U.S. DEPARTMENT OF ENERGY

Implications of Increasing Electric Sector Natural Gas Demand

WORKSHOP REPORT

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Prepared by:

ICF International

Disclaimer

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I. INTRODUCTION

Over the past decade, natural gas use in the electric power sector has increased dramatically. Reasons for the shift to gas include favorable economics and lower conventional air pollution and greenhouse gas emissions associated with natural gas relative to other fossil fuels, as well as market demand for flexible sources of electric generating capacity.

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

To date, many stakeholders have performed extensive analysis to improve real-time and near-term operations and planning in order to address natural gas-electricity interdependencies. The Federal Energy Regulatory Commission (FERC) has also hosted a number of technical meetings to discuss these topics and significant headway has been made in recent years on issues like gas and electric resource scheduling. While the conversation on short-term coordination challenges is moving forward, greater attention is needed on mid- and long-term planning issues.

This workshop was designed to explore how medium- and long-term electric sector planning is evolving given trends in electric sector natural gas consumption. The aim was to convene stakeholders from both the natural gas and electric sectors from different regions of the country so that participants could share the practices, tools, and metrics that they employ in order to understand the interdependency between the electric and natural gas industries, as well as the approaches that stakeholders have implemented to resolve challenges and leverage opportunities.

The workshop will inform the second installment of the Quadrennial Energy Review: An Integrated Study of the U.S. Electricity System. Note that DOE did not seek consensus opinions from participants at the workshop. This summary reports the discussions at the workshop. DOE does not necessarily agree with or support the content summarized herein.

Key Workshop Discussion Questions

1) In many regions, natural gas is transitioning from a secondary fuel to a primary fuel for electric power generation.
   a) How is your region integrating natural gas deliverability into your reliability analyses?
   b) How do you define natural gas deliverability (for instance, some have raised concerns about the adequacy of mainline pipelines, adequacy of the pipeline system, of natural gas storage, and/or of the natural gas resources to meet daily and seasonal demand swings, or other factors?)
   c) Have additional contingencies (for example, mechanical failure of a compressor serving a pipeline, loss of a pipeline or storage facility due to a major accident, or others) been incorporated to assess natural gas deliverability?
2) What data, tools, metrics or practices has your region developed in order to assess these questions?
   a) Does analysis of these contingencies require additional data?
   b) What information or practice sharing between the natural gas and electric sectors would best facilitate medium- and long-term electric sector planning?
3) What options do system operators have to avoid peak day constraints on gas supply?
   a) Will the level of natural gas-fired generation in your region require any physical or operational changes to the existing natural gas infrastructure (e.g. different types of natural gas storage, pipeline capacity expansions)?

    b) What options do electric system operators have to manage electric system demand during periods of peak natural gas demand, as well as to manage increasing variability of electric system natural gas demand (e.g. demand response, energy efficiency, capacity market changes, transmission investments)?
4) How are gas and electricity market structures, and recent changes in those structures, affecting the ability to coordinate gas use with electric needs in the medium and long term?
    a) Are there new types of contracts or services that natural gas pipelines could offer to natural gas-fired generators that take into account the unique market forces in the electricity sector (for instance, are there new ways to provide service to peaking generators, and are these solutions applicable to multiple regions)?
5) In a given geographic area, how do you consider alternatives to transmission, such as adding natural gas pipeline capacity?
    a) Has low-cost natural gas affected these decisions?
6) What questions remain on natural gas deliverability?
    a) What additional opportunities are there for increased coordination between natural gas consumers in the electric power sector and pipeline operators?
    b) What role can DOE play in additional education and analysis on this topic?

Workshop Format and Participants

Participants included entities responsible for power sector reliability and planning, natural gas pipeline experts, government, academia, NGOs, as well as other relevant stakeholders. A list of attendees is included in Appendix A. The workshop agenda is included in Appendix B.

II. CONCLUSIONS AND KEY TAKEAWAYS

The findings, insights, and recommendations from the workshop are summarized below. These findings reflect the discussions at the workshop and do not represent consensus among the participants. DOE does not necessarily agree with or support the content summarized below.

1. The natural gas system and the electric system are both vulnerable to disruptions. Therefore, proactively working to improve the physical and cyber security of both system is critical. Clarifying the roles of Federal, state, and local governments responsible for achieving this goal for the natural gas system would be useful.
2. Dual fuel capability at power plants can play an important role in responding to gas system constraints. However, some electric generators may not be able to utilize this option for various reasons, including air permits, limited space for fuel storage, and fuel delivery constraints.
3. When considering the potential for a gas system disruption, it is important to evaluate the implications of the disruption on both the physical system and on the markets.
4. Grid operators should verify that critical natural gas system infrastructure will not be affected by electric load shedding during a system emergency.
5. Electric generators are designed to shut down automatically if natural gas composition is out of specification, as electric generators may have tighter limits on natural gas specifications than the specifications followed by some pipelines. There are concerns that some small distribution companies may lack oversight and/or clear policies on natural gas specifications.
6. Forecasting of electricity demand and variable renewable energy resources has improved dramatically in recent years. DOE should continue to develop better electricity demand and variable renewable energy forecasting tools, techniques, and practices.
7. Smart inverter technology can enable distributed renewable resources to play a larger role in providing ancillary services, which could provide resource flexibility for the electric sector during gas infrastructure constraints. DOE RDD&D on smart inverters and control systems could help enable these resources to play this role.
8. Flexibility is a two-way street. The gas system can provide flexibility for the electric system, and in turn, the electric system—with its multiple layers of redundancy—can provide gas system flexibility in the face of a potential disruption. For example, electric transmission can mitigate constraints on gas pipelines by facilitating a shift from fuel constrained generation to non-fuel constrained generation.
9. Timescales matter for natural gas storage – storage is a time-shift of supply and/or demand. The timescale is important to understanding the value and implications of storage.
10. In some regions, merchant generators do not have a mechanism to recover costs of firm gas supply. The system may need to change to allow them to recover the costs, and a few regions (ISO NE and PJM) have introduced and/or proposed mechanisms that could improve the situation.
11. End use energy efficiency is an important resource for alleviating natural gas and electric system constraints.
12. Integrated natural gas and electric planning is of growing utility in some regions, and entities may benefit from additional analysis in this area.
13. There are opportunities to take advantage of existing infrastructure – pumped storage, LNG storage and import capacity, and dual fuel capability, among others.

14. Stakeholders and market participants need to understand who has the obligation to serve load in organized markets.
15. Pipeline adequacy is a peak demand issue. The natural gas infrastructure is adequate for the vast majority of the time and even under stressed conditions, it delivers to those who hold firm capacity. It is rare that the system does not meet contractual commitments. Generators should recognize when they are not contracting for firm service.
16. It is now very difficult to get any energy infrastructure built in a timely way.
17. The electric grid and the natural gas system are complex engineering systems. Increased efficiency is achievable through improved controls. DOE can help improve the available control systems.
18. The prioritization of gas supply curtailments for natural gas customers should be reviewed.
19. In a future energy mix that has a larger share of renewable generation, new market designs will be needed in order to support the mix of generation that is needed to balance the grid. Understanding what these future market designs look like could remove a barrier to increased renewable energy development.
20. A growing number of natural gas generators are procuring firm transportation service today; some though pipeline contracts, others through marketers.
21. Generators choose the most economical solution among a variety of options that are available to meet the performance rules that grid operators establish, including delivered firm capacity, firm capacity, dual fuel, and LNG, among others. In competitive markets, this shift has been driven by the price signals that grid operators have created to incent generators to perform during periods of peak electricity demand. These pricing principles should be aligned with cost fundamentals.
22. In some cases, natural gas producers have an incentive to build pipelines to bring their product to market.
23. ISOs may need to address fuel assurance issues through medium to long-term planning. There is a need for better models, data, and transparency to address tariffs, planning philosophy, and siting.
24. Recent natural gas system disruptions have drawn new attention to planning for low probability, high impact events. The natural gas and electric system operators could benefit from joint drills to prepare for hypothetical future emergencies.

Open questions from workshop participants:

1. Are ISO incentives appropriate or sufficient to ensure adequate fuel supply? Are reliability standards for fuel assurance needed from NERC or other regulators?
2. While natural gas storage is at high levels today, is there an adequate price signal for future development of gas storage infrastructure, and if so, who is responsible for paying for storage? Is increased natural gas production capacity replacing natural gas storage? Can electric distribution companies serve as the anchors for gas infrastructure?
3. Some are questioning the need for new natural gas infrastructure in the face of climate change and changing energy patterns of energy demand. Is it possible to conduct a cost-benefit analysis of new infrastructure costs and benefits that takes into account the social cost of greenhouse gas emissions?
4. Is natural gas the bridge fuel to a low carbon future or are we already “over the bridge?”
5. What is the next Aliso Canyon? Vulnerable assets or asset types should be inventoried. How will climate change, sea level rise, drought/land subsidence affect gas infrastructure? Safety issues and infrastructure aging could also be issues.

III. SUMMARY OF DISCUSSION

The comments from each session of the Workshop are summarized below. The summary that follows were recorded by a workshop observer and are not the exact words of the speakers listed.

Introductions

Dr. Franklin Orr, Undersecretary of Science and Energy, DOE
Energy systems have evolved over the last five years with the increased production of shale gas. Prices of solar, wind, and efficient technologies such as LEDs are dropping. Electricity will continue to be critical as a connective tissue. The energy mix is changing – gas is growing in importance. Gas fuel is real time. Aliso Canyon highlights this – the system is not able to meet peak demand without storage. It also raises issues of natural gas storage well integrity and reliability. FERC is hosting technical meetings. We are interested in mid- to long-term issues. What should DOE focus on for the Quadrennial Energy Review (QER)? What other natural gas and electric coordination issues should DOE focus on? What is the role of natural gas storage and how can we mitigate risks?

Marie Therese Dominguez, Administrator, Pipeline Hazardous Materials and Safety Administration
This is a timely discussion as PHMSA works with an interagency taskforce on underground gas storage. PHMSA is also addressing the safety of energy transportation and reducing risk. Hazardous materials are here and they need to be transported safely. PHMSA has issued a notice of proposed rulemaking (NPRM) on natural gas transportation, updating safety requirements for pipelines. PHMSA is also addressing incentives for replacement of aging infrastructure. 38 out of 50 states have addressed replacement of gas distribution pipelines. There are over 400 gas storage facilities, greater than 4 Tcf of working capacity. These facilities are mostly depleted oil and natural gas reservoirs. Some facilities are aging with old wells, old pipelines, various contaminants, corrosion, erosion, and other issues. The American Petroleum Institute (API) has a recommended practice forum. PHMSA is looking for new minimum standards but deferring to states. PHMSA is also engaging with DOE and the national labs. DOE will hold a workshop in Denver, Colorado on July 12-13th, 2016 followed by a PHMSA workshop on July 14th on a gas storage rulemaking.

Steven Walz, Metropolitan Council of Governments
New gas capacity is growing quickly – there are 20 applications for gas power plants in Pennsylvania and 1,500 MW of new capacity planned in Virginia. How will these facilities get adequate gas supply? Are regulations for interruptible supply appropriate? Some facilities may not know that their supply is interruptible. Should power plants be the first to be interrupted and will there be secondary effects if electricity is cut off to electric gas compression for pipelines? Microgrids are positioned to provide additional reliability but what is their priority for gas supply if they are supplying critical loads?

Session 1. Discussion on Natural Gas Today and in the Future (Data and Tools)

How are electric power sector usage patterns changing and how are these changes related to natural gas supply?

Energy policy is reactionary. The Aliso Canyon leak might change this and result in some proactive response. There have been gas integration issues for some time in other regions, notably New England. Aliso Canyon broadens the focus. Wellhead price deregulation started the swing to gas as an economic supplemental fuel. In the 1990s air quality became important. Gas was cheap and reliable and new generating technology allowed gas to transition from a secondary to a primary fuel. In the next decade, renewables will likely become a primary energy source and the role of gas is evolving to that of a reliability fuel. In the West, gas use for power is greater than gas use for space heating.

The gas and electricity systems have different design bases: Gas is focused on reducing cost through large infrastructure. Electricity is based on reliability – limited component size, highly networked, never lose more than one piece.

Aliso Canyon also shows that operational needs are changing: gas is transitioning to a resource that backs up renewables, which means much higher need for cycling – possibly more than gas system infrastructure or power plants are designed for. In some cases, pipelines may not provide enough pressure for this variability. Aliso Canyon is utilized for about 70 days in summer to provide support. It is more of an operational resource rather than a winter peak resource.

The gas infrastructure can also create a large single element failure risk: for example, El Paso pipeline supports 28 to 30 GW of capacity, which could be at risk if there is a failure.

In some markets, dual-fuel capacity is very important, even in California. We need to reevaluate the interruption hierarchy – maybe power plants should not be the first to be interrupted. We need to evaluate opportunities to improve coordination of network infrastructure, like the different gas utility networks in California. We need a better understanding of single element risks and mitigation strategies. How many more bottlenecks like Aliso Canyon exist? Harmonization between the gas and electric sector should continue. We also need to address stakeholder resistance to siting and construction of gas infrastructure.

Gas is an important fuel and will likely continue to play a large role for a many decades, even with increasing deployment of renewables and until electric storage becomes more substantial. We need to have gas. There is likely no one policy body that can address all of the gas and electric interdependency issues discussed today, as gas and electric policymaking are fragmented.

Integration of Gas and Electric Systems

There has been progress on policy changes to bring the natural gas and electric industries together. While there is an abundance of gas supply from shale formations, the gas composition can be variable. When there are more liquids in produced gas there is need for more processing as well as liquids pipelines. Some participants questions what would happen in the event that gas processing plants fail—what happens to liquids and gas pricing? If liquids command higher prices, how could gas supply be affected? Electric generators are designed to shut down automatically if natural gas composition is out of specification, and some electric generators have tighter limits on natural gas specifications than the specifications followed by some pipelines. In some cases, generators may need better assurance of fuel quality. There are also concerns that some small distribution companies may lack oversight and/or clear policies on natural gas specifications.

Some gas generators purchase “delivered firm” gas from marketers. In this situation, pipeline operators may not be able to tell who holds the delivered firm capacity. Electric generators take their obligation to serve load very seriously. Generators support performance contracting and the recently enacted and/or proposed market changes have severe penalties–in some cases these penalties could be larger than capacity payments for a calendar year. Dual fuel is also a key strategy but the generator must have oil on site. Some generators find that dual fuel is more economic than long-term contracts for firm delivery of natural gas. Participants noted that ISOs should not force generators to one solution, but instead provide generators with a suite of options that encourage them to achieve a desired outcome. Participants stated that LDCs may not necessarily want to curtail power customers first, and that an alternative approach to curtailment could be one based on human need.

Organized electricity markets are experiencing a transition to more gas, wind, and solar generation. Traditional markets have more diversity of supply but in some markets, diversity is declining as nuclear and coal are being retired for economic reasons. Organized markets are seeing a need for renewable load following and capacity needs, and some new incentives are being designed to meet these needs. These may transition into the traditional markets.

Generators in regulated markets often procure firm transportation, but in some cases, pipelines may be fully subscribed by other users. Some generators in regulated markets also have dual fuel capability. Peaking units in organized electricity markets often cannot afford firm supply because they face challenges recovering firm transportation cost in their power bids. Day ahead nominations for natural gas pipeline capacity to fuel their unit can also be a constraint for peaking unit operators due to uncertainty in their operational requirements.

Firm pipeline capacity is significantly more expensive than interruptible capacity, but if the capacity on a pipeline is fully subscribed, new infrastructure may need to be built in order to provide the level of service that is required by electric generators.

Some pipeline operators noted that users of the gas pipeline system should be mindful of the contractual commitments that are being made to other users of the gas system. In some cases, merchant generators purchase interruptible capacity, but local distribution companies have executed contracts that entitle them to the firm capacity. As such, priority will go to the firm customers. In some systems, some, but not all, generators are making firm commitments. Many of the issues that generators holding interruptible capacity face when fuel is not available could be solved with additional contracted firm pipeline capacity. Pipeline operators noted that firm customers are not asking for changes. Pipeline operators also noted that there are costs associated with the quality of service that is offered, and those who make the commitments will get the services.

Pipelines are generally contract and/or market driven and changes in non-firm shipping rights could negatively impact the firm customers. Power generation is about one third of the total market for natural gas. Whatever capability an end user wants depends on who will pay for it. Finally, participants noted that building new pipelines—as well as many other types of infrastructure--has become more challenging in recent years: could DOE help with this challenge?

What physical, operational, and planning process changes has your region made to accommodate increased levels of natural gas-fired generation; and what data, tools, and practices are used to manage your system?

Electric systems are generally integrated into day ahead markets. Gas system operations tend to be human-based, slower, and based on steady state models. Gas systems perform well given the available tools but may be reaching the limits of the effectiveness of existing tools. We need to look into optimization for coupling gas pipelines with power grids, as well as system-wide optimization systems using new algorithms with desktop computers. We need to better integrate markets and physical gas operations. Tools to accomplish these functions can and should be developed.

New England has been at the forefront of many emerging gas infrastructure concerns since 2004. New England has completed studies on many issues facing electric generators in the region. There is no silver bullet for addressing these issues. Communication between gas and electric system operators have improved, but many generators lack firm gas supply contracts to ensure that they can operate at all times. The ISO cannot fix all of issues facing generators with the tools that they have at their disposal today. Other regions are also facing similar issues.

Even where ISOs have implemented capacity non-performance penalties, some generators are not buying firm capacity. As the market for delivered natural gas continues to tighten, generators without firm contracts will be the first to lose service. For example, one ISO noted that it covers 120% of contingency, mostly on the power side but not on the gas side. A loss of gas supply would be hard to cover without emergency procedures, which the ISO has in place and practices their execution.

Fuel constraints in New England are recent but are considered more serious than in other regions. The electric reserve back-up in New England is also often gas-based. The region needs to maintain situational awareness and maintain close coordination with the gas industry and some practices include monitoring LNG tanker flows. The ISO-NE dual fuel program is not a panacea. Some generators are unable to use oil fuel in the summer even with state waivers due to third party liability concerns. Dual fuel has been a successful strategy over the last few winters but it has limits. There can also be constraints on liquid fuel delivery due to weather conditions or lack of trucking capacity.

Mismatch of gas demand and supply is a problem in New England, and both are sensitive to power forecasts and renewable energy variability, which are related to the weather conditions in the region. Participants noted a need to improve near-term forecasting – could we predict cloud cover, for instance? Could DOE support development of improved planning tools? Electric planners assume that the fuel is there but they don’t have jurisdiction over fuel.

Participants raised the following questions: Should NERC have jurisdiction over fuel supply? When/how should single element failure be addressed? Can/should it be done through market mechanisms or reliability standards or IRP processes? Stakeholders need methods to manage uncertainty in flows in pipelines. Can improved models operate rapidly enough to be of utility to system operators? How can we speed up the decisions on the gas side?

How does your region represent the potential for natural gas pipeline disruptions in contingency analysis?

One participant noted that there should not have been surprise about the importance of Aliso Canyon. Going forward, participants questioned how the planning process should change to address a similar low probability, high impact event.

California is looking at these issues through sensitivity analyses and is also considering what type of study plan is required. Aliso Canyon concerns are generally related to the potential implications of errors in daily load forecasts and the ability of the region to dispatch needed gas generation capacity to accommodate internal gas dispatch capacity. There is significant electric transmission capacity coming into the Los Angeles region, but grid operators need additional reactive power to use this capacity. Gas generators would not need to be dual fuel if the grid operator could access sufficient reactive power that would enable them to take advantage of the available transmission capacity.

Key Takeaways

These findings reflect the discussions at the workshop and do not represent consensus among the participants. DOE does not necessarily agree with or support the content summarized below.

1. The natural gas system and the electric system are both vulnerable to disruptions. Therefore, proactively working to improve the physical and cyber security of both system is critical. Clarifying the roles of Federal, state, and local governments responsible for achieving this goal for the natural gas system would be useful.
2. Dual fuel capability at power plants can play an important role in responding to gas system constraints. However, some electric generators may not be able to utilize this option for various reasons.
3. Smart inverter technology can allow distributed renewable resources to play a larger role in providing ancillary services. DOE RD&D on smart inverters and control systems could help enable these resources to play this role.
4. Electric generators are designed to shut down automatically if natural gas composition is out of specification, as electric generators may have tighter limits on natural gas specifications than the specifications followed by some pipelines. There are concerns that some small distribution companies may lack oversight and/or clear policies on natural gas specifications. There are concerns that some small distribution companies (munis and coops) lack oversight and clear policies.
5. In some regions, merchant generators may not have a mechanism to recover costs of firm gas supply. The system may need to change to allow merchant generators to recover the costs of firm capacity, or the cost of alternatives to firm capacity. If there are system-wide benefits to these costs, how should they be allocated to consumers?
6. Are ISO performance penalties appropriate and/or sufficient to ensure adequate fuel supply? Are reliability standards from NERC or other regulators needed?
7. Integrated natural gas and electric planning is of growing utility in some regions, and entities may benefit from additional analysis in this area.
8. Stakeholders and market participants need to understand who has the obligation to serve load in organized markets.

9. Pipeline adequacy is a peak demand issue. The natural gas infrastructure is adequate for the vast majority of the time and even under stressed conditions, it delivers to those who hold firm capacity. It is rare that the system does not meet contractual commitments. Generators should be aware of the type of service they have procured and how it may compare to firm service.
10. It is now very difficult to get any energy infrastructure built in a timely way.
11. The prioritization of curtailments should be reviewed.
12. A growing number of natural gas generators are procuring firm transportation service today, some through marketers and other directly from the pipelines.
13. What is the next Aliso Canyon? Vulnerable assets or asset types should be inventoried. How will climate change, sea level rise, drought/land subsidence affect gas infrastructure? Safety issues and infrastructure aging could also be issues.

Session 2. Discussion on Operational Strategies

Will the increase in natural gas-fired generation in your region require any physical or operational changes to the existing natural gas infrastructure in the medium and long term (e.g. different types of natural gas storage, pipeline capacity expansions)?

Gas-fired generators can pose a challenge to gas suppliers, but the magnitude of this challenge may be overstated. The generators are non-ratable – the facility is designed to be steady state but needs to operate hourly, so gas demand is variable. The capability to deal with this variable demand can be designed into the gas supply structure but needs to be known up front. Information sharing is very important. Pipelines have a significant impact on system operators and as such, system operators work closely with pipeline operators. One pipeline provides multiple nomination cycles beyond the standard NAESB cycles – up to 42 nomination cycles per day. However, in a constrained market, the first entity to take the capacity is the only one that counts. That said, the gas industry can tailor to whatever need a customer has if the customer is willing to bear the cost of providing the service.

A key question in some regions is: to what degree do natural gas pipelines rely on electricity to provide compression on the pipeline? In some regions air regulations require a greater focus on electric compression, as they have lower air emissions as compared to compressors that operate on other fuels. Some pipelines have significant electric compression while others have very little, depending on local air regulations as well as other factors.

Within a given day the demand for electricity and natural gas is variable, and while power is instantaneous, gas moves at a much slower speed. Power can re-dispatch around fuel constraints, so there is inherent redundancy in these systems. Participants noted that the same level of redundancy is not needed for both the power and gas systems; instead more flexibility in the gas sector would be valuable, and additional flexibility in the power sector may also be desirable. Most gas system limitations are local – power can dispatch around them. There is value in increasing power interconnection and networking capability.

Participants questioned what the gas system is doing on cyber security? Cyber security is not subject to FERC jurisdiction but pipelines are working with DHS, DOE, and others. These groups recently completed a table-top exercise on cyber security preparedness. Cyber security preparedness is not as formalized in the gas industry as it is in the electric sector but it is still a very high priority. The physics is different for gas, and as such gas does not create cascading outages. Other participant comments included:

- Many state, local, and Federal agencies are involved in cyber security and are working to improve coordination.
- Some participants feel we are playing catch up on cyber security preparedness – others do not.

What information or practice sharing between the natural gas and electric sectors would best facilitate medium- and long-term electric sector planning?

ISOs are working to increase visibility and transparency of gas system interdependencies through working groups and stakeholder meetings. One ISO includes a notification page on their website for potential pipeline operational issues and has a fuel impact report display page for system operators. The ISO also compiles outage reports and conducts a winter fuel survey to identify potential dependencies. The ISO is also working on providing more information about gas consumption within the ISO's boundaries. The ISO indicated that increased gas and electric communication as well as a way to test the information that they are gathering would be useful. The ISOs have introduced some new modeling tools but may need additional data on gas systems to improve these tools. They identified hourly modeling for planning studies and bringing more models and data in-house to integrate with electricity planning models as priority areas for future development.

What options do electricity system operators have to manage periods of peak natural gas demand as well as to manage increasing variability (e.g. demand response, energy efficiency, capacity market changes, transmission investments)?

Gas by wire – In New England the grid interties with other regions have minimal spare capacity. The region could use additional transmission capacity but building new transmission infrastructure is viewed as being equally difficult as building new natural gas pipelines. The ISO is getting information from pipelines and also provides information to the pipeline operators as well. They are in daily communication with pipeline operations – sometimes hourly. The ISO gives pipelines information on how much gas they expect generators to use each hour. Establishing this arrangement required jumping through initial hoops, but the experience of the polar vortex helped accelerate the creation of this relationship. The gas and electric systems have changed the timing of the day ahead market. The day ahead market previously cleared at 4:00 PM and then a final closed at 11:00 PM. Now the market closes at 10:00 AM and 12:30 PM with the final close at 4:00 PM. The ISO is carrying 20% more operating reserves and have changed their code of conduct. Shortage event changes have been made such that the price impacts of the shortage are as high as $3,550/MWh during Ten Minute Reserve Deficiencies in New England. Emergency procedures are available for fuel but have not been used yet. They have a fuel system tracking system in their control room to track status of gas supply systems. The ISO's load shedding plans can shed 50% of electric load in 10 minutes. In addition, the ISO has worked to ensure that pipelines do not have critical loads associated with load-shedding - not just gas pipeline compression stations but also other critical operations. They also coordinate with system operators in Canada.

Pipelines noted that getting ISO data on anticipated fuel use is helpful, but not meaningful until the nomination. In the long term pipelines are planned to meet firm contracts, and ultimately pipeline operators must follow their contracts.

System operators face changes that are occurring on both the fuel and power sides. For instance: Is the pipeline network flexible enough to follow ramping? Is one event on the gas side as important as multiple events on the power side?

One ISO is using GPCM (a gas system model) as well as Plexos (a power system model) for monthly gas system modeling versus hourly electric system modeling. Data is a constraint, especially short-term. The ISOs are bringing in additional expertise to run and interpret these models. They need to be able to model and test changes to the system.

One ISO looks daily at who holds gas capacity. They look at what generators have scheduled and used gas during the day. They contact every generator every day and ask if they have scheduled gas to their meter. Most days, gas is not a problem. It is the peak days that present challenges.

One national lab is developing a tool to assist operators to manage fuel by automatically pulling data from natural gas system bulletin boards.

New data are becoming available from FERC-567 (which was noted as difficult to use by some system operators) and DHS data.

Are there new types of contracts or services that natural gas pipelines could offer to natural gas fired generators that take into account the unique market forces in the electricity sector in the medium and long term?

Tariff changes are being filed in some areas on some pipelines. Some are offering hourly flexible service, including in Florida and for some LDCs. In other areas, ad hoc services are provided as they are needed, without contracts so long as they can be accommodated.

High deliverability service was identified as an answer to challenges in New England, but few signed up for it.

Some participants questions whether there are electric market designs for ancillary services that could mitigate some of the fuel problems. In addition, some noted that the power sector could improve its flexibility - perhaps with partial day/non-ratable gas services.

A mechanism may be needed for economic pricing during periods of operational deviation – which could potentially entail a tariff reform at FERC.

Some participants questioned whether NERC could potentially set gas pipeline reliability requirements. Participants noted that the Energy Policy Act of 2005 had many provisions that were intended to respond to blackouts – and that we may now have that need for similar provisions on the gas side. In the power sector there is socialization of costs across all users versus direct contract. If NERC were to set requirements – who will pay? Perhaps there is need for oversight of all fuels that are critical for power generation. Key issues include who will pay for these services and products. In addition, jurisdiction is fragmented. What is a potential FERC role in this area? Even where there are no operational effects, there can be market effects.

Local distribution companies

Aliso Canyon is important for the ramping requirements on power plants. This is increasingly driven by variable renewable energy sources – roughly equivalent to 6 GW of capacity that acts like a single power plant in Southern California. Solar has smart inverter capability – could this be used to make reactive power and increase flexibility of the rest of the grid? Is it possible to provide ride-through capability on a greater number of inverters?

Gas LDCs plan for supply 20 years out and these plans are reviewed frequently. The LDCs review many scenarios and devote significant attention to how they will meet load.

One electric utility has 4 billion cubic feet of gas storage, which is very helpful, but they need to be able to recoup the costs. Power is not the only non-ratable gas load.

Key Takeaways

These findings reflect the discussions at the workshop and do not represent consensus among the participants. DOE does not necessarily agree with or support the content summarized below.

1. Grid operators should verify that critical natural gas system infrastructure will not be affected by electric load shedding during a system emergency.
2. Flexibility is a two-way street. The gas system can provide flexibility for the electric system, and in turn, the electric system—with its multiple layers of redundancy—can provide gas system flexibility in the face of a potential disruption. For example, electric transmission can mitigate constraints on gas pipelines by facilitating a shift from fuel constrained generation to non-fuel constrained generation.

3. Integrated natural gas and electric planning is of growing utility in some regions, and entities may benefit from additional analysis in this area.
4. In a future energy mix that has a larger share of variable renewable generation, new market designs will be needed in order to support the mix of generation that is needed to balance the grid. Understanding what these future market designs look like could remove a barrier to increased renewable development.
5. Generators choose the most economic solution among a variety of options that are available to meet the performance rules that grid operators establish, including delivered firm capacity, firm capacity, dual fuel, and LNG, among others. In competitive markets, this shift has been driven by the price signals that grid operators have created to incent generators to perform during periods of peak electricity demand. We need to align the pricing principles to cost fundamentals.
6. ISOs need to address these issues through medium to long-term planning. Better models, data, and transparency may be needed to address tariffs, planning philosophy, and siting issues, among others.
7. Recent natural gas system disruptions have drawn new attention to planning for low probability, high impact events. The natural gas and electric system operators could benefit from joint drills to prepare for hypothetical future emergencies.

Session 3. Discussion on the Reliability Implications of Natural Gas Storage and Deliverability

What considerations for natural gas storage are important for electricity system operators to consider?

Storage can be 50% to 80% of peak gas demand in some places. But the revenue curve may not be sufficient to support storage. The best alternative to gas storage for the power sector may be electric storage – but participants wondered if electric storage will be available at the right price when there is greater need for storage.

Storage investments have typically been funded by LDCs. Marketers occasionally take on a portion of the market, but do not typically enter into the long-term contracts that will provide enable new large storage projects. Generators typically will not pay for long-term storage. They face the similar cost recovery challenges for storage as they do for pipelines.

Storage development is also a matter of paying the price. At present, the incentives for merchant storage are low. The arbitrage value is not there for long-term storage contracts due to strong gas supply. Gas production can ramp up and down to meet some changing demand. One key question is how to create an adequate the price signal to incent new storage going forward?

Other alternatives can be more cost-effective. Storage may be expensive compared to better power system control technologies.

What role can gas storage play in addressing high-impact, low-probability events are considered in medium and long-term contingency planning?

How can storage facilities contribute to meeting peak load? One national lab is looking at regional supply and demand balances under different peak and average conditions using public data to look at impacts on consumers of natural gas. The result is that impacts are highest where options are lowest. These events are rare – the consequence of loss of storage is typically not extreme - usually it’s just a partial reduction. What can DOE do to address this? Perhaps DOE could orchestrate integrated gas/electric exercises.

Are studies taking other supply options into account? Participants noted that studies are—to some extent. Much of the storage is owned by LDCs and therefore not available to non-LDC customers.

Recent studies show found larger electric markets are an effective way to balance renewables. LNG storage scenarios and nearby storage fields were analyzed in the EIPC study. LNG is a dual fuel option – included as part winter fuel options in the Northeast. New England wholesale markets paid an extra $5 to $7 billion for power due to gas constraints/high prices during the 2013/14 polar vortex and the proceeding winter.

New LNG storage capacity is included as a part of the Access Northeast pipeline proposal as part of meeting year-round demand. LDCs would own the storage and release it to generators. PUC proceedings are underway and controversial. The two existing North East LNG facilities in New England and New Brunswick are seeing more demand during cold spells.

California is atypical from a gas infrastructure standpoint. Gas utilities own the high pressure backbone that would be a separate interstate or intrastate pipeline in other states. Some Midwestern cities have a mid-pressure loop – city gathering system.

Other questions

Can storage resources be sectionalized so that losses are reduced? Salt cavern storage can be sectionalized. Loss of an individual well in a field is typically not a problem.

We need sorting of time scales. How can gas storage improve delivery versus better line pack? Line pack is already being used to "move gas instantaneously." There is a limit to how much more can be done to use line pack as a storage function. We need to study how much can be done.

How close should gas storage be to load?

New electric storage technology is still coming down the cost curve. For New England there is 2,000 MW of pumped storage. Pumped storage can help facilitate renewables but requires a profitable spread between the pump and generation mode in order for this resource to be regularly utilized.

Key Takeaways

These findings reflect the discussions at the workshop and do not represent consensus among the participants. DOE does not necessarily agree with or support the content summarized below.

1. Timescales matter for natural gas storage – storage is a time-shift of supply and/or demand. The timescale is important to understanding the value and implications of storage.
2. Storage is at high levels today but is there a price signal for development of gas storage infrastructure? Is increased production capacity replacing storage?
3. There are opportunities to take advantage of existing infrastructure – pumped storage, LNG storage and import capacity, dual fuel capability.
4. Storage is key but not clear who will pay for it. Can EDCs be the anchors for gas infrastructure?

IV. REFERENCES

U.S. Department of Energy (DOE). *Quadrennial Technology Review.* (Washington, D.C.: U.S. Department of Energy, 2015).

APPENDIX A

LIST OF WORKSHOP PARTICIPANTS

Name	Organization
Aguilera, Allie	PHMSA
Babula, Mark	ISO-NE
Bakke, Jordan	MISO
Barker, Kevin	California Energy commission
Bergles, Susan	American Gas Association
Bergman, Aaron	DOE
Bluestein, Joel	ICF International
Carlson, Richard	Levitan & Associates Inc.
Crockett, Valerie	Tennessee Valley Authority
Delachesnay, Francisco	EPRI
Dominguez, Marie	PHMSA
Ellsworth, Chris	FERC
Folga, Stephen	Argonne- Aliso Canyon Task Force Analysis
Frisch, Carla	DOE
Gebhart, Jette	FERC
Gilliard, Artealia	PHMSA
Greenwald, Judi	DOE
Hendrickson, Stephen	DOE
Jenkins, Sandra	DOE
Khaksari, Amir	Exelon (Constellation)
Kruse, Richard	Spectra Energy
Lefler, Kelly	DOE
Levin, Amanda	NRDC
Levitan, Richard	Levitan & Associates Inc.
Logan, Jeff	NREL
Marianne Hatch	EEI
Martin, Andrew	DOE
McMahon, Richard	Edison Electric Institute
Meyer, David	DOE
Mills, Marguerite	AEP
Norden, John	ISO-NE
Novosel, Sarah	Calpine Corporation
Oehler, Alex	Columbia Pipeline Group

Orr, Franklin	DOE
Pearce, Thomas	DOE
Pierpoint, Lara	DOE
Prabhakar, Aditya	MISO
Rosner, David	DOE
Robb, Jim	WECC
Santa, Don	Interstate Natural Gas Association of America (INGAA)
Shah, Tarak	DOE
Sheffield, Pete	Spectra Energy
Steinberg, Ben	DOE
Ulmer, Andrew	CAISO
Walsh, Christy	FERC
Zlotnik, Anatoly	LANL

APPENDIX B: WORKSHOP AGENDA

9:30 am – 10:00 am: Welcome
Dr. Franklin Orr, Undersecretary of Science and Energy, DOE
Marie Therese Dominguez, Administrator, Pipeline Hazardous Materials and Safety Administration
10:00 am – 11:15 am: Discussion on Natural Gas Today and in the Future (Data and Tools)
How are electric power sector usage patterns changing and how are these changes related to natural gas supply?
What physical, operational, and planning process changes has your region made to accommodate increased levels of natural gas-fired generation; and what data, tools, and practices are used to manage your system?
How does your region represent the potential for natural gas pipeline disruptions in contingency analysis?
What high-impact, low-probability events are considered in medium and long-term contingency planning, and are there additional events that should be considered moving forward?

11:30 am – 12:45 pm: Discussion on Operational Strategies
Will the increase in natural gas-fired generation in your region require any physical or operational changes to the existing natural gas infrastructure in the medium and long term (e.g. different types of natural gas storage, pipeline capacity expansions)?
What information or practice sharing between the natural gas and electric sectors would best facilitate medium- and long-term electric sector planning?
What options do electricity system operators have to manage periods of peak natural gas demand as well as to manage increasing variability (e.g. demand response, energy efficiency, capacity market changes, transmission investments)?
Are there new types of contracts or services that natural gas pipelines could offer to natural gasfired generators that take into account the unique market forces in the electricity sector in the medium and long term?

12:45 pm – 1:45 pm: Lunch – Presentation by Levitan & Associates, Inc.

1:45-3:00 pm: Discussion on the Reliability Implications of Natural Gas Storage and Deliverability
What considerations for natural gas storage are important for electricity system operators to consider?
What role can gas storage play in addressing high-impact, low-probability events are considered in medium and long-term contingency planning?
How does natural gas and electricity interdependency impact natural gas storage operations?
How does your region represent the role of gas storage in addressing natural gas pipeline disruptions in contingency analysis?

3:15- 4:00 pm: Concluding Discussion & Workshop Synthesis
Led by Judi Greenwald, Deputy Director for Climate, Environment, and Energy Efficiency (EPSA) and Senior Advisor to the Secretary for Climate Change
What questions remain on natural gas deliverability?
What additional opportunities are there for increased coordination between natural gas consumers and pipeline operators?
What are key issues related to the role natural gas storage in support of electric system operation?
What role can DOE play in additional education and analysis on this topic?

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