

Report from

Growing Concerns, Possible Solutions:

The Interdependency of Natural Gas and Electricity Systems



MIT Energy Initiative

An MIT Energy Initiative Symposium
held on April 16, 2013



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SUMMARY FOR POLICY MAKERS

On April 16, 2013, the MIT Energy Initiative (MITEI) sponsored a symposium on *Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems* to develop an understanding of the issues raised by the increasing interdependency of the natural gas infrastructure and electricity production and to explore policies that might be used to address these growing challenges. The deliberations were informed by eight commissioned white papers and by additional contributions submitted by symposium participants. The commissioned white papers are at the back of this report.

All of the documents are available at:

<http://mitei.mit.edu/publications/reports-studies/growing-concerns-possible-solutions>.

Here we summarize for policy makers the key points that emerged from the lively discussions among the diverse group of symposium participants. **We stress that the observations here are those of the authors and are not offered as a consensus view of the participants.**

- **The use of natural gas to generate electricity has become much more important to both the natural gas and electric power systems, and this interdependency will increase over time.**

In 1990, natural gas accounted for 12% of US electricity generation; by 2010 that share had doubled. Over this period, the share of natural gas sold to the electric power sector increased only slightly less rapidly; it rose from 17% to 31%. While few predict such dramatic changes over the next few decades, there are several reasons to expect that the electric power sector's reliance on gas will nonetheless increase substantially. It seems likely that this shift will be sufficient enough to make that sector an even more important source of demand for natural gas than it is today.

Much of the domestic coal generation fleet is relatively old; 73% was 30 years old or older at the end of 2010. Significant retirements from that fleet are expected in the next few decades, hastened by the projected long-term availability of natural gas at prices that are low by historical standards and by new and proposed EPA regulations. EPA regulations on carbon dioxide emissions from existing plants, which are necessary, but have not been proposed, may further hasten the retirement of old coal-fired generators. Proposed EPA regulations on carbon dioxide emissions from new power plants effectively rule out building coal-fired plants to replace those that are retired unless they are outfitted with carbon capture technology, which is commercially unproven and seems likely to be very expensive, and new nuclear plants appear to have significantly higher per-kWh costs than new gas-fired generators. Moreover, most US nuclear capacity must retire shortly after 2040. Also, some units will be retired earlier for economic reasons. It appears that gas will be the last thermal generation source standing.

While wind and solar power only account for about 3% of US electricity generation, unless state and federal support for these technologies is cut sharply, reliance on them will likely increase substantially in the next few decades. Both wind and solar generators are intermittent sources of energy: their outputs vary over time and are not predictable. Power systems with a high penetration of such intermittent generators need to be flexible in order to handle large fluctuations in their output. Flexibility can come from several sources, including storage, demand response, and reservoir hydro, but single-cycle gas turbines are often the most economical source. Thus, increased penetration of wind and solar power is likely to increase the value of gas-fired generation and, accordingly, to increase its importance.

- **Basic structural characteristics of the gas and electric systems imply that increased information flow between them can have considerable social value.**

Since the electric power system has become increasingly reliant on natural gas for generation and has become a more important source of demand within gas markets, actions in either system now have a more significant impact on the other. And, while the markets and other institutions in both sectors have performed well until now, and they were relatively less interdependent, the fact that both need to meet demand in real time with little or no storage increases the importance of coordination between them in both the short and long runs.

When the electric power sector was very reliant on coal, it did not matter much that the industries supplying coal were not closely coordinated with the electric utilities that burned it. Onsite storage of coal at power plants meant that temporary disruptions in coal supply rarely threatened plant operations. When utilities had to buy coal in spot markets, they faced prices that were generally stable from hour to hour and day to day. On the supply side, most utilities could buy coal from many suppliers, and each plant was served by a railroad that could deliver coal from essentially anywhere in the nation in almost any quantity that might be needed.

However, gas is different. The need for electric power systems to match supply and demand at every instant combined with the lack of gas storage at most generating plants means that short-run changes in the demand for gas from a gas-reliant electric power system closely mirror changes in the demand for its electricity. A pipeline outage generally causes electric generating capacity to go offline as well. While electric generators can buy gas in a fairly liquid market, spot prices of gas, like spot prices of electricity, can vary widely on a daily and even hourly basis. And, unlike a rail line, a pipeline's capacity is strictly limited; adding more capacity will generally require building another pipeline. Both pipelines and electric power systems offer interruptible contracts to large customers because it is sometimes necessary for both to shed load in order to maintain system integrity.

In the abstract, vertical integration between these two complex, closely coupled systems might seem a natural solution to the serious coordination problems they face. But the gas system serves other important customers, and the electric power system has other sources of energy. Moreover, in the last few decades, both systems have shown that they can handle their significant *internal* coordination problems without vertical integration. The key in both cases has been transparent, well-informed markets for gas, pipeline capacity, electric energy and related ancillary power services, and, in some regional power markets, generating capacity.

It may not be clear exactly what institutional and operational changes will best improve coordination between the gas and electric systems. However, it is clear from the way markets have solved the systems' internal coordination problems that having more timely information available to both about the state of each system and about such things as planned maintenance outages and expected changes in demand as well as supply can reduce overall risk and make costly surprises less common. Confidentiality concerns necessarily arise whenever information sharing is discussed, of course, but they should be thoughtfully addressed (by regulation if necessary), and not used to prevent the timely flow of valuable information.

- **Scheduling mismatches between gas markets and electricity markets in ISO regions should be addressed by modifying timing in electricity markets.**

In regions with independent system operators (ISOs) — some of which are also regional transmission operators (RTOs) — and organized wholesale electricity markets, the electric day starts at midnight local time, while the gas day starts everywhere at the same time: 10:00 am EST. The spot market for gas is most liquid (with high transactions volumes and low bid-ask spreads) between 8:30 am and 10:00 am EST. Day-ahead markets of various sorts for pipeline capacity and electricity open and close at times that are not synchronized. The result in New England is that generators have historically had to nominate and schedule gas with the pipelines before they knew whether their generation bids have been accepted. When the gas system is under stress, it sometimes happens that a resource's bid to generate has been accepted, so that it is committed to generate, but it cannot nominate and schedule gas to meet its generation commitment. When this happens, the system may need to turn on short notice to non-gas generators, which typically have long startup times. The ISOs view this as material concern for their ability to maintain electric system reliability.

In principle, the timing of events in the gas markets could be modified, the timing of events in the electricity markets could be modified, or both could change. Realistically, however, the electricity markets will need to change. Note first that these problems do not arise in regions with vertically integrated utilities, as these have little choice but to adapt their operating procedures to synchronize as well as possible with the gas markets. In the ISO regions, there is a central authority that designs and operates the electricity markets, but there is no equivalent to an ISO on the gas side that could dictate timing changes in the gas markets. Moreover the gas market (as distinct from markets for pipeline transport) is national, and its institutions are unlikely to change in response to a request from even a group of ISOs — assuming such a group could agree on what to request.

ISO-New England (ISO-NE) is already moving to change timing in its markets to reduce scheduling problems, and there is no reason other ISOs could not do likewise. While scheduling mismatches are clearly a problem of some importance, this is a problem that the ISOs can and should manage.

- **Changes in ISO market designs will be necessary to deal with longer-term problems of reliability and flexibility, but direct regulation may be a useful supplement in some cases.**

In the late 1990s, when New England and other regions shifted from reliance on vertically integrated utilities to reliance on organized wholesale electricity markets, gas pipeline capacity was not a concern. Merchant generators did not need to acquire firm gas supplies, since interruptible gas was cheaper and almost never interrupted. Moreover, the inherited generation fleet had adequate flexibility to handle historic fluctuations in load and relevant contingencies, and intermittent generation was not a concern. Thus, there was no short-term need to consider fuel availability or system flexibility in the design of wholesale markets. But times have changed.

Pipeline capacity is a current concern in New England and New York. Pipeline rates of return have federally regulated ceilings but no floors, so nobody would invest in a pipeline that had not, in effect, sold its capacity in advance via long-term supply contracts. Historically, gas pipelines were built if and only if local gas distribution companies (LDCs) signed sufficient contracts for firm gas supplies. In New England, there is a perceived need for additional

pipeline capacity to serve electric generating plants, but merchant generators have not been willing to enable pipeline construction by contracting for more expensive firm gas supplies. Of course, gas-fired generators could deal with peak-period interruptions in gas supply by having Liquid Natural Gas (LNG) storage onsite or by being dual-fuel capable and storing oil onsite. But it does not seem that these options are commonly acquired either.

To understand how this is a problem with electricity market design, think about a competently managed, vertically integrated utility that is required by law to provide reliable power to a substantial region. Would it consider signing a contract for firm gas supplies in order to ensure that it was able to meet that obligation? Would it also look at LNG storage and dual-fuel options on a plant-by-plant basis to see how much use it could safely make of interruptible gas supply? Of course it would.

In order to mimic this central planning process, organized markets need to give proper incentives for generators to consider these options. One way or another, the ISO regions must move beyond reliance on LDCs to finance adequate pipeline capacity, but building new capacity is not always the best way to ensure generator reliability. In markets for electric energy, one approach would be to impose very large penalties for failure to generate during tight system conditions. In capacity markets, significant extra financial incentives could be given to plants with firm gas supplies, substantial LNG storage, or dual-fuel capability plus substantial oil storage. In this spirit, Midcontinental ISO (MISO) is moving to giving full capacity credit to new gas-fired plants only if they have firm long-term gas supplies, and ISO-NE is proposing significant changes to its capacity market to clarify and strengthen incentives. Because of their locations, some generators must take gas from an LDC rather than directly from a pipeline. Such generators may be unable to procure firm gas, since guaranteeing never to interrupt supply would conflict with other LDC obligations. The New York ISO (NY ISO) faces this problem in New York City and Long Island, and it addresses it with a dual-fuel requirement. This regulation may be a sensible supplement to energy, capacity, and other markets. One could imagine achieving the same level of reliability via market design; the process would be more complicated, but the costs might have been lower.

Looking ahead, greater penetration of intermittent renewables will increase sensitivity to disruptions in gas supply as well as the value of flexibility in the generation fleet. Generating units that can start up quickly and/or change output rapidly without violating environmental constraints are more valuable than less flexible units with the same capacity. Current market designs do not provide much of an incentive to supply flexibility, however, and some observers worry that it is not adequately supplied. This, of course, is yet another market design problem. Because the generation fleets that had been designed by vertically integrated utilities had adequate flexibility when markets were introduced, the market designs put in place did not provide incentives for the supply of flexibility. Because flexibility is valuable and will prove to be even more valuable in the future, markets may need to be redesigned to provide such incentives.

But it may not be efficient for all of the necessary incremental flexibility to be provided by electric systems, even though their customers should ultimately bear the incremental costs involved. In contrast to LDCs, which are generally expected to take the same amount of gas in every hour, electric generators that operate only in peak periods need gas for only a few hours at a time. This may pose operational problems for pipelines. Similarly, emergencies of various sorts may require an ISO to dispatch generators that it had not expected to invoke and that had accordingly not contracted in advance for gas delivery, while gas nominated for delivery elsewhere cannot be redirected to be used. Engineering pipelines so they can

respond to these and other intraday changes in delivery amounts or locations would add cost, as would enhancing round-the-clock communications links with ISOs and providing hourly gas nomination schedules, or flexible transportation contracts. As pipelines are currently regulated and as their service obligations are defined, however, it is not clear that pipelines have appropriate incentives to increase their flexibility.

- **Modeling of the coupled gas and electric systems can help the parties involved develop better solutions to the issues they jointly face.**

The design and evolution of markets for energy, capacity, and ancillary services in the electric sector over the past two decades have been informed in part by a wide variety of modeling and analysis within the academic research community. These models have integrated engineering and technical constraints with economic theory to investigate the impacts of alternative market structures.

The complexity of the coupled electric power and natural gas systems that has emerged in recent years is such that changes in market rules or additional regulations in either system clearly have the potential for unanticipated consequences in both. This possibility highlights the value of careful analysis of the overall gas-electric system. However, there is currently a dearth of analytical frameworks for the analysis of electricity-gas interactions.

Researchers at MIT and collaborators elsewhere have begun the development of modeling frameworks that can be used to examine interactions between the electricity and natural gas systems. These frameworks can provide a neutral forum to facilitate productive analysis of ideas arising from multiple perspectives and discussions among the many stakeholders involved in this issue. One potential next step beyond the symposium is the formation of a small consortium of interested parties to support the development of these modeling tools and their use in facilitating discussion and informing the decisions that will be needed in the next several years as participants in these markets and other stakeholders try to better align incentives and share information.

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MITEI Associates Program/Symposium Series

The MITEI Associates Program/Symposium Series is designed to bring together groups of energy experts to examine, analyze, and report on critical and timely energy policy/technology issues with implications for near-term actions. The centerpiece of the program is a one-day symposium in which invited experts, under Chatham house rule, discuss the selected topic. Topical white papers, which are sent to the participants in advance, are commissioned to focus and inform the discussion. The information from these white papers is supplemented by work from graduate students, who generate data and provide background information.

Potential symposium topics are solicited from MITEI members and are provided to the Steering Committee for consideration. Four MITEI Associate members – Cummins, EDF, Entergy, and Hess – support the program with a two-year commitment and serve on the Steering Committee.

After each symposium, a report is prepared and published, detailing the proceedings to include a range of findings and a list of recommendations. Two students are assigned to each session. They serve as rapporteurs for the symposium and focus their master's theses on topics identified from the symposium. MITEI also develops and implements an outreach rollout to inform policy makers and the media of the results.

This report is the sixth in the series, following Retrofitting of Coal-Fired Power Plants for CO₂ Emissions Reductions, Electrification of the Transportation System, Managing Large-Scale Penetration of Intermittent Renewables, and Prospects for Bi-Fuel and Flex-Fuel Light-Duty Vehicles, and Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration.

These reports are available electronically on the MITEI web site at <http://mitei.mit.edu/publications/reports-studies/growing-concerns-possible-solutions>. If you would like to receive a printed copy of one or more of the reports, please send an email with your requested titles and quantities and your mailing address to askmitei@mit.edu.

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The MIT Energy Initiative's Symposium on Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems

1. SYNTHESIZED FINDINGS

Symposium Structure

The 2013 MITEI symposium, titled *Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems*, was held at MIT on April 16. The one-day event provided the research, industry, investment, and policy communities with a framework for understanding the challenges associated with electricity and natural gas interdependency, particularly in the context of the United States. Symposium participants identified several policy and market-driven solutions to mitigate growing economic and reliability concerns. This report synthesizes those key findings and the overall discussion.

While this report provides perspectives and policy recommendations from the symposium, it is in no way meant to represent the views of all or any individual participants or presenters. The contributed white papers are included at the end of this report. Several unsolicited papers and presentations from the event are available at <http://mitei.mit.edu/publications/reports-studies/growing-concerns-possible-solutions>.

Framing Issues

Several key themes, each explored in depth throughout the symposium, should be considered to frame further analysis of the interdependency of the natural gas and electricity markets. They include:

The unique characteristics of natural gas: Natural gas power plants have limited or no onsite fuel storage capabilities and often exhibit highly variable demand profiles. As such, they are characterized as being just-in-time fuel users, which exacerbates interdependency challenges. The effects of fuel supply disruptions are more acute for gas-fired generators than for those that rely on coal, oil, or nuclear.

Broad challenges, regional solutions: Though many electricity systems are increasing their reliance on natural gas, the challenges these systems face are diverse. For example, gas-related challenges that market-based electricity systems face are unique and at times far more complex than those of vertically integrated utilities due to the intricacies of market-based solutions. Furthermore, reliance on natural gas for uses other than electricity generation varies throughout the country. The problems, and in turn the solutions, that each region faces depend on local markets, regulations, and political will. While national solutions could solve some overarching challenges, a portfolio of solutions is needed to address regional challenges.

The changing profile of natural gas demand: Historically, natural gas pipelines have been financed and approved only after local distribution companies (LDCs) — who use gas in fairly predictable and steady rates throughout the course of a day — sign long-term contracts. Recently, nearly all new growth in natural gas consumption in the United States has been concentrated in the electric power industry. The electric power industry has a very different demand profile than LDCs because gas-fired generators are often used for peak electricity demand, and therefore require gas to be delivered in relatively large quantities over just a few hours. This shift raises the question of whether the current paradigm of pipeline financing and regulatory approval is adequate to address the needs of the power sector.

Diverse stakeholder interests: There are many stakeholders in this debate, each with different perspectives on the extent and seriousness of the problems and with different opinions on ways to address those problems. Engaging the diverse range of stakeholders is imperative to crafting policy changes that are inclusive and effective.

Timing matters: Both the United States and the European Union have recently experienced natural gas related threats to power system reliability. As this report makes clear, if the underlying causes of these reliability threats are left unaddressed such occurrences will become more common soon. In the energy industry, policy changes are complex and time intensive. Therefore, a portfolio of solutions that mitigates short-term problems while laying the groundwork for long-term structural change is needed. Reactionary policy changes after a moment of crisis will not manifest the same quality of results as thoughtful and prudent changes implemented before a crisis occurs. Unfortunately, the opportunity for pursuing deliberate and vitally necessary policy change is quickly diminishing in many regions.

Regulatory Landscape

In the United States, there are several levels of regulatory authority, ranging from federal to local and from *de facto* to *de jure*. The relevant regulatory authorities, as they relate to electricity and natural gas interdependency, include:

- **The Department of Energy (DOE)** permits LNG export sites. Exporting large quantities of natural gas could change the regionality of demand and prices of gas.
- **The United States Congress** has recently begun to consider gas-electricity interdependency issues. The House Energy and Commerce Committee's Energy and Power Subcommittee held two hearings in March of 2013 that considered the coordination challenges of natural gas and electricity interdependency, as well as possible federal solutions.¹
- **The Federal Energy Regulatory Commission (FERC)**, the highest energy-regulating body in the United States, is responsible for regional electricity market operations, regulating wholesale power transactions and interstate pipelines, and setting cost-based transmission tariffs for gas transportation services. FERC also permits the siting and construction of LNG facilities used for importing and exporting natural gas, and certifies LNG facilities engaged with interstate pipelines.
- **The North American Electric Reliability Corporation (NERC)**, which is independent from FERC, sets standards that directly affect the operation of electricity systems. However, NERC is prohibited in Section 215 of the Federal Power Act from setting reserve margin criteria or ordering the construction of transmissions to address inadequate resources.²

- **ISOs and RTOs** are under FERC's authority and operate regional electricity markets and transmission systems for wholesale power. ISO/RTOs exist to promote wholesale competition in the electricity system, and are therefore very careful not to favor any particular energy source through their operations. Proposed changes in market rules must go through stakeholder processes at the ISO/RTO and receive subsequent approval from FERC to be implemented, resulting in a lengthy rule change procedure.
- **State Public Utility Commissions (PUC)**³ have economic jurisdiction over investor-owned utilities and generally have regulatory authority over the siting of power plants and transmission assets. State regulatory commissions have some authority over the generation mix that is employed under their jurisdiction, though the magnitude of their reach varies greatly by state. PUCs also require local distribution companies to meet the needs of residential customers before all other consumers, such as natural gas power plants.
- **The North American Energy Standards Board (NAESB)** sets voluntary industry-wide standards, though some are made mandatory by various regulatory bodies such as FERC. NAESB's national gas day is used throughout the United States to standardize when and how interstate pipelines accept requests to ship gas.

Main Challenges

The following section provides an overview of the main issues surrounding the interdependency of natural gas and the electricity market that were discussed throughout the symposium. Topics include Dispatch and Market Operations; Capacity Contracts and Competing Claims; Ensuring Resource Adequacy; and Communications and Information Sharing.

Dispatch and Market Operations

Issues Summary: When real-time conditions deviate from expectations, electricity generation and gas delivery commitments are updated with increasingly expensive last-minute market transactions. Presently, mismatched market schedules exacerbate the challenges of these and less urgent transactions, reducing market efficiency and threatening system reliability. The dispatch and market operations of both the natural gas and electricity sectors need to adapt to meet the changing supply and demand landscape.

Short-term market operation and generator dispatch are the most pressing concerns for gas and electricity interdependence. While vertically integrated utilities have issues associated with natural gas and electricity interdependency, they do not worry about sensitivities surrounding market operations such as fuel neutrality, reliance on economic incentives, and market stakeholder involvement processes, factors that complicate regulatory changes and market rule design in deregulated electricity markets. Electricity market timing and natural gas transmission practices affect the dispatch of natural gas generation and pose challenges for system reliability.

Gas transmission operators often have different operating schedules than electricity markets, leading to price and quantity uncertainty for generators. In some day-ahead electricity markets, power generators are required to submit offers for producing power hours ahead of when they are able to purchase the corresponding fuel. Then, these generators purchase natural gas before they know their precise generation obligations as appointed by the power system operator. This uncertainty of generation offers and fuel purchases leads electricity system operators to dispatch generators without being truly certain that they have the appropriate fuel nominations to perform reliably.

The transmission capacity nomination process — in which gas shippers tell pipeline system operators their natural gas transmission needs — is where gas-electricity interdependency challenges are most likely to manifest. The natural gas market in the United States has been deregulated and is without a central controller (like an ISO/RTO). As such, the structure has evolved more organically than regional electricity markets, leading to three distinct and disjointed markets: the commodity gas market, the transmission capacity market, and the financial market. Coordinating needs across these three markets can be a major challenge for gas consumers.

Another challenge for natural gas consumers is that there is no way to trade for pipeline transmission capacity in real time. At times, these trading constraints lead to gas-fired generators taking more or less than their scheduled shipment of gas from the pipelines in order to address real-time changes in the electricity market. Pipeline operators impose fees for taking a different amount of gas than a shipper's scheduled volumes, a price that many generators are willing to pay for flexibility.

Key Findings: Dispatch and Market Operations

1. Market timing differences cause many power generators to incur price uncertainty in the electricity market and quantity uncertainty in the gas market. These uncertainties can lead to inefficient markets and the unavailability of generators which lead to reliability risks and price increases for the electricity sector.
2. Organized natural gas marketers close overnight, on weekends, as well as on holidays. A possible way to increase liquidity and coordination of the gas transportation market is for electricity system operators to incentivize marketers to stay open overnight and on the weekends.
3. Due to the nature of system operation for gas and electricity infrastructures, heavy penalties can result from misestimation of gas demand for both the gas and electric industries in terms of reliability and flexibility. Properly incentivizing flexibility and reliability into electricity markets can help facilitate innovations that will result in a market-based solution for reliability risks.
4. Demand response, for electricity and potentially for natural gas, is one of the major market changes that could enable a number of new market solutions to system operational constraints. However, the relative impact that demand response will have on the market is very uncertain.
5. It is important that changes to electricity market days account not only for pipeline capacity nomination deadlines, but also for the timing of liquidity and transparency in the gas commodity market. The ability for a power generator to trade fuel at times when there are very few other market participants is hardly beneficial.

Capacity Contracts and Competing Claims

Issues Summary: The interstate pipeline system that was designed to serve LDCs and their relatively predictable demands is increasingly being relied on by power generators with significantly more variable demand profiles. At the same time, while LDCs traditionally sign firm contracts, power generators are increasingly opting for interruptible contracts. An increasing proportion of interruptible capacity contracts used for shipping natural gas adversely affects how new pipelines are financed and approved, and can lead to competing claims because of the contract's lower shipping priority.

LDCs are required by state public utility commissions to sign a sufficient number of firm contracts for pipeline capacity to meet the aggregate peak demand of their customers. These firm contracts signal to FERC that the pipeline is in the interest of the public and gives confidence to investors in the profitability of their investments, the first steps in the traditional process of regulatory approval and financing. LDCs are required to supply fuel to residential consumers and hospitals above all others, so generators that are connected to the natural gas network through an LDC can have a subordinate claim for gas — even if they have firm contracts for interstate pipeline capacity.

Power plants in many parts of the country are unable to recover the higher cost of long-term firm contracts through their electricity market bids, and therefore rely on interruptible contracts for gas supply in order to adapt to changing market conditions and pass the contract cost through to their market bids as a variable cost.

The interruptible capacity contracts, which power generators depend on for flexibility, can threaten the reliability of the electricity system because of their lower delivery priority compared to firm contracts. Historically, there has been enough excess interstate pipeline capacity for LDCs to increase their shipment nominations without recalling interruptible contracts. Recently, a greater percentage of gas is being shipped using interruptible contracts, and pipeline utilization is approaching the maximum capacity in some areas. If LDCs underestimate the amount of capacity that will be required to meet demand in the short term, or if electricity system operators need an immediate influx of power from a natural gas power plant, interruptible capacity contracts often cannot guarantee that gas will be delivered for power generation.

Key Findings: Capacity Contracts and Competing Claims

1. The interstate pipeline system that was designed to serve LDCs and their relatively predictable demands is increasingly being relied upon by power generators with highly variable demand profiles. The physical operational limitations of pipelines coupled with a legacy capacity contract structure has created an impasse in new pipeline investment that threatens fuel deliverability to many power generators in critical periods.
2. State regulations for determining what qualifies as a human needs customer should be revisited, considering that heating residential homes — which serves as the basis of the human needs customer gas service obligations imposed on LDCs — often requires gas *and* electricity. As LDCs have an obligation to serve human need customers first, generators are sometimes unable to secure reliable fuel supplies in times of most extreme cold weather events.
3. There is disagreement on whether the current state of pipeline regulation and financing structures is adequate to face impending electricity system challenges. Participants suggested that allowing cost pass-through of firm contracts in electricity markets and mandating firm contracts are some options for system operators. Ultimately, system operators need to understand the financial value of reliability of generators on their system, and ensure that generator remuneration reflects this value.
4. Regulators and policy makers can look to examples in which pipelines were financed through producers or state governmental entities signing firm capacity contracts as models for how to enable alternative financing and permitting of interstate pipelines.

Ensuring Resource Adequacy

Issues Summary: Natural gas fuel delivery poses challenges not inherent in other fuels like coal, nuclear, or oil. Due to the just-in-time character of natural gas, supply chain disruptions are costly and a portfolio of different solutions is needed to increase resource adequacy.

In the context of electric power systems, resource adequacy “refers to the existence of enough available generation and network capacity, either installed or expected to be installed, to efficiently meet demand in the long term.”⁴ Providing predictable and reliable power is a challenge for natural gas power plants in an electricity system with a diversified generation mix. Ways to compensate for those challenges include:

- **Increasing fuel diversity in the electricity system:** Relying on several fuel sources with unique supply chains can add resiliency to the electricity system and reduce the likelihood of a single fuel’s constraints threatening the reliability of the entire system.
- **Diversifying delivery of natural gas:** Simply relying on pipelines alone for fuel delivery tightly links problems in the pipeline transmission system with problems in power generation. Diversifying the sources of natural gas supply available to generators through storage technologies increases reliability by adding redundancy and reducing the impact of acute supply chain constraints.

- **Increasing pipeline capacity:** Promoting pipeline investment through innovative sources of financing and regulatory revisions could reduce congestion and increase the efficiency of natural gas delivery to generators in power systems. Stranded supply, or natural gas that is abundant in a certain region but lacks the infrastructure to move to where it is in demand, can lead to price anomalies that diminish the economic value of the resource.

Key Findings: Ensuring Resource Adequacy

1. Additional pipelines are needed to move gas from new supply centers to traditional demand centers and to meet growing demand in the power sector. Lack of adequate pipeline infrastructure can lead to stranded supply and unmet demand, diminishing the economic value of new natural gas reserves and threatening electricity system resource adequacy.
2. Grid-scale underground natural gas storage and LNG facilities have a proven track record of providing fuel resources that increase power system reliability. Unfortunately, geographic constraints, regulatory hurdles, and economic barriers make it unlikely that either technology will increase its presence in the natural gas system in the near future.
3. Distributed Compressed Natural Gas (CNG) storage is an emerging technology that shows strong promise in laboratory demonstration, but requires lengthy research and development before commercialization will be possible.
4. Relying on several fuel sources with unique supply chains can add resiliency to the electricity system and reduce the likelihood of constraints of one fuel leading to a system reliability threat. Opportunities exist to better incorporate alternative fuels, through incentivizing dual-fuel capabilities of new power plants and ensuring availability of multiple fuels on the grid.
5. LDCs rely on a diverse set of gas resources to provide redundancy in their system, often having overcapacity to ensure reliability. Participants suggested considering relying on these alternative gas resources as a means to free up pipeline capacity otherwise destined for LDC use.

Communications and Information Sharing

Issues Summary: Due to the intricate nature of the interactions between power generators and the natural gas systems on which they rely, more robust communication procedures and an improved understanding of their interactions are needed to streamline normal operations and mitigate the consequences of emergency situations.

Due to information asymmetries between ISOs/RTOs and generators, electricity system operators must make assumptions about gas system conditions during day-ahead scheduling. When these assumptions do not align with actual conditions, ISOs/RTOs are often forced to make real-time operational adjustments. Without fast and transparent information exchange, the current reliance on interruptible capacity contracts presents a threat to electricity system reliability and pipeline system operations when pipelines become over-nominated and system operators are not informed of the shipping constraints experienced by generators in their networks.

The process of overtaking and undertaking natural gas from the pipelines, when a consumer takes more or less gas than their initial transmission nomination and pays penalties for the privilege later, can threaten the reliability of the pipeline network. Pipeline operators are left to scramble to keep pressure on their lines when power generators overtake gas and pipelines are fully subscribed. This problem is complicated further by the lack of central system operators in the interstate gas network.

By leveraging advances in communications technologies that enable real-time information exchange, market liquidity and coordination can be improved. Such technologies can help to make the most of the physical infrastructure as it currently exists, but also allow flexibility for adaptation to future system needs. To better gauge future needs, sophisticated modeling tools that take both the natural gas and electricity systems into account need to be developed to predict when and where fuel transportation constraints will manifest. These models would address concerns such as investment in natural gas generation, firm contracts for pipeline capacity, and the reliability benefit of dual fuel capability.

Key Findings: Communications and Information Sharing

1. When generators are not nominating with certainty due to market timing misalignment, the real-time dispatch of generators for power can result in reliability concerns for both the gas and electric systems that could be better mitigated with improved coordination and information sharing. While there has been work to outline emergency communication procedures between the industries, further thought into the expansion of communication is necessary, specifically in day-to-day situations, and recent technological advancements will be useful in this endeavor. Many electric system operators lack information about the real-time fuel availability and diversity in their systems, especially those behind the city gate, and this knowledge can help tremendously in planning for contingency events.
2. During gas constraints, there is still a possibility of curtailment, sometimes regardless of the gas contract type, when human needs customers are at risk. Communicating information regarding possible future constraints is important to better understand their likelihood and overall effect on system reliability. Coordinating the designation of human needs customers between the two industries is an important step to solving growing problems with reliability concerns. Specifically, generators that could prevent loss of load to residential customers and are behind the city gates could be categorized as human needs customers as well.
3. Improving the availability of information and real data on future outages and generation investment between stakeholders in the gas and electricity infrastructures will allow models to facilitate improved joint planning and system operation reliability for both infrastructures. There are enormous opportunities for system operators in both industries to adapt their models for system reliability to the changing patterns of demand and fuel availability caused by the growing interdependency between the electricity and natural gas sectors.

Conclusion

Nations around the world are increasingly relying on natural gas to meet their electricity and heating needs. Advocates of low-carbon energy largely welcome this shift to natural gas because it provides the same amount of electric power for about half the carbon emissions of coal. Additionally, when intermittent renewable sources are introduced into the grid, they require flexible fuel sources that can step in when the sun is not shining and the wind is not blowing. Natural gas provides this flexibility.

Despite the advantages of natural gas, having the electricity system reliant on gas as a fuel is not without its challenges. The just-in-time nature of natural gas delivery, coupled with misalignments in the timing of gas and electricity markets, can lead to the unavailability of the fuel when it is most needed by power generation and the diminished economic value of the resource.

Several observations during the symposium highlight the challenges facing natural gas and electricity interdependence. Investment in interstate pipelines with regulations and market procedures that were designed to meet the needs of LDCs has failed to keep pace with rapid changes in demand and geography of supply. Electricity market operators that historically did not concern themselves with the fuel supply chains of generators are now facing a new paradigm of systemic fuel-supply risk. Seasonal and daily demand fluctuations have begun to exceed the ability of storage facilities to fully supplement pipelines, and the prospects of new facilities look bleak due to the lack of necessary geologic conditions. The avenues for finding solutions to these problems lie in adapting both the natural gas and electricity systems through changing market timing, addressing pipeline capacity expansion and utilization, and diversifying fuel supply.

While the symposium highlighted challenges and actionable policy and market solutions, a number of questions were raised that warrant further analysis by researchers, policy makers, and system operators. They include:

- How can the value of resource reliability be best reflected in electricity market design?
- How should research and development strategies be oriented to address current and future interdependency challenges?
- How can natural gas infrastructure be regulated to maximize the value of the shifting geography of supply and the changing dynamics of demand?
- Do new market dynamics warrant revisiting communication protocols to improve system reliability, and what information and data are needed to research these problems further?

The subsequent sections of this report elaborate further on the specific issues and possible solutions presented. Our hope is that as result of this effort, the research, industry, investment, and policy communities will have a clearer understanding of the challenges at the interface of the natural gas and electricity systems in the United States and will be better suited to address these challenges.

2. DISPATCH AND MARKET OPERATIONS

Mismatched market schedules exacerbate the challenges of real-time balancing, reducing market efficiency, and threatening system reliability. This section gives an overview of how the markets function and summarizes symposium discussions of the key incentives and market mechanisms for improving their interactions.

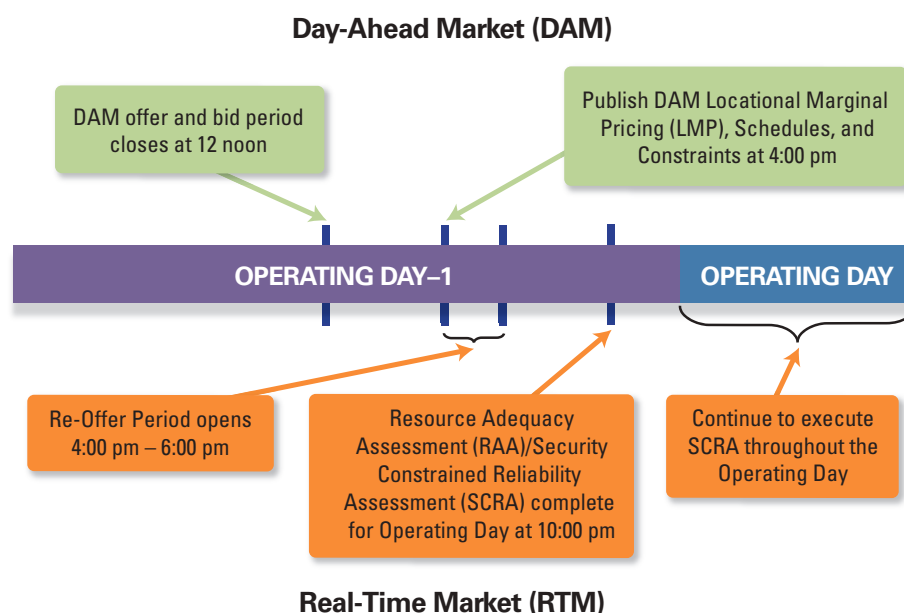
Electricity and Gas Markets Overview

The gas-related challenges that market-based electricity systems face are much greater than those of the vertically integrated utilities. Vertically integrated utilities have a great deal of freedom in how they operate their electricity systems. Operators do not worry about sensitivities surrounding market operations such as fuel neutrality, reliance on economic incentives, and market stakeholder involvement processes. The relative lack of constraints allows integrated utilities to address problems quickly and with certainty. In regions with deregulated electricity markets, much more thought and due diligence are needed to design market rules and regulatory changes.

Wholesale Electricity Market

Within the United States, a number of regions have deregulated electricity markets in which power and grid reliability products are sold competitively in various real-time and forward markets administered by ISO/RTOs. Market planning and coordination occur on several time horizons. In the long term, ISO/RTOs conduct transmission and interconnection planning and often operate a forward-capacity market that creates incentives for future capacity build out to ensure an adequate level of installed generation. In the medium term, ISO/RTOs coordinate planned power plant outages to make sure that they do not all coincide in a manner that threatens system reliability. In the short term, ISO/RTOs operate the day-ahead and real-time electricity markets and dispatch generating units. Short-term market operation and generator dispatch are where gas and electricity interdependence concerns are the most pressing. For illustration, a time line of the day-ahead market and real-time market for ISO-NE can be seen in Figure 2.1.

Figure 2.1 – ISO-NE Wholesale Electricity Day-Ahead and Real-Time Markets⁵



Source: ISO-NE

In the day-ahead market, generators submit their bids and operating constraints to the ISO/RTO which then computes the market clearing price that ensures that supply equals forecasted demand with a suitable margin of reserve generation. During the operating day, system operators must manage the system with the real-time market. The ISO/RTO makes immediate changes in five-minute increments to make up for supply and demand imbalances with security-constrained economic dispatch of the system based on calculated real-time LMP.⁶ In day-to-day operations, electricity system operators dispatch generators ignoring adequacy of fuel supply, assuming that the market knowledge of fuel constraints is intrinsically included in the generators' bids. Natural gas pipeline constraints that manifest only in real time can threaten system reliability.

Wholesale Natural Gas Market

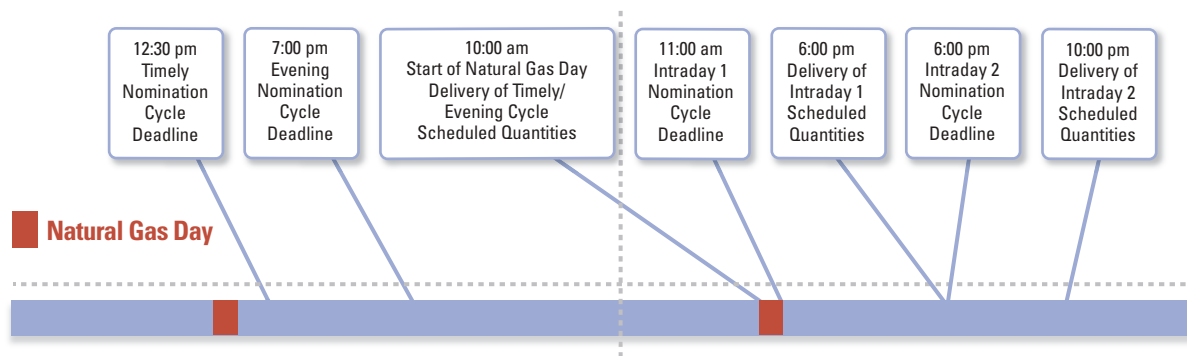
The natural gas market in the United States has been deregulated, and without a central controller (like an ISO) the structure has evolved more organically than regional electricity markets. Natural gas has three distinct markets: the commodity gas market, the transmission capacity market, and the financial market. The commodity market is where contracts for physical natural gas quantities are traded, while the transmission capacity gas market is where contracts for gas delivery are traded.⁷ The financial market is similar to that in electricity and is used for risk hedging against price changes. Understanding how consumers secure pipeline capacity through the capacity nomination process is critical to understanding how the electricity and natural gas systems interact. Therefore, the commodity market and the capacity nomination process are the focus of the following discussion.

The physical commodity markets include participants from all over the natural gas industry including producers, pipelines, marketers, local distribution companies, and large end users. Transactions in the commodity market are conducted on a bilateral basis in spot markets and hubs between market participants, often with marketers as intermediaries to minimize the costs and risks of natural gas supply.⁸ It is important to note that the gas market is most liquid between 8:00 am and 9:00 am,⁹ and outside of these times, few market participants are making transactions. Therefore, when evaluating market coordination between gas and electricity systems, it is important to consider more than just simply aligning deadlines of the two markets.

Transmission capacity nomination cycles have been standardized by NAESB as seen in Figure 2.2. Generators, marketers, and other participants contact pipeline operators to nominate capacity, specifying the amount of gas they would like to ship, the point of injection, and the point of receipt. Pipeline operators schedule deliveries with successive rounds of re-nominations, while priority of delivery is determined by capacity contracts as discussed further in Contracts and Competing Claims.

Since the unbundling of commodity sales from pipeline transportation after 1992,¹⁰ shippers and marketers have facilitated the movement of natural gas by simplifying the process of gas procurement for consumers by contracting pipeline capacity, buying gas from producers, and selling gas to LDCs and industrial customers that is delivered to the point of consumption.

Figure 2.2 – Natural Gas Transmission Capacity Market Timeline¹¹



Note: The vertical dotted line in the timeline represents midnight. All times in EST.

Source: ISO-NE

Improving Market Coordination and Availability

A major focus of the symposium was on the coordination and market flexibility surrounding natural gas-fired generation. While the electricity and gas markets have proven to work well independently, the market friction that occurs at their interface shows that there are opportunities to improve the interaction of these two markets. Due to mismatched market schedules and system inflexibility, when real-time conditions deviate from expectations, the dispatch of either gas or electricity becomes increasingly difficult for system operators. In the worst-case scenario, when a pipeline is unable to supply gas to a generator due to system constraints and that generator is unable to meet its expected power production obligations, the grid's reliability can be threatened and there will be loss of load.

Within the market context, a common point of discussion was the tension between market-based solutions and mandates as tools for market operators to use to bolster resource adequacy. Crafting incentives to steer the markets toward the operator's preferred outcomes is often difficult and time consuming in practice, but can preserve price discovery mechanisms. Mandates ensure predictable outcomes yet sacrifice the functioning of the market. It is important that market operators and regulatory bodies consider these tradeoffs.

Some ISO/RTOs are already considering changing market timing, strengthening reliability, and improving information sharing. However, changing markets is a very time-intensive procedure, and immediate solutions should be sought to address short-term reliability issues. Some issues that symposium attendees discussed were natural gas commodity trading, wholesale market timing alignment, market incentives, and demand response.

Natural Gas Marketers

Generators typically rely on marketers for commodity and transmission transactions.¹² Scheduling limitations often imposed by marketers make these transactions difficult to complete or adjust on holidays, overnight, and in early mornings.¹³ Generators will buy the supply and transportation capacity of gas in three-day (or four-day) packages or "bundles" from marketers for a number of days in order to cover periods when marketers are unavailable over weekends and holidays. In order to purchase such bundles, generators try to predict the amount of fuel that they will need for their upcoming but yet unknown dispatch obligations. When reality diverges from predication, the bundled gas and delivery packages make it difficult for gas-fired generators to adapt when system conditions change over these periods.

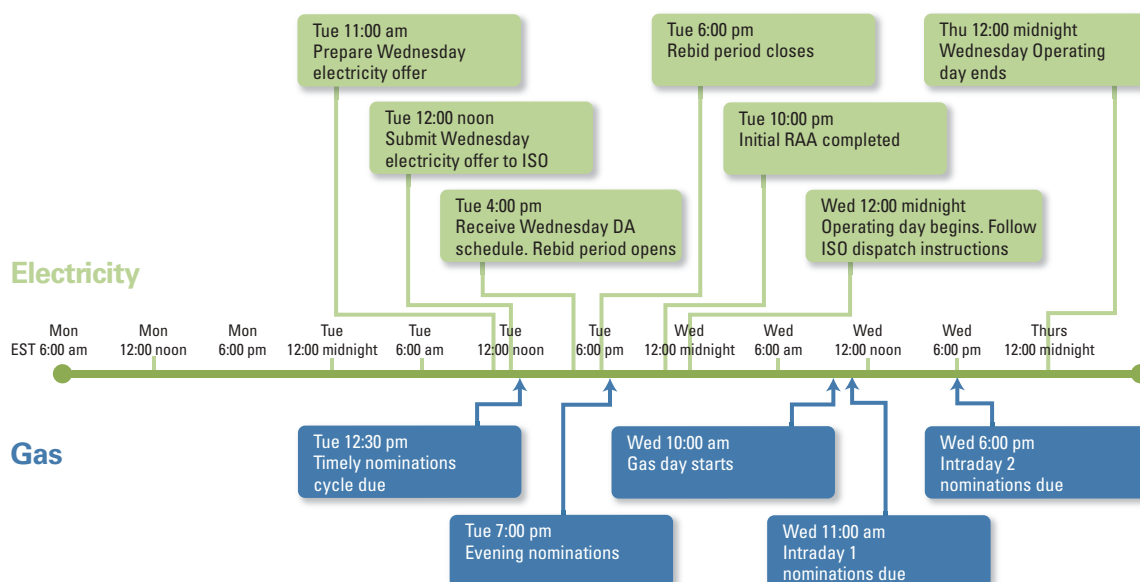
There are two holiday weekends during January and February, and some participants worried that a coinciding cold snap could cause significant scheduling and supply problems not because of a pipeline constraint but because of the lack of marketers available to facilitate purchasing of gas during these critical periods. Participants suggested that having these marketers available could facilitate better use of the natural gas commodity. Improved information exchange between the industries can also help mitigate some of the resulting reliability concerns, as will be discussed in Communications and Information Sharing.

Wholesale Market Alignment: Improving Liquidity

Problems arising as a result of the misalignment of the gas and electric market days are a topic that is frequently discussed in regard to natural gas and electric coordination. Symposium participants generally agreed that the barriers to changing the timing of the gas transmission capacity nomination cycle, which is uniform throughout the country, are far greater than for the electricity market, which varies regionally.

Figure 2.3 shows an example of a scheduling misalignment between NAESB's national gas day and a representative electricity day. Importantly, generators that use natural gas need to manage fuel procurement and transportation scheduling over two gas days for each electricity day. Here it can be seen that the power generators need to finalize their offers for electricity production (Tue 12 noon) before the first round of gas nominations is submitted (Tue 12:30 pm). Then, the generators do not receive their day-ahead schedule from the ISO (Tue 4:00 pm) until after the first gas nomination period has closed and pipeline capacity allocated (Tue 7:00 pm).¹⁴ Generators facing these uncertainties compensate by bidding conservatively into the energy market or paying penalties for overtaking gas and undertaking gas. Overtaking gas, or taking more than the pipeline operator approved during the nomination cycle, creates reliability risks for the pipeline operators that have begun discussing taking actions to protect the reliability of the gas system, including closing gas flow valves to the worst offenders.¹⁵

Figure 2.3 – Example of Standard Power Market Design and Gas Capacity Nomination Cycle Timelines¹⁶



Source: Adamson & Tabors

Note on New York Independent System Operator Market Misalignment

Generators are required to submit their electricity offers to NYISO by 5:00 am and the ISO posts the day-ahead schedule by 11:00 am. Theoretically, this means that generators have an hour and a half between when the ISO posts the day-ahead schedule and the closing of the first day-ahead gas nomination cycle at 12:30 pm. Since the gas market is most liquid between 8:00 am and 9:00 am and the NY facility system (the two LDCs) requires generators to announce the amount of capacity that they will use on the LDCs' systems by 9:30 am, generators nominate the gas that they anticipate needing before receiving a dispatch schedule from the ISO. The timing constraints caused by the market misalignment have already led to generators making economically rational decisions to postpone announcing availability to avoid imbalance fees imposed by pipeline operators, even when they are most needed by the system operators during the morning load ramp-up.

Understanding the implications of market misalignment is only the first step to addressing problems related to gas and electricity interdependence. The second step is designing changes to market rules and timelines that mitigate the issues caused by market misalignment while not introducing unforeseen and hard to predict problems of their own. ISO-NE has begun taking the steps necessary to overcome the coordination problems by proposing changes to their day-ahead market design and working through the stakeholder process,¹⁷ and can be used as an example to see the effects that making such a market change will have. Any changes made to how the gas and electricity systems interact need to consider hidden costs in the form of additional market friction and administrative burden, and weigh them against the marginal perceived benefits. There are some non-obvious reasons for certain market timing in the natural gas markets. For example, gas traders tend to follow weather model results and trading is most liquid immediately after weather forecasts are published. Due to the lack of market participation outside of these times, the price that generators pay is not representative of weather and demand¹⁸ and so the costs might be higher than usual due to the scarcity of gas being sold.

Incentivizing Flexibility in Electricity Generation — A Market for Innovation

One of the main benefits of deregulated markets is the opportunity to promote market-based solutions that provide strong incentives for efficiency. However, while there probably are technological solutions for ensuring a completely adequate electricity system dependent on natural gas, the incentives to develop and deploy them are not fully in place or understood. Market operators face the challenge of how to enable those technical solutions within the bounds of complicated regulatory and market structures. Some participants suggested that research and development priorities should be set now in order to alleviate impending market constraints, while others argued that creating appropriate economic incentives will allow the market to discover technical solutions without the need to pick winners.

Market timing misalignment was often discussed in relation to its negative effects on system reliability and participants suggested creating more incentives for flexible generation. In particular, the need to price reliability and flexibility into the wholesale electricity markets in the United States was discussed. Generator flexibility can provide opportunities for quickly shifting the load, adding resiliency to the electricity system to better handle current and future supply diversity constraints and intermittency. While aligning schedules between gas and electric markets can facilitate the ability for market participants to improve reliability, incentivizing flexibility can

promote innovation and a solution that is more market based. If the right incentives are in place, innovations such as virtual pipelines¹⁹ or dual-fuel capability can add diversity to fuel supply in an economical fashion, without any overarching mandates.

The worst natural gas constraints happen for only a few hours a year, and a number of participants argued that the need for more capacity, while at times necessary, is overstated. After some participants suggested requiring generators to sign firm contracts for pipeline capacity, other participants argued that there does not need to be enough capacity to supply all gas generators with firm deliveries simultaneously, and that it would be uneconomic to do so, even with the occasional pipeline constraint. Dual-fuel capacity, demand response, and oil-fired generation are options that could be less expensive than building more pipeline capacity.

One of the major innovations discussed throughout the symposium was facilitating the adoption of demand response to improve flexibility during constraints.

The Role for Demand Response

The standard used to assess the basis of new regulations for most PUC is “safe and reliable service at just and reasonable prices.” While safety and reliability are worthwhile objectives, under this assessment framework, the value proposition of providing service is ignored. There is currently no way for commissions to reflect the value of service on an individual customer basis, so instead they assume a common value of lost load across all customers. Demand-side signals were suggested as a way of allowing the consumers to react based on their individual value of lost load, both for electricity and natural gas. Though not a panacea, the increased ability for consumers to react to high electricity and natural gas prices caused by high demand and pipeline constraints can mitigate supply scarcity problems.

Participants agreed that regulators and market participants need to fully internalize that the electric and natural gas systems are interconnected. In this regard, demand response for electricity was discussed as a way to mitigate not just electricity price volatility, but also natural gas price volatility since the price spikes for gas and electricity often occur simultaneously. Specifically, participants discussed giving consumers a real-time pricing option for electricity and looking into what demand response options for natural gas would entail.

The role of demand response in electricity markets has been implemented in ISO-NE and NYISO to some extent.²⁰ Large consumers of electricity bid into the demand response market and system operators compensate them for reducing their consumption when electricity prices go above their offer prices. Currently, this method does not allow the growing demand of residential consumers²¹ the option to react to real-time prices, and expanding demand response programs to residential consumers could introduce much needed flexibility. Allowing consumers the ability to react to real-time prices opens up opportunities for innovative uses of existing infrastructure. For example, participants discussed the possibility of using electric heating as a type of storage since it currently causes major peaks in electricity prices during cold snaps. For example, electric heating in both residential and office buildings, if dispatched during times when prices are lower, could heat rooms before prices spike. With adequate insulation and consumer tolerance for small temperature fluctuations in their home and work environments, this heat storage could open up a flexible way to reduce some of the impact of peak electricity prices when the effect is aggregated from numerous sources, although it is unclear how effective this would be.

In addition to exploring the potential of increasing demand response in electricity systems, it is worthwhile to evaluate whether regulators should consider demand response or advanced metering with real-time pricing for natural gas at the residential consumer level as well. Participants suggested that Europe and US experiences with the real-time pricing of electricity and advanced metering be analyzed to consider how these techniques could be extended to the natural gas system.

Recent Initiative for Improving Scheduling and Market Operations

Every ISO/RTO in the United States is actively evaluating natural gas and electricity coordination issues, employing various methods, including designated task forces, special reports, or rule change proposals. For example:

- **ISO-NE** – Implemented communications strategies with pipeline operators, coordinates regional pipeline outages.²²
- **NYISO** – Created the Electric Gas Coordination Working Group.²³
- **Electric Reliability Council of Texas (ERCOT)** – Organized a conference: Natural Gas/Electric.²⁴
- **PJM** – Created the Gas Electric Senior Task Force.²⁵
- **MISO** – Formed the Electric and Natural Gas Coordination Task Force.²⁶
- **California ISO (CAISO)** – Modified its tariffs to improve coordination between pipelines, generators, and the ISO.²⁷
- **Southwest Power Pool (SPP)** – Formed the SPP Gas-Electric Coordination Task Force.²⁸

In January 2012, NAESB formed the Gas-Electric Harmonization Committee which published a report in September 2012.²⁹ In the report, the committee identified standards that could be reconsidered or amended to help the functioning of the electricity and gas markets, including market timelines and coordination of scheduling, flexibility in scheduling, and provision of information. They stopped short of offering any concrete recommendations, citing the need to consider the feasibility of reaching stakeholder consensus before pursuing any changes to national standards.

One participant suggested that FERC could propose changes to the standard market designs of ISO/RTOs that would aid in alleviating gas-electricity interdependence concerns. It was suggested that it might be a quicker solution than going through each of the ISO/RTO stakeholder processes, though may be politically very contentious.

FERC has conducted several regional and national technical conferences exploring ways to better coordinate the natural gas and electricity markets. Discussion has been limited to maximizing the utility of existing natural gas pipeline infrastructure through optimizing communication protocols, capacity release rules, and market timing. FERC staff is closely watching regional gas-electric coordination initiatives and is currently reviewing several regulatory filings directly related to gas and electricity system coordination. In particular, ISO-NE has submitted three filings to change its day-ahead energy market procedures, procurement processes, and pipeline information sharing guidelines.³⁰

Key Findings: Dispatch and Market Operations

1. Market timing differences cause many power generators to incur price uncertainty in the electricity market and quantity uncertainty in the gas market. These uncertainties can lead to inefficient markets and the unavailability of generators which lead to reliability risks and price increases for the electricity sector.
2. Organized natural gas marketers close overnight, on weekends, as well as on holidays. A possible way to increase liquidity and coordination of the gas transportation market is for electricity system operators to incentivize marketers to stay open overnight and on the weekends.
3. Due to the nature of system operation for gas and electricity infrastructures, heavy penalties can result from misestimation of gas demand for both the gas and electric industries in terms of reliability and flexibility. Properly incentivizing flexibility and reliability into electricity markets can help facilitate innovations that will result in a market-based solution for reliability risks.
4. Demand response, for electricity and potentially for natural gas, is one of the major market changes that could enable a number of new market solutions to system operational constraints. However, the relative impact that demand response will have on the market is very uncertain.
5. It is important that changes to electricity market days account not only for pipeline capacity nomination deadlines, but also for the timing of liquidity and transparency in the gas commodity market. The ability for a power generator to trade fuel at times when there are very few other market participants is hardly beneficial.

3. CAPACITY CONTRACTS AND COMPETING CLAIMS

The electricity sector continues to increase its reliance on the interstate pipeline system that was originally designed to serve LDCs. Power generators have highly variable demands compared to those of LDCs, which poses new challenges for operating and financing pipelines. LDCs and power generators often use distinct types of capacity contracts to meet their fuel delivery requirements, which establishes a hierarchy for delivery priority and affects how pipelines are financed and approved. Symposium discussion regarding interstate pipeline system operations revolved around the changing demand profile for natural gas and the implications that change has for reliability of the electricity sector.

The Changing Demands for Pipeline Capacity Contracts

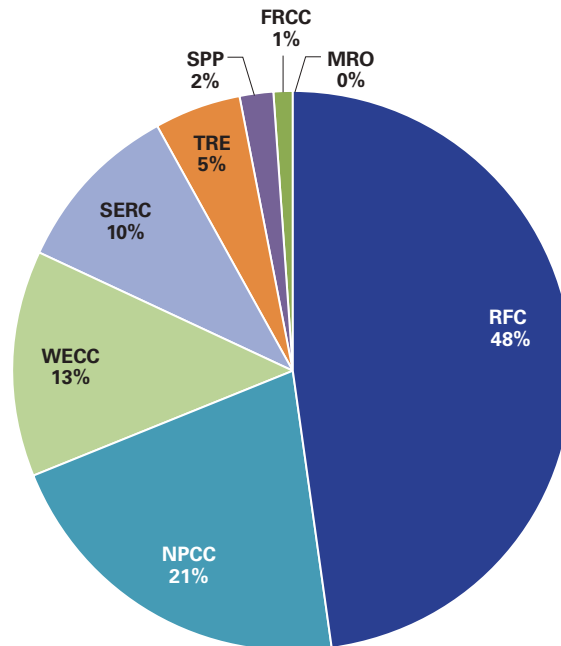
The interstate pipeline system in the United States was designed to meet the needs of LDCs and is now straining to adapt to meet growing power generation demands. LDCs are required by state PUCs to sign a sufficient number of firm contracts for pipeline capacity to meet the aggregate peak demand of their customers. These firm contracts signal to FERC that the pipeline is in the interest of the public and gives confidence to investors in the profitability of their investments. These are the first steps in the traditional process of regulatory approval and financing.

Power plants in many parts of the country rely on interruptible contracts for gas supply in order to adapt to changing market conditions because they are unable to recover the higher cost of long-term firm contracts through their electricity market bids. These short-term interruptible contracts are subordinate to firm contracts in delivery priority and do not contribute to the traditional pipeline financing and regulatory approval process.

For several years, this system worked well: gas demand increases from LDCs that signed long-term firm contracts encouraged pipeline investment and regulatory approval.³¹ Excess pipeline capacity that was not contracted or capacity that LDCs had first right to use but did not need in the short term was used by natural gas power generators that relied on interruptible contracts.

This regime has been increasingly stressed in the last two decades. Now, the growth in natural gas demand is largely from natural gas power plants that are averse to buying long-term firm contracts. The challenges from this are particularly pressing in NERC regions like the ReliabilityFirst Corporation (RFC) and National Power Coordinating Council (NPCC) where a significant percentage of forced outages³² of gas-fired generators are from a lack of fuel availability (Figure 3.1). Though power generators are a large and growing customer segment for natural gas pipeline companies, and the service that pipeline operators provide is immensely important to the operation of the electricity system, the contracts on which many generators rely simply do not encourage investment in pipeline infrastructure.

Figure 3.1 – Number of Forced Outages of Gas-Fired Generators Due to Lack of Fuel by Region³³



Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), NPCC, RFC, SERC Reliability Corporation (SERC), SPP, Texas Reliability Entity (TRE), Western Electricity Coordinating Council (WECC)

Source: NERC

Furthermore, the interruptible capacity contracts on which power generators are so dependent can threaten reliability of the electricity system. If LDCs underestimate the amount of capacity that will be required to meet demand in the short term or if electricity system operators need an immediate influx of power from a natural gas power plant that does not have fuel nominated for delivery, interruptible capacity contracts often are unable to provide certainty that gas will be delivered for power generation.

When LDCs need to increase their shipment nominations, pipeline operators recall interruptible shipment contracts and force generators to go without gas. Historically, there has been enough excess capacity for LDCs to increase their shipment nominations without recalling interruptible contracts, but with utilization rates approaching 100% in some areas, in order for an LDC to serve its customers, some interruptible service will have to be curtailed.

Natural Gas Transportation

The physical constraints of pipelines and the legal obligations of capacity contracts dictate the operations of the interstate pipeline system. Symposium discussion focused on the physical along with contractual flexibility that pipeline systems can offer electricity generators and system operators and the consequences of these constraints on electricity system reliability.

Operations of Interstate Pipelines

Pipeline operators are concerned with providing their customers with gas transportation capacity while maintaining suitable pressure within the pipeline. There are definite opportunities for pipeline system operators to fulfill their primary goals of gas transportation and maintaining pipeline pressure and also offer additional services with increased flexibility for consumers.

Pipeline Capacity Contracts³⁴

NAESB established the following capacity contract classifications and their relative levels of delivery priority:

- **Primary Firm Capacity** is bought through long-term contracts with monthly service fees, and is what most LDCs rely on for gas delivery. Primary firm customers have first priority to be served during constraints. Once a primary firm customer nominates its shipments of gas, they cannot be denied the delivery of that amount. If a primary firm customer needs to increase a previously established nomination, a shipper with an interruptible contract can be curtailed in order to satisfy this request. Any capacity that a customer like an LDC holds but does not use can be sold as secondary firm capacity.
- **Secondary Firm Capacity** guarantees delivery of the holder's initial nomination, but does not guarantee delivery of additional nominations during times of constraints. As holders of secondary firm capacity cannot be denied delivery in most cases, they can prevent primary firm capacity holders from scheduling additional gas transport in later nomination cycles. For more information about nomination cycles, see Ensuring Resource Adequacy.
- **Interruptible Capacity** contracts offer the most flexibility because they are only paid for when used, but are limited to when excess system capacity is available after all primary firm and secondary firm requests have been satisfied. As the name suggests, holders of interruptible capacity contracts are susceptible to be denied delivery when primary firm contract holders increase their nominations or when there are physical constraints on the interstate pipeline system.

Excess natural gas in the interstate pipeline that increases the pressure above the minimum that the customers require is called line-pack.³⁵ Line-pack gives pipeline operators considerable flexibility in the volume and timing of withdrawals and injections by their customers. As long as there is sufficient line-pack in the pipeline, contracts for natural gas transportation often allow customers the flexibility to overtake³⁶ and undertake³⁷ from the pipeline, meaning that customers can take more or less than the exact amount they contracted at any particular period. The added flexibility also allows for non-ratable takes,³⁸ in which the customer consumes its contracted amount over any time period. This is especially useful for power generators that have uncertain demand profiles as a result of gas and electricity market misalignment and regular demand fluctuations. Unfortunately, the sometimes excessive overtaking and undertaking of gas has caused problems between generators and pipeline operators. Since pipelines generally schedule transmission assuming the gas is taken throughout the day in regular increments, when generators withdraw large volumes of gas unexpectedly, balancing problems can occur for the pipeline system operators.³⁹

When there are difficulties in maintaining appropriate pressure in the system, operators may limit the amount of gas allowed to be overtaken and undertaken, or only allow for ratable takes from the pipeline, restricting customers to take gas in 1/24th increments throughout the subsequent 24-hour period.⁴⁰ In anticipation of such restrictions, generators may over-nominate gas, knowing that they will be restricted to 1/24th of their total nomination each hour, and sell the gas that they do not consume. In addition to the potential loss of value on the re-sold gas, power generators could also face costly imbalance fees, making ratable take scenarios quite costly.

Shipment Nominations and Contract Priorities

Pipeline operators take nominations first from holders of firm contracts. These holders of firm contracts nominate how much capacity they will be using the following period up to their total allotted firm capacity. Any excess is sold on a secondary market as released capacity and is bought on the short term by power generators and industrial users as lower priority capacity contracts.

If an LDC underestimates the amount of capacity needed for the following period, firm transportation contracts allow them to call the pipeline operator and request more capacity, up to the total firm contract amount. Any capacity in the interruptible market can be bumped without notice in order for the pipeline to fulfill its contractual obligations to the LDC.

The regulatory justification for requiring LDCs to hold ample firm capacity, while power generators have no such requirement, is to ensure that the heating needs of consumers are met, fulfilling the “human need” social obligation of the LDCs. In some cases, heaters in residential homes require electricity to operate, raising the question of whether providing fuel to power generators should be considered an equally important priority during cold weather events. A number of participants suggested that regulators reconsider rules requiring only LDCs to meet human need, suggesting that both natural gas and electricity are critical in fulfilling the social obligations of the residential energy infrastructure.

There was some discussion about the opportunity that unique and flexible pipeline transportation contracts — beyond firm, secondary firm, and interruptible contracts — can offer the gas and electricity industries.⁴¹ However, some participants noted that flexible contracts will likely offer few if any benefits on pipelines that are already fully subscribed, which is often when reliability threats manifest.

Pipeline Investment

A point of discussion was whether the traditional mechanism for increasing pipeline capacity, where pipeline financing and regulatory approval rely on firm transmission contracts, has stifled pipeline investment in a regime of increasingly high demands from customers who rely on interruptible contracts. In light of this concern, participants discussed two approaches to encourage new pipeline investment: finding ways to encourage natural gas power generators to sign firm contracts and changing the traditional approach to pipeline financing and regulation.

On the other hand, some participants suggested that the problem of underinvestment is fictitious because the high profitability of pipelines encourages adequate investment, and the appearance of underinvestment is misleading. Though statistics from FERC suggest that few miles of new pipelines are under construction, many recent pipeline additions are small feeder pipes needed to connect new supply sources to existing large interstate pipelines. Furthermore, others suggest that the volatility in natural gas prices in some regions is merely the result of a highly competitive and well-functioning market, and do not necessarily require large infrastructure investments to tame. Scarcity pricing of pipeline capacity, they suggested, is a necessary economic signal to spur innovative market solutions to ensure resource adequacy.

Encouraging Power Plants to Sign Firm Capacity Contracts

Some participants were adamant that the current state of pipeline regulation and financing is suitable to the needs of all consumers so long as power generators signed firm contracts. Vertically integrated utilities with generation assets have the ability to sign firm natural gas delivery contracts and pass the costs on to consumers to cover their total expected demand. In competitive markets, natural gas-fired generators are not able to recover the costs for firm contracts and therefore have little incentive to purchase them. As a result, the most acute problems of gas-electricity interdependency problems occur in market contexts. This particular perspective placed the burden squarely on the electricity market operators to design market rules that capture their interests by valuing reliability.

It was suggested several times, that more generators in the electricity market be encouraged to sign firm contracts. One way was for ISO/RTOs to allow the pass-through of the fixed costs of firm contracts into the energy bids of generators. Currently, market operators in the United States only allow variable costs to be included into market bids, and generators are expected to recover their fixed costs through capacity payments, ancillary markets, and scarcity rents. This type of market rule creates incentives for generators to rely on cheaper short-term interruptible contracts. However, the added explicit costs to consumers might be less than the reliability benefits and reduction of implicit costs that result from such a rule change.

Market operators could craft rules that benefit or penalize generators commensurate to the magnitude of their contribution to grid reliability. Participants suggested that such rules would naturally influence more generators to sign firm contracts if the penalties for nonperformance (particularly non-performance during periods of system constraint) were high enough, because the cost of a firm contract might be less than the cost of the penalty.

Another option is that market operators could simply mandate that generators purchase firm pipeline capacity in order to bid into the electricity capacity market. To some participants, mandating purchasing of firm capacity was seen as overly distortionary to the market because it adds an extra cost to generators that rely on natural gas, but not those that rely on coal or nuclear fuels, similar to requiring dual-fuel capability. Another problem with requiring firm contracts is that during times of constraints on the pipeline, gas-fired generators could still be curtailed. Firm capacity held by generators behind the city gate can be curtailed to provide for human needs customers (which include hospitals, residential homes, nursing homes, etc.) during gas-shortage events that occur during cold weather events.

There is a notable difference between generators behind the city gate, that obtain their gas from the city's LDCs and those directly connected to the pipeline system. These generators manage imbalances with the LDC and are subject to any additional rules and regulations they have.⁴² For example, LDCs are obligated to serve their human needs customers first. So even if a generator behind the city gate had a firm contract, it runs the risk of the LDC curtailing its gas during constraints.⁴³ It is clear that any solutions, mandates or otherwise, need to consider that not all gas-fired generators are connected directly to pipelines.

Alternative Financing and Permitting of Interstate Pipelines

Some participants argued that the traditional process through which interstate pipelines are permitted and financed needs to be changed. They suggested that innovative strategies such as charging electricity customers for the construction of the new pipelines should be considered. Any changes in how pipelines are approved require significant and time-intensive changes in federal regulations, and a less challenging suggestion to develop novel financing approaches.

Maine's Unique Approach to Pipeline Financing

Lawmakers in Maine are proposing a unique way to finance natural gas coming to their state. The state is considering issuing bonds to pay for firm capacity contracts on interstate pipelines in hopes of reducing the cost of electricity to consumers.⁴⁴

LD 1262, "An Act to Reduce Energy Costs," gives the Maine PUC the authority to issue bonds and purchase interstate pipeline capacity in the region that would benefit the state.

LD 1187, "An Act to Create the Maine Energy Cost Reduction Authority," establishes an entity to procure and resell pipeline capacity, establish construction corridors for new pipeline investment, and enter into long-term contracts for pipeline corridors.

Currently, pipelines are not built without a substantial portion of their capacity subscribed through firm contracts signed *ex ante*. One suggested solution is that FERC should be more flexible in its de facto requirements that pipeline companies have firm contracts for pipeline financing, and should consider a more nuanced approach to regulatory approval that considers who would benefit from increased pipeline capacity, and how the costs could be allocated to those beneficiaries. In particular, consumers bear the brunt of the costs of pipeline constraints through high prices of gas and electricity to finance new pipelines to relieve the problem.

In some regions of the United States, the producers, not the consumers, are signing firm contracts that encourage the construction of new pipelines. The participants suggested that research could be done to identify what the particular circumstances of this unique financing situation are, and how to replicate the success of upstream investment in midstream and downstream pipeline systems.

Other participants noted that the pipeline industry is significantly averse to taking on construction risks because it is only allowed regulated rates of return, though earnings could fall below the regulatory ceiling if demand were inadequate. The industry's risks are large because of the asset specificity of large pipeline investments, due to the sunk cost of investments in pipelines that are particularly immobile and fixed. In order to build new pipelines, the participants argued, considerable attention would need to be given to the party that bears the risk.

Key Findings: Capacity Contracts and Competing Claims

1. The interstate pipeline system that was designed to serve LDCs and their relatively predictable demands is increasingly being relied upon by power generators with highly variable demand profiles. The physical operational limitations of pipelines coupled with a legacy capacity contract structure has created an impasse in new pipeline investment that threatens fuel deliverability to many power generators in critical periods.
2. State regulations for determining what qualifies as a human needs customer should be revisited, considering that heating residential homes — which serves as the basis of the human needs customer gas service obligations imposed on LDCs — often requires gas *and* electricity. As LDCs have an obligation to serve human need customers first, generators are sometimes unable to secure reliable fuel supplies in times of most extreme cold weather events.
3. There is disagreement on whether the current state of pipeline regulation and financing structures is adequate to face impending electricity system challenges. Participants suggested that allowing cost pass-through of firm contracts in electricity markets and mandating firm contracts are some options for system operators. Ultimately, system operators need to understand the financial value of reliability of generators on their system, and ensure that generator remuneration reflects this value.
4. Regulators and policy makers can look to examples in which pipelines were financed through producers or state governmental entities signing firm capacity contracts as models for how to enable alternative financing and permitting of interstate pipelines.

4. ENSURING RESOURCE ADEQUACY

In the context of electric power systems, resource adequacy “refers to the existence of enough available generation and network capacity, either installed or expected to be installed, to efficiently meet demand in the long term.”⁴⁵ Symposium participants considered the ability of natural gas power plants in an electricity system with a diversified generation mix to provide predictable and reliable power generation. By extension, the adequacy of the natural gas system that fuels those power plants was a focus of discussion. This section reviews symposium discussion and white paper contributions regarding resource adequacy of the electric power and natural gas systems.

An Evolving Natural Gas Market

Over the last decade, access to previously uneconomic natural gas resources in the United States has lowered wholesale gas prices and increased the domestic resource base, spurring demand and radically changing the geography of supply. These rapid changes to the market bring into question the ability of the natural gas infrastructure to keep pace with shifting supply and demand.

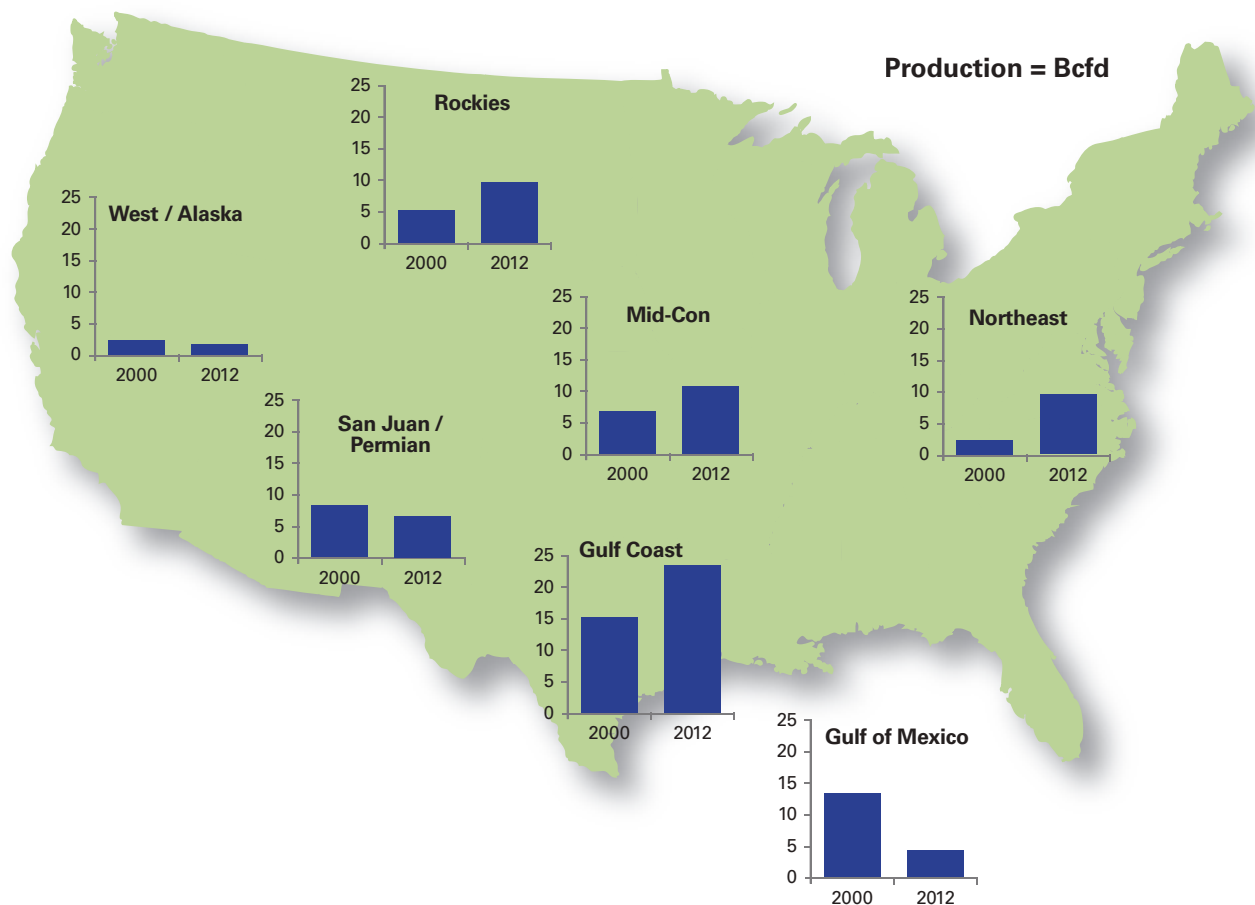
Driven by low gas prices, increasingly stringent environmental standards,⁴⁶ and the need for flexible generation to complement intermittent renewable power, the use of natural gas in the power sector has doubled in the past 15 years and is forecasted to continue to grow in absolute and relative terms for the next two decades.⁴⁷

Industrial demand is also on the rise. Many firms that relied on natural gas moved abroad as domestic prices grew to historic highs, but many are moving back to the United States now that domestic prices have dropped relative to prices in international gas markets. Several new petrochemical plants, which are very large consumers of natural gas, are planned or under construction in the United States.⁴⁸ There is also a growing commercial interest in exporting LNG, though the impact of such exports on future demand is uncertain. Infrastructure investment is needed to meet the growing demands of the power and industrial sectors, especially in light of the changing geography of supply.

Infrastructure investment is needed to meet the growing demands of the power and industrial sectors, especially in light of the changing geography of supply. Figure 4.1 shows recent changes in natural gas production in the United States. In 2000, the Gulf of Mexico supplied a quarter of the gas market in the United States, and yet in 2012 the same region provided just 6%. Meanwhile, the contribution to domestic supply from the Rockies and the Northeast doubled over the same time period, from 14% to nearly 30%.⁴⁹

Additional pipelines are needed to move gas from new supply centers to traditional demand centers. Stranded supply, or natural gas that is abundant in a certain region but lacks the infrastructure to move to where it is in demand, can lead to price anomalies that diminish the economic value of the resource. For example, a substantial negative basis⁵⁰ occurred for several years at the Opal Hub in the Rocky Mountains before new pipelines were built. As a result, gas producers were selling their natural gas at below market value because of the lack of natural gas pipeline infrastructure.⁵¹ In the Bakken oil fields of North Dakota, producers flare associated natural gas that they are unable to move to market, losing an estimated \$1 billion in fuel through 2012.⁵²

Figure 4.1 – Changing Regional Natural Gas Production in the United States⁵³



Source: Davies

Resource Adequacy and Fuel for Power Generation

The just-in-time character of the natural gas supply chain increases the challenge of maintaining power system reliability relative to other fuels in the electricity generation mix. Power generators that rely on energy dense fuels like coal, oil, and nuclear, often store fuel onsite to mitigate supply disruptions. In the case of a fuel supply interruption, many of these generators can run for several hours, and some several days, before exhausting their onsite fuel resources. This fuel buffer gives system operators time to reallocate generation resources in times of fuel supply disruptions without serious threats to system reliability.

On the other hand, operators of natural gas power plants rely on natural gas as a just-in-time resource. Most generators consume their fuel as soon as it reaches their facility because it is too expensive to store onsite. There is often some flexibility in the operation of pipelines that provides a modest fuel buffer, but even this small safeguard is threatened by reaching maximum operational capacities. Therefore, the threat to resource adequacy caused by fuel supply chain disruptions is uniquely high for systems that rely largely on natural gas.

Multiple Sources of Resource Adequacy

There are three broad categories of solutions for improving resource adequacy of the power and natural gas systems:

- **Increasing fuel diversity in the electricity system:** Relying on several fuel sources with unique supply chains can add resiliency to the electricity system and reduce the likelihood of constraints on one fuel leading to a system reliability threat.
- **Diversifying delivery of natural gas:** Diversifying the sources of natural gas supply available to generators through storage technologies increases reliability by adding redundancy and reducing the impact of acute supply chain constraints.
- **Increasing pipeline capacity:** Promoting pipeline investment through innovative sources of financing and regulatory revisions was suggested to reduce congestion and increase the efficiency of natural gas delivery to generators in power systems, particularly where pipeline congestion is the driving cause of resource adequacy concerns. Increasing pipeline capacity is discussed in depth in Capacity Contracts and Competing Claims.

Though discussion of solutions fell largely within these three categories, broad observations were made regarding the pursuit of any single strategy. As discussed in Synthesized Findings, regionality — the unique geographic attributes of interdependence challenges, regulatory jurisdiction, and market structures — is an important consideration for pursuing resource adequacy. Furthermore, the difficulty of balancing the efficiency of a market-based solution with the efficacy of mandates also poses challenges for ensuring resource adequacy, especially in regard to hidden costs of both of these approaches. For more information regarding this regulatory tradeoff, consult Dispatch and Market Operations.

Increasing Fuel Diversity in the Electricity System

Fuel diversity offers assurance to system operators that, if one fuel source becomes scarce, their systems can rely on other fuels in the generation mix to meet system demand.⁵⁴ Participants suggested several ways to increase fuel diversity in both market and nonmarket contexts.

Oil-Fired and Coal-Fired Generation

Many systems in the United States have substantial installed oil and coal-fired generation capacity that is technically available but used with decreasing frequency due to uncompetitive fuel prices and strict emissions regulations. Their actual availability is poorly understood by system operators and even by the operators of the plants themselves because some of these generators are used so infrequently. Years of underuse can lead to mechanical degradation and unreliable fuel supply chains, and as result their availability may be overstated. Furthermore, the current low-capacity factors of plants near the end of their economic lives are leading to economic retirements with uncertain time horizons, further diminishing their value as reliability resources at the disposal of system operators in the long term.

Emissions restrictions also diminish the reliability value of oil and coal-fired generation capacity. As power systems move toward cleaner generation, the run-time of especially dirty plants can be limited through regulatory mandates. System operators are faced with the challenge of rationing generation from these plants, even in times of severe system constraints. Some participants suggested that environmental regulations that limit the generation of these plants be flexible in times of power system reliability events.

One participant noted that having a modern, dual-fuel combustion, turbine power plant switch to oil is less expensive, more reliable, and less polluting than relying on vintage, oil-fired, steam cycle power plants. Therefore, market operators should consider how to incentivize fuel-switching resources to be available in favor of dispatching old, heavily polluting, and unreliable oil-fired power plants. Furthermore, older oil combustion plants rely on heavy fuel oil, which generally has more emissions than fuel used by new plants and which requires lengthy preheating times before becoming operational, further reducing their value to power system operators compared to newer oil-fired or dual-fueled power plants relying on diesel fuel.

Dual Fuel

Dual-fuel capability⁵⁵ was often discussed as a realistic option for diversifying fuel sources and adding resiliency to the electricity system. The advantages of dual-fuel capability are clear: in times of supply constraints, natural gas power plants could simply switch over to their onsite oil reserves and continue to provide power to the grid. Oil is energy dense and is relatively cheap to store and deliver without relying on the interstate pipeline infrastructure.

Participants noted, however, that system operators often have too little information about the potential availability of fuel-switching power plants in their system to rely on them for resource adequacy. Important details such as the amount of time that it takes for the plant to switch fuels and the amount of fuel reserves available onsite are often unknown to the system operator.⁵⁶ Regular audits and occasionally requiring generators to operate on their secondary fuel are ways to eliminate the information asymmetries that can threaten the adequacy of the grid. Some electricity systems have already taken steps to bolster the fuel-switching capability of their fleet (see Note on Dual Fuel in New York State).

Discussion also highlighted the difficulty for market operators to remain fuel neutral while explicitly incentivizing dual-fuel capability. Requiring dual-fuel capability is expensive and burdensome for natural gas power plant operators. On the margin this requirement could put them at a disadvantage against power generators with no secondary fuel requirements such as coal or nuclear, thus reducing the amount of natural gas on the grid below an economic optimum. System operators could consider the market value of having such a resource in their system, however, and remunerate generators through some type of ancillary reliability payment accordingly. More detail about the value of reliability can be found in Dispatch and Market Operations.

Note on Dual Fuel in New York State⁵⁷

The role of dual-fuel capability in the New York ISO was discussed in length during the symposium.

The New York State Reliability Council (NYSRC) requires that, in addition to considering reliability impacts attributed to the loss of any single power plant, the electricity system must be resilient to accommodate the loss of any single gas facility.

Only a few pipelines that supply the New York City and Long Island power plants cover a significant portion of total generation capacity for the region. The loss of a gas facility supplying those power plants would threaten the reliability of several plants at once, putting the entire system at risk. Therefore, many power plants are required to have dual-fuel capability. Furthermore, in periods of high demand, NYSRC regulations require that certain power plants begin operating on oil in advance of the peak load, ensuring that they are ready to generate electricity in case of an unexpected natural gas supply constraint.

Out-of-Market Procurement

In some cases, participants suggested that relying on out-of-market procurement, while sacrificing some market efficiency, is a suitable short-term solution to ensuring resource adequacy especially given the long time horizon for implementing non-trivial changes to market design.

An out-of-market procurement is a method by which a market operator commits generation resources through a unique procurement process to meet a specific acute objective, in a manner different from the conventional electricity market process. Participants noted that out of market procurement is a temporary fix that should only be used until a more long-term and sustainable solution is implemented. Committing uneconomical power plants increases costs to consumers and distorts market signals.

Note on ISO-NE Out-of-Market Procurement⁵⁸

ISO-NE has recently proposed procuring both oil-fired generation and demand response resources through out-of-market procurement for the 2013/2014 winter while more substantial changes are under consideration on a longer time horizon.

ISO-NE is holding a competitive bidding process to procure additional energy resources. Eligible generation resources include oil-fired generators with onsite fuel, dual-fuel generators that have onsite fuel and can prove their ability to switch to oil in less than five hours, and demand-response resources.

Diversified Delivery of Natural Gas

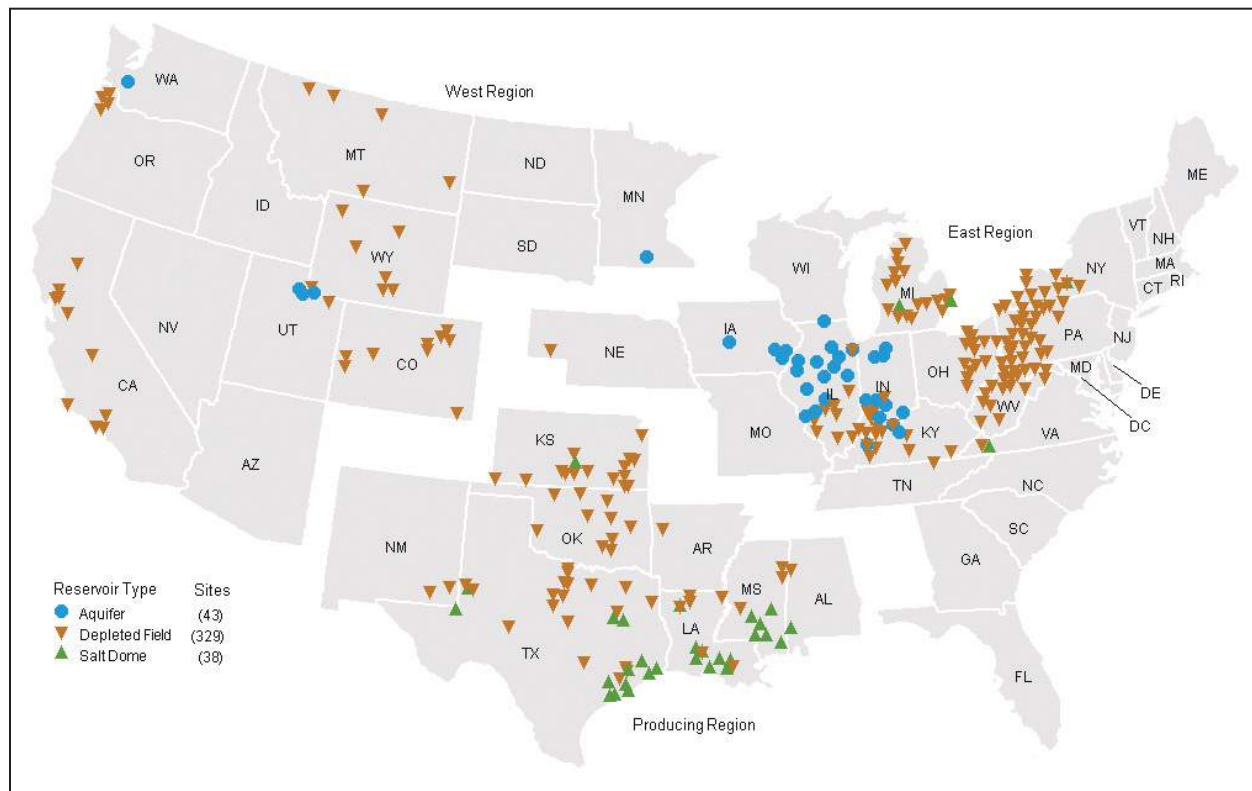
Resource adequacy can also be bolstered through diversifying the delivery of the dominant fuel. Many participants, explicitly and implicitly, discussed diversifying the sources of natural gas flowing into constrained systems. Relying on CNG city-gate storage, utilizing LNG resources, and internally diversified fuel resources of LDCs are all alternatives to strictly relying on interstate pipelines. Though this suite of solutions does not face the emissions constraints inherent in the oil and coal strategies already discussed, the real challenge lies in identifying the entities responsible for investing in diversified fuel resources and how to encourage their participation.

Some participants were careful to point out that though distinct technological solutions were proposed, ensuring that market rules are technology neutral is critical for allowing efficient market operation. As long as the correct economic incentives are in place, the market will find a mix of least-cost technology solutions.

Grid-Scale CNG Storage

There are two categories of grid-scale natural gas storage: base load and peak load. Base-load storage relies on high-volume depleted natural gas reservoirs that cycle seasonally. Gas is injected during low-demand periods and withdrawn over the course of weeks or months during high-demand periods. Peak-load storage relies on smaller salt caverns and aquifers that have very high filling and withdrawal speeds, allowing the reservoir to be filled and withdrawn in days or hours, and is used to arbitrage daily variations in gas prices.

Figure 4.2 – US Natural Gas Storage Facilities⁵⁹



Source: EIA, Underground natural gas storage facilities. www.eia.gov/maps. Accessed February 13, 2014.

Figure 4.2 shows the geographic dispersion of underground natural gas storage facilities in the United States. The difficulty with gas storage in large underground reservoirs is that geology is very important and many regions of the United States lack appropriate geologic features. Many geographic areas that are facing natural gas delivery constraints have already exploited local reservoirs and have few remaining options. Furthermore, even when located reasonably close to a demand center, large storage reservoirs offer little toward alleviating congestion and price volatility if the field is on the wrong side of a congestion constraint.

Distributed Storage

One participant mentioned that there is innovative and promising research underway to bring down the cost and scale of CNG. Though there is a long lead time for such a large technological advancement, the prospect of significant cost reductions on the horizon borne by continued research and development underscores the need to remain technology neutral in seeking solutions to alleviating gas-electricity interdependency issues.

To this point, the audience was reminded that hydraulic fracturing was such a revolution in cost reduction: high natural gas prices encouraged the commercialization of a technology that was under research and development for many years. Had research and development not begun decades ago, the US economy would still be suffering from record high natural gas prices.

LNG Storage

LNG storage can act as a backup fuel source in times of pipeline constraints. Participants expressed a need to understand the types of barriers that exist, be they technical, economic, or regulatory, to prevent system operators and power generators from building LNG storage facilities.

Participants also expressed that it is even less clear what conditions are needed to encourage new investment in LNG facilities for domestic use. As a case in point, the Everett LNG terminal in Boston was created to circumvent high pipeline transmission costs into the Massachusetts Bay area and has historically injected gas into the local pipeline system, effectively peak-shaving and alleviating high prices associated with scarcity during high-demand periods. However, low domestic gas prices and high international LNG cargo prices have diminished the economic value of the Everett LNG terminal serving the domestic market. It is unclear whether this LNG storage facility will continue to be a source of fuel on which power generators and system operators can rely in the near future.

Diversified LDC Gas Resources

One creative idea that surfaced during discussion is to investigate whether LDCs can rely on their multiple diverse gas resources that lie behind the city gate to free up capacity on interstate pipelines during times of constraints. LDCs rely on a diversified set of sources for natural gas to ensure resource adequacy behind the city gate, including propane-air injection, several types of natural gas storage, and multiple interstate pipeline connections.

Investigation into the nature of resource availability behind LDC city gates is needed to consider this solution. Research also needs to be conducted into the incentive structures required for enabling a change in LDC resource utilization and the regulatory adjustments that would be required.

Key Findings: Ensuring Resource Adequacy

1. Additional pipelines are needed to move gas from new supply centers to traditional demand centers and to meet growing demand in the power sector. Lack of adequate pipeline infrastructure can lead to stranded supply and unmet demand, diminishing the economic value of new natural gas reserves and threatening electricity system resource adequacy.
2. Grid-scale underground natural gas storage and LNG facilities have a proven track record of providing fuel resources that increase power system reliability. Unfortunately, geographic constraints, regulatory hurdles, and economic barriers make it unlikely that either technology will increase its presence in the natural gas system in the near future.
3. Distributed CNG storage is an emerging technology that shows strong promise in laboratory demonstration, but requires lengthy research and development before commercialization will be possible.
4. Relying on several fuel sources with unique supply chains can add resiliency to the electricity system and reduce the likelihood of constraints of one fuel leading to a system reliability threat. Opportunities exist to better incorporate alternative fuels, through incentivizing dual-fuel capabilities of new power plants and ensuring availability of multiple fuels on the grid.
5. LDCs rely on a diverse set of gas resources to provide redundancy in their system, often having overcapacity to ensure reliability. Participants suggested considering relying on these alternative gas resources as a means to free up pipeline capacity otherwise destined for LDC use.

5. COMMUNICATIONS AND INFORMATION SHARING

The availability of information and real data from different stakeholders regarding the interdependency of the natural gas and electricity systems was often cited as a problem throughout the symposium, and many participants suggested better methods for sharing information for research, operations, and planning purposes. This section reviews the white paper contributions and summarizes the symposium discussion on communication, information sharing, and modeling between the gas and electricity networks.

Market Uncertainty and Reliability Concerns

The amount of natural gas used for power generation continues to further stress tensions between the two infrastructures and makes data exchange and communication of increasing importance. Since the gas and electricity markets are not aligned in terms of timing, generators are bidding into the electricity market without knowing the price of gas, and nominating for gas without knowing how much they will need to meet their unconfirmed electricity dispatch commitments. The resulting reliability concerns caused by this uncertainty are compounded when pipeline capacity constraints are present.

The communication and information sharing leading up to and during infrastructure constraints influences the ability of pipeline operators, LDCs, ISO/RTOs, and generators to effectively coordinate the management of those constraints. As such, participants argued that improving communication between these entities is essential as the level of gas-fired generation in the power sector grows. Specifically, representatives from the power sector discussed the need for more communication about capacity constraints from the pipeline system in order to determine the risk that generators bidding into the reserve market might not be available when needed.

Due to information asymmetries between ISO/RTOs and generators, electricity system operators must make assumptions about gas system conditions during day-ahead scheduling. When these assumptions do not align with actual conditions, ISO/RTOs are often forced to make real-time operational adjustments. System operators are required to make fast and informed decisions to mitigate present and future reliability concerns. In order to better prepare for future contingencies, system operators are always trying to improve the level of information they have regarding generation units in their fleets. The level of information exchange is vital as the penetration of intermittent renewables continues to grow and generators are dispatched in an increasingly volatile manner.

When system operators schedule generator dispatch in the regional electricity markets, they assume fuel availability despite the uncertainty under which generators operate. For example, ISO-NE is only notified of a problem with the fuel availability of their dispatch units after they have given instructions to the generators. Notifications typically come not from the generators themselves, but from the gas pipelines.⁶⁰ Electricity system operators are not the only ones with concerns over the current system of communication and information flow. Generators can place the pipeline at risk by overtaking gas to meet their electricity side obligations.⁶¹ In order to improve these assumptions, some symposium participants agreed that both emergency communications, to deal with constraints when they happen, and day-to-day communications, to prevent an emergency, should be reviewed and improved. One suggestion was that if system operators were expecting reliability issues, it would be helpful if operators could request the generators' next hour fuel availability in detail.⁶²

Without proper information exchange, current reliance on interruptible service presents a threat to electricity system reliability when pipelines become over-nominated because it is managed by contract and human need priority.⁶³ Besides reviewing information available to electricity operators, symposium participants discussed the uncertainties in information available to pipeline operators. While pipelines are allowed to request hourly burn profiles from generators directly connected to their system⁶⁴ in many regions where the gas and electricity markets are misaligned, the burn profiles are not based on unit commitments because they have yet to be finalized.

Communication and Information Technology Advancement

Market liquidity and coordination can be aided by leveraging recent advances in communications technologies enabling real-time information exchange, not only helping to make the most of the physical infrastructure as it currently exists, but also to allow flexibility for adaptation to future system needs. However, participants raised a concern that while adopting improved information technologies is an important step in improving market liquidity and reliability, the expense of protecting such systems from the growing threat of cyber security should be taken into account.

Current Regulatory Activity

FERC has conducted several regional and national technical conferences exploring ways to better coordinate the natural gas and electricity markets. Discussion has been limited to maximizing the utility of existing natural gas pipeline infrastructure through optimizing communication protocols, capacity release rules, and market timing.

FERC staff is closely watching regional gas-electric coordination initiatives and is currently reviewing several regulatory filings directly related to gas and electricity system coordination. In particular, ISO-NE has submitted three filings to change its day-ahead energy market, procurement processes, and pipeline information sharing guidelines.⁶⁵

Communication Discrepancies with Generators Behind City Gates

Not all natural gas generators receive gas in the same way. For instance, there are natural gas-fired generators directly connected to the interstate pipeline system, and then there are generators that are located behind an LDC city gate. The latter generators are at the local distribution level and are subject to the LDC's transportation policies. Understanding the differences between how regulations affect generators directly connected to pipelines versus those that are indirectly connected through LDCs behind city gates is necessary when discussing the communication needed. For example, LDCs may curtail gas from firm contracts for generators connected through them to support residential demand⁶⁶ which is considered first priority as a human need. Human needs customers are defined as customers using natural gas for essential human needs including homes, hospitals, and nursing homes.⁶⁷

Generators behind the city gate nominate and manage imbalances through the LDC and therefore have limited ability to share their hourly burn profiles and manage imbalances with the interstate pipeline.⁶⁸ Participants from the electricity industry expressed concerns that while there is communication between LDCs, pipelines, and system operators during emergency situations, gas-fired generators behind the city gate are still a reliability risk. As these generators do not fall into the category of human need,⁶⁹ they might be curtailed even though there are times when supplying gas to a generator is necessary to prevent loss of pipeline pressure. For example, in areas like New York City and Long Island where the majority of gas-fired generators are connected through the LDCs,⁷⁰ the risk of curtailment for these generators is a significant reliability problem even if they hold firm contracts.

There are also concerns that having gas-fired generators with demands for gas that are far greater than the demand of residential customers connected to LDCs is inherently risky, especially if these generators are not properly coordinating with the LDCs and the pipelines connected to them.

One of the more important findings of the symposium was the need to consider how human needs requirements factor into gas-electricity interdependency. Both the electricity and gas infrastructures are vital for human needs customers, that by definition are vital to public well-being. Throughout the symposium, participants called for a review of regulations focused on human needs customers and whether generators vital to electric reliability should qualify. In times of emergency, such as power outages and natural gas constraints, human needs customers are given priority during the restoration process.⁷¹ Proper planning between gas and electricity infrastructures is necessary to assure that public well-being is maintained considering that many heating systems, which are the basis for prioritizing gas delivery to the public, are unable to function without electricity.

Modeling between the Industries

Predicting when and where fuel transportation constraints will manifest in the future is extremely difficult, and sophisticated modeling tools need to be developed that model both natural gas and electricity infrastructures jointly. These models are needed to address concerns such as investment in natural gas generation, firm contracts for pipeline capacity, and dual-fuel capability's benefit to reliability.

As the electricity system continues to increase its dependence on natural gas, models for both sectors will need to adapt. As previously discussed, it is important for electricity system operators to incorporate the fuel availability of generators into their system modeling. Also, gas pipeline operators will need to adapt to how their growing customer segment, the electricity generators, use the gas on their systems. Traditionally, pipelines evaluate their capability to deliver gas based on customers using 1/24th of their daily nomination each hour, even though gas-fired generators that are used in peak electricity demand times use gas in a completely different pattern and want to burn their allotted volumes during a just a few hours.⁷²

Portfolio problem modeling, in which one models the future generation portfolio that can meet demand at the lowest risk and cost to plan future investments, often does not address reality where decisions are made sequentially and not all at once. As a result, sunk costs and current capital investment costs might not be fully considered when trying to reduce the cost of the future system. For gas-fired generators that are tied to both gas and electric markets, this means not fully capturing the tradeoff between long-term and short-term investment optimization.⁷³ This has implications for the feasibility and cost effectiveness of generators signing long-term firm contracts for gas capacity.

There is a need to properly appreciate dual-fuel capability for natural gas-fired generators. In order to fully understand the benefits of investment or requirements for dual-fuel generators, participants discussed the possible need to model oil along with electricity and gas demand. It was also noted that modeling oil infrastructure with natural gas and electricity would be useful for understanding optimal courses of action during constraints on gas and electricity.

It is clear that the availability of real data on the circumstances that have led to emergency situations for the gas and electricity infrastructures should be improved. For example, in liberalized market contexts little is known about the location and timing of new power plants beforehand. Balancing authorities need to look years ahead in order to secure the reliability of their system.

Not having detailed information on new and old power plants planning for outages during regulation changes is extremely difficult. For example, MISO is in the process of modifying the topology of the electric system in light of the need for generators to comply with the EPA's Mercury and Air Toxics Standards (MATS) in the coming years.

Note on Midcontinent ISO Gas and Electric Coordination

Midcontinent ISO (MISO) has recently published a report detailing their Electric and Natural Gas Coordination Case Study aimed at preparing the region for the effect of new EPA regulations. The study supplemented a NERC analysis published in October 2010 which, while extensive, did not have the level of detail required by MISO or examine financial implications.⁷⁴ To fill this gap in information, MISO used a Quarterly Survey to gather voluntary information from asset owners on their strategies for compliance with the proposed regulations.⁷⁵

With the information from the survey, MISO is in the process of narrowing down which of the units could cause a cascading reliability problem on the system. This involves modifying economic simulations created in the early years of the study to take into account the real topology of the network.

When the EPA regulations come into effect in the MISO area, there will be an unprecedented period of outages as generators go offline to upgrade their equipment from April 16, 2015 through the end of 2017, which is a major risk to reliability. Regulations under consideration included the Clean Water Act Section 316, the MATS, Coal Combustion Residuals, and the Cross State Air Pollution Rule.⁷⁶ Retiring coal plants need to be replaced by new power generators. Unfortunately the majority of the new combined cycle gas turbines (CCGT) that are planned are not going to be in service until April 2017.

The stakeholder process, through which market operators engage market participants before submitting rule changes to the FERC for final approval, can be time consuming and cumbersome. Participants noted during the symposium that the MISO effort to improve information sharing and thus the ability of the ISO to work with generators undergoing new regulation and develop flexible plans to assure reliability was a good example for how to bring together the numerous stakeholders without needing new regulatory instruments. This could be used as a model for engaging stakeholders in natural gas and electricity coordination discussions.

With improved availability of information, better models can be developed. Natural gas and electricity models are able to provide insight into the future of natural gas use in the power sector and related physical and market constraints. There are still enormous opportunities for modeling and data analysis to provide insight into coping with current and forecasted infrastructure constraints and coordination.

Key Findings: Communications and Information Sharing

1. When generators are not nominating with certainty due to market timing misalignment, the real-time dispatch of generators for power can result in reliability concerns for both the gas and electric systems that could be better mitigated with improved coordination and information sharing. While there has been work to outline emergency communication procedures between the industries, further thought into the expansion of communication is necessary, specifically in day-to-day situations, and recent technological advancements will be useful in this endeavor. Many electric system operators lack information about the real-time fuel availability and diversity in their systems, especially those behind the city gate, and this knowledge can help tremendously in planning for contingency events.
2. During gas constraints, there is still a possibility of curtailment, sometimes regardless of the gas contract type, when human needs customers are at risk. Communicating information regarding possible future constraints is important to better understand their likelihood and overall effect on system reliability. Coordinating the designation of human needs customers between the two industries is an important step to solving growing problems with reliability concerns. Specifically, generators that could prevent loss of load to residential customers and are behind the city gates could be categorized as human needs customers as well.
3. Improving the availability of information and real data on future outages and generation investment between stakeholders in the gas and electricity infrastructures will allow models to facilitate improved joint planning and system operation reliability for both infrastructures. There are enormous opportunities for system operators in both industries to adapt their models for system reliability to the changing patterns of demand and fuel availability caused by the growing interdependency between the electricity and natural gas sectors.

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- 37 Undertaking of gas is leaving gas on the system that was previously scheduled to be removed. Pipeline operators will often resell this excess gas.
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ABBREVIATIONS / ACRONYMS

AGA	American Gas Association
CAISO	California ISO
CCGT	Combined Cycle Gas Turbine
CNG	Compressed Natural Gas
DAM	Day-Ahead Market
DOE	Department of Energy
EEL	Edison Electric Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Regulatory Commission
FRCC	Florida Reliability Coordinating Council
INGAA	Interstate Natural Gas Association of America
ISO	Independent System Operator
ISO-NE	ISO New England, Inc.
LDC	Local Distribution Companies
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
MATS	Mercury and Air Toxin Standard
MISO	Midcontinent ISO
MITEI	MIT Energy Initiative
MMBtu	Million British Thermal Units
MRO	Midwest Reliability Organization
NAESB	North American Energy Standards Boards
NERC	North American Electric Reliability Corporation
NPCC	Northern Power Coordinating Council
NYISO	New York Independent System Operator
NYSRC	New York State Reliability Council
PJM	PJM Interconnection
PUC	Public Utility Commission
RAA	Resource Adequacy Assessment
RFC	ReliabilityFirst Corporation
RTM	Real-time Market
RTP	Regional System Operator
SCRA	Security Constrained Reliability Assessment
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
WECC	Western Electric Coordinating Council

APPENDICES

- A. Symposium Agenda
- B. List of Participants
- C. White Paper, Susan F. Tierney, *Framing the Issues: Growing Tensions at the Interface of the Natural Gas and Electricity Markets*
- D. White Paper, Jan Abrell, Clemens Gerbaulet, Franziska Holz, Hannes Weigt, and Christian von Hirschhausen, *Combining Energy Networks: The Impact of Europe's Natural Gas Network on Electricity Markets till 2050*
- E. White Paper, Peter Brandien, *Addressing Gas Dependence*
- F. White Paper, Seabron Adamson, Richard D. Tabors, *Pricing Short-term Gas Availability in Power Markets*
- G. White Paper, Colin Davies, Amanda Goller, *Ensuring Future Natural Gas Availability*
- H. White Paper, Jeff D. Makholm, *Ensuring Natural Gas Availability*
- I. White Paper, Kelli Joseph, *Gas & Electric Coordination: The Need for Information Sharing*
- J. White Paper, Pablo Dueñas, Tommy Leung, María Gil, Javier Reneses, *Modeling Gas-Electricity Coordination in a Competitive Market*

SYMPOSIUM AGENDA

Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems

2013 MITEI Symposium
April 16, 2013

8:15–8:45 am **Breakfast**

8:45–10:00 am **Framing the Issues: Growing Tensions at the Interface
of the Natural Gas and Electricity Markets**

White Paper Presentations:

Susan Tierney – Managing Principal, Analysis Group
Christian Von Hirschhausen – Professor, Berlin University
of Technology

Respondent: Barbara Kates-Garnick – Undersecretary for Energy,
Commonwealth of Massachusetts

10:00–11:00 am **Competing Claims: Gas and Electric Scheduling Mismatches
and Capacity Release Issues**

White Paper Presentations:

Peter Brandien – Vice President of System Operations, ISONE
Seabron Adamson – Senior Consultant, Charles River Associates

Respondents: Lopa Parikh – Director, Federal Regulatory Affairs
for Energy Supply, Edison Electric Institute
Lawrence Makovich – Vice President, Global Power, IHS CERA

11:00–11:30 am **Morning Break**

11:30–12:45 pm **Ensuring Future Natural Gas Availability**

White Paper Presentations:

Colin Davies – Vice President of Corporate Strategy,
Hess Corporation
Jeff Makholm – Senior Vice President, NERA Economic
Consulting

Respondents: April Lee – Industry Economist, Energy Information Agency
Donald Santa – President and CEO, Interstate Natural Gas
Association of America

12:45–1:45 pm **Lunch Break**

1:45–2:30 pm **Coordination and Information Sharing**

White Paper Presentation:

Kelli Joseph – Gas and Electric Analyst, NYISO

Respondents: Lin Franks – Senior Strategist, RTO, FERC & Compliance
Initiatives, Indianapolis Power & Light Company

Dan Dolan – President, New England Power Generators
Association

2:30–3:15 pm **Dual Gas and Electric Modeling**

A New Model, A Work in Progress:

Pablo Duenas – Assistant Researcher, IIT Comillas, Madrid

White Paper Presentation:

Tommy Leung – Assistant Researcher, MIT Engineering
Systems Division

Respondent: Sam Newell – Principal, The Brattle Group

3:15–3:45 pm **Afternoon Break**

3:45–5:00 pm **Discussion and Closing Remarks**

Richard Schmalensee – Professor, Sloan School of Management
at MIT

Mort Webster – Assistant Professor, MIT Engineering
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LIST OF PARTICIPANTS

Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems

2013 MITEI Symposium
April 16, 2013

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**MITEI Symposium:
Growing Concerns, Possible Solutions:
The Interdependency of Natural Gas and Electricity Systems**

**Framing the Issues:
Growing Tensions at the Interface of the Natural Gas and Electricity Markets
(or, If You Want People to Think Outside of the Box, Don't Put Them in One)**

**Susan F. Tierney, Ph.D.
Analysis Group, Boston**

Today's Symposium focuses on a topic of increasing importance for America's energy future: the inter-relationships among the natural gas and the electric power markets and systems in the U.S. The conventional wisdom is that the electric industry will become even more dependent upon natural gas than it has in recent years, and the natural gas industry looks to a future in which significant growth in demand depends upon developments in the power sector.

Over the course of the day, the Symposium presenters and attendees will shine a spotlight on a number of the operational challenges that have begun to arise in different ways in different parts of the country. The Symposium will examine potential solutions and ways to mitigate some of the growing tensions at the interface of these two markets and their infrastructure systems.

My paper sets the context for discussion of more granular topics. It frames the issues by examining the changes underway in each industry, highlights some of the ways that their greater interdependencies are exhibiting strains, and outlines some of the implications for potential changes in the near and long term.

Several features of today's energy landscape seem clear as we approach these topics: First, the degree to which gas/electric interdependency raises serious challenges for efficient and reliable energy supply varies considerably by region and by type of issue. Second, there are lots of players with very different points of view, not only across business segments, industries and roles, but also within them. Third, the regulatory issues are complicated; while Federal Energy Regulatory Commission ("FERC") may have responsibility for a broad set of policy issues on electric/gas integration issues, the states not only have strong interests but also in some cases regulatory responsibilities that can affect market participants' behaviors as well.

Fourth, there is pressure building, and something needs to change. Because two industries will need to revise aspects of their business practices, communications, relationships, and so forth, change will surely be uncomfortable. We shouldn't let that discomfort put us in a position of gridlock, such that we find ourselves in a situation in the future where some crisis or emergency occurs and ends up propelling an immediate but reactive response that poorly or inefficiently addresses the needed changes.

And last but not least, as we approach the task of identifying options for addressing the efficiency and reliability challenges for today's and tomorrow's electric and gas systems, we should be mindful of the extent to which today's ways of doing business are grounded in assumptions about communications/information technology systems of the past, as well as tariffs, terms and conditions built on yesterday's investment requirements rather than current conditions. We should attempt to address changes for tomorrow's systems and needs, not yesterday's.

Changes leading to greater gas/electric system interdependency:

Many factors have converged over more than a decade to make the operations of the electric sector and natural gas sectors more closely connected. For years, these two systems developed on largely different paths, from a physical, economic, engineering, institutional, industrial-organization, and regulatory perspective (among others). There have been points in time, of course, during which many parallels existed among the two industries: Both evolved through some degree of vertical integration, with aspects of each industry's value chain regulated as monopolies by federal and/or state governments. The interconnected networks of each industry expanded over larger and larger geographic footprints. Both systems have undergone eras of significant industry restructuring, with new players emerging as functions became more unbundled and as competition began to make its way into different parts of the business.

Today, each industry has its own set of cost structures, operating protocols and standards, commercial instruments, pricing arrangements, and so forth. Even so, over the past two decades and especially in the past few years, the two industries' systems have become more closely intertwined, with the future of each expected to become increasingly dependent on the other's. These changes have occurred in parallel with dynamic developments in real-time, internet-based communications systems, which both affect and complicate the interdependencies and may also allow opportunities for new arrangements and solutions.

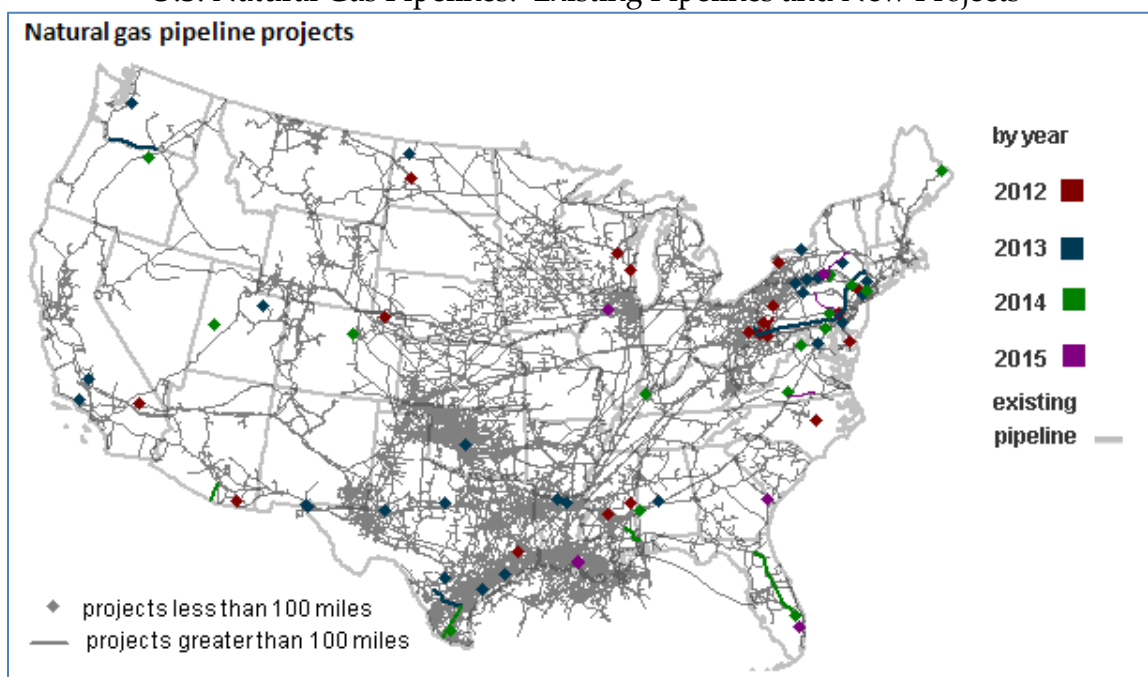
The U.S. Natural Gas System

Today's natural gas industry spans a diverse array of business segments, different market/regulatory regimes, and different types of companies touching one part or another of the system. At one end are large and small natural gas (and oil/gas) companies, service companies and others involved in exploration, drilling and production of natural gas. Other players along the value chain include companies involved in gathering and processing the gas; commodity marketers and traders arranging a variety of transactions; companies owning the interstate pipeline systems that move product for shippers. Some companies own and operate gas storage facilities; others own and operate LNG facilities. Local gas distribution ("LDC") utilities receive gas off the interstate pipeline system's citygate, resell it as a bundled product to retail customers, and provide transportation services to some end users (like power plant owners) who buy gas directly from a third party and ship it to their site across others' pipelines.

The current system infrastructure retains much of the historical 'geography' of natural gas, with production in the Gulf States and southern Plains, linked up to big natural gas market and consumer centers in the Midwest, MidAtlantic/Northeast, and California areas. As natural gas production has come on line in the Rockies and most recently in Appalachian basins, new pipeline and storage projects have been added over the years (as shown in the Figure 1, below).

The build-out of this interstate system was fostered in part by early legislation giving FERC (then the Federal Power Commission) authority to approve both the tariffs and siting of interstate gas pipelines. Since the late 1970s, Congress and FERC (and the Commodity Futures Trading Commission) have taken steps to create a single national physical and financial natural gas market, with commodity prices being set in highly competitive markets and gas pipelines being more strongly regulated. There remains little genuine vertical integration in the gas business after the industry underwent a restructuring to allow for open access to pipeline services and for the separation of marketing/ownership of commodity products from transportation services. FERC continues to regulate interstate gas pipelines, with investor-owned LDC services (and rates) being set by state utility regulators

Figure 1
U.S. Natural Gas Pipelines: Existing Pipelines and New Projects



U.S. Energy Information Administration, <http://www.eia.gov/todayinenergy/detail.cfm?id=10511#investment>

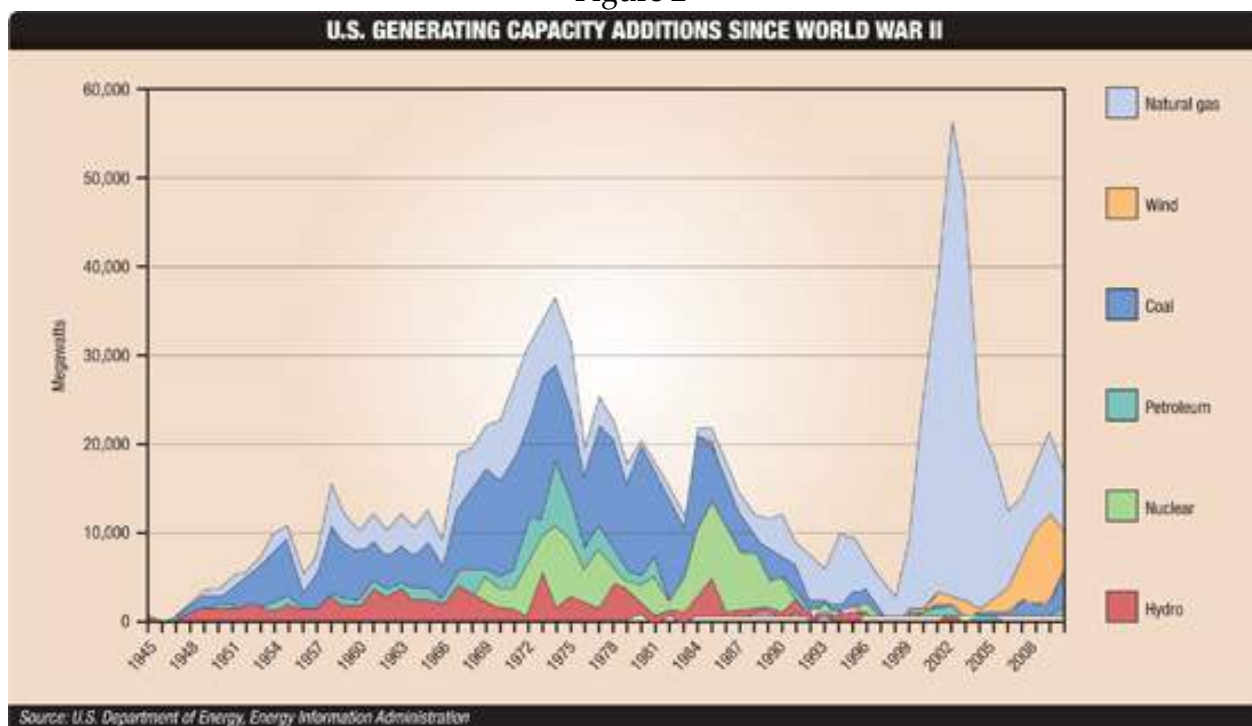
Pipeline expansion has traditionally been supported by firm gas customers (e.g., LDCs, some vertically integrated electric utilities that own power plants). Many other users (including competitive power plants and industrial customers) buy gas through interruptible commodity and transportation services that take advantage of underutilized pipeline and storage capacity in some parts of the system. FERC-regulated pipeline service allows for access under tariffed terms and conditions, with the ability of the pipeline companies to provide discounts and other arrangements to meet market needs.

Today, natural gas still tends to move long distances from production sources to users' sites, typically to locations where there is little to no storage close to or at the end-user's property. This means that from an operational point of view, gas needs to move "just in time" to the end user through pipelines that in some locations (e.g., the MidAtlantic/Northeast) become quite congested with firm gas deliveries.

The gas market has changed considerably in the past 15 years. At the end of the 1990s, several factors led to gas gaining a larger role in the electric industry. These included changes in fundamental economics of power generation technology and fuel prices, pressure to allow competition into the generation segment of the electric industry and

removal of Fuel Use Act restrictions on the use of gas for power generation. These and other conditions led to a significant increase in additions of natural gas-fired generating capacity starting around 2000, after a half-century in which coal and nuclear plants had dominated power plant capacity additions. (See Figure 2.)

Figure 2

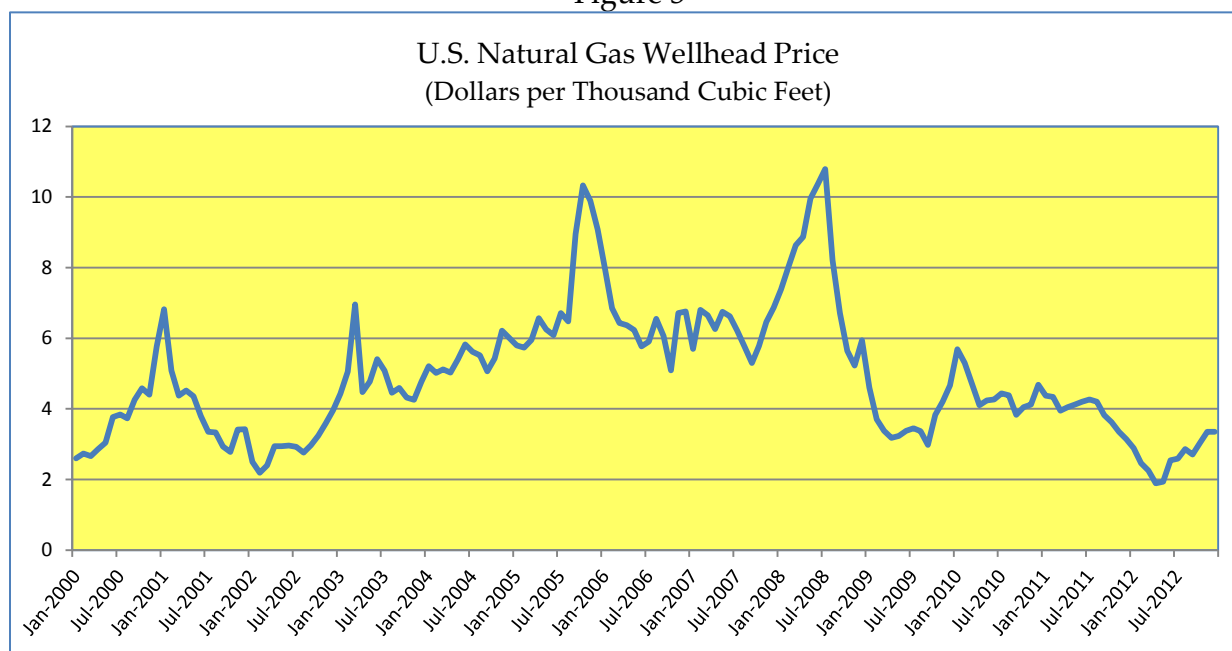


Source: U.S. Department of Energy, Energy Information Administration

<http://www.power-eng.com/articles/print/volume-115/issue-10/departments/generating-buzz/us-generating-capacity-additions-since-world-war-ii.html>

The boost in demand for gas from the power sector that followed the 1999-2003 power plant investment cycle contributed (along with declining production curves in conventional gas fields in North America) to high and highly volatile natural gas prices in the first half of the last decade. (See Figure 3.) These prices attracted investment in LNG gasification terminals as well as attempts to open up unconventional gas basins through the application of new technology. And these prices also led to significant underutilization of the natural gas combined-cycle capacity that was then in place in many parts of the country.

Figure 3



U.S. Energy Information Administration: <http://tonto.eia.gov/dnav/ng/hist/n9190us3m.htm>

These conditions eventually fostered development of many gas-rich unconventional hydrocarbon basins that became economically viable through new applications of technologies such as directional drilling and hydraulic fracturing. Accessing such supplies (such as in Texas' Barnett and Eagle Ford areas, in the Rockies, and in the Marcellus and Utica of the Appalachian region) has helped to dramatically push down natural gas commodity prices since 2008 (Figure 3), to create an outlook for relatively low prices in the future (Figure 4), and to increase the amount of natural gas used for power generation (see Figure 5). In fact, in the past 15 years, the power sector's use of natural gas has more than doubled, while the level of gas consumed by residential, commercial and industrial customers declined in absolute and relative terms (as shown in Figure 5).

Figure 4

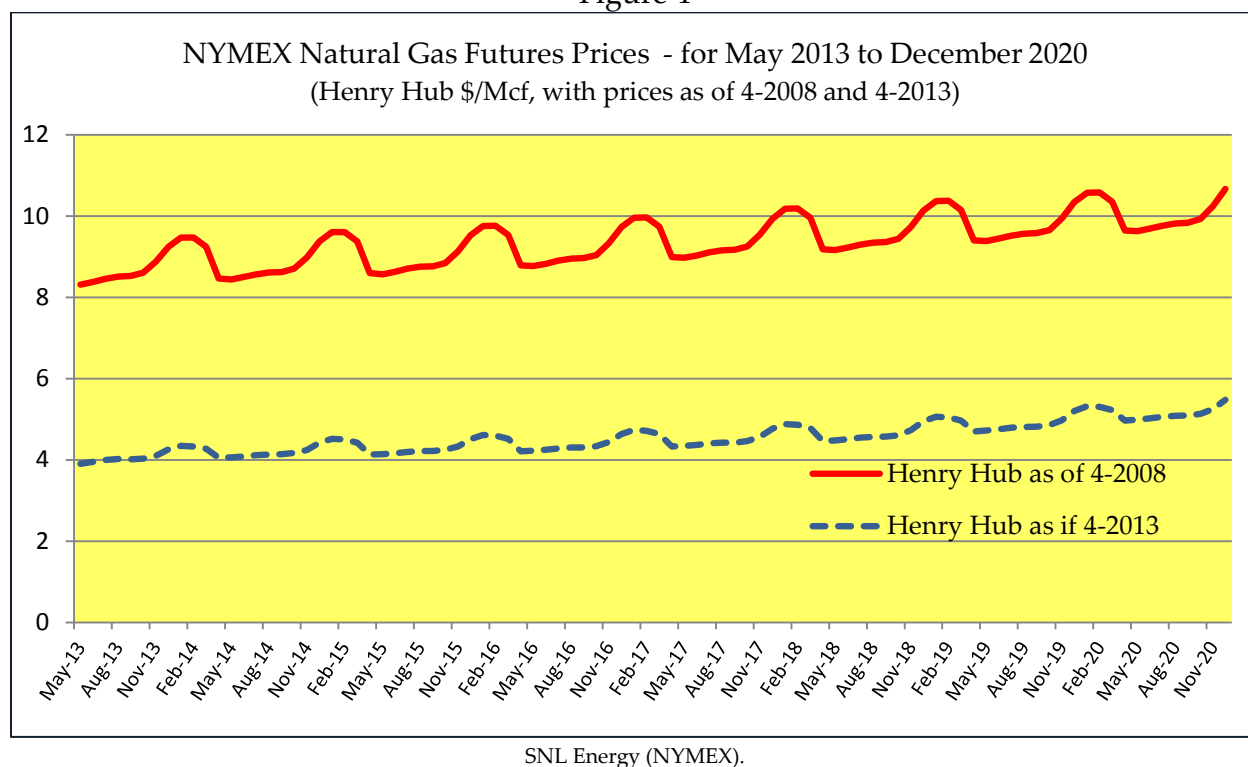
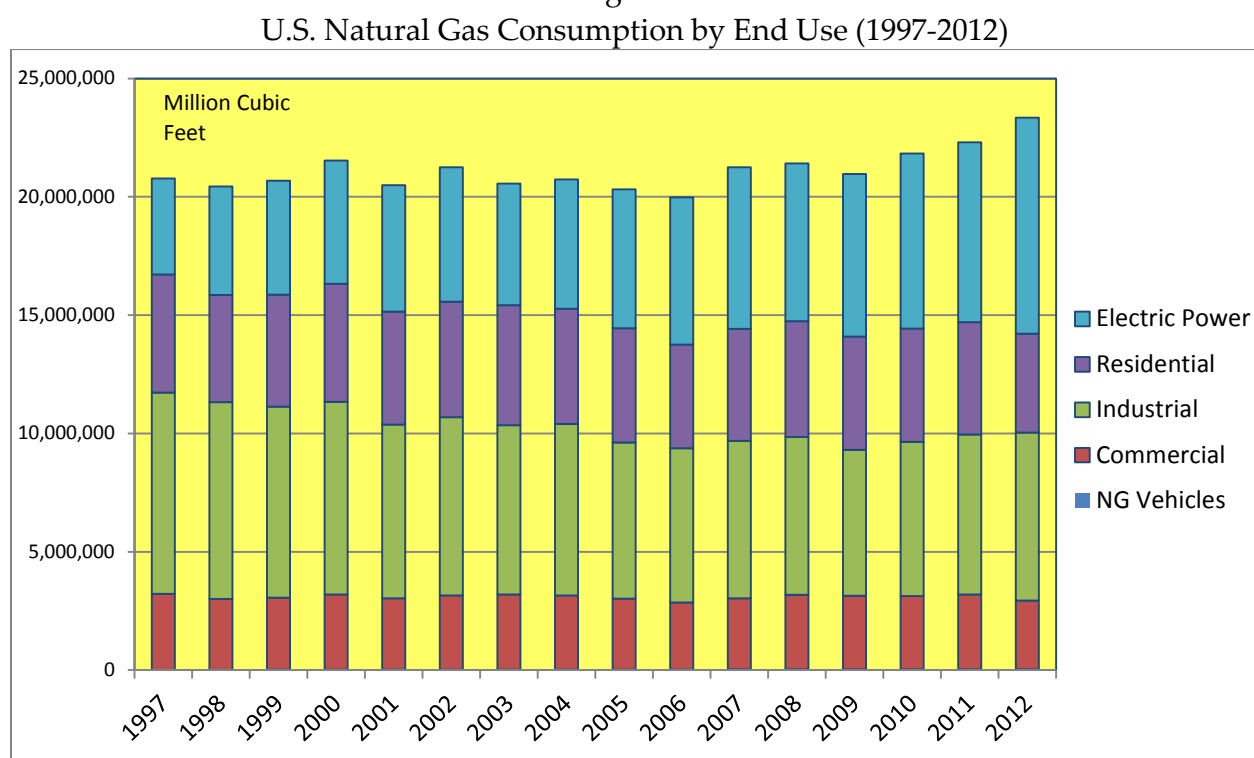


Figure 5



EIA: http://www.eia.gov/dnav/ng/ng_cons_sum_dcunusa.htm

Forecasts for growth in demand for natural gas are driven primarily (although not exclusively) by the power-generation sector (see, for example, the National Petroleum Council's "Prudent Development," 2011). But unlike LDCs' traditional year-round, bundled demand for gas to serve their firm customers, growth in the power sector's use has not been accompanied by significant expansion in the gas-delivery infrastructure. Without change in some of the key features in current business models for competitive generators or in market rules, that situation is not expected to change dramatically in the near term, making it hard to drive investment in pipeline/storage infrastructure built from power sector support.

The U.S. Electric Power System

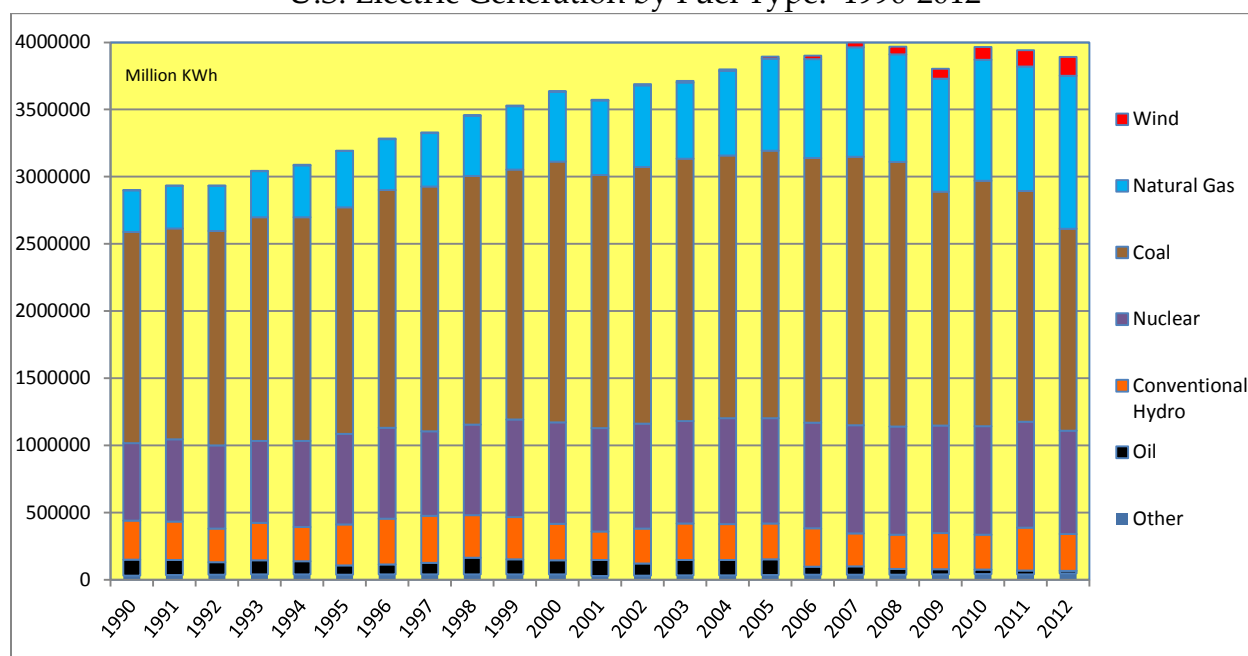
Although many parallels exist between the natural gas and electric industries and systems, there are many stark differences. For example, historically, electric systems grew up in ways that placed facilities quite close to end-use customers. The fuel used for power generation (e.g., coal, oil, uranium) moved long distances from its source to the power plant. Typically, those power stations had (and still have, in most cases) on-site fuel-storage capability, enabling access to fuel supplies as plants were dispatched on and off to meet instantaneous demands as they changed in real time on the system. Even hydroelectric power, which is often distant from consumer loads, could store its energy (e.g., behind a dam) when the plant wasn't being dispatched for power.

Over the years, local, small, vertically integrated companies (owning power plants, transmission and distribution) consolidated, creating larger vertically integrated companies. Their footprints were bigger, but they still often retained state regulation over much of the assets in their rate bases. Sales for resale (among the separate affiliates, or between them and third parties) were under FERC jurisdiction. But siting of new generation, transmission, and distribution facilities retained state supervision.

Much has changed over time, especially in the past 15 years as well. As noted in the section above on natural gas, this period witnessed the restructuring of the electric industry to allow greater competition in generation markets, and significant investment in new gas-fired combined cycle power plants. In the past decade, especially, new renewable power plants have also come on line in response to state renewable portfolio standards, federal tax incentives, and that period of high natural gas prices mid-decade. (See Figure 2.) As gas prices fluctuated over the last ten years, natural-gas-fired

generation has been the swing fuel in many respects, as that previously underutilized capacity offered options for economic dispatch. In the past few years in particular, natural-gas-fired generation has eroded the long-dominant market share of coal-fired generation. (See Figure 6.) The increasing share of wind (an intermittent energy resource) and natural gas (with its just-in-time delivery of fuel over the pipeline system) means that a larger portion of total generation comes from fuels without significant on-site fuel-storage capability (also sometimes called “limited energy generation resources”).

Figure 6
U.S. Electric Generation by Fuel Type: 1990-2012

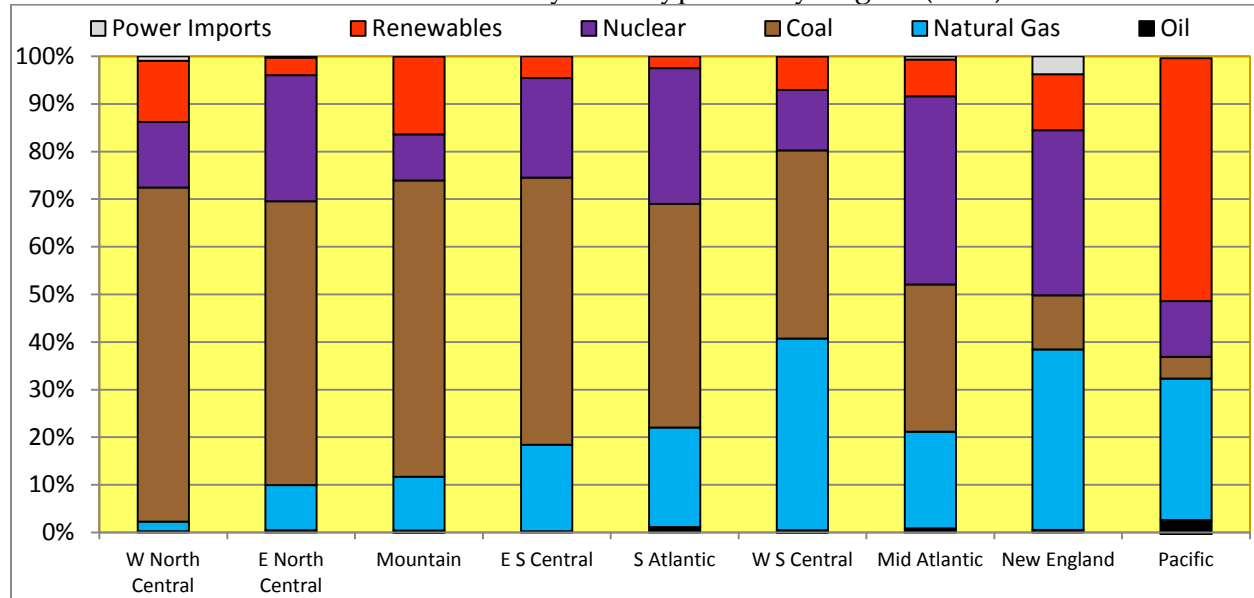


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There are significant differences among the regions. Some depend more than others on renewables (including wind) and natural gas as a percentage of capacity and energy (Figure 7, showing shares of generation by fuel). For example, New England has a relatively large share of natural gas, as do a few other parts of the country. The regions also vary in terms of their reliance on aging and inefficient coal-fired power plants, the most inefficient of which are already feeling economic pressure from low natural-gas prices. Many coal plants have announced plans for retirements and an additional amount of generating capacity that will retire as the circa-2015 compliance deadlines for the federal Mercury and Air Toxics Rule (see Figure 8 for the announced retirements to date). Retirements will likely be

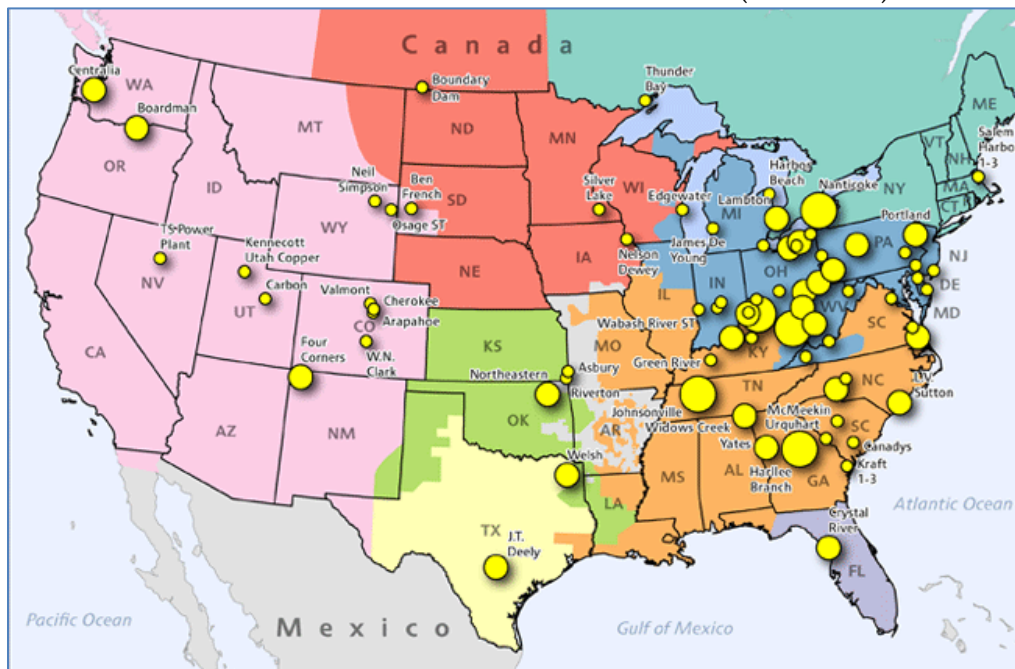
replaced in large part by natural-gas-fired generating capacity, thus reshaping the region-specific generation shares shown in Figure 7.

Figure 7
Electric Generation by Fuel Type and by Region (2012)



EIA, Annual Energy Outlook 2012, Supplemental Tables. In this figure, "Renewables" includes conventional hydro, wind, other.

Figure 8
Planned Coal Power Plant Announcements (2012-2022)



SNL Financial

Other regional variations include industry structure and the concentration of power-plant capacity owned by competitive generating companies as compared to vertically integrated utilities. Such differences have implications for gas-fired power plant owners' willingness to enter into long-term firm gas supply and/or transportation arrangements. In competitive wholesale power markets administered by Regional Transmission Organizations (such as those in the Northeast (NYISO, ISO-NE)), for example, forward-capacity markets do not extend beyond several years, and the jury is still out with regard to whether such markets adequately support sufficient long-term investment in either local gas storage and/or incremental pipeline capacity investment. (For example, nationally, natural gas pipeline capacity additions were the lowest they've been since 1997, while those in the Northeast were the highest since then, as shown in Figures 9 and 10.)

Figure 9
National Gas Pipeline Capacity
Additions Since 1997

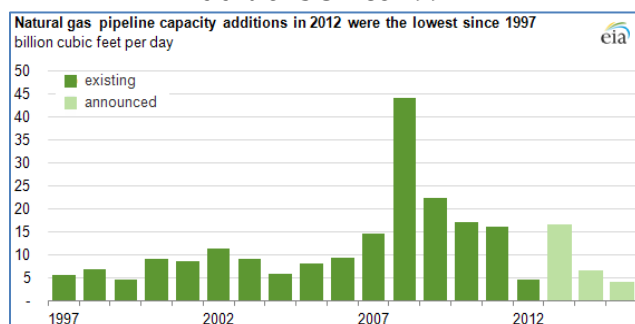
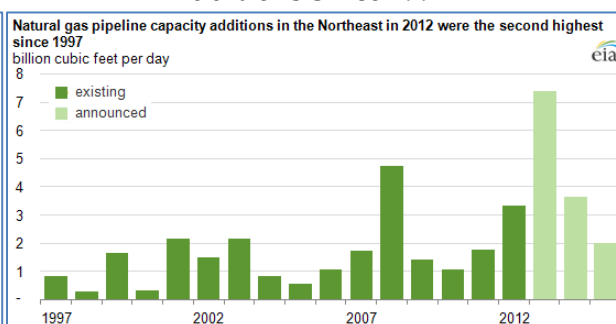


Figure 10
Northeast Gas Pipeline Capacity
Additions Since 1997



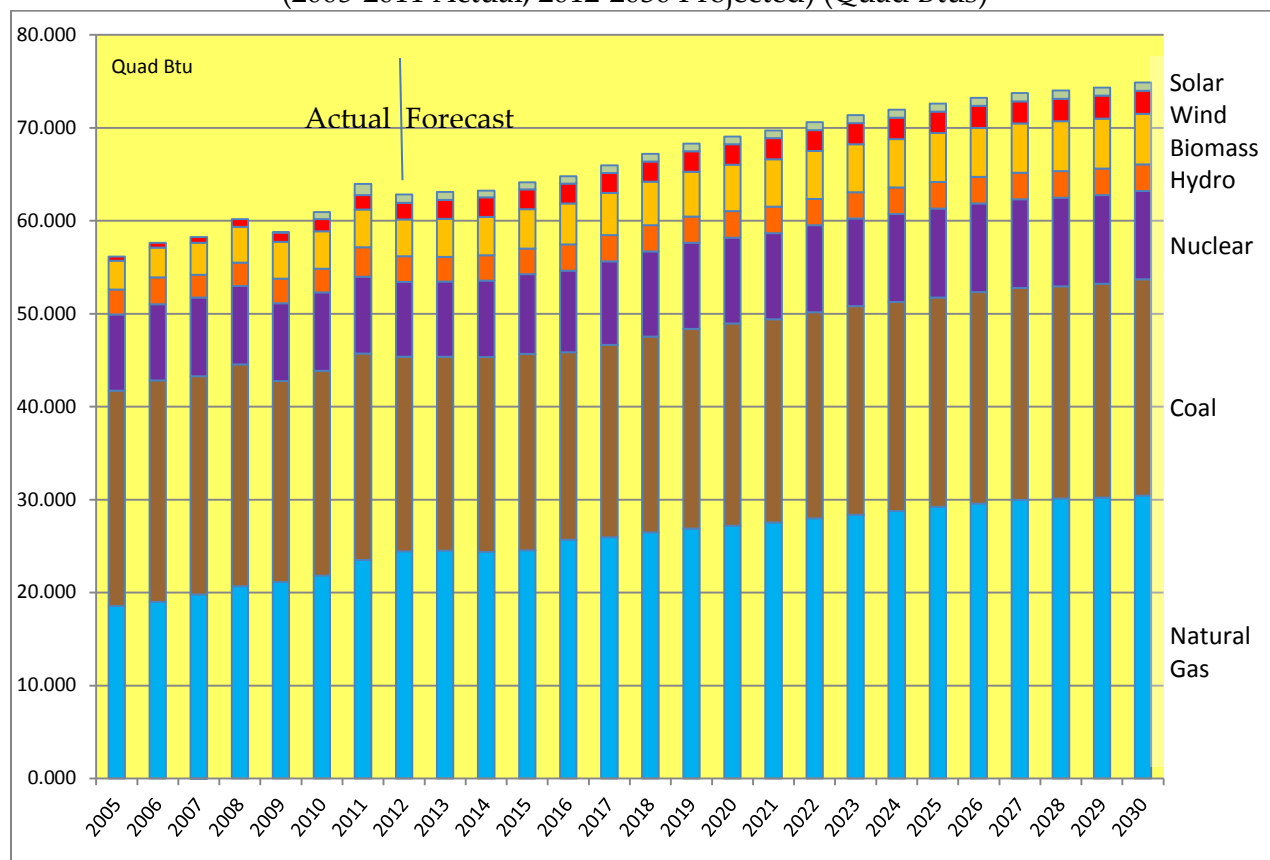
EIA. <http://www.eia.gov/todayinenergy/detail.cfm?id=10511>. Data for 2013-15 are based on companies' announcements

In states that have retained vertically integrated electric companies, there may be greater support for such long-term supplies. For example, in Colorado state regulators supported Xcel Energy's investment in new gas-fired generators to replace retiring coal plants, and approved long-term gas supply contracts with Anadarko as part of the package.

Looking ahead, the Energy Information Administration projects that most new generating capacity added in future years will be either renewables or gas-fired, continuing the trend of recent years of growing generation from "energy-limited" resources. (See Figure 11, showing projected electricity generation by fuel type, through 2030.) Given the outlook for low natural-gas prices going forward, potential new coal-fired or nuclear capacity additions face difficult economic hurdles on top of regulatory ones (e.g., related to new federal environmental regulations affecting new power plants) and other investment challenges

(e.g., long-term high-level nuclear waste management issues; risks related to national policies limiting greenhouse gas emissions). In many ways, such gas-fired generation and intermittent renewable generation can support each other's operations, with gas-fired capacity capable of providing operational flexibility to balance the intermittency of wind and solar energy power supply.

Figure 11
Electric Generation by Fuel Type
(2005-2011 Actual; 2012-2030 Projected) (Quad Btus)



EIA, Annual Energy Outlook, 2013.

Issues at the Intersection of Greater Gas/Electric System Interdependency:

Even without the projected increases in such potentially “limited energy generation resources,” the electric and gas systems are already experiencing strains at their intersection. To date, integration issues related to such increased gas-fired (and renewable) generation have been fairly manageable. But market timing and coordination issues, reliability risks, and operational challenges on both the electric and gas systems have begun

to emerge. In some regions, for example, generators need to commit to move gas volumes before knowing whether their offers into organized daily power markets have been accepted; conversely, generators need to offer prices into such energy markets without fully knowing the price of their natural gas. There are other instances where gas customers that have contracted for firm gas supply and transportation service face potential (or real) curtailments as operational conditions change upstream and downstream. Tensions are visible across the business models of different players in the two industries, and in the market rules in different regions.

These tensions have been identified in a number of public forums in the recent past. The National Petroleum Council's "Prudent Development" report in the Fall of 2011, for example, focused on the need to address harmonization of gas and electric market rules and service arrangements. The North American Electric Reliability Corporation published a special assessment ("A Primer of the Natural Gas and Electric Power Interdependency in the United States") in December 2011.

The North American Energy Standards Board ("NAESB") established an gas/electric harmonization committee, which identified a set of issues falling into three clusters:

- Issues on which NAESB should consider develop new standards or modifying existing ones (including market timelines and coordination of scheduling; flexibility in scheduling; and information availability with regard to infrastructure utilization and operating conditions);
- Issues on which policy decisions should precede any action by NAESB; and
- Issues on which commercial service arrangements may be the most appropriate course of action (rather than new standards or new policies).

The FERC technical conferences have elicited comments from a wide variety of stakeholders who identified many of the same issues and themes: mismatched operating schedules; coordination and information sharing, including near-term or real-time power generation forecasts; business-model and planning issues in each of the industries that create chicken-and-egg problems for gas and electric resources and infrastructure. Again, while some of these are issues that may be ripe for addressing by FERC (and/or NAESB), many will benefit from the innovation that may occur as market participants and other players in different regions fashion approaches that work for their particular conditions.

At NARUC meetings, state and federal regulators have had presentations on the results of many gas-electric interdependency studies. NARUC is co-sponsoring preparation of an

analysis of long-term infrastructure requirements for both industries on the Eastern side of the U.S. Many of the regional transmission organizations, such as MISO, NYISO and ISO-NE, have performed assessments and sponsored study groups to examine what types of market-rule changes might be appropriate.

Discussion in these and other forums make several things clear. First, the degree to which these issues raise serious challenges for efficient and reliable energy supply varies considerably by region and by type of issue. There are places, such as New England, where the issues are more urgent than in others. Second, there are lots of players with very different points of view, not only across business segments, industries and roles, but also within them. Third, the regulatory issues are complicated; while FERC may have responsibility for a broad set of policy issues on electric/gas integration issues, the states not only have strong interests but also in some cases regulatory responsibilities that can affect market participants' behaviors.

Fourth, there is pressure building, and something needs to change. It is hard enough to introduce change into a single industry, where there may be players who perceive themselves as winning or losing from different options for resolving small and large issues. It will undoubtedly be even harder to introduce sensible but meaningful changes affecting market participants in two industries. This will surely be uncomfortable, because both industries will actually need to change how they're doing things and there will undoubtedly be costs associated with accomplishing the changes (even if the changes are needed for efficiency and reliability gains in the future). Among those who may need to change the ways they look at these issues are regulators themselves.

Last but not least: in parallel with the significant changes that have occurred in the structure, operations, markets for natural gas and electricity, there have been transformational – if not revolutionary – changes in information systems and communications networks that support activities throughout the U.S. economy and society. In the same 15-20-year period where dramatic changes have occurred in the electric and gas industries, we have also witnessed: the proliferation of broad user access to high-speed computing capability; the commercialization of the internet, and its capabilities for real-time information sharing; the explosion of information exchanged through online systems and social networking; the development and deployment of advanced electronic-metering systems and other aspects of “smart” devices and software that support not only the operations of electric and gas systems but also connect countless users into those networks in more direct ways than in the past. Even so, there remain variations in use of such

capabilities. There are also gaps between the potential capabilities and widespread dissemination and use of such advanced information systems, on the one hand, and their actual use in companies, system operations, transaction support, and policy/market design, on the other. These gaps and variations exacerbate some of the tensions at the intersection of the gas and electric system operations, but they also create large opportunities for different approaches in the future that could support more efficient and reliable energy systems for Americans.

As we approach the task of identifying options for addressing the efficiency and reliability challenges for today's and tomorrow's electric and gas systems, we should be mindful of the extent to which today's ways of doing business are grounded in assumptions about communications/information technology systems of the past, as well as tariffs, terms and conditions built on yesterday's assets rather than current conditions.

Today's Symposium topics grapple with these same topics, with the goal of providing various communities – energy firms, energy users, investors, researchers, policy makers, and standard-setting entities – with frameworks and other approaches to addressing these challenges. Today's panels will cover:

- Competing claims: Gas and electric scheduling mismatches and capacity release issues;
- Ensuring natural gas availability in the future;
- Coordination and information sharing; and
- Dual modeling of the electric and gas markets and systems.

As we approach these issues, let's focus on changes that will foster the types of innovations we need to have gas and electric systems that are resilient, efficient and reliable.

Combining Energy Networks: The Impact of Europe's Natural Gas Network on Electricity Markets till 2050

Jan Abrell, Clemens Gerbaulet, Franziska Holz, Hannes Weigt, and
Christian von Hirschhausen

Abstract:

The issue of electricity-natural gas interdependence is becoming a major energy policy and regulatory issue in all jurisdictions around the world. In this paper, we develop a model that looks at natural gas and electricity simultaneously, and apply it to the scenarios for European decarbonization at the horizon 2030/2050. The increased role of gas fired plants in RES dominated electricity markets and the dependence on gas imports make this particular striking for the European energy market. We provide a first comprehensive combined analysis of electricity and natural gas infrastructure issues with an applied focus. We analyze different scenarios of the long-term European decarbonization pathways sketched out by the Energy Roadmap 2050. We identify criteria issues related to electricity and/or natural gas infrastructure in and the interrelation between both markets. The new modeling approach of “combining” energy markets clearly leads to insights that go beyond the traditional, sector-specific approach.¹

Key words: Europe, electricity markets, natural gas markets, networks

JEL-code: L94, L95

¹ This paper is an update of the working paper by the first four authors, developed in the framework of the EMF 28 model comparison „Europe 2050: The Effects of Technology Choices on EU Climate Policy“; it is our contribution to the MIT Energy Initiative “Symposium on gas and electricity”, April 16, 2013; the usual disclaimer applies

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1. Introduction

When both the German and the French energy system were close to a breakdown on February 9th, 2012, energy policymakers and regulators „discovered“ that electricity networks and the natural gas infrastructure, that had been treated independently from each other for the last decades, were closely interconnected. A cold spell in continental Europe had sent electricity demand in France at a long-time high of 100 GW, while six German nuclear power plants that generally assured cheap electricity exports to France had been shut down following the moratorium on nuclear power after the Fukushima disaster, in March 2011; gas-fired combined cycle plants in the South of Germany could not substitute due to a lack of access to gas pipeline capacity, while at the same time plenty of natural gas was transported from Austria and South Germany to Italy. While rolling blackouts could be avoided due to active demand management by the French operators, the issue of electricity-natural gas interdependence was launched and led to a major enquiry to the European Commission, with concrete regulatory action most likely upcoming.

The issue of electricity-natural gas interdependence is not specific to the one case mentioned, but it is becoming a major energy policy and regulatory issue in all jurisdictions around the world undergoing the transformation to a lower-carbon and/or renewables-based energy system. Naturally the issue rose to top priority in Japan after the closing down of nuclear power in 2011 (Mitchell et al., 2012), but likewise advanced to center stage in North America following the „shale gas revolution“, e.g. in PJM (Sotkiewicz, 2012). Furthermore, the developments of the Arab Spring and the recurrent disputes between Russia and its gas transit countries, Belarus and the Ukraine, highlighted the issue of supply security of the import dependent European Union.

Some countries and regions within the European Union currently are dependent on a very small number of suppliers, which makes them vulnerable to supply disruptions, even if they are temporary. The South European countries (Italy and increasingly Spain) strongly depend on pipeline imports from North Africa (Algeria, Libya) and use liquefied natural gas (LNG) to diversify their supplies and to respond to short-term demand spikes. The Central and South East European countries import almost exclusively from Russia and the current network topology does not allow them to quickly change this import pattern. For this region, storage and especially reverse flow capacities (to import from the West to the East, opposite the traditional direction from the East / Russia to the West) are put forward as remedies to increase their security of supply, in addition to increasing the number of import routes. The European Commission has stipulated these measures in its Supply Security Directive (EU, 2004)

which also guide its decisions on TEN-E and EEPR project support (EU, 2006, 2009) and are picked up by the Ten-Year Network Development Plans of the natural gas transmission system operators in Europe (e.g. ENTSO-G, 2011).

Also the further deployment of intermittent capacities of renewable energy sources (RES) in the electricity sector is supposed to increase the role of natural gas as fuel option. The European Commission (EC) states in the EU Energy Roadmap 2050 that gas “will be critical for the transformation of the energy system” as electricity production from gas has the lowest emissions compared to other fossil-based technologies and will help reach climate goals (EC, 2011a). Although the production of electricity from gas is projected to decline in the future as the influence of renewable energy sources increases, gas is assumed to be the major fossil fuel for electricity generation in the coming years (EC, 2011b).

Summarizing all those relevant aspects in both markets it becomes evident that a combined assessment is advised to derive solid recommendation about the future development of the European energy markets. However, most model-based analyzes so far are focused on one single sector. A large stream of literature addressed the development of electricity markets and networks in the wake of an increased share of RES (e.g. Weigt et al., 2010, Neuhoff et al., 2008). Studies like ECF (2011; Haller et al. (2010) and SRU (2010) determine possible development paths for the European electricity system. Investment needs in grid and generation infrastructure based on renewable targets and potentials is determined mostly in a cost-minimizing or welfare-maximizing way. In most models that determine European grid development the electricity grid infrastructure is mostly modeled with a low spatial resolution and therefore electricity-specifics like loop flows are not taken into account. Similarly, several papers address the market structure and development of the European and the global natural gas markets (e.g. Egging et al., 2008, 2010). Finally, large scale energy system and macro economic models cover the interrelation between fuel markets and the economy as a whole but in an aggregated manner. These models often lack technological details of the transmission system in particular in the electricity sector (e.g. Capros et al., 1997; Paltsev et al., 2005; IPTS, 2010; Capros, 2011).

Literature relating to an integrated analysis of electricity and natural gas network markets is scarce and so far mostly addresses methodological and technical aspects of how to combine both markets in a model framework with small test cases to highlight the applicability or derive stylized insights. For example, Unsihay et al. (2007) model an integrated gas-electricity system with the goal to minimize the short-term system operation cost examining a test case network based on the Belgian gas grid. Another approach is the hub system applied by Arnold and Anderson (2008) that decomposes a power

flow optimization problem for gas and electricity in order to model larger applications. Abrell and Weigt (2012) combine both markets within a partial equilibrium representation. Their model is applied to a European test case and shows that upward and downward influences between these sectors exist both in terms of price and quantity interactions. Furthermore, they show that effects and interactions of changes in the respective markets are not geographically limited but extend beyond the point of disturbance due to the loop-flow characteristics in the electricity market.

In this paper, we provide a comprehensive combined analysis of electricity and natural gas infrastructure issues with an applied focus and a complete dataset covering the European networks. Following the approach of Abrell and Weigt (2012) of combining both markets in an equilibrium setting, we analyze different scenarios of the long-term European decarbonization pathways sketched out by the Energy Roadmap 2050 and by the EMF 28 effort on “The Effects of Technology Choices on EU Climate Policy”.² We identify critical issues related to electricity and/or natural gas infrastructure in and the interrelation between both markets. The next section describes the initial model used and the extensions that have been made to address certain scenarios for the European decarbonization process. We also describe the network topology of the electric and natural gas infrastructure, respectively, the data and other assumptions. Section 3 describes the results of the basic model runs, while section 4 discusses the effects of different load and generation conditions on the electricity market. The impact of gas market developments on the electricity system is discussed in Section 5; Section 6 summarizes and concludes.

2. Model and Parameterization

2.1. The model

The model consists of a natural gas and an electricity representation which both take into account the respective sector’s transmission grid and can be run independently of one another or in a combined manner (Figure 1). The natural gas model, which is shown on the left hand side of Figure 1, depicts pipelines and LNG routes as multi-commodity network. The arcs in this network are directed, i.e. the natural gas flows in a predetermined direction given by the LNG value chain (exporter → importer) and the compressor stations in the pipeline network. Natural gas producers offer the extracted gas at the

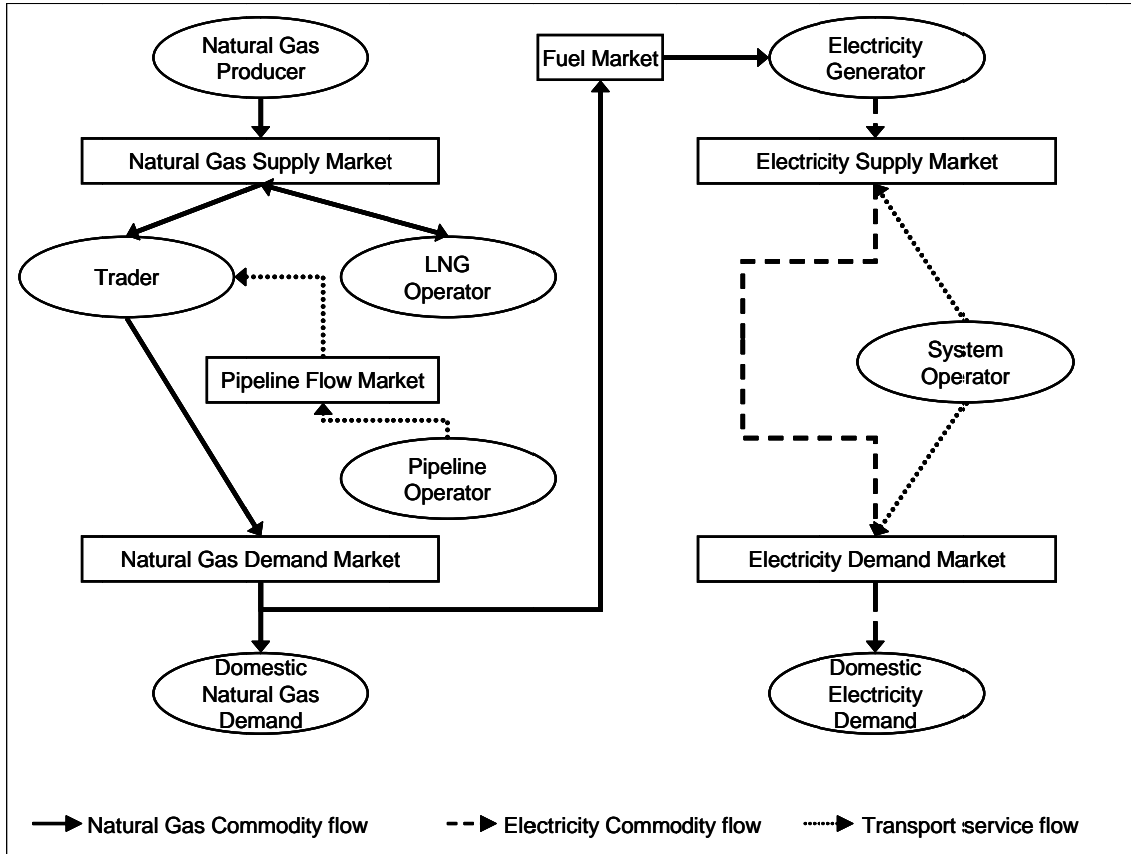
² http://emf.stanford.edu/research/emf_28_the_effects_of_technology_choices_on_eu_climate_policy/

supply market to either a LNG operator or a trader, in a similar setting than in Egging (2010). The trader demands the services of transporting the gas to the final demand market from the pipeline operator. Final consumers demand the gas at that market and pay a price which includes the transport fees. If the natural gas model is run independently from the electricity model, final demand includes the demand by the electricity generators using natural gas fired power plants.

The electricity model, which is depicted on the right side of Figure 1, includes the transmission grid using a DC-loadflow approach (Schweppe et al., 1988, Leuthold et al., 2012) and a market hub system (Hobbs, 2001). Electricity generators sell electricity to the network operator which serves final consumers. As long as the electricity model is used independently of the natural gas model, all fuel prices are exogenous. The two models are combined by including the fuel linkage: the demand of natural gas fired power plants becomes an endogenous variable in the natural gas model and the natural gas price an endogenous variable in the electricity model.

A complete mathematical model description is given in Abrell and Weigt (2012). The approach used here is static in the sense that we solve the models for one representative hour and storage is neither included in the electricity nor in the natural gas market. Furthermore, in all markets perfect competition is assumed. Moreover, we assume complete information of all agents about all variables, i.e. the model is deterministic. Finally, the cross-price elasticity of natural gas and electricity final demand is assumed to be zero, i.e. the final demand for the energy commodities is independent. The two sub-models as well as the combined one are formulated as Mixed Complementarity Problems in GAMS (Brooke et al., 2008) and solved using the PATH solver (Ferris and Munson, 2000).

Figure 1: Model Overview



2.2. Data

We combine data on the natural gas and the electricity sector for the base year 2010 and for the periods 2020, 2030, 2040, and 2050. We use hourly data for a representative demand hour. The data input will then vary in each of the scenarios.

The natural gas model contains all European countries with one node per country and some more non-EU countries that export natural gas to Europe. The nodes are linked with each other in a pipeline network and/or a virtual network of liquefied natural gas (LNG) trading routes between liquefiers (exporters) and regasifiers (importers). The pipeline network and LNG (liquefied natural gas) import capacities are based on 2010 data by the European transmission system operators (ENTSO-G, 2010). For the periods beyond 2010, the 2012 capacity data by ENSO-G (ENTSO-G, 2021) and the Ten-Year Network Development Plan (TYNDP, ENTSO-G, 2011) were the basis to determine the capacities in place. Liquefaction capacities are given by the IEA (2012a) for 2010 and are derived from IEA (2012b) for the periods thereafter. The related cost and losses parameters for pipelines, liquefaction, and regasification are based on the World Gas Model (Egging et al., 2010). PRIMES results for the Energy

Modeling Forum (EMF) 28 and the Energy Roadmap 2050 (EC, 2011) provide final demand and demand by the electricity sector for natural gas, as well as reference prices for all periods. This is yearly data for all EU-27 countries, which was scaled down to hourly data. Where seasonal differentiation was needed, it was based on monthly demand data from the IEA.

The electricity model specifies the characteristics of generation technologies in terms of the heat efficiency, emission coefficients and installed capacity for each technology at each node in the electricity grid. Furthermore, country-specific prices for the primary energy carriers nuclear, lignite, hard coal and biomass taken from the PRIMES model results are used as fuel price inputs. The transmission grid is shown in Figure 2 and based on the ENTSO-E Grid Map 2011 (ENTSO-E, 2011) and the grid extension projects described in the 2012 version of the ten-year network development plan (TYNDP) (ENTSO-E, 2012a). The grid for 2010 represents the ENTSO-E Grid Map 2011 without new built or planned projects. In the grid for 2020 all planned projects as well as the mid-term grid extension projects (2012-2016) of the TYNDP are added to the grid. The grids for 2030 and the following time steps additionally consist of the long-term TYNDP projects of pan-European significance. The grid structure in Figure 2 shows the 2030 AC-grid. For the model calculations the electricity grid is aggregated into 47 zones. Each zone consists of one or more NUTS-1 regions.

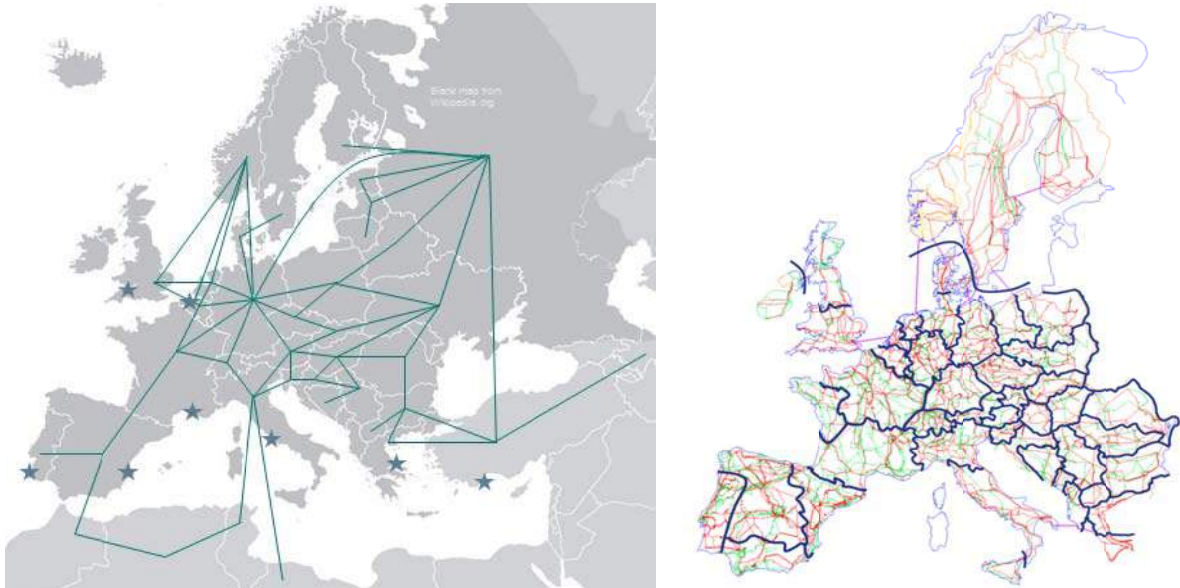
Available technologies are clustered according to type.³ The technology characteristics of the different plant types (efficiency, availability, installed capacity) are based on the PRIMES results of the EMF 28 Results Database. The spatial distribution towards the different network zones is based on the Platts Database (platts, 2011), from which each power plant's coordinates were determined. These power plant capacities were aggregated to the zones in the model using the geographical information. This allows for a regional allocation and scaling of the generation capacities reported for each country by the PRIMES model for the EMF28 model comparison for each scenario and time period. Based on the technical potential for wind and solar provided by ESPON (2010) the national RES capacities provided by PRIMES are spatially allocated to the NUTS1 zones.

The demand for electricity is each country's average winter demand. The yearly demand for electricity is taken from PRIMES but scaled with a summer/winter demand ratio determined from historical demand values obtained from ENTSO-E (ENTSO-E, 2012b). These national values are spatially allocat-

³ Those are: Nuclear, Lignite, Lignite with CCS, Coal, Coal with CCS, Gas Combined Cycle, Gas Combined Cycle with CCS, Gas Turbines, Gas Turbines with CCS, Hydropower, Biomass, Photovoltaic (PV), Concentrated Solar Power (CSP), Wind Onshore and Wind Offshore

ed to NUTS1 zone based on population share. For countries not reported in the PRIMES results (like Switzerland and Norway) assumptions regarding the development of renewable capacity expansion and electricity demand have been made based on renewable availability and the development of neighboring countries.

Figure 2: Stylized natural gas network (left) and electricity network with zones (right)



3. Basic Result Overview

In a first step we derive an overview on the development of the European natural gas and electricity markets till 2050. We analyze three of the EMF 28 scenarios in detail:

- *EU1*: representing a "moderate policy" scenario with the EU's 2020 targets in place and a European 40% CO₂ emission reduction target for 2050
- *EU6*: similar to the basic setting of EU 1 but with a more stringent CO₂ emission target of 80% till 2050 for Europe
- *EU10*: same target as the EU 6 setting but with a higher share of RES generation, stronger energy efficiency development and constrained usage of CCS and nuclear

The selected scenarios cover a diverse mix of potential developments and thus the simulated market results span quite a broad range. As the model is time static, utilizes a reference hour approach, ne-

glects global gas market interactions, and assumes perfect competitive markets the obtained results represent a lower boundary on expected market developments.⁴

Although the development paths are different there are still some common trends for all scenarios: First, the market situation in 2010 has a similar pattern in all three settings.⁵ In the electricity market we have a price separation of the Iberian Peninsula, a relatively uniform price level in Eastern Europe, a slightly higher price level in Central Europe and price spikes in Italy. Network congestion occurs mainly at the French and German borders as well as on lines towards Italy. The average generation mix consists of nuclear, coal and RES (including hydro) to equal shares and about 10% of natural gas fired plants (Table 2). In the natural gas market the absolute price level is different in the EU1 scenario due to the lower reference prices but the general price and demand pattern is similar to the EU6 and EU10 cases: Central Europe has a common price level supplied by Russian imports and North Sea gas from Norway and the Netherlands, South East Europe has a lower price level due to cheap Russian supplies and limited interconnection to Central Europe, and the Iberian Peninsula is decoupled and supplied by North African gas and LNG imports.

The second common result over all scenarios is the basic development of the natural gas market segmentation. Given the North Stream connection of Russia and Germany, further extension according to the TYNDP of the ENTSO-G within Europe, planned LNG extensions, and the assumed perfect competitive market setting network congestion plays only a minor role in the future European gas market and consequently we observe a relatively common price level across Europe for all cases. The price differences between the EU1 and EU6/EU10 (Figure 3) are based on the different underlying reference prices. However, the overall demand development and the resulting production pattern differ greatly between the scenarios. For the electricity market the projected extensions of ENTSOE's TYNDP also lead to a price convergence across Europe on average, but the development is still more scenario dependent than in the natural gas market. This is based on the different RES and nuclear developments that translate into quite different dispatch patterns (Table 2).⁶

The main differences of the three scenarios stem from the underlying reference price levels. In the EU1 setting fuel and electricity price assumptions are the highest and this also translates into the

⁴ An overview of the aggregated results is provided in the Appendix.

⁵ Note that the model uses the EMF 28 PRIMES results for 2010 and not the observed market outcomes.

⁶ A final similarity between all scenarios is the development of CCS generation. Due to the underlying emission price assumptions fossil generation without CCS has a severe cost disadvantage from 2030 onward and consequently is phased out till 2050 as more CCS plants come online.

model results. The EU1 case shows both the highest absolute price levels of all cases and the only scenario with a steady price increase for both electricity and natural gas (Figure 3). The EU6/EU10 cases have the same underlying fuel price assumptions and also show a quite similar price development particular in the natural gas market. The electricity price development shows a curved pattern with a decline towards 2050. From 2030 onward the EU6 price is above the EU10 price due to the different dispatch of RES and nuclear plants. In the EU10 setting nuclear plants phase out faster while the RES share strongly increases. The price dumping effect of RES generation leads to an electricity price decline to the absolute lowest levels (Figure 3).⁷ However, as RES is not necessarily located where the phased out nuclear plants are this increases transmission requirements which is evident by the high congestion rent in the EU10 2050 case (Table 2).

The lower prices in the EU6/EU10 cases compared to the EU1 scenario also translate into the demand level. Whereas the underlying reference demand (see section 2.2) declines in the former two cases and increases in the EU1 scenario, the model runs show a different demand development (Table 2). While the EU1 demand still grows over time the increase is significantly higher in the EU6/EU10 scenarios. This is a result of the assumed demand elasticity and the obtained market prices. The higher share of RES generation and the lower reliance on conventional power plants in the EU6/EU10 scenarios lead to a low electricity price level and allow a higher satisfied demand whereas the opposite holds for the EU1 case.

The usage of gas for electricity generation differs over the decades and the scenarios. In all cases the highest share is obtained in 2020. This is a result of low natural gas price coupled with the emission price that reduces the competitiveness of coal plants in comparison while at the same time RES and CCS capacities are not yet sufficient to fully cover the difference. From thereon the share of gas plants declines to basically 0% in 2050 in the EU1 and EU10 scenarios and remains relatively stable with 10% in the EU6 scenario. Despite the similar developments of the EU1 and EU10 scenarios the underlying reasons are strikingly different. In the EU1 case nuclear and coal CCS plants continue to supply about 40% of electricity generation while the increased RES share is compensated by a decrease in gas fired generation. In the EU10 scenario both nuclear and fossil generation are phased out and RES generation covers more than 90% of the demand in 2050. In the EU6 scenario the situation is more diverse. While both the deployment of RES and the phase out of nuclear plants are faster than

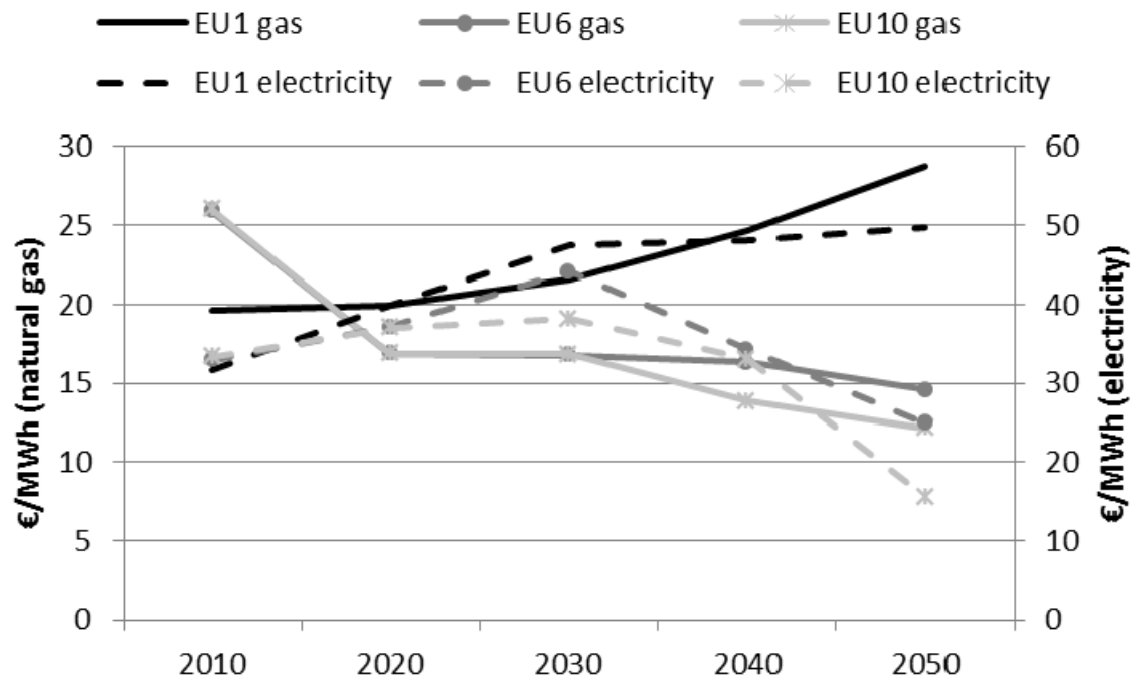
⁷ The model results represent short-run marginal costs and thus do not account for investment cost recovery.

in the EU1 setting they are still slower than in the EU10 scenario. Thus, fossil generation still plays an important role in satisfying electricity demand. However, due to the lower natural gas prices compared to the EU1 scenario (Table 1) gas fired CCS plants have a price advantage compared to coal CCS plants keeping the gas share on the 10% level and phasing out coal.

In the gas market the development till 2050 reflects part of those electricity developments as the share of demand by power plants naturally also reduces to 0% till 2050 in the EU1 and EU10 scenarios. In the EU6 scenario the share of electricity demand in the natural gas market increases till 2050 due to an increase in the absolute gas fired generation output and a decline in overall gas demand.

The endogenous supply within Europe declines to about 70% of the 2010 values over the decades. In the EU1 case the relatively stable gas demand is fuelled by increasing pipeline imports from Russia and the Caspian region while LNG imports from Nigeria and the Middle East decline. In the EU6 scenario the gas demand declines to about 75% of its 2010 values till 2050 of which 13% are for the electricity market. The low demand levels lead to a corresponding price decrease and a shift in the supply pattern. Gas demand declines stronger in Central and East Europe reducing the need for Russian gas while South Europe has a slower demand decrease keeping imports from Africa and via LNG more pronounced. This general development is accelerated in the EU10 case as the endogenous demand decrease in the natural gas sector is combined with the decline of gas usage in the electricity sector. This leads to a sharp reduction of imports both via LNG and pipeline till 2050 while the demand level is reduced to about 55% of the 2010 values. These developments have an impact on the import dependence of Europe: whereas the EU1 case has an import share of about 71% in 2050, the EU6 has a share of about 65% and the EU10 scenario a share of less than 50%. Thus, the higher environmental targets lead to less import dependency due to an overall reduction of gas demand.

Figure 3: Price development, basic scenarios



Summarizing, the basic results show that under average demand conditions network congestion is only a minor issue if the planned and projected pipeline, LNG, and transmission projects come online. The production and import pattern in the natural gas market remains similar to the current observed setting with a high dependency on Russian and African gas but this dependency can be reduced by increases in energy efficiency and RES generation. The production pattern in electricity depends on the emission price, RES capacities and nuclear restrictions while coal and gas fired plants are more or less fill-ins.

4. Congestion and Dispatch in the future European Electricity Market

The basic market results are based on average market conditions. While this is appropriate for the natural gas transmission network as storage and pipeline operation allow a relatively stable wholesale

market level⁸ the same does not hold for the electricity market. Depending on demand conditions and RES availability the actual dispatch can vary heavily between hours and thereby lead to different power flows and locational price differences. To capture those aspects following we will present a scenario analysis addressing peak demand and high RES input variations. The analysis is carried out for 2010, 2030 and 2050 to derive the general trends.⁹

4.1. Impact of peak load conditions

Electricity markets follow a daily demand pattern with the highest demand levels around noon and in the evening while night time demand is significant lower. Especially those peak demand hours can lead to an aggravation of congestion in the network. We therefore focus on such a peak setting to analyze the resulting price differences in Europe. We shift the demand level by 30% while keeping the same linear demand functionality as in the basic scenarios.

Not surprising the demand increase during peak times leads to a higher price level. In 2010 we observe an about 23% higher price in all three scenarios. However, in 2030 and 2050 the price increase is more pronounced in the EU6 and EU10 scenarios (Table 3). This is a result of the different RES share in the scenarios. As RES generation cannot be ramped up when demand increases any increase needs to be covered by conventional units. In the EU1 scenario conventional units already cover a large share of demand under average conditions and consequently set market prices in most regions. During peak conditions this setting does not change drastically. On the contrary in the EU6/EU10 scenarios the demand increase requires to ramp up conventional units in regions that could be satisfied with RES and nuclear generation under average conditions; consequently the price increase is more pronounced. Nevertheless, the overall price level in the EU6/EU10 scenario is still lower under peak conditions in 2030 and 2050 than in the EU1 scenario.

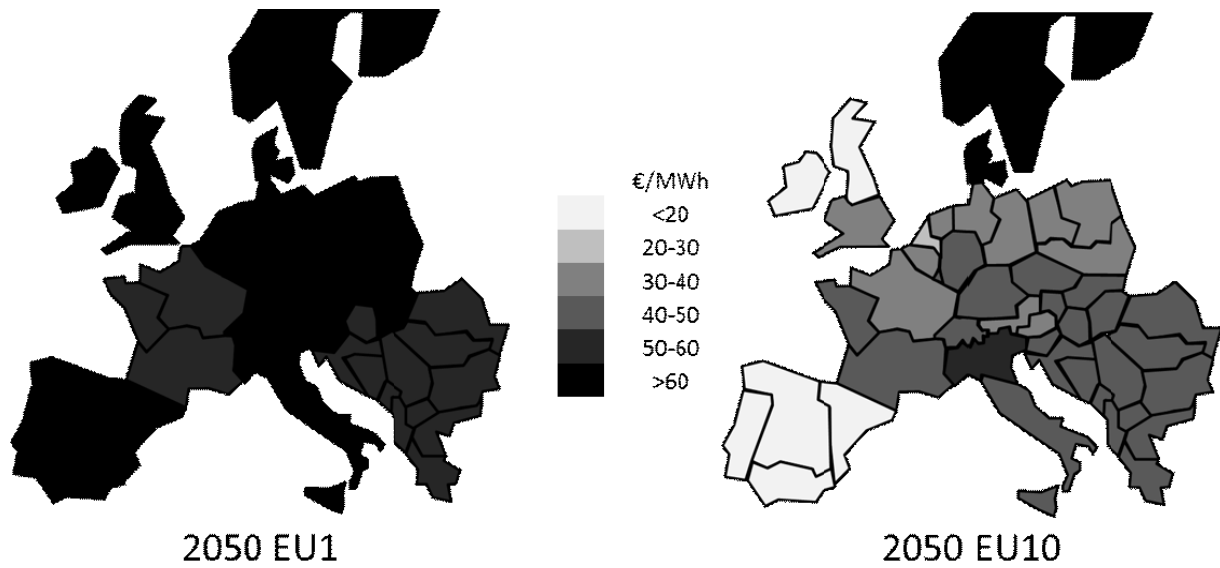
These aspects also translate into the overall network congestion level. Especially in 2050 the EU6/EU10 scenarios show a higher congestion rent in the system than the more fossil based EU1 scenario despite the about 40% lower price level. This is due to the fact that in the EU1 scenario prices are high all over Europe while in the more RES based scenarios the network is limiting exchange between regions with excess RES supply and import dependent regions that need to switch to local

⁸ On the distribution level the actual hourly demand does have significant impacts on network utilization.

⁹ The results are obtained by using the simulated natural gas market prices as fuel input prices for the electricity market model.

conventional plants (Figure 4). The high share of fossil generation also sets the congestion development in the 2010 cases. While prices are higher during peak conditions the congestion rent actually declines in all three scenarios. As peak demand requires a ramp up of local fossil plants while RES and nuclear plants are already at their maximum output the price in each region is equalized and thereby reduces the actual dependence on import and export while at the same time the overall price level increases.

Figure 4: Peak load price levels, 2050, EU1 and EU10



4.2. Impact of high RES injection

Similar to the load dependence, the availability of RES generation, too, has a significant impact on plant dispatch and thereby network conditions. We focus on the influence of intermitted solar and wind injection as biomass normally provides a base load profile. The two test cases represent a high wind input and a high solar input setting, respectively, while demand and all other input parameters are kept at the average level.¹⁰

Due to the merit order effect the resulting market prices in case of high RES input are lower compared to the average market conditions (compare Table 2 and Table 4). As the underlying wind capacities

¹⁰ For the high wind input case we assume an availability of onshore wind capacities of 70% and for offshore of 90%. For solar we assume an availability of 60% for photovoltaic systems and 80% for CSP plants.

are larger than the solar capacities also the impact of a high wind case on market prices is larger. And since the EU6/EU10 scenarios have an overall larger increase of RES capacities compared to the EU1 scenario the impact of high RES availability is also more pronounced in those scenarios.

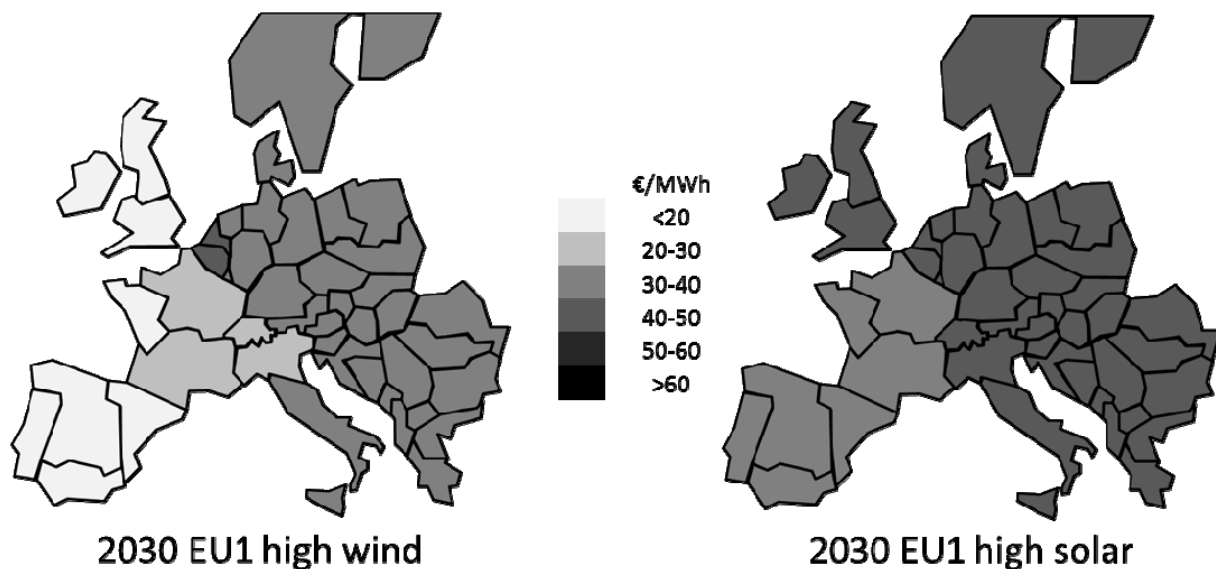
A higher RES input also leads to a higher congestion rent in the system, as the geographical diverse input cannot be equalized within Europe leading to RES induced low price regions versus high price regions depending on fossil generation. The exceptions are 2010 which for all scenarios shows slight decrease in congestion rent and the 2050 EU10 case. In the 2010 setting the RES share is still rather moderate and an increase in the availability helps to reduce import requirements for the existing high price regions.

In the 2050 EU10 case the share of RES is basically 100% and thereby all market prices are reduced to zero cancelling any congestion rents although there are still lines at their capacity limit. This case also highlights the 'oversupply' in case of high RES availability in the EU6/EU10 scenarios in the long run. Given the available capacities in both RES cases a share of the generation cannot be accommodated by the system. In the EU10 case this is more pronounced with about 50% of the available wind and 30% of the solar generation not utilized in the example cases (Table 4).¹¹

Given the higher installed wind capacities it is not surprising to find that high wind availability leads to a more widespread price reduction than solar availability by 2030 (Figure 5). Due to its high wind share, good geographical conditions for solar energy, and the limited transmission capacities towards France Spain is a low price region in nearly all cases. In the high wind settings especially Western Europe faces a significant price reduction due to its offshore capacities whereas in high solar settings the North cannot benefit as much.

¹¹ The model does not include a feed-in guarantee for RES generation, thereby limiting the impact on network congestion compared to current regulations in some European countries (e.g. Germany).

Figure 5: Electricity price levels, 2030, EU1, high wind and solar injection



Examining the load flow pattern in more detail some trends can be identified. The average load level of the transmission lines declines till 2050 for all scenarios. The wind cases show the highest load level indicating the highest divergence between generation and demand regions. Finally, the peak load flow pattern is more or less an amplified version of the average load pattern for all scenarios; congested lines are largely similar in all cases throughout the years.

Under high wind conditions particular lines in and around Germany, the UK, and between Spain and France represent bottlenecks. This holds for all scenarios. On the contrary, high solar injection has different impacts depending on the underlying scenario. In the EU1 scenario the resulting congestions is similar to the average setting. This effect is largely based on the still relatively low share of solar based generation in relation to other types. Even in the 2050 case only 30% of the RES injections are solar based in the high solar example while in the high wind example about 70% of RES injections are wind plants.

In the EU6 scenarios the increase in solar capacities is higher and therefore their impact on power flows. This leads to a higher stress of lines in Italy in addition to the congestion on Spanish connections. Despite the even higher installed solar capacities in the EU10 scenario in 2050 the impact on power flows is reduced. This is due to the higher share of PV in all regions that reduces local demand and the need for imports.

Summarizing the overall results for the electricity market we can conclude that expected developments can largely be confirmed: the increase of RES generation leads to a price reduction, the net-

work extensions favours price convergence, and finally, although congestion still remains till 2050 it will neither be more problematic than what we can observe in the current market settings nor will it shift towards regions not already addressed in current extension plans.

5. Impact of Gas Market on the Electricity System

The basic results have already shown the interdependence of the European natural gas and electricity markets; e.g. the higher share of gas fired plants in the EU6 scenario keeps gas prices above the EU10 correspondents. Despite those long term effects on prices also more short term impacts can influence the plant dispatch and resulting market prices. Given the import dependence of the European natural gas market, changes in the supply situation can feedback into the electricity market.

To test the robustness of the different scenarios with respect to external market shocks we analyze two supply interruption cases: First, a supply stop from North African gas suppliers and second, a supply stop of Russian gas via the Ukraine and Belarus while direct connections to the EU remain open (i.e., North and South Stream). In the first shock, both the pipeline and the LNG exports are disrupted, simulating a similar situation than during the Arab Spring. This disruption will potentially have a strong effect on the South European importers which strongly rely on natural gas in their electricity generation and are hardly interconnected with the rest of the European natural gas network.¹² The second shock reminds of the recurrent gas disputes between Russia and its transit countries Ukraine and Belarus (e.g. winter 2005/2006, winter 2008/2009). Given the strong dependence of East European countries on natural gas imports from Russia and the lack of possibilities to import from other sources, such a shock is likely to have a high impact in East Europe. However, after the gas disputes of the last years, the installation of reverse flow capacities that allow for West-East gas flows (opposite the traditional direction from Russia to the West) has increasingly been undertaken and is included in the network dataset starting from 2015 on.

Overall the two supply shocks produce similar market reactions in the 2010 model period. The Russian interruption is more severe, as the North Stream and South Stream options are not yet available. This effect reduces in subsequent years as Russia simply bypasses its transition countries via the Bal-

¹² See Lochner and Dieckhöfner (2012) for a disruption analysis of the North African suppliers focusing only on the natural gas sector.

tic Sea (North Stream) and the Black Sea (South Stream). On the other hand, the North African supply shock leads to a stronger decline in gas fired electricity generation as particularly Spain has a high share of gas plants that depend on imports from Africa.

In the future decades the impact of the supply shock is greatly diverse for the three scenarios. In the EU1 scenario the supply shocks always lead to a significant price increase on the natural gas market while electricity prices only experience a slight increase (Table 5). The latter is due to the relatively low average share of gas fired plants in this scenario as coal units are more competitive, regardless of the gas supply condition. On the natural gas market the demand decline is in the range of 3% to 5%. Overall the shortage of Russian gas is less severe in 2030 and 2050. This is due to the fact that gas supplies from Africa are largely consumed in South Europe and thus can hardly be replaced by other trade options beside LNG imports. As the latter are already heavily utilized under average conditions a shortage of African supplies leaves South Europe with less gas to consume. On the other hand the shortage of Russian gas via Belarus and the Ukraine leads to a reduction of availability in Eastern Europe which can partly be compensated by the reallocation of imports in Central Europe. By increasing LNG imports in the UK and shifting Norwegian gas for the UK towards continental Europe, using Germany as a distribution hub towards East and South East Europe, a large share of the disruption can be countered.

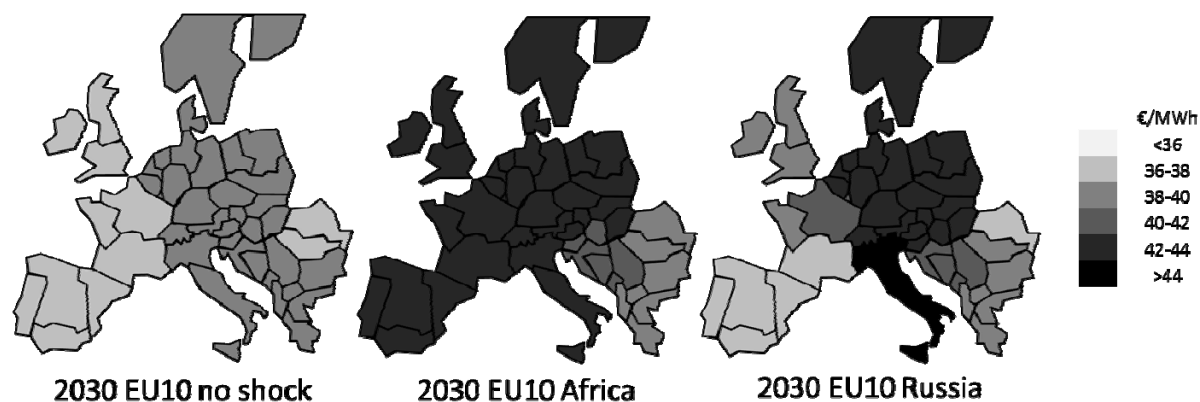
In the EU6 scenario the share of gas plants in the electricity dispatch is the highest and consequently the impact of a gas supply shortage on electricity markets is also more distinctive than in the other two scenarios. In 2030 the electricity gas demand falls by 80% and subsequently the electricity price increases by about 20% (Table 5). On the other hand the demand on the natural gas markets (for other usages like heating) slightly increases. Again the UK plays a crucial role: its large share of gas plants, coupled with its excessive LNG capacities, and import pipelines from Norway allow a flexible switching to the benefit of the continental European market. By freeing up LNG capacities (African case) or Norwegian imports (Russian case) they help to keep the impact on the gas market modest while at the same time their island nature limits feedback effects within the electricity network. In 2050 the overall gas demand has declined so far that a supply shock only induces small impacts in both markets.

In the EU10 setting Europe's gas demand is declining, thereby reducing the impact of supply shocks. Similar to the EU6 scenario in 2030 both shocks lead to a decrease of gas consumption in the electricity sector and a subsequent increase of gas demand in the natural gas market (Table 5). The sum of both is still 4% lower than without the shock but the case again highlights the interdependence of both markets. Looking in more detail at the electricity market we can observe a clear distinction between

both interruption cases. In case of a shortage from Africa, gas fired plants in South Europe and large parts of Western and Central Europe are shut down while South-East Europe is continuously supplied via South Stream limiting the price impact in that region (Figure 6). In the Russian case mainly East Europa is affected as well as Central Europe, in which most of the reallocation of gas supplies from Norway and North-Stream takes place. The Iberian peninsula as well as South East Europe are only slightly affected as their supply foundation (Africa for the former, South-Stream for the latter) are not interrupted and their interconnection towards Central Europe are limited (Figure 6).

Finally, in 2050 demand is so low and gas utilization in the electricity sector basically not relevant anymore that the existing infrastructure is capable to compensate both supply interruptions without significant price effects.

Figure 6: Electricity prices in dependence of gas supply shock, EU10, 2030



6. Conclusions

The interdependence between natural gas and electricity markets is a major development of current energy markets, in all regions of the world. In this paper, we have applied a model that looks at natural gas and electricity simultaneously, and apply it to the scenarios for European decarbonization at the horizon 2030/2050. The new modeling approach of “combining” energy markets clearly leads to insights that go beyond the traditional, sector-specific approach.

Summarizing the model simulations of the development of the European gas and electricity markets we can draw some general conclusions. First, the planned extension of the existing network infrastructure both in the electricity and gas system will help to keep congestion on moderate levels on average.

However, especially in the electricity network the timing of those extensions and the actual scale of the carried out projects is uncertain. Experiences with current extension projects show long timeframes until the projects are finally realized (e.g. the Austrian extension of the 380kV ring) and increasing resistance to new projects (the NIMBY problem). So, if some of the assumed extensions are delayed or cancelled the congestion situation is likely to be more pronounced than in the simulations.

Second, although the European natural gas market will remain import dependent the supply situation is moderate and congestion plays only a minor role. Especially the North-Stream pipeline helps to increase the availability of gas in Central Europe and thereby leads to an equalization of prices throughout Europe. Coupled with the moderate or even decreasing demand assumptions the long term question of the gas market may even shift to questions about a decrease in transmission capacities. Although, this is strongly coupled to the development of the role of gas in the electricity market which is governed by the third main insight: the future European electricity supply tends to be lower carbon-intensive. Regardless of the underlying scenario if the 2050 emission targets are to be kept, fossil plants without CCS will phase out. However, even if CCS options are in place the increasing share of RES will gradually push those to the margin. The crucial question is the timing of this process but not the result that conventional generation will be phased out in the long run.

This development has a central impact on the gas market. In case of ambitious environmental policies and a fast RES deployment (EU10) the role of gas is gradually minimized thereby freeing up gas infrastructure capacities for increased gas demand in other sectors. However, given stringent emission restrictions these demand options may not be attractive and we will face excess capacity in the gas sector. If the environmental restrictions are only gradually extended and RES deployment grows moderately (EU1), fossil generation will play a more prominent role in the electricity market. Under those conditions gas has to compete with coal if CCS technologies become available, nullifying the low emission advantage of gas.¹³ The shares of different fuels then strongly depend on the market prices of those fuels. Finally, in an in-between situation (EU6) gas may indeed play a crucial role, as the emission policy can lead to a lower general gas demand and thereby lower gas prices in Europe, while at the same time the RES deployment is not fast enough to render fossil fuels obsolete till 2050. Given this framework gas plants can benefit from low prices in Europe which may increase their share in generation compared to CCS coal plants.

¹³ The higher flexibility of gas plants is still an advantage but given the increase in wind and solar forecast reliability this may be less important in day-ahead dispatch decision and be limited to balancing service.

Concluding, we can say that the future development in Europe will be more characterized by the general political framework whereas locational aspects due to the network structure play 'only' a secondary role. However, this general framework still provides a wide range of potential development paths.

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8. Appendix

Table 1: Basic market results, natural gas

	2010	2020	2030	2040	2050
EU 1					
Price [€/MWh]	19.58	19.91	21.57	24.60	28.72
Gas Demand [GW]	801.10	834.96	813.67	798.14	780.46
Elec. Gas Demand [GW]	61.32	79.87	24.80	17.43	11.31
Pipeline Import [GW]	319.52	367.46	390.16	402.64	425.10
LNG Import [GW]	204.93	259.53	191.87	171.22	137.51
EU Production [GW]	337.97	287.82	256.44	241.70	229.15
EU 6					
Price [€/MWh]	25.89	16.85	16.76	16.30	14.57
Gas Demand [GW]	820.63	789.38	762.21	707.61	572.40
Elec. Gas Demand [GW]	47.45	91.45	83.99	82.80	87.61
Pipeline Import [GW]	321.60	361.25	375.84	347.36	253.95
LNG Import [GW]	208.42	228.18	207.34	199.98	177.30
EU Production [GW]	338.06	291.40	263.01	243.07	228.77
EU 10					
Price [€/MWh]	26.01	16.89	16.82	13.84	12.13
Gas Demand [GW]	821.43	791.61	733.63	637.60	481.17
Elec. Gas Demand [GW]	47.56	93.22	82.75	16.39	1.74
Pipeline Import [GW]	322.13	364.10	357.35	242.13	161.16
LNG Import [GW]	208.80	227.78	198.49	166.45	87.88
EU Production [GW]	338.06	292.95	260.54	245.41	233.87

Table 2: Basic market results, electricity

	2010	2020	2030	2040	2050
EU 1					
Price [€/MWh]	31.60	39.79	47.45	48.00	49.68
Demand [GW]	323.27	359.24	360.39	383.13	408.76
Congestion Rent [mn/h]	0.29	0.12	0.02	0.23	0.19
RES Share	29%	44%	56%	59%	59%
Gas Share	10%	12%	4%	2%	1%
Coal Share	29%	15%	12%	10%	10%
Nuclear Share	32%	28%	28%	29%	30%
CCS Share of fos. Gen.	0%	2%	11%	98%	98%
EU 6					
Price [€/MWh]	32.91	37.09	44.14	34.26	24.91
Demand [GW]	324.76	371.43	369.62	445.56	483.67
Congestion Rent [mn/h]	0.48	0.10	0.04	0.00	0.07
RES Share	30%	46%	63%	67%	71%
Gas Share	8%	14%	13%	10%	10%
Coal Share	28%	13%	0%	3%	3%
Nuclear Share	34%	27%	23%	19%	17%
CCS Share of fos. Gen.	0%	2%	3%	100%	100%

EU 10					
Price [€/MWh]	33.38	37.04	38.20	33.07	15.56
Demand [GW]	323.49	370.92	392.70	452.80	502.14
Congestion Rent [mn/h]	0.50	0.10	0.05	0.14	0.60
RES Share	30%	46%	67%	85%	94%
Gas Share	8%	14%	12%	2%	0%
Coal Share	29%	13%	2%	1%	1%
Nuclear Share	33%	27%	18%	12%	5%
CCS Share of fos. Gen.	0%	2%	2%	100%	100%

Table 3: Load impact on electricity markets

Load Condition:	EU1		EU6		EU10	
	Average	Peak	Average	Peak	Average	Peak
2010:						
Price [€/MWh]	31.60	38.87	32.91	40.83	33.38	41.16
Demand [GW]	323.27	399.65	324.76	398.48	323.49	397.86
Congestion Rent [mn/h]	0.29	0.20	0.48	0.36	0.50	0.35
Conventional/RES-Ratio	71/29	77/23	70/30	76/24	70/30	76/24
2030:						
Price [€/MWh]	47.45	56.59	44.14	55.95	38.20	48.30
Demand [GW]	360.39	457.89	369.62	454.75	392.70	482.57
Congestion Rent [mn/h]	0.02	0.21	0.04	0.24	0.05	0.13
Conventional/RES-Ratio	44/56	56/44	36/63	48/52	32/67	46/54
2050:						
Price [€/MWh]	49.68	63.55	24.91	36.35	15.56	37.25
Demand [GW]	408.76	499.88	483.67	577.55	502.14	568.11
Congestion Rent [mn/h]	0.19	0.42	0.07	0.42	0.60	1.63
Conventional/RES-Ratio	41/59	52/48	30/71	40/60	6/94	14/86

Table 4: RES impact on electricity markets

High RES Injection:	EU1		EU6		EU10	
	Wind	Solar	Wind	Solar	Wind	Solar
2010:						
Price [€/MWh]	29.66	31.05	30.80	32.35	30.96	32.94
Congestion Rent [mn/h]	0.29	0.28	0.36	0.46	0.37	0.49
Un-dispatched RES	0%	0%	0%	0%	0%	0%
2030:						
Price [€/MWh]	26.69	43.77	17.44	39.60	11.45	29.64
Congestion Rent [mn/h]	0.45	0.19	0.60	0.32	0.85	0.23
Un-dispatched RES	0%	0%	0%	0%	4%	0%
2050:						
Price [€/MWh]	25.04	39.38	7.37	12.17	0.00	1.36
Congestion Rent [mn/h]	0.48	0.40	0.72	0.35	0.00	0.08
Un-dispatched RES	0%	0%	13%	3%	48%	29%

Table 5: Impact of shocks in the natural gas market

Gas Shortage:	EU1			EU6			EU10		
	None	Africa	Russia	None	Africa	Russia	None	Africa	Russia
2010:									
Gas Price [€/MWh]	19.6	25.5	32.1	25.9	34.8	43.8	26.0	35.0	44.0
Gas Demand [GW]	801.1	746.6	645.0	820.6	750.5	649.3	821.4	750.3	648.7
El. Gas Dem. [GW]	61.3	6.4	35.4	47.4	6.6	36.5	47.6	6.9	34.3
Elec. Price [€/MWh]	31.6	36.6	34.8	32.9	36.1	34.3	33.4	36.4	34.6
2030:									
Gas Price [€/MWh]	21.6	31.8	28.9	16.7	22.7	23.6	16.8	19.3	19.5
Gas Demand [GW]	813.7	777.4	791.1	762.2	774.4	769.5	733.6	758.7	749.5
El. Gas Dem. [GW]	24.8	9.7	8.9	84.0	15.7	15.7	82.7	24.1	36.7
Elec. Price [€/MWh]	47.5	49.8	49.9	44.1	51.9	51.6	38.2	42.3	41.1
2050:									
Gas Price [€/MWh]	28.7	40.8	41.5	14.6	15.3	15.3	12.1	12.4	12.2
Gas Demand [GW]	780.5	748.0	750.0	572.4	573.8	578.8	481.2	480.3	480.9
El. Gas Dem. [GW]	11.3	3.0	2.46	87.6	79.8	67.0	1.7	1.7	1.7
Elec. Price [€/MWh]	49.7	50.6	50.6	24.9	25.9	27.3	15.6	15.6	15.6



Addressing Gas Dependence

July, 2012

This paper reviews the reliability issues posed by New England's increasing dependence on gas-fired generators, and proposes a number of solutions to mitigate the risks.

Section 1: Introduction and Executive Summary

In the fall of 2010, ISO New England (ISO-NE) launched a Strategic Planning Initiative to focus the region on developing solutions to five identified risks to the continued reliable, efficient operation of the bulk power system and wholesale electricity markets. One of these risks is related to increased reliance on natural gas-fired capacity. Addressing this risk has become a priority, given the reliability challenges that are already in evidence, as described below.

ISO-NE described the risk as follows:

Increased Reliance on Natural Gas-Fired Capacity, related to the risk to the New England electric system associated with reliance on natural-gas-only resources, as sufficient gas may not be available to meet power system needs during periods of very high seasonal demand, under other stressed system conditions, or when facing contingencies associated with natural gas supply/transportation system infrastructure.

In fact, gas dependence is a reality and is increasing for a number of reasons, including low gas prices. Given these low prices, generators are using Marcellus shale gas where possible to reduce their costs, which, in turn, results in low wholesale prices that ultimately benefit consumers.

While the increase in gas-fired generation has economic, environmental and operational benefits that the region wants to preserve, these benefits come at a cost. Specifically, given current and anticipated levels of gas usage, potential gas unavailability threatens the reliability of the electric system due to the limited-capacity pipelines used to transport gas, potential gas supply interruptions, and the “just-in-time” nature of the resource.

The reliability risks are also attributable to the difference between gas and electric system operational requirements and market mechanisms. For example, the gas system is designed to meet the needs of firm contract holders (typically the Local Distribution Companies), which draw more slowly and predictably from the pipeline system than generators. On the market design side, the electricity markets currently do not have sufficient incentives for generators to choose “firm” (non-interruptible) contracts for gas delivery; however, non-firm customers (typically gas generators) can be interrupted if there are issues meeting gas demand, which leads to electric reliability issues. All of these factors, and examples of the related reliability consequences, are detailed in Section 3 below.

To maintain the benefits provided by the increasing utilization of gas-fired generation, ISO-NE believes that the region must acknowledge the significant role that the natural gas transmission system now plays in the New England electricity system – and the associated challenges. In other words, both the gas and electric industries must make adjustments to ensure the reliability of both systems and the efficiency of both markets.

As described in Section 4, ISO-NE has identified a set of solutions to pursue with stakeholders. These include long-term changes to the Forward Capacity Market and the Forward Reserve Market to create better incentives for generators to perform in accordance with their operating characteristics. Generators may achieve this performance by making alternative firm fuel arrangements, such as investing in oil inventory, or entering into firm gas transportation contracts. The latter may, in turn, encourage pipeline expansion, thereby addressing current pipeline limitations.

In the short-term, to ensure reliability in the period before the changes to the Forward Capacity and Reserve Markets can improve performance incentives, ISO-NE is proposing to engage in a supplemental procurement to ensure that oil and gas generators maintain adequate levels of firm fuel capability. This is necessary to mitigate the immediate risks posed by the current system constraints, as described in this document, and to ensure that there are sufficient resources available to respond to dispatch instructions, particularly under stressed power system or gas system conditions.

ISO-NE also proposes enhancements to the flexibility of the electricity markets by changing the rules to permit generators to modify their offers intra-day to reflect fuel costs, and by moving the timing of the Day-Ahead Market to better coordinate with the gas industry's timelines. These changes are intended to address the divergence between generators' commitments and gas nominations, which often result from the uncertainty generators face in acquiring gas before they know their generation commitment and dispatch. These changes will also provide the ISO control room with necessary information on a timely basis to operate the power system reliably.

Finally, ISO-NE would like to address the problems created by the short notice of pipeline maintenance and supply disruptions, which are of particular concern given the start times required by many of the non-gas fired generators in New England. To facilitate better information flow, ISO-NE proposes to require more information from generators regarding their fuel status, thereby improving the accuracy of supplemental generation commitments and allowing ISO-NE to provide data on specific generator commitments to the pipelines. In addition, ISO-NE will seek better information on gas pipeline maintenance in order to enhance the accuracy of the day-ahead unit commitment process and to continue coordination efforts with the gas pipelines.

Like all market structures, New England's wholesale electricity markets must be dynamic in nature, by keeping pace with changing conditions, such as fuel sources, generation advances and fuel diversity. As this paper highlights, a decision to act on changes to markets to adjust for the characteristics of natural gas delivery must be made in the near future to ensure ongoing reliability.

While ISO-NE is willing to lead this market evolution, there are limits to what ISO-NE, alone, can achieve. ISO-NE should signal its performance expectations to generators through its market design and make appropriate adjustments to optimize the use of available infrastructure. This will give generators the incentives to seek firm fuel supplies. The gas industry has an opportunity to be the provider of that firm fuel by improving the services it offers to the electric system, including considering changes to the gas day to better align with the electric day load cycle, and improving the range of services offered to generators. Still others, including the Federal Energy Regulatory Commission, the States and Local Distribution Companies, will have a role to play. For example, the States could require regulated entities, including Local Distribution Companies, to invest in additional storage, pipelines, or firm contracts, and recover those costs by charging generators for those services.

ISO-NE recognizes that all of these changes will require a significant commitment from the region, and looks forward to reviewing this paper with stakeholders as a first step in that process.

Section 2: New England’s Gas Dependence

During the 1990s, the region’s electricity was produced primarily by oil, coal and nuclear generating plants, with very little gas-fired generation. In 1990, oil and nuclear generating plants each produced approximately 35% of the electricity consumed in New England, whereas gas-fired plants accounted for approximately 5%. Coal plants produced about 18% of New England’s electricity.

In contrast, by 2011, oil-fired plants produced 0.6% of electricity consumed in New England, and approximately 51% was produced by gas-fired generation. Coal production also fell by about two-thirds. Currently, during median load periods, nearly the entire fleet of dispatchable resources is made up of gas-fired generators, and a portion of the quick-start generators that would be called to respond to a loss of generation is also dependent on the same supply of natural gas.

The shift to gas-fired generation is largely attributable to the price of generating electricity with gas, which is now much lower than oil or coal-fired generation.

Current gas industry estimates are that North American shale gas reserves hold a 100-year supply; this increase in supply has pushed natural gas futures prices on the NYMEX to 10-year lows. Moreover, production from the Marcellus shale region in Pennsylvania and New York has moved significant amounts of gas supply much closer to the New England region, alleviating the need for long-haul pipeline transport from the traditional production regions near the Gulf of Mexico or western Canada. The low price of gas and its increased use by generators have resulted in a dramatic reduction in total wholesale market costs, from nearly \$13 billion in 2008 to approximately \$7.6 billion in 2011. In the first six months of 2012, these costs are about \$2.6 billion.¹

In addition to the ample, low-cost supply of natural gas, other factors will contribute to the continuing dominance of natural gas-fired generation in New England’s fleet. These include the addition of variable energy resources on the system, which will require greater flexibility in other generation resources to regulate the system. Moreover, the region’s older oil-and coal-fired power plants could opt for retirement in the near future due to market pressures and the costs of complying with environmental regulations.

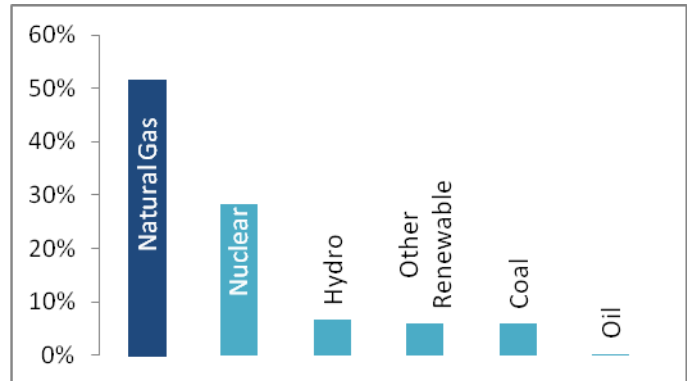


Figure 1-- 2011 Energy Production

Section 3: Resulting Electric Reliability Issues

Over the past ten years, as the region’s dependence on gas has increased, so have the reliability challenges. These challenges exist not only because of the lack of diversity of fuel sources, but also due to the “just-in-time” nature of the natural gas supply chain. In other words, New England generators have migrated away from on-site fuel storage in the form of oil and coal, where disruptions in fuel delivery chains were able to be coordinated over days and weeks. Generators are now dependent on just-in-time fuel delivery from the gas pipelines, and limitations or interruptions in this supply chain have an immediate impact on the operation of the power system.

¹ These figures come from the Internal Market Monitor’s Markets Reports. Total wholesale market costs are the sum of energy costs, Net Commitment Period Compensation, and the costs of the regulation, reserves and capacity markets.

As discussed below, the challenges are exacerbated by the insufficient market incentives for firm gas contracts, pipeline limitations, generator commitments and dispatch that do not match fuel nominations, timing differences between the gas and electric industries, gas supply disruptions, and pipeline maintenance.

Non-Firm Contracts

Natural gas is sold through brokered markets, and, in a separate transaction, is transported through an interstate pipeline system. The pipelines offer a number of transportation services that vary in priority (and expense). The charges for these services are based on tariffs that are approved by the Federal Energy Regulatory Commission and provide regulated rates of return to pipeline owners.

The pipelines sell most of their highest priority, most expensive “firm” pipeline capacity to Local Distribution Companies (LDCs). Each day, the capacity that is not utilized by the LDCs and other firm customers is available for purchase.

Currently, although generators have an obligation to perform in accordance with their offers and their declared operating characteristics, the performance incentives in the wholesale electricity market design are not strong enough to cause generators to procure firm fuel supplies – gas or oil – and to operate in accordance with their obligations. Until recently, these generators have largely been able to meet their obligations under normal operating circumstances, i.e. when the power or gas system is not stressed, without firm fuel. Currently, however, when conditions become constrained or there isn’t operating flexibility on the gas pipeline,² the interruptible generator customers may not be able to secure fuel to operate in accordance with their operating characteristics to meet the firm electrical demands of the grid. These fuel limitations generally happen with little time for electric system operators to adjust, and can affect the reliability of the power system.

Gas pipeline industry representatives have made clear that electric system reliability is threatened so long as generators continue to rely only on less expensive, interruptible “non-firm” gas transportation, and that the pipelines will not hesitate to solve their operational problems by interrupting these customers. In fact, New England’s first major issue with the availability of gas-fired generators occurred when pipelines interrupted non-firm customers, including gas-fired generators, in January 2004 during severe winter weather and record electricity demand. Gas prices spiked, but generators that could get gas had no mechanism to update their electricity offers to reflect the higher intra-day fuel prices. As a result, wholesale electricity prices were generally below break-even levels for even the most efficient gas-fired generators buying gas in the spot market.

Pipeline Limitations

During their peak winter days, the pipelines are fully utilized with not enough infrastructure to meet the needs of the gas-fired fleet. Even on non-peak days, both the Tennessee and Algonquin pipelines, which supply lower-cost gas from the Marcellus shale region, are often loaded to capacity to meet generator needs in New England. This concentration places more pressure on the pipelines.

In a study last year, ICF International confirmed ISO-NE’s concerns about pipeline limitations.³ The study assessed the capacity of the natural gas pipelines to supply generators under winter and summer design conditions looking out several years, and concluded that, “[i]n each of the scenarios and cases

² Much like the electric power industry, natural gas pipeline operators must balance injection and withdrawals to maintain reliable operations.

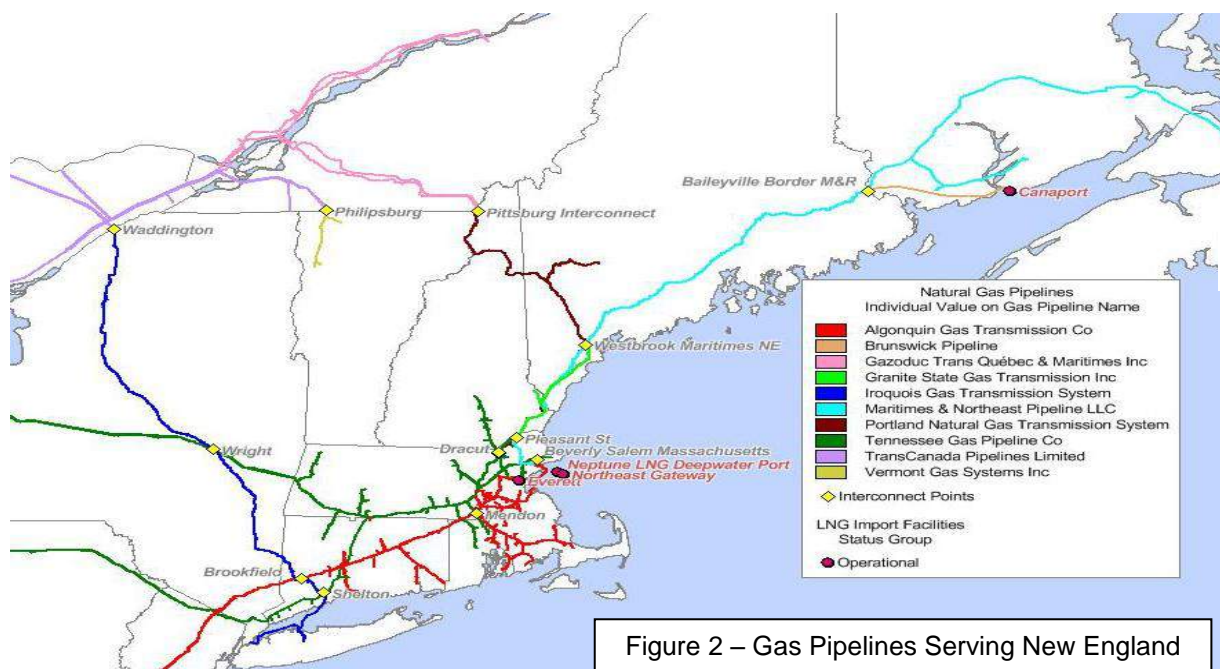
³ See the ICF report at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf.

examining gas supply and demand under winter design day conditions, there is not enough gas supply capability remaining to meet the anticipated power sector gas demand.”

The study also noted that the additional pipeline capacity that exists in non-winter periods, which is currently used by New England’s gas-fired generators, will diminish as the LDC load continues to grow. Notably, the study was conducted assuming that all pipelines are fully available in each scenario (i.e., no contingencies, maintenance, etc.) and that flows on the various pipelines are perfectly coordinated in order to maximize the throughput on the pipeline system. Given those assumptions and the use of theoretical maximums, ICF has acknowledged that the study overestimates gas availability.⁴

Input from regional pipeline companies and electric system operating experiences substantiate the study’s conclusions. The pipelines have confirmed that the pipes coming into New England from supply points to the west, including the Marcellus shale fields, are becoming constrained or operating near capacity in periods other than the winter. For example, as reported by the Algonquin Pipeline at its 2012 customer meeting, the number of days that the pipeline is restricted through the Crowell compressor station increased from a single day during the 2009/2010 winter to over a hundred days during the 2011/2012 winter. The Tennessee Pipeline has also experienced a significant increase in the number of days that the pipeline is restricted through compressor station 245 (upstate New York). Winter restrictions have increased from 42% during the 2009/2010 winter to over 99% of the days during the 2011/2012 winter. In addition, the Tennessee Pipeline has begun experiencing restrictions during the summer months. Specifically, summer restrictions have increased to 78% of the days in the summer of 2011. In contrast, in 2009, there were no restricted summer days.

Absent further expansion of pipeline capacity, New England will likely experience more limitations on gas delivery to generators and, during winter cold conditions, may experience more extreme disruptions, even with all supply sources fully committed.



⁴ ISO-NE is planning a second gas study that will aim to more realistically assess pipeline and gas availability.

Although the pipelines are at or near capacity, they will not expand until firm customers commit. Unlike the electric industry, which builds infrastructure in anticipation of demand, the gas industry requires signed contracts from firm customers before building or expanding pipeline infrastructure.⁵ In fact, the Federal Energy Regulatory Commission, which must approve pipeline projects, bases its decision that a pipeline project is in the public convenience and necessity in large part on the existence of firm contractual commitments. Accordingly, to the extent growth is due to gas-fired generation, pipelines will not expand to accommodate this growth unless the electricity markets provide generators with the incentives (comprising both revenues and penalties for non-performance) to support firm contracts in sufficient volumes to support pipeline expansion.

Conditions in January 2011 highlighted the vulnerability of New England’s bulk power system to the capacity limitations of the regional gas pipeline network. Beginning January 14 and continuing through January 24, cold weather conditions resulted in pipelines restricting gas availability to generators. On numerous occasions during this period, generators notified ISO-NE of their reduced ability to produce electricity and often subsequently placed themselves out-of-service due to a lack of gas supply.

Generator Commitments And Dispatch That Do Not Match Fuel Nominations

Based on system conditions, it may be necessary for gas-fired generators within New England to utilize more natural gas than they have nominated going into the operating day. To date, the design of the northeast pipelines has not included “no-notice” service. In general, the pipelines require that supply be procured and scheduled in advance to match actual consumption.

The overall impact of generators’ withdrawal of more gas than they have nominated depends on the operating conditions facing the pipeline at that time. On many days, the impact is minimal, if the pipeline has sufficient capacity to deliver the gas and time to recover from the over-draw before the next operating day. However, during periods of pipeline maintenance, outages or heavy system demands, the pipelines will have limited ability to meet additional demand.

In general, ISO-NE is only notified of a problem after it has issued dispatch instructions to the units. This notification generally comes from the gas pipelines and not the generator. For example, on the afternoon of December 10, 2010, without notice to ISO-NE, the gas pipelines had to reduce the supply of gas to generators within New England, equivalent to approximately 900-1000 MW. In particular, one pipeline reported serious problems with gas pressure with the potential to interrupt gas flow to certain generators due to gas-fired generators over-drawing their gas nominations. An additional 800 MW of gas-fired generation was at risk over the peak load hour due to questionable gas supplies.

The pipelines have repeatedly indicated that, due to the increased demands on their systems, they are now fully exercising their rights under their tariffs, and the use of flow control and valve shutoffs will be more common going forward when generators place the pipeline system at risk by over-drawing gas to meet their electric side obligations. In one such communication, on January 19, 2011, a representative of one of the gas pipelines held a conference call with gas-fired generators in New England and New York. The discussion focused on the low pressures caused by New England and

⁵ The media has reported on at least one potential new pipeline for New England. Spectra, the developer, has indicated that this project is in the marketing phase, during which prospective customers are contacted to gauge their level of interest and willingness to enter into firm contract commitments. Spectra has confirmed that the project will not proceed without these commitments.

New York generators over-drawing their scheduled gas from the pipeline. The pipeline representative stressed that the over-usage of gas was unacceptable and the pipeline would be taking more extreme actions to protect the reliability of the pipeline system, with the most serious of these actions being the actual closing of gas flow valves to the worst-offending power plants.

The pipelines have been true to their word. On January 19, 2012, ISO-NE committed approximately 250 MW of fast-start generation during the morning peak period. Approximately one hour later, the pipeline operator informed ISO-NE that the units had not scheduled gas and would be ordered off-line if gas was not scheduled. Fortunately, this order was coincident with the economic de-commitment of the generators.

On March 2, 2012, due to planned transmission outages in the Rhode Island area, gas-fired generation was ordered on-line to provide first contingency protection. These generators obtain their natural gas supply from the Algonquin pipeline. When another transmission line in the area had an unplanned outage, additional generation was required for contingency protection. The additional generator also obtained its gas supply from Algonquin. Extensive communications were required between ISO-NE and the generator to ensure that the necessary gas was procured. Before noon, the Algonquin pipeline issued a Critical Capacity Constraint notification due to high system demand and pipeline imbalances, requesting that all customers utilize only the gas that they had scheduled until further notice. At about the same time, the Tennessee pipeline, which also supplies gas to units in Rhode Island, issued an Operation Flow Order Balancing Alert for the New England area. Due to concerns about gas pipeline conditions, ISO-NE ordered additional non-gas fired generation on-line to maintain system operating reserves,⁶ and implemented an Abnormal Conditions Alert. The likelihood of post-contingency load shedding to protect the affected area's transmission system was high during this event; fortunately, ISO-NE was able to coordinate with the Tennessee pipeline to maintain gas supply to the necessary generators.

In addition to using more than their scheduled gas, generators also use gas in a different pattern than the pipelines expect. Gas pipeline operators evaluate their capability to deliver gas based on a generator utilizing 1/24th of its daily nomination in each of the hours of the gas day; however, peaking and other generators are often committed by ISO-NE to meet peak loads in the afternoon. Accordingly, a peaker may nominate gas for an entire gas day, but burn its allotted volume during a few hours in the afternoon.

While pipeline operators may be able accommodate the disparity between scheduled versus actual usage if the pipeline system has time to recover gas pressures, the pipelines in the northeast have not been designed for these imbalances. Absent non-ratable service requirements being planned and contracted (paid) for, the sudden ramps and shut-offs can cause pipeline pressures to vary significantly from hour to hour, thereby jeopardizing reliability to all other customers taking gas from the pipeline. These challenges will increase with the use of more variable energy resources, as gas generators are called to balance these intermittent resources. Even the best forecasts of wind generation will contain forecast error, and resources dispatched to provide balancing service will require a “bandwidth” or “swing” type of fuel supply contract.

Timing Differences Between the Gas and Electric Industries

As indicated above, generators are often not committing to the appropriate amount of gas, at the right times of the day. In part, this is due to the lack of harmonization in timing between the gas and electric industries.

⁶ Although outside the scope of this paper, it should be noted that commitment of these out-of-merit generators increases Net Commitment Period Compensation (uplift) and affects the accuracy of electricity prices.

On the electric side, ISO-NE commits generating units first through a financially binding Day-Ahead Market (DAM). The DAM is a forward market that operates one day prior to the delivery day, which is a standard 24-hour calendar day. The function of the DAM is to provide a mechanism for load and generators to hedge against real-time price volatility and to provide a base unit commitment schedule for the operating day.

At 10:00 a.m. on the day prior to the operating day, ISO-NE posts the hourly load forecast for the next operating day. At noon on the day prior to the operating day, the DAM bidding window is closed; all supply offers, demand bids, Increment/Decrement (virtual) offers, and external transactions that have been entered for the next operating day are fixed at this time. ISO-NE staff then has four hours to clear the DAM and post results by the standard deadline of 4:00 p.m.

The next step in ISO-NE operations is the Re-Offer period, which occurs after the DAM results have been published. The Re-Offer Period opens at 4:00 p.m. and closes at 6:00 p.m. During the Re-Offer period, generators not committed in the DAM can change their energy price offers in addition to changing their start-up and no-load costs. Generators that have been committed in the DAM can only change their energy price offers. One of the intents of the Re-Offer period is to allow updates for spot market fuel prices, which may have changed from noon to 4:00 p.m. The Re-Offer period also allows a generator not committed in the DAM to self schedule as a price-taker in the Real-Time Market.

Using the most recent energy price offers, ISO-NE next conducts the Reserve Adequacy Assessment (RAA) process. The purpose of the RAA is to ensure that sufficient capacity will be available to meet real-time energy demand, reserves and regulation requirements. The RAA process marks the final interface between DAM clearing and real-time operations. The initial RAA is published at 10:00 p.m., two hours prior to the start of the operating day, and is updated at intervals throughout the operating day, at 1:00 a.m., 5:00 a.m., 8:00 a.m., 12:00 p.m. and 5:00 p.m., with updates to real-time unit commitments as necessary to deal with unexpected events, including load forecast error, scheduling deviations in generation, and unplanned equipment (generation or transmission) outages, as well as contingency response.

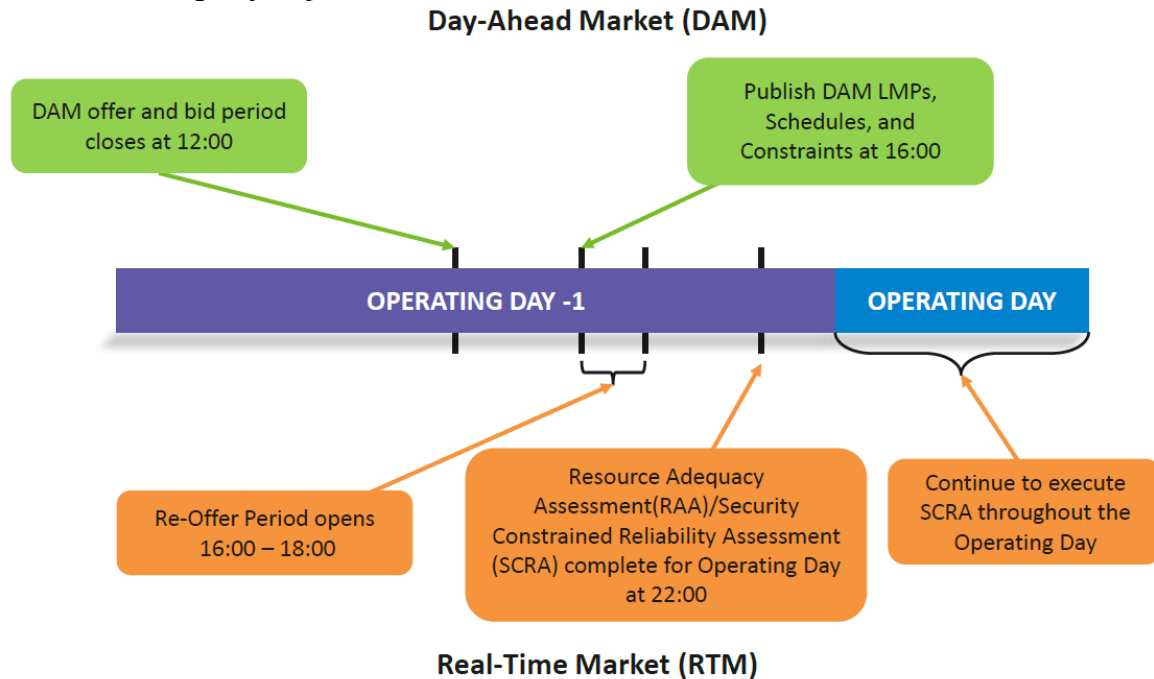


Figure 3 – Day-Ahead and Real-Time Market Timeline

The gas industry operates on a different set of time frames. As noted above, the purchase of gas is a separate transaction, generally through the brokered markets (e.g., Intercontinental Exchange) for the next gas day. The gas market is most liquid between 8:00 and 9:00 a.m. the day prior to the electric operating day.

Next, a generator must nominate (request) pipeline capacity to transport natural gas from one specified location to another over the gas day. Submitted nominations are confirmed and scheduled by the pipelines based on priority of service, available pipeline capacity and ability to maintain pressure within prescribed limits for reliable operation along the designated contract path.

Much like the electric industry, timelines are critical in coordinating natural gas flow from injection and storage to the end use customers. Natural gas transport is nominated and scheduled on a one-day advance basis, using a 24-hour gas day from 10:00 a.m. to 10:00 a.m. Eastern Standard Time. Nominations fall into three categories: Timely, Evening, and Intra-day. The timing of each nomination is detailed in Figure 4 below.

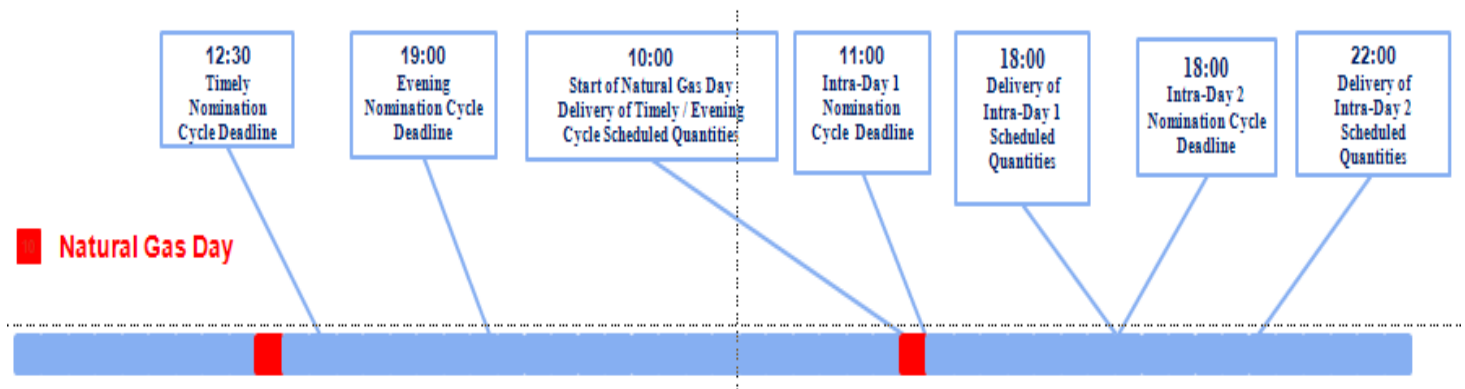


Figure 4 – Natural Gas Day and Nomination Timeline

Timely nominations give the strongest assurance to shippers that they will receive the nominated amounts of pipeline capacity throughout the next gas day, as long as they do not exceed the scheduled contract quantities. Under industry standards, firm customers that do not nominate their full entitlements during the Timely cycle effectively free up capacity for other shippers that have a lower pipeline service priority.

During the Evening nomination cycle (which occurs from 12:31 p.m. to 7:00 p.m.), “bumping” can occur. Bumping is the process by which a shipper with a higher priority can force its nomination to take precedence over a lower priority shipper’s nomination.

As the gas day progresses, the two remaining gas scheduling periods, Intra-Day 1 and Intra-Day 2, become windows of last resort with respect to nominating additional fuel as a result of a revised dispatch order from ISO-NE. In addition, gas trading does not typically take place over weekends and holidays, meaning generators must plan days in advance of weekends and holidays.

The disparate schedules used by the gas and electricity markets pose challenges for gas-fired generators. In New England, ISO-NE’s DAM closes at noon, with the results not posted until 4:00 p.m. – well after gas-fired generators must submit their initial gas demands (at or before 12:30 p.m. for the Timely cycle nomination deadline). In other words, to be assured gas delivery, generators must purchase and schedule gas before they know that they have been scheduled to generate electricity. Conversely, when the pipelines indicate that their systems will have constraints the next day, ISO-NE will not know which generators have a DAM obligation until 4:00 p.m.

DRAFT – FOR DISCUSSION

The RAA determinations are published at 10:00 p.m. (after the Evening gas nomination deadline of 7 p.m.). This can result in a situation where the resource is committed to generate, but is unable to procure the fuel in subsequent nomination periods. As result, the generator is unavailable, leaving ISO-NE little time to re-commit the replacement energy to reliably operate the system. As discussed below, the long lead-times required by non-gas generators exacerbate the reliability challenges.

Moreover, for each electric operating day, gas-fired generators must manage fuel procurement and scheduling spanning two gas days. For hours ending 11:00 a.m. through midnight, they can either purchase and nominate by the Timely cycle deadline the projected amount of natural gas they expect to use, or wait for ISO-NE's DAM results and then nominate their respective gas demands by the Evening cycle (7:00 p.m.), when there is a higher risk of not being able to schedule gas. For hours ending 1:00 a.m. through 10:00 a.m., they must rely on the Intra-Day nomination cycles from the previous gas day to schedule their fuel requirements in the overnight hours. There is an even greater risk of not being able to schedule the gas within the Intra-Day cycles. A comparison of the gas and electric days is shown in Figure 5, below.

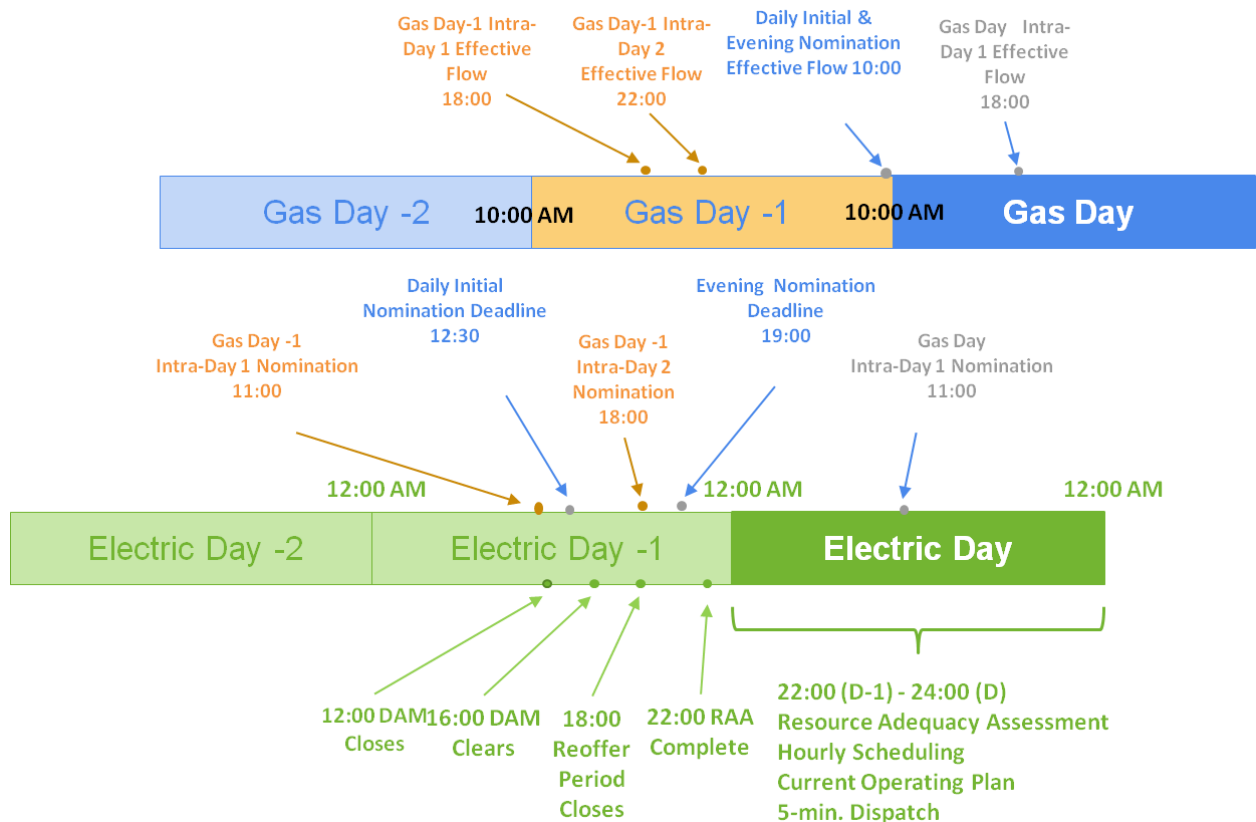


Figure 5 – Comparison of Natural Gas and Electric Days

A recent contingency on July 6 illustrates the challenges of the disparate gas and electric days. During the morning load ramp, ISO-NE was informed that two major pipelines in New England would be restricting generators. As this was the end of the July 5 gas day, the generators were unable to secure gas. A related factor, as described in the discussion of generator commitments that do not match nominations, was the generators' over-drawing earlier in the July 5 gas day. In sum, fourteen generating resources, totaling 3,800 MW, faced reductions of approximately 2,100 MW. Of the 2,100 MW of reductions, approximately 780 MW had cleared in the DAM and were unavailable for

real-time operation, while an additional 620 MW from resources committed in the initial RAA were unavailable for real-time operation. The remaining 700 MW were from market participants with offline resources who were alerting the ISO that they did not have gas to operate and those resources were unavailable and out of service.

Gas Supply Disruption

In the fall of 2005, the Gulf of Mexico was hit by two back-to-back hurricanes (Katrina and Rita). Almost 100% of both oil and natural gas production within the Gulf, both offshore and onshore, was shut-in. Despite the efforts by regional energy industries, access to a portion of the nation's energy supplies was crippled and slow to return to normal. Some production never made it back. While New England was spared the major impacts of the reduced fuel supply given the exceptionally mild winter, the storms did highlight our vulnerability in the event of a major gas supply disruption.

In November 2007, ISO-NE experienced reliability issues as a result of a temporary interruption to natural gas production at the Sable Offshore Energy Project, which is located approximately 200 km southeast of Halifax, Nova Scotia, above the deepwater oil and gas wells in the Scotian Shelf. The natural gas sector supply contingency significantly diminished natural gas injections into the Maritimes & Northeast pipeline and eventually caused several gas-fired electric power stations in Maine to go off-line due to the loss of fuel supply. As generators were reliant on this just-in-time fuel delivery system, Maine experienced electric capacity deficiencies. The loss of generation due to this fuel supply shortage came with no notice to ISO-NE.

Pipelines are able to operate with a temporary supply disruption, provided the gas pressures are maintained within acceptable limits. However, within a relatively short time, a major failure along an interstate gas pipeline could result in a loss of electric generating capacity that could exceed the electric reserves available to compensate for these losses. For instance, the Algonquin pipeline currently supports some 7,300 MW of summer capability and over 7,900 MW of winter capability, with over 3,800 MW having gas as a single fuel source. Local fuel inventory for gas generators (e.g. the capability to switch to oil or liquefied natural gas) will provide gas generators with a backup fuel option. Until the gas system issues have been fully addressed, the region will be reliant on non-gas generators (such as oil and coal units), or dual fuel gas units,⁷ to mitigate this risk.

Pipeline Maintenance

On occasion, gas-fired generators become unavailable due to pipeline inspections and maintenance. Pipeline outages tend to occur during the pipelines' off-peak season (summer) – which coincides with the peak season of the electric system. While pipeline maintenance outages are to be expected, issues have occurred both due to the timing of planned pipeline maintenance relative to high electric load conditions as well as short notice of pipeline outages.

During the week beginning June 6, 2011, several gas pipelines experienced issues related to the high electrical load coupled with pipeline maintenance, resulting in the imposition of restrictions on generators. A year later, during the week of June 4, 2012, ISO-NE was made aware of a pipeline inspection that could cause a capability reduction of the Algonquin pipeline, with effects ranging from immediate reductions of up to 65% capability to no reduction at all. In order to prepare for anticipated restrictions and potential interruptions of fuel supply to New England generators, ISO-NE committed 650 MW of non-gas-fired additional capacity to provide greater fuel diversity.

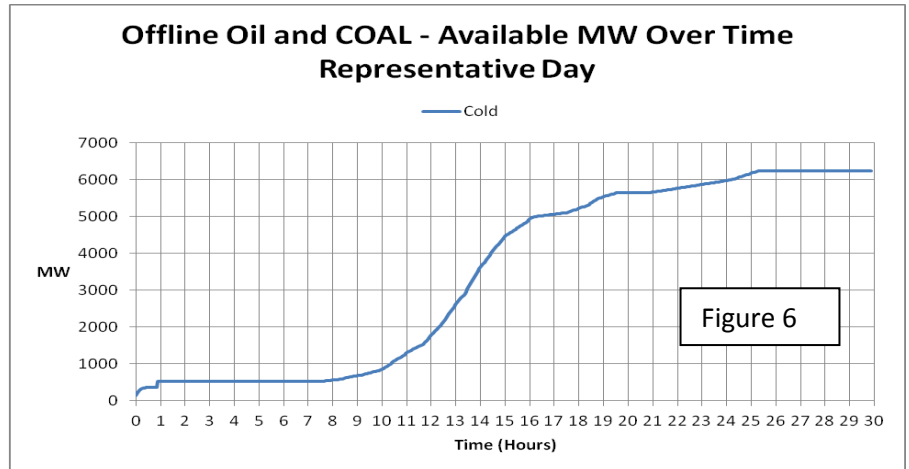
⁷ Dual fuel units have the infrastructure to allow a gas generator to switch to oil.

On June 29, 2012, as a heat wave approached, both gas pipelines from the west, Algonquin and Tennessee, were restricted due to ongoing maintenance. Due to the uncertainty of gas units being able to obtain additional gas or off-line units being able to get intra-day gas, operators committed a number of long-lead time oil and coal units. Spikes in gas prices highlighted that, even if gas were available, generators were not able to change their electricity offers to reflect increased gas costs.

Fortunately, in the examples above, ISO-NE had time to commit off-line oil- and coal-fired units, many of which require a significant amount of lead time to synchronize to the grid. As shown in Figure 6, there are approximately 6,000 MW of off-line coal and oil available to ISO-NE, of which only 500 MW is able to synchronize within 8 hours from a cold status.

When ISO-NE has insufficient notice of service interruptions, the system operator must take steps to ensure that either sufficient replacement production capacity with fuel has been committed to be on-line or sufficient quick start generation with on-site fuel or no-notice fuel delivery is available off-line. The confluence of short notice of gas service interruptions and

the long lead-times required by many non-gas generators to get on-line drives the electric system into emergency actions more quickly, potentially to the point of shedding firm load. This risk will be exacerbated if the non-gas units utilized today for fuel diversity retire for environmental and economic reasons. Ideally, as these older, less flexible units retire, there should be sufficient incentives in the wholesale markets to attract investment in flexible units that have secure fuel supplies and can be called on for dispatch within the operating day.



Section 4: Proposed Solutions

The preceding discussion highlights the vulnerability of the regional power system to dependence on gas-fired generation that does not have sufficient incentives to perform. The region has traditionally had a reasonably diverse mix of generation; however, a combination of economic and environmental pressures is making it likely that a significant portion of the oil and coal fleet will retire in the coming years. This increases the risk that ISO-NE will not be able to compensate for uncertain energy production from gas-fired generators, particularly under stressed electrical or gas system conditions. Furthermore, even if the oil and coal units were to remain on the system, the start times of these units is so long that they are of little use to address reliability issues that occur with short notice within the operating day.

System operators depend on an energy management system to commit and dispatch the power system – which automatically dispatches the generation based on the relative economics and the *stated operational characteristics of the generators, and assumes that all the generators either have, or can secure, the fuel needed to meet their real-time performance obligations*. It is clear that this assumption is no longer valid and, therefore, ISO-NE must take the necessary steps to address this reliability risk. In addition, the fact that this assumption is not valid for all generation creates a series of economic distortions in the markets, as discussed below.

To address the challenges created by gas dependence, ISO-NE believes that the region must take action in three areas: creation of sufficient incentives to cause generators to perform in accordance with operating characteristics; enhancements to the flexibility of existing markets; and facilitation of improved information flows among generators, ISO-NE and the gas pipelines.

Creating Performance Incentives

As the reliability issues described in Section 3 make evident, while ISO-NE commits and dispatches the system in accordance with generators' offers and stated operational characteristics, generators currently do not have sufficient market incentives to make the necessary firm fuel arrangements, by procuring firm gas delivery services, using stored liquefied natural gas, or, for oil- and dual-fuel generators, maintaining adequate levels of oil inventory.

All of these options have a cost that must be recovered through the offer the generator makes to the wholesale market. Currently, generators that make firm fuel arrangements do not receive value for those arrangements, as prices are often set by the generators with the least secure fuel supplies, and non-performance penalties are relatively weak. In order to compensate for the resulting reliability risk, ISO-NE often has to proactively dispatch uneconomic generators (such as coal and oil generators), thus impacting market efficiency and creating additional "uplift" costs that are unanticipated by market participants and cannot be hedged.

As discussed below, ISO-NE believes that incentives to acquire firm fuel can be created, in the long-term, through changes to the Forward Capacity Market (FCM) and the Forward Reserve Market (FRM). In the short-term, we believe the region must engage in supplemental procurement of resources with firm fuel supplies.

These long- and short-term efforts should increase generators' incentives to perform, leading them to procure firm gas commitments. These commitments, in turn, may have the additional benefit of triggering gas pipeline expansion, and the related opportunity to influence the design of the pipelines and the services offered to include no-notice type services, such that generators may meet their performance obligations without threat of fuel interruption, and bandwidth or swing type contracts, to permit generators to take their gas outside of the 1/24th structure currently assumed by the gas pipelines. Alternatively, gas generators could choose to pursue other options more suitable to them, such as investing in dual fuel capability.

FCM/FRM

The existing FCM rules include little incentive for capacity market resources to invest in the capability to operate at capacity under all fuel supply conditions (e.g., through firm gas contracts, dual fuel capability, or fuel storage arrangements). There are no enhanced payments related to product differentiation based on firmness of energy production, and there are effectively no penalties for failure to operate according to capacity supply obligations.⁸

ISO-NE's proposal for long-term FCM redesign is described in a white paper that was released to stakeholders in May.⁹ It proposes three categories of change to the FCM, staggered over time. The first set of changes involves the improved definition of the core capacity product, performance

⁸ The capacity market penalty for unavailability is currently capped at the unit's capacity. The probability that a penalty is imposed is effectively zero, given that the trigger for these penalties is a "shortage event," which rarely occurs. Penalties may occur if a capacity resource offers, as required, in the DAM and Real-Time market, clears in DAM and does not deliver in Real-Time – but only if the Real-Time price exceeds the DAM price.

⁹ See the FCM paper at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_whitepaper_final_may_11_2012.pdf.

incentives, and consequences for failure to perform. These changes would include market incentives that are sufficient to encourage and sustain adequate levels of firm fuel supply (and inventory, where appropriate) over the long-term, along with penalties for failure to perform when dispatched, so that generators that are unavailable or that fail to follow dispatch orders due to a lack of fuel are subject to penalties sufficient to encourage adequate fuel supply. Similarly, FRM product definitions could require reserve resources to invest in and maintain the ability to reliably deliver power under all fuel supply conditions.

The second set of FCM changes identified in the white paper includes definition of system operational needs (such as resource flexibility) and translation of these needs into additional product specifications for the FCM, with appropriate delivery incentives and consequences. For example, FCM product specifications could be modified to make some portion of the capacity subject to having firm service or back-up fuel capability. Resources would be required to submit additional operating information, and there would be additional constraints within the auction instead of the current single category for total resource capability. Regarding reserve products, ISO-NE and stakeholders must consider whether to continue procuring these products through the FRM or in the FCM, based in part on the price signals and timing issues.

Finally, ISO-NE proposes the specification of system locational requirements and market constructs to induce locational responses. These changes are intended to facilitate the procurement of “market resource alternatives,” which are supply and demand side resources that could substitute for the development of transmission to meet identified reliability needs. In addition to changes to FCM, changes will also be required to coordinate with ISO-NE’s planning processes. ISO-NE has released an additional paper on this topic.¹⁰

All of these changes will require auditing mechanisms to validate performance, including possibly a “deliverability test” or other means for ISO-NE to verify that the generator has scheduling rights to sufficient gas infrastructure to deliver gas on seasonal peak days, or has sufficient on-site storage of back-up fuel capability. ISO-NE may also need to routinely confirm the viability of dual-fuel capabilities.

Supplemental Procurement

As noted above, ISO-NE intends to address the issue of fuel security in the FCM performance obligations. However, it is unlikely that this can be implemented before Forward Capacity Auction 9, which purchases resources for capacity year 2018/19. In the interim, ISO-NE has proposed for discussion with stakeholders a supplemental procurement to assure appropriate levels of firm fuel capability for the existing gas and oil fleet. This temporary procurement mechanism would ensure, at a minimum, that sufficient generators maintain an adequate level of local liquid fuel inventory (e.g., oil or liquefied natural gas), or access to no-notice, variable take, firm gas supply. This procurement could also specify other characteristics that are supplemental to today’s FCM product definition, in a specific quantity. For example, ISO-NE might specify start-time, availability, and dispatch flexibility.

The payments associated with this procurement would be paired with performance penalties for failure to meet these required operating characteristics. Issues to be discussed with stakeholders include the structure of the procurement, which could be an annual auction or Request for Proposals, the qualification process, and an auditing or validation mechanism. ISO-NE intends that this procurement mechanism will expire when the FCM changes are effective.

¹⁰ See the paper at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/mra_discussion_paper_06132012_vtransmit.pdf.

Improving the Flexibility of Energy Markets

To facilitate generators' ability to procure fuel, the markets must allow generators to modify their offers to recover their costs of acquiring fuel intra-day, and the timing of the electricity market must better align with the gas markets to facilitate reliable electric operations.

Hourly Offers and Intra-day Reoffers

Currently, resources can only submit one energy market offer for each hour of the electric operating day and cannot change their energy market offer after 6 p.m. on the day prior to the electric operating day. This constrains generators in two ways. First, generators cannot reflect price differences over the two gas days that span a single electric operating day. Second, generators cannot reflect changes in fuel prices within the electric operating day in their energy market offers.

Given these limitations on bidding behavior, when the cost of producing electricity (given real-time gas market prices) exceeds the real-time electricity prices, resources fueled by natural gas may choose not to generate energy by redeclaring their operating limits or using Limited Energy Generation (LEG) rules to remove all or part of their energy production capability from dispatch. This was the case during the June 29 heat wave and the January 2004 cold snap discussed above. In those instances, generators that had access to fuel made the economically rational decision to forego producing electricity, as the costs of doing so exceeded electricity prices.

The hourly offers and intra-day reoffers solution aims to change the status quo, such that resources are able to reflect changes to costs in the energy market closer to the hour of operation. Accordingly, resources that must buy intra-day gas will be able to reflect their true costs, and generators that might not be able to get gas in real-time and want to switch to oil will have the ability to reflect the cost of switching.

By providing generators the ability to better reflect their costs to produce electricity in real-time, ISO-NE believes generators will be more likely to respond when called to come on-line or increase production in real-time. These changes will also reduce the likelihood that electricity market prices fail to reflect fuel prices, and may also facilitate the use of more expensive northern gas and alleviate the pressures on the pipelines from the west.

Timing of the Day-Ahead Electricity Market

As noted above, the timing differences between the gas and electricity sectors may be contributing to the increasing incidence of gas-fired resources informing ISO-NE that they do not have sufficient fuel to meet their generation commitments. To alleviate this problem and give system operators more notice of unavailability, so that long-lead time replacement generation can be secured and reliability maintained, ISO-NE proposes to move the timing of the DAM so that generating schedules are published before the Timely nomination deadline for gas, and before the primary gas trading period (i.e., before 10:00 a.m.). ISO-NE would also move the timing of the reoffer period and the initial RAA prior to the Timely nomination deadline for gas.

The timing adjustment will also benefit the pipeline operators, who need to know fuel scheduling requirements, including any potential intra-day short notice or short duration withdrawals that may impact pressures and the reliability of their system. Making the electric reliability determinations at 10:00 p.m., based on the current DAM process timelines, is too late for the pipelines to modify their operating plan for the next day and essentially under-utilizes the capacity of the pipeline system.

A timing change will also facilitate gas-fired generators' ability to secure gas. The existing timing differences require gas-fired generators to manage fuel procurement and scheduling over two gas

operating days for each electric operating day. Moreover, given that DAM results are not posted until 4:00 p.m. and the Timely cycle nomination for gas delivery ends at 12:30 p.m., generators have the choice to either secure gas before they know they have been scheduled to generate or take their chances with later gas nomination cycles. This problem is more difficult for generators that are scheduled as part of the RAA, the results of which are published at 10:00 p.m., well after the Evening gas nomination deadline of 7 p.m. These resources are committed to generate, but may be unable to procure fuel in the Intra-Day nomination periods.

ISO-NE recognizes that moving the market timelines is not without risk. In particular, advancing the DAM timeline creates more price risk that must be factored into offers and the reference prices used for market monitoring and mitigation. The advanced timing may also increase the uncertainty in load forecasts used to inform the bidding process, particularly for demand response and renewable resources, although preliminary analysis indicates load forecast differences due to the earlier timing may be small. These and other issues must be considered in detail with stakeholders.

Table 7 below shows a comparison of the gas and electric days after the DAM and RAA have been moved. In this example, the DAM clears in the evening two days before the operating day. While ISO-NE intends to propose this formulation to stakeholders as a straw proposal, ISO-NE notes that there may be other time frames that could achieve its goals. Table 7 is included merely for illustration.

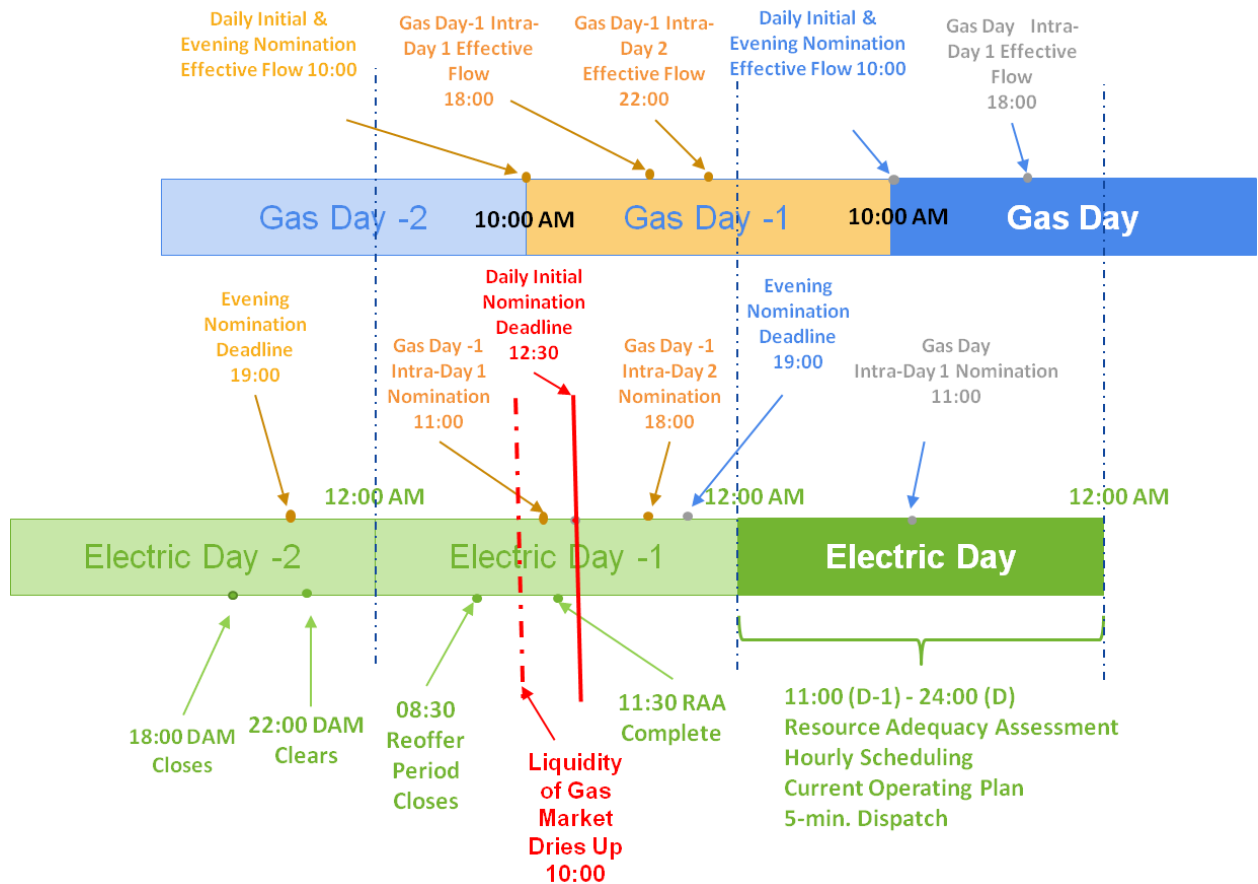


Figure 7 – Comparison of Natural Gas and Electric Days After DAM Timing Change

Information Enhancements

As indicated above, the worst stresses on the electric system occur when ISO-NE has short notice of generator unavailability due to inability to secure fuel, or of supply disruptions or pipeline maintenance. These stresses are exacerbated by the long lead-times required by many of the non-gas fired generators in New England (see Figure 6, above). To facilitate better information flow, ISO-NE proposes to require more information from generators and to continue ISO-NE's current coordination efforts with the gas pipelines.

Regarding information from generators, ISO-NE is considering enhancements to the required offer information submitted by generators. Specifically, as part of the offer process, ISO-NE would require generators to provide information on fuel schedules and any differences between cleared amounts (and/or commitments) and scheduled fuel supply. Generators would have a continuing obligation to proactively inform ISO-NE of any condition that would prevent them from meeting their DAM or RAA commitment schedules or that would otherwise restrict their ability to follow dispatch instructions. This information, in combination with information from the pipelines, would improve the system operator's ability to assess the likelihood that generators will fail to accurately follow dispatch requests.

ISO-NE also needs better information from the pipelines regarding their operations. While gas-electric coordination has greatly improved in recent years, largely due to the active communication between ISO-NE and the pipeline operators and the establishment of a Coordination Committee composed of the Northeast electric system operators, gas pipelines, liquefied natural gas storage operators and LDCs, ISO-NE needs better information about scheduled outages on natural gas pipelines.

Conversely, pipeline and storage operators as well as LDCs with gas generation in their distribution system need improved information about the potential impacts on their operations from planned or unplanned generation or transmission outages, expected changes in electricity demand, and expected changes in renewable generation. Outages on the electric transmission system can impact gas flow and pressure on gas pipelines due to dispatch of gas generation that does not have a nomination.

Finally, gas and electric operators also need to discuss real-time operating information so that they can work together to re-dispatch to maintain the reliability of both systems. To achieve this end, ISO-NE must address information policy constraints that prevent it from informing pipelines of actual generator commitments.

Section 5: Continuing Efforts

While there is no longer any uncertainty about the existence of reliability problems as a direct result of gas dependence, the solutions continue to evolve. As set forth herein, ISO-NE intends to pursue, through the stakeholder process, long-term changes to FCM, supplemental procurement, hourly re-offers, changes to the timing of the DAM, and improved information flows.

Given the mounting reliability issues, ISO-NE hopes to begin the stakeholder process regarding the identified solutions immediately. Specifically, ISO-NE has established implementation targets for the proposed solutions, as follows: information improvements by winter 2012; changes in the timing of DAM alignment in the first quarter of 2013; supplemental procurement by summer 2013; and hourly reoffers in 2014. Other changes remain possible, including changes to the Limited Energy Generation rules.

Additional solutions may stem from work with the broader industry and the North American Energy Standards Board. For example, the gas industry serving New England may want to consider implementing products to better serve electricity generators, including the no-notice, bandwidth and swing products referenced above. The electricity markets may need corresponding changes to create incentives for generators to purchase these products.

A change in the gas day may also be warranted. Figure 8 below shows the differences in timing between the gas and electric industries, as well as the hourly concentration of gas generator starts during the year. As shown, the electric morning load increase begins at approximately 3:00 a.m. The majority of daily generator starts occurs in this time period; most of these generators are those with the flexibility to cycle, which at this time is the gas fleet.

Ideally, a standard gas day would accommodate the morning load pickup and the ensuing electric peak period in a single operating day. A closer synchronizing of the gas and electric energy operating days would facilitate generators' purchase of gas in concert with their daily electric commitment; currently, if generators buy gas ahead of time, it generally only matches their DAM commitment so that they are not forced to sell any unused portion at a loss. This causes problems if conditions in real-time are materially different than the DAM schedule.

Advancing the electric DAM and RAA timelines to precede the gas Timely nomination deadline will allow generators to purchase gas to meet day-ahead and supplemental reliability commitments, enhancing system reliability. Moving the gas day start time from 10:00 a.m. to no later than 4:00 a.m. would allow generators to procure and schedule fuel for their entire daily commitment.

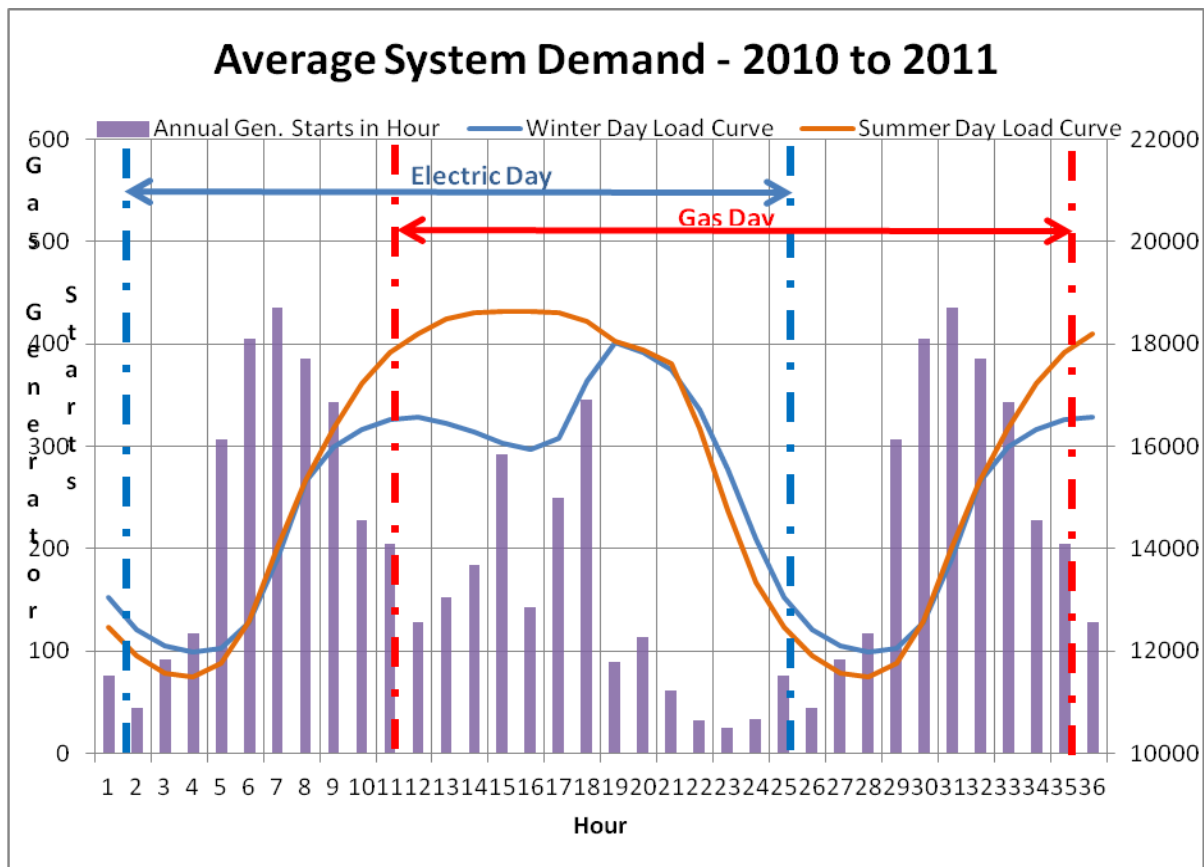


Figure 8 – Gas Day vs. Electric Day

ISO-NE looks forward to discussing these issues with stakeholders and the electric and gas industries at large. We recognize that these changes will require a significant amount of time and effort from the region, but we believe that they are necessary to ensure the reliability of the bulk power system and the competitiveness of the market structure that the region has adopted.

Session Title:

***Competing Claims: Gas and Electric Scheduling
Mismatches and Capacity Release Issues***

Pricing Short-term Gas Availability in Power Markets

Seabron Adamson¹

Richard D. Tabors^{2,3}

ABSTRACT: The rapid increase in gas-fired generation in U.S. power markets, especially those in pipeline capacity constrained regions, has raised concerns that the lack of coordination in power and gas market schedules and practices may create operational problems for Regional Transmission Operators (RTOs). In this paper, we explore the very different market structures that have evolved for the U.S. gas market and the RTOs, and explore how these differences create the potential for market inefficiencies and coordination failures, as gas availability constraints are generally not priced in the centralized unit commitment and locational marginal pricing model used by RTOs. While a major focus of attention has been on gas scheduling, we show that the time window of daily hub gas trading is generally limited, and that the lack of liquidity and transparency in next day and intra-day gas prices may pose greater problems for market efficiency.

I. Introduction

The coordination of U.S. electric and gas markets is a topic of increasing concern. In an era of low natural gas prices, and relatively high coal prices, fuel switching is increasing the reliance of the U.S. power system on natural gas for generation. Most recent and expected capacity additions – with the exception of renewables – are gas-fired. Even the addition of large amounts of wind and other renewable generation is perceived to be problematic in some regions, due to the need for gas-fired backup capacity.

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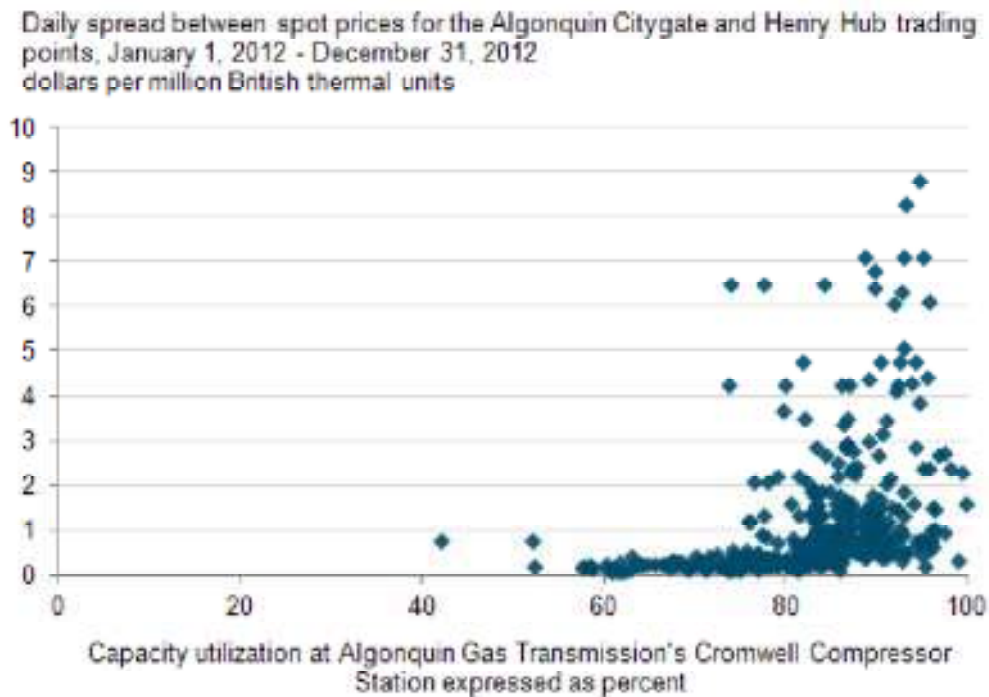
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³ The authors acknowledge the assistance of Lorna Omondi of Greylock McKinnon Associates in preparation of the paper, and helpful comments from Bill Hieronymus and Robert Stoddard. The views represented in this paper reflect those of the authors and may not represent those of any firms to which the authors are affiliated or their clients.

Given the scale of U.S. natural gas reserves and production, the current concern over gas availability is primarily a regional issue. Gas prices are currently low, and many gas basis differentials to Henry Hub—generally reflecting capacity constraints on pipelines – have fallen as new gas production in regions close to large demand centers (such as the Marcellus Shale) has increased rapidly. The primary focus is on several regional, pipeline-constrained gas markets which feed several key US power markets. In many other areas of the country pipeline capacity, storage and gas availability is high.

Figure 1 plots daily gas basis at the Algonquin Citygates versus utilization of the Algonquin pipeline, a key pipeline feeding the New England gas market.⁴ The high utilization of the pipeline in 2012 was accompanied by very high basis prices into New England – at a time when gas availability elsewhere in the U.S. was at an all-time high.

Figure 1: New England gas basis versus utilization on the Algonquin pipeline in 2012



Source: EIA

⁴ Daily gas basis is defined here as the difference between the daily Algonquin Citygates price and the daily spot Henry Hub price. The Cromwell compressor station on the Algonquin pipeline is located in Connecticut, on the main pipeline bringing gas from the Mid-Atlantic region into New England. Figure from EIA, "Short-Term Energy Outlook: Constraints in New England likely to affect regional energy prices this winter", January 18, 2013.

Similar charts for many other parts of the country would show lower utilization on average across the year on key pipelines, and dramatically lower basis prices. While broad policy issues exist across the U.S., the details and impacts are quite regionally specific.

As concerns over the gas dependence of the power system increase, and electricity prices and generation patterns reflect locational transportation gas constraints, a number of key questions arise:

- How should expected constraints on gas transportation capacity affect the planning and resource adequacy processes of electric Regional Transmission Organizations (RTOs)?
- Are there sufficient investment incentives to expand gas transportation capacity as needed when an increasing amount of gas demand will come from generators as opposed to local distribution companies?
- The operating schedules and market structures of U.S. gas and electric markets are quite different, and have developed largely independently of one another. Does this create operational and reliability issues, or spot market inefficiencies?
- Can market rules be adapted to reduce these problems at minimum social cost and without unintended negative impacts on gas and electric consumers?

The focus of this paper is on the last two operational and efficiency questions, as gas availability issues are being addressed directly in another set of papers in this symposium.

II. Potential Sources of Market Failure

As several commenting parties noted in a recent FERC docket on gas-electric coordination issues, it would be useful to have a more precise diagnosis of what may be missing before attempting to define specific solutions.⁵ In this spirit, we first seek to provide an economic framework for further analysis of these issues.

Imperfect information and transactions costs

As we discuss in more detail below, RTOs are substantial aggregators of information flows, supporting the largely centralized decision-making process of the RTO in electric unit

⁵ See for example the comments of PJM Interconnection Inc. filed in FERC Dockets AD12-12-000 and RM96-1-037.

commitment and dispatch.⁶ The information from generators comes in to the RTO in the form of price-quantity offers which are necessarily conditioned on the information available about gas prices and transportation capacity in the market. If this gas information is insufficient or stale, the offers of generators will affect power market operations through a variety of means:

- Generators may assess that gas pipeline capacity is unavailable – based on available pipeline data and market prices – when capacity in fact will be available. Conversely, a generator could be exposed in the day-ahead market if it made a commitment to generate when in fact insufficient gas was available.
- As we discuss later in this paper, gas trading volumes in regional daily spot markets are generally constrained to a relatively small time window, which may not correspond to the period when generator offers are created. Spot gas prices used by generators could therefore be stale or otherwise not representative of current forecast weather, pipeline and other conditions. This could affect the allocative efficiency of power market outcomes or require generation offers to include risk premia over the short-term volatility in local gas prices.
- Outside of high liquidity trading windows, daily gas prices (and we expect intra-day prices) show considerable bid-ask spreads, reflecting weaker liquidity, lower price transparency and the inability of market participants to hedge these temporal risks physically. If generators are required to transact out of liquid periods, these spreads could contribute to higher transactions costs and ultimately higher prices.

Unpriced constraints

A primary cause for the potential coordination failures between gas and electric markets is that gas availability constraints are not adequately priced in the decision-making processes of RTOs. If gas availability constraints are not priced in the market, they must be addressed through cumbersome and potentially inefficient command processes.

The difficulties in developing efficient coordination mechanisms for electric power and gas transmission reflect in many ways the profoundly different means in which these markets operate. To understand the impact of incomplete constraint sets on the operation of “standard market design” (SMD) markets operated by RTOs, market operation, some detailed terminology is needed.

To simplify a great deal, RTOs following the SMD recipe operate centralized security-constrained unit commitment (SCUC) coupled to a set of day-ahead locational marginal prices

⁶ As is widely recognized, the unique characteristics of AC electric systems, with their inherent need for very short-term balancing of supply and demand, make a large degree of central control necessary. This is common to RTO and non-RTO systems.

(LMPs). Transmission, load, generation and contingency constraints are modeled in the SCUC software so that the resulting operational schedules and LMPs are consistent with the known operating physical constraints on the bulk power system. During real-time operations, the RTO operate a centralized security-constrained economic dispatch (SCED) and a real-time LMP market, which reflects load, generation and transmission constraints at the time.

Table 1 compares the key attributes of a SMD power market with that of the U.S. gas market. .

Table 1: Attributes of US gas and SMD power markets

Gas market	Market attribute	SMD Power Market
Gas transportation held by shippers but subject to release	<i>Transmission rights/control</i>	RTO effectively holds all transmission capacity – allocated and auctioned transmission rights are financial only
Individually scheduled pipeline transactions by shippers	<i>Transmission scheduling</i>	Utilization of electric transmission scheduled in SCUC and SCED
Average (and generally embedded) cost based tariffs	<i>Transmission pricing</i>	Marginal pricing of congestion and losses
Individual shippers, storage operators, etc. make resource utilization decisions based on individual economic decisions	<i>Resource commitment</i>	RTO schedules generation and transmission resources simultaneously in SCUC run
Spot OTC and exchange (e.g. ICE) prior-day markets at hubs	<i>Spot markets (day ahead)</i>	Full day-ahead LMP market based on SCUC – nodal prices
Intraday OTC market – low liquidity and transparency	<i>Spot markets (real-time)</i>	Full RT LMP market based on SCED – nodal prices
Continuous-time bid-ask markets or OTC	<i>Auction design</i>	Clearing single-shot auction in each market – single rebid
Decentralized information flows and decision-making	<i>Information flows</i>	Centralized in RTO - based on bids from market participants

Paradoxically, both the gas markets and power markets work well independently – the concern is over the interaction of these two very different structures in supporting power markets increasingly dominated by gas-fired generation.

Broadly speaking, under the gas model capacity commitment and allocation decisions are made individually, and in a decentralized fashion. While the rates and operating practices of pipelines are subject to regulation, individual shippers decide when to use gas transportation services and pipelines have only the responsibility to make these services available under the terms of their tariffs. Commitments are contractual between parties and it is the responsibility of end users to contract and pay for sufficient gas resources (commodity, transportation or

storage) to meet their requirements. The US natural gas industry has been remarkably successful in evolving a market structure to meet these requirements with a minimum of top-down “design”.

In contrast, SMD power markets operate in a highly centralized fashion, with the RTO functioning in the short-term as a central planner based on bids and other information provided by market participants. Reflecting the historical structure of the industry, the nature of electricity as a commodity and the different regulatory status of power as opposed to gas, in the SMD power model the RTO is involved in virtually every decision regarding the future and current state of the power system.

Figure 2: Stylized operation of a SMD power market

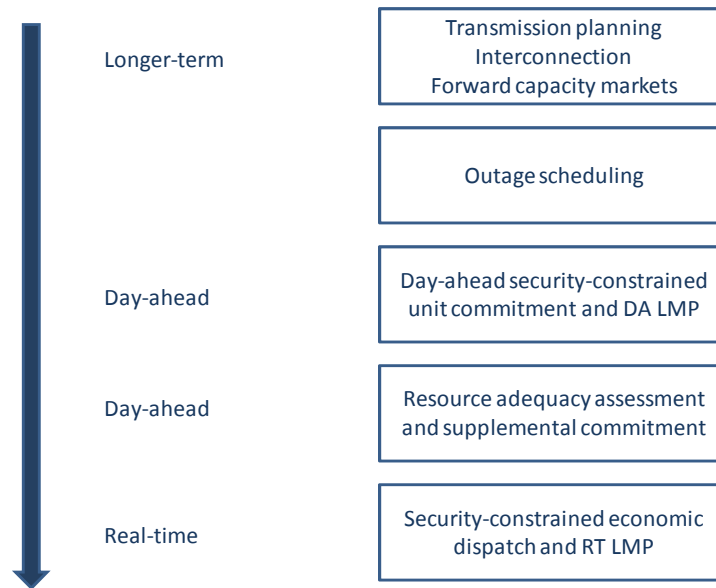


Figure 2 provides a stylized representation of the operations of an SMD power market. While planning and investment decisions are outside the scope of our present analysis, it is noteworthy that in SMD markets the RTO is responsible for transmission planning, generator interconnection planning, load forecasting, and market-based coordination of long-term generation resource adequacy. On a shorter time horizon, RTOs are also responsible for transmission outage planning and coordination for their region.

Under SMD, the primary mechanism for ensuring *operational* reliability (as opposed to longer-term generation resource adequacy and electrical transmission deliverability of that generation) is incorporating all resource constraints – including transmission constraints which affect the location of potential incremental generation, temporal constraints such as minimum on

and off-times and ramp rates, and security constraints such as maintenance of reserves and frequency – into the security-constrained commitment systems which compute both day-ahead schedules and day-ahead LMPs. In this way, a single-shot, single-clearing price auction mechanism (the SCUC) can create a set of schedules which is feasible given known constraints.⁷ Given the information set provided in the day-ahead market (e.g., generator bids and availabilities, transmission constraints, and contingency constraints) the RTO can be confident that the operating schedule meets reliability standards for the following operating day.⁸

In SMD designs, after the close of the day-ahead market, it is common to have a second, manual reliability assessment by the RTO, using its own forecast of next day load (as opposed to bid loads as in the day-ahead market), and with updated information on transmission and generation outages. RTOs can generally commit extra units as needed to protect reliability outside of the day-ahead market.

Finally, in real-time the RTO performs security-constrained economic dispatch of the system, and calculates real-time LMPs for settlement purposes.

Pricing gas constraints in the SMD framework

SMD power markets work by carefully identifying constraints that will or could affect system operations and reliability and incorporating them into the resource commitment and LMP pricing process. Notably, gas availability for generators is typically not reflected in the day-ahead unit commitment step of the SMD market operations described above, except to the extent that market participants' offers have anticipated availability constraints and that the RTO's market monitor has allowed any such premiums to be reflected in LMPs. This omission raises several material issues about the interaction between gas and electricity markets.

First, although investment and planning decisions are outside of the scope of this paper, it is worth noting that while capacity markets (such as PJM's Reliability Pricing Model and analogous markets in New York and New England) pay careful attention to the electrical deliverability of generation to meet load, they do not consider parallel deliverability issues in the gas market. The clearing of these capacity markets – which includes capacity sub-zones – reflects the fact

⁷ While the SCUC run is effectively a single-shot clearing auction for calculating the day-ahead LMPs, it is worth noting that the operation of this step takes hours to process so the day-ahead schedule and prices are not known to market participants for some hours.

⁸ Electricity transmission systems are generally operated on an N-1 contingency basis, which requires that system operational reliability be preserved on the loss of the single largest impact constraint (which could be the loss of a generator, a transmission line, etc.). Additionally, there are reliability requirements setting the minimum levels of various grades of operating reserves.

that there are electrical constraints on the grids which prevent all generation from serving all load. However, such capacity mechanisms do not consider gas pipeline constraints that might also impact generation capacity availability and deliverability. Nor do the RTOs generally perform any contingency analysis of the gas system to establish whether the mix of available generation resources is robust to the loss of an element of the pipeline system. As such, important elements of assessing future resource adequacy may be missed and therefore not priced.⁹

Second, in the day-ahead unit commitment process – the key to market-based operational reliability – gas availability constraints are not directly reflected in commitment and day-ahead schedules and prices. If the bidding timelines allow, bids from gas-fired generators could reflect contemporaneous day-ahead (traded prior day) gas prices and more realistically reflect availability of non-firm gas transportation service. At present, such constraints are often lacking, and hence cannot be reflected in day-ahead LMPs.¹⁰

Third, since day-ahead LMPs do not reflect short-run gas constraints (if these are not completely reflected in gas prices used to create generator offers), there is no scope for competing reliability alternatives to be realistically priced in the market – limiting the supply of responses available to RTOs on days of limited gas availability. These could take many forms:

- For example, at one time it was fairly common for new combined cycle gas turbine units to have liquid fuel backup. This is now less common, given the gap in natural gas and oil prices, and the unclear path for monetizing the capability without some pricing of the reserve capacity. If the gas availability constraint was priced, dual-fuel units could be paid as a form of ancillary services, calculated during the day-ahead SCUC run.¹¹
- Liquefied natural gas (LNG) peak shaving facilities are one method for meeting peak day demands. These facilities liquefy natural gas and store it cryogenically on site or transport it to remote locations by truck for regasification. Additional regional or plant site-regasification could be economically sensible if the standby capacity was priced.
- Finally, as the Energy Information Administration has noted, some of New England's recent supply issues have been intensified by lack of foreign LNG cargoes being brought in to US and Canadian regas terminals, due to the large price differentials between US

⁹ Generators typically face weak or no incentives to contract for firm gas transportation, but unavailability of fuel can raise system costs for all users as the RTO re-dispatches to meet load.

¹⁰ Certain New York City gas constraints are a notable exception.

¹¹ The authors thank Bill Hieronymus for his suggestion that dual-fired capacity could be priced as an ancillary service under the SMD framework.

regional and foreign destinations in Europe and Asia.¹² The economics of bringing in limited additional cargoes could be bolstered as high deliverability reserves if there was a counterparty available who could profitably sell backstopped gas capacity into the power market.

Fourth, the security analysis of the commitment and dispatch of electric generators is blind with respect to the gas pipeline system. This gap manifests itself in two ways. RTOs generally do not assess whether the unit commitment and dispatch is robust to a contingency on the gas system. In addition, RTOs also do not schedule reserve generating capacity with an eye towards gas availability in the region or on specific pipelines, if pipeline-specific contingencies are critical.

Our objective here is not to design specific market solutions, but rather to note that if the price signal was there U.S. gas and power suppliers are likely to show considerable ingenuity in developing cost-effective operational solutions. For this to occur, fuel capacity constraints (e.g. gas availability) must be reflected in appropriate power prices (energy, capacity or ancillary services). Market participants who can supply capacity ameliorating gas supply constraints affecting power market operations must also be treated in a non-discriminatory manner.

III. Scheduling mismatches and market timing

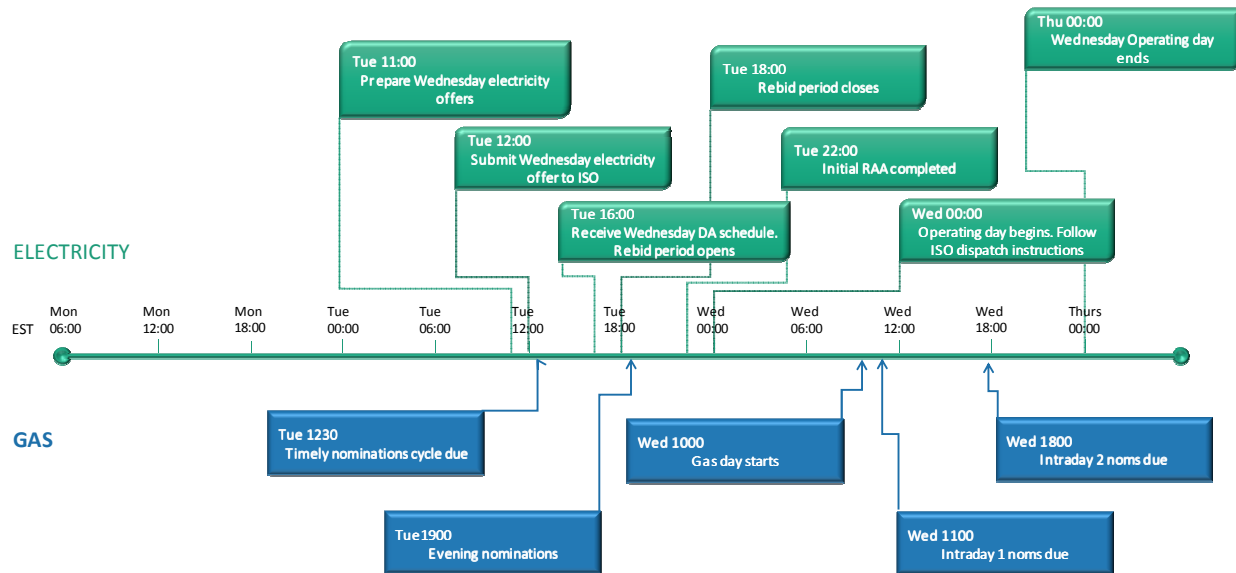
By now it is widely recognized that the power and gas markets operate on mismatched schedules, which makes their interactions complex. Figure 3 below illustrates in a simplified fashion the timelines for an example SMD market and the basic North American Energy Standards Board (NAESB) gas scheduling requirements.

There are some obvious and well known discrepancies between electric and gas market operations, as illustrated even in the simplified comparison in Figure 3. First, the electric operating day runs from midnight to midnight, with offers due at noon in this example (which reflects current ISO New England practices). The standard gas day runs from 10 A.M. one day to 10 A.M. the next, with timely nominations due at 12:30 P.M. on the prior day.¹³

¹² U.S. Energy Information Administration, "Short-Term Energy Outlook: Constraints in New England likely to affect regional energy prices this winter", January 18, 2013.

¹³ All times are Eastern Prevailing Time.

Figure 3: Simplified SMD power market and gas nomination timelines



As discussed previously, the clearing mechanisms of the gas and electric markets are different. Offers into the current ISO New England day-ahead market illustrated above are due at noon, but generators do not receive their day-ahead schedule confirming they are selected to run until 4:00 P.M., by which time the timely nominations cycle is past, and the evening nomination cycle happens a few hours later. This complex set of offer and nomination cycles inevitably creates some market frictions as power market and gas pipeline scheduling cannot be conducted jointly and simultaneously.

Timing of next-day gas trading

Electric power in an SMD market is traded in hourly blocks (day-ahead and real-time) and also in forwards markets (which are typically financial swaps against RTO prices and not for physical power). In the gas market, the primary spot market liquidity is in the next day product for delivery at a specific hub, which is traded, for example, on Tuesday morning for delivery on Wednesday starting at 10:00 A.M. This “next day” gas is traded on exchanges such as the Intercontinental Exchange (ICE) and also on an over-the counter (OTC) basis. Market transparency on ICE-traded gas is high, which aids efficient price discovery. During active trading periods bid-ask spreads – a measure of transaction costs – are low.

In addition to the next day market, intra-day gas is also traded, generally on an OTC basis. Volumes and liquidity tend to be low and transparency is substantially weaker. While there is little or no public data available on OTC intra-day trades, spreads are generally expected to be substantially higher.

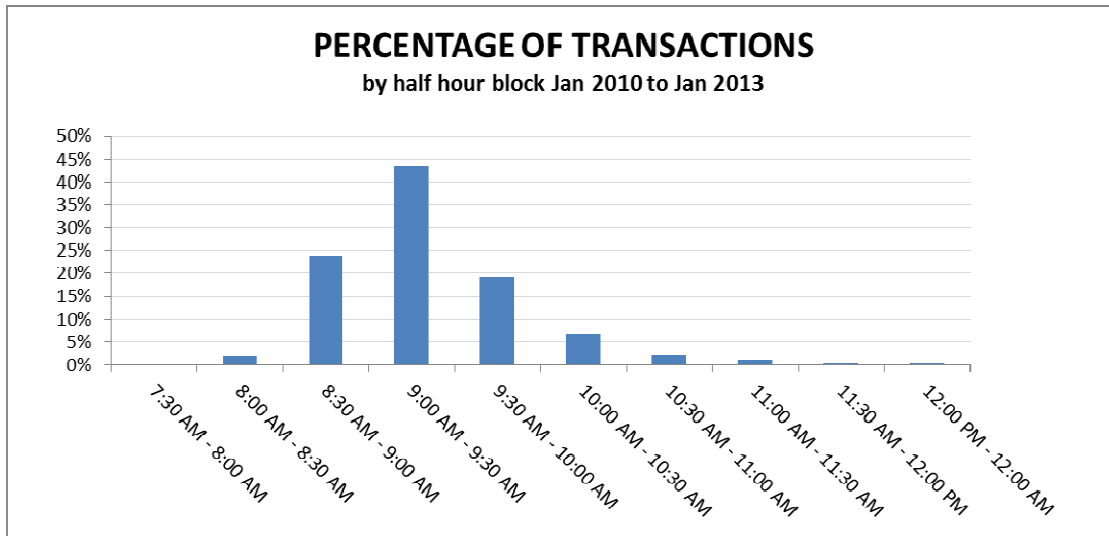
To minimize the impacts of imperfect information, it is economically preferable if offers into the day-ahead power market can reflect up-to-date market information on expected demand (e.g., weather) as well as new supply disruptions if any. This will allow day-ahead prices to best reflect the gas markets' implicit pricing of local gas availability and supply-demand balance.

We note that while the gas market nomination cycles continue through the prior day (timely, and evening) and into the operating day (intraday nominations), most actual next-day gas market trading and price discovery occurs in a much more limited window. To assess when next day markets are most liquid, we analyzed several years' worth of ICE transactional data for the Algonquin Citygates hub. This data covered the three year period from early January 2010 to early January 2013 for trading next day gas prior to the 12:30 P.M. ICE deadline¹⁵

Figure 4 indicates the concentrated nature of ICE next day trading at Algonquin Citygates. Transactions in the next day natural gas market on ICE are very heavily concentrated from 8:30 A.M. to 10:30 A.M. Eastern Time (7:30 A.M. to 9:30 A.M. Central Time) with virtually no trades before 8:00 A.M.; roughly 3% before 8:30 A.M.; 93% between 8:30 A.M. and 10:30 A.M. and 3% of the trades after 10:30 A.M.

¹⁵ The analyses reported in this section of the white paper were undertaken by the authors on behalf of the New England Power Pool (NEPOOL) in connection with ISO New England Inc.'s (ISO NE) proposed resetting of the timing for offers into the day-ahead market. Both NEPOOL and ISO NE submitted to the Federal Energy Regulatory Commission (FERC) alternative proposals to modify New England's market rules for earlier clearing of the DA energy market and earlier completion of ISO NE's reserve adequacy analyses ("RAA"). Our results were incorporated in prepared testimony filed by NEPOOL in support of its alternative proposal. Both alternative proposals are pending before the FERC in Docket No. ER13-895-000.

Figure 4: Percentage of transactions by half hourly block January 2010 to January 2013



We recognize that ICE is not the only method of next day trading at Algonquin Citygates, and that additional trading occurs on an OTC basis. However, ICE is a major trading platform in the next day gas market, and the timing of trades on ICE is generally believed to be representative of all Algonquin Citygates next day gas trades.¹⁶

The time window of liquidity in the next day Algonquin Citygates market is quite narrow. Outside of this time window, purchasers of next day gas are likely to face a much less liquid and transparent market, with attendant higher spreads and limited volumes.

¹⁶ The analyzed transactions reflect only next-day trades, and exclude trades before weekdays and holidays. Since the gas market does not trade on the weekends and holidays, larger time lags can occur on these days.

Figure 5: Timeline of power market operations and next day gas market transactions

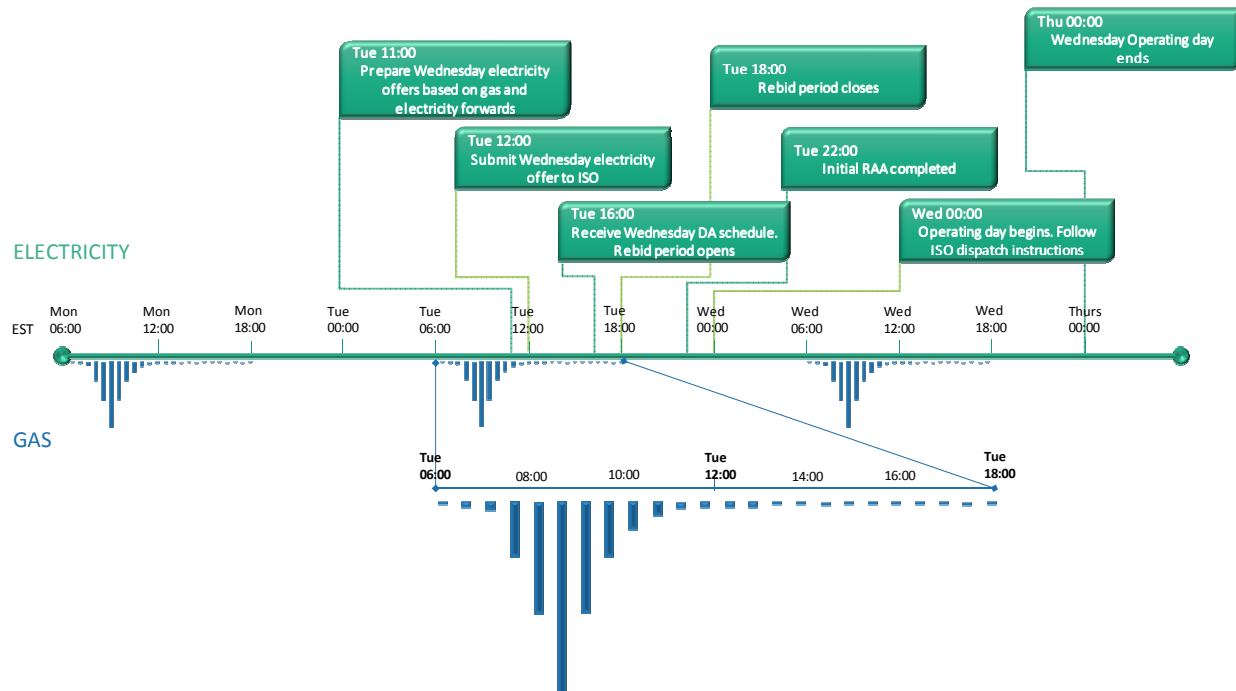
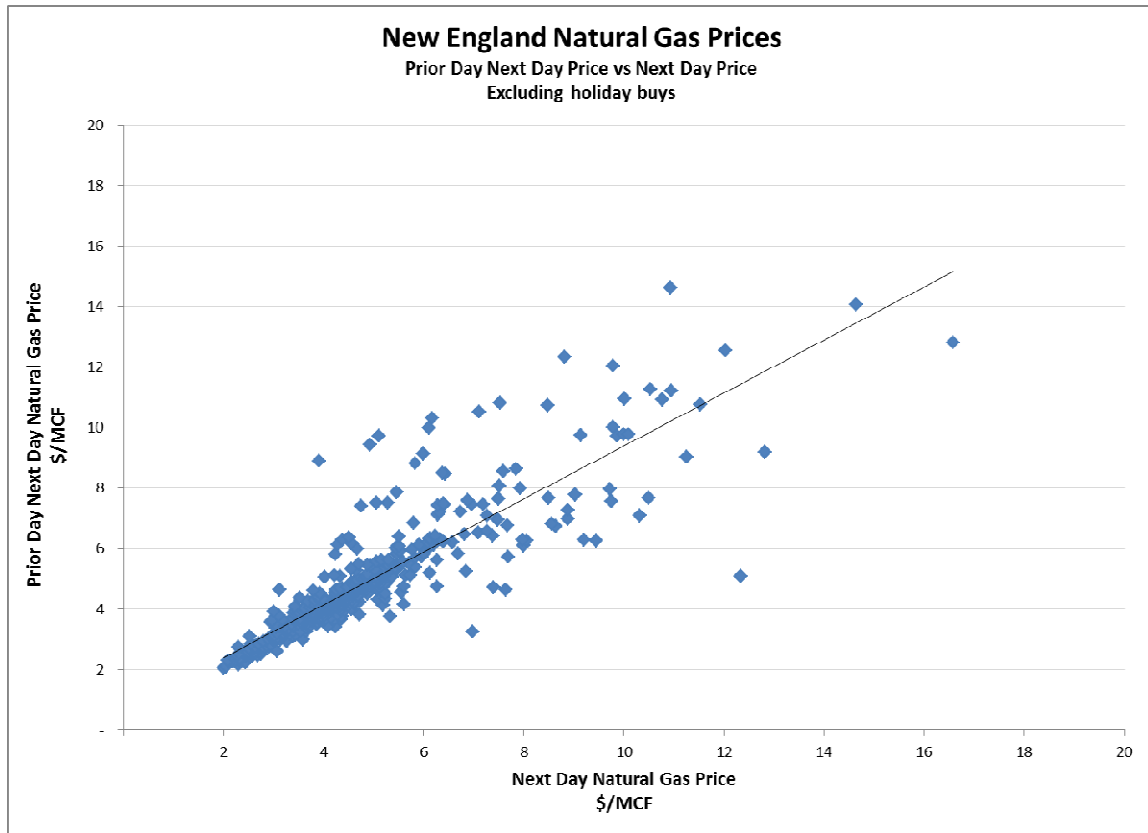


Figure 5 combines the power market timeline of Figure 3 (representing current ISO NE offer practices) with the next day Algonquin Citygates transaction volume data in Figure 4 – shown here as downward columns representing frequency of transactions. As can be seen in the figure, market volume (and hence price discovery) is strongest mid-morning, allowing current next day gas market prices to be incorporated into generator offers into the day-ahead power market.

Figure 6 helps illustrate why this is important. It shows changes in next day prices from one day to the next. Simply put, a lot can change from day to day in a capacity-constrained regional gas market, especially in winter months when demands can change dramatically with weather. To quote Mark Twain: “One of the brightest gems in the New England weather is the dazzling uncertainty of it.”¹⁷ As both power and space heating demands are strongly affected by weather, temperature variations from day-to-day can introduce large shocks to next day Algonquin Citygate prices.

¹⁷ Speech at the New England Society Dinner, 1876.

Figure 6: Prior Day Next Day v. Next Day Average Natural Gas Prices



If offers into the day-ahead market cannot be based on current gas prices, there may be quite limited price information on which to develop offers, and previous day prices are a poor substitute as shown in the figure. It thus appears likely that short-term inefficiencies will be created and that generators who have to make firm offers into the gas market will introduce a risk premium to compensate for their additional trading risks.

IV. Conclusions

More than a decade ago, the development of US power markets was faced with a question: Should American electricity markets follow the centralized operations of traditional electric utilities, the “tight pools” such as PJM, NEPOOL and the New York Power Pool (plus the British-inspired “PoolCo” model), or should they follow the largely decentralized example of the American gas industry, which had already been successfully deregulated. The ensuing debate –

which perhaps provided more heat than light – shifted over time towards a centralized view of power operations and markets. Today, most US power markets are based on the “standard market design” with LMP pricing. This approach includes centralized security-constrained unit commitment and security-constrained economic dispatch under which the RTO controls system operations. Only the Southeast and the West (outside California) retain the remnants of the bilateral power market model, and most loads in these regions are served by vertically-integrated and regulated utilities.

It is widely recognized that efficient markets for network products such as power must incorporate all important constraints into pricing. This economic truism is at the heart of the standard market design for power markets. RTOs and their stakeholders have made large efforts to reflect spatial, temporal and contingency constraints into market algorithms both to protect reliability and to create appropriate economic incentives for suppliers and users.

In effect, a new set of operational constraints – this time centered on natural gas availability – has evolved but not been fully incorporated into power market pricing. Correcting these prices could have strong economic benefits:

- Transmission planning and resource adequacy processes could better reflect real-world reliability constraints that may be as important in some specific regions as the electric transmission constraints typically analyzed.
- If gas constraints could be incorporated into the RTOs unit commitment and scheduling process, there could be much less need for costly “in the day” actions to protect reliability.
- Pricing gas constraints into LMPs or ancillary service prices – where appropriate – would provide strong incentives for new sources of fuel supply to become available in constrained regional markets, including dual-fired generation and short-term but high deliverability gas storage.
- Finally, such pricing could encourage more appropriate demand response.

Potential avenues and further questions

Providing definitive solutions for this complex problem is outside the scope of this paper, and will require a more detailed quantitative understanding of the specific issues affecting major gas and power market regions. We can however identify some potential approaches that might be explored further for addressing operational (rather than planning or investment) solutions for SMD markets dependent on gas.

- RTOs could aim to have mechanisms that would trigger when total pipeline capability was becoming very constrained, given that having every generator nominate and confirm capacity before offers are submitted is impractical given market timelines. A “tight market” market signal could perhaps be developed which would trigger on expectations of very high aggregate regional gas demand. This gas market signal might be used to schedule non-gas-fired resources or gas-fired resources on pipelines with spare capacity in the SCUC which could then be reflected in day-ahead LMPs.
- These resources, which could include dual-fueled units, or units with secured gas supply or storage, might be made available to the RTO under an ancillary service-type reserve payment. These payments could provide incentives for generators to contract for short-term storage, gas transportation or dual-fired capability to meet RTO requirements.

With respect to scheduling mismatches, the biggest issue appears not really that the nomination and offer schedules vary but that the gas market does not provide sufficiently transparent prices except during limited trading windows, and that liquidity for power generators needing to buy and sell incremental gas may be relatively poor in these hours. This lack of liquidity and transparency, in turn, provides a rationale for RTOs to limit the ability of real or expected intra-day premiums to be reflected in energy offers and, consequently, LMPs. This effect is hard to assess given the current level of information on the intra-day gas market but may warrant further analysis.



**2013 MITEI SYMPOSIUM:
Interdependency of Gas and Electricity Systems**

Ensuring Future Natural Gas Availability

April 16, 2013

Authors:

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Executive Summary

The United States has the world's second largest natural gas resource base, providing the potential for abundant low-cost gas supply for many years. The robust supply outlook is almost entirely dependent on new "unconventional" shale gas plays made commercial by the combination of horizontal drilling and hydraulic fracturing technology. Shale gas production began to grow rapidly in 2003 and accounted for over 40% of U.S. gas production in 2012; by 2025 it will likely account for over 60% of U.S. production.

As a result of shale gas growth, the production geography of the U.S. is changing. For example, in 2000 the Gulf of Mexico produced a quarter of all U.S. natural gas; by 2012 it only produced 6%. This decline is more than offset by shale growth in the Gulf Coast, Rocky Mountains and Northeast. Three shale plays, the Marcellus (Northeast), the Haynesville (Louisiana) and the Barnett (Texas) have been dominant so far and accounted for 72% of shale production in 2012. Continued efficiency has lowered breakeven gas supply costs to below \$4.00/MMBtu in the core of the best shale plays. However, insufficient demand meant Henry Hub prices dropped from \$8.86/MMBtu in 2008 to \$2.75/MMBtu in 2012. Producers responded by more than halving the gas-directed rig count from 1,465 to 529 through the same period. As demand grows and prices recover, producers will be able to increase the rig count to take advantage of large volumes of new low-cost supply.

New sources of demand are also emerging. Natural gas use in power generation increased from 18% of generation in 2002 to 30% in 2012. Continued low prices will further encourage natural gas in power generation. Nearly 10 billion cubic feet per day (bcfd) of incremental power generation demand will be added between 2010 and 2025; around half from coal substitution and half from new electricity demand. Low-cost gas will also support resurgent industrial growth, with projections of over 5 bcfd of new demand from energy intensive industries by 2025. Several new large-scale petrochemical projects are already committed. In the longer term, with sustained arbitrage between U.S. natural gas prices and oil prices (arbitrage currently around \$88/boe), it may be possible to displace oil with natural gas in certain transportation markets.

All of these new sources of domestic demand are dependent on abundant low-cost natural gas. However, low-cost gas also makes LNG exports to higher priced international markets attractive. The current policy challenge is to define the best use of U.S. natural gas over the short, medium and long term, balancing the level of exports with new sources of domestic demand.

Subsidies and regulations have enabled intermittent renewable power (excluding hydro) to grow rapidly from 2% of generation in 2003 to over 5% in 2012. Peak shaving natural gas power

generation capacity and resilient grid infrastructure are required to handle the higher short-duration voltage variations that come with increased renewable generation.

Seasonal volatility is also increasing as a result of the growth in natural gas power generation. Natural gas demand for power generation generally peaks in the summer while residential and commercial demand peaks in the winter. The gap between the monthly summer power demand peak and the residential trough has widened by 50% from 470 bcf to 700 bcf over the last 10 years and some markets are now even experiencing dual seasonal spikes.

Natural gas infrastructure has not kept pace with the changing dynamics of supply, demand and increased volatility, even though 23,000 miles of new pipeline were placed into service over the last 10 years. Historical patterns of supply from the Gulf Coast to Northeast demand markets have been disrupted by new supply from the emerging shale plays. For example, just five years ago there was hardly any production from the Marcellus in the Northeast. Today the Marcellus produces over 7 bcf/d and new infrastructure is needed. Infrastructure constraints have led to extreme price events. In 2007/8, Rockies gas prices occasionally went to zero as takeaway capacity was insufficient to handle rising production. This winter, Boston/New England prices spiked to over \$25/MMBtu as natural gas power generation demand increased and generators struggled to secure supply.

New England is a test case for gas availability and the strategic linkage between natural gas and power generation infrastructure. Natural gas power generation in New England has grown from just 5% of the capacity in 1990 to 42% in 2010 but infrastructure has not kept pace. Natural gas net inflow pipeline capacity has only increased 13% in the last decade despite Northeast production growing an astounding 356%. Peak winter monthly natural gas consumption is approaching net inflow pipeline capacity, causing constraints on peak demand days and extreme price volatility. It is ironic that in a new era of abundant natural gas supply, particularly in the Northeast, the market still experiences such extreme price spikes.

When the physical infrastructure is constrained, market integration and efficiency are critical for both natural gas and electricity. Innovations such as firm/interruptible natural gas contracts, shortened bid to dispatch time, intraday re-pricing and encouraging oil supply reserve for dual-fuel generators could help in markets where physical infrastructure is constrained.

Emergency management is an additional area where natural gas and electricity planning should be integrated. After hurricane Sandy, 250,000 customers in Manhattan and many more in New York, New Jersey and Connecticut were without power due to damaged overhead lines. Diesel backup generators quickly ran out of fuel as terminals and retail stations were unable to operate without power. However, in most cases underground natural gas infrastructure was not damaged and local natural gas generators could have provided an effective emergency

power source. Integrating the natural gas infrastructure into emergency planning could improve the resilience of energy infrastructure during natural disasters.

In summary, shale gas in the U.S. is a game changer, enabling the U.S. to become self-sufficient in natural gas. It presents the U.S. with substantial security, economic and environmental benefits. There is the potential for a renaissance in U.S. manufacturing enabled by lower cost energy, a true economic advantage at a time when competing countries have high energy costs and rising labor costs. The only way to take advantage of this is for business and political leadership to collaborate on an effective and integrated energy policy that provides the right framework of fiscal and regulatory oversight to encourage appropriate supply, infrastructure and demand-side investment in the natural gas sector.

The U.S. is the Second Largest Natural Gas Resource Holder

The United States is a world power in natural gas and is now the second largest resource holder after Russia (figure 1). Around forty percent of the vast U.S. natural gas resource endowment of around 2,170 trillion cubic feet (TCF), or 85 years of supply, is considered “unconventional” in that it comes from tight sands, shale or coalbed formations (figure 2). While energy producers have known of these resources for years, production was not economic until the 2000s when horizontal drilling combined with hydraulic fracturing technology made exploitation attractive.

Figure 1: Global Natural Gas Resources

Top Gas Resource Holders (Tcf)	Resources	% of Total Resource
1 Russia	2,623	18%
2 United States	2,170	15%
3 Iran	1,597	11%
4 Qatar	1,370	10%
5 Turkmenistan	767	5%
6 Saudi Arabia	435	3%
7 Australia	384	3%
8 Iraq	351	2%
9 China	333	2%
10 Venezuela	327	2%
Top 10 Total	10,358	72%
Total Global Gas Resources	14,412	

Source: Hess Corp.; IHS Energy; IEA; EIA; PGC

Figure 2: U.S. Natural Gas Resources

Resource Type	Tcf	% of Total
Conventional 2P	809	37%
Reserve Growth	436	20%
YTF Conventional	88	4%
Total Unconventional	837	39%
Shale Gas	679	
CBM / Tight Gas	159	
Total Resources	2,170	
Years of Supply at 2012 Consumption	85	

Source: Hess Corp.; IEA; EIA; PGC

Shale to Dominate Future U.S. Natural Gas Production

Almost all gas production growth in the U.S. will come from unconventional plays (figure 3). Unconventional production will grow by 5.2% per annum from 2010 to 2025 whereas conventional production is expected to decline by 4.5% per annum. Shale gas and tight oil associated gas (the gas produced with shale or tight oil deposits) are expected to account for 62% of U.S. natural gas production by 2025, up from just 24% in 2010. In contrast, conventional production, which accounted for nearly 40% of U.S. production in 2010, will only account for 13% of production by 2025. U.S. natural gas production potential is very highly dependent on continued successful exploitation of the vast unconventional resource base through the next two decades.

Figure 3: U.S. Natural Gas Production by Type (bcfd)

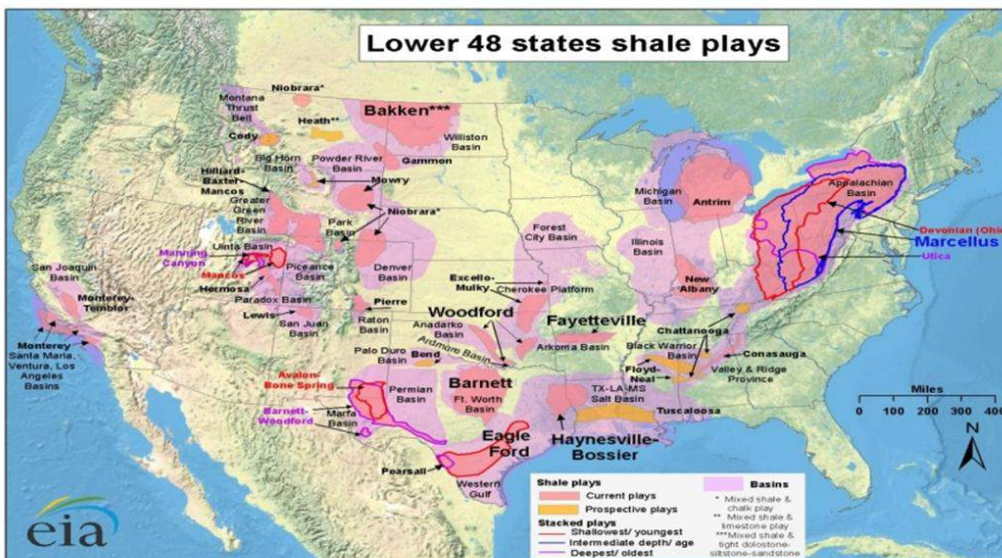
	2010	2011	2012	2013	2014	2015	2020	2025	2010-25 CAGR	% of Total 2010	% of Total 2025
Conventional	23.0	20.2	17.7	16.1	15.3	14.9	12.2	11.6	-4.5%	39%	13%
Unconventional	35.6	43.0	47.8	48.6	50.1	53.3	67.0	76.6	5.2%	61%	87%
Shale Gas	13.8	20.2	24.9	26.3	28.1	30.8	41.2	47.0	8.5%	23%	53%
Tight Oil Associated Gas	0.9	1.9	2.8	3.7	4.4	4.9	6.8	7.7	15.8%	1%	9%
Tight Gas	15.6	15.7	15.3	14.2	13.4	13.5	15.5	18.6	1.2%	27%	21%
Coalbed Methane	5.5	5.1	4.9	4.5	4.2	4.1	3.5	3.4	-3.2%	9%	4%
Total US Production	58.6	63.2	65.6	64.6	65.4	68.1	79.1	88.2	2.8%		

Source: Hess Corp.; Wood Mackenzie

Changing Geography

One of the consequences of the shale gas revolution has been a shift away from traditional producing areas. Unconventional shale gas basins are predominately located in the Rocky Mountains, Mid-Continent, Gulf Coast and the Northeast (Pennsylvania, West Virginia and Ohio) (figure 4). In 2000 the offshore Gulf of Mexico accounted for 25% of U.S. gas production; in 2012 it accounted for just 6% (figure 5). During the same period production in the Rockies and the Northeast grew from 14% of total supply to nearly 30%.

Figure 4: Map of U.S. Shale Gas Plays



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Source: EIA

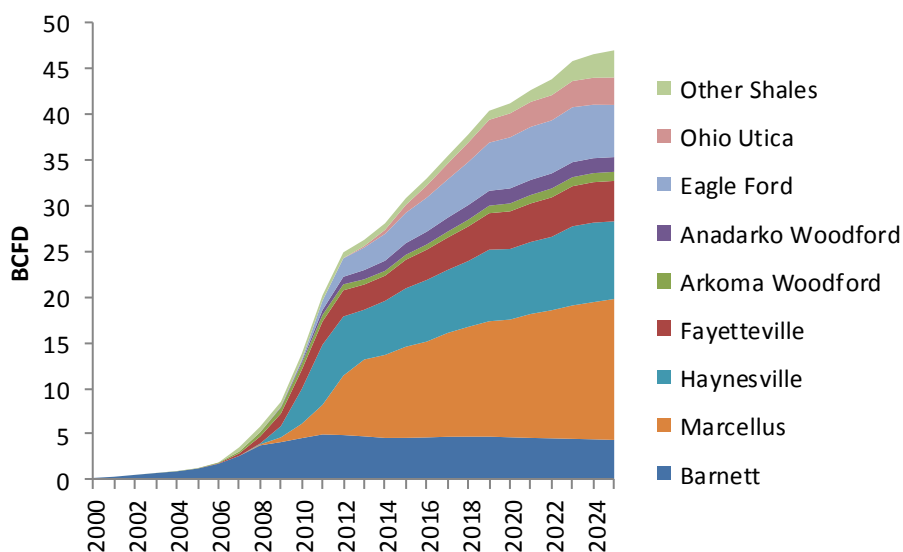
Figure 5: U.S. Gas Production by Region (bcfd)

Basin / Area	Production		% of Production	
	2000	2012	2000	2012
Rocky Mountains	5.1	9.6	10%	15%
San Juan	4.0	3.0	8%	5%
Gulf Coast	15.0	23.3	28%	35%
Permian	4.3	3.6	8%	6%
Gulf of Mexico	13.3	4.3	25%	6%
Mid-Continent	6.7	10.8	13%	16%
Northeast	2.1	9.4	4%	14%
West Coast / Alaska	2.0	1.6	4%	2%
Total	52.6	65.6	100%	100%

Source: Wood Mackenzie

The key producing shale gas plays are the Marcellus, the Haynesville and the Barnett - where shale gas production was first proven at scale in 2002/3 (figure 6). These three plays alone accounted for 72% of shale gas production in 2012 and we expect them to account for 60% in 2025. The Marcellus is the largest play in terms of area and production and is very important due to its proximity to the Northeast demand markets. The Marcellus alone will account for 17% of total U.S. gas production by 2025.

Figure 6: U.S. Shale Gas Production by Play (bcfd)



Source: Wood Mackenzie; Hess Corp.

The growth of the Marcellus has had an important impact on the Northeast. Historically, the majority of gas consumed in the Northeast came from the Gulf Coast / Gulf of Mexico and Western Canada via long distance pipeline infrastructure. In addition, liquefied natural gas (LNG) import terminals were built in anticipation of higher gas demand and limited supply. By 2009 it was obvious that the Marcellus would become the major supplier of gas into the Northeast; indeed, the Marcellus is so prolific that gas will ultimately be back-hauled out of the region.

While the producing industry is able to move quickly and adapt to these changes, the pipeline and storage industries are at an inherent disadvantage given the immovable nature of their assets and the capital required to reconfigure infrastructure to the rapidly changing production geography.

Shale Gas Breakeven Costs are Below \$4/mmbtu

The economics of shale gas are compelling and have improved dramatically in the last 2-3 years. The breakeven cost of adding new supply in the core of the key shale basins is under \$4/MMBtu (figure 7). This low breakeven cost has come about through faster drilling and completion times (more wells per rig) and improved completion designs (more gas production per well). The continuous improvement and dramatic learning curve is part of the reason shale gas production continues to grow despite significantly fewer gas-directed rigs.

Figure 7: New Gas Production Breakeven Costs by Play

Play	2012 Breakeven Cost (\$/MMBtu)	2012 Production (Bcfd)	% of Total US Production
Marcellus	2.79 / 3.34*	6.5	10%
Haynesville Core	3.41	6.5	10%
Barnett Tier 1	3.49	4.9	7%
Fayetteville	3.58	2.9	4%
Eagle Ford	2.53	2.0	3%
Arkoma Woodford	3.87	0.7	1%
Anadarko Woodford	2.70	0.8	1%
Other Shales		0.7	1%
Total Shale		24.9	38%

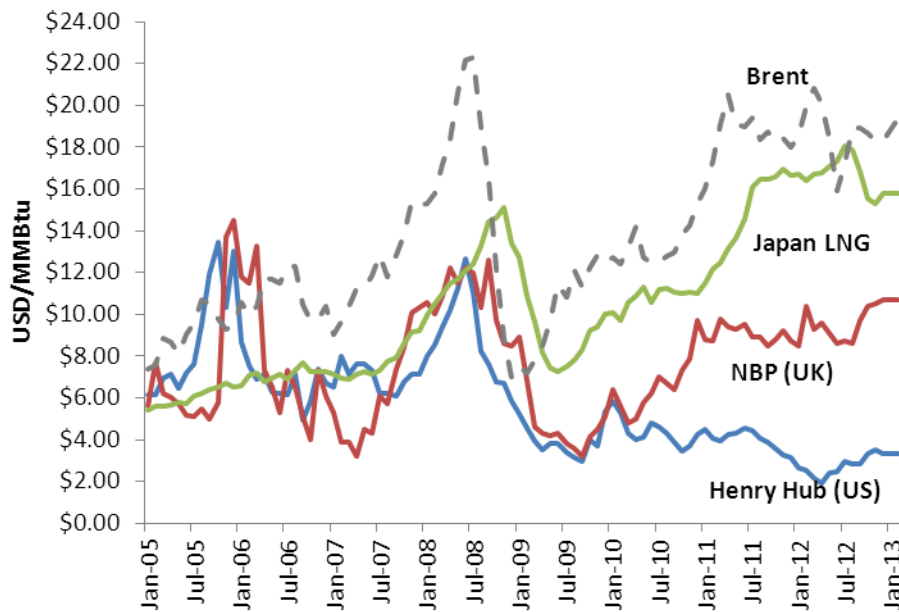
Source: Wood Mackenzie

* Marcellus wet gas = \$2.79; Marcellus Northeast PA = \$3.34

Abundant Supply Has Led to Lower Prices

Through the use of technology and innovation, U.S. natural gas production has increased to record levels. However, demand has not grown as quickly, resulting in U.S. natural gas prices (quoted at Henry Hub) falling well below gas prices in other regions (figure 8). Indeed, U.S. gas prices in 2012 averaged \$2.75/MMBtu compared to \$9.51/MMBtu at the UK's National Balancing Point (NBP) and \$16.70/MMBtu for Japanese LNG. Prices in other regions have strong links to oil prices because natural gas import contracts are generally priced off liquid fuels. Consequently a significant arbitrage of around \$88/barrel of oil equivalent has opened between Brent oil prices and U.S. natural gas prices. This provides sufficient economic incentive to export U.S. natural gas as LNG to oil linked Asian and European markets. In addition, in the longer term, displacing oil with natural gas in certain U.S. transport markets could prove attractive.

Figure 8: Global Natural Gas Prices



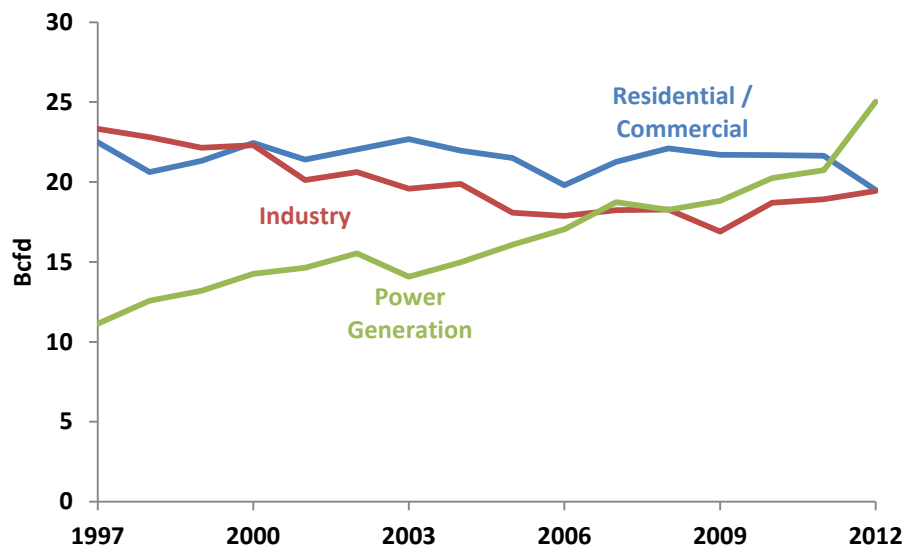
Source: Bloomberg, Hess Corp.

Changing Natural Gas Demand Patterns

The availability of significant volumes of low-cost natural gas is triggering new patterns of demand (figure 9). Power generation demand for natural gas has increased significantly, more than doubling since 1997 (the earliest year with sector consumption data), driven by lower natural gas prices, combined cycle gas turbine (CCGT) economics and coal plant regulation. Power generation reached 39% of natural gas demand in 2012, up from only 20% in 1997.

Conversely, in the first half of the 2000s, before the shale boom became apparent, rising natural gas prices caused energy intensive industries to offshore to regions with lower gas prices, such as the Middle East. From 1997 to 2009, industrial demand for natural gas dropped by over 6 bcfd (28%). However, more recent data shows early indications of a resurgence in industrial demand. Manufacturers are looking at returning to the U.S. to take advantage of low natural gas prices and the economic recovery following the great recession in 2009.

Figure 9: U.S. Gas Demand by Sector



Source: EIA

In the next few years, low cost U.S. natural gas and a continued oil/U.S. natural gas arbitrage will stimulate demand in several sectors, adding around 24 bcf/d (35%) to demand by 2025 with most growth emerging after 2015 (figure 10).

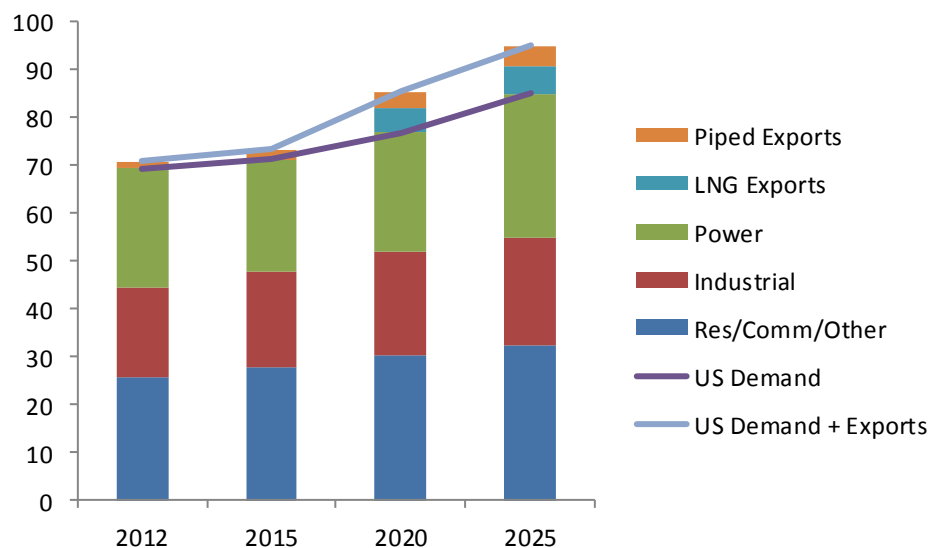
Gas-fired power generation will continue to be built in preference to coal with around 5 bcf/d of incremental demand being added. Renewable power generation, although still small in absolute terms, has grown rapidly as a result of state and government subsidies and regulations (e.g. renewable portfolio standards), from 2% of generation in 2003 to just over 5% in 2012 (excluding hydroelectric). Intermittent renewable power requires back-up generation that can cycle operations at short notice. Although natural gas power generation is the most suitable for this purpose, increased natural gas reserve capacity could strain the natural gas pipeline infrastructure feeding these plants as well as the efficiency of the interface between the pipeline operators, natural gas power generators and ISOs (Independent Service Operators). In addition, it is far from clear whether the consumer will be willing to pay for the reserve back-up capacity as well as the higher direct cost of renewable power technologies.

Around 5 bcf/d of new industrial projects are also likely to come online by 2025. Methanol, ammonia, ethylene and steel are all manufacturing industries that will benefit from low-cost

natural gas. This sector is highly sensitive to gas prices and therefore LNG export policy could have a direct impact on the level of industrial demand growth.

Currently there are 23 bcf/d (totaling 38% of U.S. production) of proposed LNG export projects and one approved project for 2.6 bcf/d.¹ It is uncertain what level of LNG exports the U.S. government will ultimately allow and there are obvious policy implications to consider, particularly the risk of eroding the price advantage that is already stimulating resurgent U.S. manufacturing. It is highly unlikely all of the proposed projects will occur but the U.S. could export 5-6 bcf/d by 2025, a similar incremental volume to industrial growth. If the U.S. allows 10-20 bcf/d of gas exports, it will most likely impact prices and might destroy some industrial or power demand.

Figure 10: Forecast of U.S. Gas Demand by Sector (bcfd)



Source: Wood Mackenzie; Hess Corp

Gas Demand Becoming More Volatile

The demand shift towards power generation is important because it has a different seasonal pattern than residential/commercial and industrial demand. For example, residential and commercial demand is highest in the winter months and lowest in the summer months while

¹ FERC, Existing and Proposed LNG Terminals, <http://ferc.gov/industries/gas/ind-act/lng.asp> (March 2013)

industrial demand does not fluctuate as much. Power demand, in contrast, spikes in the summer. Over time this spike has widened, as gas-fired power generation grows. The difference between power peak demand and residential/commercial demand in the summer of 2002 was around 472 bcf and by 2011 this gap had widened to 700 bcf (figures 11 and 12).

In some regions, “dual seasonal spikes” are occurring, meaning there are peaks on winter and summer days. However, price volatility is still higher in the winter because overall peak demand is higher in the winter.

Figure 11: 2002 Monthly Gas Demand (Bcf)

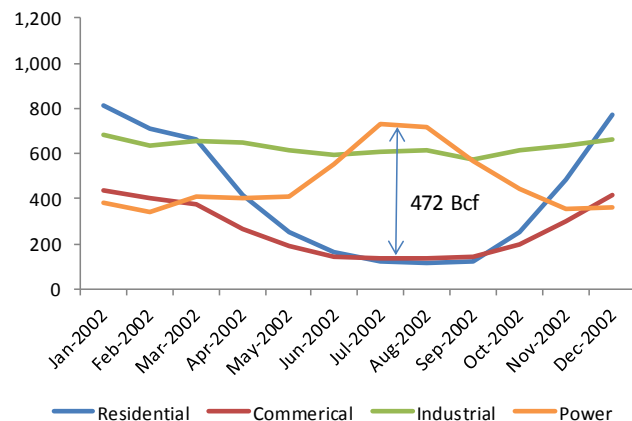
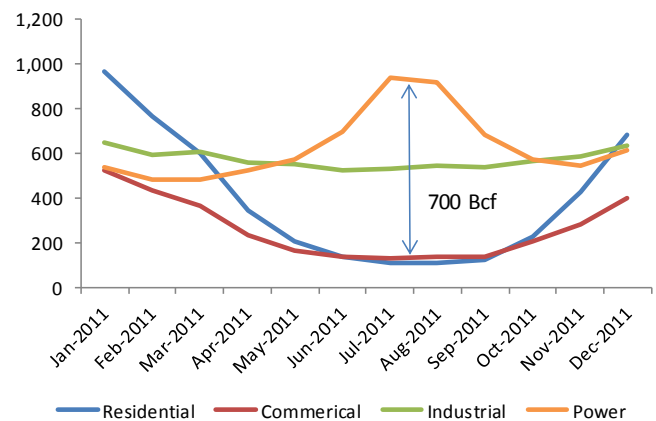


Figure 12: 2011 Monthly Gas Demand (Bcf)



Source: EIA

Gas Infrastructure Has Not Kept Pace

The U.S. has the world’s largest network of natural gas pipelines and storage. In 2011 around 205 bcf/d was transported on U.S. interstate pipelines, about three times daily demand. Average storage capacity in 2012 was 8.8 Tcf, or around 138 days of supply.² However, supply and demand centers are shifting and this is creating infrastructure bottlenecks and constraints.

² EIA, http://www.eia.gov/dnav/ng/ng_stor_cap_a_epg0_sac_mmcf_m.htm (March 2013); EIA, Natural Gas Annual 2011, Table 12

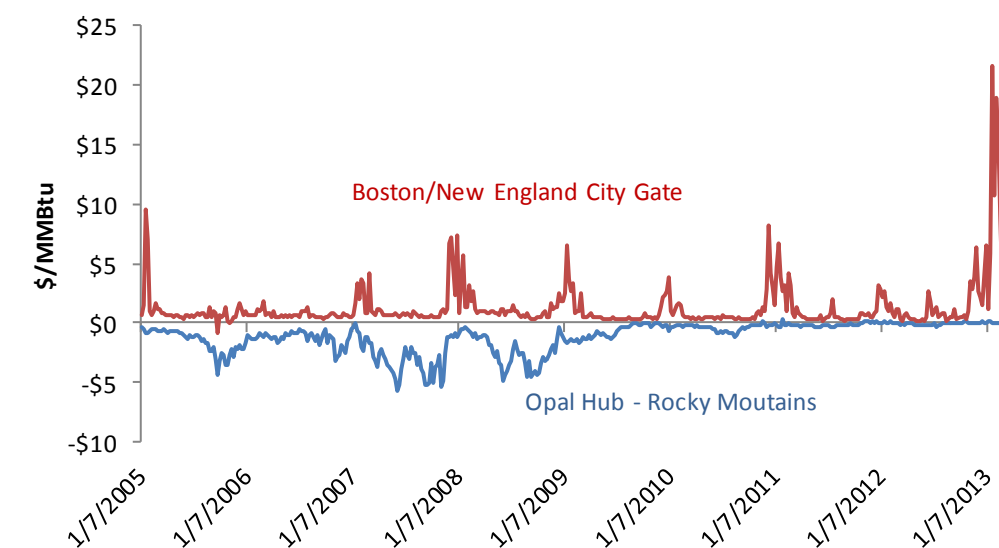
Pipelines:

Pipelines were historically used to take gas from the Gulf Coast supply region to the Northeast demand region. Over time several things have occurred: 1) supply is growing outside the Gulf Coast; 2) population growth is shifting west; and 3) demand grew for gas in power generation, which has the opposite seasonal pattern as traditional gas demand. New infrastructure has not always kept up with these shifts, leading to pricing aberrations.

An example of supply shifting occurred in 2007/08 in the Rocky Mountain supply region. Production grew quickly but pipelines and storage did not keep pace and supply became stranded, driving local prices well below Henry Hub (see figure 13). On some days prices fell to zero as suppliers struggled to find demand markets. The opening of the Rockies Express pipeline (which shipped gas to the Northeast and Mid-continent) in 2008 solved the problem and the price at the regional hub is now in line with Henry Hub.

An example of demand shifting can be seen in Boston/New England City Gate Prices (the Algonquin pipeline). The growth of gas-fired power generation in New England has placed strain on the existing infrastructure, causing extreme price volatility versus Henry Hub (see figure 13).

Figure 13: Weekly Spreads between Henry Hub and Other Spot Prices



Source: Bloomberg

From 2001 to 2011 more than 23,000 miles of new natural gas transmission pipelines were placed into service. The key additions focused on: 1) moving Rockies gas to the West Coast, Midwest and into the Northeast; 2) moving gas from the Gulf Coast into Florida; 3) expansions of lines moving gas out of growing supply areas in the Gulf Coast/Texas; 4) expansions of lines for both imports from Canada into the Northeast and exports of processed gas from Indiana/Michigan to Canada; 5) a new pipeline from U.S. to Baja Mexico.

The Central region, which includes the Rocky Mountains, saw a 317% increase in pipeline capacity versus a 53% increase in production and a 17% increase in demand (see Figure 14). Southeast capacity grew 80%, partially to meet Florida's increased demand. The Southwest region (AR, LA, NM, OK, TX) expanded 151% to meet production growth of 42%.

The only region that has not had significant pipeline capacity additions is the Northeast. Despite production growth of 356% and demand growth of 22%, pipeline capacity only grew 13%.

Figure 14: Gas Pipeline Capacity Changes by Region

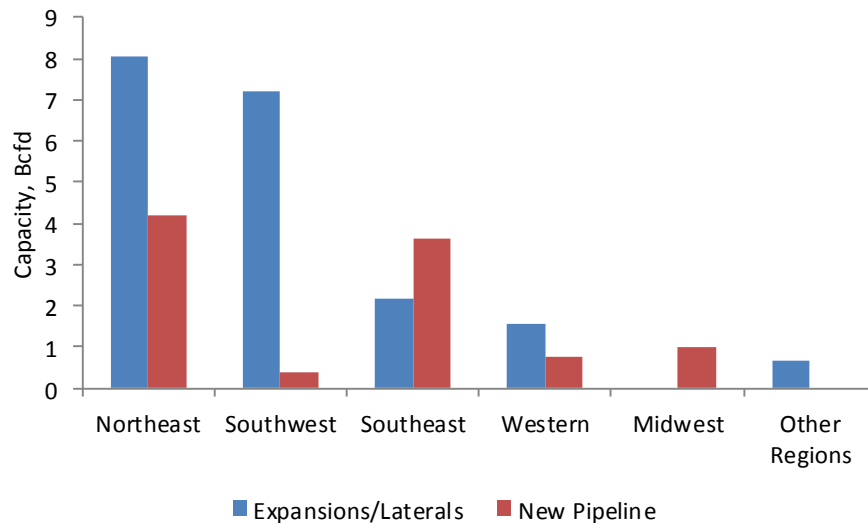
Regional Net Inflow Pipeline Capacity (bcfd)					2001-11 Change in Production	2001-11 Change in Demand
Region	2001	2011	2001-11 Change	% Change		
Canada	-12.0	-13.7	-1.6	13%	NM	NM
Central	-1.6	-6.8	-5.2	317%	53%	17%
Gulf of Mexico	-31.5	-32.6	-1.1	3%	-64%	NM
Mexico	1.4	2.2	0.8	57%	NM	NM
Midwest	17.1	18.4	1.3	7%	-40%	4%
Northeast	11.0	12.4	1.4	13%	356%	22%
Southeast	11.6	20.8	9.2	80%	-35%	60%
Southwest	-6.0	-15.1	-9.1	151%	42%	-3%
Western	10.1	14.4	4.3	42%	-35%	-8%

Source: EIA Note: Regions as defined by EIA

Over the next 3-4 years, 87% of new pipelines and pipeline expansions/laterals will occur in the Northeast, Southwest and Southeast (see figure 15). The data imply new trends: 1) expansions of lines in the Marcellus play to cope with growing production; 2) expansions of lines into the Northeast to deal with increased gas demand; 3) expansions/new lines to meet growing demand in the Southeast (primarily FL, AL, GA and MS); 4) continued expansions and laterals (to storage fields) in TX, LA and OK to accommodate growing supply. It is important to note that

not all of these projects will happen. Planned capacity additions total 30 bcfd, with roughly 40% either approved or under construction.

Figure 15: 2013-16 Gas Pipeline Projects by Region*



Source: EIA

*Includes announced, pre-applied, applied, approved and under construction projects

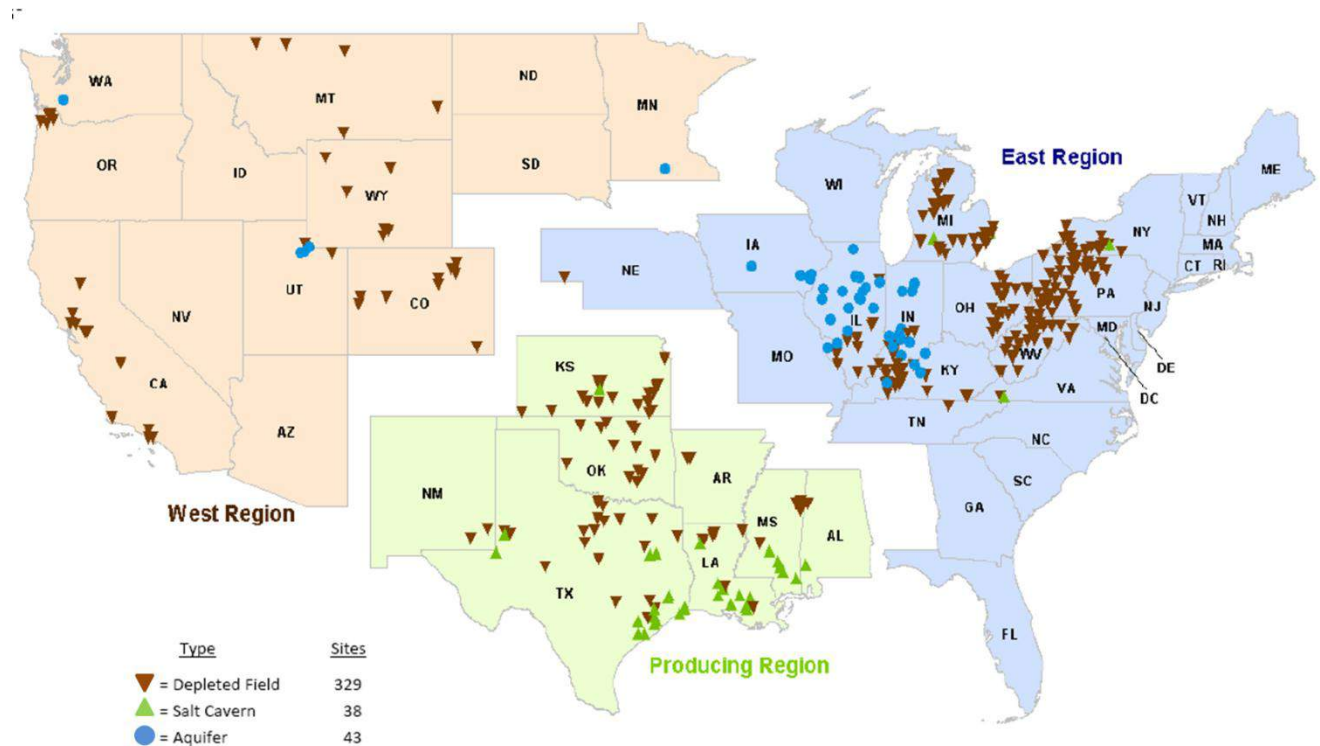
Gas Storage:

Gas storage plays an important role to help the system manage volatility. There are two primary types of natural gas storage:

- 1) Base load storage is used to handle long-cycle seasonal demand requirements. These are typically depleted oil and gas reservoirs and will be located near demand centers (see Figure 16). Around 80% of storage facilities are base load depleted reservoirs. They “turn-over” in a year, meaning there is an injection season (in the summer) and a withdrawal season (in the winter). The amount of gas that can be extracted each day is limited and therefore not useful in meeting peak load demand.
- 2) Peak load storage is used as a cushion in case of shorter term supply disruptions. These are typically salt caverns and aquifers and hold less gas than base load facilities but are able to deliver and replenish gas more quickly. Peak load facilities can “turn-over” in a few days or weeks, making them ideal for short-term demand increases. These facilities

are primarily located near production areas in the Gulf Coast and along major interstate pipelines in the Consuming East.

Figure 16: U.S. Gas Storage Facilities



Source: EIA

There is a notable lack of peak load storage facilities near some key demand centers, particularly in New England and in the West. This makes it even more difficult for generators to use natural gas for peaking and could slow the penetration of renewables.

Peak storage facilities, and in particular salt caverns, have grown the fastest (figure 17), reflecting the growth in gas-fired power generation where gas is often needed quickly during peak times. In addition to meeting peak load demand, gas storage is increasingly being used to capture short term price arbitrage opportunities. If prices surge due to a supply interruption or weather, marketers or other third parties can quickly move gas out of peak storage facilities to

capture the higher price. With gas demand for power generation continuing to grow, 62% of new storage facilities planned between 2012 and 2015 are peak load salt caverns.³

Figure 17: U.S. Natural Gas Total Storage Capacity by Type

	1999		2011		CAGR
	<u>Capacity (Bcf)</u>	<u>% Total</u>	<u>Capacity (Bcf)</u>	<u>% Total</u>	<u>1999-2011</u>
Depleted Reservoirs	6,781	82%	7,105	80%	0.4%
Aquifers	1,263	15%	1,232	14%	-0.2%
Salt Caverns	185	2%	512	6%	8.8%
Total Storage Capacity	8,229		8,849		0.6%

Source: EIA

New England Is Test Case for Gas Availability

New England is proving to be the testing ground for gas availability because of its increasing reliance on gas-fired power generation and lack of new natural gas pipeline and storage investment.

Natural gas power generation capacity grew from 1.3 gigawatts (GW) in 1990 to 15.4 GW in 2010, and went from accounting for 5% of capacity to a staggering 42% in 2010 (figure 18).

Figure 18: Nameplate Power Generation Capacity in New England*

Fuel Source	Capacity		Capacity		CAGR
	(GW)	% of Total	(GW)	% of Total	
	1990	1990	2010	2010	1990-2010
Coal	3.1	11%	3.0	8%	-0.2%
Oil	11.3	41%	8.3	23%	-1.6%
Gas	1.3	5%	15.4	42%	13.0%
Nuclear	6.9	25%	4.6	13%	-2.0%
Total Renewables	4.7	17%	5.5	15%	0.8%
Hydro	3.4	12%	3.5	9%	0.1%
Wind	0.0	0%	0.3	1%	44.4%
Solar	0.0	0%	0.0	0%	
Wood	0.8	3%	0.9	3%	0.7%
Biomass/Other	0.5	2%	0.8	2%	1.8%
Total Capacity	27.4		36.8		1.5%

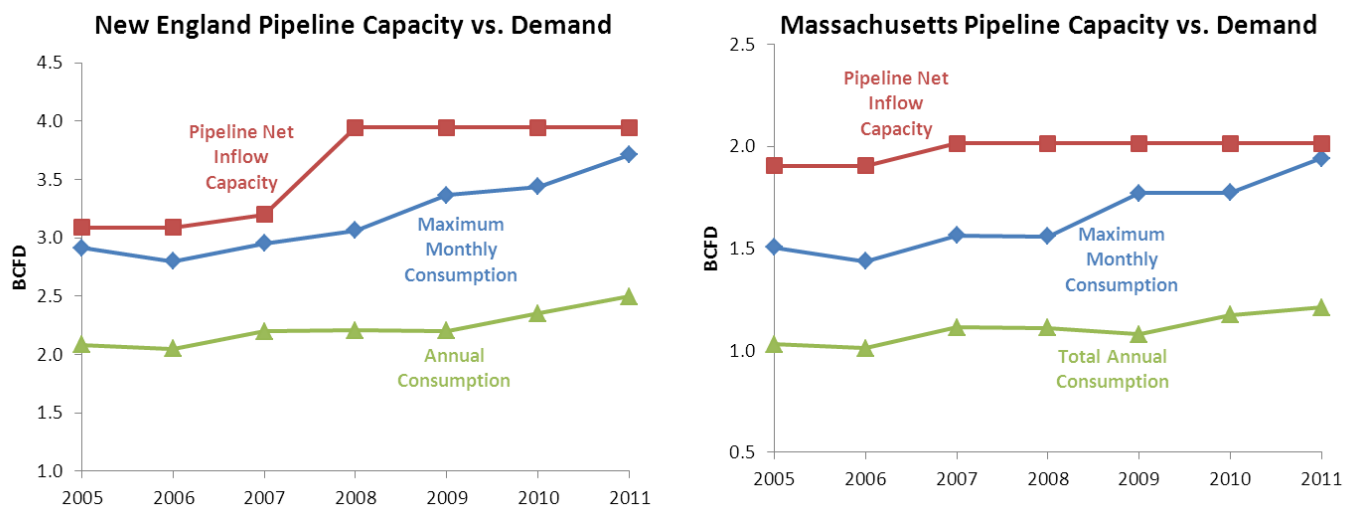
Source: EIA

*CT, ME, MA, VT, NH, RI

³ EIA, EIA-StoragePlan.xls, <http://www.eia.gov/naturalgas/data.cfm>, March 2013

In order to use this gas capacity, power generators need stable access to natural gas. Pipeline capacity into the region is constrained. In recent years New England peak monthly gas demand has approached net inflow pipeline capacity, leading to increased price volatility. The situation is particularly acute for Massachusetts (figure 19).

Figure 19: Pipeline Net Inflow Capacity vs. Monthly Peak and Total Demand



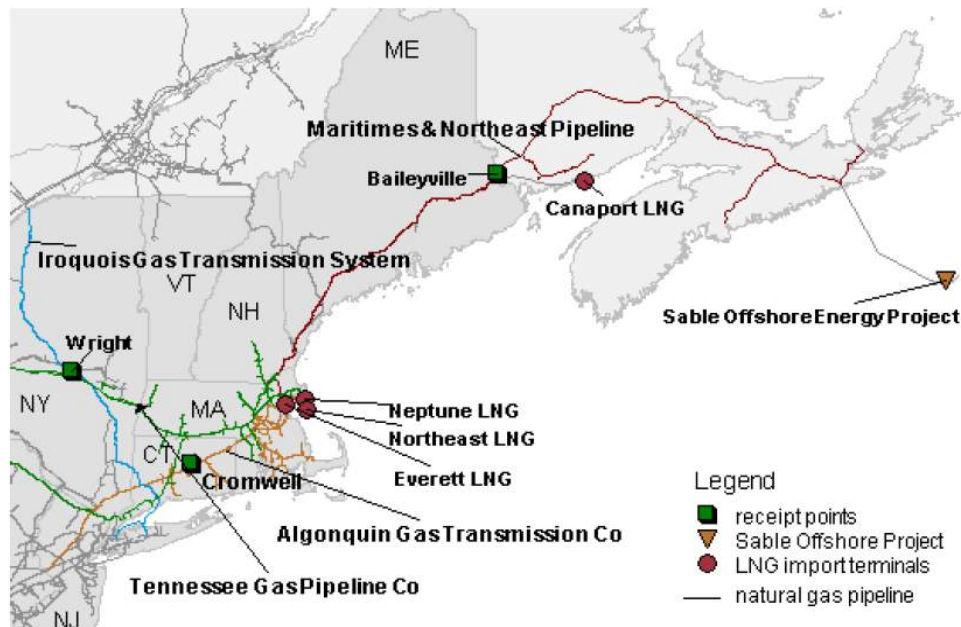
Source: EIA, Hess Corp.

The issue was highlighted in winter of 2012/13 when gas demand in New England spiked by ~700 mmcf/d (30% of New England gas demand), causing local gas prices to rise to over \$25/MMBtu versus Henry Hub at \$3.50/MMBtu. The spike in demand was due to declining production from Canada's Sable field, lower LNG imports (partly due to interrupted supplies from Yemen) and lower power generation from other sources due to nuclear outages, coal not generating at capacity and lower hydro generation. As a result, the Algonquin system and the Tennessee Gas Pipeline were required to deliver the majority of gas to the region (figure 20). Because these pipelines were already constrained, the demand spike could not easily be met. The EIA reports that both the Algonquin and Tennessee Gas Pipeline are full or nearly full. Utilization rates are above 85%, implying constraint.⁴ Going forward this situation will only

⁴ EIA, Short-Term Energy Outlook Supplement: Constraints in New England likely to affect regional energy prices this winter, January 18, 2013, page 3

worsen as supply from the Marcellus (which comes in via the Algonquin and Tennessee lines) and gas-fired generation continue to grow.

Figure 20: New England Gas Infrastructure Map



Source: EIA

The best way to solve this growing problem is to build new pipelines or expand current capacity. However, the interests of natural gas infrastructure companies and power generators are not aligned. The pipeline industry will not build new pipelines without firm contracts and power generators prefer interruptible contracts for “just-in-time” fuel delivery because the current energy market design does not allow them to recover the costs of natural gas they might not use.

In contrast, industrial customers and local distribution companies (LDCs), who predominately serve residential/commercial customers, use firm contracts and generally take precedence over power generators.

In times of peak demand, the New England Independent Service Operator (ISO-NE) will call on generators to provide more power. However, instead of calling on a single generator it

generally calls on the entire fleet because it does not know which units will actually be available. This causes every generator to enter the natural gas market at the same time, which in turn causes gas marketers to raise the price. The ISO does not compensate generators for their actual fuel costs because they rely on bids made the day before or on a previously established proxy price. Therefore, higher gas prices will in some cases push generators below breakeven. In practice, some generators may claim they cannot get access to gas when in reality they do not want to pay the high price and destroy margins.

Requiring generators to secure firm supply would be very costly and not necessarily solve these issues. Gas generators often are not chosen in the day-ahead market so they would not schedule their firm gas. Once firm rights are declined, the generator's priority becomes lower than a non-firm customer. A generator may be dispatched at different rates but the pipelines often cannot accommodate this because pipeline send out remains constant over an hour. Currently, many pipelines are flexible around generators drawing more than their allotment in one hour and less in another. However, there are already instances in New England where pipeline operators have threatened to close gas flow valves to power plants that "overuse gas"⁵.

The natural gas infrastructure and electricity system in New England are increasingly linked. New pipeline capacity is needed but in the meantime there are a number of measures that could help align interests and increase the reliability of the system:

- Changing permitting so dual-fueled generators can run oil when gas supply is unavailable or uneconomic. Giving generators the ability to recover these costs would encourage them to hold oil on reserve.
- Introduce more flexible tariff provisions which would allow alternative contracts for power generators (such as a firm/interruptible contract that ensures firm delivery of gas during certain times of the day and interruptible delivery at other times).

⁵ ISO New England, Addressing Gas Dependence, July 2012, page 7

- Longer lead time notification to gas generators (i.e. shorten up time between bids and ISO dispatch decisions so generators can go into the actively traded market instead of one that is finished trading for the day).
- Intraday re-pricing by generators (currently being planned at ISO-NE).

The Role of Gas in Natural Disasters: Lessons from Hurricane Sandy

Gas also has a role to play in natural disasters because pipelines are inherently more secure than overhead power lines. During Hurricane Sandy in October 2012, many power lines in New York, New Jersey and Connecticut were down, although gas supply remained connected and operating in most areas.

As is common for critical facilities, extensive reliance was placed on diesel-fueled back-up generators. However, diesel fuel soon became unavailable because of the power outage and damage to terminal facilities, essentially causing the whole region to shut down. Natural gas generators were a good solution for those that had them. These generators run off natural gas piped into homes and businesses and proved to be substantially more reliable than diesel generator back-up.

The day after the Hurricane, around 250,000 customers in Manhattan (serviced by ConEd) were without power. If all of these people had backup gas generators, gas demand could have spiked by 1.0 Bcfd⁶ which could have been met with current peak pipeline capacity into the city of 1.12 bcf/d.

Integrating both the gas and power grid into emergency planning and preparedness could have a tangible impact on the robustness of disaster response in the region.

⁶ Assumes each customer utilizes a home natural gas generator, running at 75% load and consuming 163 cubic feet per hour

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MIT Energy Initiative
2013 MITEI Symposium
Growing Concerns, Possible Solutions
The Interdependency of Natural Gas and Electricity Systems
April 16, 2013

Ensuring Natural Gas Availability

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I. Introduction

In the past year or so, the Federal Energy Regulatory Commission (the FERC) has sought industry input on how better to coordinate the electricity and natural gas industries.¹ Spurred by some recent problems, particularly widespread scheduled blackouts during a cold-weather event in the southwest in 2011, the Commission has scheduled technical conferences on how to deal with a nation that is increasingly relying on gas-fired generation, given the growing abundance of low-priced natural gas and its role in displacing coal and oil-fired generation. Since the FERC's concern involves two industries that it regulates, it is reasonable to ask whether better planning and coordination, and perhaps better incentives for the right kind of infrastructure (in gas pipelines and storage), are reasonable elements of a better-synchronized and more reliable energy supply business that best serves the public interest. It is also reasonable to see the industry comments emanating from the FERC initiative. As expected, the gas distributors wish to maintain the firm services that they have paid for, and rely upon, to meet their own needs. Similarly, the various independent system operators (ISOs) ask whether it is possible for pipeline companies to offer expanded services, beyond the traditional firm/interruptible variety, better to meet the needs of competitive gas-fired plants that connect to their grids.²

But it is important to consider just what the FERC is trying to do—to deal with the coordination issues between the *deregulated* components of two energy industries. Since the development of competitive US power markets, much of the incremental generating capacity (70 percent, in the NYISO, for example) has come from merchant power suppliers at competitive prices.³ And for the gas industry, *all* of the gas is produced and sold in vigorously competitive spot markets complimented by the kind of vigorous futures markets that attend other

¹ See: Federal Energy Regulatory Commission, Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets, February 3, 20120. Docket No. AD12-12-000.

² See: Comments of the American Gas Association and Joint Comments from the various ISO, Docket No. AD12-12-000.

³ See: Rick Gonzales, "Gas-Electric Coordination, the NYISO Perspective." Gas-Electric Harmonization Panel Discussion, NARUC Winter Meeting, Washington DC, February 4, 2013.

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commodities.⁴ Likewise, while interstate pipelines charge cost-based rates for the capacity they are licensed by the FERC to sell, *all* of the interstate pipeline capacity is competitively bought and sold in an advanced, well-informed, liquid and web-based market under prices and terms that the FERC ceased regulating in any way in 2008.⁵ The FERC and other regulators have accomplished great things in the United States over the past 20 years in promoting competitive gas and electricity markets. Compared to those initiatives, the electricity/gas market coordination issues the FERC is studying are modest ones. The issues concern logistics, information and coordination. By in large, they do not involve infrastructure investment planning or market making—the markets are already there, and the FERC is not in the business of planning for either gas pipeline or electricity infrastructure development.

Such is not the case in the European Union (the EU), however. While the US gas industry is based upon well-defined property rights regarding spatial and temporal shipping capacity on the pipeline system, the EU gas industry is based on the socialization of both spatial and temporal aspects of the transport of gas.⁶ That is, investment in the US pipeline system rests on the underlying property rights; capital markets support new investment when credit-worthy shippers sign capacity-based contracts on particular FERC-licensed capacity projects. In the EU, there is no ability to tie transport contract quantities to specific facilities, or to tie prices to the cost of system use; to address this, central planning for the pricing, use, and expansion of the gas pipeline network is an integral part of the EU's new 2009 regulations.⁷ Those regulations leave

⁴ The comments the largest industry group, and American Gas Association, refer to US natural gas reserves as adequate for 100 years of supply at current consumption levels and a highly reliable pipeline and storage system. Docket No. AD12-12-000, Comments of the American Gas Association, March 13, 2012.

⁵ The fully-evolved nature of gas pipeline regulations in the U.S. is amply demonstrated in June 2008 by FERC Order No. 712, where the agency displayed its satisfaction with the competitiveness of the market in pipeline capacity entitlements. It permanently eliminated any cap on the prices at which legal gas transport entitlements trade in the market. It also facilitated the assignment of entitlements to competitive aggregators for the purpose of more efficiently selling transport rights in a competitive market. See: 123 FERC ¶ 61,286 (issued June 19, 2008).

⁶ See: Vazquea, M., Hallack, M., and Glachant, J-M, "Designing the European Gas Market: More Liquid and Less Natural?" Economics of Energy & Environmental Policy, Vol. 1, No. 3., pp. 25-38.

⁷ Third Legislative Package, Explanatory Memorandum, Section 1.2. Proposal of the European Parliament and of the Council amending Directive 2003/55/EC concerning common rules for the internal market for natural gas, ("Third Legislative Package"), 2009.

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the planning for pipeline operating and expansion to gas industry transmission system operators (TSOs).

We have the two most extensive pipeline systems in the world serving many millions of gas consumers—US and EU—that share nothing in common other than the fact they both somehow transport gas through pipelines. One system handles a competitive gas market through a competitive trade in property rights to transport over a cost-based-regulated interstate pipeline system. The other handles its gas supply (the price of which is tied by long-term contract to oil prices) through a regime that socializes the spatial and temporal realities of gas transport. Hence the EU needs to centrally plan for the use and expansion of the facilities because it has decided not to use prices and contracts—and the capital markets—to handle planning competitively. One is competitive; the other is centrally planned. So what?

Economists love to study power pools and design nodal pricing models managed by independent system operators (ISOs) to price, plan and authorize expansions to power grids. There are no such institutions in US gas supply—for traditional local gas companies or for the electric generation business. However, there are such planning models for the gas pipelines in the EU, and there are ISO (called transmission system operators—TSOs) all over the EU. In this paper, I describe how the gas pipeline industry served by such unexciting technology avoids such economic and regulatory intervention in the United States—but embraces it in the EU. I start with a review of the physical properties of the industry and then describe the economic features that distinguish it from other industries generally (asset specificity) and from electricity transmission (transacting on a network). Then I turn to the institutional features that drive wedges between the performance of gas industries in the United States versus the EU, and in US gas pipelines versus US oil pipelines. Those contrasts go far to explaining the substance of the competitive market in US interstate gas transport and the reason be confident in the US gas supply industry's ability to ensure future natural gas availability.

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II. What does “Ensuring Gas Availability” Mean?

For those of us who lived through the gas problems in the United States in the 1970s and 1980s, after the OPEC oil embargo turned energy industries on their heads, *natural gas availability* generally means avoiding economic shortages of the fuel. During that era, the longstanding battles between gas producing interests and gas distributors in the United States that began in the 1950s—ranging from the Supreme Court to Congress to the Federal Power Commission (FPC)—contributed to a gas shortage in interstate markets that economists at the time estimated to cost \$2.5-5 billion per year in increased energy costs and lost production.⁸ Those problems, among others, brought about calls by prominent jurists and economists (including a currently-sitting Supreme Court Justice) for the elimination of federal regulation of the gas industry.⁹ Indeed, that shortage of gas, in markets served by US interstate pipelines, led in the 1980s and 1990s a series of events that saw those pipeline companies voluntarily open their pipelines to independent shippers and eventually exit the gas trade entirely. Today, US interstate pipelines simply transport gas owned by others by contract. They operate under a longstanding regulatory regime that limits their prices to a transparent *cost of service* for the capacity that their FERC licenses permit them to sell. But the FERC also safeguards and facilitates unregulated and transparent “Coasian” markets for the re-sale of the capacity on electronic exchanges.¹⁰ Those Coasian markets have allowed the use and expansion of the regulated interstate pipeline system to be a highly competitive activity.

It took enormous amounts of work, and great regulatory battles between organized and interested parties, to get US interstate pipelines out of the gas trade. They did not exit that business willingly. For almost a century, gas pipeline companies had been the main buyers and sellers of gas in the United States—just like the member-state pipeline companies are today the

⁸ The economic shortages of the 1970s were not due to the inadequacy of infrastructure, but rather the desire of gas sellers to evade commodity price controls until the perceived inevitability of their lifting. See: Pierce, R.J., “Reconstituting the Natural Gas Industry, from the Wellhead to the Burnertip,” *Energy Law Journal*, Vol. 9, No. 1 (1988), p. 10.

⁹ MacAvoy, P.W., *Energy Regulation by the Federal Power Commission*, Brookings, Washington, D.C. (1974), with Stephen Breyer; and *The Natural Gas Market, Sixty Years of Regulation and Deregulation*, Yale University Press, New Haven (2000).

¹⁰ Coase, R.H., “The Problem of Social Cost,” *Journal of Law and Economics*, Vol. 3 (1960), pp. 1-44.

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main buyers and sellers of gas in the European Union (EU)—or oil pipeline joint ventures (or LLPs and MLPs) own much of the oil shipped on their interstate oil pipelines. For the interstate gas pipelines of a century ago, *owning* the gas they shipped, and being free of the burdens of railroad-inspired common carriage (and the Interstate Commerce Commission), was the *sine qua non* for the business. For investors in those times —before transparency in contracts, financial information or the Securities and Exchange Commission—transacting through contracts with independent pipelines was a commercial impossibility.¹¹ Investors would not sink money into gas pipelines unless they were both vertically integrated and strictly controlled access to the lines. And Congressional legislators, from states who wanted to enjoy natural gas service, and who shaped the regulatory laws, said so.¹²

Things changed. Congress took a veritable meat cleaver to vertically integrated interstate gas pipelines in 1935, in what an economist of the era called “the most stringent, corrective legislation that ever was enacted against an American industry... [a] remedy well suited to the patient.”¹³ Then Congress passed far-sighted regulatory legislation in 1938.¹⁴ Then the courts, Congress, the federal regulator, the pipelines and the US gas distributors battled for more than 40 years about the price of the gas bought by those pipelines for re-sale to those distributors and their many millions of gas consumers. The basic character of those battles are simple enough to characterize: semi-rival regulated pipeline companies, which profit only through a return on their regulated transport investments, simply do not make responsible agents for the purchase of gas on behalf of captive distribution utilities, in illiquid markets dominated by long-term contracts.

¹¹ The means of financing independent interstate gas pipelines in the United States were not invented until the 1940s. See: Hooley, R.W., *Financing the Natural Gas Industry*, Columbia University Press, New York (1961).

¹² Senator Joseph P. Foraker (R. Ohio): “If it should go out, after they have raised the [\$5,000,000] to build the line, that any man can take possession of it to bring gas there for his own purposes, and that the line is to be under the charge of the Interstate Commerce Commission, I think it will be the end of the enterprise.” Congressional Record—Senate, 59th Congress, 1st Session (May 4, 1906), p. 6371.

¹³ Troxel, E., *Economics of Public Utilities*, p. 172. He was describing the Public Utilities Holding Company Act of 1935. 49 Stat. 803 (1935). Corporate lawyer John Foster Dulles, later President Eisenhower’s Secretary of State, was so convinced that the Holding Company Act would not survive Constitutional challenge that he gathered the executives of the leading holding companies into his Wall Street office, saying: “My strong advice to you gentlemen is to do nothing. Do not comply; resist the law with all your might, and soon everything will be alright.” Dulles was wrong, but the episode illustrates the challenges Congress has generally in crafting legislation to control American business. (Shamir, R., *Managing Legal Uncertainties: Elite Lawyers and the New Deal*, Duke University Press (1995), p. 67)

¹⁴ Natural Gas Act of 1938, 52 Stat, pp. 821-833. The Act was approved on June 21, 1938.

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Trouble was inevitable until the interstate pipelines ceased interposing themselves into gas transactions and let sellers and buyers deal with each other directly.

The gas market in the United States is today highly competitive. Natural gas is available in abundance, and competition is driving gas prices down to evidently-sustainable levels far below their oil-equivalent values. The gas market has seen the widespread application of new gas extraction technology permitting the rapid development of heretofore economically unobtainable “unconventional” gas supplies. The new pipelines needed to connect those unconventional gas supplies are licensed quickly by the federal regulators. The result is low gas prices for consumers, lower electricity prices as lower fuel costs drive down the competitive price of electricity, the re-birth of the US petrochemical industry, the displacement of gas for coal generation and its effect on carbon emissions, among other things, including impressively high returns for the independent interstate pipeline industry.¹⁵ By any reasonable measure, removing pipeline companies from the gas trade was well worth it.

This is not to say that the birth of these new markets have not caused logistical, planning or coordination problems, either in the gas market or in related industries such as power generation. However, those of us who lived through the creation of these competitive US gas and pipeline transport markets tend to make sharp distinctions between *economic shortages* in the availability of gas or pipeline capacity and the *planning/logistical problems* of ensuring adequate supplies during, for example, the coldest and windiest days of a 1-in-50 winter cold snap as occurred during the cold weather event of February 1-5, 2011 in the southwest region of the United States.¹⁶ Those at the FERC, and in the industry, are right to work toward better planning and coordination between competitive gas and power markets and the need for the public to avoid scheduled blackouts that are due to weather-induced fuel unavailability. But comparisons to regulated transmission adequacy planning for US power pools (where electric

¹⁵ See: Makholm, J.D., and Strunk, K., “Zone of Reasonableness: Coping with Rising Profitability a Decade after Restructuring,” *Public Utilities Fortnightly*, 1 July 2011; and Makholm, J.D., and Olson, W., “Fueling the Price of Power (and Gas): The Rising Profitability of Pipelines and the Need for Collective Action,” *The Electricity Journal*, June 2011, Vol. 24 Issue No.5.

¹⁶ See: Federal Energy Regulatory Commission and North American Electric Reliability Corporation, Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011,” August 2011

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transmission markets have transacting problems that gas pipeline markets do not have), or the European experience (which has great institutional problems that have prevented the development of a competitive gas market at all), do not work for the gas industry in the United States. The gas industry has never had “top-down” planning in a century of regulation. Nor has it had shortages of pipeline capital since the Great Depression—before the US interstate gas pipeline industry came under the federal regulatory system we have today.

III. Pipelines are Pipelines

Perhaps the only thing that distinguishes gas markets from those of other bulk commodities, like coal, cement, or the like, is that pipelines are the only economical way to transport that commodity any meaningful distance. Pipelines have served this function in the gas market for well more than a century. And ever since power equipment replaced hand shovels and welds replaced rivets and screw fittings nothing much has changed in the technical analysis of pipelines.

A. The Simple Physics of Pipelines

Those economists dealing with gas pipelines now know, from pipeline engineers and pipeline cost studies, that gas pipelines exhibit powerful economies of scale. The simple reason for this is the generally-accepted rule of thumb that there is a linear relationship between the construction cost of a pipeline and its diameter while the capacity of a pipeline is related to the square of the diameter. If capacity squares with diameter, while construction costs rise in proportion, then it would appear that the average cost of increased pipeline capacity is an ever-declining function. Such defines a natural monopoly, like that in the familiar figure below.¹⁷

¹⁷ See: Keeler, T.E., *Rails, Freight and Public Policy*, The Brookings Institution, Washington, D.C. (1983), p. 49.

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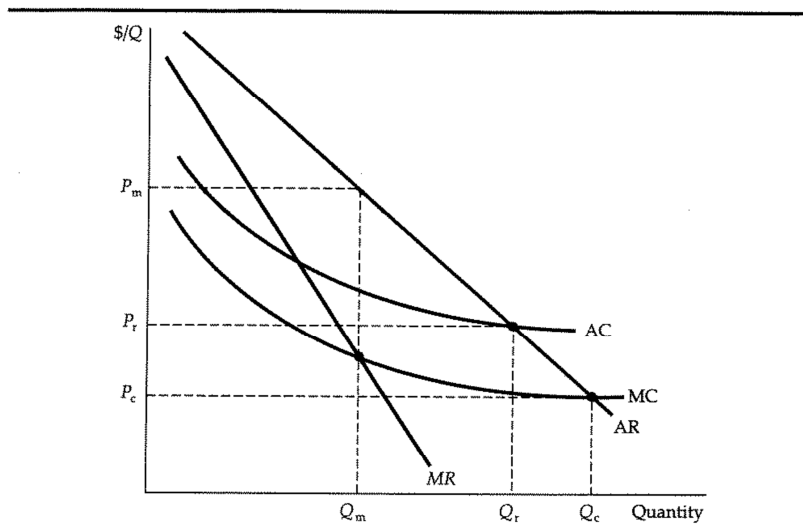
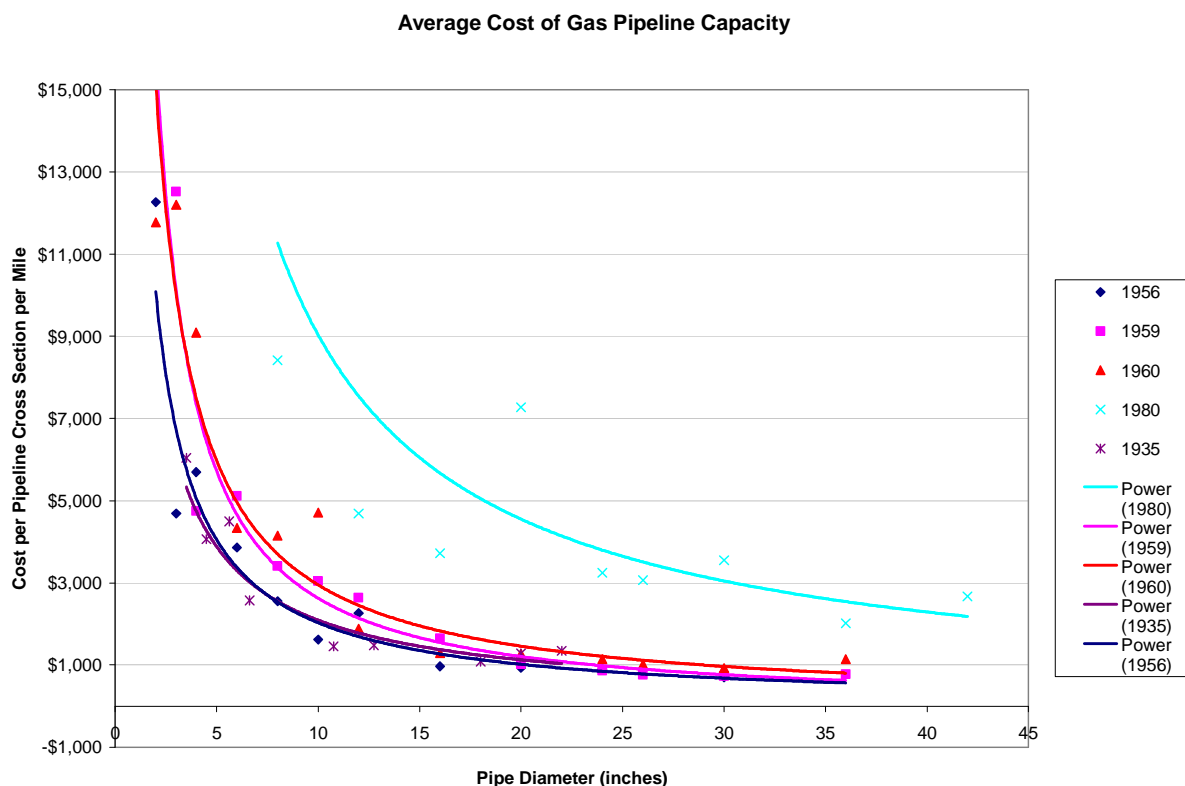


FIGURE 10.9 Regulating the Price of a Natural Monopoly. A firm is a natural monopoly because it has economies of scale (declining average and marginal costs) over its entire output range. If price were regulated to be P_c , the firm would lose money and go out of business. Setting the price at P_r yields the largest possible output consistent with the firm's remaining in business; excess profit is zero.

Do pipelines really exhibit such economies of scale? I plotted data for gas pipeline construction costs in 1980 dollars, from the 1935 to 1980, in the following figure.¹⁸ With those data I add a simple nonlinear trend line. Allowing for a certain noise in the information, the data collected at various times on gas pipeline construction costs confirm the rule of thumb. Pipeline costs are generally linear in diameter, with capacity increasing with diameter at a factor of the ratio of area to radius, or $2\pi r$. There is nothing in these data to indicate that the average cost for gas pipeline capacity is anything other than downward sloping over the entire range of existing pipeline sizes.

¹⁸ See: Troxel, C.E., "Long-Distance Natural Gas Pipe Lines, The Journal of Land and Public Utility Economics, Volume XII (1936), page 349; Leeston, A.M., Crichton, J.A., and Jacobs, J.C., The Dynamic Natural Gas Industry, University of Oklahoma Press, Normal OK (1963), pages 83-85; McAllister, E.W., (ed.), Pipeline line Rules of Thumb Handbook, Fourth Edition, Gulf Publishing Company, Houston Texas (1998), pages 510, 544.

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Of course when it comes to transporting gas long distances, installed pipeline capacity is only one measure of the total costs of delivery. Gas normally exits at producing wells at great pressure that often has to be stepped-down before it is processed to remove petroleum liquids and other impurities in order to enter gas transmission lines. Once in transmission pipelines, however, the flow of gas is caused by pressure differential, which becomes lower as the gas moves from the inlet towards the outlet of the pipeline. The greater the pressure differential the greater will be the capacity of the line. And following both the rule of thumb and the observation of pipeline costs, we have the 101-year-old Weymouth's formula.¹⁹

¹⁹ See Leeston, A.M, et al (1963), pages 69, 78. The formula is attributed to Mr. R. Weymouth (from a paper read in 1912 before the Society of Mechanical Engineers). Other, more empirical but generally equivalent approximations to Weymouth's formula appeared later, known as the Panhandle and Modified Panhandle equations, whose developments

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$$Q = 670.8 d^{8/3} \sqrt{\frac{P_1^2 - P_2^2}{GL}}$$

Here, Q is the cubic feet per hour, d is the internal diameter of the pipe, P_1 and P_2 are the inlet and out pressures, respectively, G is the specific gravity of the gas and L is the length of the pipe. While this formula was modified over time as pipeline companies gathered new information on construction and operating costs, those modifications are not material in the search for economies of scale or the natural monopoly features of single pipelines traversing the countryside. The capacity of the lines is an exponential function (8/3, or 2.66) of the diameter, and it drops by the square root of the inverse of the pipeline length.

For economists interested in pipelines, this is as far as the analysis can go—the rest is up to the engineers. Pipelines are big, dumb (i.e., mute) inanimate objects, representing almost pure capacity, that are subject to cost relationships that have been well-known for over a century. How modern fuel markets relate to the pipelines that serve them has very little to do with these cost relationships. Rather, modern fuel markets thrive or fail in relation to the institutions that govern pipeline behavior.

B. *Asset Specificity*, or “Marginal Costs with a Ball and Chain”

When President Jimmy Carter appointed Professor Alfred E. Kahn of Cornell University to deregulate the U.S. airline industry in the late 1970s, Kahn described the nature of the airline transport business as “marginal costs with wings”—capable of moving its capacity flexibly as its market demanded, as long as it was unhindered by complex entry and pricing regulation. By comparison, the pipeline business might be described as “marginal costs with a ball and chain.” Pipelines cannot shift from one location to another as Kahn’s airliners could. As the vehicles for the inland transport of oil and gas, the vast capital resources that pipelines tie up for decades along their routes is land-bound and immobile. Pipelines are built from one spot to another; to serve particular oil and gas producers at one end and refineries, gas distributors or power plants at the other. Opportunism on either end of such arrangements—oil producers shipping crude oil

paralleled the Panhandle Eastern Pipe Line Company, which became the first lengthy United States pipeline company in the early 1930s, bringing Oklahoma and Kansas gas to Illinois.

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another way or gas distributors taking from another source—can strand pipelines and wreck the value of the invested capital. Conversely, pipeline companies that refuse to serve can disrupt production and distribution operations (as Russia’s Gazprom did to the Ukraine in 2009).²⁰

The immobility of capital sunk into pipelines, those lines’ high up-front costs, their unusual longevity, and their general uselessness for any purpose other than that for which they were designed make for a peculiar kind of industry. For those who commit capital to pipelines, avoiding opportunism or uncertainty on the part of producers or refiners/users of oil and gas, and vice versa, is extremely important. Oliver Williamson calls this mutual capital-based dependence “asset specificity.” It is not surprising that, left alone, pipelines tend to vertically integrate with particular oil and gas producers to deal with asset specificity and avoid such uncertainty and risk to capital. But vertical integration has its own perils when pipelines are involved: oil and gas producers tend to use integrated pipelines as weapons against non-integrated rivals, harming competition in the production and supply of those fuels. Governments have taken various approaches to the balancing act of facilitating the flow of capital to the pipeline business—by far the most efficient method of inland fuel transport—while at the same time trying to prevent pipelines from being used to damage competition in oil and gas markets. In North America, the US and Canada sought that balance through regulation of investor-owned pipelines. Most of the rest of the world sought that balance by building monopoly government pipelines with taxpayer funds (although many of those pipelines were sold to investor-owners in the worldwide privatization wave of the late 20th century). All of those efforts—either private or public—depend on a range of governance institutions to track costs, set prices, raise (or lower) barriers to competitive entry and support (or inhibit) markets in the fuels they carry. Evaluating markets served by these inanimate objects subject to age-old physical constraints is all about institutions.

²⁰ “Russia Cuts Off Gas Deliveries to Ukraine,” New York Times,
http://www.nytimes.com/2009/01/02/world/europe/02gazprom.html?_r=0

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C. *Transacting on a Network: Pipelines Versus Wires*

The distinctly differing technologies of gas and electric transport/transmission systems make for fundamentally different transacting requirements. Transacting by contract between points on a pipeline system is easy when the pipeline is engineered to handle the distinct physical needs of suppliers and consumers. While everyone's gas is commingled, it is a matter of straightforward accounting to compute whose gas is flowing where. Such transacting is impossible under current technology for AC electricity grids. Economists designing modern power markets have long recognized this transacting problem for electric grids even if they have not referred to it in the language of transaction cost economics, as such.²¹ As a result, economists and regulators have designed all newly competitive power markets with regulated governance organizations to deal with the electric grid operation, pricing and investment—the independent system operators (ISOs). Regulating the system operation, pricing and expansion of a pooled transmission grid serving diverse suppliers and users is a complicated affair with its own direct costs, externalities, inefficiencies and uncertainties. Under current technology, competitive power markets have no other choice.

But it does not make sense to apply such a transacting scheme—with its regulation, uncertain governance, unpredictability and uncertainty in pricing and planning—to an industry that could, and did, grow up transacting inalienable property rights without regulatory oversight outside of licensing and ratemaking.

²¹ In her 2002 book on power markets, my late colleague Sally Hunt usefully recognized the technical distinction between gas pipeline systems and power transmission networks:

[T]he pipeline contracts are not complicated—they are for point-to-point transport on a given system—a contract path. In electricity, the transmission system is a grid; the laws of physics mean that electricity does not flow over the designated contract path. (In other words, point-to-point in gas is equivalent to contract path, whereas in electric, point-to-point is different from the contract path). What this means is that the physical laws governing flows of electricity on the grid make it extremely difficult to create a system of tradable property rights in transmission capacity that can facilitate trading power. Rights are both difficult to define and to enforce. ... what [gas users] paid for and what they use is unambiguous in gas, and is not in electricity. (Hunt, S., *Making Competition Work in Electricity*, John Wiley & Sons, New York (2002), p. 400.)

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D. Has the US Government Ever Planned a Fuel Pipeline?

The US government has indeed planned and financed a major new pipeline project. Once—in 1942. Indeed, that project, part of the Texas Eastern system, continues to serve Northeast US markets (and my own home).

Before World War II, the gas pipeline industry was generally an American phenomenon.²² Some of these gas pipelines were impressive and expensive, but they did not represent a network on a continental scale. Barely more than a quarter of gas marketed in the United States was shipped through these pipelines across state lines.²³ By the late 1930s, however, construction of new pipelines slowed, with not a single significant pipeline appearing after 1937.²⁴

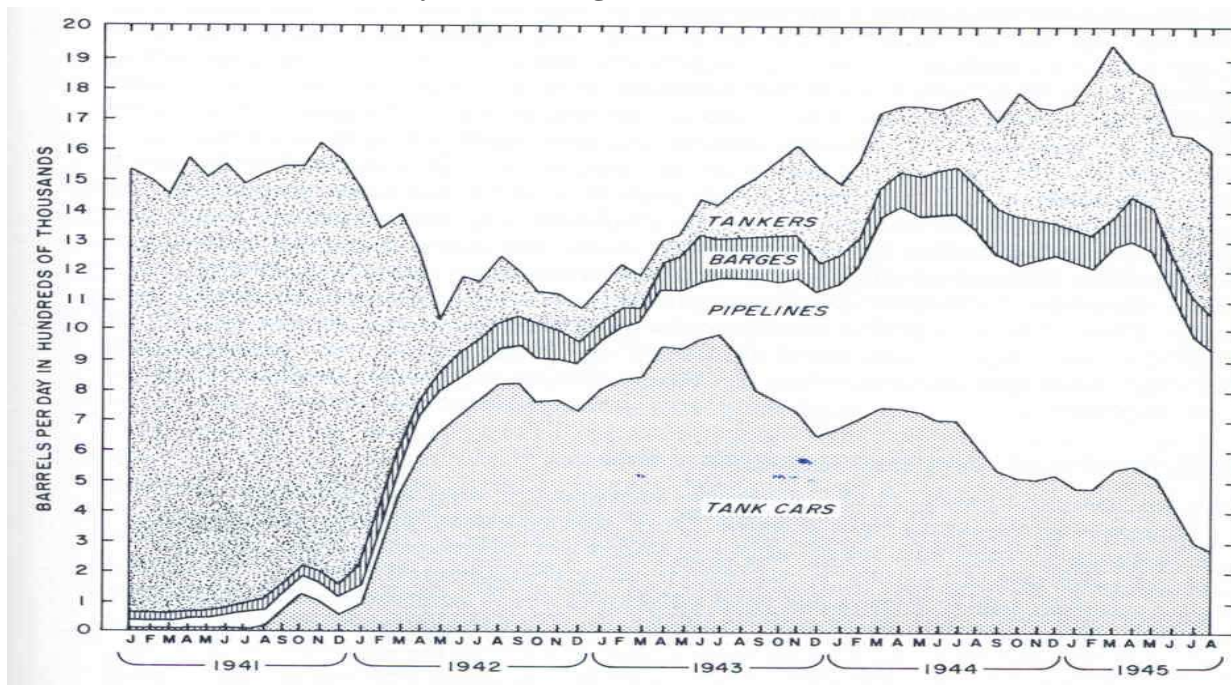
WWII changed the gas industry. In early 1942, U-boats were sinking up to a dozen oil tankers a month on the east coast of the United States. It was an extreme national emergency, for not enough oil reached the cities of Washington, New York and Boston to fuel the rapidly expanding war effort. Whole trains of rail tank cars were thrown together and rushed into service to help with the shortfall. But tank cars were an expensive and inefficient way to ship oil compared to tankers and barges. The following chart shows how, from a tiny share of oil deliveries in 1941, two new federally-financed oil pipelines grew to become the biggest source of East Coast oil by the end of the war. They were the first large diameter, long distance petroleum pipelines in the world.

²² Before World War II, Europe's production of natural gas was insignificant outside of some local gas use in the traditional oil and gas producing countries of Poland and Romania. The Canadian natural gas industry started after the war as well, as did those in South America (Argentina and Bolivia). Mexico had been shipping natural gas for industrial use around its oil and gas producing properties in the Yucatan since about 1930, but these were very small and local efforts until the 1950s. See: Leeston, A. M., Crichton, J. A., and Jacobs, J C., *The Dynamic Natural Gas Industry*, University of Oklahoma Press, Normal Oklahoma (1963), Chapter 14 ("The Natural Gas Industry in Foreign Countries").

²³ Hooley, R.W., *Financing the Natural Gas Industry*, AMS Press, New York (1968), page 13.

²⁴ Castaneda, C. J., *Regulated Enterprise: Natural Gas Pipelines and Northeastern markets, 1938-1954*, Ohio State University Press, Columbus Ohio (1993), page 23.

**Oil Deliveries to the East Coast of the United States
January 1941 to August 1945.**



Source: Johnson (1967)

But it was a wartime effort only. Believing that the introduction of major new petroleum pipelines to the major East Coast markets would severely disrupt the industry in ways that they could not foresee, the US oil industry wanted nothing to do with them after the war. Eventually, the newly-formed Texas Eastern Gas Pipeline Company won the bid to acquire the assets and convert them to natural gas—the last US pipelines to begin with government planning and financing.

IV. It's All About Institutions

Large pipeline systems exist in various parts of the world, but three are useful for illustrating how the performance of fuel markets depend on the institutions used to govern pipeline relations. In this section, I draw two contrasts: (1) between the gas industries in the United States and the EU; and (2) between the oil and gas industries in North America.

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A. The Institutional Divide between North America versus the European Union and its Consequences

I have elsewhere described the sources of the institutional divide between the gas industries in the United States and Europe.²⁵ There are six critical institutional differences: (1) Europe has internal sovereign borders; the US does not; (2) third-party access (TPA) applies in the EU, not in the US; (3) there are no independent gas distributors in the EU to agitate effectively on behalf of their own consumers; (4) information on finances or operations for pipelines is not public in the EU; (5) pipeline companies in the EU generally transport their own affiliated gas supplies, while no US pipelines do; and (6) there is no EU licensor of capacity that parallels FERC pipeline licenses. There is a seventh that affects the pace of shale gas development: in Continental Europe, the State owns mineral rights beneath the surface, while in North America the landowner does, making for very different incentives in the desire to extract that resource.

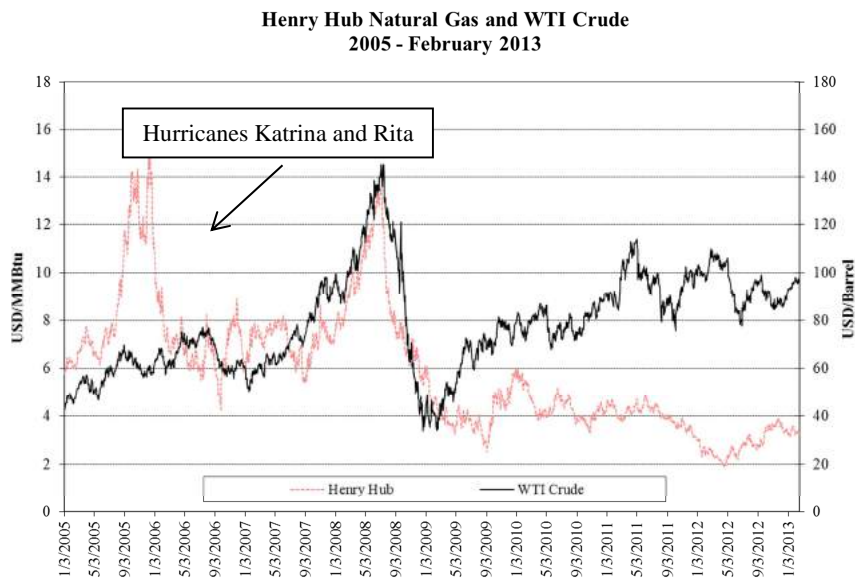
The result of these deep institutional differences appears in the following two graphs. US gas prices split from oil prices immediately after the great 2008 run-up and subsequent collapse of oil prices after the credit crisis in 2009—as the figure below shows. It has hovered in the \$3/Mbtu range throughout all of 2012, compared to a comparable oil-equivalent energy price of around \$9/Mbtu. The comparison with Europe is stark, where most flowing gas supplies are linked under long-term contracts to the oil price, the result of which is evident in the figure below. The difference in gas prices, on roughly equivalent volumes, is that EU gas consumers pay about \$1 billion every four days (€1 billion every five days) more than their US counterparts.

²⁵ Makholm, J.D. “Seeking Competition and Supply Security in Natural Gas: the US Experience and the European Challenge,” in Lévêque, F., Glachant, J.-M., Barquín, J., von Hirschhausen, C., Holz, F., and Nuttal, W.J. (eds.), *Security of Energy Supply in Europe*, Edward Elgar, Cheltenham, UK (2010), pp. 21-55.

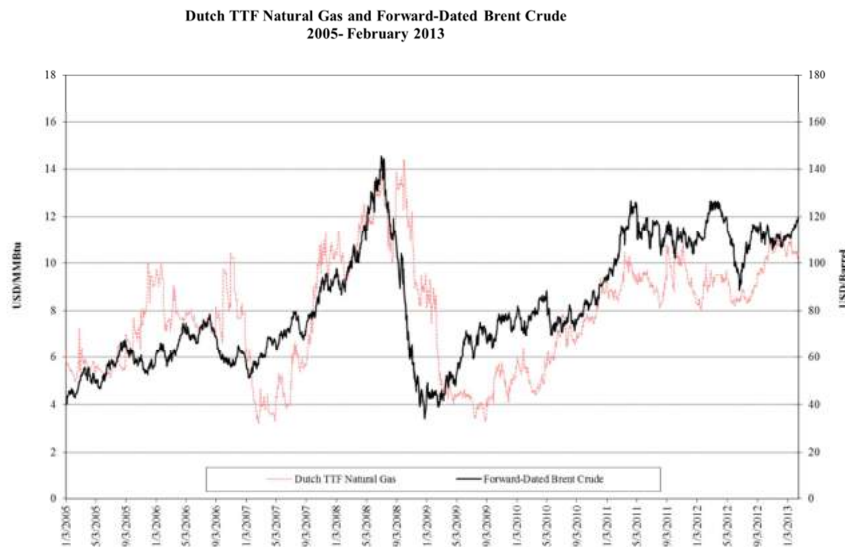
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Relative Gas and Oil Prices in North America



Relative Gas and Oil Prices in Europe



To be sure, it is not the pipelines themselves, or where they travel, that cause EU consumers to pay €1 Billion more than their US counterparts every five days. Rather, it is the way those pipelines are owned, governed and regulated that accounts for the differences,

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particularly the way in which the regulatory rules have been created to effectively insulate each member state's incumbent gas company from competitive entry of other gas suppliers or other pipeline companies.

B. The Institutional Divide Between US Oil and Gas Pipelines and its Consequences

Liquid petroleum (crude and oil products pipelines) and natural gas pipelines perform essentially similar inland transport functions. Often enough, pipelines built to transport gas are converted to transporting oil (or vice versa). Nevertheless, despite their technological and operational similarities and capability to be converted from one type of fuel to the other, the ability of the two systems to respond flexibly to transport bottlenecks is very different. These differences stem from US interstate oil and interstate gas pipelines being subject to quite dissimilar kinds of federal regulatory legislation. Interstate oil pipelines are “common carriers” according to the 1906 Hepburn Amendment to the 1887 Interstate Commerce Act,²⁶ while interstate gas pipelines are “contract carriers” subject to the Natural Gas Act of 1938.²⁷ The property rights over federally-licensed capacity that form the foundation of the competitive Coasian market in gas transport do not exist for oil pipelines—for the capacity is not federally licensed and common carriage rules prevent the sale of exclusive capacity in any event.²⁸

Without the ability to sell exclusive capacity, as such, and apply to the FERC for a license that will override all state and local issues of eminent domain, the barriers facing new crude oil pipeline development are considerably greater than for gas pipelines.²⁹ A consequence of this difficulty in building oil pipelines is that it is hard to secure new rights of way to build new pipelines when oil production and use patterns shift. Such a problem has occurred in the

²⁶ Makhholm, Jeff D. *The Political Economy of Pipelines* (Chicago: University of Chicago Press, 2012), 98.

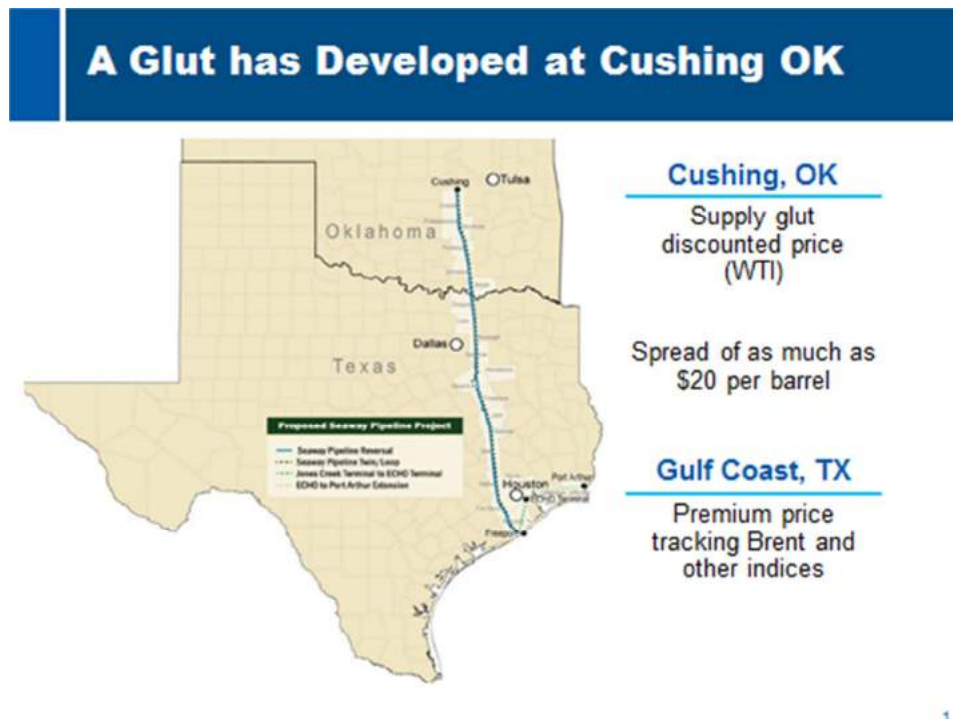
²⁷ Ibid, 103.

²⁸ Much of the discussion in Chapters 6 and 7 in *The Political Economy of Pipelines* (pp. 97-152) concerns the details of where these two still-active legislative controls came from and now they affect the competitiveness of the oil and gas pipeline systems as they serve those two respective inland fuel markets.

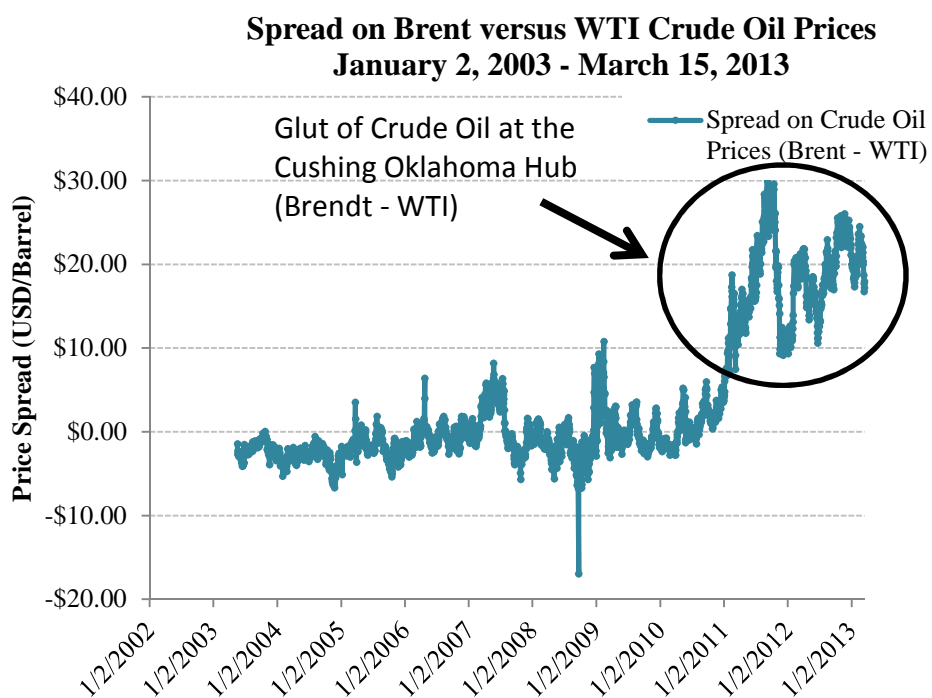
²⁹ This is not to say that the FERC has not recently approved methods to mimic for oil pipelines some of the rights that gas pipeline shippers enjoy, by setting priorities on shipments and even, most recently, providing for the assigning of rationing rights to other shippers. See *Shell Pipeline Co., L.P.*, 139 FERC ¶ 61, 228 (2012) and *Shell Pipeline Co., L.P.*, 141 FERC ¶ 61,017 (2012).

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past few years as the direction of crude oil movements in the United States has shifted. Historically, oil moved north from the Gulf of Mexico toward the oil hub of Cushing, Oklahoma and the mid-continent oil refineries. The development of tar sands oil in North Dakota and Alberta have shifted the flow in the direction of Cushing and south. That oil could only readily move to the Gulf from Cushing by reversing the flow of existing oil pipelines or converting lesser-used gas pipelines for that purpose.



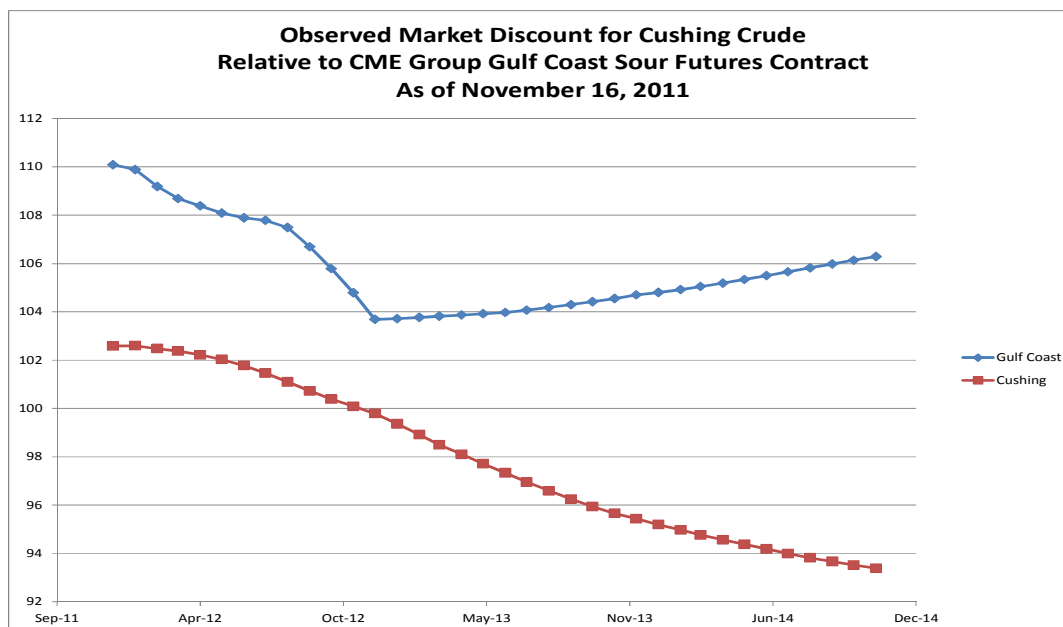
The difficulty in accomplishing either is evident in the existing and projected (futures-market-based) basis spreads between the price of crude oil at Cushing and the world market price (represented by the Brent crude oil price). Discounts for crude oil at Cushing have remained well above \$10/barrel for more than three years, when the reasonable cost of transport by pipeline is in the vicinity of \$3.50 to \$4.00. Century-old federal oil pipeline regulations, which inhibit the necessary market responses, lie at the heart of this difference.



Notes and Sources:

Data from Bloomberg, L.P.

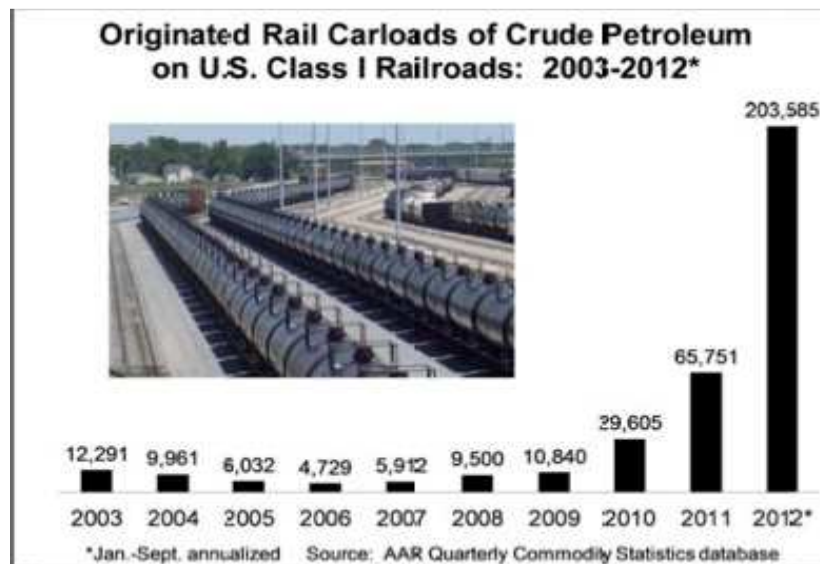
Brent crude oil spot prices were only available beginning May 19, 2003.



Source: Bloomberg Financial Systems

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There is another way to picture the difficulty in pushing through new oil pipelines, as show in the figure below. Given the lack of federal licensing authority, combined with various other elements that make new crude oil pipeline planning and construction considerably more troublesome than for the independent, contract-based gas pipeline market, we just saw “the year of the tank car” in 2012.³⁰ (The reader may wish to turn back a few pages to re-examine the growth in rail tank cars for interstate crude oil shipments 1942 and 1943.) Both of the remarkable booms in oil tank cars link directly to the trouble in building new oil pipelines. In 1942-43, large-scale pipelines were at the edge of the technological envelope. In 2012-13, the problems are no longer technological, but institutional and regulatory. While it is true that tank cars provide a type of flexibility that pipelines do not (Kahn would say “marginal costs on wheels”), the biggest market is between two fixed points—the tar sands fields in North Dakota/Alberta and refineries on the Gulf Coast. In that market, where rail costs perhaps 2-4 times oil pipeline costs per barrel, rail cars (costing well more than \$100,000 apiece with an 18 month backlog in early 2013) are only a temporary stopgap until various pipeline options (reversal of oil pipelines, conversion of underutilized gas pipelines, new builds) come on line.



³⁰ <http://rbnenergy.com/crude-loves-rocking-rail-the-year-of-the-tank-car>.

V. Even a Well-Designed Market Needs Information and Logistics

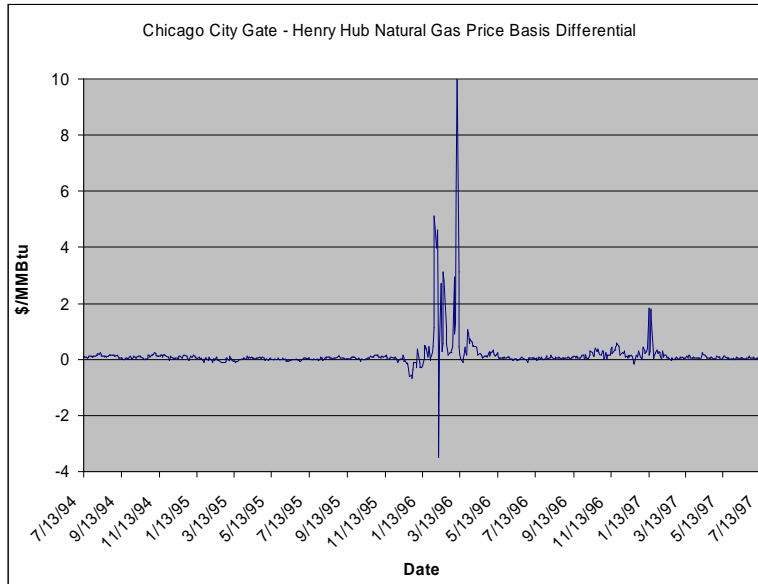
The property-right-based gas pipeline market makes the competitive gas market possible but has taken time for actors in the market to get used to. Three recent market stresses since 2000 highlight the response of the US market for natural gas.

A. Chicago Cold Snap of 1996

The beginning of the heating season of 1995-1996 began with below normal temperatures. This resulted in large natural gas storage withdrawals that could not be readily replaced with storage injections because the low temperatures and corresponding high natural gas demand persisted for an extended period of time. When temperatures again dropped dramatically across the Midwestern US, there was not enough available gas in storage to meet the spiking demand. Accordingly, the local price of natural gas spiked. The figure below displays the price differential for the Chicago city gate pricing point relative to the Henry Hub. The cold snap in 1997 was much like the one in 1996, but market and traders had learned from the year before, and the temporary rise in basis differentials was only one fifth as high.

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Chicago Cold Snap of Winter 1996



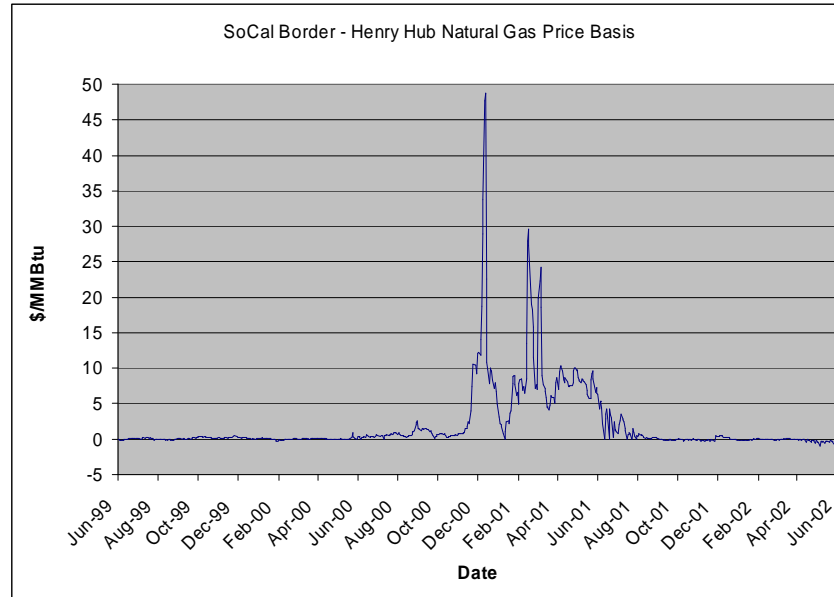
Source: Natural Gas Intelligence Press

B. California Energy Crisis of 2000-2001

Supply constraints, among other factors, resulted in widespread electricity shortages across the Western US during the much-publicized California Energy crisis of 2000-2001. Accordingly, the price of natural gas spiked because of the increased value of electricity generated in natural gas burning power plants. The figure below shows the basis price for the SoCal Border natural gas pricing point relative to the Henry Hub price.

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California Energy Crisis of 2000-2001



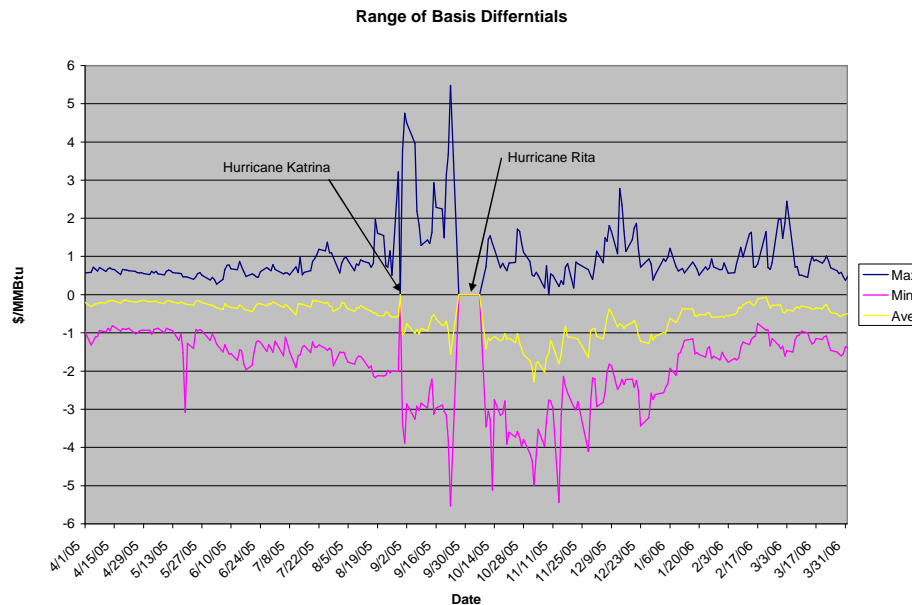
Source: Natural Gas Intelligence Press

C. Hurricanes Katrina and Rita in 2005

The figure below shows the range and average of the 84 basis differentials relative to the price at Henry Hub in Louisiana between April 2005 and April 2006. During this period of already tightening energy supplies, hurricanes Katrina and Rita disrupted a large portion of the US natural gas supply and production. In addition to completely shutting down the Henry Hub for a day and week, respectively, Hurricanes Katrina and Rita led to different and larger than normal supply-demand imbalances across the country, and thus larger basis spreads.

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The Hurricane Season of 2005



Source: Natural Gas Intelligence Press

In each of the three cases above, the market responded to an exogenous shock to supply and/or demand, the spot price moved according to the local supply and demand for natural gas, and the market was able to clear. In order for this to occur, adequate pipeline capacity must be available and able to respond to changing market conditions.

D. The Cold Weather Event of February 1-5, 2011

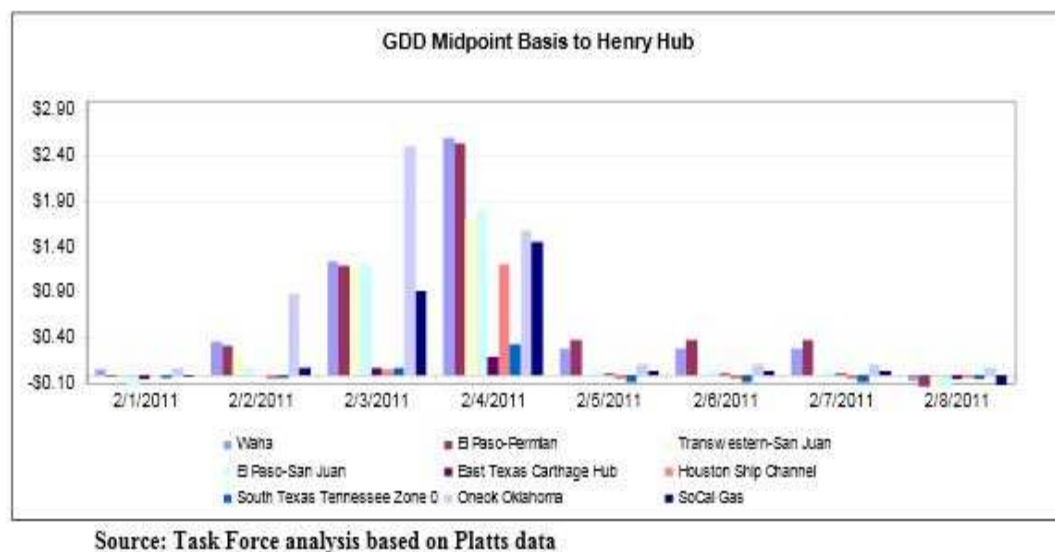
Much has been made of the problems that occurred in New Mexico when the worst winter storm in 50 years hit the southwestern region on the United States in February 2011.³¹ During that event, a total of 210 individual generating units in the Electric Reliability Council of Texas, Inc. (ERCOT) had an outage or a failure to start. Combined with other events with generators in Arizona and New Mexico, about 4.4 million electric customers suffered controlled blackouts. In the analysis of unavailable generation, about *10 percent* was attributed to a

³¹ For example, in terms of convective heat loss (the combination of low temperatures and wind speed), El Paso Texas recorded the most severe weather event in 49 years. See: Federal Energy Regulatory Commission and North American Electric Reliability Corporation, Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011," August 2011, p. 169.

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curtailment of gas supplies. Most power plant failures owed to the cold weather itself or mechanical/operator failures.³²

In addition, 50,000 natural gas customers in New Mexico, Arizona and Texas experienced extensive curtailments of service. While the sources of the weather-related problems were diverse, a large component owed to various failures of planning and weatherization to permit cold starts of electric plants (including operator error), and also a widespread freeze-off of gas wellheads (which is a relatively normal occurrence as frozen water obstructs wellheads). The cold-weather events did have an effect on the price of gas, but it was short lived (limited to about three days) and highly localized—the Henry Hub price barely moved, as shown below.³³



The events—both predictable and unpredictable—have caused the FERC to schedule a series of coordination meeting around the country to study how better to handle logistical coordination between electricity and gas supply in the face of severe weather and other

³² See: Federal Energy Regulatory Commission and North American Electric Reliability Corporation, Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011,” August 2011, pp. 140-141.

³³ Ibid., p. 138.

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disruptions that can tax the ability of the gas supply system to respond to heightened electricity and gas demand.

VI. Adequate Infrastructure/Investment

A number of the questions put to me by the conference organizers relate to concerns about adequate pipeline investment:

A. Top-Down Planning?

Whether there is any involvement by regulated or bureaucratic governance organizations, like TSOs, in the planning and financing depends on whether there is a market for the movement of fuel or not. For example, some of the most complicated planning and logistical models that exist concern the transport, refining, distribution and retailing of gasoline. But that is all a private affair, taking place outside regulation (that is, since the OPEC oil crisis of the early 1970s when state “energy czars” directed gasoline supplies during the shortages).

Similarly, the gas pipeline system in the US has for more than 100 years depended solely on private investment, either in the form of vertically-integrated pipelines investments before 1935, or independent pipeline ventures based on the Natural Gas Act and its supportive institutions after WWII. There is no practical possibility of top-down government involvement in the planning of gas pipeline capacity in the US, as the industry grew up under private planning and investor ownership, which has satisfied the requirements of the plurality of interests that the system serves.

Of course none of these institutions, nor the pluralities of interests that they serve, exist in the EU. That jurisdiction has purposely avoided adopting the institution of contract carriage and open access on the US model and is attempting to create virtual markets for gas with virtual transport models based on the UK experience. These choices almost guarantee the expansion of the gas pipeline system in Europe with public funds (or at least private funds with socialized prices guaranteed by regulators). The choice of planning is almost purely a function of the underlying regulatory institutions and allowed vertically-integrated market structures—not on the need for better coordination, as such.

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B. Market Signals for Pipeline Capacity and Role of Long-Term Contracts?

Despite having been dragged through a restructuring process that essentially compelled them to exit the gas trade (even if it was somewhat unfairly called “voluntary” at the time), US gas pipelines remain reasonably highly profitable.³⁴ I show below the largest of the pipeline holding companies, their market shares in 2009 and their average estimated return on equity in the table below.

Summary Table of Parent Company Market Share (2009)

Parent Company	Number of Pipelines Owned	2009 Rate Base (\$000)	Market Share	Average Estimated ROE
Berkshire Hathaway Inc.	2	3,346,125	5.1%	19.76%
Spectra Energy Corp	5	4,453,808	6.8%	18.68%
Williams Companies, Inc.	3	4,812,198	7.4%	17.85%
El Paso Corporation	7	8,572,920	13.2%	16.47%
TransCanada Corporation	7	4,267,743	6.6%	14.89%

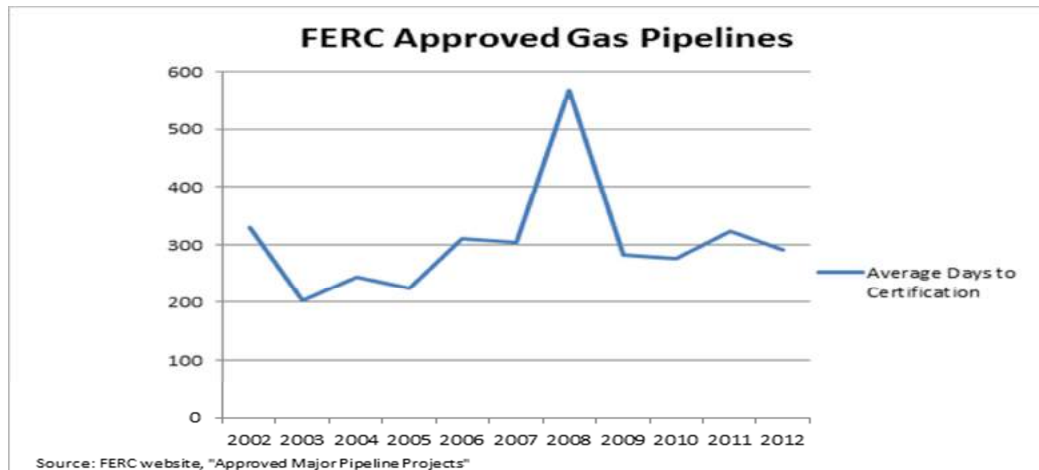
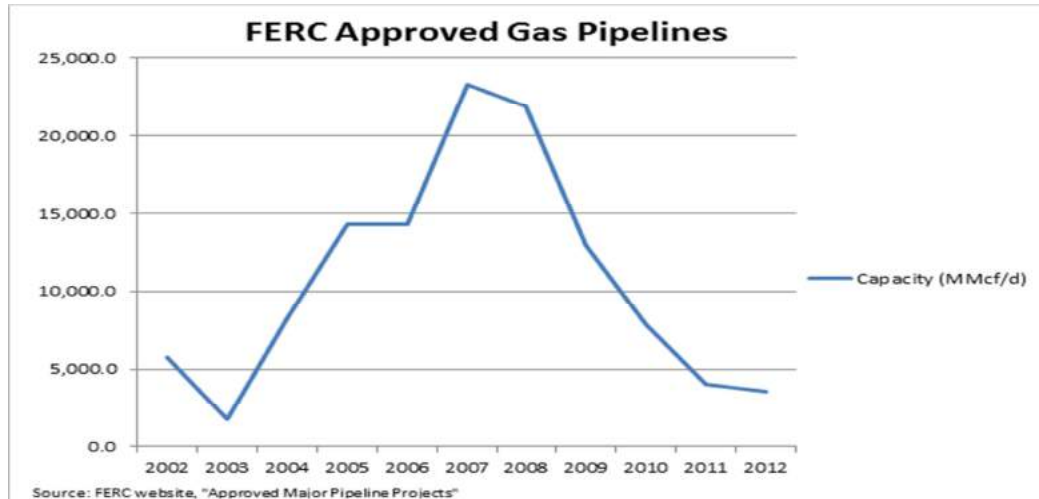
*Note: Author calculations.

In the past few years, investment in new infrastructure to accommodate unconventional gas supplies has been very vigorous, as has the profitability of the sector and the ease with which new pipelines are planned and licensed by the FERC. The following figures show the extent of new pipeline construction since the completion of the rules for contract capacity trading in 2000. The number of project and miles of pipeline capacity spiked with the rising gas prices, leading up to the high prices of 2008, after which the shifting pattern of gas production with available capacity (shortening the transit for much of the gas in the northeastern United States) has meant more numerous and smaller projects. With the development of market-area shale gas, the projects are less numerous and more geared to small “interconnectors” to connect existing interstate pipelines to the most productive shale producing regions. For example, 34 licensed projects in 2007 averaged 82 miles each; nine projects in 2012 averaged 12 miles each.

³⁴ See: Makhholm and Strunk (2009), and Makhholm and Olson (2009).

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Ease of New Licensing



To be sure, the competitive US market for gas is causing unintended regional price spikes. Low US gas prices have affected the Everett LNG terminal in Boston, which was constructed in the 1970s to bypass the high cost of interstate pipeline shipping from the Gulf Coast. From that time until the mid-2000s, that LNG terminal imported regular cargoes, and helped supply the Boston-based peak demand. That situation has changed, as Everett imports fewer cargoes and the two new New England offshore terminals are unlikely to see cargoes at all. The lack of LNG to support the winter needle peak has caused basis differentials at the Algonquin Hub to spike three times to the \$6-\$7 range in the past 18 months. Both of the traditional pipeline suppliers to the region (Algonquin and Tennessee pipelines) have initiated or planned projects to increase peak capacity to the region. The optimal solution may well depend

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on some mix of LNG and pipeline capacity weighted against the anticipated weather-driven prices spikes—a situation that, as the FERC reports, the gas users in the region are themselves taking steps to remedy.³⁵

VII. Conclusion

My late colleague Alfred Kahn would (and did) respond vigorously to calls for more regulatory intervention into the airline industry after deregulation. He never claimed that simple deregulation of pricing and entry would solve all of the industrial and consumer problems with airline rates and services. But he always maintained that the benefits of deregulation far outweighed the costs of unnecessary regulation—a point about which few economists would disagree. Safety and security concerns aside, when it came to entry and exit to routes and markets, and above all prices and the profitability of carriers, Fred always maintained that the carriers were on their own. To him, a in air transport would result from competition in routes and fares. The era of *regulation* in those respects ended during his time at the Civil Aeronautics Board in the 1970s, and the benefits to the public in terms of low cost for discretionary travel—to say nothing of safer travel and saved lives—was the payoff. There was no turning back.

There is also no turning back from the features that characterize the US gas market and the pipelines that permit that market to be so vigorously competitive. The regulatory model for the industry was forged in Congress in the 1930s to serve a plurality of interests in the middle of the Great Depression—oil and gas producing companies, pipeline owners, and gas distributors principally among them. The difficulty that Congress has in regulating any aspect of US business (particularly in the oil industry) is demonstrated in the longstanding nature of those regulations, as they have served as the foundation for everything that has come since. With great struggle from 1938 to 2000, pipeline companies exited the gas trade, and, except for temporary and localized affairs, do nothing to inhibit the most vigorous gas trade. The huge gas price disparity between the US and Europe, reflecting about \$100 billion per year in cost savings for the US vis-à-vis Europe, is a testament to what gas markets can do when pipeline interests stay out of the way of gas markets and focus on their contract transport role. With competition in the

³⁵ See: Winter 2012-2013 FERC Energy Market Assessment, November 15, 2012.

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supply of gas, and competition in the use and expansion of the pipeline system, the resulting low price of gas has brought the US petrochemical industry back and contributes to a smaller price for electricity on a wide scale.

To the extent there is a problem with gas/electricity coordination, it would appear to be the result of competitive gas-fired plants that have not yet had the need to plan for storage, alternate fuels or firm service—items that would dent their earnings. The ISOs themselves are looking at their requirements and trying to determine whether it makes sense to enhance, for example, the dual fuel requirements. They are analyzing all of their policies and rules to determine whether they can mitigate the new risks associated with a greater concentration of gas-fired generation. The ISOs have questioned the whether traditional “firm” and “interruptible” services efficiently meet the needs of the intersection of the gas and electricity markets. But those ISOs also have to contend with a pipeline system representing firm delivery capacity that was largely built to serve, and almost completely underwritten by, gas distributors and their connected users. Traditional firm services were tailor made for the requirements of gas distributors, and the type of pricing of those services (including straight-fixed-variable and incremental pricing) have been key parts of the foundation for the highly competitive deregulated capacity market.³⁶ Any new pipeline services or prices targeted at power generators would have to consider their effect both on traditional services for gas distributors and the working of the highly successful deregulated pipeline capacity market.

Top-down planning for the gas industry in Europe appears to be the choice of Brussels, which has issued three sets of regulatory rules since 1998. Great institutional barriers prevent the emulation of the US experience in removing pipelines from the gas trade, and the path that the EU has chosen is to live with those barriers while attempting to create a model for “competitive” gas supply, perhaps in concert with competitive power generation, to elicit efficiency and rivalry in the industry. Economists in the EU are hard at work creating the models for socialized regional and temporal gas transmission contracts that rely on TSO-based planning for the adequacy and expansion of the various member-state gas systems. Such models may or may not

³⁶ See *The Political Economy of Pipelines*, pp. 140-149.

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ensure the adequacy of gas supply to the EU. But they do nothing to foster the entry of new transport links or gas supplies—the drivers for innovation and low prices seen in the United States.

Solutions to the problems caused by the increased share of natural gas in the US generating portfolio, and the need for those assets to be useful in times of weather-induced stress, would appear to lie in better information, more coordination and improved logistics—not in top-down planning or market modelling. Given that the demands in New England (with its historical LNG resources) are different from those in the southwest US (which has never had LNG), it is also likely true that one new set of rules will not satisfy every region. Overall, with the work undertaken over the past two decades to create deregulated US power and gas markets, there is little likelihood that the FERC would choose to implement a solution to such coordination problems that would inhibit the continuing success of these markets—or to intrude into the private planning of both gas and power markets.

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Gas & Electric Coordination: The need for information sharing

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2013 MIT Energy Initiative Symposium

Power generation now accounts for the majority of the natural gas consumed in the United States. However, the structure of the gas and electric markets do not align. Differences in market timing between the gas day nomination schedule and the electric day scheduling process make it difficult for generators to bid with certainty about the *price* of their fuel, on the electric side, and to nominate with certainty about the *quantity* of fuel they will need, on the gas side.

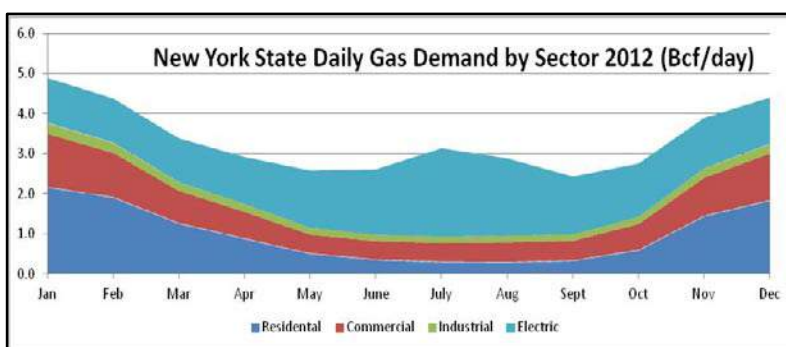
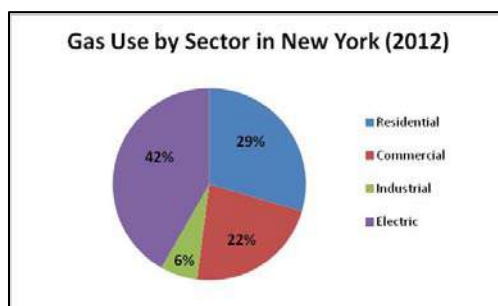
In addition, long-term natural gas transportation contracts have been designed around the idea that gas coming from the interstate pipelines will be shipped to local gas distribution companies (LDCs), mostly to serve the needs of residential and commercial end-use consumers. As we shall see, these long-term contracts play an important role in the construction financing for new pipeline capacity. So, while there appear to be more than adequate natural gas supplies to meet expected demand, ensuring sufficient pipeline capacity for electric generators remains a challenge.

The need for information sharing arises because of reliability concerns on both the gas and electric systems. The physical flow of gas molecules through the pipeline system requires strict pressure balancing. While pipelines can accommodate nomination changes and have balancing agreements in place to handle gas either left on the system or gas taken off the system outside of what was scheduled, pipeline system pressure drives any potential flexibility on the pipeline system. When generators operate outside of their nominated schedule, they can limit pipeline flexibility, and impact pipeline system reliability.

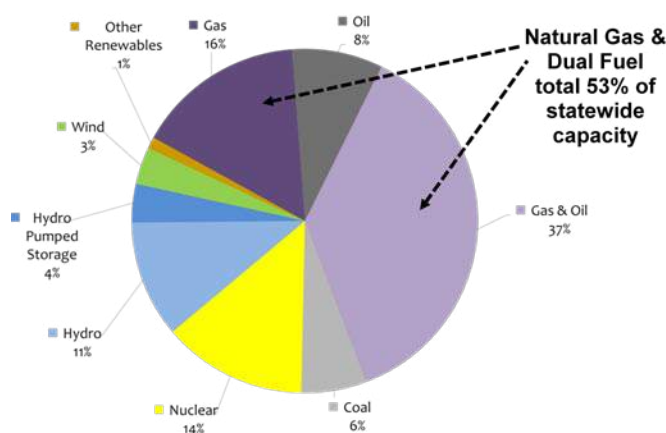
This paper seeks to answer two questions related to gas and electric coordination. First, what drives the need for information sharing? Second, what kind of information or coordination is needed? Both day-ahead and real-time electric scheduling practices assume fuel availability. Generation is scheduled to meet expected next-day load (demand) through day-ahead markets. In real-time, however, system conditions change. There may have been more or less load than expected, a transmission line may be out, or a generator might trip. Each of these situations requires a system operator to respond, and may require the re-dispatch of a previously scheduled unit, or the dispatch of a unit not scheduled previously. The ability of a gas-fired generator to respond to these signals could depend on how much gas a generator nominated, already burned, and/or depending on the pipeline system conditions at the time. As more natural gas-fired units make up the pool of generators available to meet electric load, coordination and information sharing between the pipeline system and the electric system becomes more important.

The New York State Gas and Electric Markets

On average, New York consumes about 3.3 billion cubic feet (Bcf) of natural gas per day, with peak gas demand around 5.0 Bcf/day in the winter.¹ For the past ten years, the electric sector has accounted for around 30-35% of the total natural gas consumed in New York State, about the same as the total gas consumed by the residential sector. In 2012, however, the electric sector accounted for 42% of the total natural gas consumed in New York State, the highest gas consumption by the power sector in the past ten years. This represents a nearly 30% increase in natural gas consumption by the electric sector since 2008.



The following figures highlight current and expected gas-fired generation across New York State, as well as current gas supplies into New York State. Natural gas-fired generation accounts for more than half of the total generation capacity in New York. The majority of natural gas units in New York are dual-fuel units; currently, less than 20% of New York's entire gas-fired capacity relies on natural gas only.² Of the new generation proposed in New York, natural gas units account for nearly half.



Source: 2012 Load and Capacity Data Report, NYISO, April 2012

¹ All natural gas consumption data from: U.S. Energy Information Administration, New York Natural Gas Consumption by End Use.

² As we shall see, there are reliability rules associated with much of this dual-fuel capacity.

Current and Expected Gas Demand and Supply in New York State (Bcf)³	
Total Gas Generator Winter Usage (2012)	6.9
Total Gas Generator Summer Usage (2012)	9.9
Total Gas Generator Usage (2012)	16.8
Total Gas Winter Capacity (MW)	22,447
Total Gas Summer Capacity (MW)	20,489
Total Expected Winter Gas Generation Capacity (Interconnection Queue)	5,920
Total Expected Summer Generation Capacity (Interconnection Queue)	5,490
Total Winter Gas Usage Expected (2012 usage + interconnection queue)	8.9
Total Winter Gas Usage 2012 (Res/Commercial/Industrial)	17.0
Total <u>Winter</u> Supply into NY @ 5.9 Bcf/day in 2012⁴	35.4
Total Expected Winter Demand (All Sectors)	25.9

While current natural gas supplies into New York State are enough to offset expected demand in the electric generation sector, getting the gas to electric generators during the coldest winter months when pipelines are operating at or near capacity remains a challenge. The next sections address some of these challenges, and the related information sharing and communication needed.

³ Consumption data from the U.S. Energy Information Administration: Consumption by End Use and Movements of Natural Gas by State. Total daily gas supply includes all New York International and Interstate Receipts coming into New York. The above chart does not take any expected residential, commercial, or industrial growth into account, and only looks at increased gas-fired electric generation already in the NYISO interconnection queue. New York City's plan to switch residential units from heating oil to natural gas will add considerable residential gas demand during winter months, as well as the New York Department of Public Service focus on expanding natural gas heating use. NYISO Interconnection queue as of March 2012. Summer and Winter Capacity reflect the 2012 NYISO *Load and Capacity Data Report*.

⁴ The average monthly supply into New York in 2012 was 5.9 Bcf/day. The winter operating period runs from November-April. Note that this is the average monthly total of *all* international and interstate receipts coming into New York, and does not capture days when the pipelines are operating at full capacity, particularly during the winter.

The need for information sharing

Reliability concerns on both the gas and electric systems are driven by: (1) market timing differences between the two sectors; (2) the market structure of the gas system; and (3) the physical reality of the way gas moves through the pipeline system.

(1) Differences in market timing

The timing of the electric and gas markets are not aligned. Not only does the gas day, which runs from 10 a.m.-10 a.m. (Eastern Standard Time), not match up with the electric day, which runs from 12 a.m.-12 a.m., but the scheduling times in each market differ. As a result, in ISO/RTO markets, generators either bid their energy offers before knowing what the price of gas will be and/or nominate gas prior to receiving a firm operating commitment. Moreover, the gas market is most liquid between 8 a.m. – 9 a.m., prior to the release of day-ahead energy schedules in any electric market.

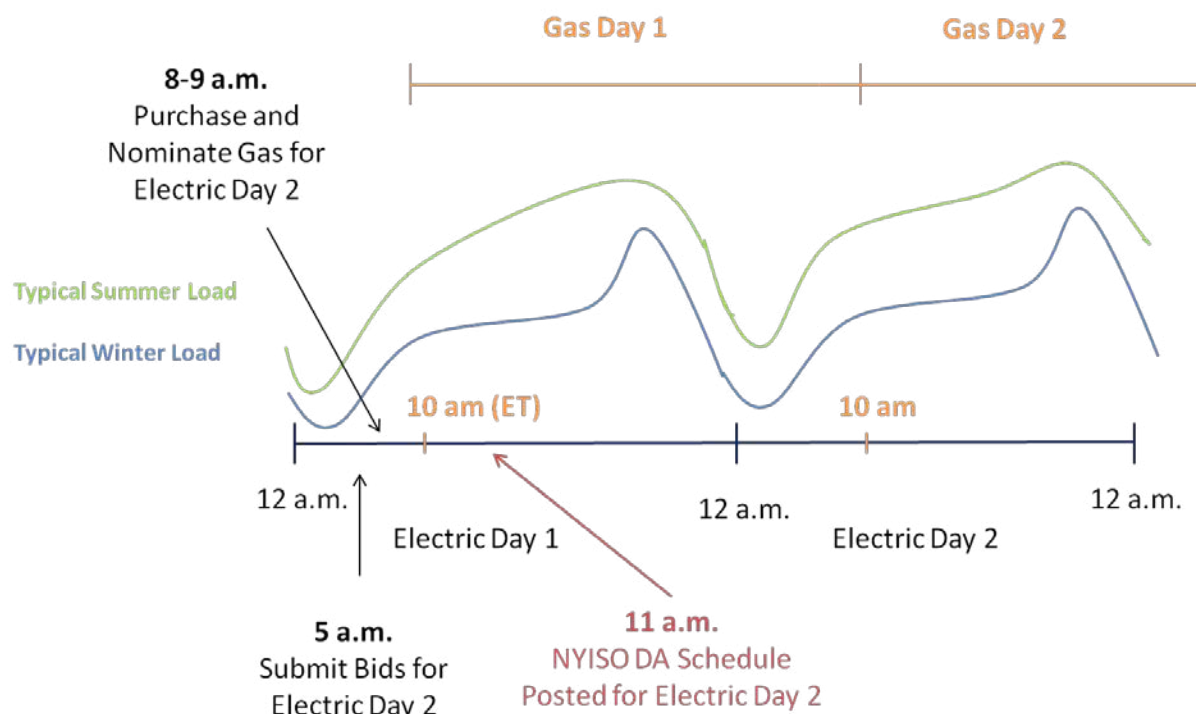
The NYISO requires generators to bid offers by 5:00 a.m. and posts its Day Ahead schedule by 11 a.m. In other words, a generator in New York must bid without knowing the price of gas,⁵ and then purchase and schedule that gas *before* it knows its operating schedule. While the NYISO is the only ISO/RTO that releases its day-ahead market commitments prior to the 12:30 p.m. (ET) timely nomination cycle close of the gas market,⁶ most generators within the NYISO market nominate gas prior to receiving a day-ahead commitment, in order to ensure gas is procured while the gas market is most liquid, or, on some LDC pipeline systems, to ensure capacity is reserved.

Further, day-ahead gas nominations are made Monday-Friday, and there is often no day-ahead weekend or holiday gas scheduling.⁷ Generators typically purchase a weekend gas package, which bundles gas supply with the gas transportation contract. This means that on any given weekend, gas generators must purchase and nominate on Friday the gas they think they will need for Saturday, Sunday, and Monday. Complicating this even more, generators often must nominate the same amount of gas for each day. So, going into a Holiday weekend, generators are purchasing and scheduling the same quantity of gas for Saturday, Sunday, Monday, and Tuesday. If (when) system conditions change over the weekend period, it could be difficult for gas-fired generators to adapt to changing real-time system condition needs by making changes to their nomination schedule.

⁵ The NYISO has a mechanism in place to allow generators to manage some of the risk of purchasing gas intra-day: increasing bids in real-time (IBRT). This is an important market design that at least allows generators the opportunity to bid costs associated with purchasing (more expensive) spot market gas in real-time.

⁶ See appendix A for an overview of ISO/RTO market closing times.

⁷ These scheduling limitations are often imposed by the marketers through whom generators purchase and nominate gas, not necessarily the interstate pipelines or LDCs.



(2) The market structure of the gas system

The gas pipeline system – as it exists today – was not designed to serve a mostly gas-fired electric system. Pipelines were built to serve the needs of local gas distribution companies (LDCs), who buy long-term firm transportation contracts⁸ on one or more interstate pipelines in order to meet customer demand on a peak winter day. Just like on the electric system, while there are sufficient resources available to meet a peak demand day, not all of these gas resources are needed every day. Most LDCs rely on some combination of interstate pipeline gas, storage gas, and/or liquefied natural gas (LNG) to meet peak demand. Thus, even though the interstate pipelines are fully subscribed, they are not always fully utilized.

To manage the efficient use of their pipeline transportation contracts, most LDCs sell any capacity not needed in a secondary market, called the capacity release market.⁹ On the pipeline system, the transportation contracts held by LDCs (or other long-term anchor shippers) are known as primary firm. Transportation contracts purchased via the capacity release markets are known as secondary firm.

⁸ There can be other long-term anchor shippers holding primary firm transportation contracts. In fact, in recent years, some shale gas developers began purchasing long-term primary firm contracts on the interstate pipelines. For the purposes of this paper, I refer to LDC primary firm contract holders.

⁹ Details on the restructuring of the interstate pipeline system are outside the scope of this paper. However, an important part of the capacity release market story is the unbundling of the gas commodity from the transportation of that gas. By recognizing that transportation contracts on the pipeline system are a property right, the Federal Energy Regulatory Commission set up the possibility for a robust capacity release market. For a detailed history of the United States pipeline systems see: Makholm, Jeff D. 2012. *The Political Economy of Pipelines: A Century of Comparative Institutional Development*. University of Chicago Press. Combined with the revolution in shale gas supply, the development of the capacity release market has played an important role in incentivizing greater gas-fired generation.

On any given day, the interstate pipelines ship gas under primary firm contracts to their long-term, anchor shippers (typically, LDCs), under secondary firm contracts that are bought and sold in the capacity release markets, and any remaining pipeline capacity is filled with various forms of interruptible contracts. Most gas-fired generators are purchasing either secondary firm transportation contracts, or some type of interruptible transportation contracts.

While this purchasing strategy works most of the time, on the coldest winter days, generators receiving gas directly from the interstate pipelines or an LDC¹⁰ are at risk of not receiving their gas supply. This is because interstate pipelines are obligated to ensure that their primary firm contract holders are supplied before shippers holding any other contracts. In other words, even though, theoretically, there is plenty of North American gas supply to meet the needs of gas generators and other gas users, on peak gas demand days, there may not be enough pipeline capacity to meet the needs of shippers holding anything but primary firm transportation contracts.

Since existing pipelines are fully subscribed, the only way for gas-fired generators to purchase primary firm transportation contracts is to build new pipelines or add more loops to existing pipelines.¹¹ However, pipelines are not allowed to charge their existing customer base for the costs of new pipeline capacity, so new pipelines are constructed only when pipeline operators can demonstrate that the pipeline is in the public interest. The most common method of demonstrating that a project is in the public interest is through long-term transportation contracts. This financing model has worked when the largest consumer of natural gas has been residential and commercial loads: The LDC can finance the construction of a new pipeline through the purchase of firm transportation rights associated with the pipeline capacity, and then can recover these long-term costs through their regulated rates. By lining up these long-term anchor shippers, the pipeline is able to demonstrate that the new project is in the public interest.

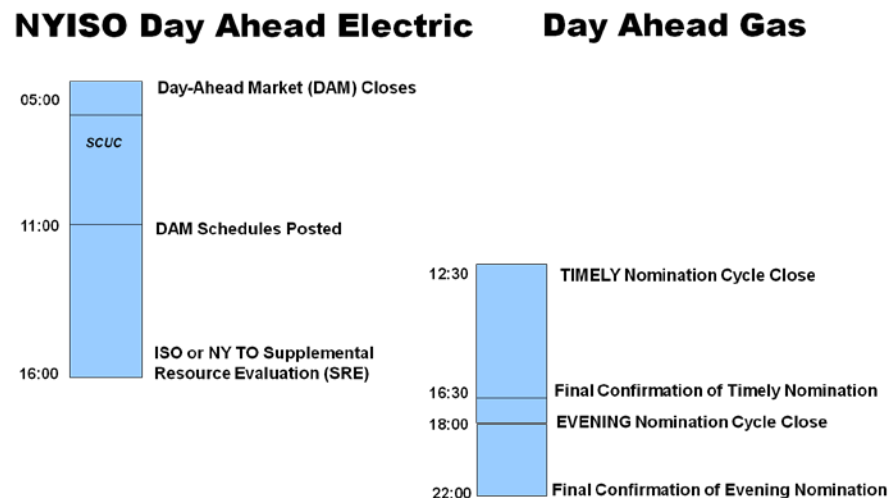
Generators in competitive wholesale markets, however, generally have little incentive to purchase long-term primary firm transportation contracts. A long-term primary firm transportation contract includes a fixed monthly charge to reserve the pipeline capacity. Peaking plants likely would not run enough to recover this fixed cost. Even if a gas generator ran as a base load plant, generators are allowed to bid only their incremental variable costs. This means that even though the largest natural gas consuming sector in the United States is now the electric sector, electric generators selling energy in competitive wholesale markets have little incentive to support the construction of additional pipelines via primary firm transportation contracts.

¹⁰ As will be discussed, not all generators are directly connected to the interstate pipelines. In fact, in New York State, much of the gas-fired generation is behind the city-gate, i.e. gas is received through the local gas distribution company. Generators on the New York Facilities System (in New York City and Long Island) are generally considered interruptible.

¹¹ Looping entails adding capacity to an existing pipeline by expanding an existing right of way. There may also be some primary firm contracts available when a long-term anchor shipper contract expires. Some generators hold primary firm transportation contracts.

(3) The physical reality of the pipeline system

Just because a generator has a transportation contract, this does not mean they automatically have gas available. They are still required to purchase and nominate the gas flow.¹² The NAESB grid-wide Gas Day consists of four separate scheduling cycles for nominating gas: two day-ahead cycles and two intra-day cycles.¹³ However, most gas is scheduled during the first day-ahead cycle, known as the “timely” cycle. This is when the gas market is most liquid, and secondary firm transportation contracts, once scheduled, cannot be bumped.



Each pipeline has a minimum required operating pressure, and line pack, the quantity of gas stored in the pipeline above that minimum, is used to balance pressure throughout the pipeline system. As gas moves through the pipeline system, pressure declines. Compressor stations are used to offset this decrease in pressure. Gas can be fed into the pipeline system from gas wells, storage tanks, as LNG, or at an interconnection point where two pipelines meet. Day-to-day gas usage is managed by balancing pressure through line pack, compressor stations, and gas injections.

There is some flexibility built into the pipeline scheduling process through balancing agreements. In particular, shippers may leave gas on the system at the end of the gas day (“undertake”), or may use slightly more than scheduled (“overtake”), as long as it is within an amount specified by the pipeline’s tariff. These variations are tracked daily, and there are usually fees associated with these imbalances. As long as the pipelines can handle the imbalance – for example, because there is sufficient line pack remaining on the system or because a shipper scheduled an additional injection later in the day at some point on the system that can offset the pressure decline – then the pipelines are generally able to handle over/under takes.

In addition, there is some flexibility on the timing of the gas taken throughout the day. That is, non-ratable takes, or gas taken at different times during the operating day, are allowed; again, as long as the pipeline can manage the pressure and balancing throughout the system. Some pipelines offer hourly

¹² As explained, marketers sometimes bundle gas supply with the transportation contract.

¹³ See Appendix B for a detailed description of the North American Energy Standards Board (NAESB) Wholesale Gas Quadrant (WGQ) Nomination and Scheduling Standards and Procedures.

nomination schedules, and some offer various types of flexible transportation contracts. Not all pipelines offer these flexible transportation contracts, and even those that do limit the availability of these contracts until after all primary firm shippers are served.

Restrictions on this flexibility occur when pipelines are experiencing, or anticipate experiencing, difficulty maintaining pressure. A system alert, for example, communicates that shippers must stay within their scheduled quantities. Shippers may be restricted to overtaking or undertaking within a specified range, or may be asked to operate within a ratable take. In the latter case, this could limit shippers to taking gas within 1/24th increments, so a strict hourly flow.¹⁴ If an alert is issued, taking more or less than scheduled could lead to a pressure problem on the pipeline.

If these system alerts are not followed, the pipelines could issue an operational flow order (OFO). Though rare, an OFO is issued when the pipeline is experiencing significant pressure issues. If over or undertaking gas is allowed at all during an OFO, shippers could pay penalty charges in addition to any imbalance charges.

Just like transmission lines in the electric sector, the gas pipelines can be congested, or “over-nominated,” at particular points on the pipeline system. Day-to-day congestion (over-nomination) is managed by priority, according to the type of transportation contract a shipper has with the pipeline. Shippers holding primary firm contracts, with nominated and scheduled gas transportation, always have priority. On peak days it can be difficult to schedule any additional gas, during the gas day, through particular congestion points without a primary firm contract. Secondary firm capacity, once nominated and scheduled, though not as high priority as primary firm, is a type of firm transportation contract. Once confirmed, secondary firm could prevent primary firm nominations submitted in a later cycle (e.g. the evening cycle) from being scheduled. On a peak day, this means that secondary firm contracts not scheduled during the timely cycle could have difficulty being scheduled at all. Interruptible capacity is only available after all firm requests have nominated and scheduled gas. Once scheduled after the first intra-day cycle, however, interruptible capacity cannot be bumped.¹⁵

Potential Reliability Concerns on the Electric System

Despite the fact that gas pipelines have some flexibility built into gas transportation scheduling and offer balancing services,¹⁶ there are still day-to-day operational conditions that could impact electric system reliability.

As explained, generators in NYISO markets are committed through a financially binding day-ahead market. Results are posted by 11 a.m. the day-before the actual dispatch day. The day-ahead market

¹⁴ In this situation, a gas generator would need to nominate over and above what is required to operate on a normal day, since they will only receive 1/24th of what they nominate per hour. Even without any electric dispatch changes on a day when pipelines are operating a full capacity, a ratable take restriction leaves generators with excess gas to be sold intra-day (typically, at the wellhead price, not the spot market price), as well as an imbalance on the pipeline system.

¹⁵ See Appendix C for a discussion of the NAESB grid-wide transportation contract priority levels.

¹⁶ Gas generators not directly connected to the pipeline manage imbalances through their LDC.

ensures that enough generation is committed to meet expected load, as well as to meet all operational reserves and regulation requirements.¹⁷

In real-time, however, system conditions may differ from what was assumed when scheduling generator commitments day-ahead. There may have been more or less load than expected, a transmission line may be out, or a generator might trip. Planning for these types of contingencies ensures that the loss of the largest generator, or the loss of particular transmission lines, do not impact overall system stability. However, each of these situations requires a system operator to respond in order to keep the system within these contingency limits and prevent an emergency situation. To that end, electric system operators may require the re-dispatch of a scheduled unit, or the dispatch of a unit not scheduled previously.

The difference between the time generators bid and then purchase gas makes it difficult for generators to nominate with certainty the quantity of gas they will need to meet an operating commitment. The challenge comes when gas generators nominate a particular amount of gas, and then are called upon by the system operator to run more or less than what was nominated. Depending on how much gas a generator nominated, already burned, or depending on the pipeline system conditions at the time, a gas-fired generator may or may not be able to respond to dispatch signals in real-time. Thus, not only do over/under takes create headaches for pipeline system operators trying to manage sufficient line pack to meet the needs of *all* its transportation customers (especially its primary firm shippers), but if generators cannot respond, then electric system reliability could be at risk.

Moreover, gas is not easily purchased and scheduled on peak usage days, holidays, during the overnight hours, or during the early morning hours. Even though some ISO/RTO markets (for example, NYISO) allow bids to be increased in real-time to reflect the higher gas procurement costs in the intra-day gas spot markets, depending on the time of day, there may not be the possibility to procure additional gas. Thus, there could be a situation where a generator is called on outside of the day-ahead dispatch schedule, and the pipeline could manage the imbalance, but there is no gas marketer available to arrange the gas purchase.

Directly connected generators vs. Generators located behind the city-gate

In some ISO/RTO markets, the majority of gas-fired generators are directly connected to the pipeline system. Directly-connected generators have a dedicated meter point off of the interstate system, share their estimated hourly burn profiles with the pipeline (when required), and manage imbalances with the interstate pipeline. In other ISO/RTO markets, for example in NYISO, many gas-fired generators are located behind the city-gate. These generators nominate gas to their local gas distribution company (LDC), manage imbalances with the LDC, and in some cases, may see additional restrictions, depending on LDC pipeline system conditions.

¹⁷ The NYISO is responsible for the reliable operation of the New York Control Area power system, according to all applicable North American Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and New York State Reliability Council (NYSRC) reliability rules and standards. Regulation services support load balancing and the maintenance of frequency at 60 Hz. Reserves provide back-up generation during system contingencies.

LDCs have an obligation to serve and are responsible for ensuring that the gas on their system is in balance on both an hourly and daily basis. On the New York Facilities System, which is managed by two gas LDCs serving New York City and Long Island customers (Consolidated Edison and National Grid), generators, by definition, are considered an interruptible customer. This means that even if a New York City generator had primary firm transportation on the interstate system, at the local-level, where they receive their scheduled gas, they run the risk of being interrupted when the pipeline system is stressed.¹⁸ Moreover, pipeline capacity on the New York City and Long Island LDC system is reserved daily by 9:30 a.m., prior to the posting of the NYISO day-ahead operating commitment.

Some of this fuel uncertainty is managed by a dual-fuel requirement. New York State Reliability Council (NYSRC) rules require that the New York bulk power system operates such that the loss of a single gas facility does not result in the loss of electric load within the New York City or Long Island zones. Since the loss of a single gas line on the NYFS could result in the loss of multiple generators, there are additional operating requirements for generators within the Consolidated Edison and National Grid system. Upon a loss of gas pressure, or when electric load is predicted to be above a certain level, either the minimum oil burn¹⁹ or the automatic fuel swap²⁰ rules require generators to operate on an alternate fuel source. However, just because these units have dual-fuel capability does not mean they can easily make the switch to their alternate fuel, and some units require start-up gas to make the switch.

Finally, given an increased focus on safety on local gas distribution pipelines, some pipelines on local gas systems may see requirements to reduce the maximum allowable operating pressure on some lines. More testing of pipelines at the local distribution level could reveal that pipeline operating pressures must be reduced for safety reasons. These reduced pressures could impact gas-fired generators behind the city-gate.

Opportunities for Improved Coordination and Information Sharing

Given market timing differences, the structural reality of the gas market, and the physical reality of the way gas moves through the pipeline system, the reliable operating of the electric system depends on improved coordination and information sharing with the gas pipelines, gas LDCs, gas generators, and ISO/RTOs. While there may be room for improved market design on both systems, increased day-to-day communication between pipeline operators, LDCs, gas-fired generators, and the ISO/RTO may also be needed. Certainly, communication when either system is stressed, is crucial.

The information needed will depend on system conditions on both the pipeline/LDC system and the electric system. In particular, there are two types of system conditions that would require coordination:

¹⁸ Generators located behind the city-gate in other regions may also have tariff agreements with their LDC that limit their gas supply during particular system conditions, or when the temperatures are below a certain level. For a discussion on some of the impact of gas-fired generation behind the city-gate, see: NAESB Gas Electric Coordination Task Force – LDC Presentation, January 2004.

¹⁹ Minimum oil burn applies to generators with the ability to simultaneously burn gas and oil.

²⁰ New or re-powered gas units (combined cycle units) are required to be operated with the ability to switch automatically to an alternate fuel.

- (1) Day-to-day conditions on the electric system that require a change in the scheduled dispatch of gas-fired generators.
- (2) An emergency, as defined by either system.

The type of communication required would differ in each of these situations. In addition, who is actually doing the communicating could differ.

Day-to-day changes in the scheduled dispatch of generators occur in real-time, in response to electric system conditions. There are procedures in place for generators to communicate any unavailability, both prior to the day-ahead scheduling process and in real-time. Given that changes on the electric system could require a generator to overtake outside of their scheduled amount, there may be a need for additional communication/coordination between the LDCs and pipelines in order to manage possible imbalances and prevent reliability concerns on the pipeline system.

For example, the pipelines or LDCs could request additional information from generators. FERC Order 698 already allows pipelines to request hourly burn profiles from generators directly connected to their system. This kind of communication could be requested from generators located on LDC systems, could be modified such that generators communicate changes to this profile throughout the day, and/or could include detail on how generators and pipelines/LDCs can manage the imbalance, if it can be managed.

Keeping in mind that actions by system operators to maintain reliability are an attempt to *prevent* an emergency situation, additional communication procedures could be put in place whereby generators communicate this information to the ISO/RTO during specific system conditions. During expected cold weather snaps, for example, generators could communicate their next-hour fuel availability. This would allow electric system operators to know how much gas a generator has nominated, how much gas a generator has already burned, and how much alternate fuel is available. This is not information that would be required at all times, but during these identified system conditions, knowing next-hour generator capability could enhance reliability.

During an emergency – as defined by either system – direct communication procedures between the ISO/RTOs, pipelines, and LDCs are already outlined. If a generator is identified as being critical to maintaining reliability, there is an effort to communicate with the pipelines and LDCs to determine if there is capacity to transport gas. Even in this case, however, gas may not be available. Furthermore, interstate pipelines have a requirement to serve their primary firm transportation holders, and LDCs have a requirement to serve their “human needs” customers first. Generators often do not fall into either category.

Beyond the type of information needed, there are market implications for acting on this information. What if a generator has overtaken gas from the pipeline, but is certain they can work around any imbalances? At what point do pipeline operators notify system operators that a generator’s actions cannot be accommodated? Requiring generators to manage their fuel requirements and notify the ISO/RTO of any limitations – as is done now – could help to avoid some of these uncertainties. But what if a generator is assuring the ISO/RTO they will have gas, yet the pipeline or LDC is anticipating that they cannot handle the current imbalance, and has notified the system operator. Perhaps the generator is working with a marketer to schedule gas, but has not yet placed the nomination, so the pipeline or LDC

is unaware that the expected imbalance may not occur. Moreover, what happens when the anticipated reliability concern does not occur, but generator profits were impacted because of ISO/RTO or pipeline actions? Clear “checkpoints” must be in place to define appropriate actions to be taken to maintain system reliability.

Conclusion

The most important issues related to the need for information sharing between the gas and electric systems are: (1) the differences in the timing of gas and electric scheduling, and (2) the market structure of the gas pipeline system; and (3) the physical reality of the way gas moves through the pipeline system. Firm contracts are necessary for ensuring gas supply, but they are not sufficient to guarantee supply; generators must also nominate the gas they need. Given differences in the timing of gas and electric markets, it may be difficult for gas generators to nominate enough gas supply to meet real-time electric system needs, leading to reliability concerns on both systems.

Since the pipeline system was not designed to serve a mostly gas-fired electric system, understanding the current pipeline financing model is an important part of the gas-electric coordination process. Even with the abundance of natural gas, there are still transportation congestion issues on peak demand days.²¹ Additional pipelines may be needed, but it is difficult for the largest –and fastest growing – natural gas consumer to finance the construction of pipeline infrastructure, especially if the need for additional capacity occurs only a few days of the year.

Furthermore, the ability of generators to respond to changing electric system conditions depends on pipeline system conditions. Generators typically do not hold primary firm contracts, and even if they did, most pipelines do not offer “no-notice” transportation service. This means that generators may not easily make changes to their scheduled nominations in real-time. Thus, even without a pipeline or gas LDC system alert or OFO in effect, the real-time availability of a gas-fired generator could be limited. There may not be capacity available on the pipeline system, or the gas system may be unable to accommodate large swings in gas usage at that particular moment.

There may be a need for communications and market design changes in both markets in order to ensure that reliability on either system is not threatened, to supply electricity on the coldest winter day, or even to ensure system reliability during normal operating days. Even then, enhanced planning and communication will be required on both the gas and electric sides for both emergency situations, as well as for every day system fluctuations.

²¹ Gas prices reflect congestion patterns on the pipeline system, and gas prices during January and February of 2013 were almost twice as high as the price of oil on some very cold days.

Appendix A

Market timing across ISO/RTOs

<u>ISO/RTO</u>	<u>Bids Due</u>	<u>DA Market Posted</u>
PJM	11 am (ET)	4 pm (ET)
ISO-NE	12 pm (ET)	4 pm (ET)
MISO	11 am (ET)	3 pm (ET)
CAISO	7 am (ET)	4 pm (ET)
ERCOT	11 am (ET)	2:30 pm (ET)
NYISO	5 am (ET)	11 am (ET)

Appendix B

North American Energy Standards Board (NAESB)

Wholesale Gas Quadrant (WGQ) Nomination and Scheduling Standards and Procedures

*Eastern Standard Time

1. *The Timely Nomination Cycle*: Deadline 12:30 p.m.
 - Made the day prior to the gas flow day
 - No scheduled quantities are carried over from the previous gas day
 - If nominated quantities exceed available pipeline capacity, reductions are made, following the scheduling priorities
 - *Final confirmation*: 4:30 p.m.
 - Scheduled quantity reports available to shippers and interconnected operators by 5:30 p.m. These reports also indicate quantities scheduled to flow the next gas day, as well as reasons for any reductions to originally nominated quantities.
2. *The Evening Nomination Cycle*: Deadline 7:00 p.m.
 - Made the day prior to the gas flow day
 - Scheduled quantities are carried over from the Timely Cycle
 - Previously scheduled interruptible (IT) nominations may be bumped at this cycle to accommodate new firm requests
 - If nominated quantities exceed available pipeline capacity, reductions are made, following the scheduling priorities
 - *Final confirmation*: 10:00 p.m.
 - Scheduled quantity reports available to shippers and interconnected operators by 11:00 p.m. These reports also indicate reasons for any reductions to originally nominated or previously scheduled quantities
3. *The Intraday 1 (ID1) Nomination Cycle*: Deadline 11:00 a.m.
 - The first opportunity to modify previously scheduled quantities during the Gas Day
 - ID1 nominations effective at 6:00 p.m. (8 hours after the start of the Gas Day)
 - Scheduled quantities are carried over from the Evening Cycle
 - Previously scheduled interruptible (IT) nominations may be bumped to accommodate new firm requests
 - Because gas is already flowing based on previously scheduled nominations, reductions to remaining nominations are limited to the amount that would have flowed up to the effective time of the changes (i.e. 6:00 p.m.), called the Elapsed Prorated Scheduled Quantity Process (EPSQ)
 - *Final Confirmation*: 2:00 p.m.

- Scheduled quantity reports available to shippers and interconnected operators by 3:00 p.m. These reports also indicate reasons for any reductions to originally nominated or previously scheduled quantities

4. *The Intraday 2 (ID2) Nomination Cycle:* Deadline 6:00 p.m.

- The final opportunity to modify previously scheduled quantities during the Gas Day
- No bumping permitted: All ID2 nominations compete for available capacity remaining after the ID1 Cycle
- As with reductions in the ID1 Cycle, ID2 reductions are limited by EPSQ. However the EPSQ calculation for ID2 includes an adjustment for the additional four hours of effective flow after ID1
- *Final confirmation:* 9:00 p.m.
- Scheduled quantity reports available to shippers and interconnected operators by 10:00 p.m. These reports also indicate reasons for any reductions to originally nominated or previously scheduled quantities

Appendix C

North American Energy Standards Board (NAESB)

Wholesale Gas Quadrant (WGQ) Nomination and Scheduling Standards and Procedures

Transportation Service Provider Scheduling Priorities

1. *Primary Firm Capacity*: Once scheduled, cannot be bumped
2. *Secondary Capacity*: In most cases, cannot be bumped, so may prevent nominations for primary capacity from being scheduled if submitted in a later cycle
3. *Interruptible Capacity*: Only paid for when actually used. Have no entitlement or right to transport gas, only able to use system capacity when it is available after all firm requests
4. *Other Priorities*:
 - a. *Authorized Overrun*: Nominated firm that exceed the firm contract's entitlement. Only scheduled after all firm and interruptible nominations served.
 - b. *Imbalance*: Nominated to clear up over- or under-supply situations.

Modeling Gas-Electricity Coordination in a Competitive Market

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Abstract

As climate concerns, low natural gas prices, and renewable technologies increase the electric power sector's dependence on natural gas-fired power plants, operational and investment models for gas and electric power systems will need to treat the interdependencies between these two systems to accurately capture the impacts of one on the other. Currently, few hybrid gas-electricity models exist. This paper reviews the use of computational models in electric power systems, the state of the art for gas-electricity models, and presents a new model and case study that illustrates a few effects of simultaneously considering the gas (purchases and capacity contracting) and electricity (power plants operation) system in a competitive market under uncertainty from renewable energy sources.

Introduction

A brief overview of the complex decision space in a power system

In developed countries, citizens tend to view electricity as a right, not as an energy commodity. Yet, the ease with which most consumers have access to electricity belies the complex nature of the electric power system. The planning, investment, and operation decisions that make electricity possible span timescales from seconds to decades and require careful consideration of future uncertainties such as demand, fuel availability, the environment, and government policy.

Much of the complexity and uncertainty related to planning and operating an electric power system stems from the fact that electricity supply and demand, unlike other energy commodities, must remain in instantaneous balance as a matter of physical law. In each power system, generators that produce electricity are connected to each other via thousands of miles of transmission lines and turn synchronously as a single, monolithic machine. Small differences between electricity supply and demand are instantaneously balanced by conversions between mechanical and electrical energy that speed up or slow down the frequency of this monolithic machine. Large deviations between supply and demand can lead to electrical and mechanical failures. Storage technologies, such as pumped hydro reservoirs, can serve as a buffer for some of these deviations by charging during times of excess supply and discharging during times of excess demand. However, because most power systems cannot economically store large amounts of electricity, balancing consumption and generation generally requires real-time adaptation at the demand and generation level.

Determining the economically efficient long-term investments and short-term operations that will balance consumption and generation pose a difficult challenge because these decisions are time-coupled. For example, long-term investment decisions directly impact short- and medium-term decisions for the duration of an investment's lifetime. At short timescales ranging from seconds to hours, operators must decide which plants in its system to dispatch such that the chosen plants, in aggregate, will have the greatest chance of coping with all expected and unexpected changes (e.g., in demand, generator availability, and renewable generation) at the lowest cost. At medium timescales ranging from days to a few years, operators must make decisions about how to manage limited resources, such as hydro reservoirs to help meet peak demand while coping with uncertainty about future rainfall and water availability. At large timescales ranging from years to several decades, stakeholders must make appropriate investments such that the entire generation portfolio and transmission network can efficiently meet changes in expected demand while also complying with new regulatory policies such as a renewable portfolio standard. Because long- and medium-term decisions directly impact the range of

possible medium- and short-term decisions, determining the “correct,” economically efficient, optimal, welfare-maximizing investments and operations at each timescale under uncertainty poses a quantitatively complex challenge for all stakeholders in a power system.

Stakeholders in electric power systems

Before the 1990s, vertically integrated utilities operated most electric power systems around the world under cost-of-service remuneration. These utility companies implicitly acted as central planners; they made all short- and long-term decisions in their systems ranging from daily dispatch to generation and transmission investments. Under the supervision of a regulatory agency, a vertically integrated utility earned all of the costs of its business plus a fair rate of return (as determined by the regulator) in exchange for providing its customers with reliable electricity. Given the political and social consequences of electricity failures, although utility companies and regulators tended to err on the side of caution when making investment and operation choices and approving costs (leading to potentially inefficient choices), vertically integrated utilities generally handled their central planning responsibilities well, and electricity failures occurred infrequently.

When power systems began to “deregulate” and “liberalize” in the early 1990s, many governments around the world separated their vertically integrated utilities and created competition at the generation level to incentivize greater economic efficiency.¹ Independent power producers that wanted to build a power plant and sell electricity could do so by requesting a connection to one of these liberalized power systems and then submitting bids to a market operator (in most power systems, the market operator and the system operator are the same entity). Markets exist today for many electricity “products,” including energy and reserve services differentiated by time.

In the process of creating these electricity markets, many of the central planning functions that vertically integrated utilities previously performed were either implicitly transferred to stakeholders such as regulators, system operators, utilities, and independent power producers, or lost due to market structures that misaligned individual incentives with the system’s total welfare. For example, today, concerns about failures that arise in liberalized electricity markets about broadly fall into three time-delineated categories: reliability in the short term, firmness in the medium term, and adequacy in the long term.

¹ Transmission and distribution networks remained regulated as natural monopolies because of their economies of scale. Per unit capacity, larger capacity power lines cost less than smaller capacity lines. As such, allowing multiple companies to build smaller, overlapping networks would actually increase total consumer costs.

1. In the short term (seconds to days), if a system operator commits a power plant to operate in the next day, and then that power plant fails to start up because of a mechanical problem, the system operator must rely on the remaining plants that it has dispatched to make up the difference. While the owner of the generator holds financial responsibility for the energy that he cannot generate, to ensure the proper operation of the power system, the system operator must physically find a feasible combination of increased generation and decreased consumption to mitigate the effects of this real-time failure.
2. In the medium term (weeks to years), the owner of a portfolio of natural gas plants in a power system must contract for pipeline capacity in advance to prevent that owner from being unable to offer capacity from his gas plants at a later time in the year. In this situation, the owners of the gas plants may or may not hold financial responsibility for the electricity that they now cannot physically deliver (perhaps those owners had participated in an energy auction with the system operator, or they were planning to just sell their energy in the day-ahead market). Besides the economic losses that will incur the owner, depending on the reserve capacity of this power system and the fraction of capacity and generation that natural gas power plants provide, the feasible solution may entail higher marginal prices and rolling blackouts and, hence, the system operator again must find a feasible combination of increased generation and decreased consumption to make up the imbalance.
3. In the long-term (across multiple decades), independent power producers may decide not to invest in additional capacity that the system needs to meet future demand changes. For example, they may decide not to build a peaker plant because they do not expect to fully recover their fixed costs through the current available revenue streams, or they may decide not to build a wind turbine despite a renewables mandate because the feed-in tariff is too small.

The examples in this section illustrate the types of economic and physical problems and uncertainties (e.g., demand forecasts, plant and fuel availabilities, new technologies, environmental concerns, and new regulations) that affect all stakeholders in electric power systems. To address these types of problems in a liberalized system, individual stakeholders must act under “correct” market incentives and policies such that their individual behaviors achieve a desired outcome in aggregate (e.g., a reliability or efficiency target); determining what the “correct” set of incentives and policies are is not trivial. Similarly, vertically integrated utilities face similar challenges, but their regulated business models lead to different economic efficiency challenges, and determining the “correct” level of efficiency is also not trivial. *To tractably grasp the complexity of these*

types of challenges and to understand how one decision affects another, power systems stakeholders—regulators, system operators, independent power producers, and utilities—rely on computational models to gain insight about what the “correct” set of long-term outcomes, short-term operations, market rules, and government policies should look like.

Computational models for gas-electricity systems

Stakeholders in electric power systems use computational models to understand and make optimal decisions about operations and investments. For example, a system operator might use an optimal power flow model to determine the lowest cost set of electricity bids that will meet tomorrow’s demand, as well as to calculate the corresponding marginal prices for clearing day-ahead transactions. With this same optimal power flow model, in a different power system, a regulator might analyze a vertically integrated utility’s operations to approximate its operating costs and set the next rate base. This dual use for optimal power flow models and other electricity models is not coincidental: under the traditional economic assumptions of perfect competition, complete information, and rational behavior, the optimal, economically efficient decisions for an electric power system—regardless of whether it operates as a vertically integrated utility or as a market with individual agents—are the same. (I.J. Perez-Arriaga & Meseguer 1997) While the assumption of perfect competition is strong, many electricity models can also represent various levels of competition; the key idea is that these models can give quantitative insights and benchmarks about what optimal outcomes should resemble. As such, stakeholders in electric power systems rely on models for both operational and regulatory purposes.

Computational models such as the optimal power flow example above operate by capturing the salient features of a power system and then calculating a set of feasible decisions that best meets a specific system objective. A power system’s physical and operational constraints define the set of possible decisions that the system can take, and the system’s objective typically involves either minimizing total cost or maximizing profit. Typical electricity models that address short-term concerns include economic dispatch (to determine the least-cost plants that can meet demand), unit commitment (economic dispatch with an explicit consideration for which plants to turn on and off), and optimal power flow; in the medium-term, hydrothermal coordination models provide insights about how to use limited storage resources such as water stored in a reservoir; and in the long-term, capacity expansion models explore the investment decisions needed to meet future demand and policies. At the simplest level, these models are nontrivial math problems, and for a real-world sized system, they can require significant computing resources and time to solve. Additionally, depending on the mathematical formulation, some of these models may not have a provable optimal solution. Advances in operations research have greatly improved the size of problems that can be solved. For examples and more details about the state of the art of electricity models, see (Ventosa et al. 2005) on electricity markets;

(Padhy 2004) on unit commitment; and (Qiu et al. 2009) on optimal power flow.

State of the art for gas-electricity models

Traditionally, electricity models have assumed that thermal plants such as coal and gas generators have access to unlimited and completely reliable fuel supplies. However, recently, due to environmental concerns, low natural gas prices, and the operational flexibility of gas plants, many power systems are increasingly relying on natural gas as a primary source of energy for electricity generation. As this trend continues, the traditional models that have guided operations, investments, and policies in these power systems will need to take into consideration additional constraints that arise from the coupled gas-electricity system, or risk missing potential failures related to the coupling. Despite these interdependencies, thus far, the academic literature contains relatively few articles about hybrid electricity-gas models. The remainder of this section reviews the current state-of-the-art; many of the papers presented in this section are drawn from references found in (Rubio et al. 2008).

For a single snapshot time period, various authors have proposed models that jointly analyze the gas and power system by including the gas network and compressor stations:

- (Munoz et al. 2003) propose a model that evaluates the maximum amount of electric power generation possible from all of the combined-cycle power plants in a power system, taking into consideration gas demand by nonelectric customers, the gas network, and gas availability. Many reliability models take as inputs information about a plant's maximum output. Traditionally, reliability models have considered the maximum output of thermal plants as a constant parameter. However, this assumption does not hold under fuel uncertainty. In addition to updating the treatment of combined-cycle plants in reliability studies, this model also introduces a new stakeholder in the gas-electric system that did not previously exist in the electric power system alone: nonelectric consumers whose demand for gas (perhaps as a heating source) might preempt demand for gas in the electric sector.
- (An et al. 2003) propose an optimal gas- and power-flow model that maximizes the total social welfare by summing benefits for all electrical and gas consumers and subtracting the cost of all operations. Similarly, (Unsihuay et al. 2007) propose an optimal gas- and power-flow model that minimizes costs. Unlike traditional welfare-maximizing electricity models, these hybrid model recognize the welfare of all agents (consumers and producers) in both systems when determining the optimal set of gas and power flows and corresponding marginal prices.
- (Urbina & Z. Li 2008) propose a cost-minimizing security-constrained unit commitment model that also takes into consideration optimal gas flows and interruptible gas contracts.

In the short term, (M. Shahidehpour & Wiedman 2005) discuss the impact on the power system of different contingencies in the gas infrastructure that cut off the supply of NGPPs; (T. Li et al. 2008) solve the unit commitment problem subject to gas network constraints with the possibility of fuel switching; (Chaudry et al. 2007) include line-pack capacity and gas storage facilities when minimizing the gas supply, gas operation and electricity generation costs; and (Liu et al. 2009) consider, besides gas storage, compressor stations to solve the unit commitment problem.

In the medium and long term there is little literature to our knowledge. In the medium term, (Bezerra et al. 2006) propose a dynamic programming model to obtain the operation plan of hydrothermal and gas systems subject to stochasticity; and (Dueñas et al. 2012) seek to maximize the profits when managing gas supply contracts (including gas network congestions) in imperfect power markets. In the long term, (Unsihuay-Vila et al. 2010) extend their single period model to capacity expansion of both systems.

Growing importance of natural gas in electric power systems

During the last two decades, natural gas has appeared as a relevant source of energy for electricity production. Gas consumption by the electric sector in the U.S. has increased 2.24 times from 1997 to 2012. Furthermore, technological improvements in shale gas extraction and the subsequent reduction in costs have boosted reliance on natural gas for electricity generation. But, beyond these facts and numbers, two main reasons explain the preference of gas over other fossil fuels, such as coal or oil distillates. First, while gas prices may not always be lower than coal prices in monetary units per unit of released thermal energy, the higher conversion efficiency of natural gas power plants (NGPPs) with respect to coal power plants (60% and 30%, respectively and environmental regulations that limit or tax CO₂, SO₂, and/or NO_x emissions² make gas prices habitually lower than any other fossil fuel. Second, because NGPPs have significantly lower investment costs than other thermal plants, their rate of return on investment is relatively larger than other fossil fuel technology.

The increasing importance of NGPPs in current electricity systems justifies the joint analysis of gas and electricity systems. Although huge investments have taken place in gas systems to adapt their infrastructure to growing demand, generation companies sometimes face scarcities of gas pipeline capacity that may prevent a company from participating in the electricity market. Therefore, if several consumers (households, industries, or generation companies) share the pipeline and the capacity might be scarce at some future moment (e.g., in the middle of winter), contracting capacity in advance, which is similar to make a

² Natural gas is said to be the cleanest fossil fuel. According to Energy Information Administration of the U.S., it emits half as much CO₂ and a third as much NO_x. SO₂ emissions from gas are negligible.

hotel reservation, is very interesting for generation companies. The objective of the model presented below is to analyze pipeline capacity contracting by a generation company that shares the pipeline with other consumers.

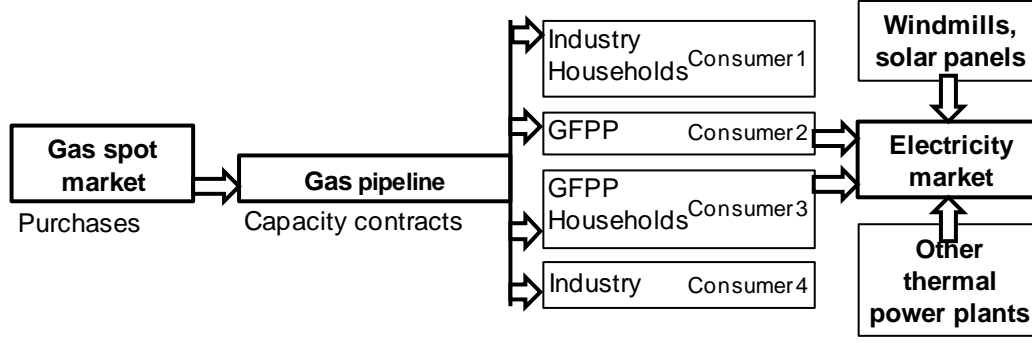
Besides contracting gas pipeline capacity, the generation company must acquire gas. The gas consumers, and the generation company, can purchase gas in the spot market. But the higher the demand, the higher the price. As long as the generation company is competing in the electricity market with other producers, the previously defined objective extends to include the analysis of pipeline capacity contracting by a generation company that shares the pipeline with other gas consumers and participates in a gas spot market and in an electricity market.

NGPPs have an additional competitive advantage over most thermal power plants: they offer operational flexibility at reduced costs. Nowadays, renewable energy sources introduce intermittency in electricity systems. NGPPs have greatly supported the integration of renewable energy sources and improved the power system stability. However, in the context of liberalized electricity markets, generation companies must be ready to respond to sudden changes in renewable power generation. They must incorporate the uncertainty of renewable energy sources into their decision-making process, particularly when they contract for pipeline capacity well in advance. Consequently, our previous objective is finally extended to analyze pipeline capacity contracting by a generation company that shares the pipeline with other consumers. This generation company also participates in a gas spot market and an electricity market, and the market clearing is subject to the uncertainty of renewable energy sources.

Coupling gas and electricity decisions under uncertainty

The main objective of the model is to simulate the behavior of a generation company that owns a set of NGPPs, purchases gas in spot markets, and contracts capacity to supply its NGPPs. The model presented in this paper has tried to fill a gap that is of concern in current deregulated gas and power systems: the long- to medium-term decisions related to contracting pipeline capacity and the short-term decisions related to NGPP operation subject to the uncertainty of renewable power generation.

There are two markets at both extremes of the figure: the gas spot market and the electricity market; and one physical infrastructure, a gas pipeline, that connects both markets. The purchased gas flows through the pipeline, as long as capacity has been contracted, to the electricity market or to other gas consumers, such as industries or households. But the gas consumption of the electricity market depends on the market-clearing process in which the gas technology competes with other thermal (coal, gasoil, etc.) technologies. Let us assume that wind and solar are always dispatched.



In short, there is a zonal gas spot market, z . A gas pipeline connects the market to the gas consumers, $e=1,2,\dots,E$. A balance between the inflows (market purchases) and the outflows (demands) is monitored each day, $d=1,2,\dots,D$. Part of the gas demand satisfies the industrial users and households, and another part feeds the NGPPs. These power plants together with other thermal (coal, gasoil, etc.) power plants constitute the group of power generators, $g=1,2,\dots,G$, which satisfy the residual thermal electricity demand (after the dispatch of the renewable energy sources). As long as renewable generation is subject to uncertainty, the residual electricity demand will be defined for different scenarios, $k=1,2,\dots,K$.

The model, a mixed-integer quadratically programming (MIQP) problem, is formulated as a combination of a quadratically programming (QP), a linear programming (LP), and a mixed-integer programming (MIP) problems. We start with the description of the gas spot market model. Then we present the capacity contracting model. Finally, we introduce the electricity market model and its link to the gas system. During the description of the model, uppercase and Greek letters stand for parameters, while lowercase letters stand for continuous and positive variables (except when explicitly indicated).

Optimizing gas purchases

Let us consider that within the gas spot market the dependence of the marginal gas cost $c(v_{zdk}^{HUB})$ on the daily purchases v_{zdk}^{HUB} can be represented by an affine function with cost intercept α_0 , and cost slope α_1 :

$$c(v_{zdk}^{HUB}) = \alpha_0 + \alpha_1 \cdot v_{zdk}^{HUB} \quad (1)$$

The consumers acquire gas at the zonal hub to comply with their certain conventional (industry and households) demand D_{zed}^{CNV} , and with the variable, and uncertain, demand of their NGPPs d_{zedk}^{NGPP} :

$$v_{zdk}^{HUB} = \sum_e (d_{zedk}^{NGPP} + D_{zed}^{CNV}) \quad \forall z, e, d, k \quad (2)$$

Even though the gas spot market is liquid and large enough, and the purchases are not limited, the total demand will be constrained by the pipeline capacity:

$$\sum_e (d_{zedk}^{NGPP} + D_{zed}^{CNV}) \leq Q_z^{OUT} \quad \forall z, d, k \quad (3)$$

Naturally, the consumers would like to acquire gas at its minimum cost, or, concisely, the consumers minimize the expected acquisition costs:

$$\min_{v_{zdk}^{SPOT}} \sum_{z,d,k} \omega_k \cdot c(v_{zdk}^{HUB}) \cdot v_{zdk}^{HUB} = \sum_{z,d,k} \omega_k \cdot (\alpha_0 + \alpha_1 \cdot v_{zdk}^{HUB}) \cdot v_{zdk}^{HUB} \quad (4)$$

The new parameter ω_k is the weight of each scenario and represents the probability of occurrence of the scenario. Naturally, the sum of the weights is equal to one.

The objective function (4) subject to the balance constraint (2) and the maximum pipeline capacity (3) constitutes a QP problem (quadratic objective function and linear constraints) that minimizes the expected gas acquisition costs considering uncertainty in renewable power generation.

Optimizing pipeline capacity contracting

In broad terms, the operator offers capacity contracts with different time scopes. Accordingly, the consumers can contract capacity in the long term h_{ze}^{OUT} (i.e. during several years); in the medium term h_{zem}^{OUT} (i.e. during a month); and in the short term h_{zedk}^{OUT} (i.e. during a day). The correspondence between the time scopes and the time horizons follows a standard that commonly takes place in reality. Standardized long-, medium- and short-term capacity contracts expire several years later, the next month or the next day, respectively. In addition, we consider that long- and medium- term contracts represent firm capacity contracts, while short-term contracts characterize interruptible capacity contracts since the gas consumers cannot be sure that enough free capacity will be available when the time of contracting comes. The immediate consequence is that short-term contracting decisions are different for each scenario, while long- and medium-term contracting decisions are common for all the scenarios.

Capacity prices vary with the time scope, being habitually less expensive to contract capacity in the long term FC_z^{OUT} , than in the medium term FC_{zm}^{OUT} ; and in the medium term than in the short term FC_{zd}^{OUT} ; as the pipeline operator is anticipating incomes and reducing the risks of keeping idle capacity. In addition, the operator may apply a variable tariff VC_{zed}^{OUT} to the gas flow.

Daily, each gas consumer holds a portfolio th_{zedk}^{OUT} of long-, medium-, and short-term firm capacity contracts:

$$th_{zedk}^{OUT} = h_{ze}^{OUT} + h_{zem}^{OUT} + h_{zedk}^{OUT} + h_{zedk}^{\Delta OUT} - h_{zedk}^{\nabla OUT} \quad \forall z, e, d, (m/d \in m), k \quad (5)$$

The daily portfolio includes the acquisitions $h_{zedk}^{\Delta OUT}$ and releases $h_{zedk}^{\nabla OUT}$ that take place in secondary capacity markets, where capacity is negotiated:

$$\sum_e h_{zedk}^{\Delta OUT} = \sum_e h_{zedk}^{\nabla OUT} \quad \forall z, d, k \quad (6)$$

Similar to the gas demand that is limited by the pipeline capacity (3), the consumers' total capacity portfolios are constrained by the maximum capacity of the pipeline

$$\sum_e th_{zedk}^{OUT} \leq Q_z^{OUT} \quad \forall z, d, k \quad (7)$$

If the consumer has contracted enough capacity, the operator will let the amount of gas flow through the pipeline:

$$d_{zedk}^{NGPP} + D_{zed}^{CNV} \leq th_{zedk}^{OUT} \quad \forall z, e, d, k \quad (8)$$

There is one common long-term and medium-term contracting decision for all the scenarios as firm capacity contracts may be formalized well before (up to several years before) the time of operating the NGPPs that is, however, subject to the uncertainty of the renewable energy sources.

Finally, the gas consumers minimize the resulting costs from contracting both firm and interruptible capacity:

$$\min_{\substack{h_{ze}^{OUT}, h_{zem}^{OUT} \\ h_{zedk}^{OUT}, d_{zedk}^{NGPP}}} \sum_{z,e} \omega_k \left[FC_z^{OUT} \cdot h_{ze}^{OUT} + \sum_m (FC_{zm}^{OUT} \cdot h_{zem}^{OUT}) + \sum_{d,k} [FC_{zdk}^{OUT} \cdot h_{zedk}^{OUT} + VC_z^{OUT} \cdot (d_{zedk}^{NGPP} + D_{zed}^{CNV})] \right] \quad (9)$$

The objective function (9) subject to the constraints (5)–(8) constitutes a LP problem that allows the gas consumers to optimize their portfolio of capacity contracts under uncertainty.

Optimizing power plants operation

The main consequence of the gasification of electric power systems is the dependence of the electricity price on the gas cost and, therefore, the importance of analyzing how generation companies operate in the gas system. Moreover, in scenarios of high demand, if the generation companies have not foreseen the requirements of pipeline capacity or gas purchases, the power system may face non-supplied energy situations.

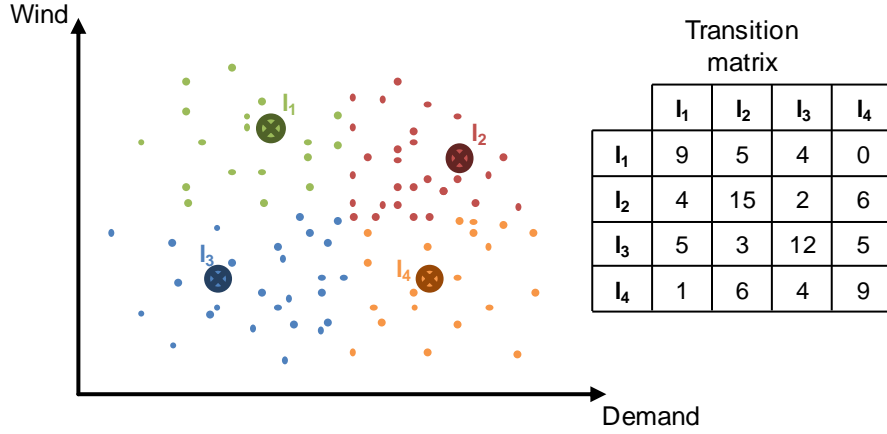
Before describing the model, let us focus on electricity demand. Demand and

supply must be balanced instantaneously because electricity cannot be stored at competitive costs. Modeling power systems with such a level of temporal detail would be intractable. For instance, markets that also utilize algorithms to determine the dispatch and the price “group the instants” in each hour. But even modeling in the long or medium term each hour may be troublesome. For this reason, traditionally, a load duration curve has been constructed and some load levels (e.g. peak and off-peak, working and non-working days) have been established that were able to capture the behavior of hydrothermal systems with no penetration of renewable energy sources³, in exchange for losing the chronology. Lately, since the deployment of renewable energy sources, the net load duration curve (demand minus renewable generation) is starting to be used to define the load levels. The main disadvantage of still using this procedure to define the load levels is that, for instance, off-peak load levels will combine hours with high demand and high wind conditions with (significantly different) hours with low demand and low wind conditions⁴. Moreover, the chronology should try to be maintained because the intermittency of the renewable energy sources can modify sharply the operation of the power plants (in contrast to the “calm” operation of old times). For these reasons, we define the load levels in a different manner: as the so-called states of the system. A state of the system is a predefined set of circumstances that occur simultaneously and frequently in the system during the analyzed period of time (a week, a month, a year, etc.); hence, each hour of the period is assigned to a state with the advantage of maintaining the chronology because the transitions between the states (i.e. the hours) are known. The way to define the states is explained with the next example.

Let us consider a small isolated system with windmills, and one diesel fuel power plant. The weather conditions will undoubtedly set the price of the electricity. Let us define four states as a combination of two events: high and low demand; high and low wind conditions. We now construct a scatter plot with the hourly demand in the X-axis and the hourly wind generation in the Y-axis and then apply a clustering technique to obtain four representative points out of the whole sample. Each hour will be linked to a state and the transitions between the states will be the number of the transitions between the hours. The four states are I_1 (low demand, high wind); I_2 (high demand, high wind); I_3 (low demand, low wind); and I_4 (high demand, low wind).

³ The operation of traditional power systems was characterized by rigid structures: nuclear power plants were producing always; coal power plants shut down the weekends if demand was too low; hydro power plants shaved the peaks; and gas and/or oil distillates power plants adapted to the residual demand due to their flexibility.

⁴ In this example, spinning reserves are critical in high demand scenarios to answer to a sudden decrease of wind generation; not so in low demand scenarios.



Returning to the description of the model, we can define several power system states, $l=1,2,\dots,L$. Consequently, each day is made up of different states, whose duration in hours is known T_{dlk}^{ST} . As previously mentioned, the load levels are defined for a period of time (hereinafter, a month) and the chronology is not lost because the number of transitions between two states l and l' within the month is known $N_{ml'k}^{TRN}$.

We have defined the net electricity demand D_{mlk}^{PWR} in each load level within the month as the difference between the electricity demand and the renewable power generation. As a result, there is a scenario of net electricity demand for each scenario of renewable power generation and, therefore, different state durations and transition matrices for each scenario. The generation companies, who own thermal power plants, produce an amount of electricity q_{gmlk} to cover the monthly electricity demand:

$$D_{mlk}^{PWR} = \sum_g q_{gmlk} \quad \forall m, l, k : p_{mlk}^{PWR} \quad (10)$$

One advantage of using QP and LP problems is the possibility of obtaining the dual variables of the technical constraints whose economic interpretation is usually of interest. For instance, (10) provides the electricity price p_{mlk}^{PWR} .

The generated quantity is limited by the maximum power Q_g^{MAX} , the technical minimum Q_g^{MIN} , and a binary decision variable that reveals whether the group is committed u_{gmlk} :

$$q_{gmlk} \leq Q_g^{MAX} \cdot u_{gmlk} \quad \forall g, m, l, k \quad (11)$$

$$q_{gmlk} \geq Q_g^{MIN} \cdot u_{gmlk} \quad \forall g, m, l, k \quad (12)$$

Nevertheless, the commitment of a group depends on the start-up and shut-down decision. If a group starts up between the states l and l' , it will be committed during the state l . In contrast, this group will not be committed anymore, if it shuts down between the states l' and l . The following constraint that includes the start-up $u_{gml'l'k}^{UP}$ and shut-down decisions $u_{gml'l'k}^{DN}$ describes these processes:

$$u_{gmlk} - u_{gml'k} = u_{gml'l'k}^{UP} - u_{gml'l'k}^{DN} \quad \forall g, m, l, l', k \quad (13)$$

A fact worthy of mentioning is that the start-up and shut-down decision variables need not to be binary, but limited between zero and one, because their value is automatically determined by the binary commitment decisions.

The generation companies, within a perfectly competitive framework, minimize the operating costs of their thermal power plants. The main costs of the thermal groups can be summarized in the variable cost CV_g (related to the generation); the fixed cost CF_g (related to the commitment); the start-up cost C_g^{UP} , and the shut-down cost C_g^{DN} :

$$\min_{\substack{q_{gml}, u_{gml}^{UP}, u_{gml}^{DN} \\ u_{gml'l'k}^{UP}, u_{gml'l'k}^{DN}}} \sum_{g,m,l,l',k} \omega_k \cdot \left(\sum_{d \in m} T_{dlk}^{ST} \cdot (CV_g \cdot q_{gmlk} + CF_{gml} \cdot u_{gmlk}) + \sum_{l'} N_{ml'l'k}^{TRN} \cdot (C_g^{UP} \cdot u_{gml'l'k}^{UP} + C_g^{DN} \cdot u_{gml'l'k}^{DN}) \right) \quad (14)$$

The objective function includes the weight of each scenario ω_k because in this case it makes no sense to define a common decision for all the scenarios, but for every scenario, because the power plants operation is a short-term decision. In addition, the start-up and shut-down decisions (0,1) are multiplied by the number of transitions between the states in order to better reflect their costs. (The variable costs of the NGPPs connected to a zonal hub are already considered in (4) and, hence, $CV_g=0$)

The MIP problem that is constructed with the objective function (14) subject to the constraints (10)–(13) allows the generation companies to optimize their electricity generation decisions in the power market.

The resulting gas-electricity model

So far, we have broken down a model that optimizes the gas purchases and the gas pipeline capacity contracting by the gas consumers, and the power plants operation by the generation companies in the electricity market under uncertainty. Now, we gather all the objectives function and constraints in the following unique model:

$$\begin{array}{ll}
\min & (4)+(9)+(14) \\
\text{s.t.} & \begin{array}{l} (2)-(3) \\ (5)-(8) \\ (10)-(13) \end{array}
\end{array}$$

However, a constraint that links the NGPPs production to the gas system has not been established yet. In detail, the NGPPs connected to the analyzed pipeline consume a daily amount of gas that depends on their gas-to-power conversion factor $F_g^{G \rightarrow P}$:

$$d_{zedk}^{NGPP} = \sum_{g \in (z,e),l} F_g^{G \rightarrow P} \cdot T_{dik}^{ST} \cdot q_{gmlk} \quad \forall z,e,d,(m/d \in m),k \quad (15)$$

The daily consumption (in each scenario) of the NGPPs which are connected to the same pipeline and belong to the same generation company, links the decisions in the electricity market to the decisions in the gas system.

Incorporating this last constraint, we obtain the final MIQP model:

$$\begin{array}{ll}
\min & (4)+(9)+(14) \\
\text{s.t.} & \begin{array}{l} (2)-(3) \\ (5)-(8) \\ (10)-(13) \\ (15) \end{array}
\end{array}$$

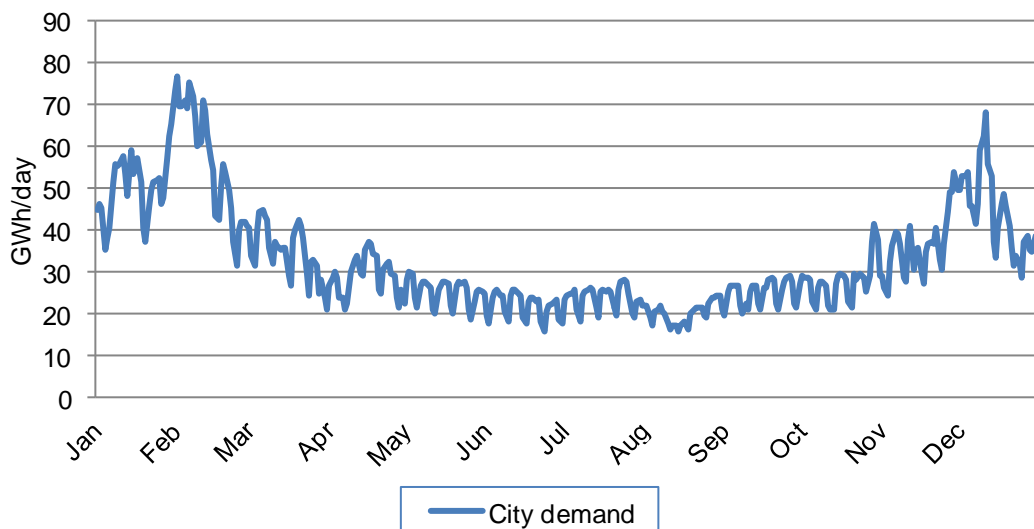
Description of a realistic system

The objective of the case study is to examine the behavior of a generation company, which only owns NGPPs; hence, the generation company has to coordinate its purchases at the gas spot market with its pipeline capacity contract portfolio and, simultaneously, to compete in the electricity market with other power producers. We do not intend to represent an actual system, but a system that reproduces actual operation conditions. Our lab system consists of a gas spot market, a shared gas pipeline and an electricity market. In the following, we describe in detail the elements of the chain from gas acquisitions to electricity production. The different values (capacities, prices, etc.) are inspired by real systems, but not by a specific system. The time scope is one year.

The gas spot market is characterized by a price-quantity curve. The minimum daily price is 13 €/MWh-t. The price increases 0.05 € per daily purchased GWh-t of gas. In addition, the gas spot market establishes the gas price of the whole system, also of the NGPPs that are not connected to the shared gas pipeline. In a few words, there are other gas pipelines whose reference price is determined by the gas spot market, but we consider neither their contracting nor their

operation.

The gas pipeline capacity is 85 GWh-t/day. The gas pipeline feeds an imaginary city, whose demand has preference over other demands. The demand curve reflects two relevant cold waves that reduce the free gas pipeline capacity to other consumers, like the NGPPs connected to the same gas pipeline, up to 9.7%. In fact, the generation company owns four NGPPs that are connected to this shared gas pipeline: two CCGT and two OCGT power plants (named CCGT1, CCGT2, OCGT1 and OCGT2). One of the basic concerns of gas-power systems that we have tried to represent with this realistic system is how scarce capacity affects the contracting and operation of a generation company. At the most, the free pipeline capacity after supplying the city allows the generation company to use its four NGPPs at full capacity during 184 days of the year, or its two CCGTs during 325 days of the year and its two OCGTs during 349 days of the year (being each pair considered individually at full capacity).



The long-term contract price amounts to 26,415 €/(GWh/day). The generation company pays for the contracted capacity each month during the years that the contract is in force, instead of paying in a punctual moment. Medium- and short-term contract prices are multiplied by a factor that is different for each month. As winter months are strongly penalized, the company has an incentive to contract properly during months when gas facilities are highly demanded. For instance, the incurred costs during 10 days and 20 days of short-term capacity contracting are equivalent to contracting a whole winter and summer month, respectively. At last, a variable tariff is applied to every unit of gas that flows through the pipeline, 567 €/GWh.

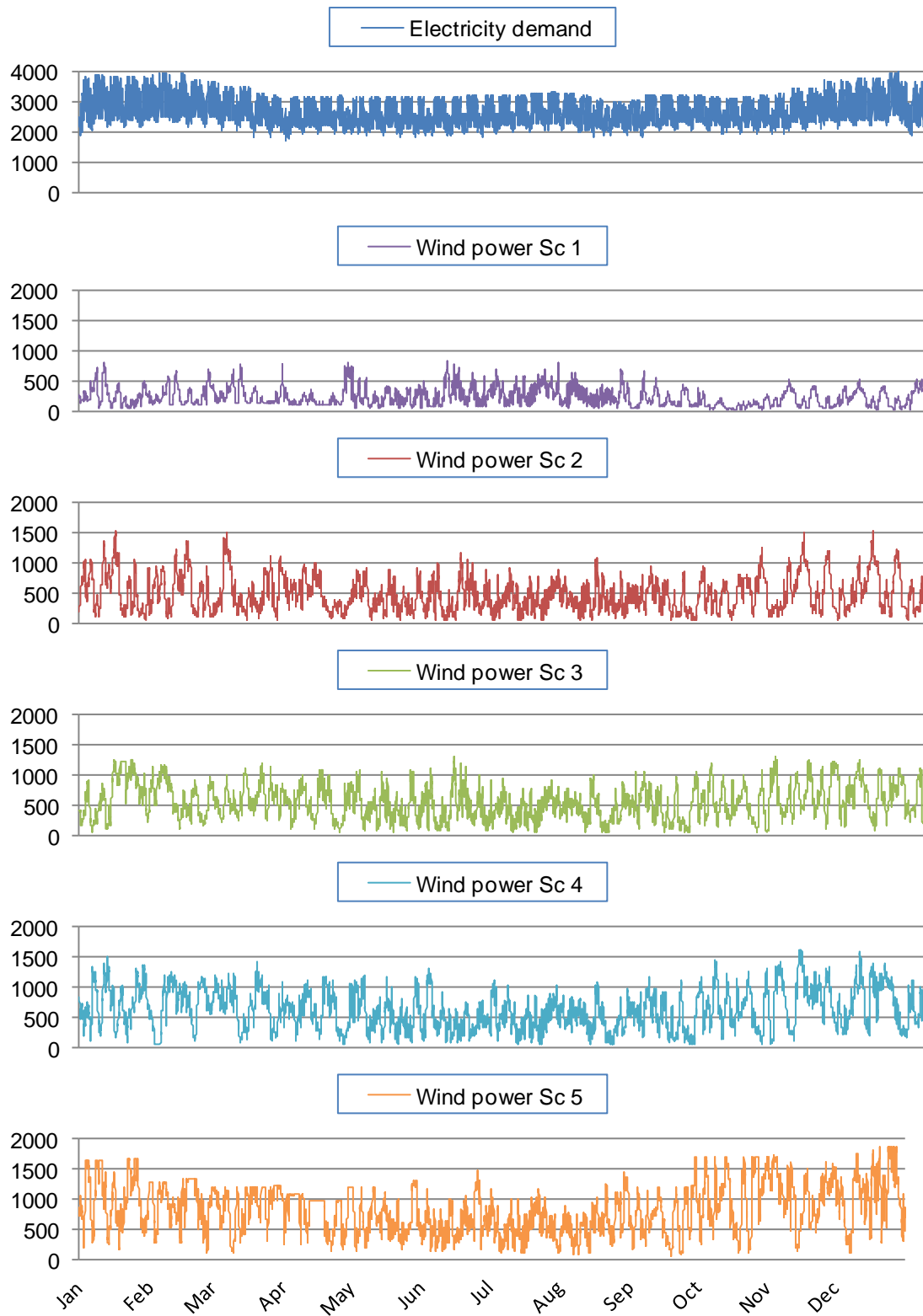
Month	Medium-term contract factor	Short-term contract factor
Jan-Mar	2	0.20

Feb-Sep	1	0.05
Oct-Dec	2	0.20

The power system consists of nuclear, natural gas (CCGT and OCGT), coal and gasoil power plants. The variable cost of the NGPPs results from the gas spot market.

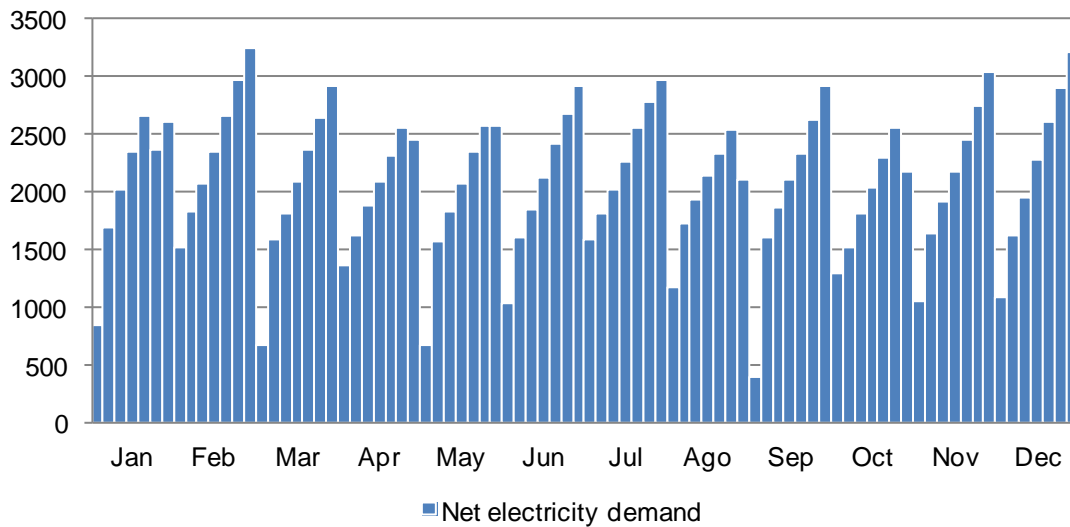
Thermal group	Maximum power (MW-e)	Technical minimum (MW-e)	Gas-to-power factor (MW-t / MW-e)
CCGT1	400	200	1.7
CCGT2	400	200	1.7
CCGT3	400	200	1.7
CCGT4	400	200	1.7
Coal1	600	300	-
Coal2	600	300	-
OCGT1	200	0	2.5
OCGT2	200	0	2.5
OCGT3	200	0	2.5
OCGT4	200	0	2.5
Gasoil	600	100	-

Thermal group	Variable cost (€/MWh-e)	Fixed cost (€/h)	Start-up cost (€)	Shut-down cost (€)
CCGT1	-	650	50,000	3,000
CCGT2	-	650	50,000	3,000
CCGT3	-	650	50,000	3,000
CCGT4	-	650	50,000	3,000
Coal1	35	900	100,000	7,000
Coal2	35	900	100,000	7,000
OCGT1	-	1,000	10,000	1,000
OCGT2	-	1,000	10,000	1,000
OCGT3	-	1,000	10,000	1,000
OCGT4	-	1,000	10,000	1,000
Gasoil	70	1,200	30,000	2,000



The production of the thermal power plants and the wind generation satisfy the inelastic electricity demand. The average electricity demand is 5.3 GW, while the

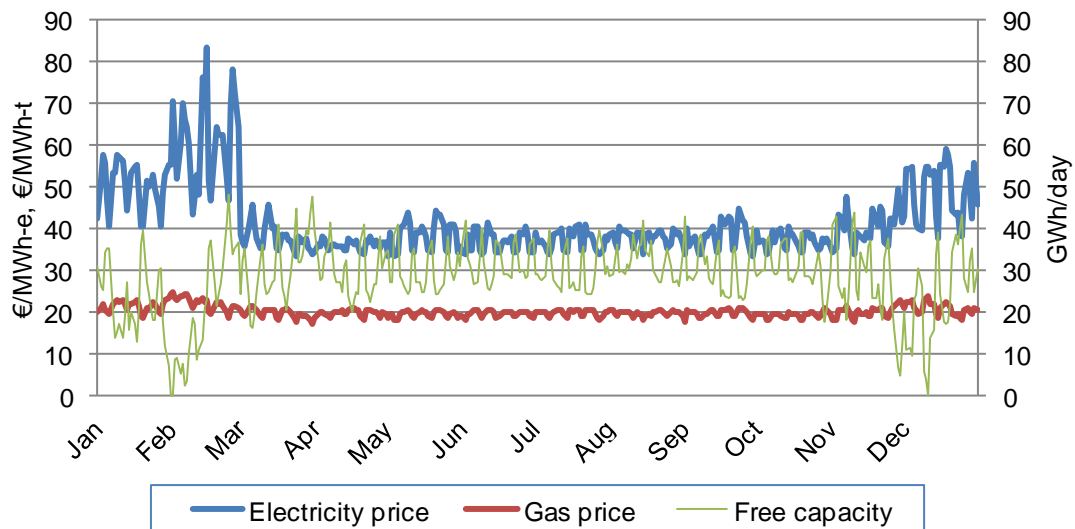
average wind power scenarios range from 0.5 GW to 1.5 GW. In detail, the wind power penetration in each scenario is 9%, 18%, 20%, 23% and 29%. The probability of each scenario is 0.05, 0.25, 0.4, 0.25 and 0.05, respectively. Given that we consider a wind profile that differs for each scenario, we have five net electricity demand curves with their corresponding state transition matrices and state durations. As an example, we reproduce the net electricity demand curve of the central scenario and the transition matrix corresponding to the month of January of the central scenario. The load levels have been determined with the MATLAB® clustering function k-means. There are two remarkable facts: 1) the matrix is not symmetric, so transition does not have to be between consecutive load levels; and 2) as expected, the number of transitions is equal to the number of hours.



	State 1	State 2	State 3	State 4	State 5	State 6	State 7
State 1	56	14					
State 2	14	72	19	3			
State 3		22	88	28	3		
State 4			34	66	33		
State 5				35	63	20	
State 6				1	19	69	17
State 7						17	51

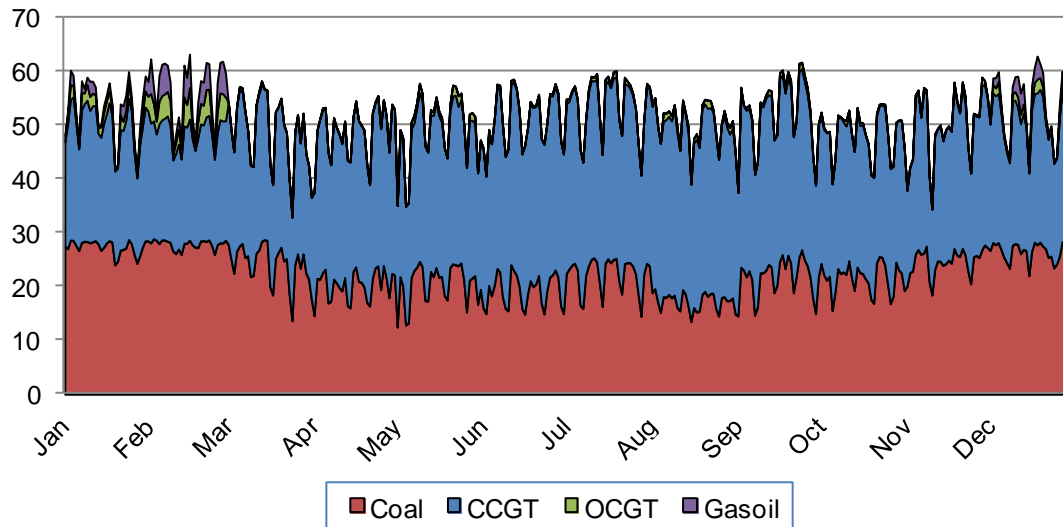
Model results

One of the first results that can be observed from the stochastic solution is the strong relationship between the gas and the electricity prices. But the electricity price behavior is not only a consequence of the gas price evolution; the price spikes, which are particularly noticeable during both cold waves, seem to be more related to the scarce capacity of the pipeline than to the gas price increments.

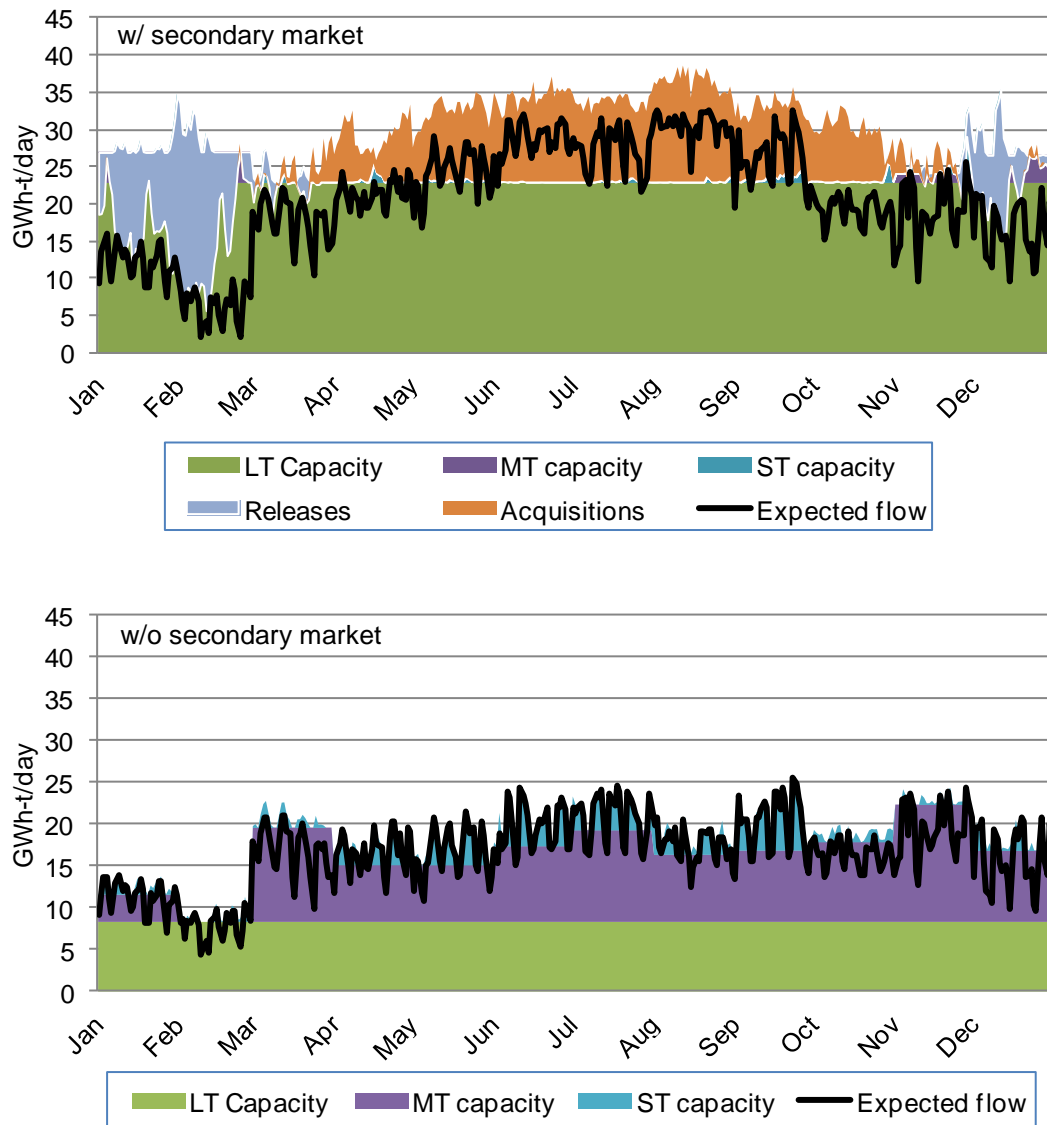


The generation mix also confirms the relevance of gas technologies to respond to wind variations. Coal power plants almost operate as base plants due to their reduced flexibility, which is reflected in higher start-up and shut-down costs with respect to other thermal power plants. In contrast, CCGTs deal with the demand variations most of the time. For instance, CCGTs decrease their production from 28.9 GWh-e to 19.7 GWh-e at the mid of November, while they increase their production from 23.0 GWh-e to 32.9 GWh-e at the beginning of September, in one day. OCGTs and gasoil power plants are used for satisfying demand spikes due to their flexibility. The latter power plants are especially relevant when the pipeline capacity is scarce and NGPPs cannot be fed.

Regarding the shares of each technology, gas accounts for 55% of thermal generation, while coal accounts for 44%. On the contrary, a meager 1% of thermal power generation corresponds to gas-oil power plants, although they are essential to prevent non-supplied energy. This test system could be a mirror of an actual system that is transiting from a coal-based production to a gas-based production. At this point, we remind the reader that hydro power plants, which often play a relevant role in power systems, have not been considered in this test case. Moreover, wind power generation covers approximately a 20% of the demand. (Below we present the residual demand, that is, the total demand net of renewable generation.)



The main objective of this paper is to analyze the capacity contracting behavior of a generation company under uncertainty, who shares the pipeline with other consumers. At first sight, we can observe that the generation company contracts capacity over the expected gas flow as a consequence of the uncertainty that stems from the wind power generation. The mean margin between the gas flow and the contracted capacity is about 25%, being 311 days above 10%. The second very relevant result is the amount of releases and acquisitions, which underlines the importance of secondary markets. In detail, the generation company and the city exchange 3.1 TWh-t in total, which means that about 10.2% of the pipeline capacity is traded daily. To examine the importance of secondary markets, we make a sensitivity analysis, in which the secondary market is closed, that is, acquisitions and releases of capacity are impeded. The results show that the generation company increases the quantity of medium-term capacity contracts, which are twice as expensive as long-term contracts during winter months, in exchange for reducing the share of long-term capacity contracts. The immediate consequence is a deterioration of the company's merit order position and a decrease of production from 5.1 TWh-e to 3.55 TWh-e. From the point of view of the system, the total costs increase from 887.8 million euro to 890.2 million euro. Furthermore, the stability of the electricity system may be compromised since the margin between the gas flow and the contracted capacity is negatively affected as it is reduced to 9%, as well as the number of days above 10% to 126.



Conclusions

We have addressed (partially) an intertwined energy system of gas and electricity markets. The link between both markets is the natural gas power plant that, in the framework of liberalized markets, is operated by a generation company who is in charge of acquiring the gas, contracting pipeline capacity and submitting production offers to the electricity market. With the objective of supporting the decision-taking process of the company, we have developed a novel model that optimizes simultaneously the following:

- The gas purchases in the gas spot market.
- The contract portfolio of pipeline capacity contracts subject to the uncertainty of renewable power generation.
- The operation in the power market under the uncertainty of renewable

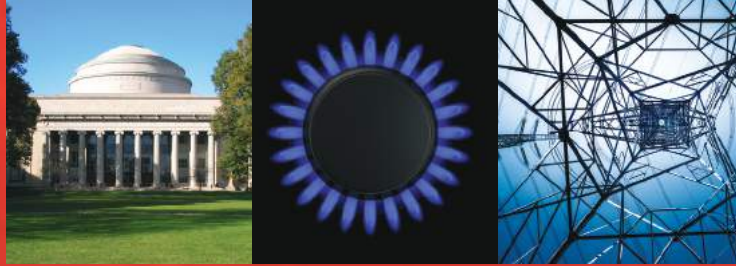
energy sources. In addition, we have established a different method to define the load levels that considers the intermittency of the renewable generation and allows internalizing the real start-up and shut-down costs.

Furthermore, we have shown (and quantified) the importance of liquid and competitive secondary capacity markets, in which the consumers can release their unused capacity and other consumers can acquire and benefit from the released capacity; benefits that also have a positive effect on the whole system.

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