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Impact of Regulatory Change to Coordinate Gas Pipelines and Power Systems

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ABSTRACT

Economic, technological, and political factors have encouraged the extensive installation of gas-fired power plants in the United States, which has caused electric systems to depend heavily on reliable gas supplies. This has greatly strengthened the interdependence between the electric power and natural gas industries. Recently, the intra-day fluctuations in pipeline loads that arise from changes in gas-fired electric power plant operation have become particularly problematic. In order to provide pipeline operators better insight into these loads, this paper describes the procedures used by power system operators to decide when and where electric generators are committed to operate, and at what level. We place particular emphasis on the evolving role played by gas-fired generators. In addition, we discuss recent Federal Energy Regulatory Commission (FERC) policy changes that aim to improve operational coordination between the two industry sectors.

INTRODUCTION

New extraction technologies, cheaper gas, and other factors have led to widespread installation of gas-fired electric power plants and caused the electric power grid to depend on reliable gas supplies. Recently, natural gas has eclipsed coal as the largest fuel source for electric power production in the US. Gas-fired generators are advantageous for meeting peak electric loads and providing rapid-response contingency power. However, these attributes can cause high and unpredictable intra-day variability in takes from gas transmission pipelines. These new conditions create challenges for current methods for flow scheduling and real-time physical control. The resulting impacts on pipeline efficiency, capacity, and security often translate to gas price fluctuations, supply disruptions, and increased operating expenses. Better coordination between the electric power generation and natural gas transmission industries would mitigate some of these problems. However, coordination between power and gas industry markets and intra-day planning of physical operations is nontrivial.

In the gas marketplace, day-ahead and intra-day bilateral gas contracts are purchased, sold, and cleared. These agreements are based on steady rated gas takes, and gas transmission companies then use this information to create operational plans. The resulting flow schedules are based on capacities rated by FERC regulations, which are estimated using steady-state flow models. Real-time pipeline control is then performed in reaction to customer behaviors that may not be communicated in advance. This approach to pipeline scheduling and control is satisfactory when nearly all customers were local distribution companies (LDCs), which are firm contract holders whose takes were more predictable and far less variable. In current markets where over half the gas customers are electric power plants who purchase non-firm contracts, this approach may not be sufficient to guarantee supplies to non-firm contract buyers with highly variable demand. Today, operators need to make decisions in a limited time-frame based on only a handful of scenarios that were evaluated using transient simulations.

Regional electricity markets are cleared by independent system operators (ISOs) that determine time-dependent generator commitment and dispatch schedules to balance production with forecasted electric loads. The result is a day-ahead schedule that determines when all power plants on the system are online and how much electricity they produce. This market is cleared by solving a large-scale optimization problem in which these variables are decided on an hourly basis. Production must also be re-adjusted in near real-time to balance loads, and this is done by solving another optimization problem every 5 to 15 minutes. If loads unexpectedly increase, the production of a gas-fired power plant may be quickly ramped up. The resulting changes in power flows quickly re-adjust throughout the entire power system. Thus, electricity market clearing and operational decisions take place on a faster time-scale, and the physical effects propagate faster throughout the system, than in the case of natural gas.

Users of both power and gas markets make transactive decisions based on inexact information regarding actual upcoming load volumes, spatiotemporal distribution patterns, and prices. The contracts generated in both markets will thus only approximate the actual conditions the two industries must deal with operationally. Because both markets and operations are faster in the power sector, the uncertainties in electricity loads compound the uncertainties in pipeline planning, resulting in a cascading effect. This impact on pipeline operations increases the uncertainty in gas availability and pricing, which in turn compounds the uncertainty in electric power plant commitment and dispatch.

Moreover, for efficient grid operation, the time-dependent schedules of gas-fired generators often call for them to burn their nomination over only part of the contract interval, even if gas transmission planning is most efficient under steady withdrawal throughout the contract interval. The gas-fired generator schedule may also be changed to compensate for unexpected events throughout the electric grid, such as weather-related changes to wind-farm output. Such variation and unpredictability in timing and volume can be extremely challenging to pipeline operators. Because the largest variation and uncertainty in gas transmission is now caused by gas-fired electric power plants, it is useful for the gas sector, and especially interstate pipeline operators, to consider the regulatory environment, market clearing, and operations of electric power systems.

The lack of coordination between the natural gas and electric power sectors has become an issue of concern in many quarters, and recent regulatory changes attempt to address this. FERC order 787 relaxes the information barriers between interstate pipelines and ISOs, while FERC order 809 requires better synchronization of gas and electricity markets in addition to the exchange of operational schedules. These FERC regulatory changes empower the engineering groups in both industries to coordinate intra-day operations of gas pipelines with their customers in the electric power sector. How this coordination can best be done is presented as an open question before both industries.

The daily operational behavior of the electric industry is now of crucial concern to gas operations, yet the processes generating this behavior are not widely and deeply understood within the pipeline simulation community. Conversely, pipeline operations are often only superficially understood within the electric industry.

In this paper, we therefore provide a short tutorial on the market operations in the electric industry, and in particular the daily generator scheduling procedures used by ISOs. This will cast light on the decisions regarding when and where gas-fired generators are activated, and how their power production is modulated. An explanation of the generator commitment procedure will give pipeline operators more insight into daily power plant behavior, and will give simulation practitioners more material for potential cross-industry joint simulation/optimization. The effect of these factors on gas pipelines will be discussed in the context of the recent FERC regulations, and operational scenarios will be examined to show the implications of regulatory, technological, and industry developments. Furthermore we point out specific information from the electric industry that could help predict which power plants are likely to alter the volume of their gas takes during the current operational day, the times when this unscheduled operation is most likely to occur, and the likelihood of a specific gas-fired generator deviating from its scheduled day-ahead gas takes. We also note that improved inter-sector communication would be most beneficial when implemented together with transient optimization techniques for pipeline flow control on the time-scale of intra-day power system operations.

The rest of the paper is organized as follows. We first summarize the key issues that are caused by the growing interdependence between power grids and gas pipeline systems. The key points and intentions of the recent FERC regulatory changes are then discussed. The next section contains a tutorial on electric power system operations, which is followed by a summary of issues of concern for power system operators. We conclude following a discussion of possible solutions and compelling directions for technical research and development.

GAS-GRID INTERACTION ISSUES

Gas transmission companies usually experience two main issues with gas-fired power plants. First, generators may quickly come online without providing enough warning for the pipeline to pack the system with additional supply. Second, gas-fired power plants are often scheduled to burn their total daily nomination in a shorter time than the steady ratable contract stipulates. Therefore, pipeline operators must decide what to do with supply scheduled for power plant use while the plant is offline and where to get extra supply while the plant is online. Additional capacity must be reserved for moving around the extra supply, using for example line pack or storage withdrawals. However, line pack and storage capacities are limited, and LDCs have traditionally used all available capacity at times of their peak demand. As firm contract holders, LDCs have a priority on line pack capacity.

Periods of simultaneous high demand for gas for both power and non-power usage often leads to a power plant attempting to draw more gas than the pipeline can provide given its other firm contracts. A typical consequence is that the plant pulls down the pipeline pressure so far that the facility can no longer draw the gas it needs for full operation, and/or deliveries to other pipeline customers with firm service contracts may not be fulfilled. When pipeline pressure is too low, a gas-fired generator cannot run or must reduce output. When supplies are tight, pipelines may issue an operational flow order (OFO) that will restrict generators to only their scheduled quantity, or else they will be shut off by the pipeline. For example, the power plant may be scheduled to be available for dispatch for only 16 hours, and offline for 8 hours, even though the supply contract is purchased for 24 hours at a steady rated take. When demand for gas is low, pipelines will often allow generators to overdraw their scheduled quantities. However, when demand is very low, the pipelines may issue an OFO that requires generators to take at least their scheduled quantities regardless of their cumulative imbalance positions. Such an OFO will often force power grid operators to activate more expensive generating reserves.

As a result of the growing dependence of power systems on reliable natural gas supplies, the wholesale prices of electric power and natural gas have become closely related. This is illustrated in Figure 1 for the New England region. Gas-fired power plants play a complex role in the natural gas market because their demand is price sensitive. Thus, the lack of coordination between the gas transmission sector and electricity markets, whose demand could quickly change, can cause a miss-allocation of resources that is exacerbated under extreme conditions. We identify several examples below, and also describe interdependence effects and market contrasts.

Polar Vortex

A phenomenon has been observed in several recent years in which a shortage of electric power resources occurs during the winter season in the Northeastern United States. As a result of the "polar vortex" effect, in which regional temperatures suddenly drop and stay low for days, consumers increase their demand for both gas and electricity for heating. This causes LDCs to increase their gas consumption and utilize nearly all of their transportation rights. This leaves very little transportation capacity for non-firm contract holders, so that gas-fired power plants in the region must raise their price bids to ISOs dramatically. This effect can be seen clearly as price spikes in December to February of 2013, 2014, and 2015, shown in Figure 1. The polar vortex problem can also be aggravated by the lack of inter-sector communication regarding energy pricing. Gas-fired power plants in locations with adequate line pressure (e.g. in the West) will submit lower bids to the ISO than power plants in locations where non-firm contract holders are at risk of curtailment (e.g in the East). The Western power plants could thus be dispatched to generate when electricity demand is peaking in the East, causing power flows from West to East to hit line flow limits. The Western plants will procure additional gas supplies, although it is more effective overall to transmit gas to the East. This may cause an imbalance in gas availability without a corresponding adjustment in price, and the problematic generator dispatch may continue to worsen the situation.

Sudden Heat Wave

During the summer months when demand for natural gas for heating is low, suppliers use transportation rights to move gas into low-pressure storage in aquifers or salt formations. This process cannot be quickly reversed, because significant energy is required to re-pressurize the stored gas. In the event of a sudden increase in regional temperature that may then be prolonged for several days, an increase in electricity usage for air conditioning may occur. A gas-fired generator may be dispatched to compensate for this increased demand exactly at the time when the gas storage facility is leaving little transportation capacity available on regional pipelines.

Interdependence Effects

The installation of electric-powered gas compressors, rather than (or in addition to) turbines that draw their power by burning gas from the pipeline, may be required to satisfy emissions restrictions or other environmental regulations. Such gas compression stations that depend on electric power may constitute a significant load on the power grid, and may be subject to electric power curtailment at times of peak electricity demand during the summer season. However, the reliability of gas supplies is most critical to the grid at exactly those peak periods. Situations have occurred where electric curtailment warnings were sent to a compressor station without realizing that the station was needed for adequately supplying a gas-powered generating plant. If this situation had not been recognized and avoided, it would have led to a much greater impact on the grid than the electric power curtailment was intended to mitigate. Adequate communication and a degree of mutual understanding between industries are needed to prevent this sort of situation.

Alternatively, a *winter* failure of a power plant may cause an outage at an electrically-powered compressor station, which could lead to under-pressurization of a pipeline at a time of peak gas demand from gas-fired generator plants even if they are firm contract holders.

Discrepancies Between Markets and Physics

Several aspects of current methods for gas pipeline operations lead to the issues described above. First, the market clearing, flow scheduling, and planning of physical operations are conducted consecutively rather than jointly. The contracts sold in the regulated market are bilateral agreements between traders who may not be equipped to account for complex physical considerations. Flow scheduling methodologies are usually based on steady-state models, and day-ahead physical operational plans often are as well. Consequently, even though estimated gas-fired power plant burn schedules with hourly time-granularity are often available, such temporal information may remain unused. Instead, transient, time-dependent factors concerning varying physical flows could be taken into account in real-time only on a reactive, local, ad-hoc basis.

In order to overcome the challenges of increasing and more variable loads, a promising approach is to integrate market and physical operations in the gas industry. This would involve obtaining space- and time-dependent prices and flow schedules simultaneously by solving optimization problems that account for forecasted transient conditions in the day-ahead market. Subsequent re-adjustments of prices and flow schedules could be made in real-time (hourly) spot markets. Clearing the natural gas market in this way would determine the price at a given location in a pipeline network based on the physical ability to deliver gas there.

Furthermore, this approach, if realized, would greatly aid in coordinating markets and operations in the natural gas and electric power transmission sectors. In the following section, we summarize the regulatory changes initiated through

REGULATORY CHANGES

In November of 2013, FERC finalized Order 787 authorizing interstate gas pipeline and electric transmission operators to voluntarily share non-public, operational information in order to promote reliable service or operational planning on either the public utility's or pipeline's system. This order allows an ISO to share estimated gas withdrawal schedules of generators on its system with the operator of the servicing pipeline. Moreover, in April of 2015, FERC issued Order 809 requiring synchronization of gas and electricity markets in addition to the exchange of operational schedules. It requires ISOs to time their day-ahead schedules so that gas-fired generators have time to buy gas within nomination cycle deadlines. We examine these orders in more detail below.

FERC 787 - Nov 15, 2013

To put recent orders into context, recall the broad restructuring of the interstate pipeline industry in the United States mandated by FERC Order 636 in April of 1992. The major policy goal was to enhance competition in the natural gas industry and to ensure that adequate and reliable service is maintained. Subsequent orders have refined the market structure into its current form. A crucial aspect of this market is to ensure a level playing field for the information available to all buyers and sellers of gas transportation. Any non-uniformities in information access, or “inside information” known to particular market agents, can lead to gaming of the market to the great detriment of all other parties. Hence, certain information was designated as “public”, but strong restrictions were put into place about what non-public information could be shared and by what entities.

However, from an engineering perspective, sharing less data makes it more difficult to operate these complex interconnected networks in a resilient and efficient manner. As gas pipelines and the electric grid became more tightly coupled, the engineering problems associated with these information barriers increased. Recognizing these problems, FERC undertook an extended process with industry participants to create new standards and issue FERC Order 787, released in June 2014. This order explicitly *allows and encourages* broad flexibility in information sharing between interstate gas pipelines and the interstate electric transmission industry. It is worth reading the following excerpt directly from the order. The language is clear and unequivocal:

> “[FERC 787] *amends the Commission’s regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility’s or pipeline’s system. The revised regulations will help maintain the reliability of pipeline and public utility transmission service by permitting transmission operators to share information with each other that they deem necessary to promote the reliability and integrity of their systems.”*

The full text of the order contains many examples of the general type of situation where information sharing could help, for instance:

> *“… electric transmission operator may find it valuable to know whether the interstate natural gas pipeline will be able to provide a non-uniform flow rate to meet the demands on the electric system. By the same token, it may be valuable to an interstate natural gas pipeline to know the demands that may be placed on its transportation system by gas-fired generators and whether such demands may cause a problem with its ability to deliver gas to other customers.”*

The document makes it clear that this is

> “*not just during emergencies, but also for day-to-day operations, planned outages, and scheduled maintenance”* and includes *“actual, anticipated, or potential effects”*.

However, the Commission also explicitly rejected the idea of envisioning and enumerating all the exact situations in which information sharing could possibly be done. Instead they gave a broad, flexible authority to the industrial players to decide what can be shared by operators. On the other hand, the commission addresses the prevention of market gaming by implementing an inflexible “No-Conduit” rule that enumerates information sharing that may *not* be made, such as with internal or external marketers.

> *“[FERC] is intentionally permitting the communication of a broad range of non-public, operational information to provide flexibility to individual transmission operators, who have the most insight and knowledge of their systems*
>
> …
>
> *informational needs of system operators vary by region and, therefore, a specific and exhaustive list of permissive communications that may be relevant in one region may not address the communications and operational needs of transmission operators in another region. The Commission also recognizes that the informational needs of transmission operators may evolve over time as the generation mix in regions change and as transmission operators*

> *develop further insight into, and gain additional experience with, gas and electric coordination issues.*
> *…*
> *transmission operators should feel confident in their ability to engage in robust communications with each other, subject to the No-Conduit Rule, whenever necessary to promote reliable service…".*

It should also be noted that some situations technically blocked by the no-conduit rule, such as communicating with a power plant separated from a pipeline by an LDC, can be addressed by revising individual tariffs. So there is a potential for even more flexibility beyond the already broad scope of communication FERC encourages.

By granting this flexibility, FERC explicitly empowers the industry to be creative in determining what information to share, and how to use it. It is recognized that understanding of what information to share is only tentatively understood and may change with experience, and some of the technology to take advantage of broader information availability may not have even been developed yet.

FERC 809 – April 16, 2015

Another important FERC order increases the electric industry's scheduling flexibility by increasing the number of the intraday gas nomination cycles (from 2 to 3) and introducing multi-party gas transportation contracts. Timing of the gas nominations cycles has been better harmonized with the needs of the electric industry and their volatile loads.

In response to order 809, the North American Energy Standards Board (NAESB) has issued the updated gas nomination schedule given in Table 1 in the appendix.

Although the new schedules are an immense improvement for electric planning, the increase in the number cycles adds to the analysis burden on gas transmission companies. They must make more frequent decisions regarding available capacity, and these decisions must be made in a shorter time frame than before. FERC recognized the problem of limited decision time, and tried to space the cycles adequately far apart..

> *"… there needs to be sufficient time between the scheduled quantity posting of one cycle and the nomination deadline for the next cycle to enable shippers to review their transportation needs prior to the next nomination deadline"*

Regardless, the intervals are shorter than in past years, and any technical tools to make this easier for the pipelines would be welcome. We note that the 3 intraday intervals is actually the minimum number that must be offered. If a pipeline has adequate resources to effectively offer even tighter nomination schedules, it may do so. Software tools might well be an enabler for such advances.

> *"Individual pipelines may offer additional scheduling opportunities beyond the standard nomination cycles"*

In order for these FERC orders to produce improved coordination as intended by the Commission, decision makers in the gas transmission industry must understand the decision making processes in the electric power transmission sector. In the following section, we provide a short tutorial on how market clearing and physical operations take place within the electric power transmission industry.

POWER SYSTEM OPERATIONS

Electric power systems in the United States are usually managed by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), which are non-profit corporations. Each such authority is responsible for operating high-voltage electric power transmission systems for a region consisting of one or more states, where it also administers the wholesale electricity markets, and manages the power system planning process. A hallmark of an ISOs independence is that its employees, management, and board of directors do not have any financial interest in any of the companies participating in its markets. In addition, ISOs do not own any transmission lines, distribution lines, or power plants, do not buy or sell electricity, do not profit from the markets that they administer, have no role in setting energy or environmental policy, do not favor any fuel or technology, and do not take any position regarding the siting of new natural gas pipelines or electric transmission lines. ISOs also have no financial or other connection to the natural gas industry other than to coordinate with pipeline operators when needed to ensure system reliability.

Day-ahead market clearing for power systems is conducted by solving optimization problems that incorporate time-dependent constraints on generator flexibility and determine adequate allocation of reserve resources. Additional optimization problems are solved in real time to ensure that electric power production is balanced with loads, while power flows do not exceed thermal limits on any active lines, and grid stability is secure in the event of line and generator outages. We will describe these procedures in detail below, using as an example the market operations schedule for an ISO in New England. Because much of the uncertainty in the activity of gas-fired power plants is related to their use as reserves, we first summarize the reserve requirements mandated by North American Electric Reliability Corporation (NERC) guidelines.

RESERVE REQUIREMENTS

All bulk power systems need reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. Operating reserves are the unloaded capacity of generating resources, either online or offline, which can deliver electric energy within 10 or 30 minutes.

Each ISO maintains a minimum level of reserves to be in compliance with North American Electric Reliability Corporation (NERC) guidelines. These requirements are designed to protect the system from the impacts associated with the loss of generation or transmission equipment. In New England, the ISO must maintain a sufficient amount of reserves to be able to recover from the loss of the largest single system contingency within 10 minutes. This requirement is referred to as the total 10-minute reserve requirement. Additionally, reserves must be available within 30 minutes to meet 50% of the second-largest system contingency. Adding this additional requirement to the total 10-minute reserve requirement comprises the total system reserve requirement.

Between 25% and 50% of the total 10-minute reserve requirement must be synchronized to the power system. The exact amount is set by the system operators, and this amount is referred to as the 10-minute spinning reserve (TMSR) requirement. The rest of the total 10-minute reserve requirement can be met by 10-minute nonspinning reserves (TMNSR). The remainder of the total reserve requirement can be served by 30-minute operating reserves (TMOR). In addition to the system wide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas, i.e. areas into which electric transmission line capacity is limited.

In addition, the ISO is required to meet contingency response criteria, which are designed to ensure adequate response in the case of a large single source supply loss. Such contingency response allows the system operators to quickly restore system reserve margins and position the system for a second large single source supply loss. Currently, the ISO is required to recover Area Control Error (ACE) within 15 minutes of a large single source loss greater than 500 MW. ACE is the difference between scheduled and actual electrical generation within the control area on the power grid, which takes frequency bias into account. The ISO must restore ten-minute reserves within 90 minutes of recovering ACE or falling below the ten-minute reserve requirement. Additionally, the ISO must restore total operating reserves within 240 minutes of falling below the total operating reserve requirement.

Day-Ahead Scheduling

The first step in the generation dispatch process occurs through a financially binding Day-Ahead Market (DAM). The DAM is a forward market that operates one day prior to the operating 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. In addition to pricing, the DAM clearing results provide a base unit commitment (UC) schedule for the operating day that includes hourly dispatch levels for each committed resource. This UC schedule determines when generators must be available for dispatch. The market is cleared by first solving the UC optimization problem, which is a mixed-integer program. The results of the UC optimization problem are then used as inputs to the economic dispatch (ED) optimization problem, which determines the dispatch level for each committed resource. The inputs to the UC problem are offers representing a generator's costs of operation, which include no-load costs, start-up costs, and incremental energy costs. In the ED problem, only a generator's incremental energy offers are considered. These costs are offered by all large electric power generators on the system managed by the ISO.

At 10:00 a.m. on the day prior to the operating day, the DAM bidding window closes. At this time all supply offers, demand bids, increment/decrement (virtual) offers, and external transactions that have been entered for the next operating day are fixed. The ISO then has up to three and a half hours to clear the DAM and post results between 12:00 p.m. and 1:30 p.m.

As soon as the DAM results are posted, the Re-Offer period opens and remains open until 2:00 p.m. During the Re-Offer period, generators not committed in the DAM have the ability to change their start-up and no-load costs as well as their incremental energy offers. Generators that have been committed in the DAM, however, can only change their incremental energy offers. One of the objectives of the Re-Offer period is to give generators the ability to update their offers and costs for spot market fuel prices, which may have changed from 10:00 a.m. to 2:00 p.m. The Re-Offer period also allows generators not committed in the DAM to self-schedule as a price-takers in the Real-Time Market. The timing schedule of this bidding process is given in Table 2.

Reserve Adequacy Assessment

Using the most recent incremental energy offers, the ISO 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 the DAM clearing and real-time operations. The initial RAA is published at 5:00 p.m. on the evening prior to the operating day, and each generator receives its expected schedule for the next operating day (12:00 a.m. - 12:00 a.m.). The schedule is a forecast only. It is not binding and will likely change during the real-time dispatch. The RAA process is continually updated at set intervals throughout the operating day, with updates to real-time unit commitments as necessary to account for unexpected events, load forecast error, generation scheduling deviations, unplanned equipment (generation or transmission) outages, and contingency response. Figure 1 shows the day-ahead scheduling timeline for both the DAM and RAA process.

Real-time Balancing

During the operating day, the ISO re-dispatches all generating units every 5-15 minutes through the Real-Time

Market (RTM), or spot market, in order to meet energy demand, reserves, and regulation requirements. All units committed in the DAM, RAA process, and in the Real-Time Unit Commitment process are included in the dispatch. The Real-Time Unit Commitment process runs every 15 minutes and commits additional qualified fast-start resources as needed throughout the operating day. Qualified fast-start resources are generating units that can start-up within 30 minutes and meet several other operating requirements.

During the operating day, generators can update their offers up until 30 minutes prior to the hour in which the offer would apply. One of the objectives of providing generators the ability to update their offers intraday is to allow them to reflect the real-time cost of fuel in their offers. In addition, intraday reoffers allow generators not committed in the DAM or RAA process to self-schedule as price-takers in the RTM. If the intraday reoffer deadline has passed for an hour (30 minutes prior to the hour in which the offer would apply), the ISO allows generators to call the control room directly to request a self-dispatch level and an effective time. Such requests are honored if they do not cause or worsen a reliability constraint.

REAL-TIME CONTINGENCIES

When the ISO has insufficient notice of service interruptions, the system operator will take steps to ensure that either sufficient replacement capacity with available fuel has been committed, or sufficient fast-start generation with on-site fuel or no-notice fuel delivery is available off-line. During these situations, the ISO will commit as many generation resources as necessary to meet the forecasted demand and reserve requirements. These resources are committed in order according to the cost of committing the resource. As the peak demand period for the operating day approaches, fewer resources are available for commitment due to their operating requirements. If there are not enough resources available to commit during the operating day, the ISO will use emergency procedures to maintain reliable operation of the power system, up to and including the shedding of firm load.

The resources that are typically called upon during these times are coal- and oil-fired power plants with access to fuel stored on-site. As natural-gas-fired power plants have displaced coal- and oil-fired resources over the last decade, the volume of fuel maintained in inventory by these resources has declined and the infrastructure to deliver fuel to these resources has been used less frequently. As a result, many coal- and oil-fired generators have shifted to the same type of “just in time” fuel inventory management that is prevalent in the natural gas system. However, when the electric and natural gas systems are simultaneously stressed, such as during long stretches of extreme cold weather, the energy available from coal- and oil-fired generators will also likely be limited.

THE GENERATION MIX

Presently, the generation mix in North America is undergoing rapid change, including a transition to natural gas. For example, the change in New England’s generation fleet over the past 15 years is shown in Figure 3. The region’s reliance on natural gas to generate electricity has continued to increase over the last decade along with the retirements of coal, oil, and nuclear power plants and increasing levels of wind and solar resources and energy-efficiency measures. Since 1997, 80% of all new online capacity has been natural-gas-fired along with almost 65% of all new proposed generation. Last year, natural-gas-fired power plants produced just under half, or 49%, of all electricity generated in New England. This amount is up from 15% in 2000, and is more than any other fuel source in the region. Currently, during typical load periods, nearly the entire fleet of dispatchable resources is made up of gas-fired generators, and a portion of the fast-start generators that would be called on to respond to a contingency are also dependent on natural gas.

Conversely, the combined use of coal and oil has fallen dramatically over the same period, from 40% to 6%. Today, coal- and oil-fired resources rarely operate. By 2019, the region will have lost more than 10% of its current capacity with the retirement of 4,200 megawatts of power plants that do not use natural gas. In addition, as much as 6,000 MW of aging coal- and oil-fired power plants are at risk of retirement. These plants rarely operate and are typically only called on to run during the summer during peak load times, or in the winter when either natural gas pipelines are constrained or natural gas price spikes make them economical. The retiring coal, oil, and nuclear plants will likely be replaced by more natural gas plants and wind.

This transformation to a predominantly natural gas fleet has been driven in part by the fact that new natural-gas-fired power plants are highly efficient, relatively easy to site, and less expensive to build and run than other types of power plants. In addition, increased production of natural gas from the Marcellus Shale, located just west of New England, has made low-priced natural gas available to the region.

POWER SYSTEM ISSUES

Many regional markets currently use natural gas as a primary fuel. For example, 44% (13,650 MW) of total generation capacity in New England uses natural gas. However, the vast majority of this capacity relies on interruptible gas contracts to obtain their fuel supply. As a result, the availability of natural gas for power generation has a significant impact on grid reliability. When there is enough pipeline capacity to serve the region’s power generation demand, such as during the summer when heating demand is low, generators have little trouble obtaining gas. During the winter, however, when the pipelines serving the region are often operating at full capacity just to meet heating demand, generators have experienced challenges obtaining gas. The lack of fuel diversity on the system is exacerbated by the fact that natural gas is a “just-in-time” resource. As a result, New England generators have migrated away from on-site fuel storage in the form of coal and oil, where disruptions in fuel delivery chains were able to be coordinated over days and weeks. Now these generators are dependent on just-in-time fuel delivery from the gas pipelines, and any interruptions in this supply chain have an immediate impact on the operation of the power system. Specific issues that have contributed to these challenges are described below.

NON-FIRM CONTRACTS

Many of the electric reliability issues related to gas dependence in New England originate from the fact that most gas-fired generators do not procure firm priority rights to pipeline capacity, and thus operate with an interruptible fuel source. Most generators also do not have the ability to switch to an on-site fuel supply. This means that when conditions become constrained on the gas pipelines these interruptible generator customers may not be able to schedule fuel or use the fuel delivery system to operate in accordance with their operating characteristics. Such fuel delivery interruptions or limitations generally happen on short notice and give system operators little time to respond.

PIPELINE LIMITATIONS

While pipeline usage is often at or near capacity during the winter months, pipeline operators will not expand pipeline capacity without signed contracts from firm customers. In addition, FERC, which must approve pipeline projects, bases its decision on whether a pipeline project is in the public convenience and necessity in large part on the existence of firm contractual commitments. As a result, to the extent that projected growth is due to gas-fired generation, pipelines will not expand to accommodate this growth unless the electric industry begins to sign firm fuel supply contracts.

GENERATOR COMMITMENTS AND DISPATCH THAT DON'T MATCH FUEL NOMINATIONS

Occasionally, gas-fired generators use more natural gas than scheduled for the operating day. The impact of this practice on natural gas pipelines depends on the current operating conditions on the pipelines themselves. Sometimes, the impact is minimal because the pipelines have 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 high system demand, the pipelines may have limited ability to serve this additional demand. During these times, the pipeline operators may need to exercise their rights under their tariffs and will use flow control and valve shutoffs when generators place the pipeline system at risk by overdrawing gas to meet their generation obligations.

In addition, as previously discussed, generators use gas in a different pattern than is ideal for pipeline operators. Pipeline operators determine their ability to deliver gas based on a customer utilizing $1/24^{th}$ of its daily nomination in each hour during the gas day. However, peaking units are often committed by an ISO to meet peak loads during the afternoon. As a result, such units may schedule gas for the entire gas day, but will burn their total allotted volume during only a few hours in the afternoon.

While some pipeline operators may be able accommodate these differences between scheduled and actual usage if their pipelines have time to recover gas pressure, the pipelines in the Northeastern United States have not been designed to handle these imbalances. The sudden ramps and shut-offs can cause pipeline pressures to vary significantly from hour to hour, thereby jeopardizing reliability to all other customers withdrawing gas from the pipeline. *These challenges will become greater as more wind resources are connected to the electric system and gas generators are increasingly called on to balance the increasingly volatile system.*

TIMING DIFFERENCES BETWEEN GAS & ELECTRIC SYSTEMS

As described above, generators are often not consuming gas as expected by the pipeline operators throughout the operating day. In part, this is because of differences in timing between the gas and electric systems. The gas industry operates on a different schedule from that of the electric system, which was described in detail in the previous section. The purchase of gas is generally through brokered markets (i.e. Intercontinental Exchange) for the next gas day. The gas market is most liquid between 8:00 a.m. and 9:00 a.m. the day prior to the electric operating day. It is during this trading period that prices for the next gas delivery day become known and can be used to formulate offer prices by generators for the DAM.

Next, a generator must nominate pipeline capacity to transport the natural gas from one specified location to another over the gas day. Submitted nominations are confirmed and scheduled by the pipeline operators based on service priority, available pipeline capacity, and the pipeline's ability to maintain pressure requirements along the designated contract path. Natural gas transport is nominated and scheduled on a one-day advance basis, using a 24-hour gas day from 10:00a.m. to 10:00a.m. Eastern Standard Time. Nomination cycles fall into three categories: Timely, Evening, and Intraday. Timely and Evening nominations are for deliveries on the following gas day, while Intraday nominations are for deliveries in the same gas day. The timing of each nomination cycle is detailed in Table 1.

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

During the Evening nomination cycle "bumping" can occur. Bumping is the process by which a customer with a higher priority can force its nomination to take precedence over that of a customer with a lower priority. As the gas day progresses, the three remaining gas scheduling periods, Intraday 1, Intraday 2, and Intraday 3 become windows of last resort for nominating additional fuel. Furthermore, gas trading typically does not take place over weekends and holidays, meaning generators must plan several days in advance during these times.

For each electric operating day, gas-fired generators must also manage fuel procurement and scheduling that spans two gas operating days. For hours ending 11:00 a.m. through midnight, generators can purchase and nominate their gas during the previous day's Timely Nomination Cycle based on the DAM results. For hours ending 1:00 a.m. through 10:00 a.m., they must rely on the sum of the Timely Nomination Cycle from 2 days prior, plus the Intraday nomination cycles from the previous gas day to schedule their gas. During the Intraday nomination cycles, there is high risk of not being able to schedule gas, or being forced to pay high premiums. If such intraday gas cannot be scheduled, that leaves the early hours of the next morning dependent on nominations made 2 days prior. In effect, gas nominated for those periods is based on *very* stale information if gas from intraday nominations cannot be purchased due to supply limitations or other reasons.

GAS SUPPLY DISRUPTION

Often pipelines are able to operate with a temporary supply disruption if gas pressure is maintained within acceptable limits. However, a major failure to an interstate gas pipeline could result in the loss of electric generating capacity that exceeds system operating reserves available to compensate for these losses. For example, a single major pipeline currently supports approximately 10,000 MW of generation capacity in New England. A major supply disruption to this pipeline would likely result in the need for emergency procedures to maintain reliable operation of the power system.

PIPELINE MAINTENANCE

Occasionally, gas-fired generators become unavailable to enable pipeline inspections and maintenance. Normally, pipeline outages occur during the pipelines' off-peak season (summer), which coincides with the peak season on the electric system. While pipeline maintenance outages are expected, issues have arisen both due to pipeline operators providing short notice of such outages and the timing of such outages during periods of high electric system demand.

POSSIBLE SOLUTIONS

There are several promising directions for overcoming the hurdles posed by issues described above. These can be categorized as improvements in communication, market structures, and technological advancement in transient optimization and uncertainty management.

COMMUNICATION IMPROVEMENTS

First and foremost, the most straightforward and immediate improvements follow from communication between operators of transmission systems for the two sectors. The day-ahead planned schedules for gas-fired generator operation (burn sheets) are already usually available from ISOs. However, because the use of generating reserves is decided in real time, the actual schedules of gas-fired generators are uncertain.

However, statistics could be computed on a per-generator basis to quantify the deviation from the planned schedule as a function of time throughout the day. In addition, because the production of 10 minute non-spinning contingency reserves must be replaced within 90 minutes, such generators are only operated at times of peak stress. Thus, given the locations on the pipeline of such generators, the pipeline operator can know where additional line pack could be maintained to mitigate the effect of sudden additional gas loads. Thus, two types of information that pipeline operators should seek from ISOs are

- Day-ahead gas-fired generator schedules
- Locations and usage statistics for gas-fired generators used as 10-minute non-spinning reserves

More details on the pertinent information are given in our next presentation [17]. Specifically, a Reserve Adequacy Assessment (RSA) report from the ISO *can indicate which power plants are likely to alter the volume of their gas takes during the current operational day*. The total power system load forecast, given by the ED schedule, *can indicate the times when this unscheduled operation is most likely to occur.*
A history of reserve activation in the real-time market of an ISO *can indicate the likelihood of a gas-fired generator deviating from its scheduled day-ahead gas takes*.

If such information is only shared with managers responsible for operations, the market participants would not be affected. However, for any information to be effectively utilized, the participants must agree to the types of information to be shared, and which actors are permitted to obtain and use it.

MARKET IMPROVEMENTS

We have described above how the electricity market is cleared by solving a series of optimization problems that minimizes the cost of production while taking into account the physical process of delivering energy between production and consumption locations. This process takes advantage of optimization technology to account for the physical limitations of the power grid in both space and time using so-called locational marginal prices (LMPs) for electricity.

In contrast, the natural gas market is based on bilateral transactions between traders who seek to balance supply and demand. This mechanism can be slow to respond to contingencies, and is imperfect for ordinary day-to-day operations.

One possible direction for improvement is to formulate an optimization problem that an *independent non-profit entity, similar to an ISO*, could use to clear the day-ahead natural gas market given bids from producers and suppliers. When consumption by non-firm contract holders is an optimization variable based on a cost curve (e.g., related to the heat-rate of a gas-fired generator and the LMP for electricity), an LMP for gas could be computed. This would allow the price of gas throughout a pipeline system to be computed based on the physical ability to deliver it from suppliers. A principled, physics-based balance of electricity and gas prices would mitigate the interdependence issues described above. It is recognized that this is a very ambitious suggestion, but one that merits technical investigation because of the potential size of the payoff. Implementation would require a formal cross-industry project at least as large as the one that led to FERC orders 787 and 809.

ADVANCING TRANSIENT OPTIMIZATION

In the context of the current FERC natural gas market scheme with more frequent nominations, transient optimization has the potential for being an invaluable tool. In the control room, and in conjunction with a state finding tool, it can help pipeline operators know how to best operate their stations in a predictive manner, and reposition line pack as the variable loads unfold across the system during the day. As a planning tool, it can be invoked using generic starting states so that transient system characteristics can be examined over multi-day scenarios to determine, for example, the actual system capacity as opposed to steady state approximations. Hence objectives such as capacity validation and/or maximization are typical choices for planning, as are fuel cost minimization and the achievement of regional linepack targets at specified target times.

For a day-ahead market-clearing scheme that is coupled with predictive grid-load information, transient optimization becomes even more attractive. Because of the slow speed of gas flow relative to electricity flow, day-ahead market-clearing computation for natural gas would need to take transient flows into account. This is challenging because of the high nonlinearity and complexity of the resulting optimization problem. It would require more advances in gas pipeline modeling and optimization technology, and specifically the advancement of transient optimization into use in the field. To take full advantage of communicated information, and to make possible a principled market clearing mechanism, reliable and fast methods for transient optimization are required.

Transient optimization is thus a key enabling step for effective gas-electric coordination. If it is made robust, fast, and practical for large systems, this approach can help companies estimate available capacities more accurately before each nomination cycle begins. In the event of tighter coordination with the electric industry, other objective functions will certainly be formulated.

Several approaches to transient optimization have been proposed. Some examples of different approaches to transient optimization can be found in [8], [10], [11], [12], [15], and [16]. Explicit inclusion of load uncertainty has also been considered [9], [14]. Inclusion of discrete variables is also an active topic of research. Despite these advances, challenges remain in areas such as computational runtime, problem scaling, and multiple local solutions. Solving a formulation coupled with electrical grid components will enhance these challenges.

Because of the diversity and importance of transient optimization applications, the development of a wide variety of competing and complementary approaches is very welcome. This topic will be discussed in more detail in [17], where we also present a new method based of recent approaches from the control theory community.

CONCLUSIONS

FERC has established a new playing field where operational coordination between the electric industry and the pipeline industry is both allowed and encouraged. The industries are also allowed and encouraged to invent and innovate using their respective domain expertise to exploit these capabilities. Information firewalls still rightfully remain for market-specific situations, but our industries are expected to find ways to improve joint operation in technical areas.

We have presented a tutorial to educate pipeline researchers regarding what is occurring on the other side of the gas-electric infrastructure coordination curtain. We hope that this will encourage new ways of looking at collaborations.

Currently, "burn sheets" are one of the ways the two industries communicate, but when grid conditions change unexpectedly, they can be very unreliable. However, there is other specific information from the electric industry that can help predict which power plants are likely to alter the volume of their gas takes during the current operational day, the times when this unscheduled operation is most likely to occur, and the likelihood of a specific gas-fired generator deviating from its scheduled day-ahead gas takes.

Finally, we presented our own thoughts about improvements, both near term using minimal new inter-industry communication, and longer term using more ambitious ideas.

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FIGURES

Figure 1 – Natural Gas and Electricity Prices are Linked

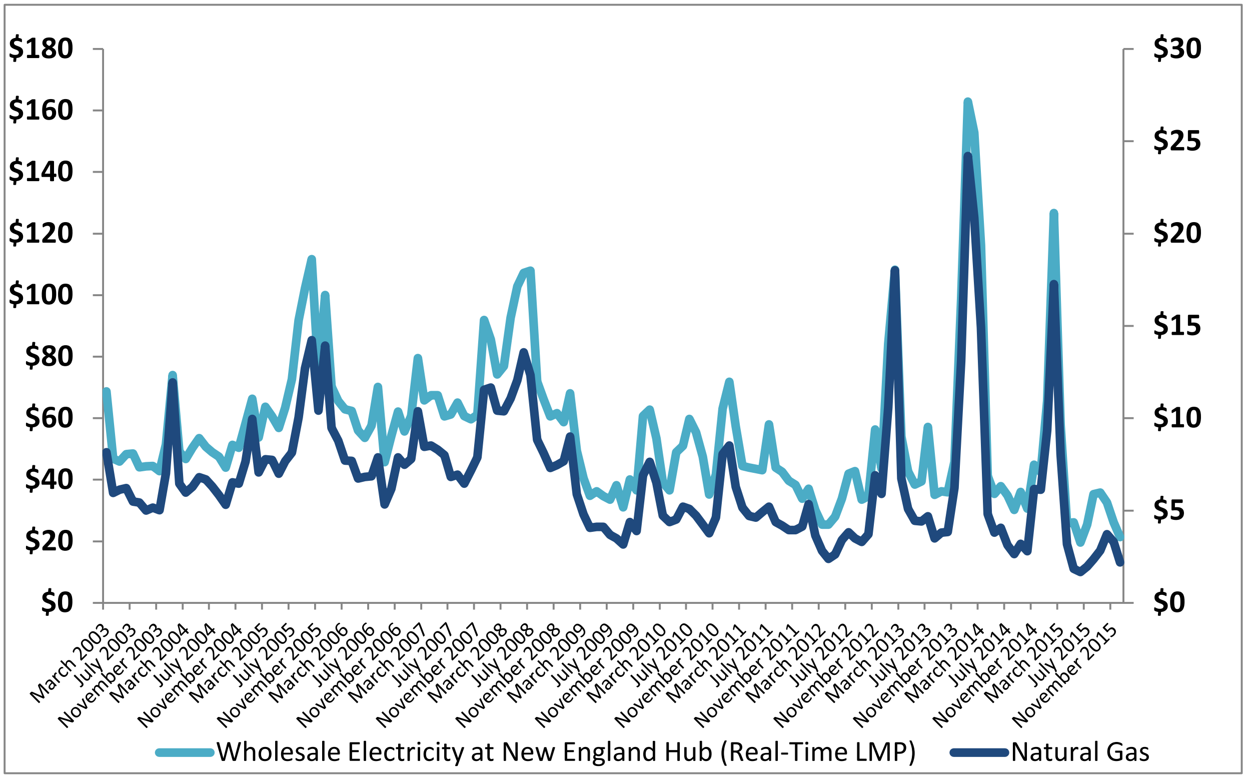


Figure 2 – Day-Ahead Scheduling Timeline

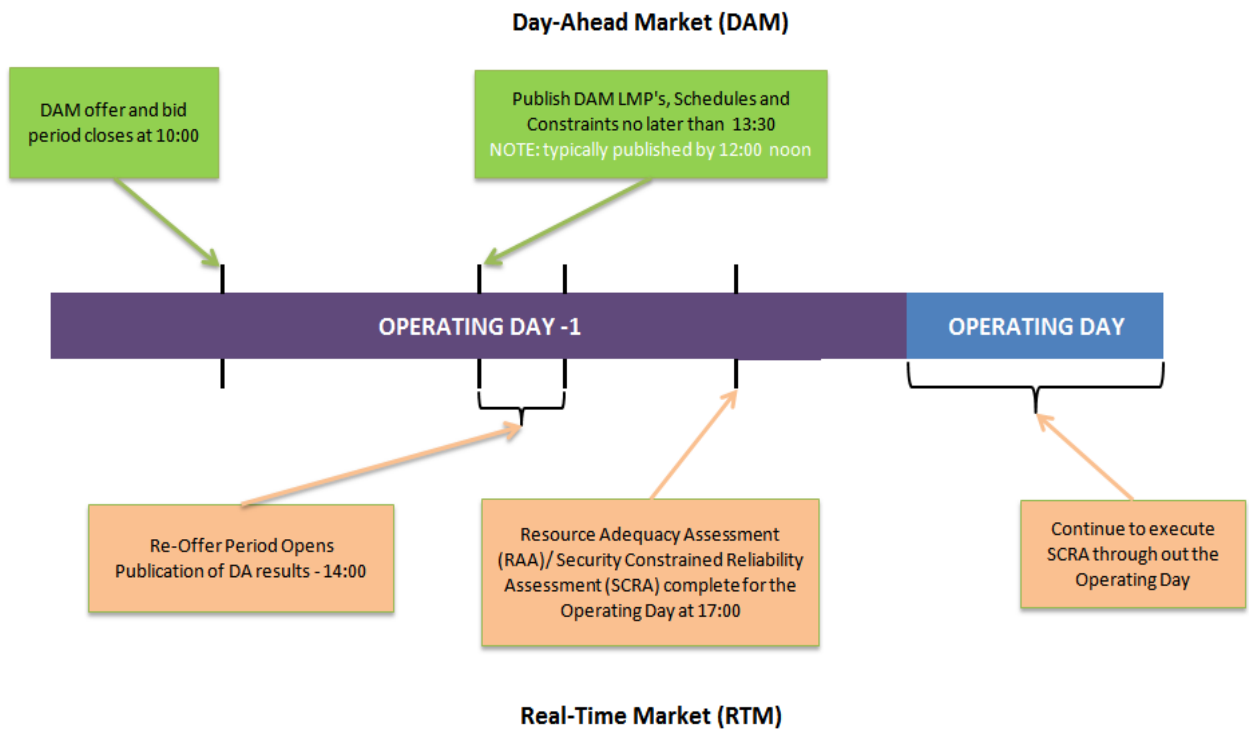
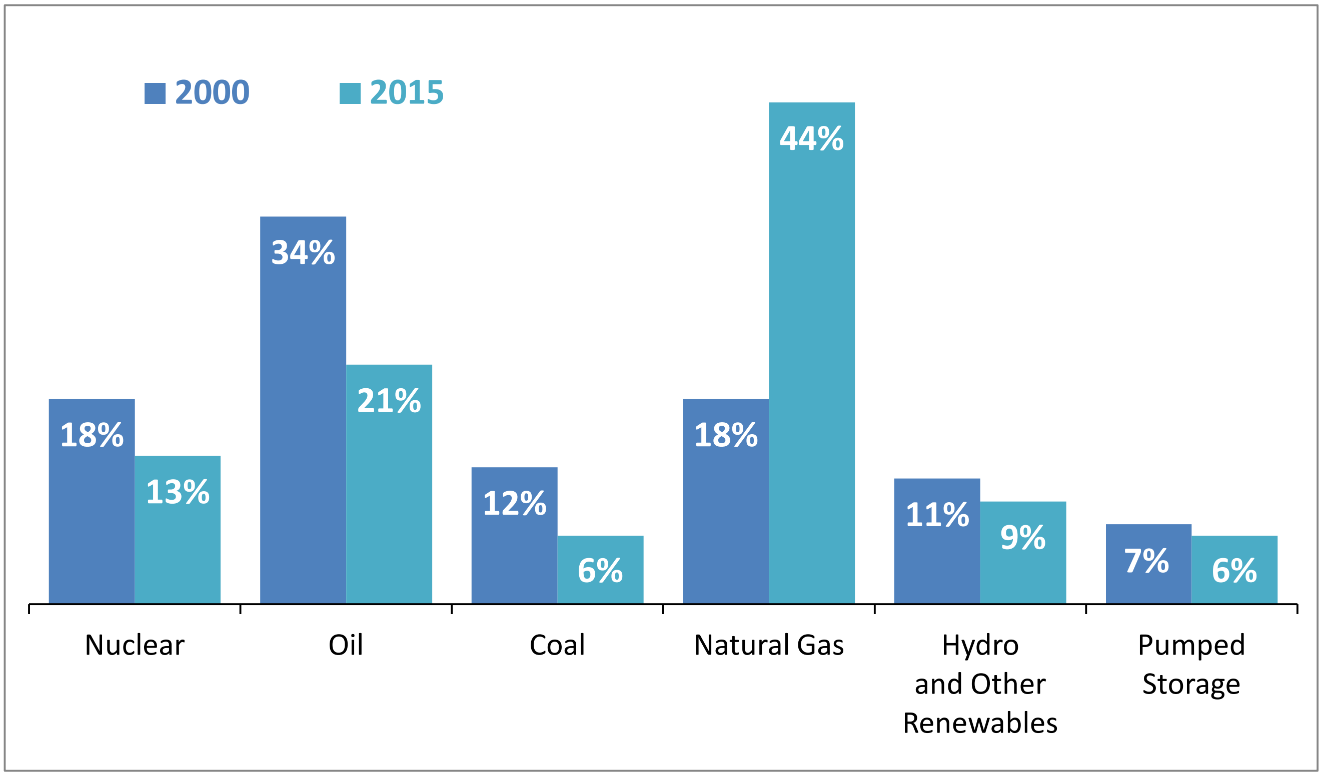
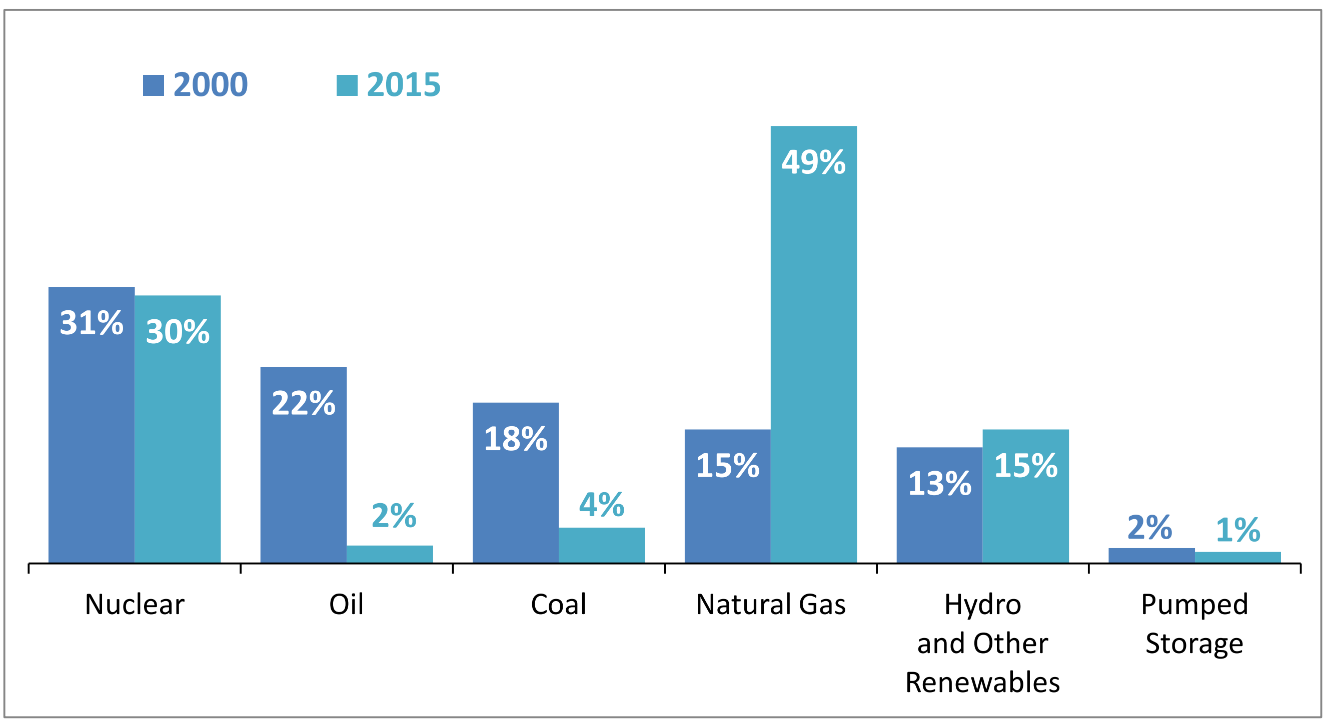


Figure 3 – Installed Electric Energy Production Capacity in New England



Source: 2015 CELT Report, Summer Seasonal Claimed Capability (SCC) Capacity
Other renewables include landfill gas, biomass, other biomass gas, wind, solar, municipal solid waste, and miscellaneous fuels

Figure 4 – Electric Energy Production by Fuel Source



Source: ISO New England Net Energy and Peak Load by Source
Other renewables include landfill gas, biomass, other biomass gas, wind, solar, municipal solid waste, and miscellaneous fuels

Table 1 – Standard NAESB Gas Nomination Cycles (Eastern Standard Time)

Nomination Cycle	Nomination Deadline	Notification Time	Nomination Flow Begins
Timely	2:00 pm	5:30 pm	10:00 am next day
Evening	7:00 pm	11:00 pm	10:00 am next day
Intraday 1	11:00 am	2:00 pm	3:00 pm current day
Intraday 2	3:30 pm	6:30 pm	7:00 pm current day
Intraday 3	8:00 pm	11:00 pm	11:00 pm current day

Table 2 - ISO Scheduling Time (New England - Eastern Time)

Day-Ahead (DA) Energy Market Step	Deadline Starting in 2013	Previous Deadline
Participant bids to supply DA energy	10:00 am	12:00 pm
ISO posts DA results	12:00 – 1:30 pm	4:00 pm
Re-offer period for participants	From post time until 2:00 pm	4:00 – 6:00 pm
ISO completes reserve adequacy analysis (RAA) process	5:00 pm	10:00 pm