

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Grid Reliability and Resiliency Pricing

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Docket No. AD18-7-000

**COMMENTS OF
THE NUCLEAR ENERGY INSTITUTE**

Pursuant to the Federal Energy Regulatory Commission’s (“FERC” or the “Commission”) January 8, 2018 order establishing the captioned proceeding,¹ the Nuclear Energy Institute (“NEI”) provides its comments on the March 9, 2018 filings of the Independent System Operators / Regional Transmission Organizations (together, the “RTOs”) in this inquiry proceeding.²

¹ *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures*, 162 FERC ¶ 61,012 (2018) (“Resilience Inquiry”).

² *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000, Responses of the Midcontinent Independent System Operator, Inc. (Mar. 9, 2018); *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000, Response of the New York Independent System Operator, Inc. (Mar. 9, 2018) (“NYISO Comments”); *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000, Comments of Southwest Power Pool, Inc. on Grid Resilience Issues (Mar. 9, 2018); *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000, Comments of the California Independent System Operator Corporation on System Resiliency and Threats to Resilience (Mar. 9, 2018); *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000, Joint Comments of the Electric Reliability Council of Texas, Inc. and the Public Utility Commission of Texas (Mar. 9, 2018); *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000, Comments and Responses of PJM Interconnection, L.L.C. (Mar. 9, 2018) (“PJM Comments”); *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000, Response of ISO New England, Inc. (Mar. 9, 2018) (“ISO-New England Comments”) (collectively, the “RTO Comments”).

I. EXECUTIVE SUMMARY

Resilience, and the need to appropriately compensate generating units that support a resilient grid, should be among the Commission’s highest priorities. NEI commends the Commission for its leadership, but urges timely action to stem the early retirement of nuclear units whose continued operation supports a resilient grid. This is not a theoretical problem; the existing generator retirement process is already underway for several nuclear units and that process has *not* analyzed fuel security risks.³

The RTO Comments present varying views on resilience – both in defining the nature of the problem and plotting a path forward – but the Commission will notice a change in tone from the RTOs’ comments filed on the Secretary of Energy’s September 29, 2017 notice of proposed rulemaking on resiliency pricing (“DOE NOPR”).⁴ For example, ISO-New England emphasizes its well-documented and urgent fuel security problem, which threatens its resilience. ISO-New England concludes that “[t]he increasing shift away from generators with on-site fuel to natural

³ See PJM, Generation Deactivation Notification Update (May 3, 2018) (deactivation reliability study findings for Davis-Besse and Beaver Valley nuclear stations); <http://www.pjm.com/-/media/committees-groups/committees/teac/20180503/20180503-teac-generation-deactivation-notification.ashx>; PJM, Generation Deactivation Notification Update (July 13, 2017) (deactivation reliability study findings for Three Mile Island nuclear station), <https://www.pjm.com/-/media/committees-groups/committees/teac/20170713/20170713-generation-deactivation-notification.ashx>.

⁴ *Grid Resiliency Pricing Rule*, 82 Fed. Reg. 46,940 (Oct. 10, 2017). PJM and ISO-New England argued for rejection of the proposed rule, but both have since undertaken significant new efforts to consider market reforms to address fuel security and resilience. *Grid Resiliency Pricing Rule*, Docket No. RM18-1-000, Comments of ISO New England, Inc., 1 (October 23, 2017); *Grid Resiliency Pricing Rule*, Docket No. RM18-1-000, Initial Comments of PJM Interconnection, L.L.C. on the United States Department of Energy Proposed Rule, 6 (October 23, 2017). ISO-NE has indicated that it is working on reforms to its markets to value fuel security. ISO-New England Comments at 2. This includes possible changes to Pay For Performance parameters, increased incentives for forward fuel supply and re-supply, and including opportunity costs associated with scarce fuels and emission allowances. *Id.* PJM has similarly announced its Valuing Fuel Security initiative, which will analyze market-based mechanisms to ensure resilience. PJM Interconnection, L.L.C., “Valuing Fuel Security,” at 1 (April 30, 2018) (“PJM Fuel Security Initiative”), <http://www.pjm.com/-/media/library/reports-notice/special-reports/2018/20180430-valuing-fuel-security.ashx?la=en>.

gas-fired generators relying on ‘just-in-time’ fuel-delivery infrastructure (or to generators using inherently variable fuel, in the case of wind and solar) has further exposed the limitations of New England’s existing fuel-delivery system and heightened the region’s fuel-security risk, particularly during the winter.”⁵ While PJM suggests its current grid is well-suited to maintain resilience, it also acknowledges significant shortcomings in gas-electric coordination,⁶ and a major blind spot in its planning practices with regard to resilience.⁷

Taken together, the RTO Comments simply do not demonstrate that the grid is ready to handle the increasing reliance on gas-fired generation. They also fail to assure the Commission that the loss of nuclear generation to early retirement will not increase the resilience risk of the rush to gas.⁸ Beyond the RTOs, the North American Electric Reliability Corporation (“NERC”) has previously warned that becoming too reliant on natural gas increases the risk to the bulk power system, because “within a relatively short time, a major failure” to the natural gas

⁵ ISO-New England Comments at 6.

⁶ PJM Comments at 6-7. PJM asks the Commission to “[e]stablish improved coordination and communication requirements between RTOs and Commission-jurisdictional natural gas pipelines to address resilience as it relates to natural gas-fired generation located in RTO footprints.” *Id.* at 6.

⁷ In a follow up to their initial comments in this docket, PJM has acknowledged that its reliability studies do not include consideration of “the resilience of the system with various potential [resource] portfolios nor the risks associated with significant disruptive events,” that PJM “needs to understand the fuel-supply risks in an environment trending toward greater reliance on natural gas supply and delivery,” and that PJM’s capacity market could be reformed to “send a price signal . . . to incent investment in fuel-secure infrastructure.” PJM Fuel Security Initiative at 1.

⁸ “The interrelationship between existing and planned gas-fired generation facilities and the upstream gas supply infrastructure, and the power system’s associated exposure to a significant event affecting such infrastructure should be incorporated into resilience assessments of the power sector.” See ICF, *The Impact of Fuel Supply Security on Grid Resilience-Interim Report* at 7, May 5, 2018, attached hereto as Appendix A (“ICF Report”).

transportation system “could result in a loss of electric generating capacity that could exceed the electric reserves available to compensate for these losses.”⁹

To illustrate this point, NEI commissioned the international consulting firm ICF to evaluate whether the grid can remain resilient given the increasing reliance on natural gas-fired generation in PJM. ICF’s interim report – *The Impact of Fuel Supply Security on Grid Resilience* – raises important questions about the vulnerability of several discrete clusters of generation in PJM to disruption of the gas supply and transportation infrastructure.¹⁰ Specifically, the ICF Report (addressed in more detail below) shows that the loss of a single gas pipeline serving a cluster of gas-fired generation in PJM could result in the loss of over 18 GW of electric generation from an extended outage.¹¹ The ICF Report concludes that a detailed analysis is required of our gas infrastructure to better understand the implications of the increased use of natural gas and the implications of nuclear retirements:

While the interstate pipeline network is robust and highly interconnected, there are locations within the system where disruption events could have cascading implications on generation resources. RTO/ISOs should review the interrelationship between existing and planned gas-fired generation facilities and the upstream gas infrastructure and related power transmission systems.¹²

The ICF Report illustrates the type of analysis that is not currently being undertaken in short-term or long-term planning by the RTOs.

While planning is critical, a conversation about mitigating resilience risks must also

⁹ NERC, 2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power; Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System 3-4 (May 2013).

¹⁰ ICF Report at 13-14.

¹¹ *Id.* at 1.

¹² *Id.* at 44.

address market compensation.¹³ The failure to properly compensate power plants in the market will continue to force early nuclear retirements unless action is taken. The continued loss of high capacity factor, fuel-secure, and zero carbon emission nuclear resources will place even greater pressure on other fuel sources to perform at higher levels now and in the future.

NEI urges the Commission to evaluate the RTO Comments and undertake three parallel tasks to address to resilience: **Define, Foster, and Retain**. Because resilience is threatened *today* through the ongoing retirements of nuclear generation, we encourage the Commission to undertake these efforts quickly.

Define Resilience
to Address Fuel Security

The Commission’s definition of resilience must incorporate the importance of long-term fuel security. In order to withstand the loss or degradation of one fuel source (a low frequency / high impact event), there must be enough generation not dependent on that fuel source. In defining resilience, and setting out the scope of its regulatory mission to protect resilience, the Commission should resist calls to focus resilience solely on short-term reliability metrics and should instead focus on the need for diverse, fuel-secure resources.

Foster Resilience
by Creating Conditions in Which Units that Contribute to Resilience Survive

Through RTO market reforms (including PJM’s price formation initiatives), the Commission must adopt policies based on a foundational principle that wholesale market rates that threaten resilience (and therefore long-term security, reliability, and cost) are not just and reasonable. The Commission should adopt planning standards and market rules that ensure that generators

¹³ ISO-New England captures the essence of the intersection between fuel security concerns and market compensation: “*Despite periods of highly volatile energy market prices, New England continues to see the retirement of coal, oil, and nuclear power plants, which, as recently experienced, are needed to maintain reliability when the natural gas-fuel infrastructure is unavailable to the generators.*” ISO-New England Comments at 7 (emphasis added)

that contribute to resilience are incentivized to participate in the market. We must encourage new resilient generation and preserve the resilient resources we already have.

Retain Resilience
by Adding Resilience Analysis
to RTO Generator Retirement Studies

RTOs are not currently empowered to keep resilience-critical units on line in the absence of a short-term reliability threat. The Commission should require that each RTO expand the generator retention authority in their respective tariffs to add a resilience analysis for planned generator retirements. Such authority would require a new type of retirement study that examines the role of the retiring unit, and the RTO's ability to withstand a high-impact low-frequency event.

II. ABOUT NEI

NEI is the Washington, D.C.-based policy organization of the nuclear technologies industry. NEI's mission is to foster the beneficial uses of nuclear technology and to communicate accurate information about the importance of nuclear energy and technology. NEI is responsible for establishing unified policy on behalf of its members relating to matters affecting the nuclear energy industry. NEI's members include entities licensed to operate commercial nuclear power plants in the United States, nuclear plant designers, major architect and engineering firms, fuel cycle facilities, nuclear materials licensees, and other organizations involved in the nuclear energy industry.

In the United States, there are currently ninety-nine nuclear reactors, at sixty distinct sites, spread across over thirty states. These units represent approximately 99,635 MWe of baseload generating capacity. In 2017, nuclear energy produced 20 percent of U.S. electricity supply (*i.e.*, 804.9 billion kilowatt-hours), and prevented 547.5 million metric tons of carbon

dioxide emissions.¹⁴ 2017 also saw U.S. reactors continue to operate at a remarkably high capacity factor – *i.e.*, how much energy was generated against the maximum that could have been produced at continuous full-power operation during a specific period of time – of over 92 percent.

Nuclear energy accounted for 56 percent of America’s carbon-free electricity in 2017 — three times more than wind energy.¹⁵ The amount of carbon dioxide emissions avoided by U.S. nuclear energy facilities is equal to the carbon dioxide emissions produced from 117 million passenger cars—more than all the passenger cars in the United States. Without nuclear power plants operating in thirty states, carbon emissions from the U.S. electric sector would be approximately 30 percent higher.

In addition, nuclear energy contributes approximately \$60 billion annually to the gross domestic product of the United States, accounts for approximately 475,000 full time jobs (direct and secondary), and provides nearly \$10 billion annually in federal tax revenues and \$2.2 billion in state tax revenues.¹⁶

III. COMMENTS

NEI strongly supports the Commission’s continued efforts to address the ongoing threats to resilience, and urges timely action.

As noted earlier, NEI is encouraged that the RTO Comments (and other recent announcements) suggest a greater commitment to resilience reforms than was reflected in the

¹⁴ NEI, US Nuclear Power Plants, General U.S. Nuclear Info, <https://www.nei.org/resources/statistics/us-nuclear-generating-statistics>; NEI, Nuclear By The Numbers, CO2 Emissions Avoided by the US Power Industry at 6, <https://www.nei.org/resources/fact-sheets/nuclear-by-the-numbers>.

¹⁵ NEI, Nuclear By The Numbers, 2017 US Emissions-Free Fuel Shares at 5, <https://www.nei.org/resources/fact-sheets/nuclear-by-the-numbers>.

¹⁶ NEI, Nuclear By The Numbers, US Nuclear Industrywide Capacity Factors at 8, <https://www.nei.org/resources/fact-sheets/nuclear-by-the-numbers>.

RTOs' response to the DOE NOPR. ISO-New England and PJM, which both urged rejection of the DOE NOPR¹⁷, both now raise concerns about the impact of fuel security on resilience and ask the Commission for more authority to address the issue. While this shift is notable, the RTO Comments are in several respects too narrow, and miss the bigger picture challenges and threats to resilience. NEI encourages the Commission to consider the following comments as it formulates its resilience strategy.

A. Defining Resilience to Include Fuel Security

In order to maintain a resilient power system, the Commission should adopt a comprehensive definition of resilience that recognizes fuel diversity and fuel security are critical drivers of resilience. In its Resilience Inquiry, the Commission proposed the following definition of resilience: *“The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.”*¹⁸ The Commission should add the following to its proposed definition: *“The effectiveness of a resilient bulk-power system necessarily depends on ensuring a diverse and fuel-secure set of resources on both a short and long-term basis.”*

The Commission should resist the urge to place too great an emphasis on short-term reliability and too little attention on fuel security and the longer-range factors that contribute to a loss of resilience. As stated by PJM, *“resilience actions are anchored in, but go beyond what is strictly required for compliance with, the existing reliability standards.”*¹⁹ Applying traditional reliability considerations and focusing only on whether the lights will stay on tomorrow ignores whether steps can be taken today to ensure that the grid has access to the right resources to

¹⁷ *Supra* n.4.

¹⁸ Resilience Inquiry at P 23 (emphasis added).

¹⁹ PJM Comments at 5.

maintain resilience now, in future years, and beyond. Some RTO comments conclude that their respective systems are currently reliable, and that any future resilience issues can either be addressed later, or will be resolved based on various analytical tools and processes within each RTO.²⁰ Examples touted by the RTOs include regional-specific studies and reliability analysis, new tools to assess fuel availability within the region, operational and forecasting measures in response to recent extreme cold periods, and continued efforts on electric-gas coordination.²¹ This emphasis on short-term reliability ignores the structural changes that these markets are now experiencing and the threat these changes pose to resilience.

One of the most significant current risks to long-term resilience is an over-reliance on natural gas as a fuel source. As evidenced by the comments filed by ISO-New England, and as PJM now recognizes, over-reliance on gas can lead to serious fuel security risks.²² Retaining economically threatened nuclear plants would ensure that similar fuel security problems do not reach the same urgent levels outside New England. The linkage between fuel security and resilience must be reflected in the Commission's definition of resilience. Specifically, the Commission should incorporate an explicit reference to the need to maintain a diverse and fuel-secure generation fleet in each region. It is a fundamental concept of resilience that having plants fueled by multiple fuel sources enhances our collective ability to withstand the loss or disruption of any one fuel source.

²⁰ NYISO Comments at 1, 5-6, 8, 28; PJM Comments at 3-4 (stating that its BES is currently reliable while urging the Commission to develop processes to help with the identification and mitigation of future grid resilience challenges and the mitigation of current vulnerabilities).

²¹ PJM Comments at 34-35, 53-54; NYISO Comments at 2-3, 12-14; ISO-New England Comments at 23-26, 34.

²² ISO-New England Comments at 33.

B. Fostering Resilience Through Market Rules and Planning Reform

Having established the importance of resilience, the Commission should immediately consider actions it can take to foster resilience. Reforms to market rules and planning paradigms are necessary to help ensure that the RTOs can properly analyze risks to resilience and appropriately compensate resources that support a resilient grid.

The RTO Comments support such reforms.²³ The Commission still has time to ensure that market structures are in place in areas of the country outside of ISO-New England so that they do not reach the same threatened condition.²⁴ ISO-New England not only recognizes that it has a serious resilience problem based on challenges to fuel security,²⁵ but has now reached the point that the RTO is taking emergency action by asking the Commission for a waiver of its tariff in order to keep several units otherwise planned for retirement online through a cost of service agreement while it works on market reform.²⁶ In its comments, PJM claims that, *“[g]eneration within PJM is both geographically and fuel diverse, which provides an inherent level of resilience by avoiding circumstances in which a single weather event can affect a disproportionate number of assets or a dependence on a single fuel source can create a single point of failure.”*²⁷ PJM’s recognition that fuel diversity is such an important contributor to grid resilience necessarily leads to the question of how such resilience can be maintained so PJM can continue to benefit from this diversity.

²³ PJM Comments at 65-66;

²⁴ ISO-New England has raised this very same fuel security issue for several years, emphasizing the need for action. ISO-New England Comments at 6-7; *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000, Reply Comments of ISO-New England, Inc., 1 (Nov. 7, 2017).

²⁵ ISO-New England Comments at 33-34.

²⁶ ISO-New England Inc., *Petition for Waiver of Tariff Provisions* at 1-2, Docket No. ER18-1509-000, (filed May 1, 2018) (ISO-New England notes that stakeholders are grappling with a growing threat to the region posed by its increasing reliance on natural gas-fired generation despite essentially static regional natural gas pipeline capacity) (“Emergency Tariff Waiver”).

At pages 5-8 of its comments, PJM details a list of proposed reforms that PJM believes the Commission should either undertake, or order PJM to undertake. NEI generally supports those reforms as far as they go. But NEI specifically urges the Commission to focus on long-term resilience planning and compensation.

1. FERC Should Mandate Long-Term Resilience Planning, Including Analyses of the Increased Reliance on Gas and Renewables

The RTOs have not yet done enough to understand the magnitude of the threats to grid resilience. Before considering external threats to resilience, RTOs must better understand what risks are inherent in their market structures and how current market conditions may unwittingly be exacerbating those risks. As is evident from the RTO Comments and the ICF Report, in depth and comprehensive resilience-based planning is not yet happening. To facilitate that planning, the Commission should mandate that RTOs adopt meaningful resilience planning standards. A primary analytical question on which RTOs should focus is whether the continued transition to a fleet predominately comprised of gas and renewables presents risks to resilience, and whether early retirements of nuclear units exacerbate that risk.²⁸

The RTO Comments indicate that resilience is not yet a sufficient and consistent part of long-term RTO planning criteria. More importantly, RTOs do not sufficiently analyze whether the current gas supply and transportation infrastructure can support a resilient grid without other baseload resources currently threatened by the market. A core focus of resilience planning must be a comprehensive analysis of vulnerabilities of natural gas infrastructure. The Commission and RTOs must devote resources to studying this issue in depth. The ICF Report raises serious concerns that must be evaluated and addressed.

²⁷ PJM Comments at 47.

²⁸ See ICF Report at 3-4.

a. Establishing Resilience Planning Standards

PJM says that it is “actively evaluating how to incorporate resilience into the planning process” but expresses a concern that it lacks the authority to do so. PJM asks the Commission to issue “an order concluding that the regional planning responsibilities of RTOs currently mandated under 18 CFR § 35.34(k)(7), also include an obligation for RTOs to plan for and address resilience....”²⁹ NYISO states that it “is embarking this year on a comprehensive re-evaluation of its current planning processes and procedures with its stakeholders. The objective of this effort is to identify enhancements and efficiency improvements to the NYISO’s current reliability, economic, and public policy planning processes...”³⁰

Planning for resilience should be more than just trying to identify near-term threats.

Long-run resilience planning must, at a minimum:

- Identify key generating units and other energy facilities that contribute to system resilience;
- Identify market conditions and RTO market structures that threaten generating units that RTOs rely on for resilience; and
- Analyze threats to natural gas infrastructure.

NEI supports implementing consistent resilience planning standards across the RTOs. It is also critical that fuel security becomes a key consideration in those new standards. An RTO cannot effectively study and plan for resilience without a full understanding of how its resource mix either facilitates or threatens long-term resilience (as opposed to just near-term reliability). Consistent with other reforms endorsed herein, each RTO should be required to study the potential loss of nuclear plants and the impact of these retirements on resilience. These studies should be conducted on a routine basis, not just in response to a planned or announced retirement

²⁹ PJM Comments at 33-34.

³⁰ NYISO Comments at 2.

of a nuclear plant. Prudent planning processes must anticipate adverse contingencies (like the early retirement of a nuclear plant) before the contingency materializes.

In response to PJM's request for more authority, NEI requests that the Commission clarify that RTOs are required to consider resiliency in their planning and market designs.³¹ NEI further urges the Commission to give the RTOs whatever additional authority they need to proactively evaluate resilience on a regular basis.

b. Analysis of Gas Supply and Transportation Infrastructure

A key element of the Commission's resilience program should be analyzing the impact on resilience of the growing shift to gas-fired generation and renewables in several key RTO markets. ISO-New England's Operational Fuel-Security Analysis shows: (a) overdependence on certain resources; (b) potential vulnerability of New England's power system due to the prolonged loss of any one of several key energy facilities; and (c) current trends that are pushing New England toward greater fuel-security risks (over 80 percent of the 23 scenarios studied resulted in load shedding for base 2024/2025 winter).³² Similarly, PJM admits it is increasingly

³¹ Consideration also should be given to the need for RTOs to model the emissions effects of market changes in their planning efforts.

³² ISO-New England Comments at 35. ISO-New England also noted the following in its Emergency Tariff Waiver filing:

A number of factors in combination continue to highlight fuel security as an important issue for the ISO and the regional electric system. These factors include the continued growth of local gas distribution companies' gas demand, retirement of existing resources with on-site fuel storage (such as both the Vermont Yankee (615 MW) and Pilgrim (683 MW) nuclear facilities, the large Brayton Point Station (1,528 MW), Salem Harbor (747 MW), and several others in recent years), and the replacement of these resources with new, combined cycle natural gas-fired generating facilities, most of which are without comparable on-site fuel storage, do not have firm gas fuel arrangements, and cannot get fuel during periods when the constrained natural gas pipeline system is being fully utilized by other customers.

Emergency Tariff Waiver, Brandien Testimony at 11.

reliant upon a natural gas infrastructure that it cannot easily control.³³ PJM has also previously admitted that the “risk to the system wasn’t that resources couldn’t necessarily provide reliability attributes, that the potential concentration of a single fuel source or low-probability, high-impact events could cause significant impacts to the system.”³⁴

As effectively conceded in the RTO Comments and demonstrated by the circumstances in ISO-New England, reliability-based planning tools and processes have already proven inadequate in PJM and New England, while some of the previously proposed solutions have not had the impact that was anticipated.³⁵

c. ICF Study of Gas Infrastructure

The ICF Report analyzes the natural gas infrastructure in the PJM market to determine how the grid would respond to a disruption of certain critical components of the gas supply and transportation system. The ICF Report (containing the results of the first phase of ICF’s work) begins to address the very fuel security issue that PJM has identified in its April 30, 2018 release. Specifically, PJM stated:

³³ PJM Comments at 26-28. In fact, IHS has recently concluded that the 65 million consumers who rely on PJM grid-based power supply are better off if something is done to prevent the uneconomic closures of PJM nuclear resources because the PJM power supply portfolio is more efficient, more resilient, and environmentally responsible with the continued contribution of cost-effective nuclear resources. IHS Markit, *Ensuring Resilient and Efficient PJM Electricity Supply* at 35 (April 2018), available at <https://www.nuclearmatters.com/report-21> (“IHS Study”).

³⁴ PJM, Press Release, *PJM Study: System Reliable Even with Much More Gas, Renewables; Resilience Key to Operational Reliability* (Mar. 30, 2017) (quoting Michael Bryson, PJM Vice President of Operations, <http://www.pjm.com/~media/about-pjm/newsroom/2017-release/20170330-pjm-evolving-resource-mix-and-system-reliability.ashx>). More recently, PJM’s Fuel Security Initiative explained that while PJM could remain reliable with the addition of more natural gas and renewable resources, “heavy reliance on one resource type” raises potential resilience risks beyond existing reliability standards. PJM Fuel Security Initiative at 1.

³⁵ See PJM Comments at 57-58 (“Although PJM was hoping that the Capacity Performance changes would spur a corresponding array of new service offerings by pipelines (and generators seeking such options), at least on the public record such new pipeline services have not been offered as new open season requests.”).

As defined by PJM, fuel security is the ability of the system's supply portfolio, given its fuel supply dependencies, to continue serving electricity demand through credible disturbance events, such as coordinated physical or cyber-attacks or extreme weather that could lead to disruptions in fuel delivery systems, which would impact the availability of generation over extended periods of time. To define potential fuel-security criteria, PJM needs to understand the fuel-supply risks in an environment trending towards greater reliance on natural gas supply and delivery. The goal is to identify triggering thresholds (such as a simulated loss of load) that indicate locations on the system where additional fuel security assurance is needed.³⁶

NEI will provide ICF's full analysis to the Commission in this docket upon completion.

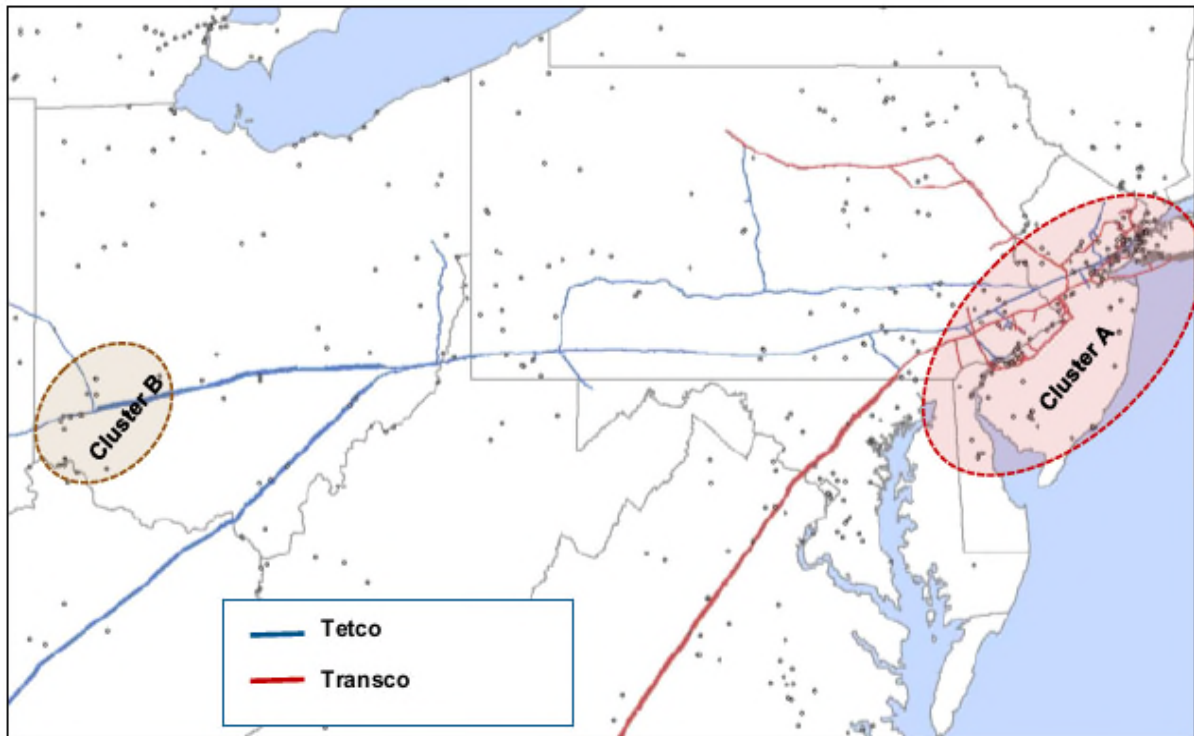
As framed by ICF, "[t]he focus of the study was assessing the exposure of the RSO/ISO system to gas infrastructure events and the ability of such system to maintain deliveries and recover from significant gas infrastructure events."³⁷

ICF's conclusions are stark and unambiguous: neither the RTOs nor the Commission yet have an adequate understanding of whether the natural gas infrastructure is robust enough to support a resilient grid. This is not to fault the Commission or the RTOs; the entire industry is coming to terms with the need for grid resilience, but the message is no less clear.

ICF analyzed various pockets of generation to determine the actual effect on power generation of the loss or disruption of specific gas pipelines. ICF identified the following generation "clusters" within PJM that are all dependent on the same upstream infrastructure for fuel supply. ICF identified two main clusters of gas-fired generation units within the PJM region: Northern New Jersey / Philadelphia region, and the Dayton Ohio / Lebanon Hub.

³⁶ PJM Fuel Security Initiative at 1.

³⁷ ICF Report at 13.



The review focuses on these generation clusters and their relationship to the gas pipeline system:

For each cluster we review the regional pipeline assets and their recent flow rates and interconnectivity. We then summarize the gas-fired generation capacity associated with each cluster/pipeline combination. Finally, we provide an assessment of the potential impact of a gas infrastructure event based on the level of gas-fired generation, anticipated daily gas requirements associated with such facilities, associated oil backup capabilities, and estimated on site oil storage levels.³⁸

After identifying the clusters, ICF identified the gas-fired generation associated with each cluster, estimating the total gas consumption within the cluster. ICF also analyzed how many of those generators had some limited availability to operate on back-up fuel, such as distillate fuel oil or kerosene (“DFO”) and residual fuel oil (“RFO”). Based on that data, ICF estimated how much gas-fired generation could be lost within the cluster if the service over the pipeline serving the cluster was disrupted or fully interrupted for any reason.

³⁸ *Id.* at 26.

ICF concludes that,

Natural gas has unquestionably evolved into a major and growing source of supply for the power generation sector. RTO/ISOs throughout the country have become increasingly reliant on this fuel source. While the interstate pipeline industry has an admirable safety record, gas infrastructure events and the associated loss of supply to markets are not unknown. Observed and realized gas supply disruptions can be significant in size and duration. And intentional and directed acts of sabotage could be more impactful.

....

Gas-fired generation units connected to the same interstate pipeline, or even interconnected pipelines or LDCs, are at risk for concurrent loss of supply during a significant gas infrastructure event. While the interstate pipeline network is robust and highly interconnected, there are many locations within the system where disruption events could have cascading implications on generation resources. RSO/ISOs should review the interrelationship between existing and planned gas-fired generation facilities and the upstream gas infrastructure and related power transmission systems.³⁹

Specifically, ICF concludes that out of 18.7 GWs of gas-fired generation in Cluster A, there is ***“the potential to lose 6.7 GWs of gas-only generation during a gas infrastructure event with an additional 12 GWs at risk based on the availability of backup fuel. Based on historical inventory levels at these plants, backup fuel resources could be depleted within 10 to 20 days or much shorter if plants are required to operate at higher load factors.”***⁴⁰ Similarly, while Cluster B’s results are not as stark, of the 1.9 GWs of gas-fired generation there, 1.2 GWs (62 percent) represents gas-only generation facilities with no reported oil back up. The ICF Report adds that, due to the limited switchable capacity in the region, “reported oil inventories would support 19 days of supply at historical load factors.”⁴¹

³⁹ *Id.* at 43.

⁴⁰ ICF Report at 31-32.

⁴¹ *Id.* at 39.

ICF's initial conclusion provides significant evidence that the pace of our generation fleet transformation has outpaced the RTOs' framework for analyzing the resilience implications of these changes. ICF's report illustrates precisely the types of analysis that the RTOs should undertake to better understand how resilient the grid currently is, and the impact each retired generator could have on overall grid resilience.

2. Compensation

The Commission must also make compensation a central focus of its resilience analysis. Rates that threaten resilience are not just and reasonable. Supporting continued price formation reforms in PJM and elsewhere will support establishing market prices conducive to maintaining a resilient grid. Many of the other reforms discussed in the RTO Comments will amount to band-aids if the Commission does not make generator compensation a central component of its efforts on resilience. NEI urges the Commission to quickly consider price formation reforms and engage in an analysis of long-run prices. If the grid is overly reliant on natural gas, wholesale market prices become more vulnerable to spikes in commodity prices and more susceptible to shortage pricing when gas supply is disrupted.⁴² Conversely, a resilient grid helps ensure rate stability during disruptions and keeps rates just and reasonable over the long-run. A recent IHS Markit report found "the uneconomic loss of the nuclear contribution to the PJM power supply portfolio caused by market distortions is a lose-lose proposition."⁴³ The outcome involves both higher power production costs as well as higher CO2 emissions. Since environmental

⁴² IHS Study at 33 (explaining that the uneconomic retirement and replacement of nuclear power plants in PJM increases the variation of PJM production costs, and estimating that the cost to restore this level of resilience for consumers via natural gas hedging mechanisms is \$714 million annually).

⁴³ *Id.* at 4.

responsibility requires making efficient environmental cost and benefit trade-offs, uneconomic PJM nuclear closures and replacements are not environmentally responsible.”⁴⁴

In its comments, PJM urges the Commission to enact (or order PJM to develop) market reforms to protect and maintain a resilient system. Specifically, PJM reiterates the need for compensation reforms in its markets:

Focusing on physical infrastructure is clearly important for the reasons addressed earlier in PJM’s responses, but without a compensation mechanism that properly values the attributes that any particular resource brings to the grid; we will inevitably frustrate many of the initiatives seeking to integrate emerging technologies such as microgrids, advanced storage and DER to mitigate resilience challenges on the BES. Further, without a proper compensation mechanism, we will fail to properly attract the funding this capital-intensive industry needs to make some of these critical investments, particularly those needed to ensure a resilient generation fleet. That being the case, resilience efforts warrant a review and refinement market-based constructs, operating procedures, industry collaboration and planning processes.⁴⁵

PJM has released whitepapers describing possible market reforms to encourage the pricing necessary to provide compensation to units that contribute to grid resilience but whose viability is otherwise threatened by current market compensation. These include development of new operating reserve products,⁴⁶ changes to the demand curve to better reflect true shortage pricing,⁴⁷ and importantly, reforms to allow all PJM-scheduled resources to compete to set the locational marginal price (“LMP”) and include start-up and no-load costs in the LMP where applicable.⁴⁸ PJM has also indicated that it will incorporate constraints into its capacity market after it completes the necessary fuel security analysis of its system.⁴⁹ NEI urges the Commission

⁴⁴ *Id.* at 4.

⁴⁵ PJM Comments at 74.

⁴⁶ *Id.* at 75-77.

⁴⁷ *Id.* at 78.

⁴⁸ *Id.* at 78-80.

⁴⁹ PJM Fuel Security Initiative at 1-2.

to press PJM (and other RTOs as applicable) to adopt these reforms immediately. Without market reforms to ensure fair compensation, it becomes difficult to justify continued capital investments in nuclear plants that contribute to resilience.

C. Retaining Attributes of Resilience

This proceeding has exposed a deficiency in the RTO tariffs that the Commission can and should quickly remedy. The RTOs currently evaluate proposed generator retirements only for their impact on reliability; their tariffs do not permit them to retain generation whose retirements would threaten resilience, but not reliability. The enclosed ICF Report shows the type of analyses the RTOs should undertake before a generator is permitted to retire.

In April 2018, the leadership of ISO-New England sent a memorandum to the NEPOOL Participants Committee regarding its intent to seek a waiver from its tariff to address two pending retirements from the perspective of fuel security. ISO-New England's Emergency Tariff Waiver is now before the Commission in Docket No. ER18-1509-000.⁵⁰ In addition to the short-term waiver, ISO-New England also announced its intention to file tariff modifications later in the year to put that authority into the tariff. ISO-New England has concluded that two major generating units need to be retained in order to maintain resilience and fuel security, but has concluded it lacks the tariff authority to do so.

NEI supports giving RTOs the authority to retain units that contribute to resilience, even if the current reliability-focused "reliability-must-run" ("RMR") eligibility criteria is not met. The Commission should approve the waiver and tariff filings ISO-New England plans to make, but should go a step farther and require other RTOs to quickly file with the Commission similar provisions (*e.g.*, within 90 days). Taking this step would have no adverse effect on wholesale

⁵⁰ ISO New England, Inc., *Petition of ISO New England Inc. For Waiver of Tariff Provisions*, Docket No. ER18-1509-000 (May 1, 2018) ("Emergency Tariff Waiver").

markets, because the authority would only be invoked if the RTO determined that a unit should be retained in order to safeguard the resilience of the grid.

IV. PROPOSED NEXT STEPS

NEI urges the Commission to continue to devote the necessary resources to quickly pursue critical reforms to define resilience, foster resilience, and retain generating units whose retirements would threaten resilience. NEI respectfully request that the Commission take the following immediate steps:

1. **Define:** Adopt a definition of resilience that includes fuel security and diversity as a key attribute of resilience and specifically focuses on the important role of non-gas baseload resources in maintaining resilience in both the short- and long-term;
2. **Foster:** Adopt resilience planning standards and grant RTOs whatever additional authority they require to implement such standards; require RTOs to engage in near constant evaluation of the vulnerabilities of the grid to a disruption of the natural gas supply and transportation infrastructure; and require RTOs to reform their market design to ensure that appropriate compensation is being provided to resources that contribute to resilience; and
3. **Retain:** Compel RTOs to adopt tariff provisions to provide RMR-like mechanisms to retain generating units that propose to retire, but whose retirements would compromise system resilience.

To be clear, while the Commission must evaluate these issues appropriately before undertaking action, it should move quickly to take action. Early nuclear retirements are likely to continue and, with them, the resilience benefits of nuclear generators will be permanently lost. As NEI has previously emphasized, once a nuclear generator closes, that action is irreversible, no matter what RTO or Commission efforts may be brought to bear. Thus, the Commission must act quickly lest invaluable resilient generation be lost in the interim.

V. ATTACHMENTS

Appendix A *ICF, The Impact of Fuel Supply Security on Grid Resilience-
Interim Report, May 5, 2018*

VI. CONCLUSION

For the foregoing reasons, NEI respectfully submits these reply comments and requests that the Commission act expeditiously to address these important issues in RTO markets.

Respectfully submitted,

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Dated: May 9, 2018

CERTIFICATE OF SERVICE

I certify that on this 9th day of May, 2018, I have caused a copy of the foregoing document to be served electronically on each person listed on the Secretary's official service list for the above-referenced proceeding.

/s/ Jonathan M. Rund
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APPENDIX A



The Impact of Fuel Supply Security on Grid Resilience

Interim Report

May 5, 2018

Study prepared at the direction of the
Nuclear Energy Institute



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1 Executive Summary

Over the last 10 to 15 years, the power generation sector in the US has grown increasingly reliant on natural gas as a fuel source. This reflects natural gas' capital and variable advantages relative to several alternative fuel sources, as well as associated environmental benefits relative to some fuels. While the interstate natural gas supply system has an admirable safety and reliability record, the increased reliance on a single fuel source can raise questions regarding the resilience of the power grid in response to a significant natural gas infrastructure event. This risk can be increased if associated gas-fired generation units are concentrated in a particular region and rely on the same upstream infrastructure resources for supply (i.e., a generation 'cluster').

This report provides interim results of a study on the potential exposure of RTO/ISO systems to gas infrastructure events. Phase I of this work, discussed in this report, is designed to characterize the gas infrastructure system supplying PJM in relation to existing and planned gas-fired generation capacity, and assess the potential impact of a significant gas infrastructure event on the availability of gas-fired generation in this region. Phase II takes the results of the Phase I work and assesses how the loss of gas-fired generation resources could impact resilience in PJM. While the study focused on PJM, the issues addressed are relevant for other RTO/ISOs throughout the US power system.

Summary Conclusions

The interim results suggest that a significant natural gas infrastructure event could result in the loss of up to about 18.7 GWs of gas-fired generation capacity in PJM, depending on the severity and location of such event. Over 35 percent of this capacity has no backup fuel capability and could be immediately unavailable during such an event. While the remaining capacity reports having dual-fuel backup capabilities, historical on-site inventory levels maintained at such plants would generally support less than 10 to 15 days of operation at recent average utilization levels. On-site fuel resources would last far fewer days, generally less than 5, if these units experience the higher load factors expected as a result of the loss of gas-only resources during such an event.

The ability of the upstream oil distribution network to replenish backup fuel supplies during such an event, and the associated logistics of such refill, is questionable, particularly if such event is widespread. Moreover, such events are not just theoretical or require the level of intervention associated with a malicious, intentional act (e.g., terrorism). The industry has experienced gas infrastructure events of the size that could have a real and significant impact on the availability of gas-fired generation resources if they were to occur at critical points within the system. Impacts from some of these events lasted for many months. Such levels and durations can have significant implications for the resilience of the power generation grid.

1.1 Background

Over the past few years, the US' reliance on natural gas for power generation has grown significantly. As summarized in Table ES-1, annual consumption of gas by the US power sector grew by a total of 32 percent between 2011 and 2016, with multiple regions experiencing more than 45 percent growth.¹

Table ES-1: Annual Gas Consumption for Power Generation by Census Region (Bcf/year)

	2011	2012	2013	2014	2015	2016	Increase Since
<i>New England</i>	438	433	358	335	387	386	-12%
<i>Mid-Atlantic</i>	940	1,119	1,035	1,091	1,193	1,306	39%
<i>East North Central</i>	386	644	466	472	687	881	128%
<i>West North Central</i>	112	167	134	104	139	181	61%
<i>South Atlantic</i>	1,636	2,008	1,849	1,852	2,259	2,393	46%
<i>East South Central</i>	629	787	619	654	850	937	49%
<i>West South Central</i>	2,119	2,287	2,031	1,969	2,330	2,280	8%
<i>Mountain</i>	556	645	648	630	721	735	32%
<i>Pacific (contiguous)</i>	716	980	1,015	1,006	1,016	864	21%
Total Lower-48 US	7,532	9,071	8,157	8,114	9,583	9,961	32%

Source: EIA "Natural Gas Delivered to Electric Power Consumers"

http://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_veu_mmcf_a.htm

This trend reflects both growth in natural gas power generation capacity and greater utilization of existing gas-fired generation units. Gas-fired generators' share of total regional capacity has increased significantly in almost all census regions.² For example, as summarized in Table ES-2, PJM added nearly 14 GWs of gas fired generation capacity in the last five years. This has increased natural gas' share of total installed generation capacity in the region from 28 percent to more than 35 percent.

¹ EIA 2017 data was not final at the time of report preparation. Preliminary numbers for 2017 indicate a decline in gas consumption in the power generation sector of about 6 percent, and an increase in gas-fired power capacity of about 4 percent, relative to 2016.

² See EIA: "Existing Nameplate and Net Summer Capacity by Year, Energy Source, and State (EIA-860). <https://www.eia.gov/electricity/data/state/>

Table ES-2: Installed Generating Capacity by Fuel Source -- PJM

(June values)	2011		2016		Change	
	MW	% Total	MW	% Total	MW	% Total
Natural Gas	50,729	28.0%	64,728	35.6%	13,999	7.6%
Nuclear	33,146	18.3%	33,051	18.2%	(95)	-0.1%
Coal	76,968	42.4%	66,620	36.6%	(10,348)	-5.8%
Hydroelectric	8,030	4.4%	8,850	4.9%	821	0.4%
Petroleum	11,212	6.2%	6,780	3.7%	(4,433)	-2.5%
Solar Thermal and Photovoltaic	15	0.0%	252	0.1%	237	0.1%
Wind	634	0.3%	1,019	0.6%	386	0.2%
Solid Waste	705	0.4%	767.50	0.4%	62	0.0%
Total	181,439		182,067		629	

Source: PJM Monitoring Analytics State of the Market reports.

Market trends and expectations for the relative competitiveness of natural gas support the continued and increased reliance on this fuel source. Developers have announced over 70 GWs of new gas-fired generation capacity, with more than half of this currently under construction or approved.³

1.2 Study Approach

Two specific questions were asked in the analysis:

- What is the potential exposure of the PJM grid to a gas infrastructure event based on its anticipated reliance on gas-fired generation in the future?
- How would the early retirement of existing nuclear generation resources affect the resilience of the PJM grid during such an event?

The analysis was divided into two phases:

- **Phase I** is designed to characterize the gas infrastructure supplying PJM in relation to existing and planned gas-fired generation capacity and assess the potential impact of a significant gas infrastructure event on the availability of gas-fired generation in the region. The analysis leverages ICF’s proprietary Gas Market Model, which provides a detailed characterization of the natural gas infrastructure throughout the US.⁴ This is supplemented with publicly available data on gas flows, installed generation capacities, locations of gas-fired units, reported and estimated interconnectivity of such units with the upstream gas supply infrastructure, reported back-up fuel capabilities, and historical, observed inventory levels of backup fuel by facility.
- **Phase II** is designed to take the results of the Phase I work and assess how the loss of gas-fired generation resources could impact resilience in PJM. This subsequent analysis leverages ICF’s proprietary Integrated Planning Model (“IPM”) and associated transmission flow models to assess the impact of the gas infrastructure event on regional loads, including identifying unmet load. The transmission flow analysis will account for how the existing transmission grid might be leveraged to

³ Source: EIA 860M December Data

⁴ Appendix A provides a summary of the GMM and IPM models leveraged for this work.

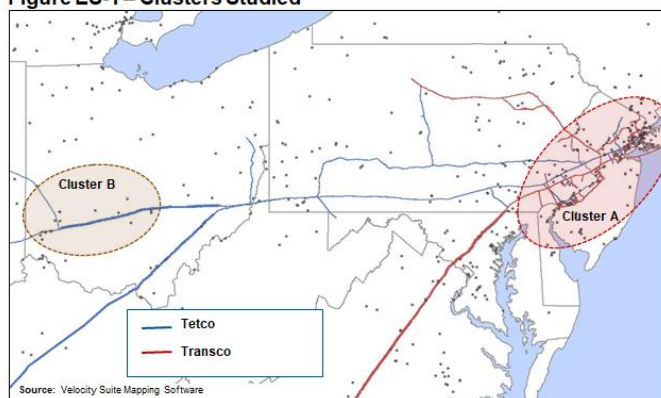
accommodate the loss of significant gas-fired generation in one region. The analysis will also assess how the early retirement of nuclear generation units could exacerbate such impacts. This assesses the grids ability to sustain deliveries and recover during a significant gas infrastructure event (i.e., resilience).

1.3 Initial Phase I Results

Clusters Studied

For the purposes of this study, ICF identified 'clusters' of gas-fired generation as a function of generation capacity and pipeline interconnectivity. As summarized in Figure ES-1, the Phase I scoping work focused on two cluster/pipeline combinations as follows:

Figure ES-1 – Clusters Studied



- **Cluster A** – This cluster is located in the New Jersey / Philadelphia region and focuses on plants supplied by Texas Eastern Transmission Company (“Tetco”) and Transcontinental Gas Pipe Line Company (“Transco”). The EIA form 860s identify just over 50 GWs of generation capacity in the associated cluster area. Of that capacity, 27 GWs of gas-fired generation, or over 50 percent of the region’s total capacity, is connected directly to or highly interconnected with Tetco or Transco. Roughly two-thirds of this gas-fired generation capacity reports dual-fuel capabilities. Of note, Cluster A includes several counties in New York. While these counties are outside the PJM region they are highly dependent on gas supply sourced through PJM to the New York City area. This highlights the interconnectedness of the gas infrastructure beyond the immediate RTO/ISO regions.
- **Cluster B** – This cluster is centered on the Dayton, Ohio / Lebanon Hub and focuses on plants supplied by Tetco along the path from Tetco’s Berne compressor station through the Lebanon Hub and west into Indiana. The EIA form 860s identify just over 5 GWs of generation capacity located in the associated area. Of that capacity, the Cluster B pipeline combination covers just under 2 GWs of gas-fired generation. Forty percent of this gas-fired capacity reports dual-fuel capabilities.

Potential Infrastructure Events

In assessing the potential exposure of an RTO/ISO system to a gas infrastructure event, it is important to emphasize that the natural gas industry has an excellent reputation for both reliability and safety. However, it is also important to note that infrastructure events of various degrees do in fact happen. Examples include:

- Known outages related to planned maintenance events and/or construction activity
- Unplanned outages of equipment, such as compressor failures
- Accidents and intrusions from third parties
- Acts of God and nature, such as well freeze-offs, landslides, or earthquakes
- Failed or corroded pipe

Disruptions can also occur as a result of intentional actions of third parties that are malicious in nature. This would include events such as a directed terrorist attacks on physical assets or a cyber-attack on supporting infrastructure.

While the scope of this study did not include a detailed review and categorization of historical disruption events, two real world examples provide some perspective on the degree and potential duration of a gas infrastructure event:

- **Tetco Delmont Line 27 Incident** – This relates to a pipeline rupture due to corrosion along two circumferential girth welds that occurred on Tetco’s Penn-Jersey system, which moves gas from Western Pennsylvania to New Jersey markets. The incident occurred on April 29, 2016 and was not fully resolved for over 6 months. Based on Tetco’s own reports, in excess of 1 Bcfd of deliverability was impacted and could have been unavailable the following winter if repairs were not completed and approved by October of 2016.⁵
- **ANR Southeast Mainline Capacity Reduction** – This relates to a disruption of ANR’s mainline system out of Southeast Louisiana up to markets in the Midwest caused by the infiltration of drilling muds and CO₂ from production activity adjacent to the pipeline. All natural gas transactions (flows) on ANR’s Southeast Mainline flowing north of the Jena Compressor Station were curtailed, or in excess of 1 Bcfd based on throughput levels.⁶ The incident occurred on June 18, 2013 and was not fully resolved until well into the following winter.⁷

The Phase I scoping analysis assumes a natural gas infrastructure event of sufficient size to exceed the average daily demand of gas-fired generation units in the affected area (roughly 1.6 Bcfd for Cluster A and 0.1 Bcfd for Cluster B) and of a duration of one season (e.g., winter or summer).

⁵ See:

<https://infopost.spectraenergy.com/GotoLINK/GetLINKdocument.asp?Pipe=10076&Environment=Production&DocumentType=Notice&FileName=Delmont+System+Operations+and+Pipeline+Development+Updates.pdf&DocumentId=8aa1649f5720493a01572daf026e021b>

⁶ Estimated from Point Logic data for the Jena Compressor station

⁷ See ANR Informational Postings: Critical, Force majeure, 20130618, ANR PIPELINE COMPANY, 006958581

Potential Impact of Gas Infrastructure Event

Table ES-3 summarizes gas-fired generation by backup fuel as identified for Cluster A for Transco connected plants. As a whole, the cluster has over 18.7 GW of gas-fired generation. Of these plants, 12 GW of capacity have dual-fuel capability, although only about 9.5 GW appear to hold significant quantities of backup fuel in inventory. 6.7 GWs of capacity are gas-only facilities.

Table ES-3: Cluster A / Transco Gas-Fired Generation by Back-up Fuel 1/

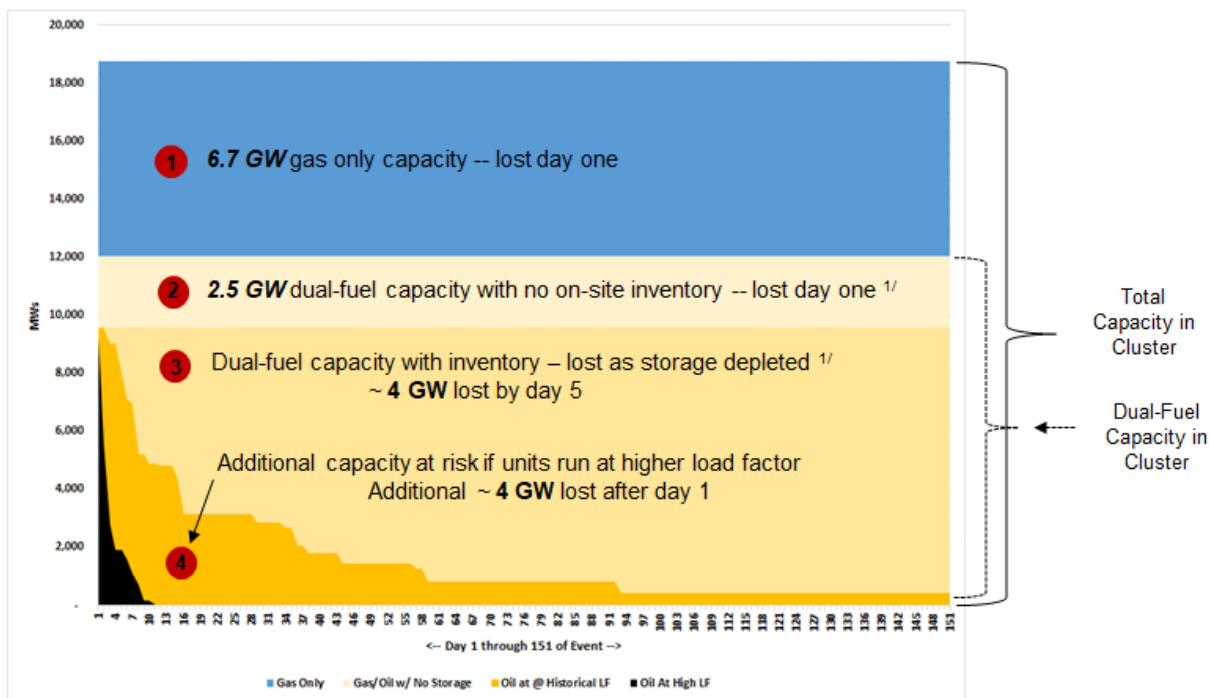
	Natural Gas	Natural Gas, Distillate Fuel Oil	Natural Gas, Residual Fuel Oil	Total
MW of Capacity 2/				
Low Heat Rate Units	5,323	3,314	-	8,637
Medium Heat Rate Units	1,189	3,095	2,796	7,080
High Heat Rate Units	206	2,079	746	3,032
Total	6,718	8,488	3,542	18,748
Avg. Daily Demand (MMBtu/day) 3/				
Low Heat Rate Units (<8000)	535,286	346,538	-	881,824
Medium Heat Rate Units (8-12,000)	52,116	124,795	137,403	314,314
High Heat Rate Units (>12000)	1,880	22,184	7,394	31,458
Total	589,282	493,516	144,797	1,227,596
Barrels Equivalent/day:		84,722	23,031	
Barrels of Storage 4/:		1,005,754	331,990	
~Days of Supply at Historical LF		11.87	14.41	

NOTE: 1/ Sources: EIA 860, EPA National Electric Energy Data System (NEEDS), and ICF IPM inputs
Includes plants reporting upstream pipeline as PSEG (50%) and Brooklyn Union. Excludes Iroquois and TGP
2/ Low Heat Rate < 8,000, Medium 8-12,000, High >12,000
3/ Estimated based on historical load factors for gas units by Heat Rate for region:
 <8,000 @ 60%, 8-12,000 @18%, >12,000 at 3%
4/ Based on maximum inventory level as reported to EIA 923 for 2016 by plant. Astoria reported at
4 MM Barrels, adjusted to 300,000 Barrels based on reported total tank capacity in:
www.dec.ny.gov/dardata/boss/afs/permits/263010018500009_r3.pdf

On average, the 18.7 GWs of capacity use an estimated 1.2 Bcf/d of gas (based on average heat rates and historical load factors). This equates to nearly 14 percent of the estimated combined delivery capacity of the Transco and Tetco systems into the region (~3.8 Bcf/d for Transco and 5 Bcf/d for Tetco).

Figure ES-2 provides a more complete picture of how a gas infrastructure event could impact Cluster A. Key points are as follows:

Figure ES-2: Cumulative “Lost” Generation Capacity – Transco



1/ On-site inventory based on maximum inventory in 2016 from EIA 923 by plant

- 1** On day one of an event, Cluster A / Transco would lose 6.7 GW of gas-only generation capacity. This capacity could be unavailable for the duration of such an event.
- 2** To the degree dual-fuel units do not have on-site inventories, these facilities would be unavailable until such time as oil supplies could be brought on-site. Based on reported inventories, this implies an additional 2.5 GWs would be unavailable on day one of an event. Taken together with the gas-only units this represents over 49 percent of the Cluster A Transco capacity. More importantly, this represents nearly fifteen percent of the total generation capacity identified within the Cluster A region (i.e., including other fuel sources and gas-fired generation capacity not connected to Transco or Tetco).
- 3** Dual-fuel units with on-site inventories could switch to backup fuels during an infrastructure event. These units could provide roughly 9.5 GWs of secure supply. However, based on historical maximum inventories for these facilities, by day 5 of an event 4 GWs of this capacity would exhaust on-site backup fuel resources. Less than 1 GW of the original 18.7 GWs would be expected to have sufficient on-site inventories to last through an entire season of a disruption. These values assume these units are run at historical average load factors for their respective heat rates.
- 4** If dual-fuel units are run at higher than historical average load factors, which we would expect during an event, they will exhaust on-site inventories much more quickly. At the 100 percent load factor operation, on-site inventories are essentially exhausted by day 5. While this

is on the high-end of expected utilization it is equally unrealistic to assume units will run at historical load factors.

Table ES-4 summarizes similar results for Cluster A / Tetco.

Table ES-4: Cluster A / Tetco Gas-Fired Generation by Back-up Fuel 1/

	Natural Gas	Natural Gas, Distillate Fuel Oil	Natural Gas, Residual Fuel Oil	Total
MWs of Capacity 2/				
Low Heat Rate Units	1,914	916	-	2,829
Medium Heat Rate Units	1,111	1,623	-	2,734
High Heat Rate Units	72	2,998	-	3,070
Total	3,097	5,537	-	8,634
Avg. Daily Demand (MMBtu/day) 3/				
Low Heat Rate Units (<8000)	200,024	91,984	-	292,009
Medium Heat Rate Units (8-12,000)	55,043	60,523	-	115,566
High Heat Rate Units (>12000)	1,043	28,401	-	29,444
Total	256,110	180,908	-	437,018
Barrels Equivalent/day:		31,057	-	
Barrels of Storage 4/:		890,564	-	
~Days of Supply at Historical LF		28.68	-	

NOTE: 1/ Sources: EIA 860, EPA National Electric Energy Data System (NEEDS), and ICF IPM inputs
Includes plants reporting upstream pipeline as PSEG (50%). Excludes Iroquois and TGP

2/ Low Heat Rate < 8,000, Medium 8-12,000, High >12,000

3/ Estimated based on historical load factors for gas units by Heat Rate for region:

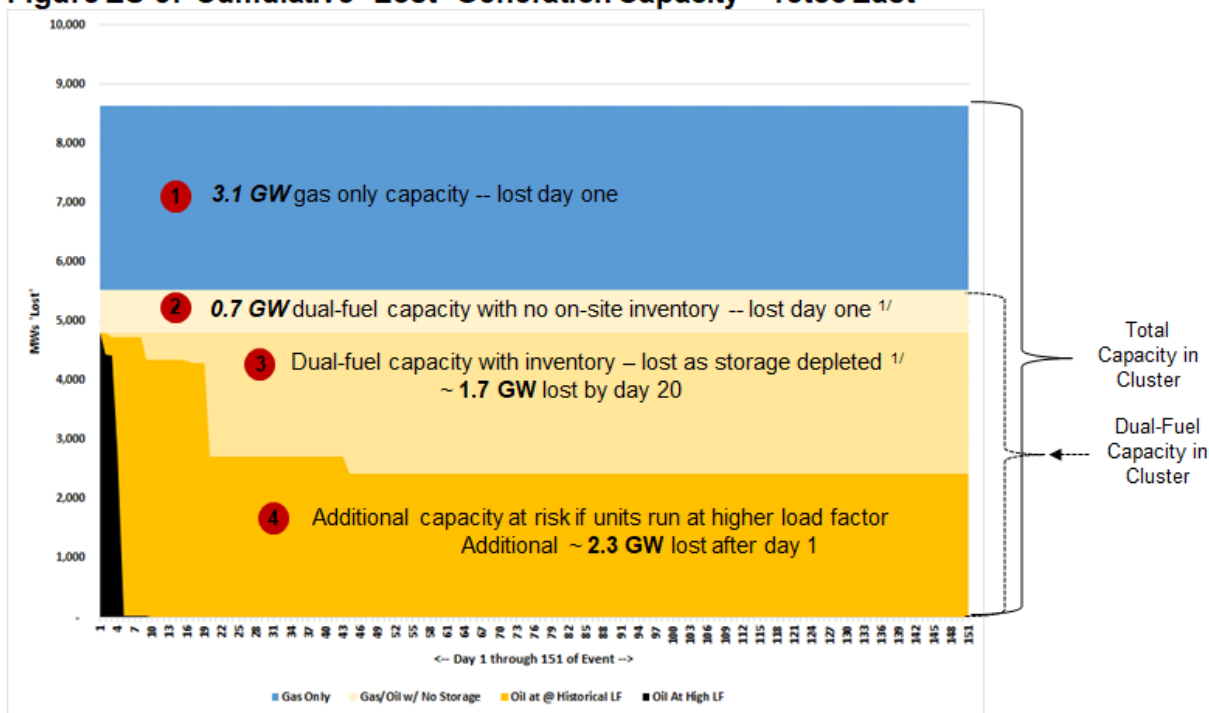
<8,000 @ 60%, 8-12,000 @18%, >12,000 at 3%

4/ Based on maximum inventory level as reported to EIA 923 for 2016 by plant. Astoria reported at 4 MM Barrels, adjusted to 300,000 Barrels based on reported total tank capacity in:
www.dec.ny.gov/dardata/boss/afs/permits/263010018500009_r3.pdf

Tetco has 8.6 GWs of directly or indirectly attached gas-fired generation in the cluster region. This consists of a combination of low heat rate, high load factor combined cycle units (~2.8 GW) and an additional 5.8 GW of higher heat rate units. Estimated daily gas requirements associated with these plants run roughly 0.4 Bcfd. Of the 8.6 GWs of gas-fired capacity, 2.0 GWs or 36 percent is gas-fired only. More significantly, of the 2.8 GW of low heat rate, high load factor units, 1.9 GWs or over 68% is gas only. Distillate units hold an average of 28 days of supply on site (no gas/resid units were identified for this pipeline/cluster).

Figure ES-3 provides a more complete picture of how a gas infrastructure event could impact Cluster A. Key points are as follows:

Figure ES-3: Cumulative “Lost” Generation Capacity – Tetco East



- 1** On day one of an event, the Cluster A / Tetco combination would lose 3.1 GW of gas-only generation capacity. This capacity could be unavailable for the duration of such an event.
- 2** To the degree dual-fuel units do not have on-site inventories, these facilities would be unavailable until such time as oil supplies could be brought on-site. Based on reported inventories, this implies an additional 0.7 GWs would be unavailable day one of an event.
- 3** Dual-fuel units with on-site inventories could switch to backup fuels during an infrastructure event. These units could provide roughly 5 GWs of secure supply. However, based on historical maximum inventories for these facilities, by day 10 of an event 1.7 GWs of this capacity would exhaust on-site backup fuel resources. This assumes these units are run at historical load factors for their respective heat rates.
- 4** If dual-fuel units are run at higher load factors they will exhaust on-site inventories much more quickly. At the 100 percent load factor rate, on-site inventories are essentially exhausted by day 5. Actual observed durations would fall somewhere between the shaded area boundary and the dotted lines.

Table ES-5 summarizes similar results for Cluster B. As a whole, the cluster has nearly 2 GW of gas-fired generation. On average, these units use less than 100,000 MMBtu/day. This reflects a much lower utilization rate than observed for Cluster A due to the greater percentage of higher heat rate plants in the cluster. On-site inventories would last an estimated 19 days at

historical heat rates. This duration falls significantly if units are run above historical heat rates given the higher average heat rates of the cluster facilities.

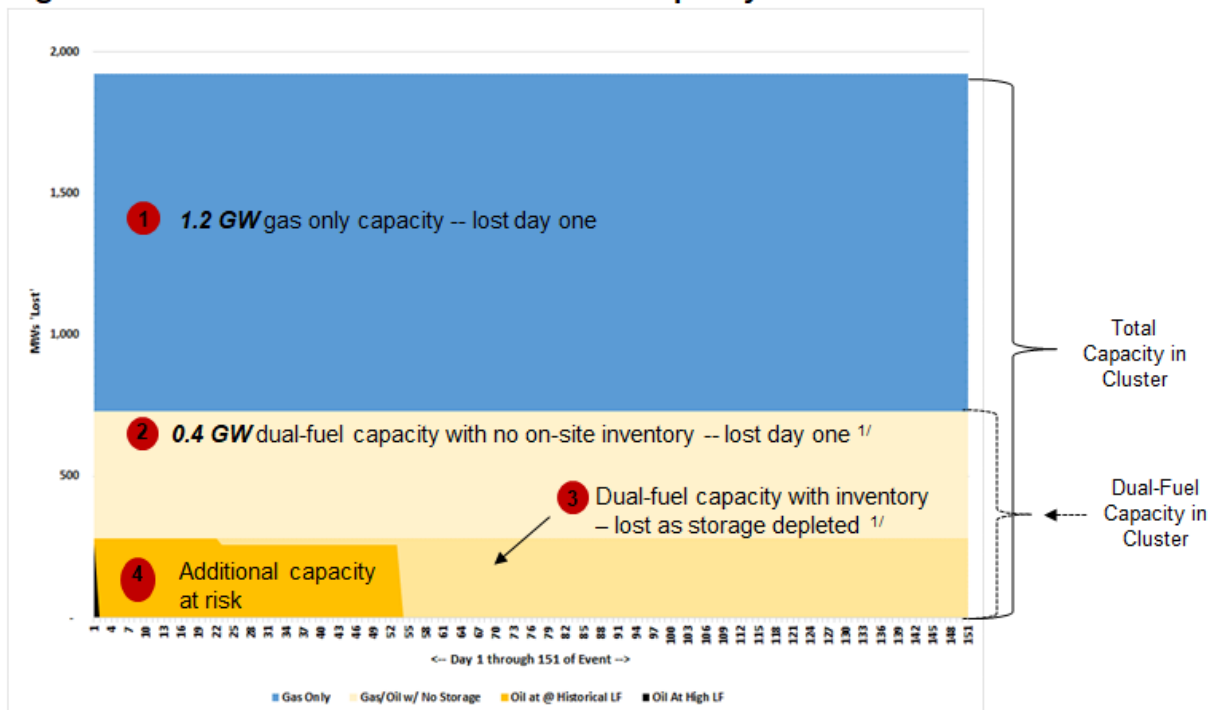
Table ES-5: Cluster B Gas-Fired Generation by Back-up Fuel 1/

	Natural Gas	Natural Gas, Distillate Fuel Oil	Natural Gas, Residual Fuel Oil	Total
MW of Capacity 2/				
Low Heat Rate Units	518	-	-	518
Medium Heat Rate Units	176	-	-	176
<u>High Heat Rate Units</u>	<u>503</u>	<u>728</u>	<u>-</u>	<u>1,231</u>
Total	1,197	728	-	1,925
Avg. Daily Demand (MMBtu/day) 3/				
Low Heat Rate Units (<8000)	57,809	-	-	57,809
Medium Heat Rate Units (8-12,000)	8,697	-	-	8,697
<u>High Heat Rate Units (>12000)</u>	<u>8,757</u>	<u>8,077</u>	<u>-</u>	<u>16,834</u>
Total	75,262	8,077	-	83,340
Barrels Equivalent/day:		1,387	-	
<u>Barrels of Storage 4/:</u>		<u>26,943</u>	<u>-</u>	
~Days of Supply at Historical LF		19.43		

- NOTE: 1/ Sources: EIA 860, EPA National Electric Energy Data System (NEEDS), and ICF IPM inputs
Includes plants reporting ANR in region (Lebanon lateral), Vectren OH. Excludes Columbia plants.
- 2/ Low Heat Rate < 8,000, Medium 8-12,000, High >12,000
- 3/ Estimated based on historical load factors for gas units by Heat Rate for region:
<8,000 @ 60%, 8-12,000 @18%, >12,000 at 3%
- 4/ Based on maximum inventory level as reported to EIA 923 for 2016 by plant.

Figure ES-4 provides a more complete picture of how a gas infrastructure event could impact Cluster B.

Figure ES-4: Cumulative “Lost” Generation Capacity – TetcoWest



^{1/} On-site inventory based on maximum inventory in 2016 from EIA 923 by plant

- 1** On day one of an event, Cluster B would lose 1.2 GW of gas-only generation capacity. This represents over 50 percent of total Cluster A gas-fired capacity.
- 2** An additional 0.4 GWs would be unavailable day one of an event based on historical inventory levels by plant.
- 3** Dual-fuel units with on-site inventories could provide roughly 250 MW of capacity for an estimated 50 days.
- 4** If dual-fuel units are run at higher load factors they will exhaust on-site inventories in less than 5 days.

While the Cluster B capacity is smaller than Cluster A, the cluster exhibits a similar relative exposure to gas only generation and availability of backup oil supplies. This, in combination with regional power infrastructure, could still imply exposure of the area to a gas infrastructure event (to be evaluated in Phase II). Moreover, these values reflect current asset mixes. Continued growth of gas-fired generation could lead to greater concentrations of such assets in the future.

1.4 Refill Logistics

On-site oil storage can be replenished. However, doing so during an infrastructure event presents significant challenges. Upstream oil distribution resources will generally be sized to manage expected calls on resources. During a significant and extended gas infrastructure event, oil refill requirements associated with dual-fuel units can be sizeable (~115,000 barrels per day of distillate for Cluster A per Table ES-3).

It is unclear whether upstream oil distribution resources have the necessary capacity to sustain the refill requirements associated with dual-fuel units during a significant infrastructure event, particularly if such an event is widespread and of significant duration. For example, EIA reports that New Jersey consumes just over 30 MM barrels of distillate fuel oil per year, or roughly 80,000 barrels per day.⁸ While the Cluster A plants include a number of New York City facilities, the combined daily demand for distillate for this cluster assuming normal load factors exceeds the daily average demand of New Jersey's entire distillate market by nearly 35,000 barrels per day. Moreover, the logistics of such refill activity (e.g., number of tanker trucks required per hour, availability of barges, etc...) would be challenging and warrants further evaluation.

⁸ See EIA: State Energy Data 2016, Table F7: Distillate Fuel Oil Consumption Estimates, 2016 (New Jersey).

2 Study Focus and Methodology

2.1 Background

On January 8, 2018 the Federal Energy Regulatory Commission's ("FERC") initiated a proceeding on Grid Resilience in Regional Transmission Organizations and Independent System Operators (Docket No. AD18-7-000). As significant participants in Regional Transmission Organizations and Independent System Operators (jointly "RTO/ISO"), the Nuclear Energy Institute ("NEI") and its members sought to provide the FERC with useful insights on resilience for potential incorporation into policy decisions and/or subsequent policy initiatives. Given their focus on nuclear generation, the NEI specifically looked to provide insights on the relative benefits of nuclear generation resources on RTO/ISO resilience.

One benefit of a nuclear generation facility relative to many other types of resources is the on-site nature of its fuel source. While nuclear generation facilities are subject to the same downstream transmission risks as other generation resources, including transmission contingencies incorporated into RTO/ISO planning and reliability assessments, their use of on-site fuel sources eliminates a risk to production that many other resources cannot claim. This means nuclear facilities may provide a degree of resilience to the power grid, particularly during significant events affecting upstream deliveries of fuel supplies to other resources (e.g., weather events, supply infrastructure disruptions, etc...).

Risks of fuel delivery vary by resource and, in some instances, can be mitigated through the use of backup fuel supplies. One such resource includes gas-fired generation. Gas-fired generators represent a significant and growing segment of the generation stack in the United States. With limited exceptions, these resources are subject to the availability of gas supply via the interstate pipeline network (as well as downstream risks on local distribution company ("LDC") distribution systems).

On-site storage of backup fuels, such as distillate fuel oil or kerosene ("DFO") and residual fuel oil ("RFO"), can provide additional security of supply for many of these gas-fired resources. However, the value of such backup supplies is limited by their ability to be used by the generation resource and their ready availability to the resource during a disruption of its primary resource. This necessitates that the facility be designed to utilize such backup fuel and, in general, that such fuel resources be located on-site where they are readily available during a curtailment of the primary resource. This also requires that sufficient backup resources be available to sustain the generation facility over the potential duration of the curtailment event in question and that infrastructure be in place to accommodate the replacement of such resources as needed during such event.

2.2 Study Question

In light of FERC's request for comments, NEI requested that ICF provide an assessment of the resilience of RTO/ISO systems in the event of a significant gas infrastructure interruption or curtailment. The focus of the study was assessing the exposure of the RTO/ISO system to gas infrastructure events and the ability of such system to maintain deliveries and recover from significant gas infrastructure events.

For this study the decision was made to focus on PJM. However, similar analyses should be considered and pursued for other RTO/ISOs throughout the US power system. The specific questions asked were:

- What is the potential exposure of the PJM grid to a gas infrastructure event based on its anticipated reliance on gas-fired generation in the future?
- How would the early retirement of existing nuclear generation resources affect the resilience of the PJM grid during such an event?

2.3 Methodology

The analysis leverages ICF's proprietary models characterizing the power and gas system throughout the lower-48 United States and Canada (see Appendix A for background). These were supplemented with publicly available data on gas flows, installed generation capacities, locations of gas-fired units, reported and estimated interconnectivity of such units with the upstream gas supply infrastructure, reported back-up fuel capabilities, and historical, observed inventory levels of backup fuel by facility.⁹ The analysis was divided into two phases (this report provides an interim summary of the Phase I work).

PHASE I

Phase I was designed to establish the framework needed to assess the potential impact of a major gas infrastructure event on an RTO/ISO's system. This involved characterizing the gas-fired generation resources within the region, the gas supply network supplying that region, developing potential gas infrastructure contingencies for that region, and assessing the potential impact of such events on the availability of the regional gas-fired generation resources.

The Phase I work involved several tasks:

- Develop an inventory of gas-fired generation facilities, including their associated capacities, heat rates, backup fuel capabilities, on-site backup storage resources, and interconnectivity to the upstream interstate pipeline network.
- Characterize the natural gas infrastructure supplying the gas-fired generation resources in this region, including identifying the primary sources of supply, interconnectivity between such resources, intra-regional supply and storage resources, and seasonal gas flows.¹⁰
- Define gas infrastructure events that could occur and evaluate the potential impact of such events on the gas-fired generation resources in the region.

⁹ Key sources were derived from EIA reports and forms, as well as EPA's NEEDS data base.

¹⁰ ICF notes that the analysis developed for this study does not represent an integrated model of pipeline system flow constraints. Rather, it represents a reasonable characterization of inter and intra-regional pipeline flows and interrelationships for assessing relative exposures to gas infrastructure events. As follow up, more granular analysis of flow and interconnectivity, such as with ICF's RYMS model, would provide more detailed information on flow dynamics and impacts from events.

The data base of gas-fired generation plants used for this study was developed using publicly available data compiled from the EIA 860 and 923 reports, as well as additional public resources and proprietary ICF data bases. These reports provide summary information on existing generation resources throughout the US, including:

- **Pipeline Interconnectivity** - Respondents to the EIA 860 are requested to provide details regarding upstream pipeline interconnections associated with each facility. ICF's review of this information found that reported details are generally accurate, but many respondents provide less than complete information. As such, ICF leveraged locational information on units relative to the interstate pipeline grid to allocate plant capacity where such information was not provided in the 860.¹¹ Facilities identifying their upstream supply source as a local distribution company were allocated to upstream pipelines based on the relative reliance/interconnectivity of the applicable LDC to the upstream pipeline network.¹²
- **Alternate / Backup Fuel Capabilities** – The EIA 860 also requests information on dual-fuel/backup fuel capability, including fuel type and time to switch between resources. Again, ICF's review of this information found reported details generally accurate but responses less than complete. The EIA 860 information was supplemented from information from other resources, including EPA's National Electric Energy Data System ("NEEDS") data base.¹³
- **Fuel Oil Storage Capabilities** – The EIA 923 provides data on monthly oil receipts, oil consumption and stocks but does not provide details on storage capacities. For the purposes of this study, ICF used the maximum observed inventory level at each facility over the year 2016 as an indication of on-site storage capability. While physical capacities may be higher than this observed inventory level, the observed level reflects actual utilization and planning activity by individual generators. As such it is arguably more indicative of the amount of storage capacity likely to be on hand during a gas infrastructure event.¹⁴
- **Emission Limits** – In addition to the availability of supply on-site, use of secondary fuel sources can also be limited by emission restrictions. ICF compiled such

¹¹ Given limitations on the EIA 860 and 923 data, ICF recommends that each RTO/ISO develop and maintain a specific data base of such information for facilities within their region.

¹² ICF notes that during the occurrence of a pipeline infrastructure event, gas generation facilities located on an LDC would likely experience resource constraints / limitations even if such LDC is connected to additional upstream pipelines not experiencing a curtailment. This is because the LDC would be expected to first allocate any available resources to higher priority core residential and commercial customers.

¹³ More importantly, neither the EIA nor EPA data base provides an assessment of the voracity of the dual-fuel capability, including whether such capability has been recently tested and or verified. ICF notes that use of secondary, backup fuels can raise operational and maintenance concerns at a facility (including having implications for the facility's LTSA agreement and, possibly, associated warranties). This study does not take a position on the voracity of such reported capabilities and assumes if the facility states it has a secondary backup fuel it is able to utilize such fuel without limitation.

¹⁴ No adjustment to observed inventory levels was made to account for the amount of inventory on-hand that would be deemed 'unusable.' ICF notes that over long periods sediments in stored oil accumulate at the bottom of storage tanks, leaving a portion of such inventory generally unacceptable for use, particularly in newer, more advanced/clean-burning generation technologies.

information from EPA's NEEDs data base, as well as state-specific limitations on NOx, as applicable.¹⁵

The characterization of the key natural gas infrastructure supplying PJM was developed leveraging data used to maintain ICF's proprietary Gas Market Model ("GMM"), which provides a detailed, nodal summary of gas demand, supply, and flow dynamics throughout North America. As discussed in further detail below, the work focused on gas infrastructure supporting two specific 'cluster' subregions within PJM (i.e., NJ/Philadelphia and Dayton, Ohio/Lebanon Hub). Inter and intra-regional capabilities were characterized primarily from observed historical flow data for the applicable pipelines derived from information reported on their applicable bulletin boards and compiled from flow data as reported by PointLogic. Observed, operational flow data was deemed more useful than design capacity information as it reflects the actual, realized capabilities of the regional infrastructure. Again, subsequent analysis may warrant more detailed, even hydrological assessments of inter and intra-regional flow capabilities.

The output of Phase I, discussed in this interim report, represents a scoping assessment of the potential impact of a gas infrastructure event on gas-fired generation resources within the study region. The results identify the magnitude of potential impacts a gas infrastructure event could have on the generation resources available to the study region, the ability of such resources to utilize backup supply during such event, and their ability to maintain such backup supply over the duration of an extended infrastructure event.

PHASE II

The gas infrastructure assessments developed in the Phase I work are scoping in nature. While the analysis identifies orders of magnitude of potential impacts, it does not account for the ability of the RTO/ISO grid and generation stack to accommodate such an event through reliance on other, unaffected resources, or through re-dispatch of the intra and inter-regional transmission system. Phase II of the analysis is designed to provide a broader assessment of impacts by accounting for how the regional RTO/ISO system would adjust to the loss of specific gas-fired generation resources. The impact of nuclear generation units on grid resilience is further assessed through separate scenarios regarding the level of nuclear retirements under the gas infrastructure event.

The Phase II work involves several tasks:

- Establishing a Base Case and Alternative Case for PJM's future generation stack:
 - The Base Case reflects a business-as-usual scenario based on market expectations for loads, gas prices, and other market drivers. This provides a projection of the change in generation mix over the period 2020 through 2040 under expectations of key market drivers, as well as likely regulations, and will include expected nuclear retirements as provided by NEI

¹⁵ ICF notes that during a gas infrastructure event various emission limitations may be waived under emergency provisions (under both existing emergency procedures and event specific scenarios).

- The Alternative Case assumes economic circumstances justify the early retirement of a broader range of nuclear facilities than assumed in the Base Case. ICF's IPM model is utilized to assess the technologies/fuel sources that would likely be installed to replace this additional lost nuclear generation capacity. This then defines the overall generation stack available under this alternative scenario.
- Identifying new gas-fired generation facilities anticipated over the forecast horizon under each scenario and estimating their likely location based on results from the IPM analysis. Additions to the gas supply infrastructure will also be considered, however these expansions will also come with additional associated load obligations and do not necessarily relieve or eliminate regional exposures to a gas infrastructure event.¹⁶
- Testing the resilience of the PJM system in response to the gas infrastructure event using ICF's load flow model. Impacts will be assessed under the two scenarios for the future generation stack. Specifically, based on contingencies developed in the Phase I work, ICF will determine which gas-fired generators would not be able to generate during the specified event (and/or what limitations on their generation capabilities would exist based on their reliance on backup fuel during such event). The load flow analysis will then determine whether or not load can be met given the resource mix and operational limitations specified.

The output of the Phase II work will be an assessment of the resilience of the PJM system under the gas infrastructure event based on the scenarios for future generation mixes. In cases where the load flow analysis solves, or completes, the system will be deemed "resilient" for that particular scenario. More detailed flow evaluation accounts for how the combination of interregional transmission capabilities and future generation stacks might accommodate impacts from the loss of gas-fired generation due to a gas infrastructure event, including reliance on higher heat rate gas/oil units for more generation than under normal operating conditions

In cases where the analysis does not solve, ICF will reduce demand in the relevant areas in the load flow analysis until the system solves. The amount of reduced load, given the existing transmission system and forecasted generation stack, will be the amount of load not served in MWh, which will serve as the metric for the level of resilience in the system.

¹⁶ Significant interstate pipeline expansions are not built on a speculative basis. For both financial reasons and regulatory reasons these projects must be substantiated by showing evidence of need (generally in the form of commitments from downstream end-users). Recent expansions have realized very high load factors. This implies that while additional expansions may increase the size of the interstate gas system, they do not create 'excess' or latent capacity that would be available during a significant gas infrastructure event.

3 Background

3.1 Placing the Growth in Gas-Fired Generation in Context

The US' reliance on natural gas for power generation has grown significantly. As summarized in Table-1, annual consumption of gas by the US power sector has grown a total of 32 percent over the last five years, with multiple regions experiencing more than 45 percent growth.

Table ES-1: Annual Gas Consumption for Power Generation by Census Region (Bcf/year)

	2011	2012	2013	2014	2015	2016	Increase Since
<i>New England</i>	438	433	358	335	387	386	-12%
<i>Mid-Atlantic</i>	940	1,119	1,035	1,091	1,193	1,306	39%
<i>East North Central</i>	386	644	466	472	687	881	128%
<i>West North Central</i>	112	167	134	104	139	181	61%
<i>South Atlantic</i>	1,636	2,008	1,849	1,852	2,259	2,393	46%
<i>East South Central</i>	629	787	619	654	850	937	49%
<i>West South Central</i>	2,119	2,287	2,031	1,969	2,330	2,280	8%
<i>Mountain</i>	556	645	648	630	721	735	32%
<i>Pacific (contiguous)</i>	716	980	1,015	1,006	1,016	864	21%
Total Lower-48 US	7,532	9,071	8,157	8,114	9,583	9,961	32%

Source: EIA "Natural Gas Delivered to Electric Power Consumers"

http://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_veu_mmc_f_a.htm

This trend reflects both growth in natural gas power generation capacity and greater utilization of existing gas-fired generation units. As summarized in Table 2, installed gas-fired generating capacity in the US has grown from a total of 414 GW in 2011 to 446 GW in 2016. Across the US, installed gas-fired generation capacity has increased on average of 7.5 percent, with all regions but the West South Central and Pacific regions seeing increases. Several regions, including the Mid-Atlantic and South Atlantic regions have experience particularly significant increases over this period.

Table 2 -- Installed Gas-Fired Generation Capacity by Census Region

	2011		2016		Change 2011 to 2016		
	MWs	% of Total Regional Capacity	MWs	% of Total Regional Capacity	MWs	Increase %	Increase % in Gas as % Total
<i>New England</i>	13,483	39.3%	14,143	41.5%	660	4.9%	2.2%
<i>Mid-Atlantic</i>	38,957	37.5%	48,085	46.6%	9,128	23.4%	9.1%
<i>South Atlantic</i>	74,503	35.8%	90,340	43.4%	15,837	21.3%	7.6%
<i>East North Central</i>	44,579	29.2%	47,329	32.7%	2,750	6.2%	3.5%
<i>West North Central</i>	19,771	23.7%	21,481	23.6%	1,711	8.7%	-0.1%
<i>East South Central</i>	33,143	36.7%	37,439	43.3%	4,297	13.0%	6.6%
<i>West South Central</i>	109,077	63.0%	103,998	56.6%	(5,078)	-4.7%	-6.4%
<i>Mountain</i>	32,699	37.4%	34,695	37.0%	1,996	6.1%	-0.4%
<i>Pacific (Contiguous)</i>	48,144	42.5%	48,026	38.8%	(118)	-0.2%	-3.7%
Total Lower-48 US	414,354	39.6%	445,536	41.7%	31,182	7.5%	2.1%

Source: EIA Electric Power Monthly

More importantly, Table 2 illustrates how gas-fired generation as a percent of total installed generation capacity within a region has increased dramatically in several regions. The Mid-Atlantic, South Atlantic, and East South Central regions have all experience more than a 6 percent increase in their relative reliance on gas-fired generation over this period.

Table 3 illustrates this in more detail for PJM. As the table summarizes, PJM added nearly 14 GWs of gas fired generation capacity in the last five years. This has increased natural gas' share of total installed generation capacity in the region from 28 percent to more than 35 percent.

Table 3: Installed Generating Capacity by Fuel Source -- PJM

(June values)

	2011		2016		Change	
	MW	% Total	MW	% Total	MW	% Total
Natural Gas	50,729	28.0%	64,728	35.6%	13,999	7.6%
Nuclear	33,146	18.3%	33,051	18.2%	(95)	-0.1%
Coal	76,968	42.4%	66,620	36.6%	(10,348)	-5.8%
Hydroelectric	8,030	4.4%	8,850	4.9%	821	0.4%
Petroleum	11,212	6.2%	6,780	3.7%	(4,433)	-2.5%
Solar Thermal and Photovoltaic	15	0.0%	252	0.1%	237	0.1%
Wind	634	0.3%	1,019	0.6%	386	0.2%
Solid Waste	705	0.4%	767.50	0.4%	62	0.0%
Total	181,439		182,067		629	

Source: PJM Monitoring Analytics State of the Market reports.

This increased focus on gas-fired generation reflects the impact of several trends:

- The relative economic advantage of gas-fired generation given low gas prices throughout the US as a result of major advances in shale gas production
- The capital cost advantage of gas-fired generation relative to alternatives

- Substantial retirements of coal-fired generation throughout the US as a result of uncompetitive economic and environmental pressures

More importantly, as summarized in Table 4, general expectations call for continued reliance, and even increased reliance, on natural gas as a primary fuel source for generation throughout the US. Announced plans for new gas-fired generation call for an additional 70.8 GWs to be installed by 2025. Not all of this capacity will ultimately be completed, and some will displace older, less efficient gas-fired generation units. However, units currently approved and under construction would add 25 GWs by 2020.

Table 4: Forecasted Additions of Gas-Fired Generation By Status (MW)

	Regulatory approvals pending. Not under construction	Planned for installation, but regulatory approvals not initiated	Regulatory approvals received. Not under construction	Construction complete, but not yet in commercial operation	Under construction, less than or equal to 50 percent complete	Under construction, more than 50 percent complete	Grand Total
2018	721	1,639		2,734	5,111	11,943	22,149
2019	15,702	1,759	2,608		1,881	583	22,533
2020	3,881	2,906	4,538		2,994		14,319
2021	1,724	5,033	2,847				9,604
2022	794	196	227				1,217
2025	858						858
Total	23,680	11,532	10,221	2,734	9,986	12,526	70,759

Source: EIA Inventory of Planned Generators as of December 2017 (www.eia.gov/electricity/data/eia860m/xls/december_generator2017.xlsx)

While ranges for projected growth in gas-fired generation vary, few forecasts in the industry call for sizeable declines in the use of this fuel source in the foreseeable future. As such, it is clear it will continue to play an important role in providing power for US markets. This makes assessing the infrastructure supporting the resource, and evaluating the grids exposure to critical impacts on that infrastructure an important factor when evaluating the resilience of RTO/ISO systems.

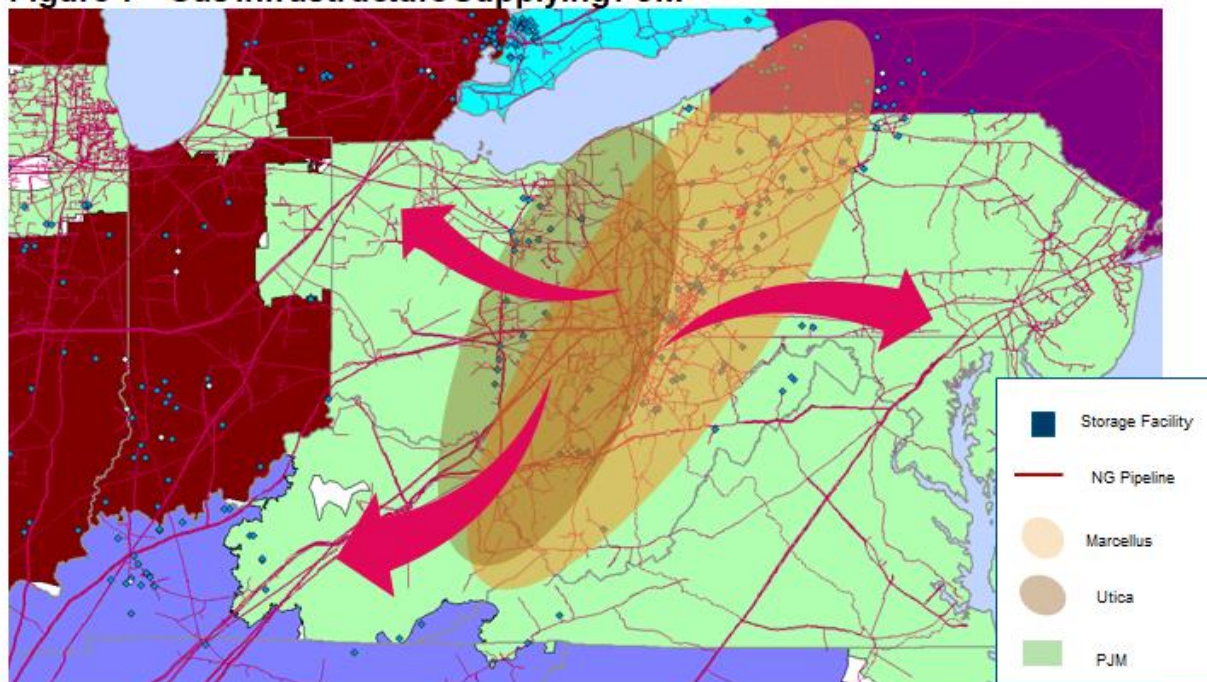
3.2 Gas Infrastructure Supplying PJM

As a first step to understanding the interdependence of the PJM Power Grid with the regional gas infrastructure, Figure 1 summarizes the key gas infrastructure supplying the PJM region. The red lines represent the major interstate pipelines within the region. Key pipelines in the region include:

- **“Trunkline” Pipelines** – Trunkline pipelines are long pipelines that historically moved gas supply from the Gulf and Midcontinent regions to Northeast markets. Key trunkline pipelines supplying this region include Transcontinental Gas Pipeline (“Transco”), Texas Eastern (“Tetco”), and Tennessee Gas Pipeline (“TGP”)
- **“Spider Web” Pipelines** – Spider web pipelines are complex, multi-lined pipelines that partially act as regional gathering systems to aggregate historical production in the Appalachian region, but also act as major suppliers of gas to key markets within the region. Key spider web pipelines in the region include Columbia Gas Pipeline (“Columbia”), Dominion Gas Pipeline (“Dominion”), National Fuel Gas Supply Corporation (“National Fuel”), and Equitrans
- **Regional Pipelines** – These include various pipelines within the region that connect a specific production area or hub to a market or other downstream pipeline.

Examples include Millennium Pipeline and Crossroads Pipeline, but also include newer projects such as Rockies Express Pipeline (“REX”) and Rover that primarily export gas from the region to other areas.

Figure 1 – Gas Infrastructure Supplying PJM



Source: Velocity Suite Mapping Software

As noted by the red arrows in the figure, gas produced in the Marcellus/Utica region is moved east to key markets in the Mid-Atlantic (e.g., NJ, Philadelphia) and also to downstream markets in New York and New England (and more recently also then moves south to markets along the East Coast that were historically ‘upstream’ of the Mid-Atlantic market area). Additionally, supply is moved out of the Marcellus/Utica regions to the Gulf Coast via reversals of the various pipelines that historically moved supply north to storage in the region and then downstream to eastern markets. And more recently, expansion projects such as those on Rockies Express, Rover, and the soon to be certified NEXUS project, move additional supplies west to Midwestern and Eastern Canadian markets.

Regional storage capacity (noted by the square blocks on the figure) consists primarily of depleted gas and oil reservoirs that have been converted to underground gas storage facilities. Not surprisingly, these are concentrated in the same areas as the production. As such the gas infrastructure serving key market centers in PJM, such as New Jersey and Philadelphia, consist primarily of pipeline capacity where supply is sourced upstream of the market. Limited storage resources exist within these major market centers. The exception would be various LNG peakshaving facilities held by local distribution companies to meet core customer requirements during extreme weather events.

The infrastructure is heavily interconnected and interdependent. However, the flexibility to move from one pipeline to another is generally limited by a few key interconnects (discussed in more detail below). This is particularly true outside the more integrated production area.

A key take-away from this figure is that the core PJM markets in the New Jersey and Pennsylvania region are all downstream of regional supply and storage resources. While not as dramatically at the ‘end of the pipe’ as New England, this section of PJM still has limited options to replace lost infrastructure via rerouting or resourcing supply. In contrast, the western side of PJM, and certainly the areas deep within the Marcellus/Utica production region, are more interconnected and have the potential for sourcing supply from multiple directions.

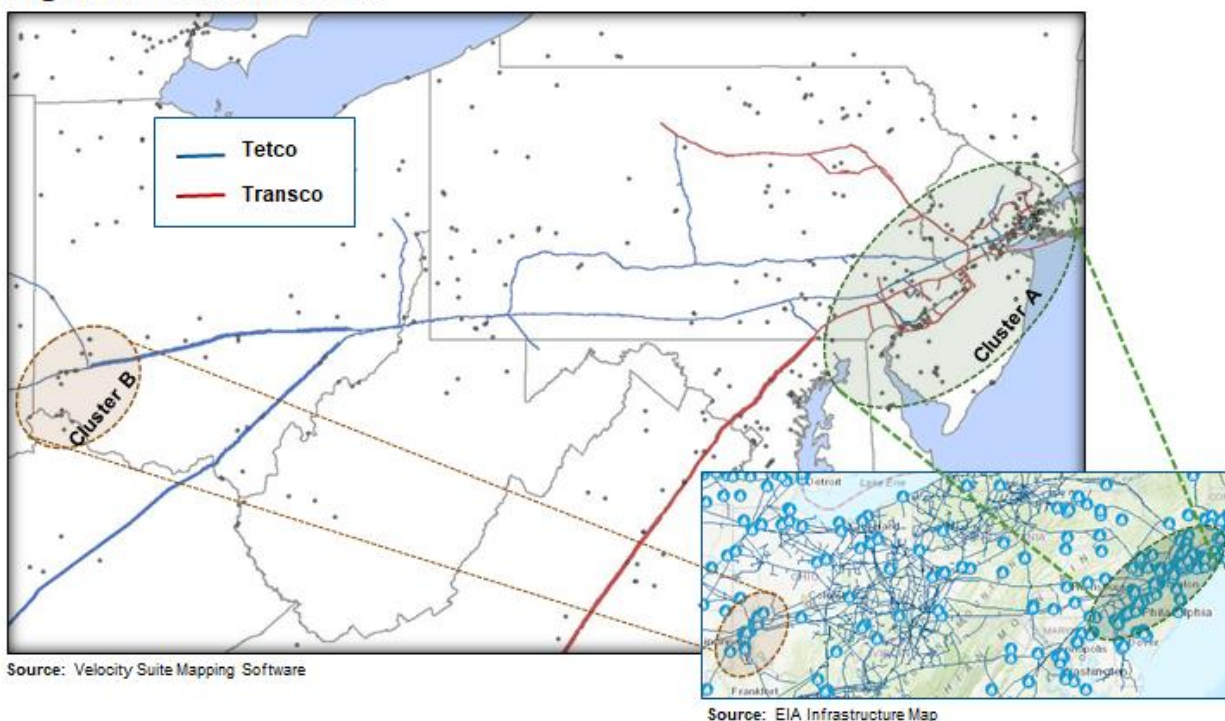
3.3 Identification of Study Clusters

Figure 2 summarizes the generation / pipeline clusters focused on in this study. The bottom section of the figure shows a segment of EIA’s infrastructure map covering the PJM region where all gas-fired generation facilities and interstate pipelines have been identified. The larger section of the figure expands the region and highlights the Tetco and Transco pipelines.

- **Cluster A** – This cluster is located in the New Jersey / Philadelphia region
- **Cluster B** – This cluster is centered around the Dayton, Ohio / Lebanon Hub region

While additional pipelines provide some supply into the relevant cluster regions, and have direct connects to some gas-fired generation in each region, Transco and Tetco are by far the largest suppliers to each cluster.¹⁷ As such, subsequent sections of the analysis focus on these two pipelines.

Figure 2 – Cluster Focus



Cluster “A” Description

¹⁷ Other key pipelines supplying the two study clusters include: Tennessee, Columbia, Iroquois Gas Transmission, Dominion, Rockies Express, Texas Gas Transmission

Cluster A is defined as follows:

- All of New Jersey
- Delaware – While large sections of Delaware are supplied by the Eastern Shore Natural Gas pipeline, this system is itself significantly sourced from Tetco and Transco (Columbia is also a supplier to this pipeline)
- Pennsylvania counties around Philadelphia along Transco and Tetco’s rights-of-way (Bucks, Delaware, Montgomery, York, Northampton, and Philadelphia)
- New York counties where generators identified either Transco or Tetco as their supplier or the LDC is highly dependent on one or both pipes for supply (Bronx, Kings, Nassau, New York, Queens, Richmond, Rockland, and Suffolk). New York LDC markets would also be supplied by Tennessee, Iroquois Gas Transmission, and Algonquin

While the New York counties are outside the PJM region they are highly dependent on gas supply sourced through New Jersey. A gas infrastructure event affecting plants in the PJM region would also impact downstream units in New York and have associated implications for the NY-ISO (and arguably NE-ISO and even SERC). This highlights the interconnectedness of the gas infrastructure beyond the immediate RTO/ISO. Consideration of this interrelationship is no different than incorporating the potential for increased imports from a neighboring RTO/ISO during a contingency event as part of system planning.

The EIA form 860s identify just over 50 GWs of installed capacity within the cluster region. Of this, an estimated 27 GWs is connected directly (or via downstream LDCs) to Transco and Tetco. Roughly two-thirds of this gas-fired capacity reports dual-fuel capabilities.

Cluster “B” Description

Cluster B is defined by the path from Tetco’s Berne compressor station in Fairfield County, Ohio through to the Lebanon Hub in Warren County, Ohio. From here Tetco splits with one section continuing west into Indiana and another moving North West to Indiana where it interconnects with ANR and Panhandle. This northerly section of the pipeline is jointly owned with ANR pipeline. Counties along the combined path include Butler, Clermont, Clinton, Darke, Fairfield, Fayette, Franklin, Green, Hamilton, Highland, Licking, Madison, Mercer, Montgomery, Pickaway, Preble, Ross, and Warren. The EIA form 860s identify just over 5 GWs of capacity within this region. Of this capacity just under 2 GWs represents gas-fired capacity connected to Tetco with forty percent of that reporting dual-fuel capabilities.

3.4 Potential Infrastructure Events

In assessing the potential exposure of an RTO/ISO system to a gas infrastructure event it is important to characterize the nature of the event being evaluated, and to place such an event in context with realized or experienced events in the industry. In doing so, it is important to emphasize that the natural gas industry has an excellent reputation for both reliability and safety. Pipelines are subject to rigorous maintenance and oversight programs and are monitored on a 24x7 basis. Automatic control valves and other safety measures are in place throughout the system to cut off gas supply in the event of a serious pipeline disruption. Lines

are regularly pigged and evaluated for defects and corrosion and regular maintenance programs are broadly in place to replace older, at risk sections of the infrastructure. Moreover, pipelines have established relationships with up and downstream pipeline systems to address emergency events, including improved lines of communication with the power sector developed as part of FERC's gas/power coordination efforts.

These facts established, it is also important to note that disruption events are not unknown. Infrastructure events affecting gas supply and operational capacity of various degrees do in fact happen on a regular basis. Examples include:

- Known outages related to planned maintenance events and/or construction activity. While some of these can last for weeks or longer, they represent planned events and are coordinated with customers to prevent the broader disruptions that are the focus of this study
- Unplanned outages of equipment, such as compressor failures or related events. These can last for short periods of time while maintenance is performed or for longer periods if the cause necessitates the ordering and installation of new equipment. Loss of a compressor does not necessarily affect the broader integrity of the pipeline system but will reduce total throughput through a section of pipe and can also affect downstream pressure levels. Throughput reductions are generally managed through allocation rules in the associated pipeline's tariff (e.g., restricting secondary out of path nominations first, then secondary in path, then, if required, primary path flows). And the degree of impact will depend on the importance of the particular compressor to system flows. Importantly, while downstream gas may still flow, reduced pressure levels may still affect downstream generators who often require that gas is delivered at levels above 600-700 psi.¹⁸
- Well freeze offs, which affect the general availability of gas supply resources into the pipeline. Again, these generally do not completely eliminate supply available along a given path but do result in reduce flow capabilities.
- Disruptions due to accidents / intrusions from third parties. This would include things like an inadvertent severing of a line of pipe by a third party contractor as part of some other construction activity, including accidental incidents as part of construction expansion activities. Risks of such events are reduced by the clear marking of pipeline rights of ways.
- Disruptions due to acts of God / nature. This would include disruptions resulting from severe weather events, such as flooding or earthquakes, which can sever lines of pipe as a result of extreme erosion events during flooding or have related impacts (e.g., flood compressor stations). For example, flooding associated with Hurricane Harvey affected operations along several pipelines in the Gulf.
- Disruptions due to failed or corroded pipeline. These incidents occur when regular maintenance activities and inspections fail to identify sections of a pipeline at risk of failure. Given the underlying cause of such disruptions they often require the longest

¹⁸ The scope of this study did not include an assessment of how reduced operating pressures resulting from smaller infrastructure events might impact gas-fired generator operations and availability.

period to recover as up and downstream systems must generally be inspected to confirm that related issues do not exist elsewhere on the pipeline.

Disruptions can also occur as a result of intentional actions of third parties that are malicious in nature. This would include events such as a directed terrorist attacks on physical assets or a cyber-attack on supporting infrastructure.

While the scope of this study did not include a detailed review and categorization of historical disruption events, the following highlights two real world examples for perspective.

- **Tetco Delmont Line 27 Incident** – This relates to a pipeline rupture that occurred on Tetco’s Penn-Jersey system, which moves gas from Western Pennsylvania to New Jersey markets:
 - The incident occurred on April 29, 2016
 - Line 27 ruptured with an associated fire
 - Four parallel lines at the site were shut down within one hour
 - Subsequent repair work required inspections, permits, and engineering work
 - While permit approval processes were expedited, repairs would require the entire summer to complete
 - Tetco’s own documents support that if repairs could not be completed by that winter they would experience a loss of operational capability in the range of 1 Bcf¹⁹
- **ANR Southeast Mainline Capacity Reduction** – This relates to a disruption of ANR’s mainline system out of Southeast Louisiana up to markets in the Midwest²⁰
 - The incident occurred on June 18, 2013
 - ANR’s mainline was disrupted by the leakage of CO₂, hydrocarbons, and drilling mud from failed oil wells operated by a third party adjacent to the ANR system near Delhi, Louisiana
 - All natural gas transactions (flows) on ANR’s Southeast Mainline flowing north of the Jena Compressor Station were curtailed
 - The curtailment prevented downstream shippers in the Midwest from nominating gas from the Southeast pool to their city gate
 - Under normal operations, the pipeline flows in excess of 1 Bcf through this location
 - The event lasted through the following winter

These two events include some notable differences that highlight the importance of several key aspects of an event. In the case of the Tetco disruption, the event occurred during the summer period and along the lines designed to move gas from storage fields in Pennsylvania to the New Jersey market area. As such, the loss of capacity represented a loss of resources not generally

¹⁹See:

<https://infopost.spectraenergy.com/GotoLINK/GetLINKdocument.asp?Pipe=10076&Environment=Production&DocumentType=Notice&FileName=Delmont+System+Operations+and+Pipeline+Development+Updates.pdf&DocumentId=8aa1649f5720493a01572daf026e021b>

²⁰ See ANR Informational Postings: Critical, Force majeure, 20130618, ANR PIPELINE COMPANY, 006958581

utilized during the period of the event. However, as noted in Tetco's own documents, if the event had continued through the following winter the region would have experienced a loss of roughly 1 Bcfd of supply or over 1/3 of the associated line's delivery capability into the region.

In contrast, the ANR event, which was arguably as significant with respect to the quantity of capacity affected, did in fact last through the following winter. Moreover, that was the winter of the Polar Vortex. However, while the loss of this supply may have affected market prices during the event, it does not appear that it directly resulted in lost generation capacity. This is arguably because ANR's system includes several interconnects downstream of the severed line where backup supplies could be purchased and nominated to end-use markets in the mid-west. In addition to the existence of such interconnects, the availability of supply and capacity at those points also played critical roles.

Key points of this discussion are:

- While gas infrastructure events are uncommon, they do occur and can be significant
- Initial impacts from such events are generally very significant (e.g., Tetco temporarily shutting down all four lines during the Delmont event as the situation was assessed)
- Recovery from such an event is not necessarily quick. Recovery periods for more significant events easily exceed days and often can last seasons as permitting activity, inspections of related systems, ordering of equipment, and related activities are required.
- The level of impact on downstream markets depends on several factors:
 - The timing of the event, with peak winter months being more critical than summer periods
 - The location of such an event, particularly relative to downstream resources and supply alternatives

4 Gas and Power Infrastructure Dynamics

The following discussion reviews the interim results of the Phase I work. For each cluster we review the regional pipeline assets and their recent flow rates and interconnectivity. We then summarize the gas-fired generation capacity associated with each cluster/pipeline combination. Finally, we provide an assessment of the potential impact of a gas infrastructure event based on the level of gas-fired generation, anticipated daily gas requirements associated with such facilities, associated oil backup capabilities, and estimated on site oil storage levels.

Estimated daily gas requirements are based on the heat rates associated with each gas-fired generation plant and the historical market load factor for plants with such heat rates in the market. As such, plants with heat rates of 8,000 or less are assumed to run at a 60 percent load factor. Plants with heat rates from 8-12,000 are assumed to run at an 18 percent load factor and plants above 12,000 at 3 percent. As discussed further below, during an event it can reasonably be expected that higher heat rate oil and gas/oil units will experience higher load factors as they compensate for the loss of lower heat rate gas only units.

For each cluster/pipeline combination, the gas infrastructure event is assumed to be sufficient to match the total historical projected daily demand associated with all gas fired generators within

the cluster/pipeline combination. For Transco based plants this is roughly 1.2 Bcfd (0.8 Bcfd of low heat rate/high load factor assets). For Tetco based plants in Cluster A this is estimated at roughly 0.4 Bcfd and in Cluster B at roughly 0.1 Bcfd. Such disruption levels are not inconsistent with the level of impacts observed in the industry as illustrated by the examples reviewed above. More extreme events, including deliberate disruption events, would be expected to exceed this level of curtailment.

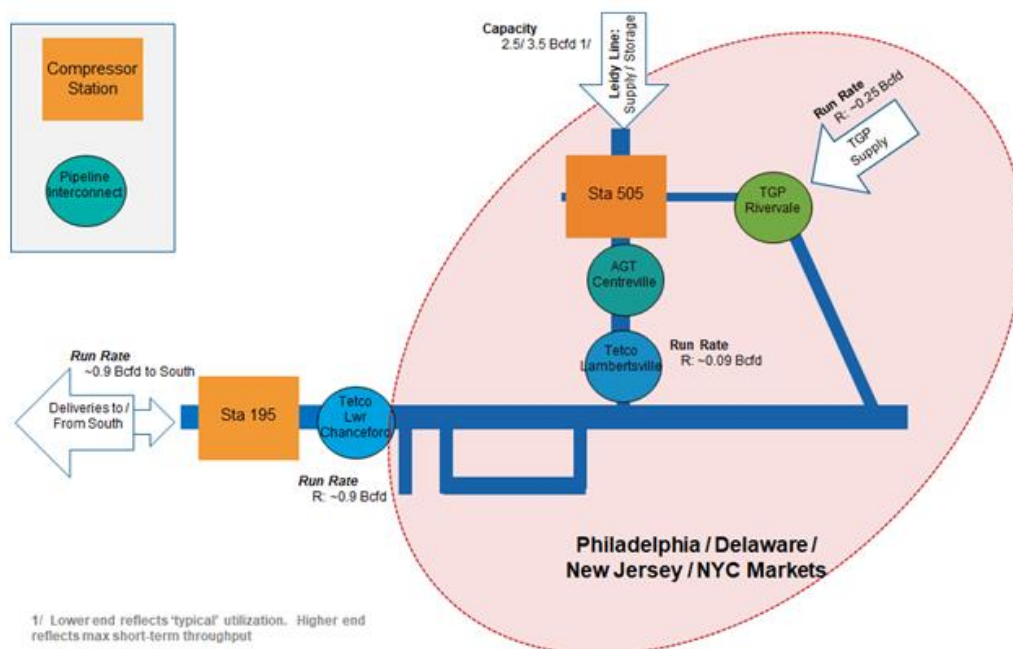
In addition, the assumption is made that, of end-use markets, gas-fired generation will be impacted most significantly during a disruption. ICF recognizes that choosing ‘winners’ and ‘losers’ during such an event is very difficult. In practice, markets will adjust and gas will be re-traded to the highest marginal end-user. However, gas-fired generation units typically do not own firm capacity on upstream pipelines. As such, they must purchase supply on a delivered basis. During a significant infrastructure event, resources that remain in service would be held by firm shippers and generally used to supply core system loads before being released for use on the open market.

4.1 Cluster A: Transco

4.1.1 Flow Mechanics

Figure 3 provides a simplified schematic of Transco’s gas supply infrastructure related to Cluster A. With the advent of substantial production in the Marcellus/Utica region, gas on Transco now flows south on the Leidy Line year round. From here it moves east to Northern New Jersey / New York markets and West / South to Southern New Jersey markets. Supplies from the Gulf, which traditionally moved north through Station 195, have now been displaced by Marcellus/Utica supply moving south in the Maryland, Virginia, and South Atlantic markets.

Figure 3: Transco Flow Schematic



At the border between Pennsylvania and New Jersey, the Leidy Line consists of three looped lines (30" Leidy A, 36" Leidy B, and 42" Leidy C). At Station 505 these lines split and create a loop in northern New Jersey. Southward the line has an additional loop around Philadelphia into New Jersey and then continues south through Maryland. Several important interconnects with other pipelines play important roles in supplying gas to Transco, with the Tetco Lower Chanceford interconnect being the most significant (~0.9 Bcf/d).

Figure 4 summarizes historical flows on this section of the Transco system.

- The blue shaded areas summarize gas supply delivered to Transco from other pipelines in the region. Most notably, Tetco delivers nearly 1 Bcf/day (primarily from the Lower Chanceford interconnect). TGP provides an additional roughly 250,000 MMBtu/day at the northern end of the system
- The dark green area represents gas received into the region off the Leidy line that stays within the region. The highly seasonal nature of this supply is consistent with its use to support seasonal heating loads of the regional LDC markets.
- The light green area on the left hand side of the figure shows gas flows received from the southern end of the system moving into the cluster region. Notably, this northern flow has all but ceased as Marcellus/Utica production and associated capacity expansions have been placed into service.
- The final pale pink area summarizes additional flows received from the Leidy line that flow through and south to markets along the South Atlantic.

Figure 4: Historical Flows on Transco

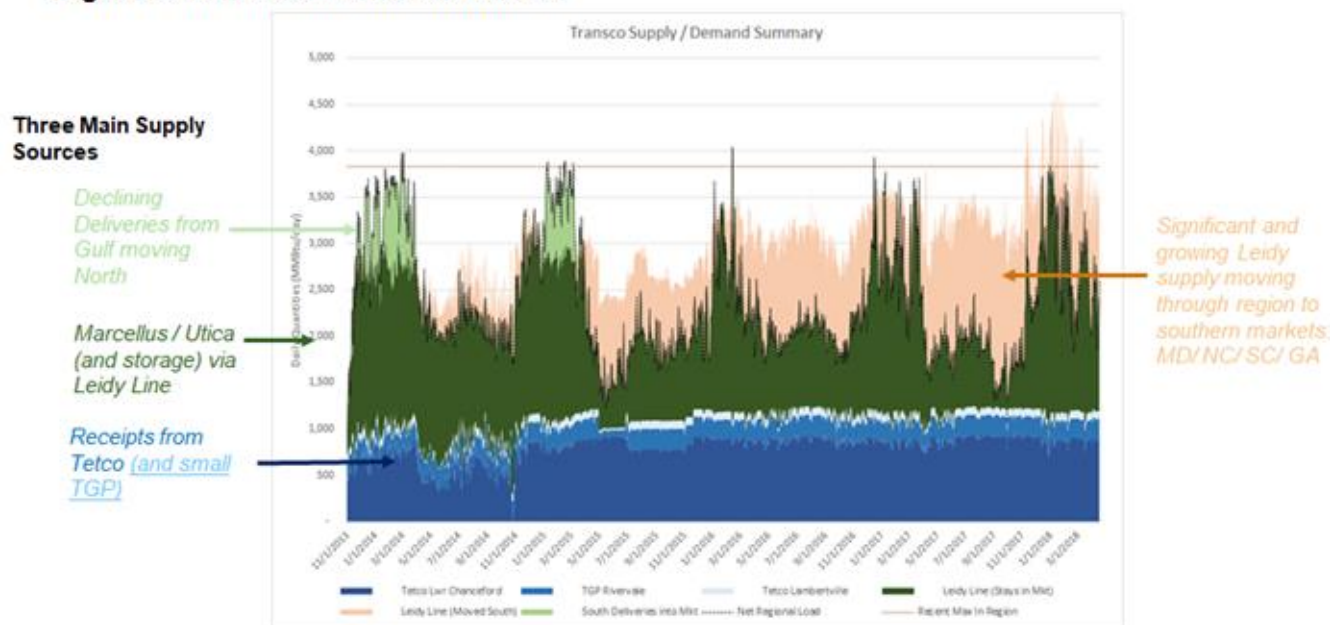
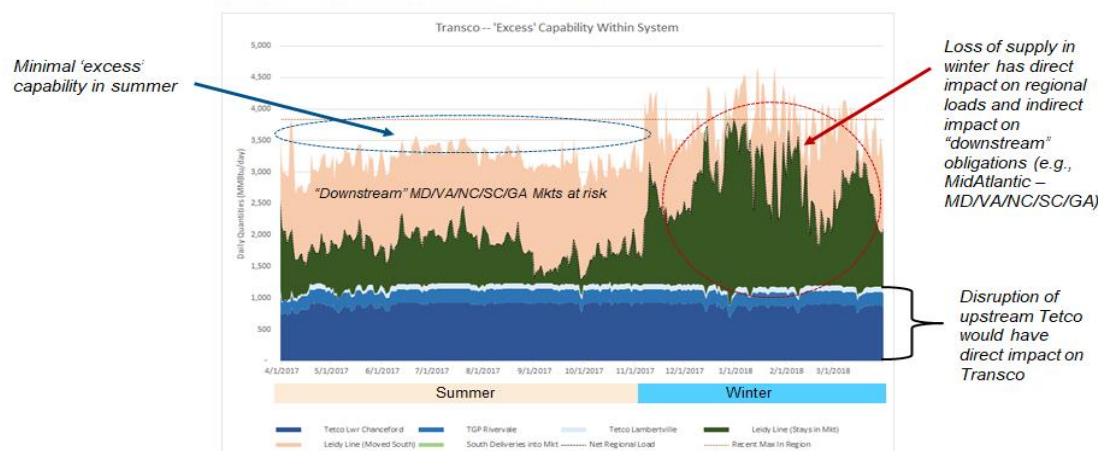


Figure 5 reproduces Figure 4 focusing on the most recent year. This highlights several important characteristics of the Transco gas supply infrastructure serving Cluster A.

- Some 'excess' may be available during the summer periods but even during these months the pipeline infrastructure is utilized at high load factors

- During the winter months there is little to no excess capacity in the market. Capacity not used to meet intra-cluster requirements is generally fully utilized to move supply to southern markets (i.e., pale pink area). This implies that any significant disruption of regional capacity will directly reduce supply available to loads within the cluster or ‘downstream’ markets along the South Atlantic
- Tetco is a major source of supply to Transco. A disruption of supply on the Tetco system or to the Lower Chanceford interconnect would very likely have immediate and direct implications for Transco

Figure 5: Historical Flows on Transco – Last Year



4.1.2 Gas-Fired Generation Capacity Associated With Transco in Cluster A

Table 5 summarizes gas-fired generation in the Cluster A region where the generator identified Transco as its primary pipeline source or the unit was otherwise allocated to Transco based on ICF’s review. Capacity has been divided by backup capability (i.e., gas only, gas/distillate, gas/resid) and heat rate. As noted in the highlighted area, Transco has 18.7 GWs of directly or indirectly attached gas-fired generation in the cluster region. This consists of a combination of low heat rate, high load factor combined cycle units (~8.6 GW) and an additional 10 GW of higher heat rate units.

Estimated daily gas requirements are based on average load factors by heat rate observed for the PJM market region, resulting in an average daily gas load of roughly 1.2 Bcfd. The maximum values reported represent potential maximum gas consumption associated with the capacity based on a 24 hour run (~4.3 Bcfd). This higher value overstates the likely consumption associated with these units given the much lower daily load factors associated with peaking units, but it does provide a perspective on the range of potential demand. Of the 18.7 GWs of gas-fired capacity, 6.7 GWs or 36 percent is gas-fired only. More significantly, of the 8.6 GW of low heat rate, high load factor units, 5.3 GWs or over 60% is gas only.

Table 5: Gas-Fired Generation Associated With Transco in Cluster A

Transco Position 1/ 2/	Natural Gas			Total
	Natural Gas	Natural Gas, Distillate Fuel Oil	Natural Gas, Residual Fuel Oil	
Low Heat Rate Units (<8000)				
Capacity (MW)	5,323	3,314	-	8,637
Wtd Avg HR	6,983	7,263	-	
Avd Daily MMBtu 3/	535,286	346,538	-	881,824
Medium Heat Rate Units				
Capacity (MW)	1,189	3,095	2,796	7,080
Wtd Avg HR	10,150	9,332	11,377	
Avd Daily MMBtu 3/	52,116	124,795	137,403	314,314
High Heat Rate Units (>12000)				
Capacity (MW)	206	2,079	746	3,032
Wtd Avg HR	12,663	14,819	13,763	
Avd Daily MMBtu 3/	1,880	22,184	7,394	31,458
Total Capacity (MW)				
	6,718	8,488	3,542	18,748
Avg Daily MMBtu Req't 3/				
	589,282	493,516	144,797	1,227,596
			MAX 4/:	177,687 /hr
Gallons Equivalent/day:		3,558,336	967,315	4,264,496 /Day
Barrels Equivalent/day:		84,722	23,031	
			Barrels of Storage 4/:	
		1,005,754	331,990	
		**Days of Supply at LF	12	14

NOTE: 1/ Sources: EIA 860, EPA National Electric Energy Data System (NEEDS), and ICF IPM inputs
Includes plants reporting upstream pipeline as PSEG (50%) and Brooklyn Union. Excludes Iroquois and TGP
2/ Low Heat Rate < 8,000, Medium 8-12,000, High >12,000
3/ Estimated based on historical load factors for gas units by Heat Rate for region:
<8,000 @ 60%, 8-12,000 @18%, >12,000 at 3%
4/ Based on maximum inventory level as reported to EIA 923 for 2016 by plant. Astoria reported at
4 MM Barrels, adjusted to 300,000 Barrels based on reported total tank capacity in:
www.dec.ny.gov/dardata/boss/afs/permits/263010018500009_r3.pdf

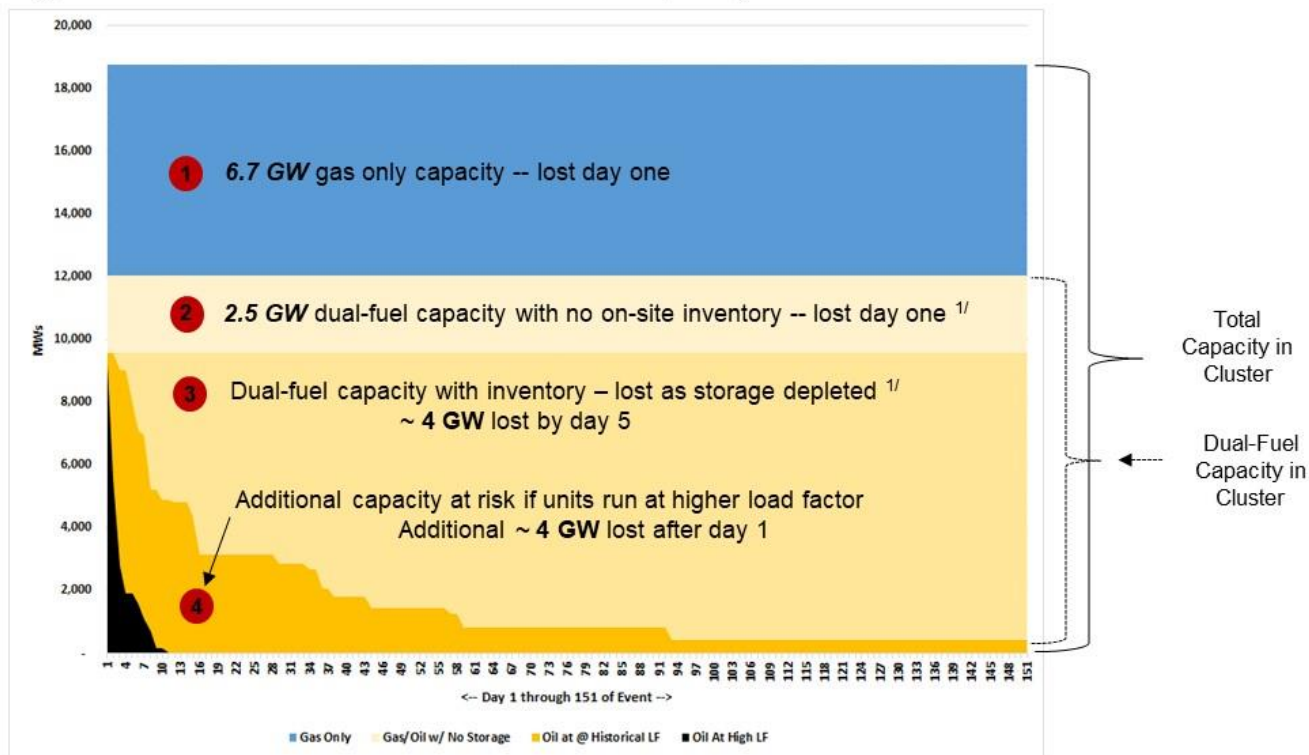
The table also converts the average daily gas supply requirement associated with the units into an equivalent oil requirement and compares this to the reported on-site storage inventories. Distillate units hold an average of 12 days of supply on site and resid units hold an average of 14 days.

4.1.3 Potential Impact of Gas Infrastructure Event

A gas-infrastructure event with the potential to impact all gas-fired generation on Transco in Cluster A would be sized in the range of the average daily consumption associated with these facilities, or roughly 1.2 Bcfd. This is just slightly more than the size of the Tetco/Transco interconnect at Lower Chanceford. Alternatively, this represents the loss of roughly one of the three looped lines supplying the cluster off the Leidy Line. To have the full impact on the region, such an event would generally need to occur during the winter when the assets serving this market are basically operated at one-hundred percent load factors. Similar impacts could be incurred in summer months but would generally require a more substantive impact on regional resources (e.g., larger impact on Leidy Line or combined impact on Transco and Tetco affecting the Lower Chanceford interconnect).

In such an event, gas-only units would theoretically be off-line and unavailable to support regional power requirements. Gas/oil units could be run to the degree these facilities have on-site supplies of backup fuel. Figure 6 summarizes the results as follows:

Figure 6: Cumulative “Lost” Generation Capacity – Transco



1/ On-site inventory based on maximum inventory in 2016 from EIA 923 by plant

- 1 On day one of an event, the Cluster A / Transco combination would lose 6.7 GW of gas-only generation capacity. This capacity could be unavailable for the duration of such an event.
- 2 To the degree dual-fuel units do not have on-site inventories, these facilities would be unavailable until such time as oil supplies could be brought on-site. Based on reported inventories, this implies an additional 2.5 GWs would be unavailable day one of an event.
- 3 Dual-fuel units with on-site inventories could switch to backup fuels during an infrastructure event. These units could provide roughly 10 GWs of secure supply. However, based on historical maximum inventories for these facilities, by day 5 of an event 4 GWs of this capacity would exhaust on-site backup fuel resources. This assumes these units are run at historical load factors for their respective heat rates.
- 4 If dual-fuel units are run at higher load factors they will exhaust on-site inventories much more quickly. At the 100 percent load factor rate, on-site inventories are essentially exhausted by day 5. Actual observed durations would fall somewhere between the shaded area boundary and the dotted lines.

In summary, the Transco Cluster A market has the potential to lose 6.7 GWs of gas-only generation during a gas infrastructure event with an additional 12 GWs at risk based on the

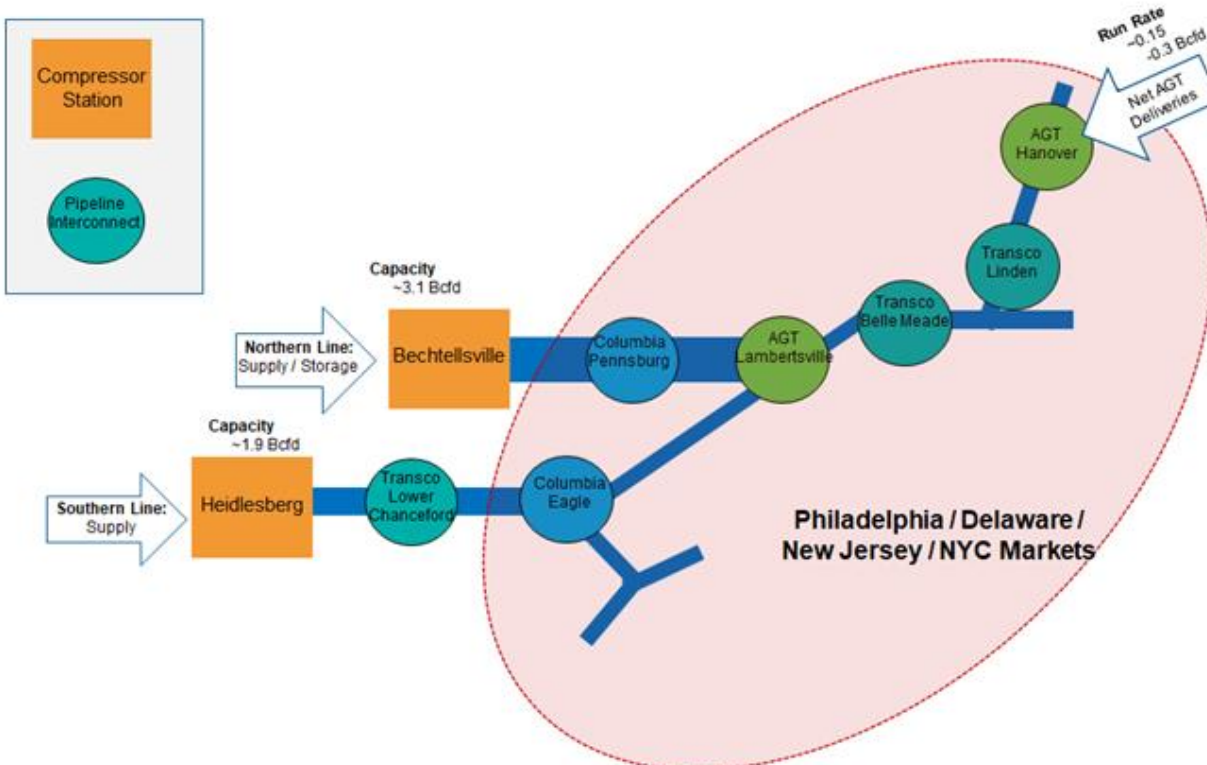
availability of backup fuel. Based on historical inventory levels at these plants, backup fuel resources could be depleted within 10 to 20 days or much shorter if plants are required to operate at higher load factors.

4.2 Cluster A: Tetco

4.2.1 Flow Mechanics

Figure 7 provides a simplified schematic of Tetco's gas supply infrastructure related to Cluster A. The Tetco section of Cluster A is supplied by two lines. The northern line traverses through central Pennsylvania and connects with upstream production and a Tetco lateral that interconnects the pipeline with storage resources in the region. The line consists of multiple parallel lines culminating in three main lines into New Jersey (36", 30", and 24") with additional looping.

Figure 7: Tetco Flow Schematic – Cluster A



The southern line traverses along the southern Pennsylvania border and then northeast along the Pennsylvania / New Jersey border around the Philadelphia area where it connects with the northern line in Lambertsville, New Jersey. This also consists of various parallel lines and associated looping culminating in two main lines into the region (20" and 36"). In Western Pennsylvania (not illustrated on figure) this line reconnects with the northern line (creating a loop within Pennsylvania) and then extends west into West Virginia and Ohio. This western portion of the line is the section of Tetco that is most interconnected with upstream Marcellus/Utica production in western Pennsylvania, West Virginia, and Eastern Ohio.

Several interconnects with other pipelines play important roles in supplying gas to other pipelines in the region, most notably Transco. The pipeline also is heavily interconnected with Algonquin Gas Transmission, which is essentially an extension of the Tetco system. However, in contrast to historical flows, AGT now net delivers gas to the Tetco system as a result of various expansions on AGT connecting it with TGP and Millennium Pipeline (and upstream Marcellus/Utica production).

Figure 8 summarizes historical flows on this section of the Tetco system.

- The blue shaded area summarizes gas supply delivered via the southern line into the region. As illustrated, this line delivers a constant ~1.9 Bcfd into the region.
- The green shaded area summarizes the net receipts of supply from AGT. This represents net receipts and deliveries at the various AGT/Tetco interconnects (e.g. Lambertsville, Hanover).
- The orange shaded area summarizes deliveries along the northern line. In contrast to the southern line, this line exhibits significant seasonal swings in supply. This reflects the use of this line to deliver storage resources in central Pennsylvania into the market.
- In contrast to the Transco graphs, the Tetco graphs do not include the pale pink area that represented flows through the system to downstream markets. In this sense, the Cluster A region represents the end of the system for Tetco.

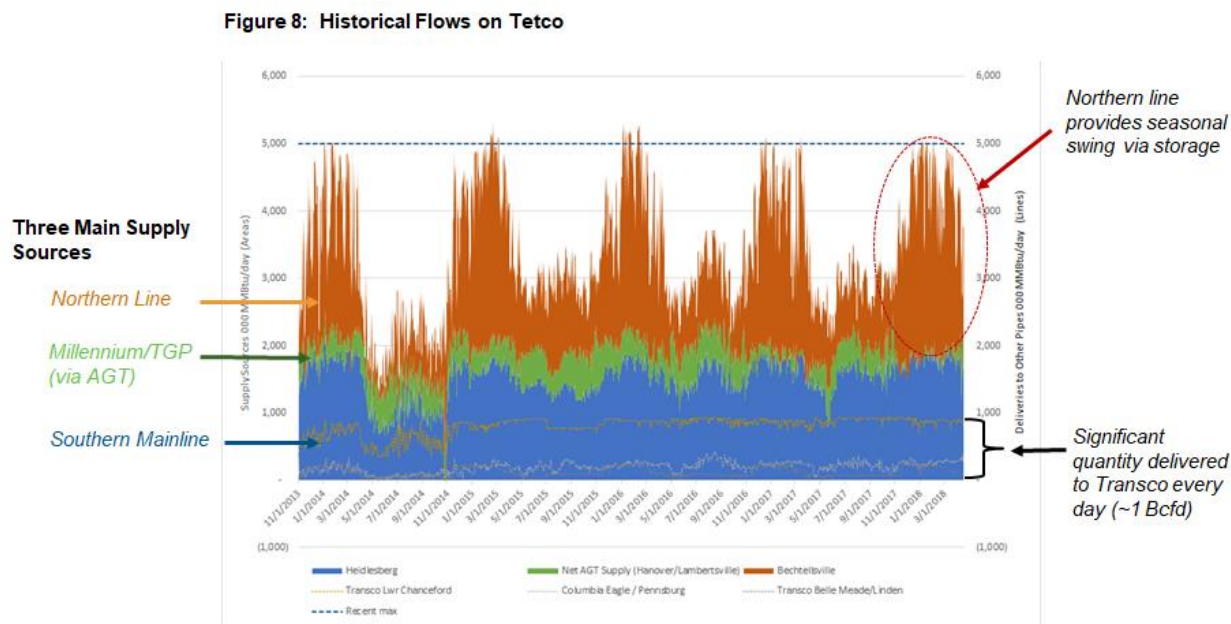
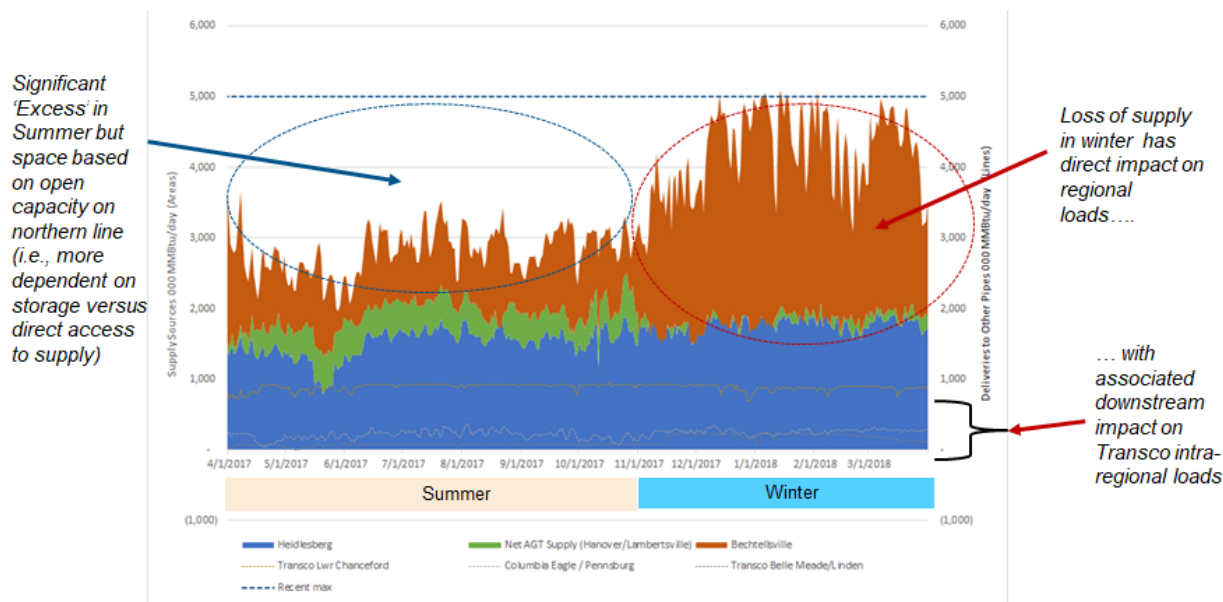


Figure 9 reproduces Figure 8 focusing on the most recent year. This highlights several important characteristics of the Tetco gas supply infrastructure serving Cluster A.

- Excess capacity appears to exist along the northern line during the summer period. This implies a greater ability of this pipeline to accommodate disruptions during the summer months than estimated for Transco. This appears to be supported by observed conditions over 2016 during the Delmont Line incident.

Figure 9: Historical Flows on Tetco – Last Year



- Tetco’s southern line appears to be fully utilized on an annual basis. Loss of supply on this line, even in the summer, could have a substantive impact on regional resources, including downstream impacts on Transco.
- While there appears to be some excess capability during winter months on non-peak days, the availability of this space for third party deliveries may be limited. In general pipelines must reserve some of their capacity on a daily basis to accommodate no-notice swing rights of LDCs (e.g., used to manage unanticipated heating loads if cold fronts move in early or stronger than anticipated).

4.2.2 Gas-Fired Generation Capacity Associated With Tetco in Cluster A

Table 6 summarizes gas-fired generation in the Cluster A region where the generator identified Tetco as its primary pipeline source or the unit was otherwise allocated to Tetco based on ICF’s review. As noted in the highlighted area, Tetco has 8.6 GWs of directly or indirectly attached gas-fired generation in the cluster region. This consists of a combination of low heat rate, high load factor combined cycle units (~2.8 GW) and an additional 5.8 GW of higher heat rate units.

Table 6: Gas-Fired Generation Associated With Tetco in Cluster A

Tetco East Position 1/ 2/	Natural Gas, Distillate Fuel Oil, Residual Fuel Oil			Total
	Natural Gas	Distillate Fuel Oil	Natural Gas, Residual Fuel Oil	
Low Heat Rate Units (<8000)				
Capacity (MW)	1,914	916	-	2,829
Wtd Avg HR	7,259	6,975	-	
Avd Daily MMBtu 3/	200,024	91,984	-	292,009
Medium Heat Rate Units				
Capacity (MW)	1,111	1,623	-	2,734
Wtd Avg HR	11,466	8,631	-	
Avd Daily MMBtu 3/	55,043	60,523	-	115,566
High Heat Rate Units (>12000)				
Capacity (MW)	72	2,998	-	3,070
Wtd Avg HR	20,117	13,158	-	
Avd Daily MMBtu 3/	1,043	28,401	-	29,444
Total Capacity (MW)	3,097	5,537	-	8,634
Avg Daily MMBtu Req^{3/}	256,110	180,908	-	437,018
			MAX 4/:	87,924 /hr
Gallons Equivalent/day:		1,304,378	-	2,110,173 /Day
Barrels Equivalent/day:		31,057	-	
Barrels of Storage 4/:		890,564	-	
Days of Supply at LF		28.68	-	

NOTE: 1/ Sources: EIA 860, EPA National Electric Energy Data System (NEEDS), and ICF IPM inputs includes plants reporting upstream pipeline as PSEG (50%).

2/ Low Heat Rate < 8,000, Medium 8-12,000, High >12,000

3/ Estimated based on historical load factors for gas units by Heat Rate for region:

<8,000 @ 60%, 8-12,000 @18%, >12,000 at 3%

4/ Based on maximum inventory level as reported to EIA 923 for 2016 by plant.

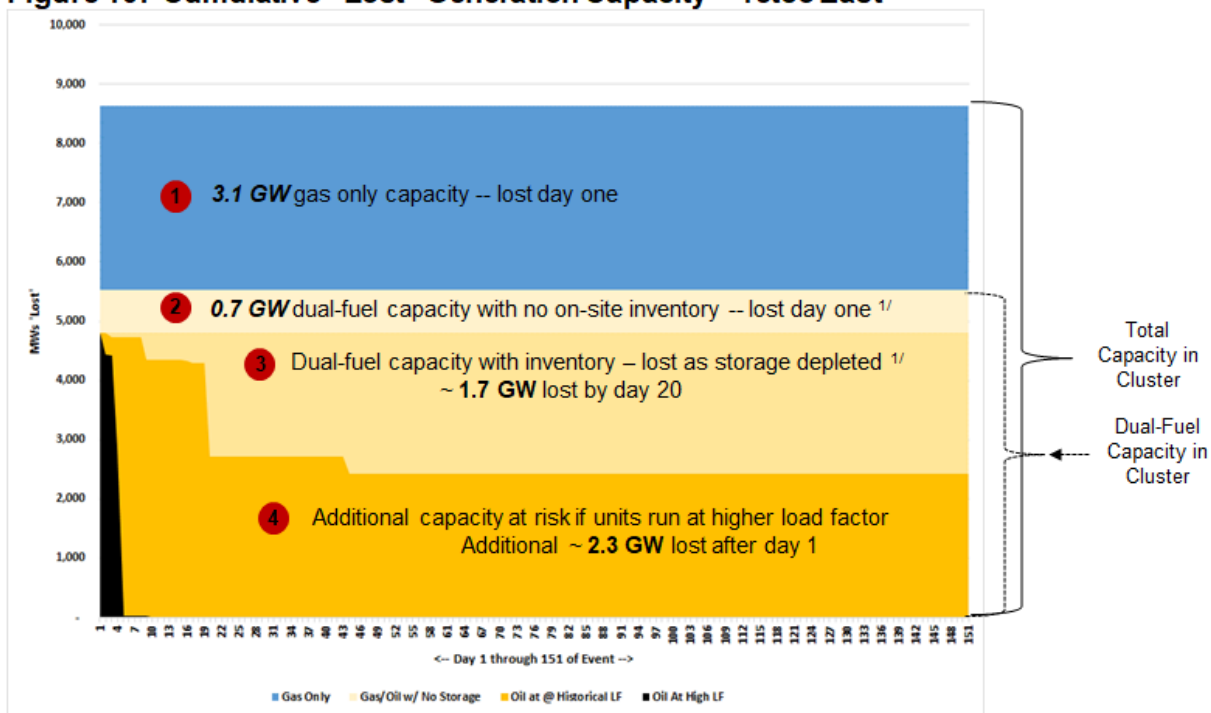
Estimated daily gas requirements associated with these plants run roughly 0.4 Bcfd with maximum potential runs upwards of 2 Bcfd. Of the 8.6 GWs of gas-fired capacity, 2.0 GWs or 36 percent is gas-fired only. More significantly, of the 2.8 GW of low heat rate, high load factor units, 1.9 GWs or over 68% is gas only. Distillate units hold an average of 28 days of supply on site (no gas/resid units were identified for this pipeline/cluster).

4.2.3 Potential Impact of Gas Infrastructure Event

A gas-infrastructure event with the potential to impact all gas-fired generation on Tetco in Cluster A would be sized in the range of the average daily consumption associated with these facilities, or roughly 0.4 Bcfd. Such an impact could easily be experienced through the loss of even one supply line into the region, although significant impacts appear to be limited to winter months. Again, in such an event, gas-only units would theoretically be off-line and unavailable to support regional power requirements. Gas/oil units could be run to the degree these facilities have on-site supplies of backup fuel.

Figure 10 summarizes potential impacts as follows:

Figure 10: Cumulative “Lost” Generation Capacity – Tetco East



1/ On-site inventory based on maximum inventory in 2016 from EIA 923 by plant

- 1** On day one of an event, the Cluster A / Tetco combination would lose 3.1 GW of gas-only generation capacity. This capacity could be unavailable for the duration of such an event.
- 2** To the degree dual-fuel units do not have on-site inventories, these facilities would be unavailable until such time as oil supplies could be brought on-site. Based on reported inventories, this implies an additional 0.7 GWs would be unavailable day one of an event.
- 3** Dual-fuel units with on-site inventories could switch to backup fuels during an infrastructure event. These units could provide roughly 5 GWs of secure supply. However, based on historical maximum inventories for these facilities, by day 10 of an event 1.7 GWs of this capacity would exhaust on-site backup fuel resources. This assumes these units are run at historical load factors for their respective heat rates.
- 4** If dual-fuel units are run at higher load factors they will exhaust on-site inventories much more quickly. At the 100 percent load factor rate, on-site inventories are essentially exhausted by day 5. Actual observed durations would fall somewhere between the shaded area boundary and the dotted lines.

In summary, the Tetco Cluster A market has the potential to lose 3.1 GWs of gas-only generation during a gas infrastructure event with an additional 5.5 GWs at risk based on the availability of backup fuel. Based on historical inventory levels at these plants, backup fuel

resources could be depleted within 15 to 20 days or much shorter if plants are required to operate at higher load factors.

4.3 Cluster B: Tetco

4.3.1 Flow Mechanics

Figure 11 provides a simplified schematic of Tetco's gas supply infrastructure related to Cluster B. The Tetco section of Cluster B is interconnected with supply sources in three ways. The main Tetco line moves Marcellus/Utica production from Eastern Ohio/West Virginia/Western Pennsylvania west to the Lebanon Hub. At this point the system splits with the southern line moving supply south and to the Gulf, and the northern line moving gas northwest and into Midwestern markets. Both western lines historically moved supply into the region from the west but have since been 'reversed'. The Lebanon Hub is an interconnect between various regional pipelines as noted.

Figure 11: Tetco West Flow Schematic

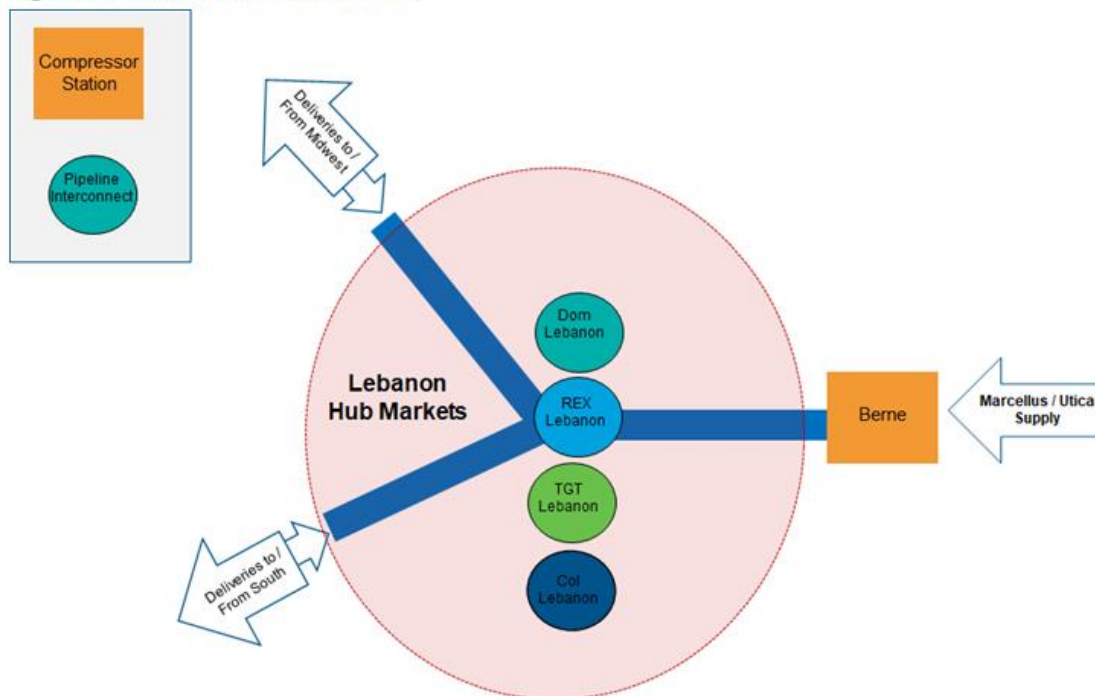


Figure 12 summarizes historical flows on this section of the Tetco system.

- The grey shaded area illustrates the deliveries of gas into the region from the southern Gulf line. As noted, these supplies have declined to a negligible volume as a result of various reversal projects on Tetco
- The blue shaded area represents deliveries of Marcellus/Utica via the eastern line through the Berne compressor station. These now constitute the primary source of supply into the region, running at roughly 700,000 MMBtu/day.
- The orange line summarizes deliveries through the system to the Lebanon Lateral and into the Midwest. The negative values over the 2014/15 period represent net 'imports' into the cluster from the Midwest. More recently, however, gas delivered

into the cluster is almost entirely dedicated to flows downstream (represented by the positive values for the orange (Midwest) and yellow (Gulf) lines on the right hand side of the figure

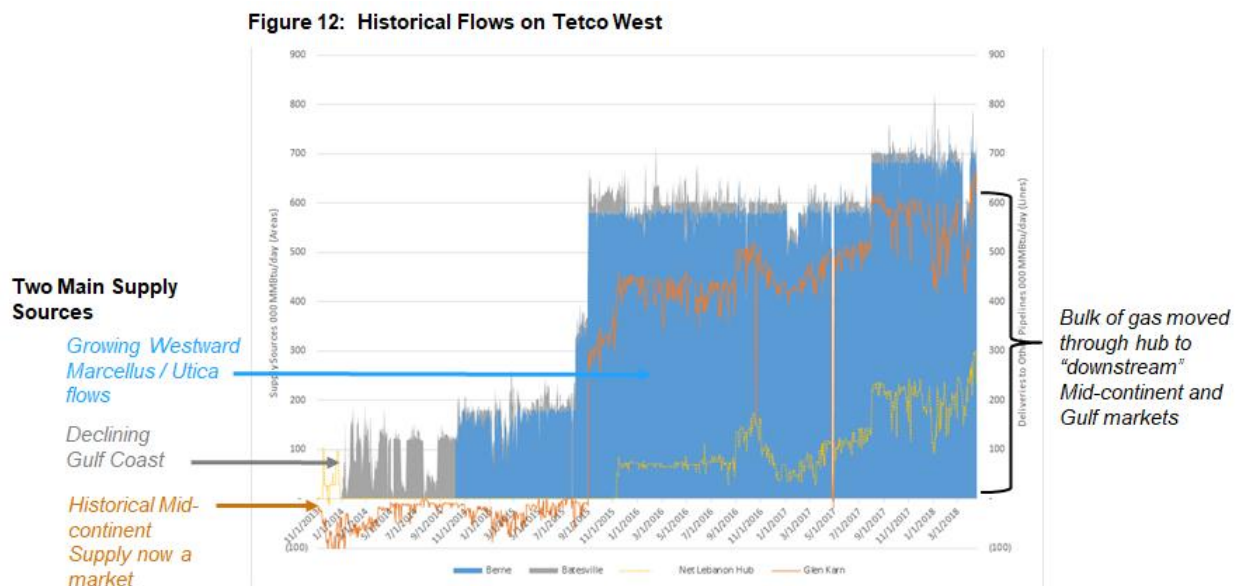
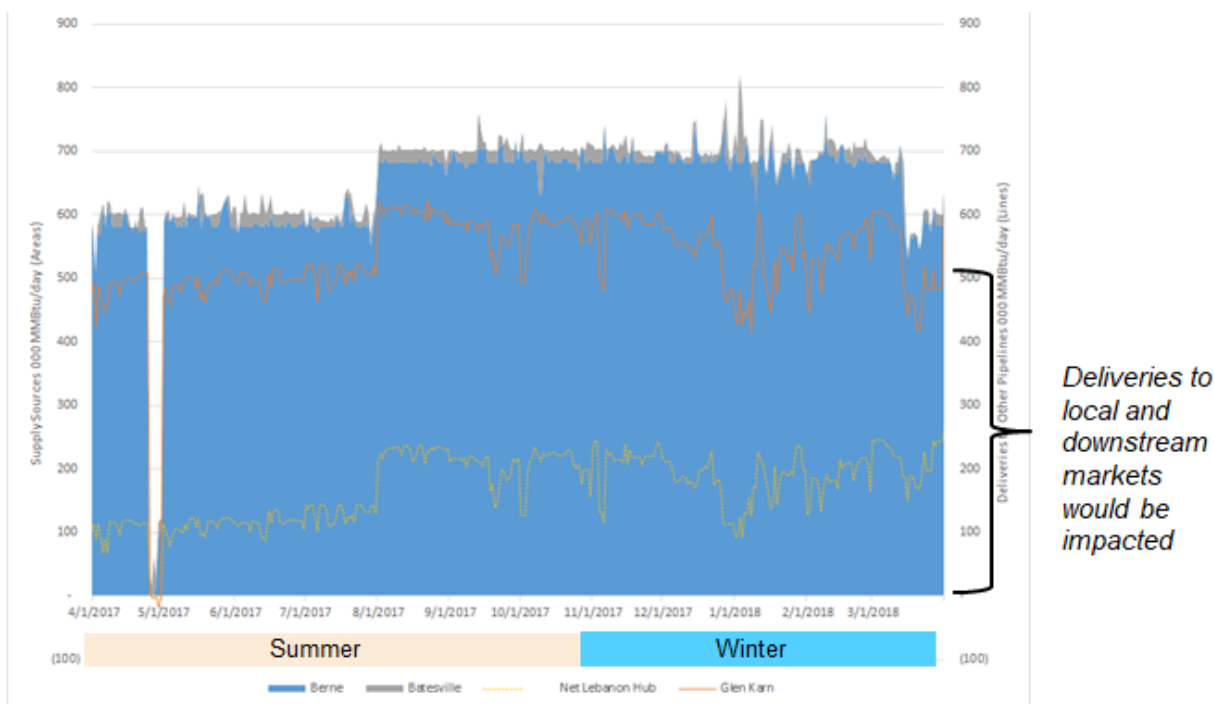


Figure 13 reproduces Figure 12 focusing on the most recent year. In contrast to the Cluster A scenario, this figure shows very little supply remaining within the cluster region. As discussed below, this reflects the relative heat rates and anticipated load factors of units in this cluster area.

Figure 13: Historical Flows on Tetco West – Last Year



4.3.2 Gas-Fired Generation Capacity Associated With Tetco in Cluster B

Table 7 summarizes gas-fired generation in the Cluster B region where the generator identified Tetco as its primary pipeline source or the unit was otherwise allocated to Tetco based on ICF’s review. As noted in the highlighted area, Tetco has 1.9 GWs of directly or indirectly attached gas-fired generation in the cluster region. This consists of a combination of low heat rate, high load factor combined cycle units (~0.5 GW) and an additional 1.4 GW of higher heat rate units.

Figure 7: Gas-fired Generation Associated with Cluster B Tetco

Tetco West Position 1/ 2/	Natural Gas, Natural Gas, Natural Gas,			Total
	Natural Gas	Distillate Fuel Oil	Residual Fuel Oil	
Low Heat Rate Units (<8000)				
Capacity (MW)	518	-	-	518
Wtd Avg HR	7,750	-	-	
Avd Daily MMBtu 3/	57,809	-	-	57,809
Medium Heat Rate Units				
Capacity (MW)	176	-	-	176
Wtd Avg HR	11,439	-	-	
Avd Daily MMBtu 3/	8,697	-	-	8,697
High Heat Rate Units (>12000)				
Capacity (MW)	503	728	-	1,231
Wtd Avg HR	24,179	15,406	-	
Avd Daily MMBtu 3/	8,757	8,077	-	16,834
Total Capacity (MW)	1,197	728	-	1,925
Avg Daily MMBtu Req't 3/	75,262	8,077	-	83,340
Gallons Equivalent/day:		58,240	-	MAX 4/: 29,408 /hr 705,797 /Day
Barrels Equivalent/day:		1,387	-	
Barrels of Storage 4/:		26,943	-	
~Days of Supply at LF		19.4	-	

NOTE: 1/ Sources: EIA 860, EPA National Electric Energy Data System (NEEDS), and ICF IPM inputs
Includes plants reporting ANR and Vectren Ohio as their supplier on EIA forms
2/ Low Heat Rate < 8,000, Medium 8-12,000, High >12,000
3/ Estimated based on historical load factors for gas units by Heat Rate for region:
<8,000 @ 60%, 8-12,000 @18%, >12,000 at 3%
4/ Based on maximum inventory level as reported to EIA 923 for 2016 by plant.

Estimated daily gas requirements associated with these plants run roughly 80,000 MMBtu/day with maximum potential runs upwards of 700,000 MMBtu/day. In contrast to the Cluster A scenario, of the 1.9 GWs of gas-fired capacity only 0.5 MW or 27 percent represents low heat rate units with expected higher load factors. This would initially imply less exposure to a gas infrastructure event for this cluster. However, of the 1.9 GWs, 1.2 GWs (or 62 percent) represents gas only generation facilities with no reported oil back up. For the limited oil switchable capacity in the region, reported oil inventories would support 19 days of supply at historical load factors.

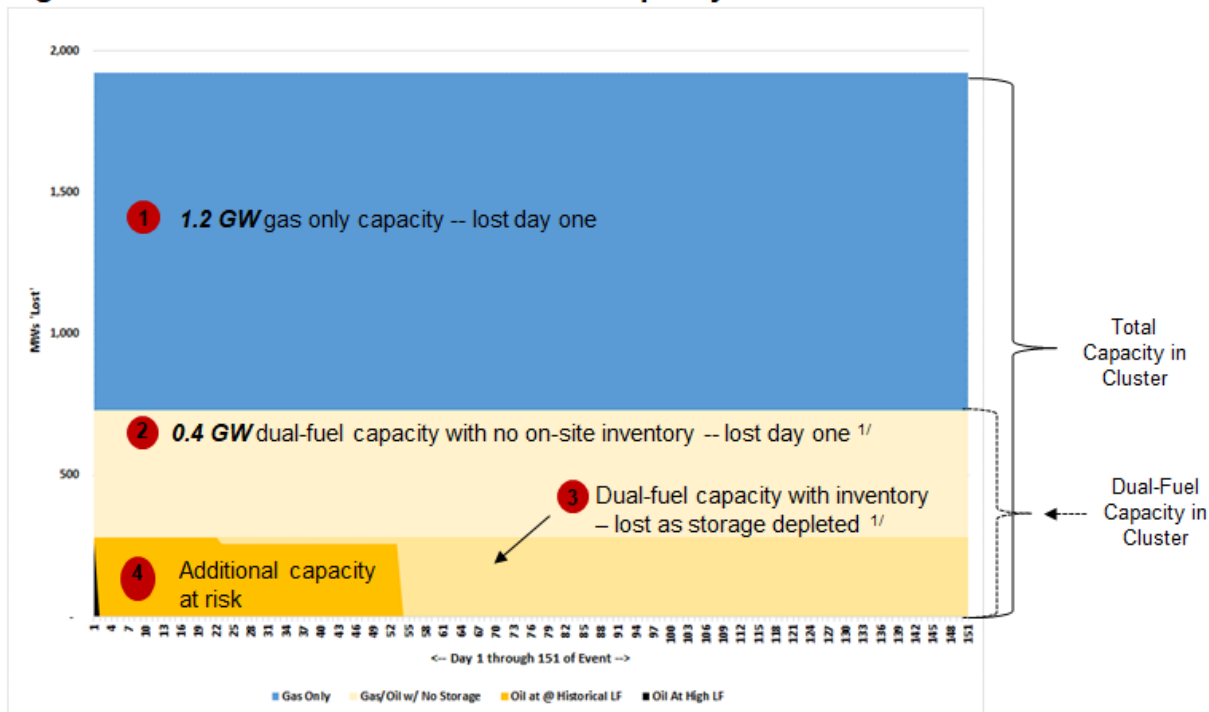
4.3.3 Potential Impact of Gas Infrastructure Event

A gas-infrastructure event with the potential to impact all gas-fired generation on Tetco in Cluster B would be sized in the range of the average daily consumption associated with these facilities, or roughly 0.1 Bcfd. Such an impact could easily be experienced through the loss of even one supply line into the region. However, in contrast to Cluster A, Cluster B has more

flexibility to recover from the loss of a supply line. Both the western lines into Indiana are bi-directional and could be reversed to supply markets in this region if the eastern line from the Marcellus/Utica was impacted. While this would have implications for downstream loads in the Midwest, these loads would have access alternative supply sources. The full implications of a major infrastructure event required a broader analysis of inter-regional supply capabilities and responses to such an event (e.g., via a RYMS or hydrological analysis).

Figure 14 summarizes potential impacts as follows:

Figure 14: Cumulative “Lost” Generation Capacity – Tetco West



^{1/} On-site inventory based on maximum inventory in 2016 from EIA 923 by plant

- 1** On day one of an event, Cluster B would lose 1.2 GW of gas-only generation capacity. This capacity could be unavailable for the duration of such an event.
- 2** To the degree dual-fuel units do not have on-site inventories, these facilities would be unavailable until such time as oil supplies could be brought on-site. Based on reported inventories, this implies an additional 0.4 GWs would be unavailable day one of an event.
- 3** Dual-fuel units with on-site inventories could switch to backup fuels during an infrastructure event. These units could provide roughly 250 MWs of secure supply for upwards of 50 days based on historical load factors.

4

If dual-fuel units are run at higher load factors they will exhaust on-site inventories much more quickly. At the 100 percent load factor rate, on-site inventories are essentially exhausted by day 2.

5 Other Considerations during an Event

5.1 Logistical Implications of Oil Refill

The assessments of backup capabilities reviewed above were based on reported inventory levels at dual fuel plants. Higher actual storage inventories would extend the ability of dual fired facilities to provide backup supply during a significant gas infrastructure event. Likewise, replacement of inventory during such an event could also extend the ability of such resources to provide backup support. While an assessment of the ability to refill oil storage inventories is outside the scope of this study, ICF developed some initial, high level estimates for the feasibility of managing oil refill requirements.

Refill/replacement options are very unit / location specific. In cases where facilities are located near waterways, refill options may include barge deliveries. River barges can carry from 20 to 90,000 barrels or as much as 3.8 million gallons of replacement fuel. One such barge could easily replace a dual fuel facility's inventory. However, the logistics of this service need to be considered.

River barges travel an average of 4-5 mph and must be contracted for, filled, transported to the plant, and unloaded. Dock space and associated pipeline capacity must exist and be available to allow the off-loading of such replacement supplies. Moreover, the barge must be ordered and deliveries coordinated around any pre-existing obligations for the barge capacity.

To place this refill requirement in perspective, ICF compared average daily distillate consumption in New Jersey to the potential daily refill requirement associated with the dual-fuel units in Cluster A. EIA reports that New Jersey consumes just over 30 MM barrels of distillate fuel oil per year, or roughly 80,000 barrels per day.²¹ While the Cluster A plants include a number of New York City facilities, the combined daily demand for distillate for this cluster (assuming normal load factors) exceeds the daily average demand of New Jersey's entire distillate market by nearly 35,000 barrels per day. While more detailed analysis should be performed, this questions the ability of the existing oil distribution network to provide replacement supplies on short notice and in sufficient quantities during a significant infrastructure event.

Alternatively, on-site storage could be refilled leveraging tanker trucks. The advantage of tanker trucks is they can access more locations, including plants located off-river. Tanker trucks hold on average from 7-10,000 gallons. To assess this option ICF considered a 500 MW combined-cycle facility with a 7,500 heat rate. Such a unit could be expected to run at roughly a 60 percent load factor under normal operating conditions, requiring roughly 60,000 MMBtus of gas

²¹ See EIA: State Energy Data 2016, Table F7: Distillate Fuel Oil Consumption Estimates, 2016 (New Jersey).

supply per day. This equates to roughly 430,000 gallons of DFO per day. Based on per-tanker truck capacity, this one facility would require in the range of 48 trucks per day to maintain storage levels based on historical utilization rates. This amounts to roughly one delivery every half hour. Even if excess tanker capacity were available in the market, the logistics of such a refill for extended periods would be challenging, particularly across multiple units.

5.2 Emissions Limitations

Under this task, ICF reviewed SO₂ and NO_x limits at dual-fired units in PJM along with a review of the Title V Operating Permits for a subset of units.

For the dual-fired unit permits reviewed for this exercise, the SO₂ requirements were specific to the fuel being burned. In other words, it wasn't an average rate across the natural gas and oil. However, a majority of the permits required that the units burn ULSD below a specified sulfur content. There were some permits where the unit was required to burn natural gas only, but there were exemptions in place for emergency situations.

For example, for a dual-fired combined cycle in Maryland, the permit requires the source to burn natural gas or LNG, however, ULSD may be used in situations where supply of natural gas is limited. The source is subject to a NO_x limit when burning ULSD, but this limit can be exceeded if a PJM system emergency has been declared and natural gas is unavailable. Under no circumstances may the source burn ULSD for more than 2,400 turbine hours.²²

The Clean Air Act contains a number of provisions for waiving emissions limitations in the event of an emergency. The waivers have been granted in instances of emergencies such as the waiver of fuel emissions standards for gasoline in the aftermath of hurricanes affecting the Gulf Coast. Relating to stationary sources, for example, 42 U.S. Code § 7410 (f) which covers State Implementation Plans for primary and secondary National Ambient Air Quality Standards (NAAQS), contains provisions for during an emergency. If the President determines that a national or regional emergency exists, a temporary emergency suspension may be issued. The suspension will only be issued if the Governor of the State in which the source(s) is located determines that within the vicinity of the source there exists a temporary energy emergency resulting in high levels of loss of necessary energy supplies for residential dwellings.

In addition to waivers within the Clean Air Act, the Title V Operating Permits for stationary sources also often contain provisions for emergency situations due to acts of God, etc. They varied depending on the state in which the source is located, but all had a number of factors in common. For example, several of the permits defined an emergency as an unforeseeable event beyond the control of the source, which leads to the exceedance of an emission limit specified in the permit. Additionally, in any enforcement proceeding, the burden of proof that an emergency occurred is on the source. The source must also prove that any increase in

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<http://www.mde.state.md.us/programs/Permits/AirManagementPermits/Test/KMC%20Thermal%20Brandywine%20Power%20Facility.pdf>

emissions was not due to improper operation or maintenance and that every effort was made not to exceed the limitation.²³

5.3 Implications of Pipeline Expansions

Multiple projects for expanding the interstate pipeline network are in various stages of approval and construction. Phase II of the analysis will incorporate anticipated expansions into a revised assessment of regional exposures to gas infrastructure events. However, it should be noted that any planned or proposed expansions will be associated with underlying incremental loads. Pipeline projects are neither built nor approved on a speculative basis. As such, while these could increase capacity into the respective cluster areas, they would not necessarily alleviate the potential impact of a gas infrastructure event on net available gas supplies.

6 Conclusions

Natural gas has unquestionably evolved into a major and growing source of supply for the power generation sector. RTO/ISOs throughout the country have become increasingly reliant on this fuel source. While the interstate pipeline industry has an admirable safety record, gas infrastructure events and the associated loss of supply to markets are not unknown. Observed and realized gas supply disruptions can be significant in size and duration. And intentional and directed acts of sabotage could be more impactful.

Importantly, significant quantities of gas-fired generation capacity do not have the ability to burn an alternative fuel in the event of a gas supply disruption. These resources would be immediately lost during such an event and for the duration of such event. Based on the cluster analysis in this study, the loss of such gas-only capacity alone (i.e., ignoring dual fuel capable units without inventory on-site) would not be unlike the loss of a major transmission line within an RTO/ISO region.

While many gas-fired generation units have back up fuel capabilities, the benefit of this flexibility is limited by the availability of supply. To assure reliability and performance, this alternative supply needs to be located on site and in sufficient quantities to sustain performance as needed during an infrastructure event. Based on observed inventory levels the industry appears to maintain less than 10-15 days of back up supply on-site at best. To the degree an infrastructure event requires higher heat rate units to run at higher load factors, existing on-site storage resources would be depleted far more quickly.

Replacing on-site oil storage used during an infrastructure event presents significant logistical challenges. Upstream oil distribution resources do not necessarily have the capacity to sustain refill requirements associated with unanticipated oil needs, particularly if such event is

²³ Examples at http://www.dnrec.state.de.us/air/aqm_page/docs/pdf/Connectiv%20Edge%20Moor%20Proposed%20Title%20V%20Permit.pdf and http://www.dec.ny.gov/dardata/boss/afs/permits/401220004400014_r1_2.pdf

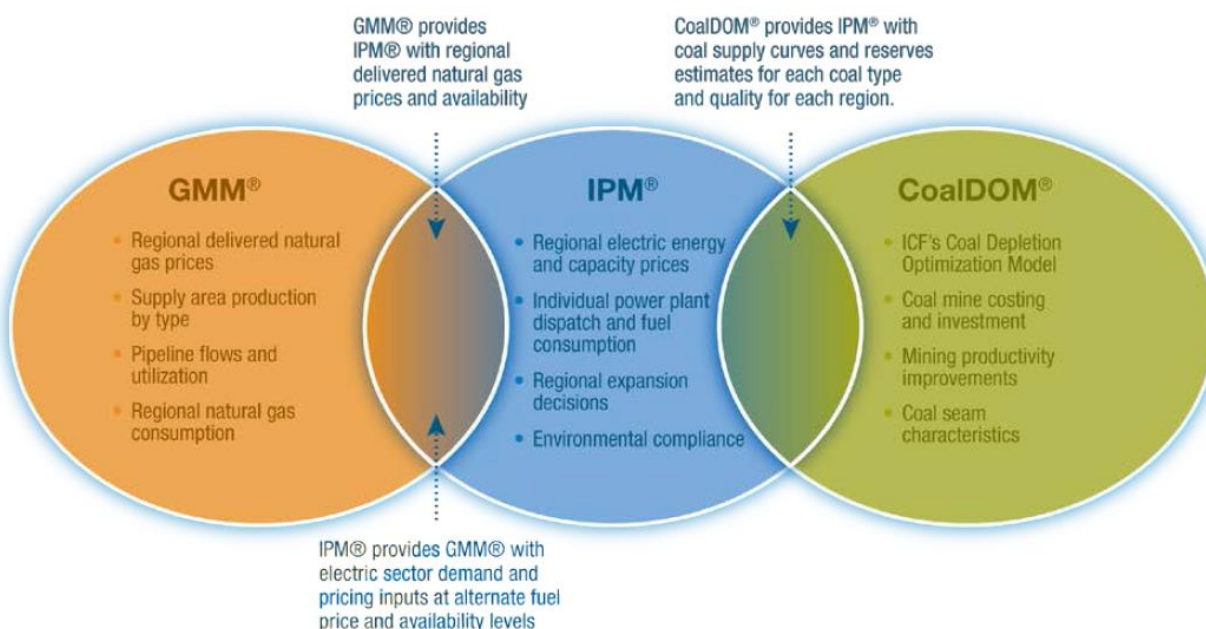
widespread and of significant duration. Further analysis of the industry's capability to support such refill requirements is warranted.

Gas-fired generation units connected to the same interstate pipeline, or even interconnected pipelines or LDCs, are at risk for concurrent loss of supply during a significant gas infrastructure event. While the interstate pipeline network is robust and highly interconnected, there are locations within the system where disruption events could have cascading implications on generation resources. RTO/ISOs should review the interrelationship between existing and planned gas-fired generation facilities and the upstream gas infrastructure and related power transmission systems.

Interstate gas supply systems cross multiple RTO/ISO systems. The disruption of a pipeline has the potential to affect gas-fired generation resources across more than one RTO/ISO at the same time. Therefore, the impact of such interrelationships and exposures should also be incorporated into resilience assessments of the power grid.

APPENDIX A

ICF's analysis was supported based on a combination of several integrated modeling suites, developed and maintained by ICF, which are outlined below. These include ICF's proprietary Integrated Planning Model (IPM), Gas Market Model (GMM), and its CoalDOM model. These allow for an integrated and holistic analysis of such factors as power market fundamentals and drivers, coal pricing dynamics, emission guidelines and policies, and gas infrastructure and supply and demand dynamics.



GAS MARKET MODEL (GMM)

ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed by Energy and Environmental Analysis, Inc., now a wholly owned business unit within ICF International, in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace.

GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- ▶ Analyses of different pipeline expansions.
- ▶ Measuring the impact of gas-fired power generation growth.
- ▶ Assessing the impact of low and high gas supply.
- ▶ Assessing the impact of different regulatory environments.

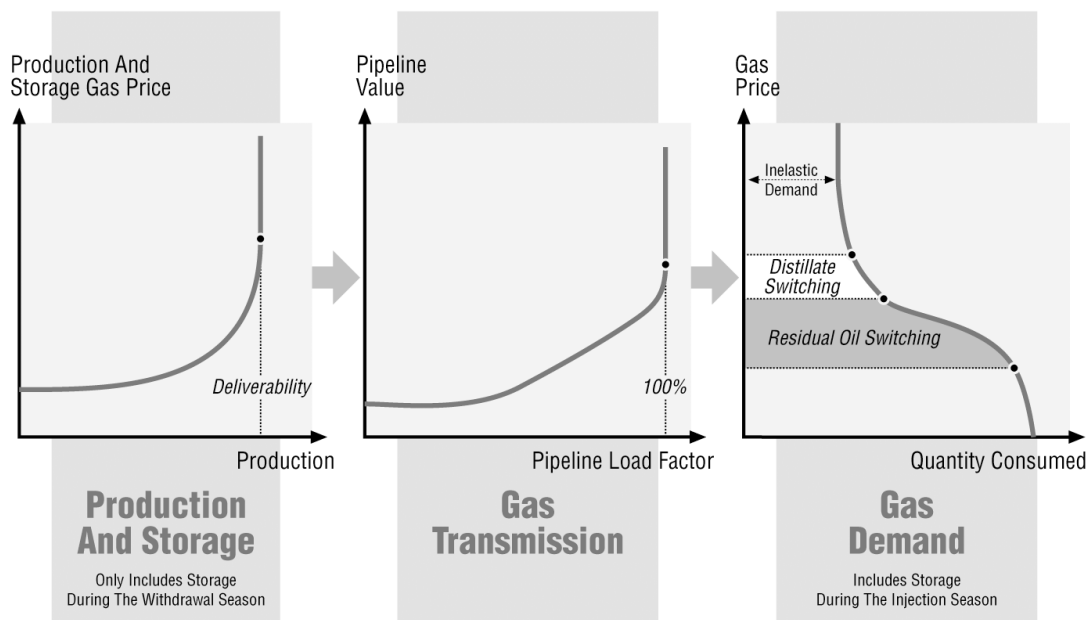
In addition to its use for strategic planning studies, the model is widely used by a number of institutional clients and advisory councils, including the recent Interstate Natural Gas Association of America (INGAA) study. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003.

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model’s nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure A-1). Prices are also influenced by “pipeline discount” curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model’s curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Figure A-1: Natural Gas Supply and Demand Curves in the GMM

Gas Quantity And Price Response

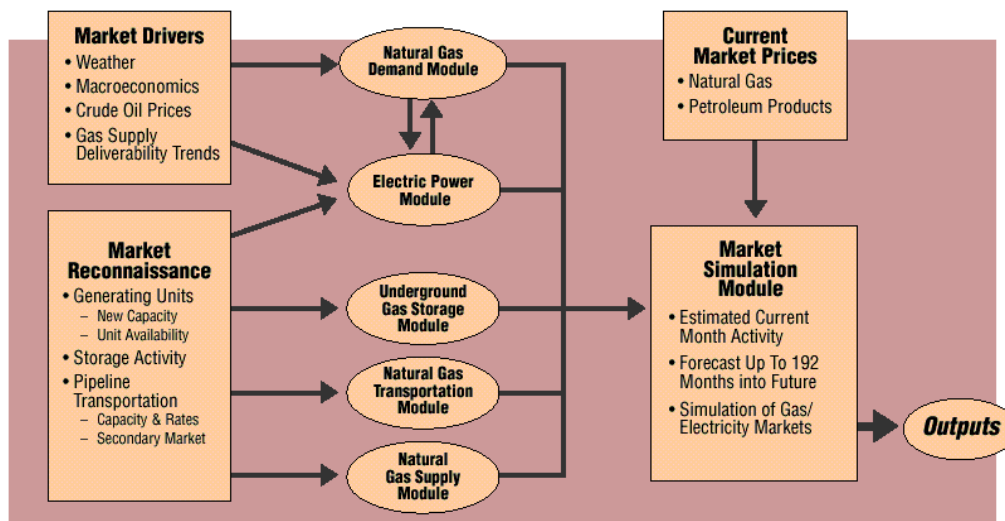


Source: ICF GMM®

There are nine different components of ICF’s model, as shown in Figure A-2. The user specifies input for the model in the “drivers” spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF’s market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

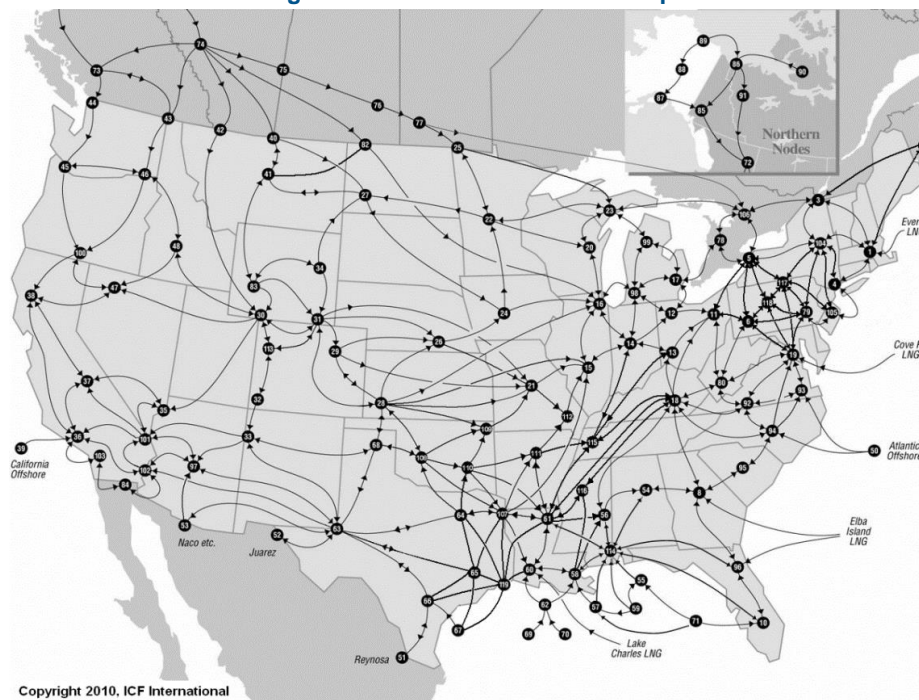
The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure A-3. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The supply component may be integrated with the GMM to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (*i.e.*, gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (*i.e.*, end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Figure A-2: GMM Structure



Source: ICF GMM®

Figure A-3: GMM Transmission Map



Source: ICF GMM®

The Integrated Planning Model (IPM)

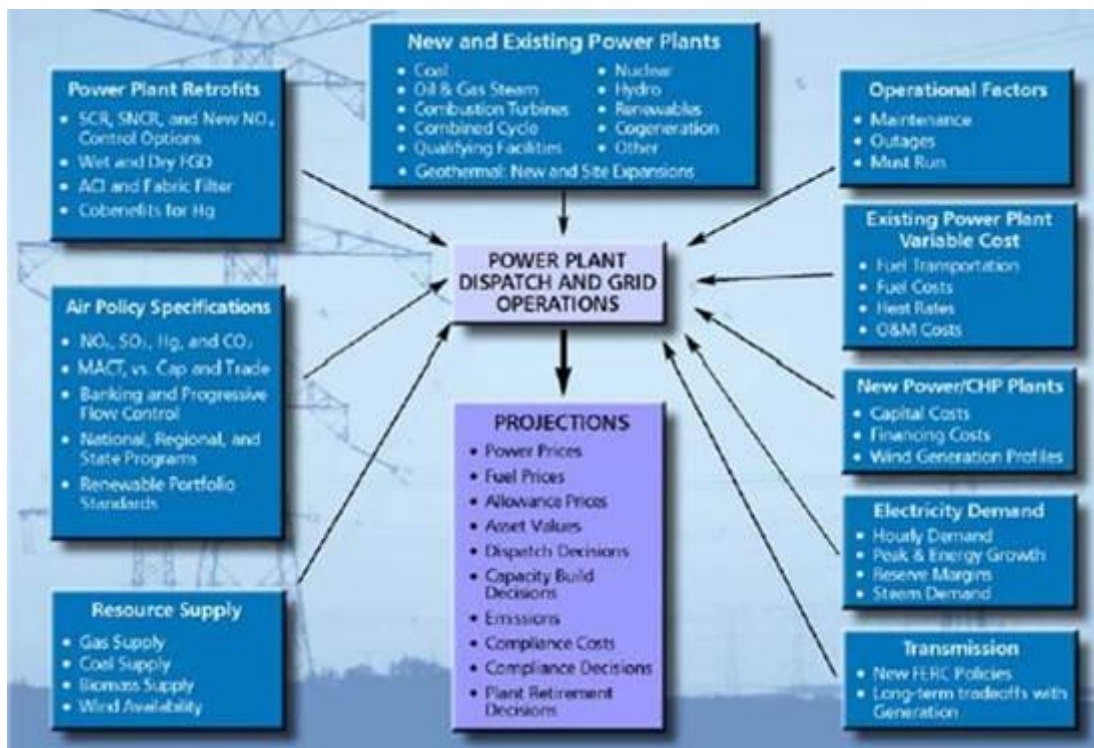
IPM is a detailed engineering/economic capacity expansion and production-costing model of the power and industrial sectors supported by an extensive database of every boiler and generator in the U.S. and Canada. It is a multi-region model that provides generating capacity and transmission expansion plans, generating unit dispatch and regulatory compliance decisions, and power, fuels, and allowance price forecasts, all based on energy market fundamentals. IPM explicitly considers gas, oil, and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals. Figure A-4 illustrates the key components of IPM.

The IPM is a linear programming model that uses a forecast of the electric demand in 76 U.S. and nine Canadian regions to determine the generation within each region, the transmission between each region, and the power, coal, and natural gas prices. Power prices are determined for each region, while coal prices are determined for 43 North American supply regions, which are included in a total of 64 global supply regions. The IPM also determines the delivered cost of coal and natural gas to each generating plant that uses those fuels.

All existing utility-owned boilers and generators are modeled, as well as independent power producers and cogeneration facilities that sell firm capacity into the wholesale market. IPM also is capable of explicitly modeling individual (or aggregated) end-use energy efficiency investments. Each technology (e.g., compact fluorescent lighting) or general program (e.g., load control) is characterized in terms of its load shape impacts and costs. Costs can be characterized simply as total costs or more accurately according to its components (e.g., equipment or measure costs, program or equipment costs, and administrative costs), and

penetration curves reflecting the market potential for a technology or program. End-use energy efficiency investments compete on a level playing field with traditional electric supply options to meet future demands. As supply side resources become more constrained or expensive (e.g., due to environmental regulation) more energy efficiency resources are used.

Figure A-4: IPM Overview



IPM has been used in support of numerous project assignments over the last 30 years including:

- Valuation studies for generation and transmission assets
- Forecasting of regional forward energy and capacity prices
- Air emissions compliance strategies and pollution allowances
- Impact assessments of alternate environmental regulatory standards
- Impact assessments of changes in fuel pricing
- Economic or electricity demand growth analysis
- Assessment of power plant retirement decisions
- Combined heat and power (CHP) analysis
- Pricing impact of demand responsiveness
- Determination of probability and cost of lost or unserved load

Outputs of IPM include estimates of regional energy and capacity prices, optimal build patterns based on timing of need and available technology, unit dispatch, air emission changes, retrofit decisions, incremental electric power system costs (capital, FOM VOM), allowance prices for controlled pollutants, changes in fuel use, and fuel price impacts. Results can be directly reported at the national and regional power market levels. ICF can readily develop individual state, province, or regional impacts aggregating unit plant information to those levels.

IPM analyzes wholesale power markets and assesses competitive market prices of electrical energy, based on an analysis of supply and demand fundamentals. The model does not extrapolate from historical conditions but rather provides a least cost optimization projection for a given set of future conditions which determine how the industry will function (i.e., new demand, new power plant costs, new fuel market conditions, new environmental regulations, etc.). The optimization routine has dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over a specified time horizon, such as 20 or 30 years). All major factors affecting wholesale electricity prices are explicitly modeled, including detailed modeling of existing and planned units, with careful consideration of fuel prices, environmental allowance and compliance costs, transmission constraints and operating constraints. Based on looking at the supply/demand balance in the context of the various factors discussed above, IPM projects hourly spot prices of electric energy, coal, and natural gas prices within a larger wholesale power market.

