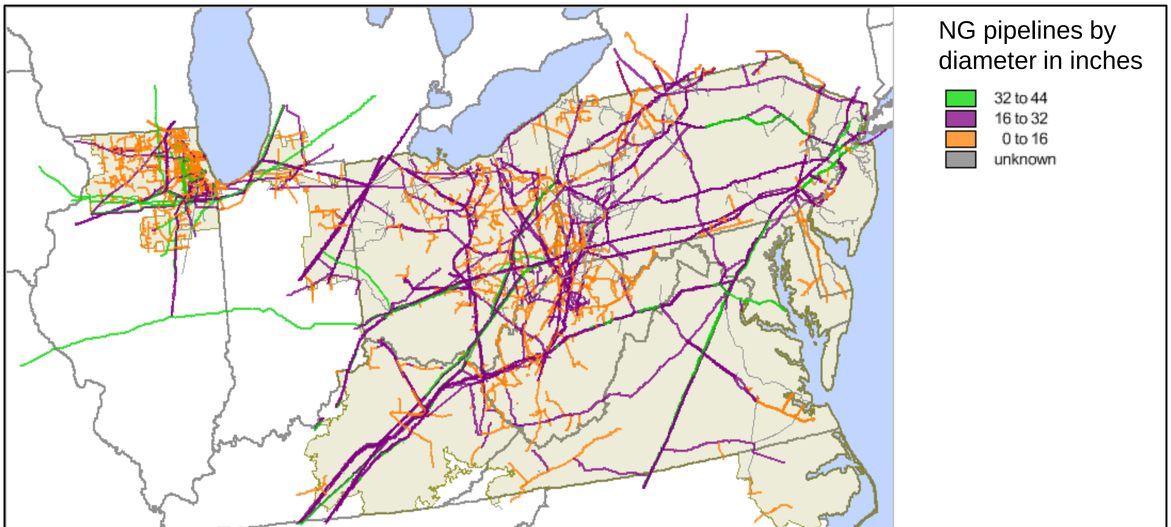
interaction between natural gas contracts and markets with electricity markets –is currently under examination by FERC and other regulatory bodies and is beyond the scope of this paper.

4.1 Existing Infrastructure and Delivery Points

There are more than 40,000 miles of natural gas transmission and distribution pipelines with diameters between 2 and 44 inches that serve the PJM area as shown in Exhibit 4-1. (1) This represents approximately 65 pipelines owned by 40 holding companies. These pipelines provide the PJM region with access to approximately 60 Bcf/d (~383 GW) of external interstate pipeline capacity and 7 Bcf/d (~45 GW) of internal interstate pipeline capacity, which exists wholly within the PJM footprint. Not all of the gas that crosses the PJM boundary is usable within PJM, because some of the gas is transmitted through PJM to areas in New York, New England, and Canadian Maritimes among others.

About 60 GW of natural gas-fired generating units were operating in the PJM area in May 2014, as shown in Exhibit 4-2. (1) Most of the generating units are located near major demand centers and are located on major natural gas pipelines.

Exhibit 4-1 PJM natural gas pipeline 2 to 44 inches in diameter



Diameter (in)	Unknown	2 to 16	18 to 32	34 to 44
Pipeline miles	~5,500	~12,500	~19,500	~4,000

Exhibit 4-2 Natural gas-fired generating units in PJM

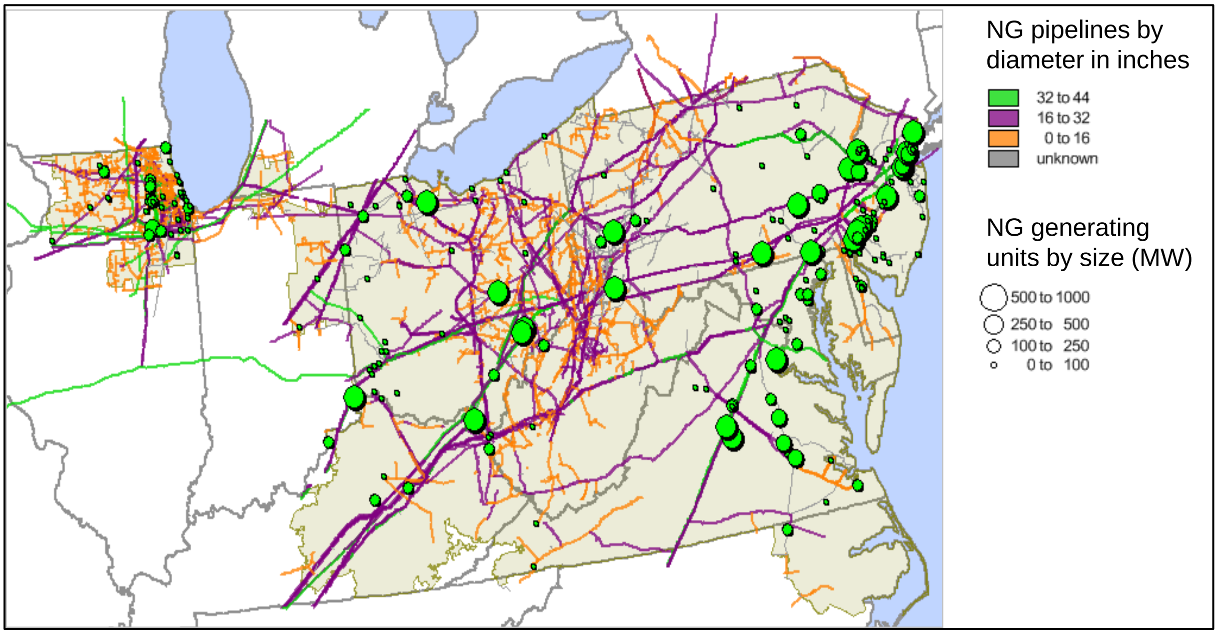


Exhibit 4-3 indicates that residential and electrical plant natural gas demands are 97 percent of the total natural gas demand in the PJM area. (1) However, further analysis of the data indicates that the categories shown are major users with direct pipeline contracts, with the category labeled "Residential" including deliveries to LDCs. Many smaller or intermittent commercial, industrial, or power gas delivery contracts are with the LDCs, resulting in their demand being hidden in the residential data. The data indicates that directly contracted natural gas usage for electric power generation is relatively consistent between approximately 1 and 5 Bcf with peaks occurring during summer high electrical demand periods. The data also shows a clear increased demand during the winter months, which can be attributed to increased residential usage for home heating with the maximum demand period occurring during the extreme cold weather pattern experienced by PJM in January 2014. (1)

Exhibit 4-3 PJM natural gas demands[22]

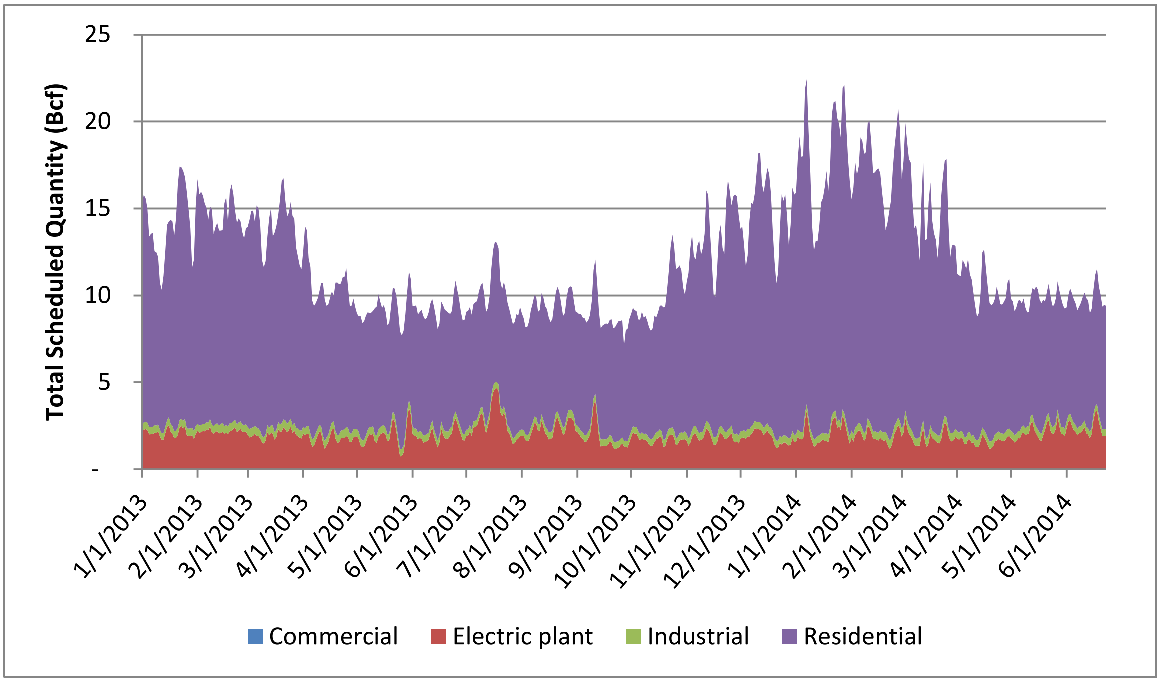
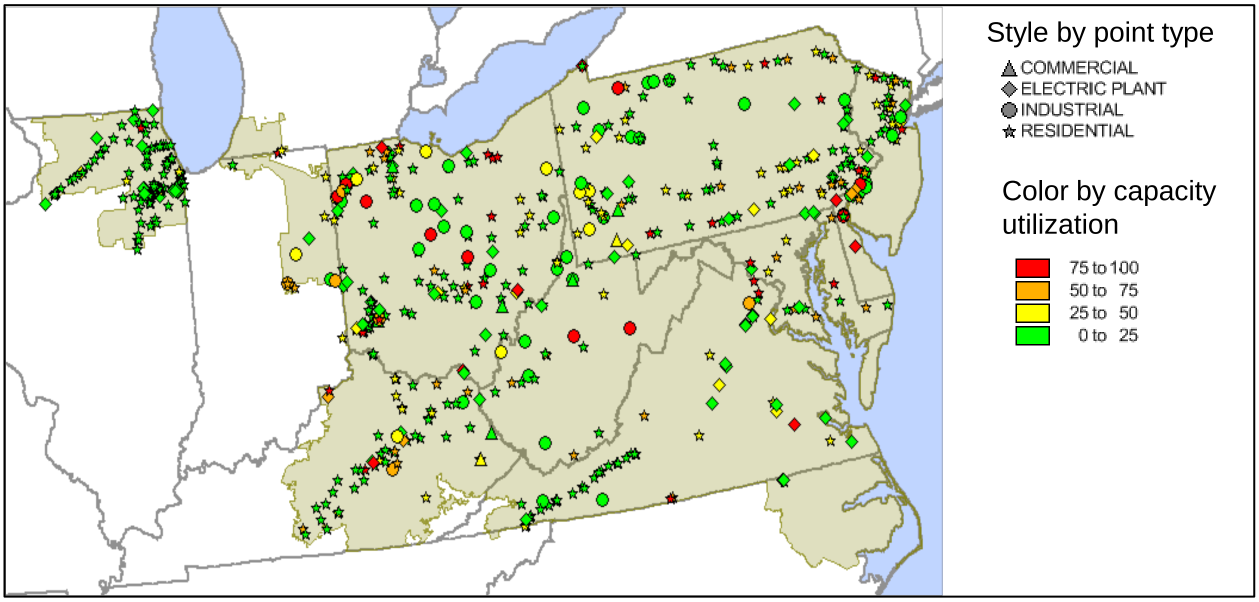


Exhibit 4-4 presents the natural gas delivery points within PJM. (1) The percentage of delivery utilization represents the percent of maximum operating capacity for that point on January 27, 2014, which was the maximum natural gas demand day for PJM. The delivery point types are as follows:

- Residential – represents gas delivered to an LDC or gas utility from a transmission pipeline for the main purpose of residential use. As mentioned above, this could include small commercial, industrial, or electrical generators. Some of these points also represent LDC-owned natural gas storage sites
- Industrial – represents gas that is delivered to a large industrial user, such as cement plants, manufacturing, or paper mills
- Commercial – represents gas that is delivered to a large commercial user, such as hospitals, schools, casinos, or agriculture consumers
- Electric Plant – represents gas that is delivered directly to an electric power plant

[22] Total Scheduled Quantity is reported as the quantity to be delivered or received at the identified location, point, or contract for a given day. When aggregated, the total of all scheduled capacity across the aggregated time period will be displayed.

Exhibit 4-4 PJM natural gas delivery points



4.2 Planned Infrastructure and Delivery Points

About 30 GW of new natural gas-fired generating units are planned to be added in the PJM area as shown in Exhibit 4-5. (1) All units shown are expected to be online by 2020.

Planned capacity includes about 10 GW of certain and 20 GW of speculative by 2020, mostly located near existing gas pipelines. New certain units include generating units that are permitted and under construction. New speculative units include generating units that are proposed with approval pending or under feasibility study. The likelihood of the speculative units being constructed will be determined by market forces.

About 3,000 miles of new natural gas pipelines are planned to be added in the PJM area as shown in Exhibit 4-6. (1) Planned new pipelines that have been announced are mostly greater than 16-inch diameter transmission pipes with one major pipeline starting in northern West Virginia and extending through Pennsylvania to New York, which will be an extension to the Rockies Express (REX) that extends across the U.S.

Exhibit 4-5 PJM planned natural gas generating units

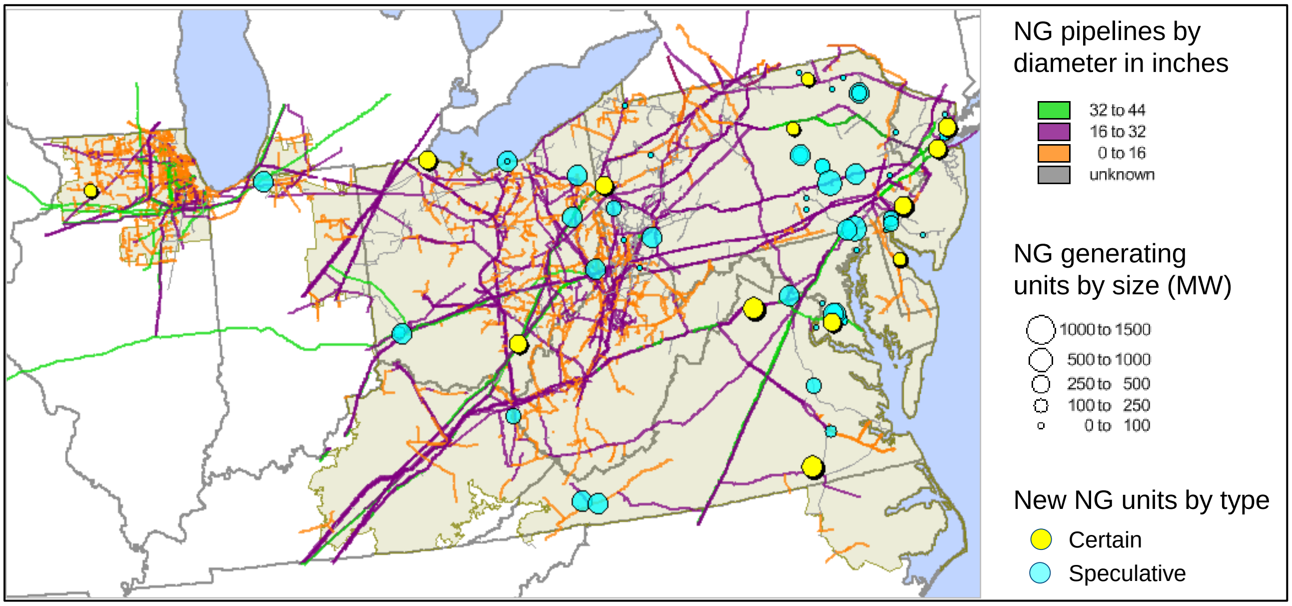
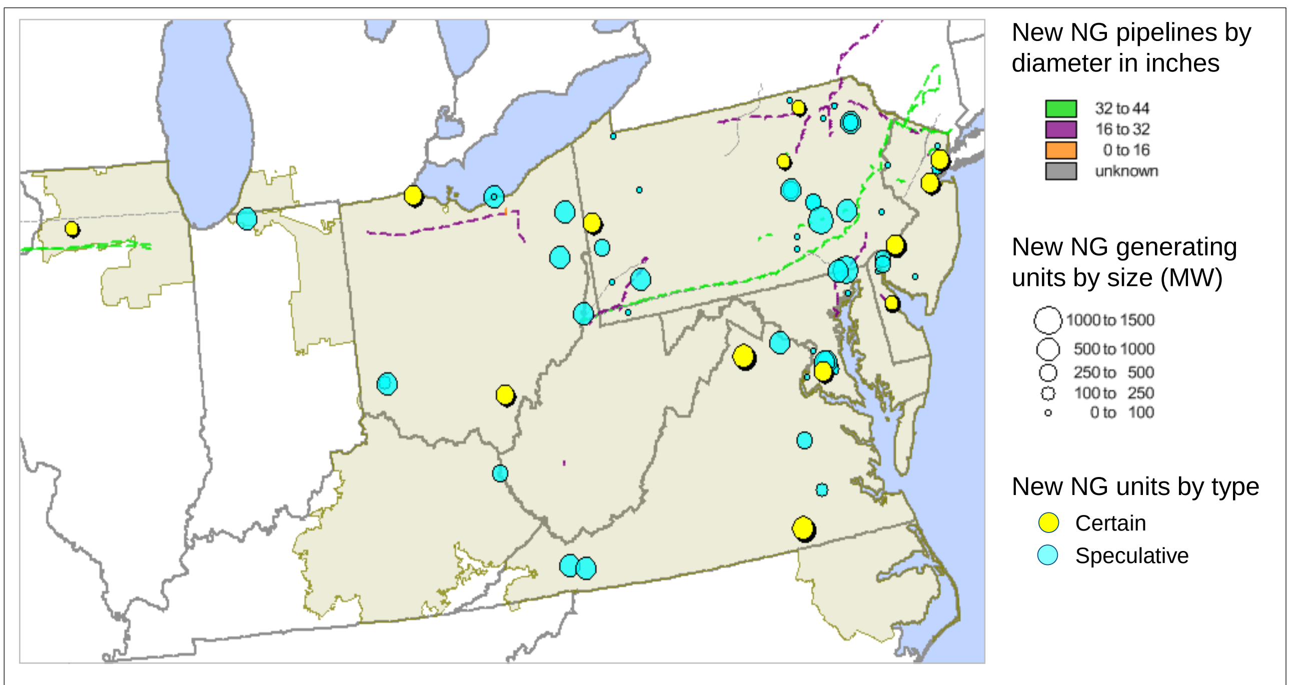


Exhibit 4-6 PJM planned new natural gas pipelines



Note: New certain units include generating units that are permitted and under construction. New speculative units include generating units that are proposed approval pending or under feasibility study. All units are with 2020 commercial online date.

5 Natural Gas Storage in the PJM region

The PJM region is currently home to around 13.5 percent of the U.S. working natural gas storage capacity, with a majority of the storage facilities clustered in Western Pennsylvania and West Virginia. This storage serves as a repository for pipeline quality gas that may eventually be delivered to any pipeline customer served by the connected pipeline as contract and market agreements dictate and, as described below, have limitations on the rate of withdraw.[23]

Most of these storage facilities are operated by interstate pipeline companies; however, many of these operators are subsidiaries or affiliate companies of the major LDCs within the PJM footprint. By working volume – i.e., the amount of gas that can actually be withdrawn – over 80 percent of the working gas capacity is owned by two companies, Columbia Gas Transmission and Dominion Transmission (Exhibit 5-1). Because of LDC rights of first refusal along with contract and market agreements, this means that a large portion of the stored natural gas is slated for distribution through an LDC for use in home heating or transmission to meet agreements, many of which require interstate transmission to delivery points external to PJM. This is consistent with residential use outweighing industrial use, as described above in Exhibit 4-3.

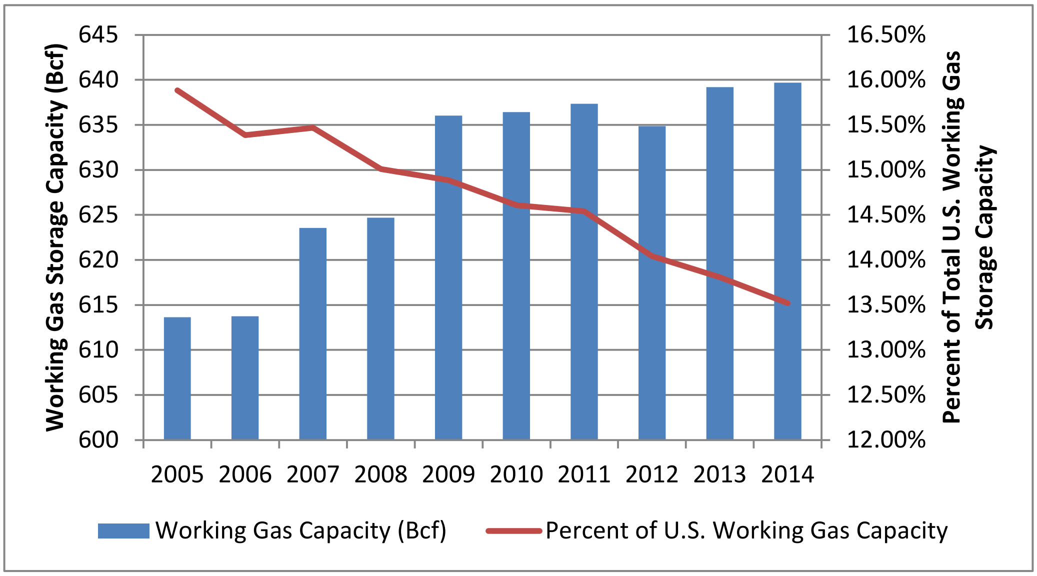
Exhibit 5-1 Natural gas storage operators by working capacity (15) (16)

Company	Working Gas Capacity Operated (Bcf)	LDC Affiliate?
Columbia Gas and affiliates	284.14	X
Dominion Transmission and affiliates	242.66	X
EQT	39.97	X
Texas Eastern Transmission	18.3	
Tennessee Gas Pipeline	17.3	
National Fuel Gas	12.22	X
All others	32.3	X
Total	646.89	

Working gas storage capacity within PJM's footprint has increased 4.2 percent since 2005; however, the total percentage of U.S. storage capacity within PJM has decreased by 2.3 percent over the same period (Exhibit 5-2), with no new storage additions currently planned within PJM after 2014. The lack of planned storage additions is likely due to the existing price inversion between the Henry and Marcellus Hubs, shown previously in Exhibit 3-3, as well as recent warm winters which had storage full in recent years.

[23] For more information on this topic, see NETL's "The Role of Natural Gas Storage in Maintaining Reliability of the Electric Power System" (37)

Exhibit 5-2 PJM natural gas working storage capacity (15) (16)



While the working gas capacity and daily capacity deliverable from storage within PJM's footprint have increased since 2005, they have fallen as a percentage of the total U.S. values (Exhibit 5-2, Exhibit 5-3).[24] The capacity increase is mostly due to technological improvements that have allowed for more efficient storage operation without compromising facility viability. While the deliverable capacity represents more than 10 times the quantity of projected power sector demand, storage is highly limited in its flexibility to respond to demand changes and a limited number of operational cycles per year (Exhibit 5-4). This means that an event requiring a storage release is not immediately recoverable. Additionally, PJM's normal summer peak occurs during the peak storage input season, meaning that storage operators are injecting gas into reserve and the gas is not available.

[24] Daily deliverable natural gas storage capacity is the amount of gas that can be withdrawn daily from the storage facilities.

Exhibit 5-3 PJM daily deliverable natural gas storage capacity (15) (16)

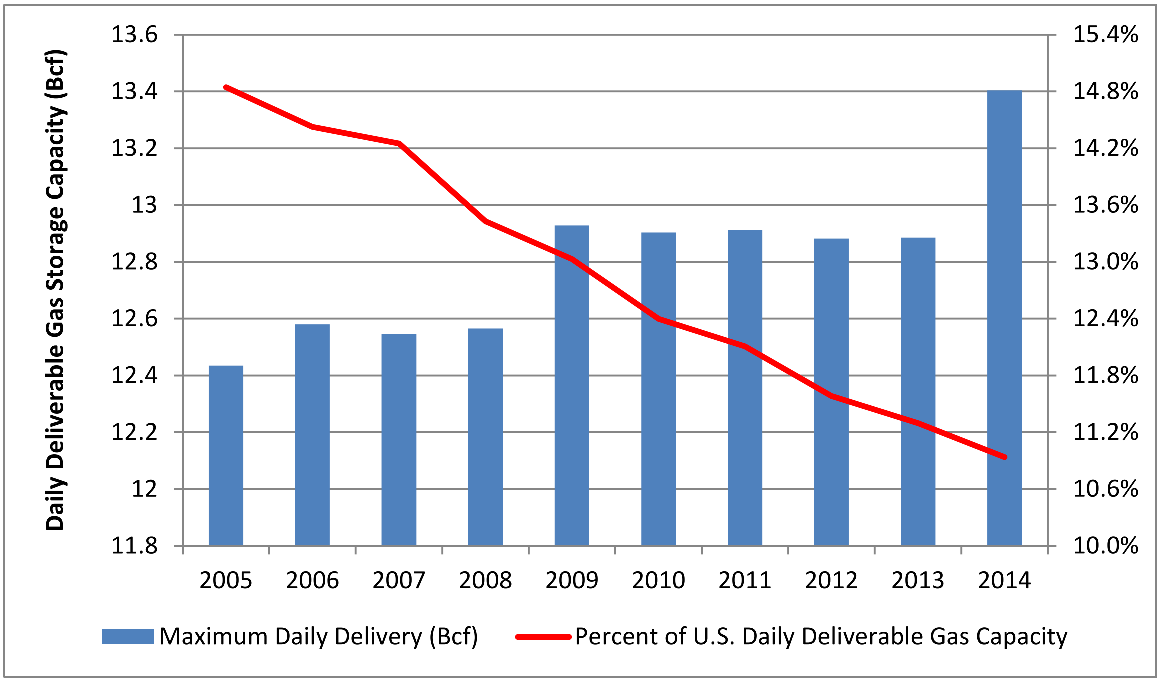


Exhibit 5-4 Underground storage cycling comparison (17)

Storage Type	Injection Period (Days)	Withdrawal Period (Days)
Aquifer	200 to 250	100 to 150
Depleted Field	200 to 250	100 to 150
Salt Dome	20 to 40	10 to 20

6 Infrastructure Outlook

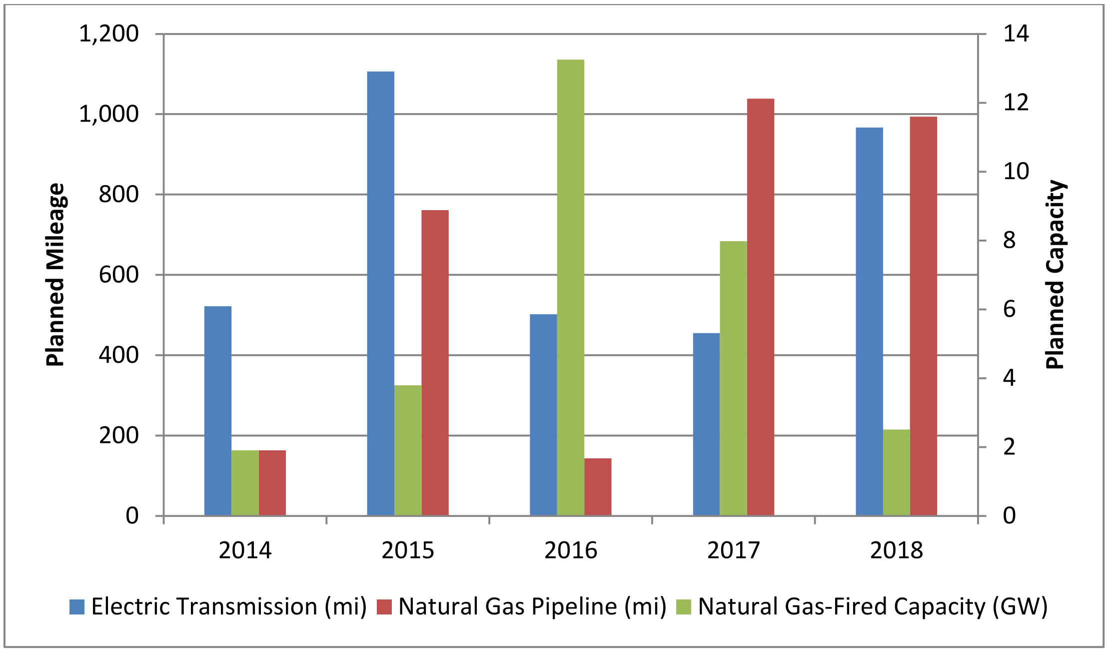
Over the next five years, more than 6,000 miles of electric transmission and 3,000 miles of natural gas pipeline are planned within the PJM footprint. At the same time, 29.5 GW of new natural gas-fired capacity is planned. Exhibit 6-1 shows the breakdown of the planned infrastructure by anticipated year of entry into service. The exhibit reveals the effects of enacted environmental regulations on the electricity sector, with peak electric transmission additions entering service in 2015 coincident with the peak in capacity retirements shown in Exhibit 3-2. Most of the transmission projects entering service in 2015 are intended to serve as reinforcement for retiring capacity.[25]

New natural gas-fired capacity additions are expected to peak in 2016. The largest natural gas pipeline expansion is expected to occur later than the peak in natural gas-fired capacity and

[25] As identified in the Energy Sector Planning and Analysis (ESPA) bi-monthly transmission tracking report to Strategic Energy Analysis & Planning (SEAP).

electric transmission build-outs due to the lag between pipeline construction, regulatory approval, and market prices. It generally takes an additional three to five years for the construction and permitting of a new pipeline after the pipeline operator has committed to building it.[26] This creates the potential for short-term increases in natural gas pipeline congestion.

Exhibit 6-1 Planned infrastructure in the PJM footprint (13)



Breaking down the components of Exhibit 6-1 by their current status reveals that infrastructure construction, for the most part, is only occurring on pipeline and transmission projects that will enter service within the next 18 months, and on generators that will enter service within the next 24 to 30 months (Exhibit 6-3, Exhibit 6-4, and Exhibit 6-5). These timelines coincide with the normal construction time for each of the project types.[27]

According to a report by The INGAA Foundation,

> Pipeline cost assumptions have been derived by considering Oil and Gas Journal's Annual Pipeline Economics Special Report, U.S. Pipeline Economics Study, 2013 (hereinafter 6 referred to as 'the OGJ report'). Based on the survey in the OGJ report, pipeline costs recently have risen to $155,000 per inch-mile from $94,000 per inch-mile . . . *[the OGJ report]* assumes that the costs will remain constant at the most recent value in real terms over the entire projection period. Regionally, costs vary significantly, with costs being considerably higher in the northeastern states and significantly lower in the southwestern states. Costs also are assumed to vary by grade of pipe, so the smaller diameter pipes used mostly in gathering systems have lower cost factors applied. (18)

[26] Pipeline Requirements and Electric Transmission Requirements are detailed in Appendix A.

[27] NGCC data at http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Plant%20Case_FClass_051607.pdf;
Natural gas pipeline data at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/develop.html;
Electric transmission data at http://www.eei.org/issuesandpolicy/transmission/Pages/transmissionprojectsat.aspx

Exhibit 6-2 shows that 86 percent of natural gas pipelines have an inside diameter (I.D.) between 1” and 8”. The average cost per mile in that range is approximately $172,000 per mile. This cost increases tenfold when the diameter is between 8” and 16”. The cost more than doubles to $3.5 million dollars per mile for a pipeline with an I.D. between 16” to 24”, and the cost increases an additional 63 percent for I.D.s greater than 24”.

Exhibit 6-2 Pipeline capital expenditures by diameter class, 2014-2035

Parameter	1" to <=8"	>8" to <=16"	>16" to <=24"	>24"
Thousand miles	291.2	24.3	9.6	13.7
% Total NG Pipeline miles	86.0%	7.2%	2.8%	4.0%
Billions of 2012$	$50.1	$40.9	$33.7	$78.3
$/mile Pipeline	$172,047	$1,683,128	$3,510,417	$5,715,328

Based on these findings, additional pipelines and transmission projects would have minimum lead times of 18 months for construction, while natural gas generator lead times could range from 9-to-12 months (for a simple cycle combustion turbine) to 16-to-30 months for a more efficient combined cycle (NGCC). (6) The siting and permitting process is a multi-month to multi-year process that would be added onto these lead times.

Exhibit 6-3 Planned natural gas pipeline mileage by status (13)

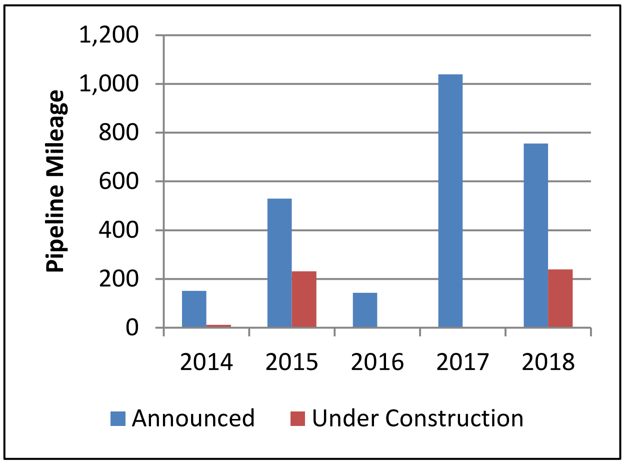


Exhibit 6-4 Planned electric transmission mileage by status (13)

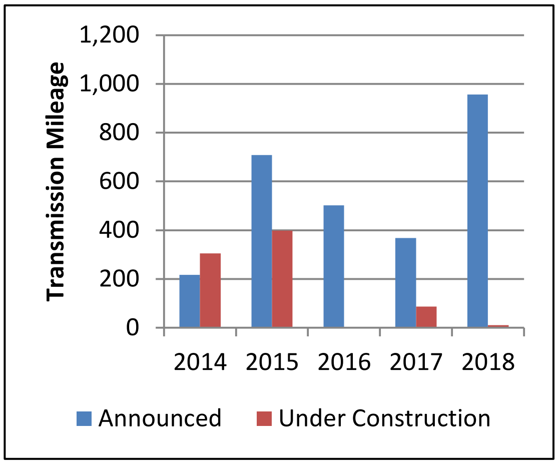
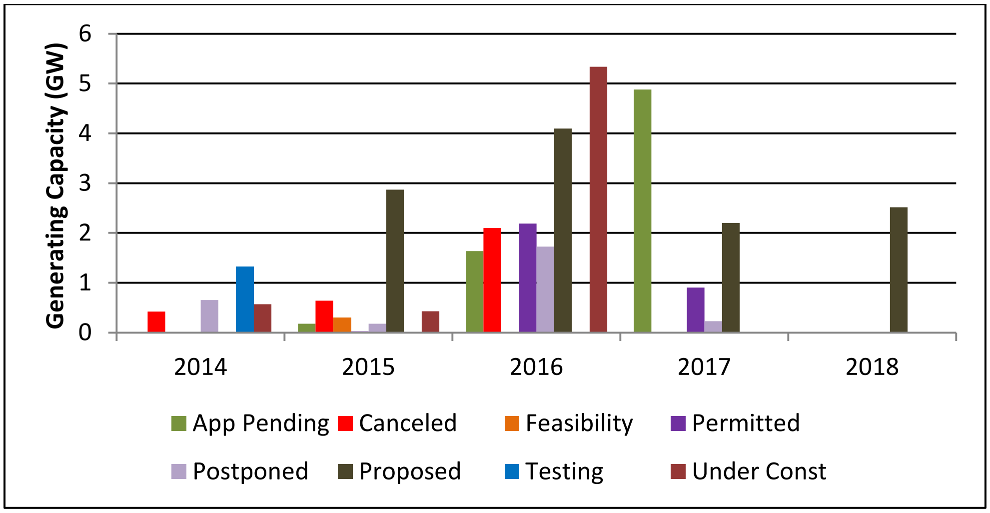


Exhibit 6-5 Planned natural gas-fired generating capacity by status (1)



7 Key Findings

The PJM region is expected to undergo a major shift from coal-fired capacity to natural gas-fired capacity with the planned natural gas-fired capacity in PJM expected to increase from 60 to 90 GW with most of this capacity located near existing infrastructure. The current natural gas infrastructure in the PJM region is sufficient to meet current demand because only a few natural gas delivery points were at 75-100 percent utilization during peak 2014 natural gas demand. However, after 2016, additional generating capacity is expected to be required to meet NERC planning reserve requirements, and, after 2020, additional generating capacity will be required to meet peak demand. A security-constrained economic dispatch model shows that, if this additional generating capacity is gas-fired, the gas delivery requirements increase 133 percent between 2014 and 2025, or an average of 8 percent per year, which may lead to congestion in the gas delivery infrastructure. Incrementally, the largest increases in gas-fired capacity production will occur in 2015 and 2016 as units are dispatched more heavily to replace retiring coal- and petroleum-fired units. At the same time, PJM will also see its power transmission import needs from other regions increase significantly.

Currently, there are approximately 3,000 miles of new natural gas pipeline planned for the PJM region. (1) Much of this is large transmission pipeline, which will facilitate transportation of gas from the developing Marcellus and Utica gas producing regions to other areas of the U.S.

Working natural gas storage is clustered in the central PJM region and has increased 4.2 percent since 2005 with the daily capacity deliverable from storage increasing by 7.8 percent, mostly due to technological improvements. However, no new storage is planned after 2014. The lack of planned storage additions is likely due to the existing price inversion between the Henry and Marcellus Hubs driving the cost of natural gas below the point of economic recovery for new storage within the PJM footprint.

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Appendix A: Natural Gas Pipeline and Electric Transmission Permitting Requirements

A.1 Natural Gas Pipeline Requirements

There are many issues regarding the legal, regulatory, institutional, and societal issues that can affect a pipeline project, not just physical factors (such as topography) that need to be taken into account during the design, construction, and operation. There are so many different state regulations on pipeline installation, usage, etc. that the National Association of Pipeline Safety Representatives published a compendium in September 2013 outlining 1,361 specific safety enhancements that have been adopted. (19) These regulations are in addition to the federal regulations required for interstate pipelines as shown below:

- Clean Water Act
- Clean Air Act
- National Historic Preservation Act
- Archeological and Historic Preservation Act
- Coastal Zone Management Act
- Endangered Species Act
- Wild and Scenic Rivers Act
- National Wilderness Act
- National Parks and Recreation Act
- Executive Order 11988 (Floodplain)
- Executive Order 11990 (Wetlands)
- Fishery Conservation and Management Act
- Erosion and Sediment Control Plan
- Site Access Road Permit
- Stream Crossing Permit
- Road Boring Permits
- Hazardous Materials Transportation permit (Petroleum/NG)

Typically, the process to build a new natural gas pipeline begins with the operator providing notice to Federal Energy Regulatory Commission (FERC) (interstate) and state regulators (intrastate) of their intent to build. Once this notice is made, the operator follows either the traditional or the pre-filing process to determine routing, necessary facilities, proposed right(s)-of-way, cost, and environmental impact prior to receiving a *Certificate of Public Convenience and Necessity* and *Notice to Proceed* with construction. (20)

A.2 Electric Transmission Requirements

As with natural gas pipelines, there are many issues that can create barriers to the construction of electric transmission lines. The process to build an electric transmission line begins with a utility or merchant transmission owner requesting the new transmission with a Regional Transmission Organization (RTO). The RTO evaluates the request for power system impacts, which typically take one-to-two years. If it clears this point, approval of interstate transmission projects moves to the state level for evaluation of cost allocation, which typically takes 6-to-12 months. Once costs allocations are approved, additional approvals/permits may be required from the other state and federal agencies listed below; this may take up to an additional 6-to-10 years (21):

- Council on Environmental Quality: Environmental Impact Statement
- U.S. Army Corps of Engineers: Navigable Waterway Crossing Permit
- U.S. Fish and Wildlife Service: Protected Habitat Crossing Permit
- Environmental Protection Agency: Air Quality Permit
- U.S. Bureau of Land Management: Right-of-way grant, temporary use permit, antiquities and cultural uses permit, plan of development
- U.S. Forest Service: Special use permit and easement or lease
- Federal Highways Administration: Federal Highway Encroachment Permit
- Bureau of Alcohol, Tobacco, and Firearms: Explosive Users Permit
- Federal Aviation Administration: Form 7460-1 (required near runways)
- State utility commission siting authorization

Justin M. Adder
justin.adder@netl.doe.gov

Robert Wallace
robert.wallace@contr.netl.doe.gov

www.netl.doe.gov
Pittsburgh, PA • Morgantown, WV • Albany, OR • Sugar Land, TX • Anchorage, AK
(800) 553-7681