UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resiliency Pricing	)))	**Docket No. AD18-7-000**

SUPPLEMENTAL COMMENTS OF
THE NUCLEAR ENERGY INSTITUTE

Pursuant to the Federal Energy Regulatory Commission's (the "Commission") January 8, 2018 order establishing the captioned proceeding,[1] the Nuclear Energy Institute ("NEI") provides these supplemental comments for the limited purpose of submitting the attached ICF report, ***The Impact of Fuel Supply Security on Grid Resilience***.[2] The ICF Final Report analyzes how the PJM Interconnection, L.L.C. ("PJM") grid would respond to a disruption of certain critical components of the gas supply and transportation system under two policy scenarios: one where announced nuclear retirements are reversed based upon policy changes and one where significant amounts of nuclear generation capacity retire prematurely.

I. EXECUTIVE SUMMARY

NEI commissioned ICF to analyze the implications of continued retirements of nuclear units, combined with the increasing reliance on natural gas as a fuel source in PJM, and whether that trend presents a resilience risk in PJM. In its initial comments in this proceeding, NEI

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[1] *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures*, 162 FERC ¶ 61,012 (2018).

[2] ICF, *The Impact of Fuel Supply Security on Grid Resilience*, Final Report, June 8, 2018 attached hereto as Appendix A ("ICF Final Report"). "The study highlights that, while the interstate pipeline network is robust and highly interconnected, there are locations within the system where disruption events could have cascading implications on gas-fired generation resources. The retirement of other types of generation supply, such as nuclear, as shown in this analysis, exacerbates the risk that load will not be served, potentially for an extended period of time." *Id.* at 3-4.

submitted ICF's interim report.[3] In that report, ICF concluded that the loss of gas pipeline infrastructure serving clusters of gas-fired generation in PJM could result in the loss of many GWs of electric generation capacity. Phase II of ICF's analysis (included in the attached report) demonstrates that this type of event, when combined with the continued retirements of nuclear capacity in PJM, would result in as much as 22 percent of the PJM Mid-Atlantic area's load being shed in the highest load hours. Conversely, the ICF Final Report concludes that the scenarios in which nuclear capacity is preserved show no such outages.

The ICF Final Report illustrates the type of analysis that must be undertaken to fully understand the impact on resilience of the increased reliance of gas-fired generation and the continued retirement of nuclear resources. NEI urges the Commission to fully consider the ICF Final Report and take actions to protect resilience consistent with its conclusions.

II. SUMMARY OF ICF FINAL REPORT

In its Phase I analysis, ICF analyzed various "clusters" of generation in PJM, each of which are dependent on the same upstream infrastructure of fuel supply, to determine the actual effect on power generation of the loss or disruption of specific gas pipelines. While Phase I identified potential impacts of such disruptions on gas-fired generation resources, it did not yet address PJM's ability to withstand such an event given the potential availability of other resources, and the potential for re-dispatch of the intra- and inter-regional transmission system. This more detailed analysis was the focus of Phase II.

Building from the work completed in Phase I, Phase II assessed how the loss of gas-fired generation resources could impact resilience in PJM under two distinct nuclear retirement scenarios. The first scenario assumed announced nuclear retirements are reversed as a result of

[3] *Grid Reliability and Resiliency Pricing*, Docket No. AD18-7-000, Comments of the Nuclear Energy Institute, Appendix A, ICF, *The Impact of Fuel Supply Security on Grid Resilience-Interim Report*, May 5, 2018 (May 9, 2018).

policy changes that would stem nuclear retirements (the "Policy" case), while the second scenario assumed current market conditions lead to additional nuclear retirements (the "Extended" case). ICF evaluated both scenarios against electricity demand patterns consistent with the 2014 and 2015 winter seasons. ICF then used power flow models to assess whether PJM would lose load under the four different cases (Policy/Extended, 2014/2015). Together, the four cases represent plausible impacts of current market conditions and policy options on the future generation mix in PJM under recently observed weather conditions.

The ICF Final Report provides further details and analysis regarding ICF's Phase I and II results, and reaches several important conclusions. First, the ICF Final Report shows that a significant gas infrastructure event in PJM can trigger substantial and extended outages if existing nuclear capacity continues to retire in the region. Under the "Extended" scenarios described above, such an event could place as much as 27 GWs of gas-fired generation—18 GWs in PJM and an additional 9 GWs in the New York Independent System Operator ("NYISO") region—at risk.[4] In the process, as much as 22 percent of the PJM Mid-Atlantic area's load would be shed in the highest load hours with outages for up to 65 consecutive hours.[5] In addition, during a 60-day event, PJM would experience load losses for more than 200 hours spread across as many as 34 days.[6]

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4 ICF Final Report at 1. Notwithstanding the risks to generation resources outside of PJM, the power flow modeling portion of the ICF analysis conservatively assumes this additional 9 GWs of resources in NYISO is available to serve load during the event. *Id.* at 2, 41.

5 *Id.* at 1, 41.

6 *Id.* at 41.

Table 1-1: Case Specifications and Findings for Loss-of-Load Analysis

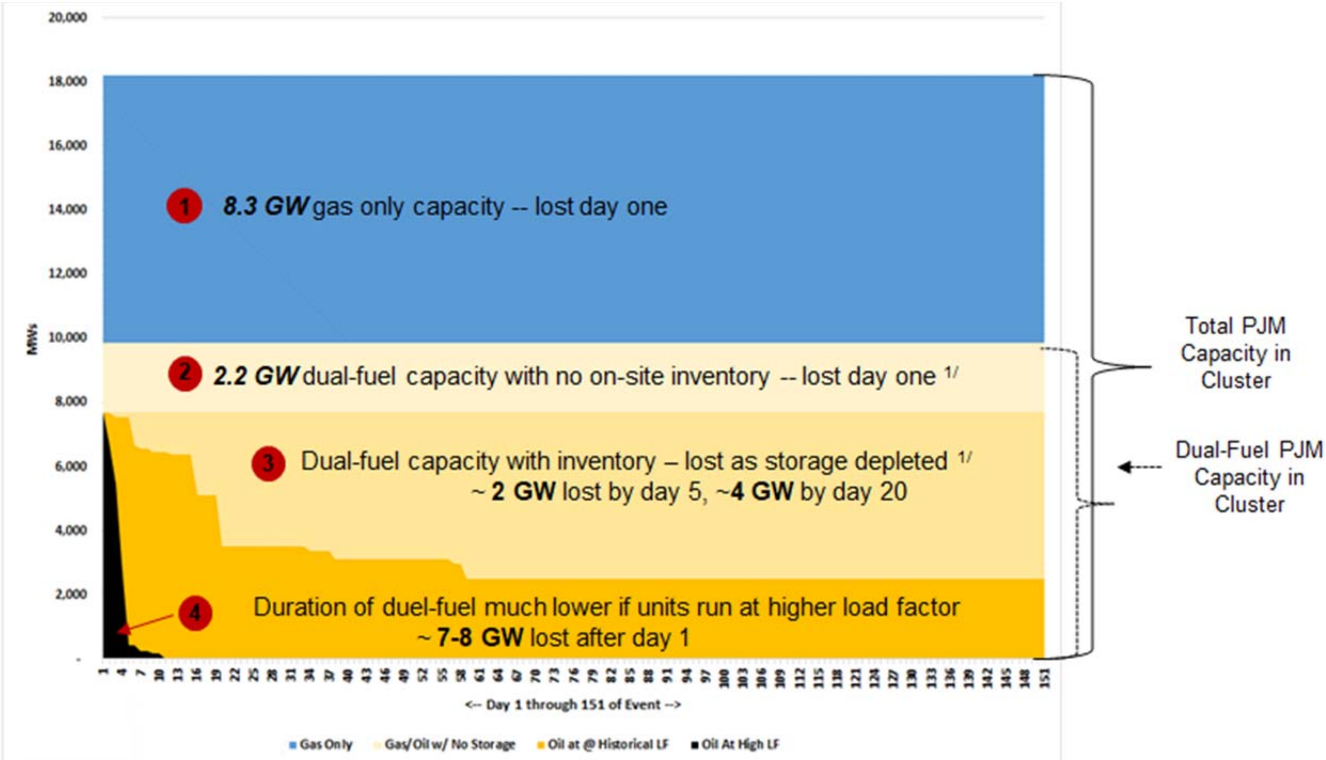
Scenario Specification	Case Name	Policy 2014 (Preserve Nuclear)	Policy 2015 (Preserve Nuclear)	Extended 2014 (Additional Nuclear Retirements)	Extended 2015 (Additional Nuclear Retirements)
	Length of Outage	60 Days			
Findings for Outage Period	Maximum Hourly Loss of Load (MW / %*)	No Loss of Load	No Loss of Load	8,754 MW 17%	10,889 MW 22%
	Days with Loss of Load			34	20
	Hours with Loss of Load			280	209
	GWh of Loss of Load			707	675

Second, the ICF Final Report demonstrates how quickly these possible outages can occur during an event. Figure 1-1 shows that of the nearly 18 GWs of gas-fired capacity within PJM that could be impacted by a significant gas event in PJM, "over 45 percent has no backup fuel capability and would be immediately unavailable."[7] And while the remaining capacity may have dual-fuel backup capabilities, the historical on-site inventory at such plants would generally last less than 15 to 20 days at average utilization levels, and more likely would last less than 5 days if such units are operated at higher load factors.[8]

7 *Id*. at 2.

8 *Id*.

Figure 1-1: Cumulative "Lost" Generation Capacity – Cluster A PJM Units



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

Third, the results of the ICF Final Report refute the notion that simply because Regional Transmission Operator ("RTO") systems are currently *reliable* they are therefore *resilient*. As NEI noted in its prior comments, 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. The Extended cases demonstrate how resilience concerns can arise in PJM even when traditional reliability analyses would not reveal a problem.[9] Because reliability and resilience are distinguishable concepts, resilience planning must include a comprehensive analysis of

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9 For example, while PJM has found that portfolios composed of up to 86 percent natural gas-fired resources can maintain traditional operational reliability in PJM, *see* PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability*, 5, March 30, 2017, ICF shows that fuel-security risks may arise even when natural gas makes up a much smaller portion of the fleet. *See* ICF Final Report at 38, Figure 6-2. PJM acknowledged that it was not attempting to study fuel security in the referenced report and has since announced a fuel security initiative. PJM Interconnection, L.L.C., "Valuing Fuel Security" (April 30, 2018), http://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180430-valuing-fuel-security.ashx?la=en.

vulnerabilities of the gas supply and delivery infrastructure and fuel-dependent resources. As the ICF Final Report notes:

> To preserve system resiliency, RTO/ISOs must understand this interrelationship between existing and planned gas-fired generation facilities, the zonal and regional capacity mix, and the upstream gas infrastructure and related power transmission systems.[10]

Finally, the ICF Final Report demonstrates the value currently provided by nuclear power plants in PJM. Unlike the Extended cases described above, if the current nuclear units in PJM continue to operate (*i.e.*, the Policy cases), "the nuclear capacity that remains online is able to offset the gas generation impacted by the [significant gas] infrastructure event, resulting in load being served in all hours."[11] In addition to these resilience benefits, ICF also shows that preservation of nuclear plants within PJM provides significant environmental benefits: projected CO_2 emission in PJM in 2023 are 21 percent (or 78 million tons) lower in the Policy case.[12]

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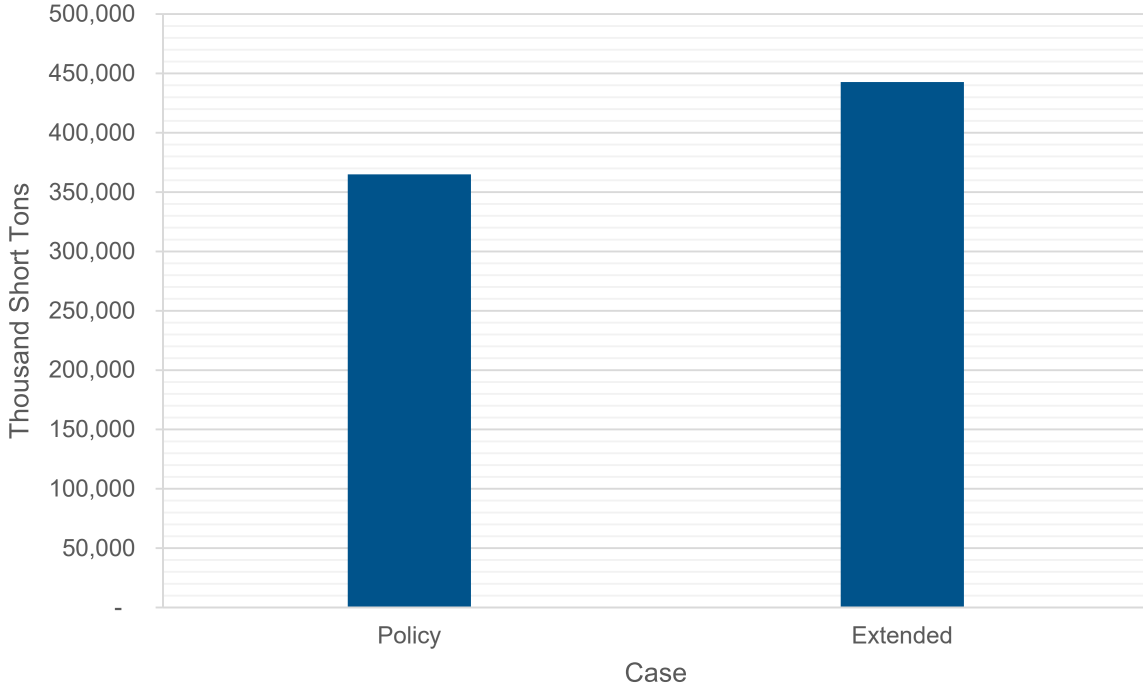
10 ICF Final Report at 4. As the ICF Final Report demonstrates, because disruptive events have the potential to affect gas-fired generation resources across more than one RTO or Independent System Operator ("ISO") at the same time, the impact of such interrelationships and exposures across RTO/ISOs should also be analyzed. *Id*. at 41-42.

11 *Id*. at 39.

12 *Id*. at 37.

Figure 6-3: Projected PJM CO_2 Emissions in 2023



III. CONCLUSION

NEI respectfully submits these supplemental comments and the attached ICF Final Report and requests that the Commission act expeditiously to address the important resilience issues they raise.

Respectfully submitted,

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Dated: June 8, 2018

CERTIFICATE OF SERVICE

I certify that on this 8th day of June, 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.

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Appendix A

The Impact of Fuel Supply Security on Grid Resilience in PJM

Final Report

June 8, 2018

Study prepared at the direction of the Nuclear Energy Institute by ICF

IMPORTANT NOTICE:

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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. 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').

The Nuclear Energy Institute (NEI) commissioned ICF to perform an analysis of how a gas infrastructure event affecting gas-fired generation resources in PJM might affect system resiliency. NEI specified the scenarios for the analysis and the key assumptions for those scenarios. The work characterizes the gas infrastructure system supplying PJM in relation to existing and planned gas-fired generation capacity, and assesses the potential impact of a significant gas infrastructure event on the availability of gas-fired generation in this region.[1] It then takes the results of that work and assesses how the loss of gas-fired generation resources could impact resilience in PJM when combined with two policy scenarios for future nuclear capacity. One scenario where existing announced nuclear retirements are reversed based upon policy changes ("Policy") and one where the current challenging environment leads to a broad swath of additional retirements ("Extended"). Both scenarios were evaluated against electricity demand patterns consistent with the winters of 2014 and 2015, which are the two years with the highest January and February electricity demand levels in PJM in the past decade.[2] The cases provide a range of options for the future generation mix in the region that reflect the potential impact of current market conditions and economic pressures on nuclear generation, as well as various policy proposals around these resources

As summarized in Table 1-1 below, the results of this analysis show that a significant gas infrastructure event could prevent the PJM Mid-Atlantic area from serving electric load on a number of days if existing nuclear capacity was retired. Such an event could result in the loss of nearly 27 GW of gas-fired generation, with 18 GW serving the PJM Mid-Atlantic area, depending on the severity and location of such event.[3] When combined with the retirement of a similar amount of nuclear capacity, the analysis implies such an event would put as much as 22 percent of the area's load at risk of being shed in the highest load hours. Over an assumed 60-day event, those loss-of-load impacts could take place for over 200 hours spread across as

[1] A similar analysis was performed by ISO New England for the New England region. See "Operational Fuel-Security Analysis", January 17, 2018, ISO-NE,public.
[2] PJM's historical hourly load profiles can be found at http://www.pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx
[3] The study focused on gas-fired generation units directly or heavily reliant on Transco and Texas Eastern in the Philadelphia, New Jersey, and Delaware region. Upwards of 27 GWs were identified. This includes 18 GWs located directly in the PJM market (the focus of the study) but also an additional 9 GWs located downstream in NYISO that would likely be impacted by an infrastructure event impairing the PJM units. Load impacts were assessed for PJM only. Downstream impacts in NYISO were outside the scope of the study.

many as 34 days. The study also shows that the preservation of nuclear capacity in PJM would successfully mitigate the loss of load risk.

Table 1-1: Case Specifications and Findings for Loss-of-Load Analysis

Scenario Specification	Case Name	Policy 2014 (Preserve Nuclear)	Policy 2015 (Preserve Nuclear)	Extended 2014 (Additional Nuclear Retirements)	Extended 2015 (Additional Nuclear Retirements)
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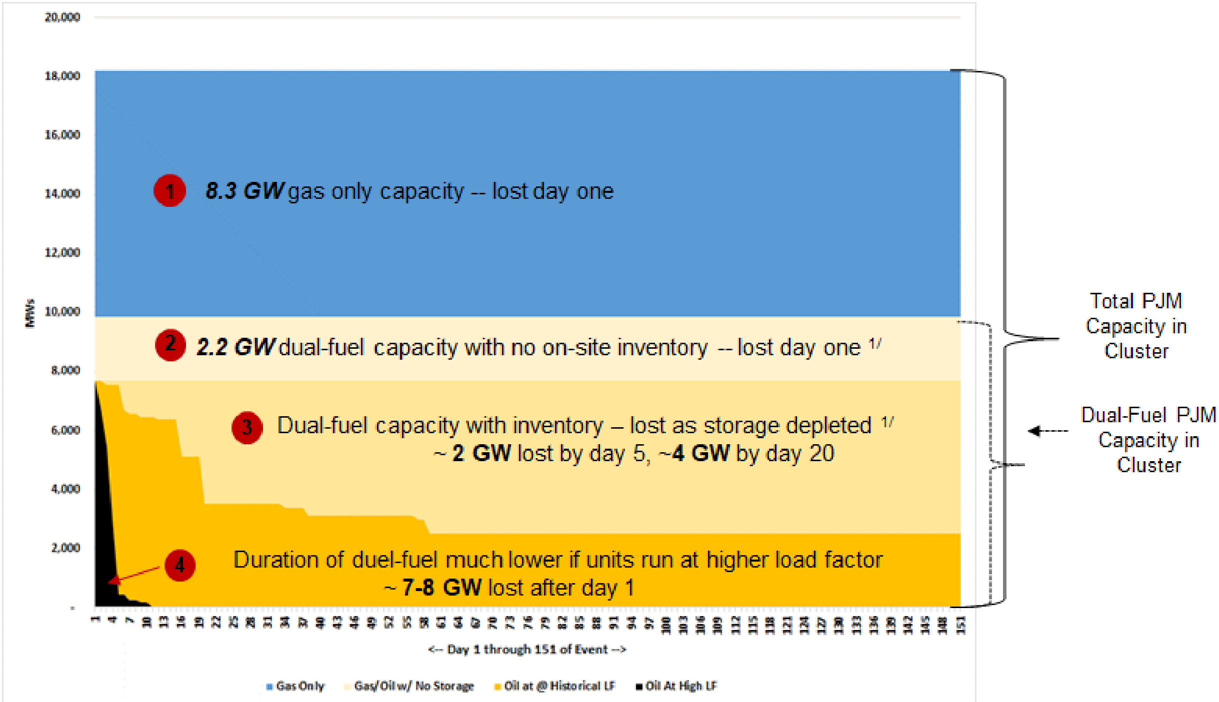
	Hours with Loss of Load			280	209
	GWh of Loss of Load			707	675

* Percentage of PJM Mid-Atlantic estimated winter peak

As summarized in Figure 1-1, of the nearly 18 GW of gas-fired capacity that could be impacted by such an event, over 45 percent has no backup fuel capability and would 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 15 to 20 days of operation at recent average utilization levels (represented by the shaded orange area). On-site fuel resources would last far fewer days, generally less than 5, if these units are operated at higher load factors as a result of the loss of gas-only resources during such an event (represented by the shaded black area). While backup supplies could be ordered to replace fuel used during such an interruption, the ability of the upstream oil distribution network to replenish such supplies during such an event, and the associated logistics of such refill, is questionable, particularly if such event is widespread.

The study scope focused on generation assets and loads in PJM. For reasons of modeling simplification, resources in other regions, particularly NYISO, were assumed unaffected. However, a gas infrastructure event affecting generation in the study area would also place downstream resources in New York at risk. Based on the analysis developed for this study, a gas infrastructure event affecting the PJM target area would also place an additional 9 GW of downstream resources at risk, with associated implications for loads in NYISO. This in turn would likely have feedback implications for loads in the PJM study area. This highlights the inter-regional nature of the gas infrastructure supporting ISOs/RTOs and the need to evaluate these and related risks on a broad basis.

Figure 1-1: Cumulative "Lost" Generation Capacity – Cluster A PJM Units



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

The study scope did not include an assessment of the probability of such an infrastructure event. However, the industry has experienced gas infrastructure events of the size that could have a 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 historical events lasted for many months. While uncommon, the report reviews two such events that occurred in the last five years. Both example events are estimated to have impacted over 1 Bcfd of deliverability on the affected pipeline and lasted well beyond the 60-day outage horizon assumed for this analysis.

Historical infrastructure events affecting the gas supply infrastructure were generally the result of natural causes (e.g., weather events, degraded infrastructure, or failure of equipment). Deliberate, malicious acts (e.g., terrorism) also have the potential for harm, and, if executed in a coordinated manner, could result in greater impacts over a broader area.

It should also be noted that the study assumes gas-fired generation resources can access gas supplies outside of an infrastructure event, regardless of weather conditions. However, many generators in the PJM region do not own or hold firm transportation capacity on the upstream pipelines. As such, these generators are arguably more exposed to infrastructure events (because their rights are secondary in nature) and may already be taxing on-site backup oil resources prior to such an event because transportation capacity in the market is being fully utilized by shippers holding firm rights in the market.

The study highlights that, while the interstate pipeline network is robust and highly interconnected, there are locations within the system where disruption events could have cascading implications on gas-fired generation resources. The retirement of other types of generation supply, such as nuclear, as shown in this analysis, exacerbates the risk that load will not be served, potentially for an extended period of time. To preserve system resiliency, RTO/ISOs must understand this interrelationship between existing and planned gas-fired generation facilities, the zonal and regional capacity mix, and the upstream gas infrastructure and related power transmission systems.

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. In fact, results from the study highlight how the gas infrastructure serving gas-fired generation in the US crosses multiple RTO/ISO boundaries. 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 B 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.[4] The analysis was divided into two phases. The sections below describe the analytical approach to each phase.

2.3.1 Phase I Approach

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:

1. 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.
2. Characterize the natural gas infrastructure supplying the gas-fired generation resources in this region, including identifying the primary sources of supply,

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

interconnectivity between such resources, intra-regional supply and storage resources, and seasonal gas flows.[5]

3. Define gas infrastructure events that could occur and evaluate the potential impact of such events on the gas-fired generation resources in the region.

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.[6] 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.[7]
- **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.[8]
- **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

[5] 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.
[6] 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.
[7] 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.
[8] More importantly, neither the EIA nor EPA data base provides an assessment of the veracity 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 veracity 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.

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.[9]

- **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 information from EPA's NEEDs data base, as well as state-specific limitations on NOx, as applicable.[10]

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, 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.

2.3.2 Phase II Approach

The gas infrastructure assessments developed in the Phase I work are scoping in nature. While the analysis identifies potential impacts on gas-fired generation resources, it does not account for the ability of an 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 assessing whether the PJM system would face potential loss-of-load concerns in the event of the loss of specific gas-fired generation resources subject to two alternative nuclear capacity futures.

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[9] 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.

[10] 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).

In order to assess the interplay between nuclear generation resources (under pressure from low prices in the wholesale market) and natural gas-fired generation, ICF undertook two tasks:

1. **Evaluation of Nuclear Scenarios** - First, ICF prepared forecasts of future generation and capacity resources for the PJM region based on two scenarios for nuclear retirement for the period of 2020 to 2040.
2. **Gas Outage Resiliency Impact** - Second, ICF assessed the impact of a loss of gas-fired generation due to a natural gas infrastructure event impacting the NJ/Philadelphia generation market based on its impact on power load flows for the year of 2023.

Evaluation of Nuclear Scenarios

NEI specified two nuclear retirement scenarios for evaluation:

1. The **Policy Case** reflects a scenario under which existing nuclear units in PJM continue to operate beyond 2022 as a result of actions by the states or federal government. The only currently operating nuclear unit in PJM that retires prior to 2023 in the Policy Case is Oyster Creek 1, which is scheduled for retirement in October 2018; and
2. The **Extended Case** assumes economic circumstances cause the retirement of 19.4 GW of nuclear capacity across PJM prior to 2023.

The unit-level retirement assumptions are shown in Appendix A.

Utilizing these nuclear retirement assumptions, ICF utilized its Integrated Planning Model (IPM®) to evaluate changes in the generation mix in PJM, as well as incremental capacity needs or retirements consistent with the nuclear capacity scenario.[11] As described in Appendix B, IPM is a capacity expansion model used widely across the industry to project builds and retirement of generating stations.

Assessment of Loss-of-Load

At NEI's direction, ICF applied two different hourly load profiles to each case based on historical load profiles from PJM for the years 2014 and 2015, which are the two years with the highest January/February loads in the past decade.[12] ICF scaled those profiles to represent PJM's projected total demand in 2023.[13] The combination of future PJM capacity mix scenario (i.e., nuclear capacity case) and load profile year result in four separate cases for analysis:

1. Policy Case based on the 2014 profile (Policy 2014)
2. Policy Case based on 2015 profile (Policy 2015)
3. Extended Case based on 2014 profile (Extended 2014)
4. Extended Case based on 2015 profile (Extended 2015)

ICF then used the PowerWorld power flow model to assess whether PJM would face loss-of-load conditions under gas infrastructure events and nuclear retirement scenarios. PowerWorld is ideal for simulating the transfer of large blocks of power across a transmission grid or for importing or exporting power to neighboring systems. Therefore its evaluation accounts for how

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[11] Note: The IPM analysis also provides associated estimates of CO_2 emission levels with and without the associated nuclear generation facilities.

[12] PJM's historical hourly load profiles can be found at http://www.pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx

[13] PJM projected load from PJM 2018 Load Forecast Report http://www.pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report.ashx?la=en

the combination of transmission capabilities and the remaining generation stack might accommodate impacts from the loss of gas-fired generation due to a gas infrastructure event. The power flow analysis simulates an instantaneous system condition (i.e. the system condition of a certain point of time) and is used to model the peak load condition.

For the purpose of this study, ICF simulated the Eastern Interconnection system in PowerWorld with a focus on the performance of PJM's network. ICF derived the Policy and Extended power flow cases by matching the supply stack to the capacity build-out and retirement in IPM for each case. On the demand side, the modeled peak condition was assumed to be the peak load requirement over a 60-day period covering January and February in 2023.

If PowerWorld projected that the system would meet load in the peak hour, then it was assumed that load would also be met in the remaining hours over the 60-day period. If the projected system did not serve load in the peak hour, then ICF reduced load from the forecast until load could be met, resulting in a gigawatt value that could be served in the face of the combined gas generation outages and nuclear retirements. That gigawatt value was then applied to the remaining hours over the 60-day period to determine how many hours and gigawatt-hours in total would not be served given that available capacity.

The analysis also accounted for the capability of dual-fuel units to serve load consistent with their estimated oil inventories. This study assumed that those units would run only until their existing inventories were depleted and that they would not be able to re-stock over the 60-day gas infrastructure event period.[14] The units with oil were dispatched as needed according to heat rate, with units with the most favorable heat rates dispatching first, until their oil reserves were depleted, at which time they were removed from the supply stack. The analysis did not take into account ramping issues or minimum run-time requirements that could substantially limit the operation of the units in such an event.

3 Gas Generation and Pipeline Infrastructure in PJM

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 3-1, 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.

[14] Inventory levels were based on the maximum reported inventory levels for 2016 by facility.

Table 3-1: Power Sector Gas Consumption by Census Region (Million Cubic Feet)

	2011	2012	2013	2014	2015	2016	Increase Since
New England	438	433	358	335	387	386	-12%
Mid-Atlantic	940	1,119	1,035	1,091	1,193	1,306	39%
East North Central	386	644	466	472	687	881	128%
West North Central	112	167	134	104	139	181	61%
South Atlantic	1,636	2,008	1,849	1,852	2,259	2,393	46%
East South Central	629	787	619	654	850	937	49%
West South Central	2,119	2,287	2,031	1,969	2,330	2,280	8%
Mountain	556	645	648	630	721	735	32%
Pacific (contiguous)	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. As summarized in Table 3-2, 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 experienced particularly significant increases over this period.

Table 3-2: 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
New England	13,483	39.3%	14,143	41.5%	660	4.9%	2.2%
Mid-Atlantic	38,957	37.5%	48,085	46.6%	9,128	23.4%	9.1%
South Atlantic	74,503	35.8%	90,340	43.4%	15,837	21.3%	7.6%
East North Central	44,579	29.2%	47,329	32.7%	2,750	6.2%	3.5%
West North Central	19,771	23.7%	21,481	23.6%	1,711	8.7%	-0.1%
East South Central	33,143	36.7%	37,439	43.3%	4,297	13.0%	6.6%
West South Central	109,077	63.0%	103,998	56.6%	(5,078)	-4.7%	-6.4%
Mountain	32,699	37.4%	34,695	37.0%	1,996	6.1%	-0.4%
Pacific (Contiguous)	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 Power Month

More importantly, Table 3-2 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 3-3 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 3-3: 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 3-4, 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 3-4: 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 grid's exposure to critical impacts on that infrastructure an important factor when evaluating the resilience of RTO/ISO systems.

3.2 Gas Infrastructure Supplying PJM

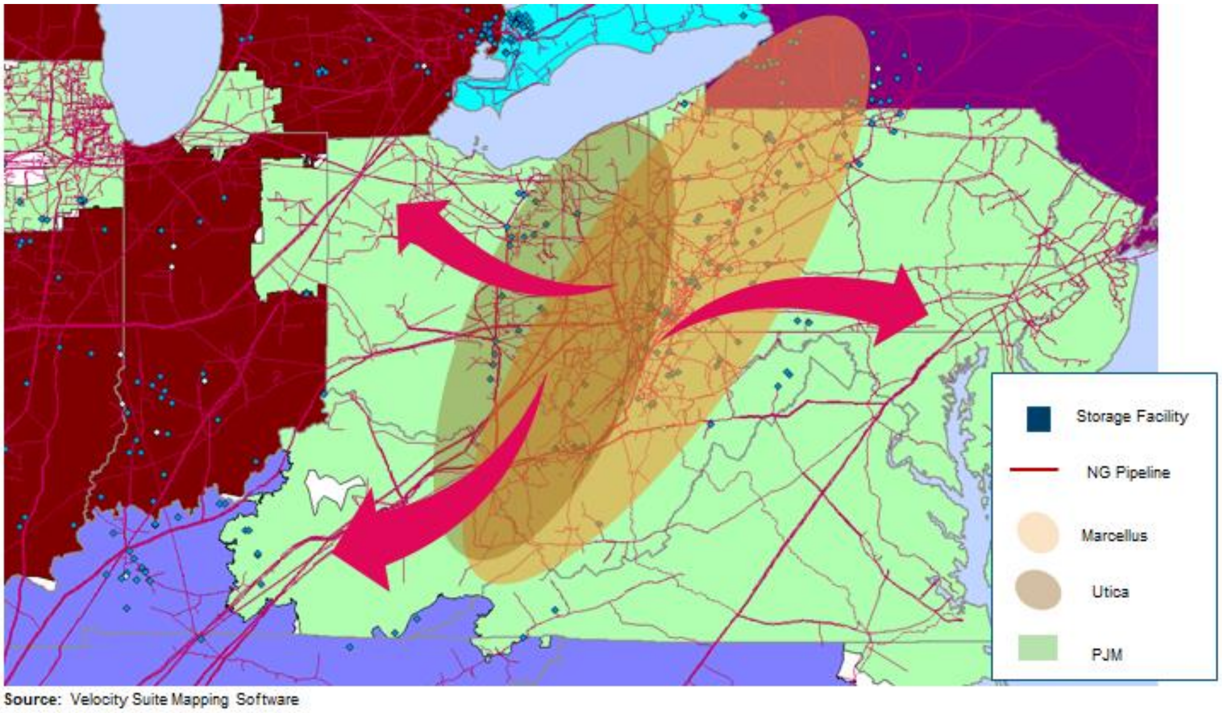
As a first step to understanding the interdependence of the PJM Power Grid with the regional gas infrastructure, Figure 3-1 summarizes the key gas infrastructure supplying the PJM region. The red lines represent the major interstate pipelines within the region. Key pipelines in the region include:

- ***"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.

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 moves this supply 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 peak-shaving facilities held by local distribution companies to meet core customer requirements during extreme weather events.

Figure 3-1: Gas Infrastructure Supplying PJM



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.

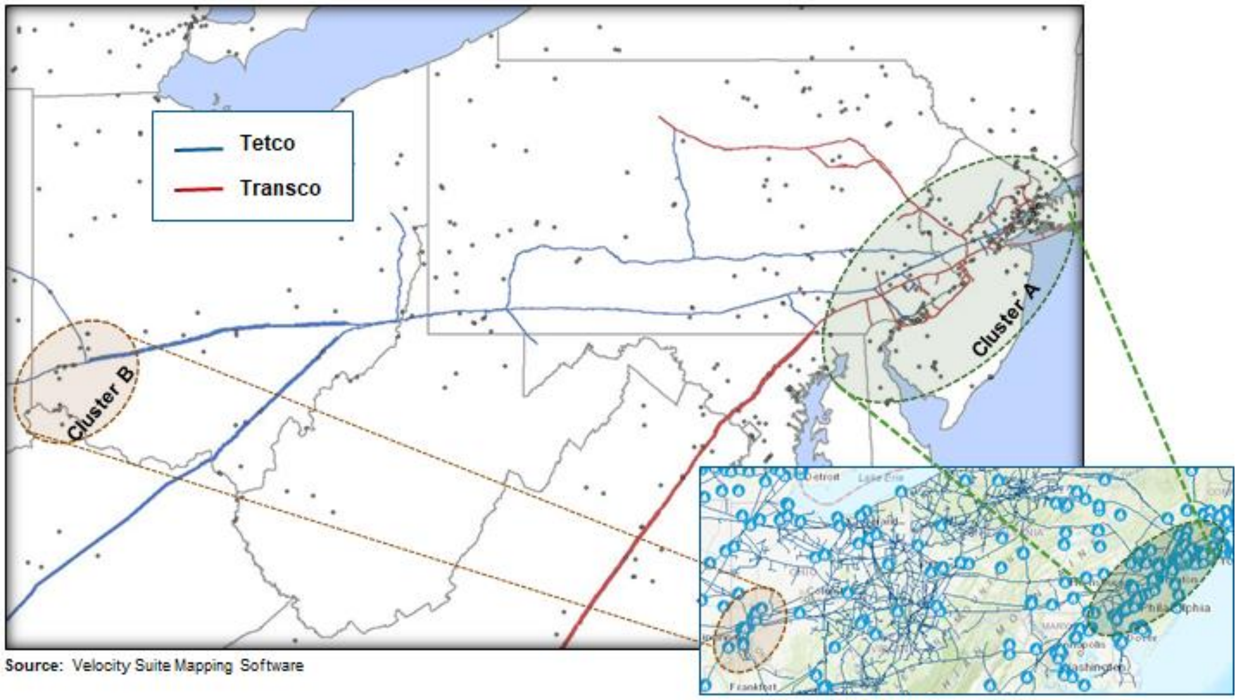
A key take-away from this figure is that the core PJM markets in the New Jersey and Pennsylvania region are all downstream of regional supply and storage resources. While not as dramatically at the 'end of the pipe' as New England, this section of PJM still has limited options to replace lost infrastructure 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 3-2 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

Figure 3-2: Cluster Focus



Source: Velocity Suite Mapping Software

Source: EIA Infrastructure Map

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.[15] As such, subsequent sections of the analysis focus on these two pipelines.

Cluster "A" Description

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

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

the NYISO (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.[16]

- 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 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

[16] 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.

  - 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 Bcfd[17]
- **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[18]
  - 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 Bcfd 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 as heavily 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 deliverability into the region or over 1/3 of the associated line's delivery capability.

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)

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[17]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

[18] See ANR Informational Postings: Critical, Force majeure, 20130618, ANR PIPELINE COMPANY, 006958581

- Recovery from such an event is not necessarily quick. Recovery periods for larger 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

In this section, we review the regional pipeline assets and their recent flow rates and interconnectivity for each cluster. 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, could be expected to exceed this level of curtailment.

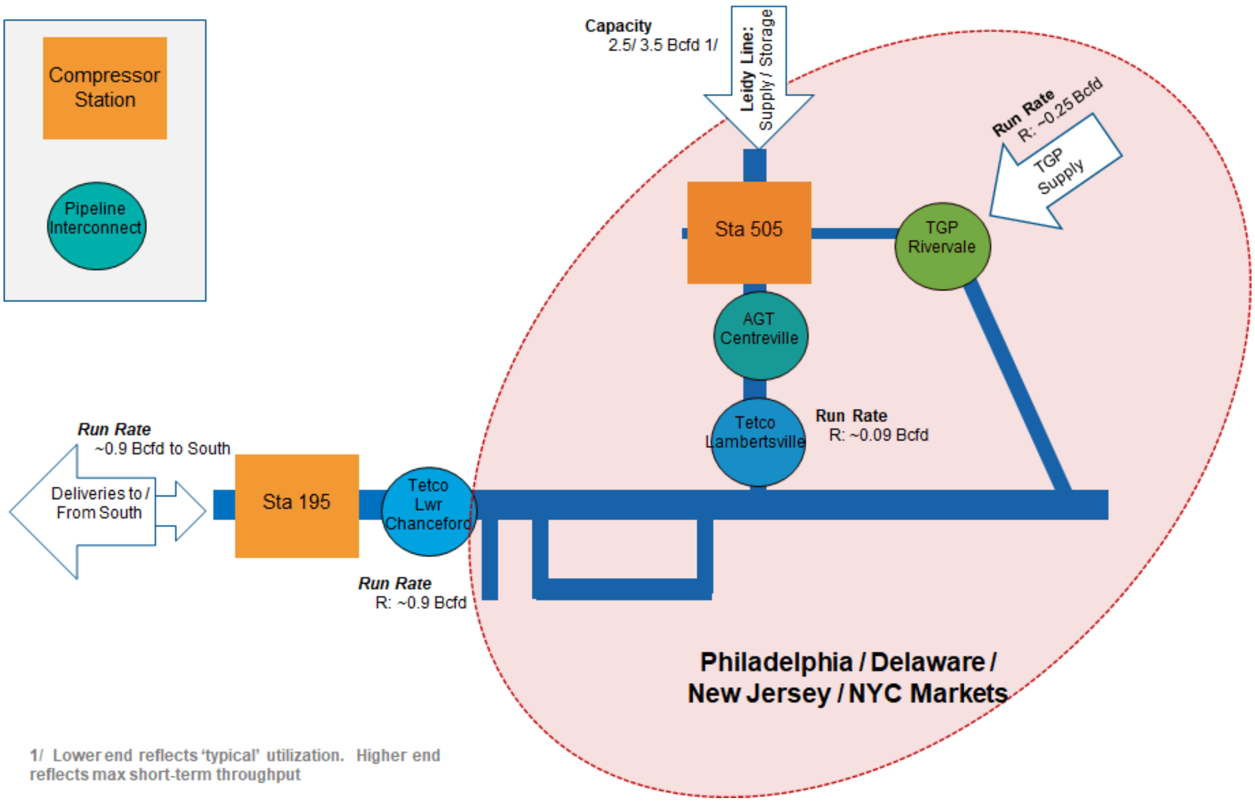
In addition, the assumption is made that, of end-use markets, gas-fired generation will be impacted most significantly during a disruption. ICF recognizes that choosing ‘winners’ and ‘losers’ during such an event is difficult. In practice, markets will adjust and gas will be re-traded to the highest 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 4-1 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 4-1: Transco Flow Mechanics



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 Bcfd).

Figure 4-2 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 Bcfd (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.
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Figure 4-2: Transco Flow Schematic

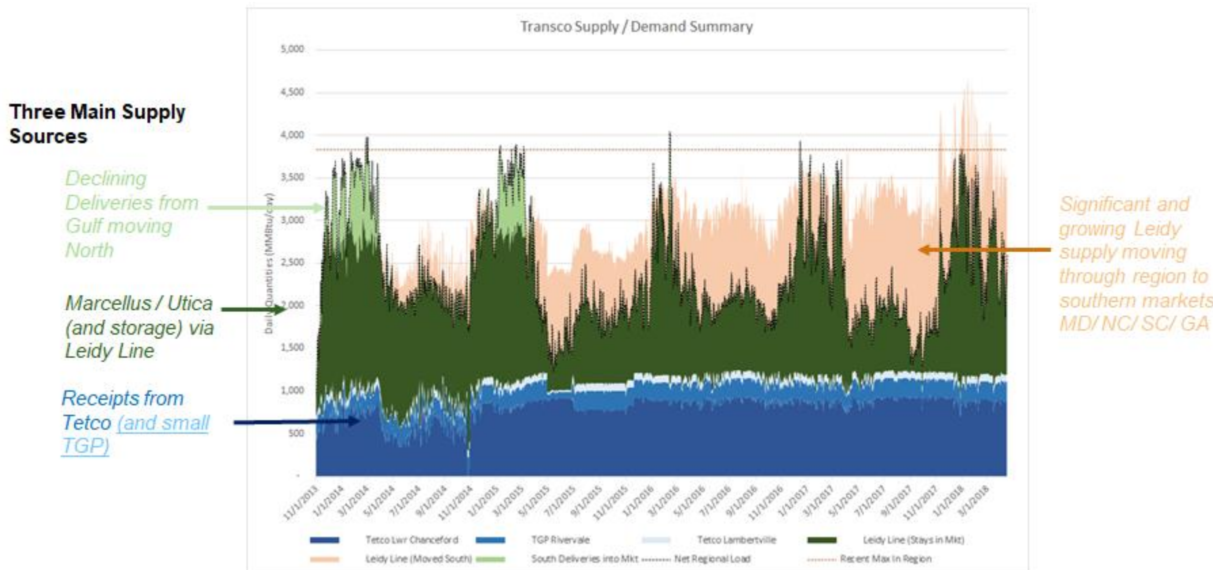
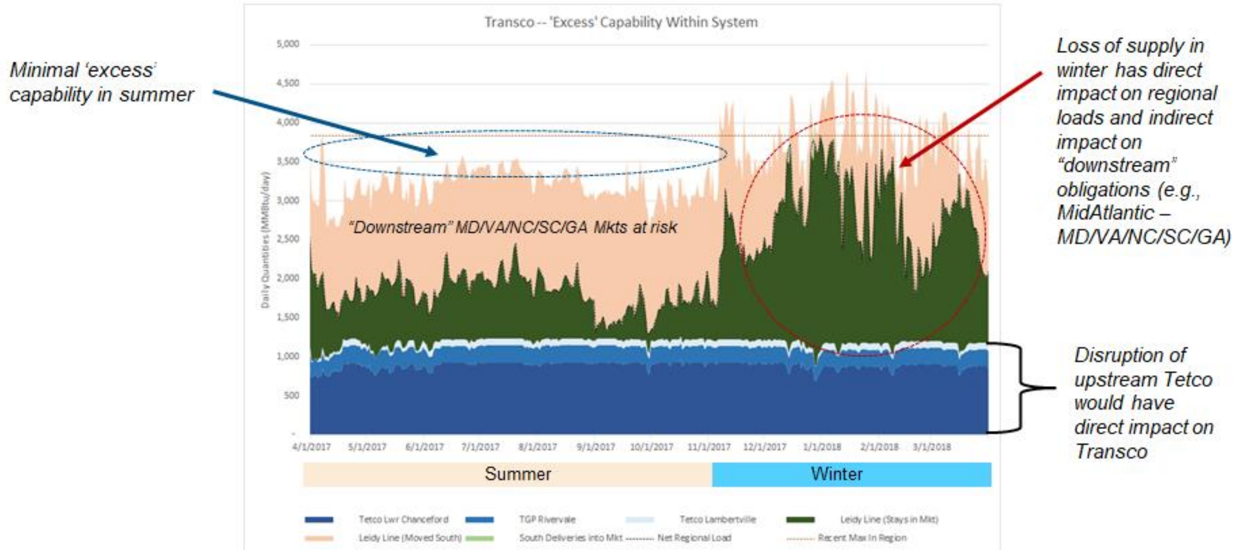


Figure 4-3 reproduces Figure 4-2 focusing on the most recent year. This highlights several important characteristics of the Transco gas supply infrastructure serving Cluster A.

- 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 likely have immediate and direct implications for Transco

Figure 4-3: Historical Flows on Transco – Last Year



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

Table 4-1 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, and 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. It is important to note that this summary includes capacity off Transco located outside the PJM study region in NYISO. Of the total 18.7 GW noted in the table, roughly 7 GWs represents gas-fired generation located in the New York City region.

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 4-1: Gas-Fired Generation Associated with Transco in Cluster A

Transco Position 1/ 2/	Natural Gas	Natural Gas, Distillate Fuel Oil	Natural Gas, Residual Fuel Oil		Total	
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

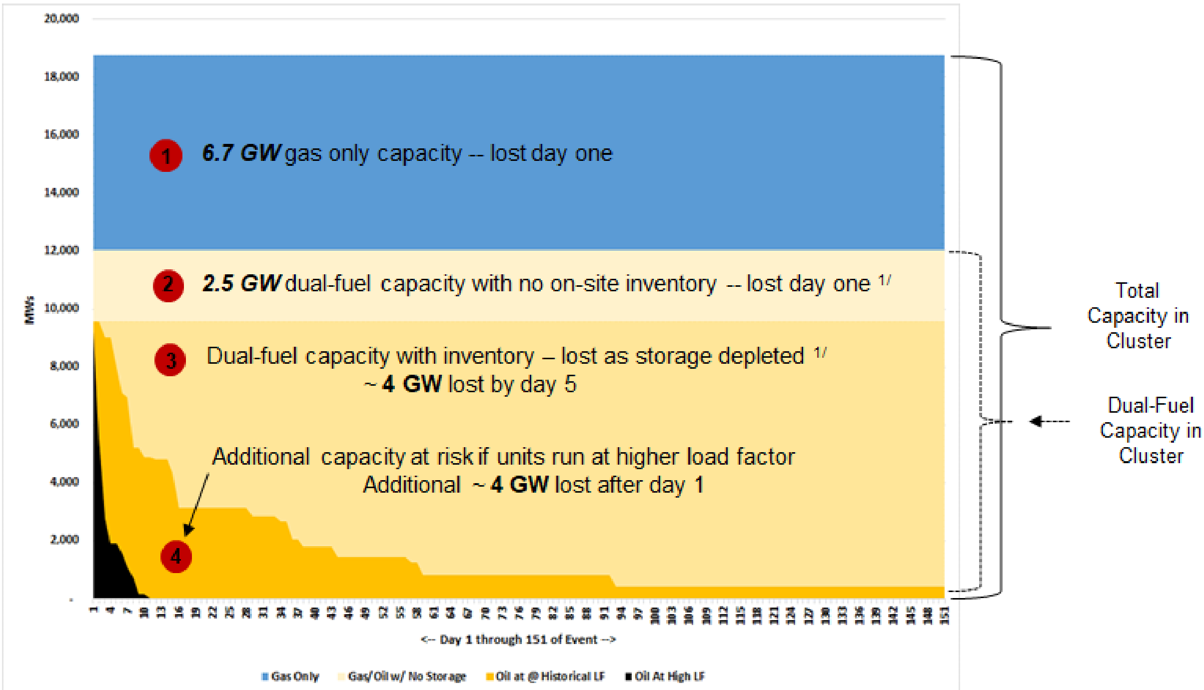
The table also converts the average daily gas supply requirement associated with the units into an equivalent oil requirement and compares this to the reported on-site storage inventories. Distillate units hold an average of 12 days of supply on site and resid units hold an average of 14 days.

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 4-4 summarizes the results as follows (again for the entire cluster including facilities in NYISO):

Figure 4-4: 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.

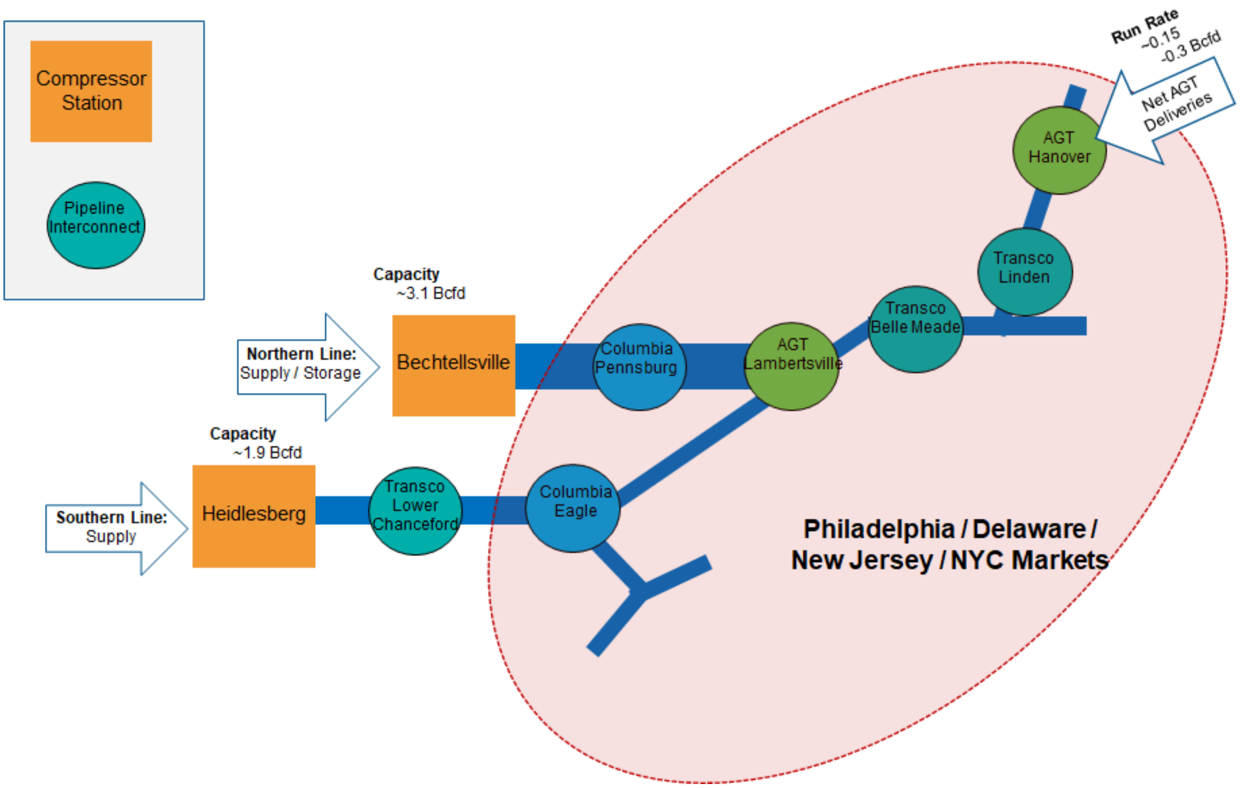
In summary, the Transco Cluster A market has the potential to lose 6.5 GWs of gas-only generation during a gas infrastructure event with an additional 12 GWs at risk based on the availability of backup fuel. Based on historical inventory levels at these plants, backup fuel resources could be depleted 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 4-5 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 4-5: Texas Eastern Flow Mechanics – East System



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 Lambertville, 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 4-6 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. Lambertville, 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 4-6: Historical Flows on Tetco

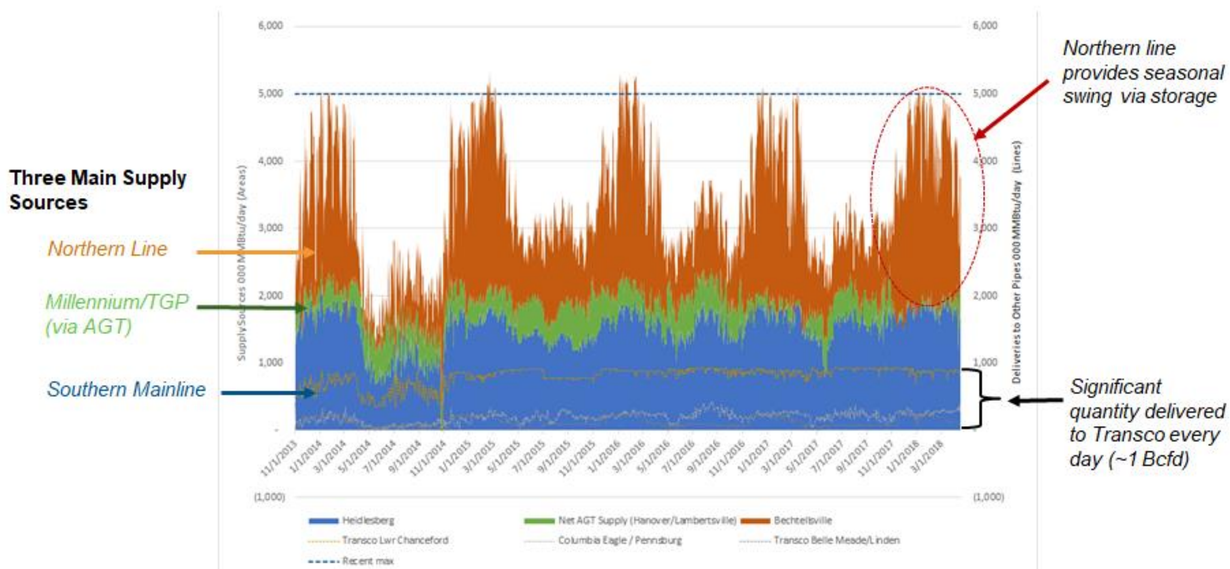
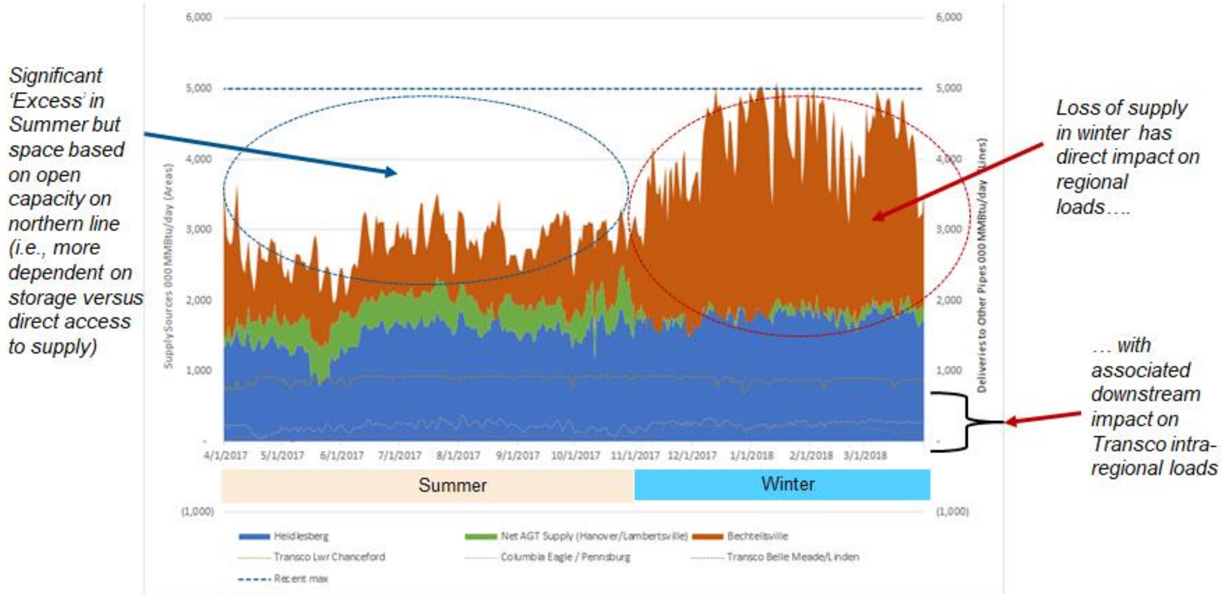


Figure 4-7 reproduces Figure 4-6 focusing on the most recent year. This highlights several important characteristics of the Tetco gas supply infrastructure serving Cluster A.

- 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 4-7: 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 4-2 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. Again, it is important to note that this summary includes capacity off Transco located outside the PJM study region in NYISO. Of the total 8.6 GW noted in the table, roughly 1.9 GWs represents gas-fired generation located in the New York City region.

Table 4-2: Gas-Fired Generation Associated with Tetco in Cluster A

Tetco East Position 1/ 2/	Natural Gas	Natural Gas, Distillate Fuel Oil	Natural Gas, Residual Fuel Oil		Total	
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't 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.

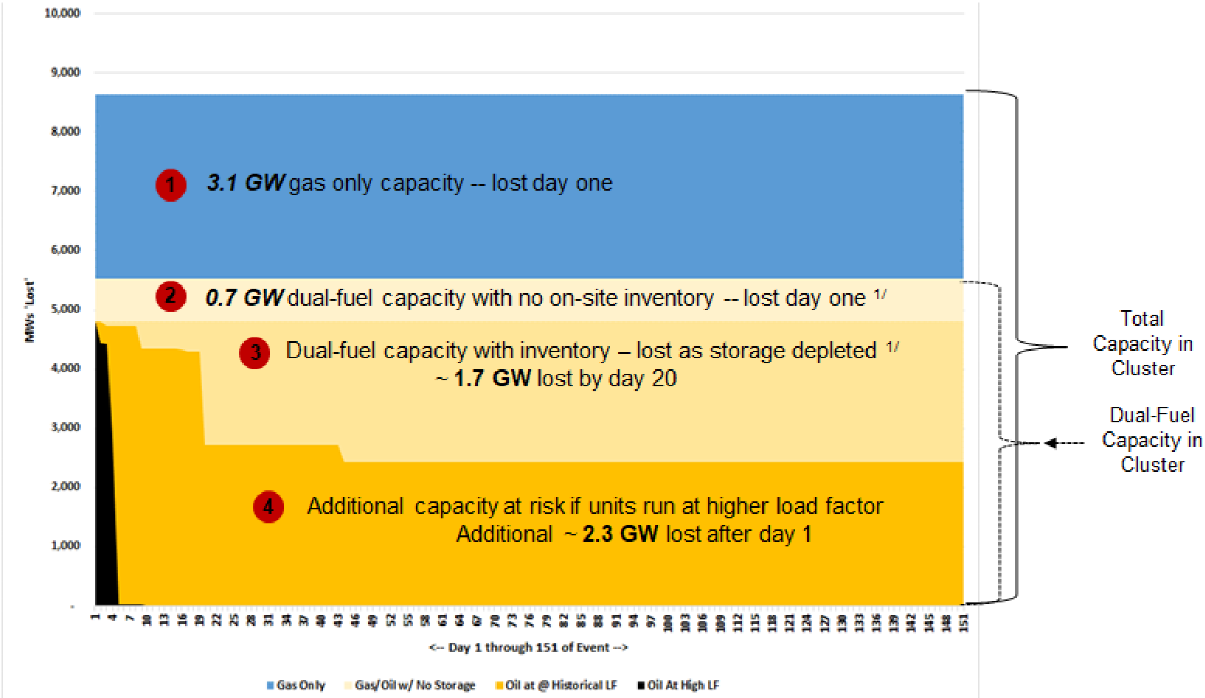
Estimated daily gas requirements associated with these plants run roughly 0.4 Bcfd with maximum potential runs upwards of 2 Bcfd. Of the 8.6 GWs of gas-fired capacity, 2.0 GWs or 36 percent is gas-fired only. More significantly, of the 2.8 GW of low heat rate, high load factor units, 1.9 GWs or over 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 4-8 summarizes potential impacts as follows:

Figure 4-8: 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 4-9 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 4-9: Texas Eastern Flow Mechanics – West System

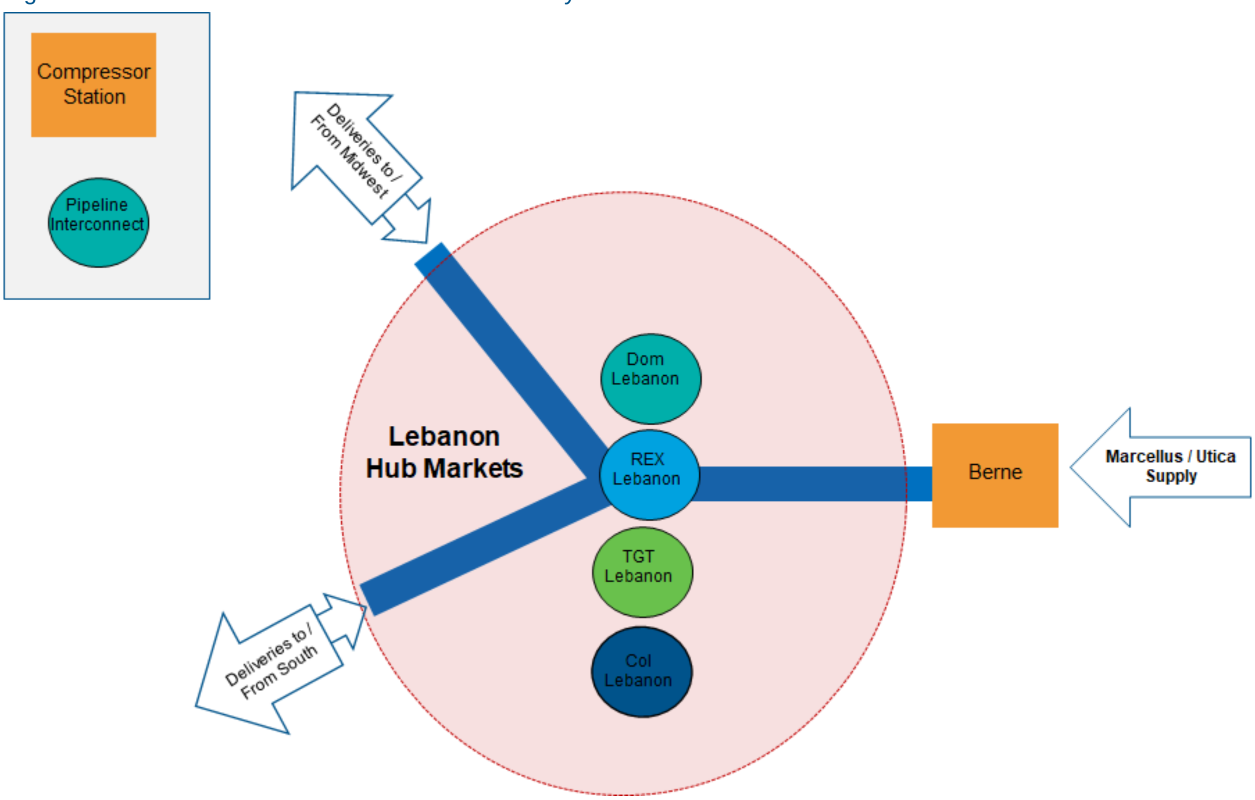


Figure 4-10 summarizes historical flows on this section of the Tetco system.

- 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 delivers 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 4-10: Historical Flows on Tetco West

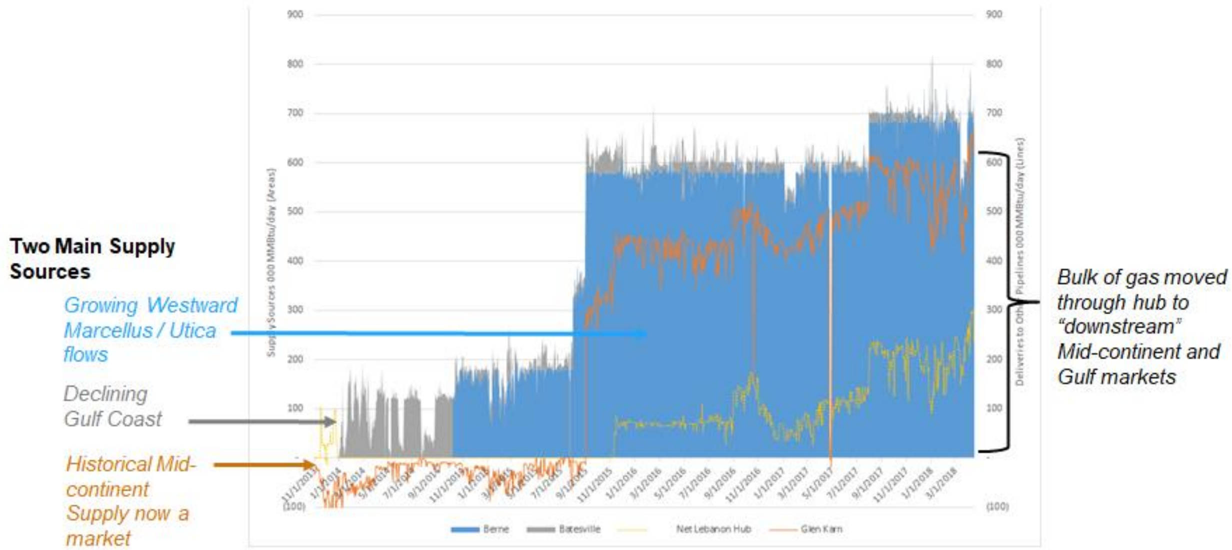
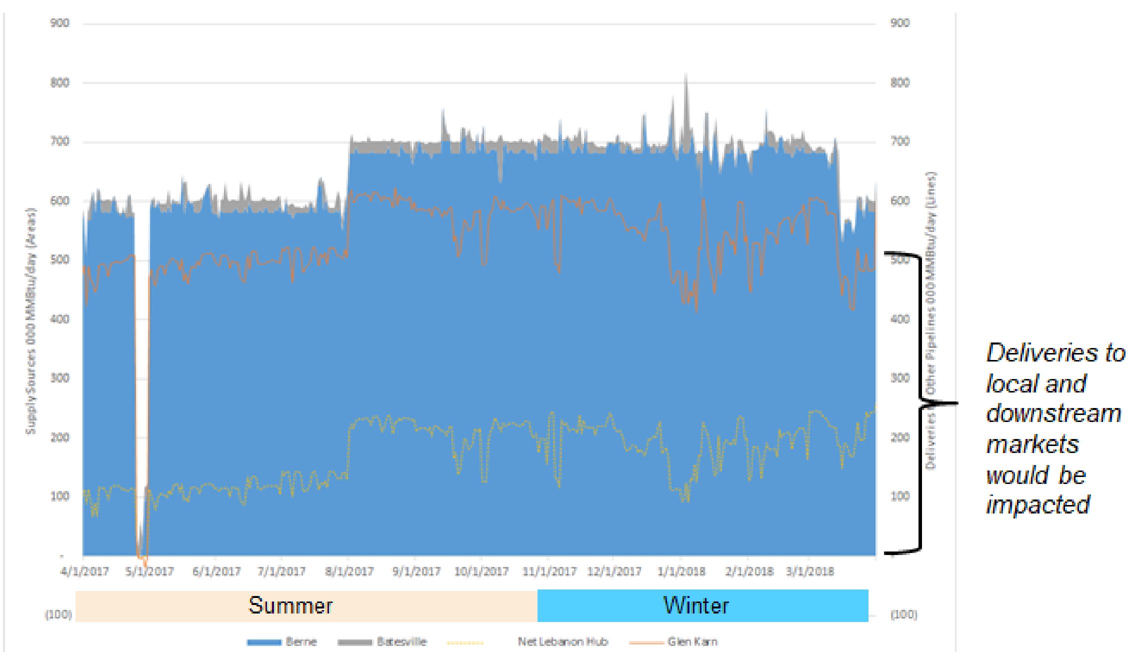


Figure 4-11 reproduces Figure 4-10 focusing on the most recent year. In contrast to the Cluster A scenario, this figure shows very little supply remaining within the cluster region. As discussed below, this reflects the relative heat rates and anticipated load factors of units in this cluster area.

Figure 4-11: Historical Flows on Tetco West – Last Year



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

Table 4-3 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.

Table 4-3: Gas-Fired Generation Associated with Cluster B Tetco

Tetco West Position 1/ 2/	Natural Gas	Natural Gas, Distillate Fuel Oil	Natural Gas, Residual Fuel Oil		Total	
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	
				MAX 4/:	29,408	/hr
Gallons Equivalent/day:		58,240	-		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.

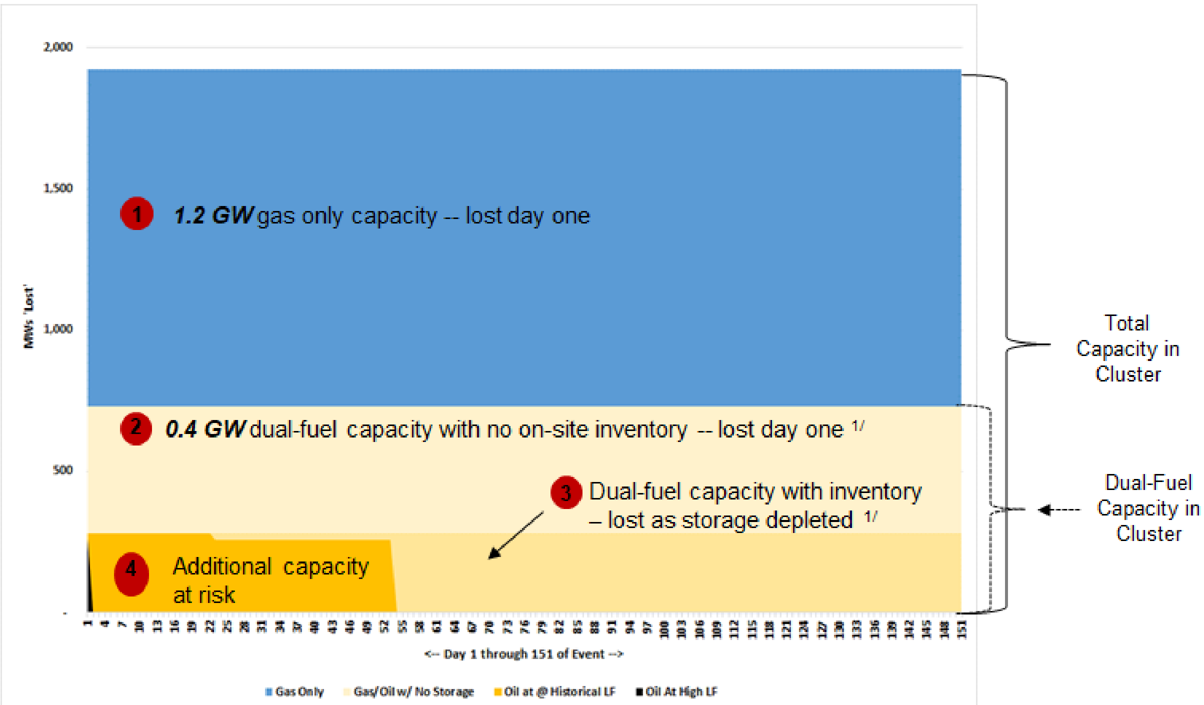
Estimated daily gas requirements associated with these plants run roughly 80,000 MMBtu/day with maximum potential runs upwards of 700,000 MMBtu/day. In contrast to the Cluster A scenario, of the 1.9 GWs of gas-fired capacity, only 0.5 MW or 27 percent represents low heat rate units with expected higher 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 4-12 summarizes potential impacts as follows:

Figure 4-12: 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 unit- and 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.[19] 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 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.

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

5.2 Emissions Limitations

Under this task, ICF reviewed SO_2 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 SO_2 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.[20]

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 emissions was not due to improper operation or maintenance and that every effort was made not to exceed the limitation.[21]

5.3 Implications of Pipeline Expansions

Multiple projects for expanding the interstate pipeline network are in various stages of approval and construction. However, it should be noted that any planned or proposed expansions will be

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

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

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 Implications of Infrastructure Event

Based on the cluster definitions and the inventory of gas-fired generating facilities, along with their associated dual-fuel capabilities, as discussed in Sections 4 and 5, ICF assessed the potential for loss of load under scenarios with a varying degrees of nuclear retirements. In the interests of time, the analysis examined impacts related to the Cluster A generators in PJM connected to both the Transco and Tetco pipelines, as described in Sections 4.1 and 4.2. Cluster A exhibited the higher concentration of generation units relative to the associated upstream infrastructure and potential locational generation requirements.

Several nuclear power plants have announced their intended retirement over the past years – most recently FirstEnergy's Perry, Davis-Besse, and Beaver Valley facilities. At the same time, several states, such as Illinois, New York, and most recently New Jersey, have explored policy pathways to maintain the economic viability of nuclear power plants in the face of depressed electricity prices. These policies provide nuclear facilities with a revenue stream that values the zero-emission quality of the electricity produced at nuclear power plants.

Ideally, in the event of natural gas pipeline outage in a certain area, an ISO would dispatch reserve resources within its integrated system to offset the loss of impacted generation capacity. However, if demand still exists after the reserves are depleted or utilized to a predetermined level, the ISO may call for load reduction to maintain the balance between demand and supply. Such an action is often deemed an emergency operation procedure that indicates system stress. In this analysis, ICF evaluated the potential of PJM's system stress through the assessment of the need for load shedding in the face of gas supply contingencies. This analysis gives the answers to two questions: 1) whether the system can handle the loss of Cluster A gas generation capacity in PJM without sacrificing demand under different nuclear scenarios, and 2) if shedding is inevitable, what would the level of load impact be.

6.1 Results

Table 6-1 highlights key results for capacity mix, generation mix, and emission for the IPM analysis of the Policy Case and the Extended Case. Results for each of the three categories are detailed further in the individual results sections following the summary. As described in those sections, the impact of the Extended nuclear retirement case on renewable generation and capacity is marginal and therefore not included in the summary table.

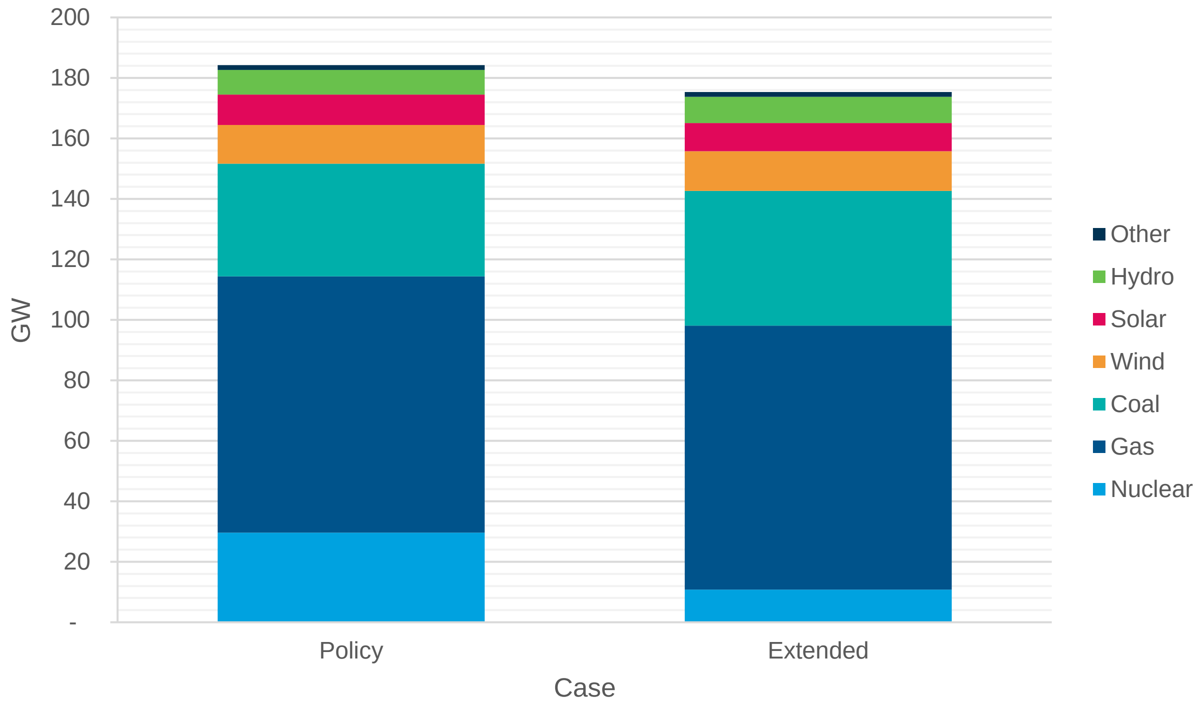
Table 6-1: Summary of Projections for PJM

Category	Detailed Category	Policy Case	Extended Case	Delta Absolute	Delta %
Generation	Generation - Nuclear (TWh)	263	114	-150	-57%
	Generation - Gas (TWh)	288	342	54	19%
	Generation - Coal (TWh)	231	281	50	22%
	Share of Generation Mix - Nuclear (%)	31%	14%	-17%	-55%
	Share of Generation Mix - Gas (%)	33%	42%	8%	25%
	Share of Generation Mix - Coal (%)	27%	34%	7%	28%
Capacity	Capacity - Nuclear (GW)	30	11	-19	-64%
	Capacity - Gas (GW)	85	87	3	3%
	Capacity - Coal (GW)	37	44	7	19%
	Share of Capacity Mix - Nuclear (%)	16%	6%	-10%	-62%
	Share of Capacity Mix - Gas (%)	46%	50%	4%	8%
	Share of Capacity Mix - Coal (%)	20%	25%	5%	25%
Emissions	PJM CO_2 Emissions (000 Tons)	365,011	442,807	77,796	21%

6.1.1 PJM Capacity Mix

Figure 6-1 shows the installed capacity in 2023 in the PJM Interconnect under the two nuclear retirement scenarios. In the Extended Case, nuclear capacity is 19 GW lower than in the Policy Case. These nuclear retirement assumptions lead to a variety of different impacts. The overall capacity in PJM is 8.8 GW lower in the Extended Case as compared to the Policy Case. Coal capacity is 7.2 GW higher, as fewer coal plants retire given the nuclear retirements. Lastly, gas-fired capacity increases by 2.7 GW to replace some of the retiring nuclear capacity. Renewable capacity is not impacted in a meaningful way, as the reduction in nuclear capacity drives an overall increase of 180 MW of capacity, made up largely of increased wind builds.

Figure 6-1: Projected Capacity Mix in PJM in 2023



6.1.2 Projected PJM Generation Mix and Emissions

As summarized in Figure 6-2, which shows the shares of total PJM generation by type in 2023, the generation mix in PJM is consistent with the capacity mix. With the nuclear units retired, the remaining nuclear units combine to make up 14% of PJM's total generation in 2023 in the Extended Case, as compared to 31% in the Policy Case. Gas generation's share of total generation increases from 33% to 42%, reflecting the addition of new facilities and the higher utilization of existing gas-fired facilities. Coal's share of generation also increases in the Extended Case from 27% in the Policy Case to 34% in the Extended Case, accounting for the greater coal capacity in the Extended Case. Overall, generation in the region falls by 5% in the Extended Case.

As a result of the higher coal and gas generation, emissions in the Extended Case are 21%, or 78 million tons, higher than in the Policy Case in 2023. That difference is sustained over the time horizon of the analysis, resulting in cumulative CO_2 emissions (2020 – 2040) in the Extended Case being 379 million tons, or 16.5%, higher than in the Policy Case. (See Figure 6-3)

Figure 6-2: Projected PJM Generation Mix in 2023

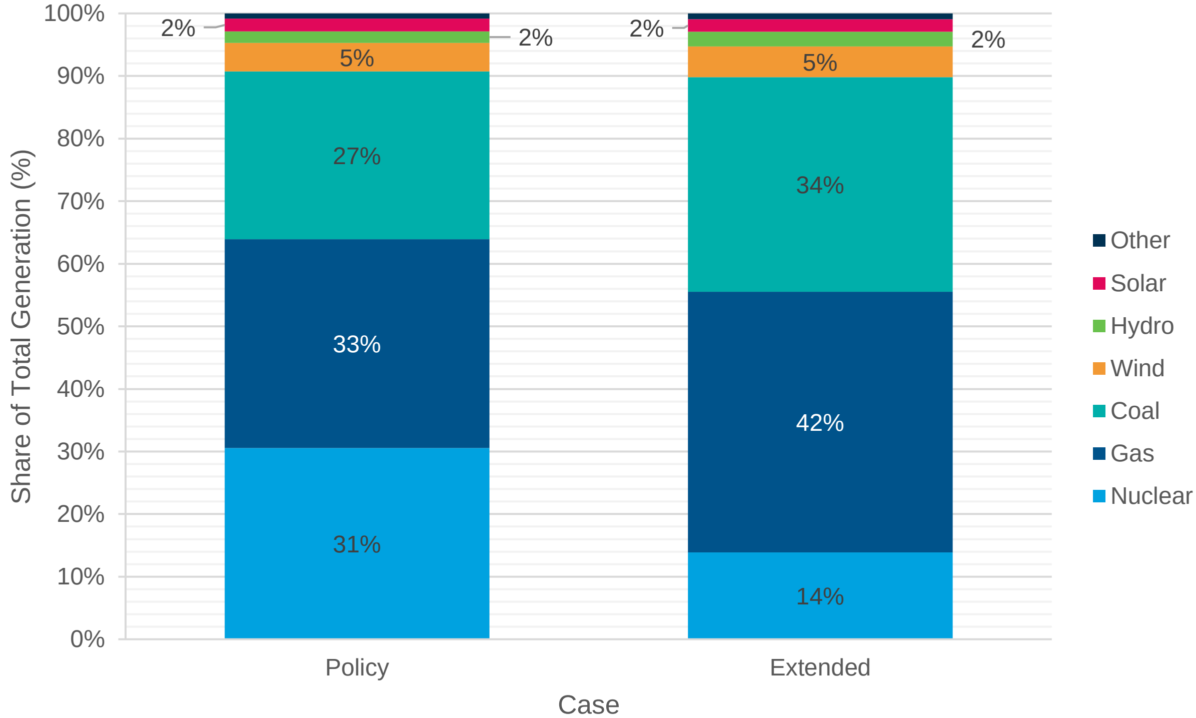
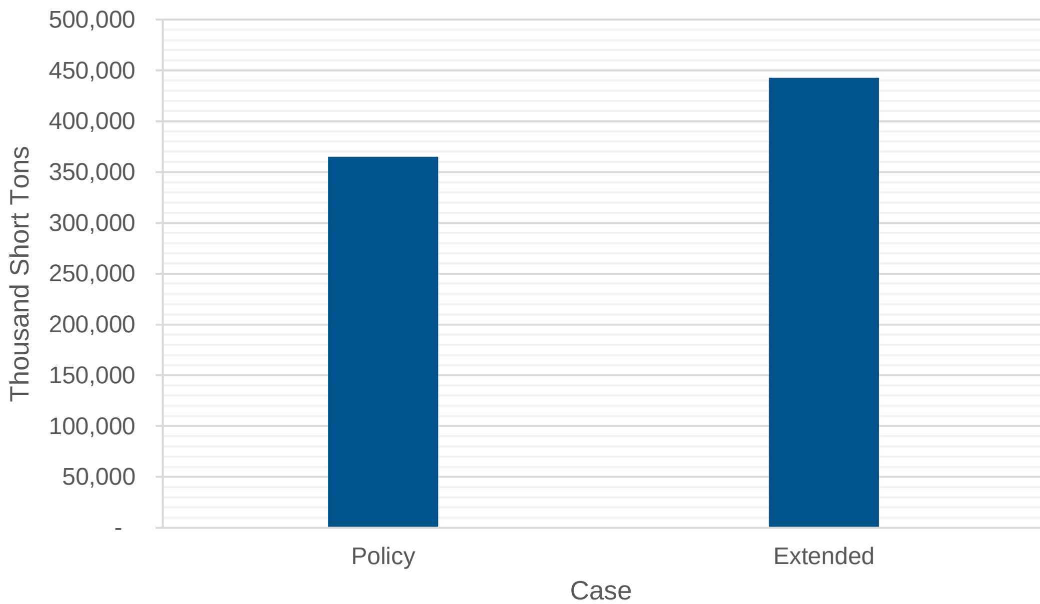


Figure 6-3: Projected PJM CO_2 Emissions in 2023



6.1.3 Gas Outage Resiliency Impact

The output of the IPM analysis serves not only as an indicator of the capacity and generation mix under the two nuclear retirement scenarios, but more importantly as an input into the loss-of-load analysis. The load flow analysis incorporates the projected builds and retirements under the two nuclear scenarios to assess the reliability of the grid in the year 2023. Table 6-2 below presents the findings for the four gas outage cases listed in 2.3.2. The top five rows in the table specify the case and the remaining rows present the results of the loss-of-load analysis. In both of the Policy Cases, the nuclear capacity that remains online is able to offset the gas generation impacted by the infrastructure event, resulting in load being served in all hours over the 60-day period of the event. Without the nuclear capacity still online in 2023, as represented by the Extended cases, ICF identified that the PJM Mid-Atlantic area is unable to meet load requirements in over 200 hours over the 60-day period.

The Extended cases show a maximum hourly loss of load of between 8.7 and 10.9 GW, representing 17% and 22% of the 2023 estimated peak hourly load for the PJM Mid-Atlantic area for the 2014 and 2015 profiles, respectively. The Extended 2014 case results in greater total hours and GWh not served, with load not served for a total of 280 hours spread across 34 days out of the 60-day gas infrastructure event period. The Extended 2015 case, however, shows the longer sustained outage, reaching 65 consecutive hours of outage out of the total 209 hours with loss of load within the 60-day period.[22]

Table 6-2: Scenario Specifications and Findings for Phase II

<table>
<tr><td rowspan="5">Scenario Specification</td><td>Case Name</td><td>Policy 2014</td><td>Policy 2015</td><td>Extended 2014</td><td>Extended 2015</td></tr>
<tr><td>Gas Cluster</td><td colspan="4">Cluster A, Transco and Tetco</td></tr>
<tr><td>Length of Outage</td><td colspan="4">60 Days</td></tr>
<tr><td>Nuclear Case</td><td>Policy (Preserve Nuclear)</td><td>Policy (Preserve Nuclear)</td><td>Extended (Additional Nuclear Retirements)</td><td>Extended (Additional Nuclear Retirements)</td></tr>
<tr><td>PJM Load Profile Year</td><td>2014</td><td>2015</td><td>2014</td><td>2015</td></tr>
<tr><td rowspan="5">Findings for Outage Period</td><td>Maximum Hourly Loss of Load (MW / %*)</td><td rowspan="5">No Loss of Load</td><td rowspan="5">No Loss of Load</td><td>8,754 MW
17%</td><td>10,889 MW
22%</td></tr>
<tr><td>Days with Loss of Load</td><td>34</td><td>20</td></tr>
<tr><td>Hours with Loss of Load</td><td>280</td><td>209</td></tr>
<tr><td>GWh of Loss of Load</td><td>707</td><td>675</td></tr>
<tr><td>Longest Sustained Period of Loss of Load (hours)</td><td>19</td><td>65</td></tr>
</table>

* Percentage of PJM Mid-Atlantic estimated winter peak

[22] This analysis did not address the potential for PJM to call on demand response (DR) resources to meet load. Because of the length and scope of the outages, it is not clear how many DR resources would be available and for how many hours to offset the loss of load.

Figure 6-4 and Figure 6-5 illustrate the unserved load under the Extended 2014 and Extended 2015 cases. The "Loadshed Cutoff" line shows the maximum level of load that can be met in the PJM Mid-Atlantic area under the Extended Case, assuming the loss of the gas and dual-fuel generators in the event of combined outages across Cluster A on the Transco and Tetco gas pipelines. The areas shaded in yellow illustrate the load that can be served by dual-fuel units with existing oil inventories.

Figure 6-4: Unserved Load in PJM Mid-Atlantic Area (Extended 2014)

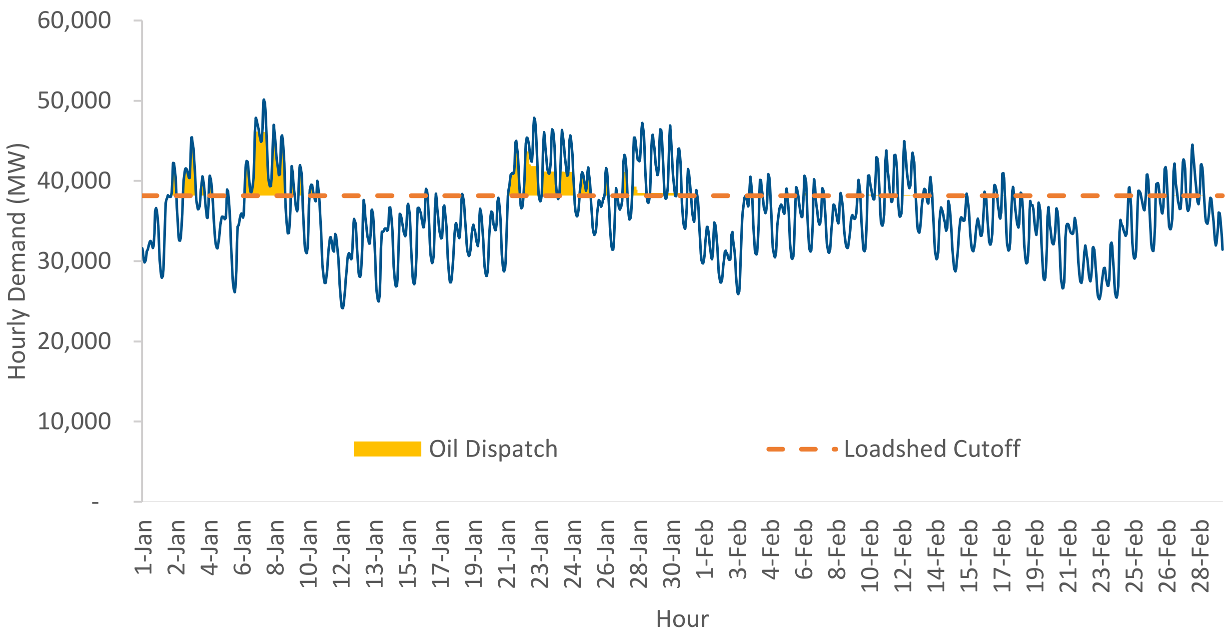
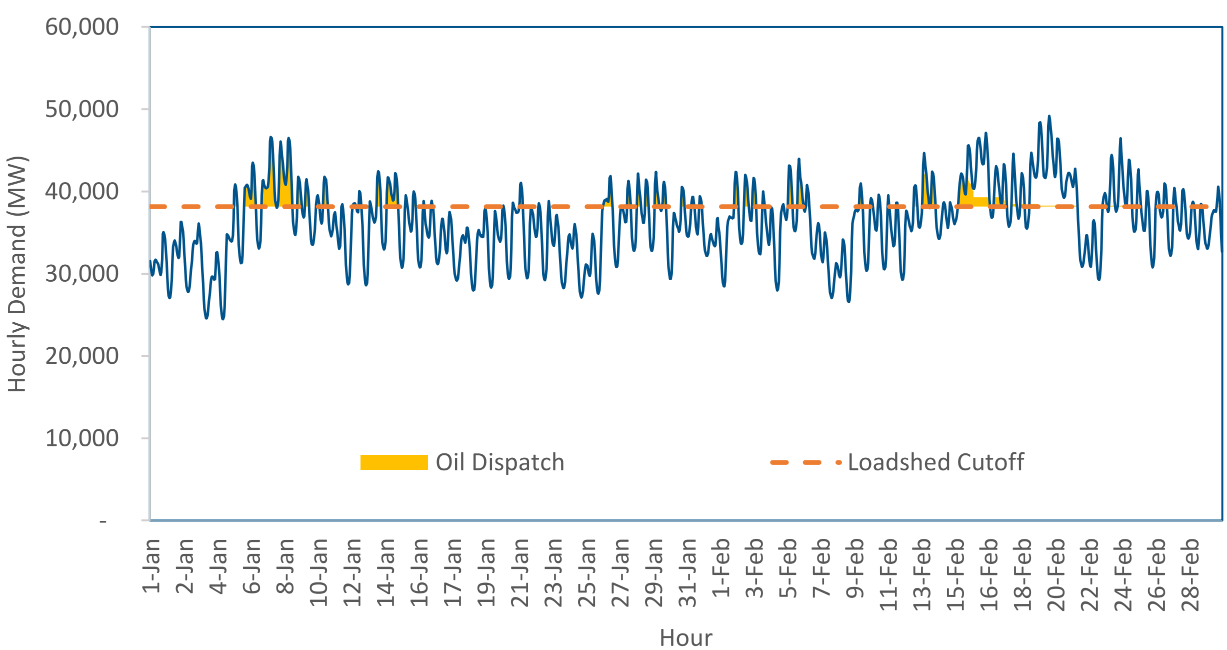


Figure 6-5: Unserved Load in PJM Mid-Atlantic Area (Extended 2015)



There are factors that may increase the loss of load relative to the values shown above. First, as noted previously, this analysis looks at just those gas-fired units in the affected cluster that are located within PJM. Units downstream (e.g., NYISO units) would also be at risk. Loss of these units due to the same event would arguably increase loss of load impacts in the region. In addition, this analysis does not impose any operating reserve requirement on top of the hourly loads. Load is considered served when the generator supply, including the dual-fuel units, and available transmission are capable of meeting load in the hour, even if limited or no excess resource would be available as a buffer should other resources become unavailable. Should a margin be included, the loss of load shown would need to be greater. Similarly, weather-related generator outages for other types of units, such as coal-fired facilities, are not addressed in this analysis but would also increase pressure on supply. Finally, retirement of the additional nuclear capacity under the Extended Case is projected to delay the retirement of 7 GW of coal units beyond 2023. A portion of these units have already announced planned retirements and may retire despite the loss of the nuclear capacity due to other factors, such as for environmental or other reasons. These retirements would exacerbate the loss of load.

7 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. 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 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.

The results of this analysis show that a significant gas infrastructure event could prevent the PJM Mid-Atlantic area from serving electric load on a number of days if existing nuclear capacity was retired. Such an event could result in the loss of nearly 18 GW of gas-fired generation in PJM, depending on the severity and location of such event. When combined with the retirement of a similar amount of nuclear capacity, the analysis implies such an event would put as much as 22 percent of the area’s load at risk of being shed in the highest load hours. Over an assumed 60-day event, those loss-of-load impacts could take place for over 200 hours spread across as many as 34 days. The study also shows that the preservation of nuclear capacity in PJM would successfully mitigate the loss of load risk.

Moreover, interstate gas supply systems cross multiple RTO/ISO systems. The same gas event described above would also place an additional 9 GW of downstream resources in NYISO at risk. 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 across RTO/ISOs should also be incorporated into resilience assessments of the power grid.

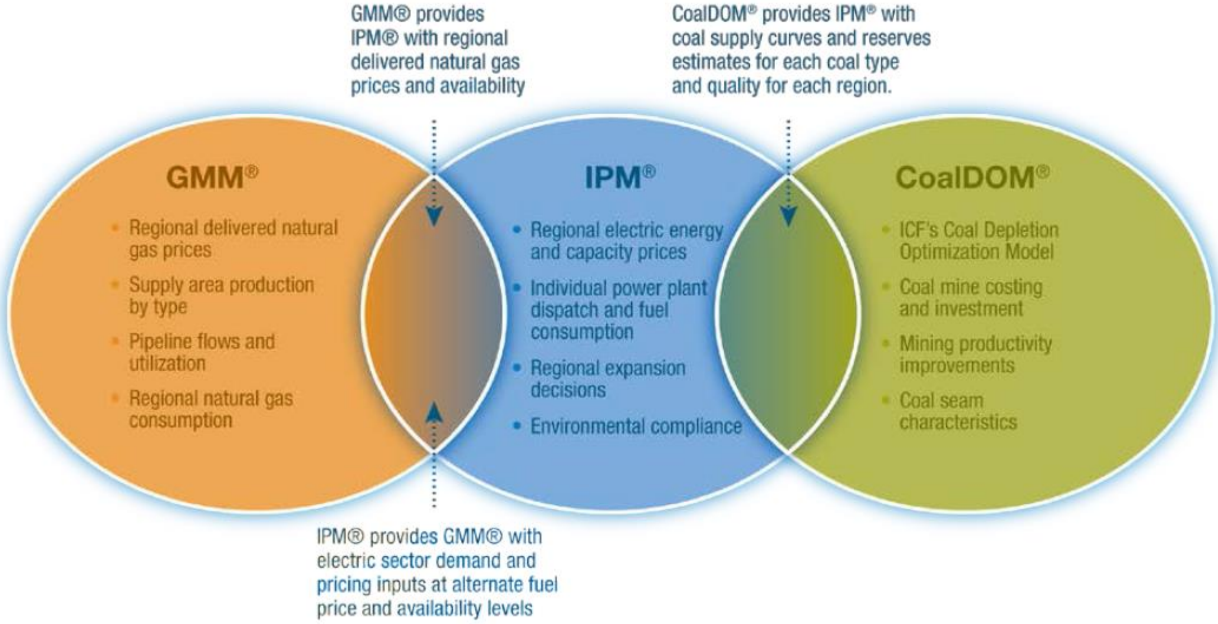
APPENDIX A: Nuclear Case Specification

Reactor Name	State	ISO	Capacity	Extended	Policy	Closure year
Clinton	Illinois	Midcontinent ISO	1,065	X		
Duane Arnold	Iowa	Midcontinent ISO	601			
Fermi 2	Michigan	Midcontinent ISO	1,085			
Palisades	Michigan	Midcontinent ISO	803	X	X	2022
Point Beach 1	Wisconsin	Midcontinent ISO	591			
Point Beach 2	Wisconsin	Midcontinent ISO	593			
Millstone 2	Connecticut	New England ISO	869			
Millstone 3	Connecticut	New England ISO	1,233			
Pilgrim 1	Massachusetts	New England ISO	685	X	X	2019
Seabrook 1	New Hampshire	New England ISO	1,246			
Ginna	New York	New York ISO	581			
Indian Point 2	New York	New York ISO	1,006	X	X	2020
Indian Point 3	New York	New York ISO	1,031	X	X	2021
James A. Fitzpatrick	New York	New York ISO	828			
Nine Mile Point 1	New York	New York ISO	630			
Nine Mile Point 2	New York	New York ISO	1,143			
Braidwood 1	Illinois	PJM ISO	1,178			
Braidwood 2	Illinois	PJM ISO	1,152			
Byron 1	Illinois	PJM ISO	1,164			
Byron 2	Illinois	PJM ISO	1,136			
Dresden 2	Illinois	PJM ISO	867			
Dresden 3	Illinois	PJM ISO	867			
LaSalle 1	Illinois	PJM ISO	1,118			
LaSalle 2	Illinois	PJM ISO	1,120			
Quad Cities 1	Illinois	PJM ISO	908	X		2022
Quad Cities 2	Illinois	PJM ISO	911	X		2022
Calvert Cliffs 1	Maryland	PJM ISO	855	X		2022
Calvert Cliffs 2	Maryland	PJM ISO	850	X		2022
Donald C. Cook 1	Michigan	PJM ISO	1,009			
Donald C. Cook 2	Michigan	PJM ISO	1,060			
Hope Creek 1	New Jersey	PJM ISO	1,173	X		2022
Oyster Creek 1	New Jersey	PJM ISO	614	X	X	2018
Salem 1	New Jersey	PJM ISO	1,166	X		2022
Salem 2	New Jersey	PJM ISO	1,160	X		2022
Davis Besse	Ohio	PJM ISO	894	X		2020
Perry 1	Ohio	PJM ISO	1,240	X		2021
Beaver Valley 1	Pennsylvania	PJM ISO	892	X		2021
Beaver Valley 2	Pennsylvania	PJM ISO	885	X		2021
Limerick 1	Pennsylvania	PJM ISO	1,146	X		2022
Limerick 2	Pennsylvania	PJM ISO	1,150	X		2022
Peach Bottom 2	Pennsylvania	PJM ISO	1,122	X		2022
Peach Bottom 3	Pennsylvania	PJM ISO	1,122	X		2022
Susquehanna 1	Pennsylvania	PJM ISO	1,260	X		2022
Susquehanna 2	Pennsylvania	PJM ISO	1,260	X		2022
Three Mile Island 1	Pennsylvania	PJM ISO	805	X		2019

APPENDIX B: Analytical Framework

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.

Figure A-1: ICF's Integrated Modeling Suite



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.

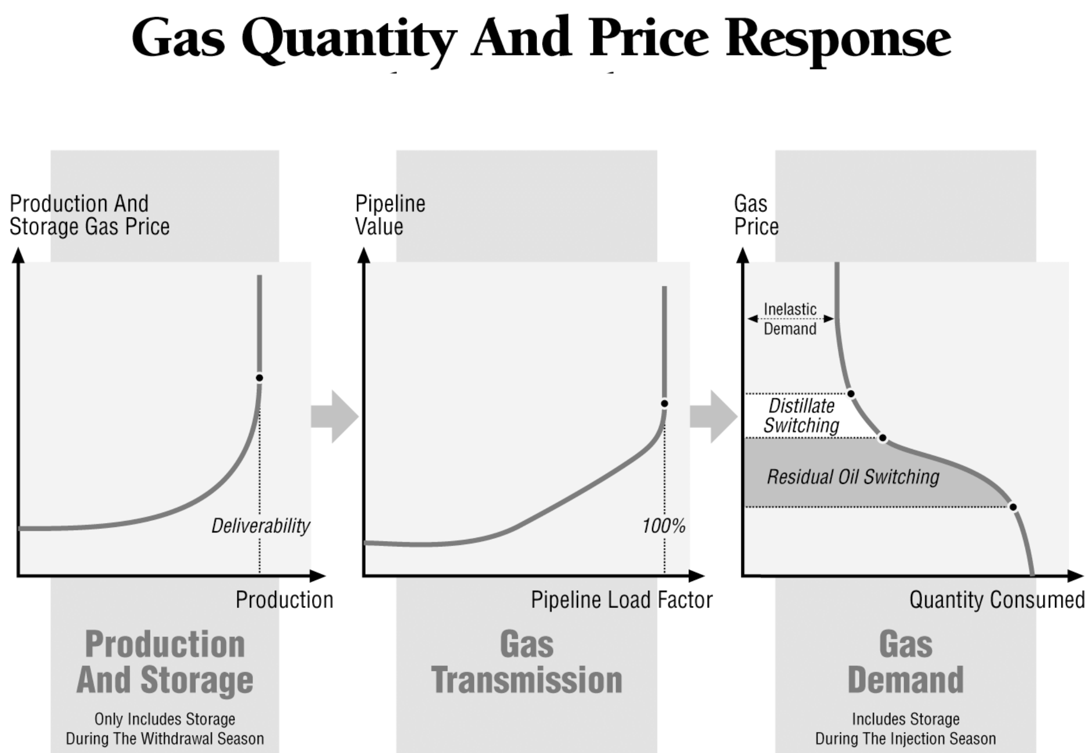
In addition to its use for strategic planning studies, the model is widely used by a number of institutional clients and advisory councils, including the recent Interstate Natural Gas

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-). 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-2: Natural Gas Supply and Demand Curves in the GMM

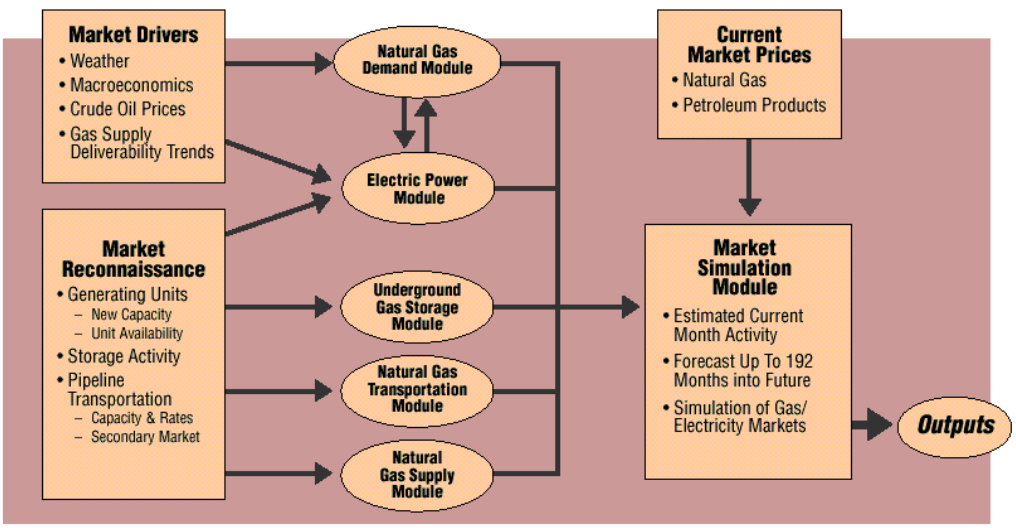


Source: ICF GMM®

There are nine different components of ICF's model, as shown in Figure A-. 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.

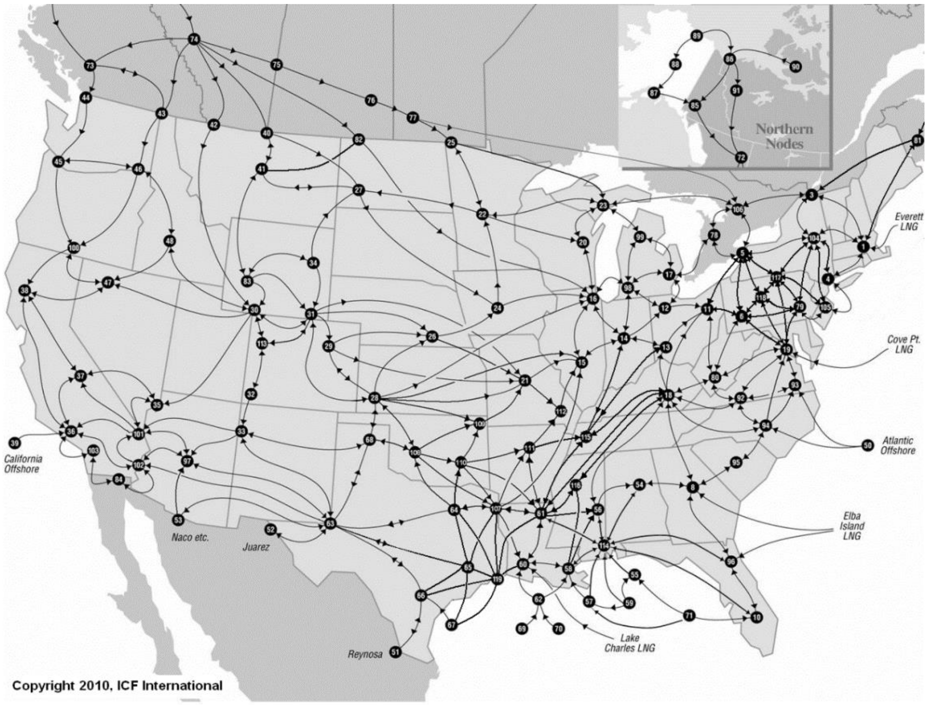
The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which 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-. 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-3: GMM Structure



Source: ICF GMM®

Figure A-4: 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-5 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-5: 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.

ICF