# Measurement of Energy Market Inefficiencies in the Coordination of Natural Gas & Power

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## Abstract

*Coordination issues associated with natural gas and electricity markets have become more acute as gas penetration in the electric generation sector has grown. This paper focuses on the debate surrounding the need for coordination of market timing – a likely major challenge for both Federal and State regulators and institutions responsible for electric reliability. This paper describes the coordination problems between existing electric and gas market structures and provides a case study of the risk premium that participants in the New England day ahead electricity market would need to charge in order to account for information uncertainty in natural gas prices due to a potential change in scheduling practices.. The paper concludes with an estimate of the potential price impact of these risks on Northeast market price*

## 1. Introduction and background

The coordination of U.S. electric and gas markets has become a topic of increasing concern over the past 4 years. The advent of vertical drilling technology (fracking) has produced and abundance of natural gas in the US market and with this an era of low natural gas prices. As indicated in Figure 1, low gas prices, threat of environmental regulation and relatively higher coal prices have moved the US toward an increased reliance on natural gas for power generation. In addition, most recent and planned capacity additions – with the exception of renewables – are natural gas-fired, most commonly combined cycle units. Because of the flexibility of natural gas fired units, even with the addition of large amounts of wind and other renewable generation, additional gas-fired generation is desirable as a complement to the intermittent renewable generation.

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 key US power markets – most specifically those in the Northeast and in California. In many other areas of the country pipeline capacity, storage and gas availability is high.

The objective of this paper is to isolate the issues in coordination; most specifically those associated with the basic business models in gas and power and identify the market constraints, including temporal market issues that mitigate against tight coordination of the two markets.

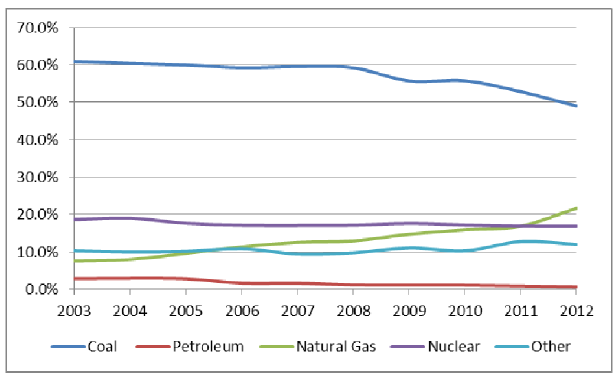


Figure 1: % Electric Generation by Fuel 2003 - 2012

## 2. Coordination in the constrained regions

The Northeast of the US and specifically the ISO NE and NYISO areas are gas delivery constrained when temperatures drop and heating loads increase. The local distribution systems hold the firm gas pipeline capacity that they release (often to power generators) when not required. Few power generators hold firm transmission rights.

Figure 2 below plots daily gas basis at the Algonquin Citygate hub versus utilization of the Algonquin pipeline, a key pipeline feeding the New

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England gas market. 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.

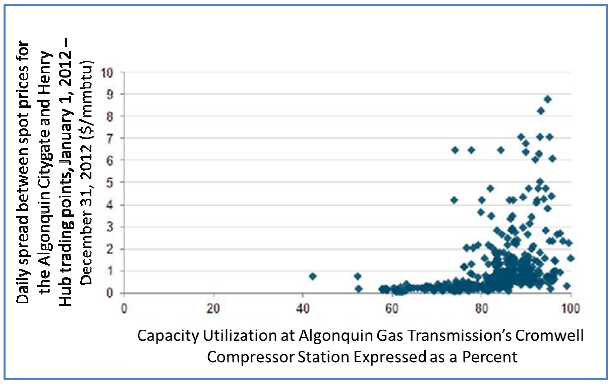


Figure 2: Pipeline utilization v. daily price spread at Algonquin Citygate [11]

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 have[2] arisen with regard to the relationship between the two[3] markets.

Paradoxically, both the gas markets and power markets work quite well independently. The concern is over the interaction of these two very different market structures in supporting power markets increasingly dominated by gas-fired generation. In the gas model operational capacity commitment and allocation decisions are decentralized. 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 and generally bilateral 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 flexible market structure to meet these requirements with a minimum of top-down or centralized decision making/design.

In contrast, power markets, and most specifically those operating under what has been termed the "Standard Market Design" (SMD) with locational marginal prices operate in a highly centralized fashion, with the Regional Transmission Organization (RTO) or Independent System Operator (ISO) functioning in the short-term as a central system planner/operator 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, under the SMD approach the RTO/ISO is involved in virtually every decision regarding the future and current state of the power system.

The natural gas and central electric markets have evolved successfully but dramatically differently. Here we focus on the following two issues / questions.

- 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?
- Are there market rules changes that can be adapted to reduce the coordination problems at minimum social cost and without unintended negative impacts on gas and electric consumers?

## 2. Structure of market operations

Within the structure of the organized power markets the central player, either the RTO or the ISO is responsible for ensuring operational reliability (along with a level of responsibility for longer term reliability assurance that varies with the entity). In shorter time horizon, RTO/ISOs are also responsible for incorporating all resource constraints – whether transmission constraints which affect the location of potential generation or temporal constraints such as generator minimum on and off-times and ramp rates – into the security-constrained unit commitment systems (SCUC) which compute both day-ahead schedules and day-ahead Locational Marginal Prices (LMPs)s. In this way, a single-shot, single-clearing price auction mechanism (the SCUC) can create a set of schedules which is feasible given the known constraints. While the SCUC process is single-shot it is a multi-hour process such that generators do not know the outcome for between 4 and 6 hours after submitting their initial offers.

Given the information set provided in the day-ahead market (e.g., generator bids and availabilities, transmission constraints, and contingency constraints) the RTO/ISO can be confident that the operating schedule meets reliability standards for the following operating day.

In the RTO/ISOs, after the close and publication of the outcome of the day-ahead market, it is common to have a second manual reliability assessment by the RTO/ISO. This second assessment uses the RTO/ISO's own forecast of next day load (as opposed to bid loads as in the day-ahead market), and to incorporate updated information on transmission and generation outages. RTO/ISOs can generally commit extra units that they judge to be needed to protect reliability outside of the day-ahead market.

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

The RTO/ISO power markets work by identifying the constraints that will or could affect system operations and reliability and incorporating them into the resource commitment and LMP pricing process.

Notably of concern here is the fact that gas availability for generators is typically not directly (if at all) reflected in the day-ahead unit commitment step of the RTO/ISO market operations described above. While these markets consider the physical constraints of the electrical transmission system they do not look at the delivery capability of the gas system. Not taking into account the gas delivery capability is an issue both in day to day operations as well as in the planning of long-term resource adequacy.

In the day-ahead unit commitment process a key to market-based operational reliability – gas availability constraints are not directly reflected in commitment and day-ahead prices. If the bidding timelines allow, bids from gas-fired generators could reflect contemporaneous next day (traded prior day) gas prices and more realistically reflect availability of non-firm gas transportation service – the general arrangement by which power generators schedule gas deliveries to their units. At present, such constraints are often lacking, and hence cannot be reflected in day-ahead LMPs.

Since day-ahead LMPs do not reflect short-run gas constraints given that these are generally reflected only in part 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 RTO/ISOs on days of limited gas availability.

Because the RTO/ISO markets are structured around individual, time specific (single-shot) auctions, these auctions operate on a highly rigid clock. Generators must create their offers to supply by fixed deadlines, allowing for enough time for offer preparation, checking and data submission.

In interviews with teams responsible for submission of offers into the ISO NE day ahead market, we were able to identify the approximate timing required for calculation of the offer to be submitted. Working backwards from the market close it was then possible to define the last time at which information could be acquired that would be useable in an offer into the day ahead market. The answer was roughly "market close minus an hour" meaning that if the market closed at 12 noon EST, the last information that could go into the offer had to be in the generator's hands at 11am EST. By the same token if the market closed at 9am EST the last information that could be used would need to be received by 8am EST. A market close of 5am EST requires information at 4am EST at the latest.

The principal RTO/ISO DA markets close at a variety of hours.

| | |
|---|---|
| NY ISO | 5am EST |
| ISO NE (proposed) | 9am EST |
| ISO NE (post 5/13) | 10am EST |
| MISO | 11am EST |
| ISO NE (pre 5/13) | 12pm EST |
| PJM | 12pm EST |
| ERCOT | 10am CST |

The need for a specific "closing time" in DA power markets reflects the physical constraints on the power system as well as the legacy of utility unit commitment processes. DA markets – which clear based on daily SCUC runs – are structured on a daily basis due to the widely varying shape of electric demand over a day, which peaks typically in the daylight areas when the RTO/ISO must ensure that sufficient generating capacity is available. Many of these units require significant time to start and ramp up to meet daily peaks so a significant time window is needed over which to optimize daily operations.

Gas markets also operate on a daily basis, but usually trade only on week days and on a different schedule, as discussed in more detail below. Given the storability of gas, within and outside the pipeline, time horizons are more relaxed and there is less need to schedule on an hourly or sub-hourly basis to meet instantaneous demand. Pipelines do require nominations for transactions to be made in advance, but these are made on a pipeline by pipeline basis and there is no overall central scheduler and operator for an entire region – the role filled by the RTO/ISO on the electric side.

Developments in unit commitment and operations software may eventually allow electric markets to be operated on more of a continuous time basis – not tied to a single DA schedule. Such a market structure might, in theory, allow for easier coordination with the less centralized gas markets.

## 3. Timing of market operations

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 generally runs from midnight to midnight, with offers due at noon in this example (which reflects the pre May 2013 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.

As discussed previously, the clearing mechanisms of the gas and electric markets are different. Offers into the day-ahead market illustrated 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 for natural gas is past, and the evening nomination cycle happens a few hours later. This complex set of offer and nomination cycles inevitably creates a level of market friction as power market and gas pipeline scheduling cannot be conducted jointly and simultaneously.

Timing in the natural gas market is significantly different from that in electricity largely because the market is openly (often bilaterally) traded. Much of the gas that is used in power generation is typically purchased from the next day gas market. While this is but one of a breadth of markets from which gas can be purchased for greater or lesser time frames, it is the market that matches most closely the timing of the day-ahead markets for power in the RTO/ISO markets. There are four critical factors affecting the relationship between the next day gas market and gas-fired generator offers into the day ahead power market.

1. Electric demand is only a small proportion (today) of the demand for next day gas.
2. The majority of the trades of next day gas occur between 8:30 and 10am EST (7:30 and 9am CST) Figure 4 shows the percent distribution of gas trades at the Algonquin `Citygate hub (the market price for New England).

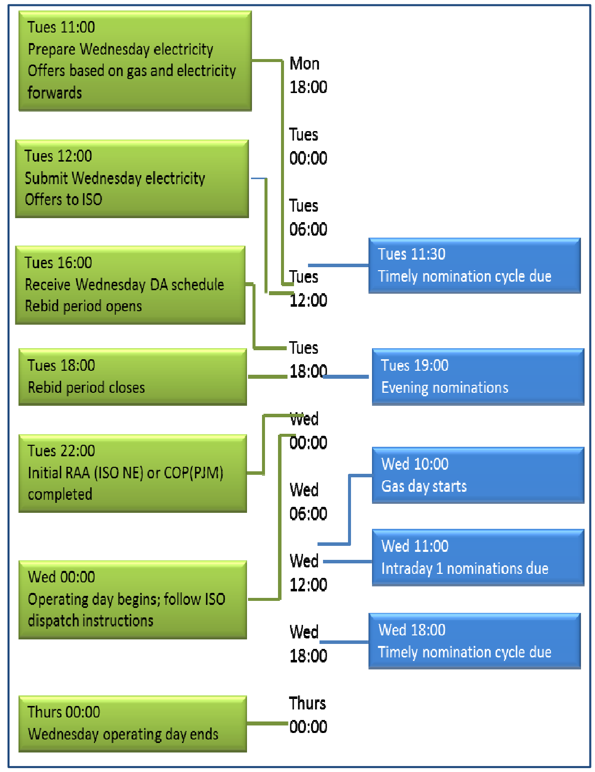

Figure 3: Electric and gas market timing

The pattern seen at Algonquin Citygate is virtually identical to that found throughout the country for next day gas largely as a function of the opening time of trading in Houston, the home of the largest number of traders and trading organizations. Regardless of location within the US, next day gas is traded (for individual hubs) predominantly between 7:30 and 9am Central Standard Time.

3. By 9am EST the price for next day gas is known (has reached the expected value for the next day). There is little change in price that occurs after this time. Figure 5 shows the relationship between gas prices as known at 9am EST relative to what is known at 10am EST. The importance of this high temporal correlation is that so long as the RTO/ISO market close rules allow the generator offering into the market sufficient time to be able to access and utilize (in the generator offer calculations) the next day data available at 9am EST it will be the most current available at any point in the day.

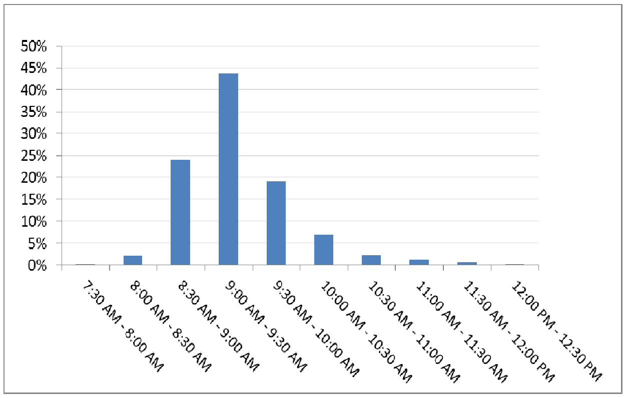


Figure 4: Natural gas trades on ICE (%) at Algonquin Citygate


Figure 5:Next day average natural price 8am to 9am v. 9am to 10am

4. If the generator offer is not based on at least the 9am next day gas prices the generator will be forced to use stale information from the prior day next day gas market that is generated a day earlier. Figure 6, again for the Algonquin Citygate hub, shows the relationship between the prior day next day clearing price and the next day clearing price. As can be seen both graphically and statistically, there is significantly less uncertainty in the day of next day price information than in the prior day next day price information upon which the natural gas generator can base its offer into the RTO/ISO day ahead market.

The conclusion from the above is obvious, use of the freshest information allows for the most gas price certainty in development of an offer for the day ahead power market.

As a result of these differences, the coordinating factor between the markets has tended to be the cost and availability of natural gas for power generation that is embedded in the day ahead power bids.

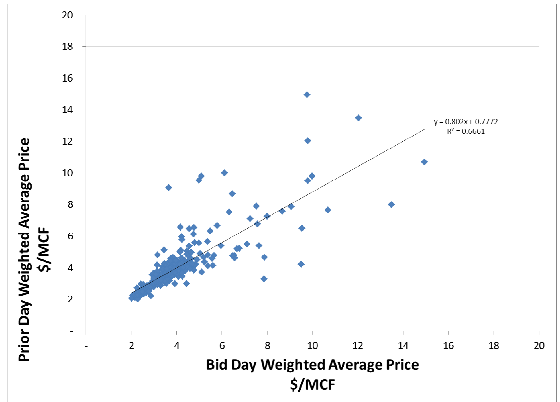


Figure 6 Average prior day next day natural prices v. next day natural gas price

Given that the price of natural gas is the coordinating value between the markets, the quality (freshness) of market data available to the gas-fired generator when that generator is structuring its offer into the day-ahead market becomes a critical input.

## 4. Resetting the power market clock

The discussion and any debate concerning the coordination of gas and power have primarily focused on issues of short-term operations and the assurance of short-term reliability. Using New England as an example, the issue centered on the risk that ISO NE had that the gas fired generation that cleared in the day ahead market would fail to be able to secure a next day gas supply and therefore would not, justifiably, be available at the time of rebid. The result for ISO NE would then be insufficient capacity available for the next day and additional units would have to be committed. At one level this process in and of itself left the ISO NE with added uncertainties but also knowing that there was non-gas fired capacity that had not cleared the day ahead market that would be available for dispatch. However, with the natural gas fired flexible (and short start time) units either committed or unable to run because of an inability to purchase gas in the timely nomination cycle, only generally older thermal units requiring long start times were available to fill the reliability gap.

The solution proposed by ISO NE was to move the close of the day ahead market forward by three hours. ISO NE argued that given that it could not shorten the cycle time required for their operational model runs, and that moving the offer deadline three hours earlier would assure them (ISO NE) the time needed to commit the slower starting units.

The decision of ISO NE was challenged by generators through the NEPOOL organization who argued that while moving the close of the market was probably the correct decision, moving it to 10am EST rather than 9am EST was the better decision.[3] The response of ISO NE supported by a consulting report[1], as it had been in New York earlier, was that the gas market would adjust its market timing to meet this new closing time of the ISO NE day ahead market. As indicated earlier, the next day gas market operates on an independent time table. The FERC would be the final arbiter.

## 5. Quantification of generator risk

The generators argued that they faced a greater risk in their offer into the day ahead market because they were now going to have to base their offer on prior day next day gas information. The discussion that follows presents a methodology (and the results of its application) for the calculation of a risk premium that would need to be added to the offer price of electricity from a gas fired generator in the day ahead market as well as a discussion of the range of cost to the New England power consumer.

There is no standard formula for calculating a risk premium associated with the exact type of natural gas purchase price risk occasioned by the ISO-NE proposal. While our calculation is based on analysis of the specific situation of gas fired generators in ISO NE, the methodology is generally applicable and, within bounds, the impact of similar timing decisions in other of the RTO/ISOs is likely to be of similar order of magnitude given similar dependence on natural gas fired generation at the margin.

In this section of the paper we describe the calculations we have used to estimate a reasonable range for the gas price premium associated with the ISO-NE proposal compared with the NEPOOL proposal. We believe that this estimate is conservatively low, and that the actual risk premium could well be higher.

The price risk associated with the ISO-NE proposal is related to the volatility in prices from day to day at the Algonquin City Gate. In our economic model, a gas-fired generator in the day ahead market must base its offer on a prediction of the price for next day gas using actual results for the prior day, as next day gas prices corresponding to the day ahead offer day are not yet available when the offer is due to ISO NE. This timing change from what had been the existing market close substantially magnifies the generator's risk. The risk was minimal under the original system of offers given that the purchase price of gas when the unit was called seldom differed significantly from the morning next day prices seen before the offers were submitted to the day ahead market. With a higher probability of the difference between the gas price used in the offer and the gas price paid when the unit was accepted for the next day, the gas-fired generator would be in a position to lose money, either out of pocket or in the form of opportunity costs. It also could, if course, make money if actual prices for gas that is burned are lower than reflected in its day ahead offer. Given a long enough series of daily prices, we would expect (and indeed have seen in the data) no statistically significant mean difference between prior-day and offer-day Algonquin Citygate prices for next day gas.

However, there is substantial variation in next day gas prices from day to day and this variation creates risk for gas-fired generators at or near the margin in the DA market. This variation is defined as the standard deviation of daily logarithmic returns. So, for example, if the price varies the ISO-NE proposal effectively would require generators to engage in "risk arbitrage", and hence deploy additional capital both to execute their gas trades and cover their losses. As risk capital has an opportunity cost for a generator; a risk premium will be required for those costs unless they are insured elsewhere in the market.

In order to estimate the risk premium for a generator, we used a well-accepted method to determine what it might cost to hedge these risks using options on Algonquin next day natural gas prices. [8] The calculation assumes that a generator making an offer could hedge its risks on a day-to-day basis using a simple option structure. Our calculation uses actual Algonquin Citygate gas price volatility data to estimate call option prices since there are no market-traded options in next day Algonquin gas of which we are aware. The cost to the generator of hedging the risks would then be related to the total costs of purchasing such options, which would include considerable bid-ask spreads. Based on estimated bid-ask spreads, we calculate a minimum risk premium that would be needed to cover such option costs.

In analyzing short-term risks, analysts and traders use the concept of daily volatility, which is defined as the standard deviation of daily logarithmic returns. If the price varies from 10 on one day to 11 the next day, the daily logarithmic return is the natural log of (11/10), which is 0.095.

Using the InterContinental Exchange (ICE) data for Algonquin Citygate next day prices, we calculated the daily volatility for all of the weekdays where the prior day and the offer day is only one day apart – eliminating certain weekend and holiday scheduling issues. For the entire data period, the historical daily volatility was 0.13. Volatility was significantly higher in 2012 because of increasing constraints on the gas system, and we expect more recent volatility will better predict future volatility until there is additional supply. Nonetheless, we used the entire sample period volatility, which we think understates the current volatility and, correspondingly, predicts a lower risk premium. The average Algonquin Citygate price for all of the data used was $4.78/mmbtu

The cost of such an option cannot be used directly as a risk premium, though, for the following reason. If the generator was able to recover the full cost of the option in each and every day in the power market, it would be insulated entirely from risks of prices rising after the offer was made (e.g. the prior day price was lower than the actual price on the offer day, since the option would pay off on those days), but could benefit on days when prices fell. There are therefore some days when this call option price may be too high for the risks faced. We wish to eliminate this possibility in our calculation,, and note that in an idealized option with a known distribution, the option cost the generator would be forced to pay (before any transactions costs, such as bid-ask spreads on the option) offsets any gains to the upside.

What is left to be paid by the generator – and would form the minimum basis for the risk premium - would be the considerable transactions costs associated with such options. These transactions costs are related to the bid-ask spreads on such options. There is no direct data available on the bid-ask spread in Algonquin Citygate gas next day options, as such options are not traded. The best we can rely on is knowledge of bid-ask spreads from related well-traded option markets.

The bid-ask spreads on options on the Henry Hub NYMEX futures contracts, for example, relate to one of the most liquid and heavily traded commodity markets in the world. Even so, there are bid-ask spreads on options on the most heavily traded contracts, such as options on the front month futures. These spreads are on the order of 3% to 4% of the option price. On options that are less liquid (not on the very front contracts or even somewhat "off the money") the spreads grow rapidly.

There are reasons these bid-ask spreads are comparatively low for Henry Hub gas futures. The market is extremely large and liquid, so a market-maker selling options (such as the commodities desk of a bank) has excellent transparency and real-time price data on the underlying contract. More importantly, as the underlying NYMEX natural gas futures are widely traded, the options seller (e.g. the bank) can cheaply and effectively hedge much of its price risk from selling the option through an offsetting position in the futures market. In the Algonquin next day gas market, none of these hedging approaches are possible, and daily volatility is generally higher than it is in Henry Hub natural gas futures. Nor is there any significant amount of short-term storage with the flexibility to allow these risks to be hedged physically. In effect, any Algonquin gas options market-maker would effectively have to sell a "naked" option. This would be extremely risky in a constrained and illiquid gas market exhibiting a large tail risk in price changes. We conclude that the bid-ask spreads on an equivalent Algonquin option would be much higher – at least 20% of the option value, and could be even higher.

Using this approach, we estimate a minimum risk premium (related to the bid-ask spread) of $0.05/mmbtu (20% of the calculated option price of $0.25/mmbtu) is reasonable, and use an upper bound of $0.12/mmbtu. To put these values in context, during periods of high gas demand Algonquin next day prices can move by $5/mmbtu from day to day.

We did not attempt to account for additional fixed or variable costs that might be associated with managing these gas price risks, which could include additional staffing, systems and management time. Nor did we attempt to account for any additional transactional or brokerage costs that might be associated with active risk management strategies for purchasing next day gas. Furthermore, we ignored the complex quantity risks that might be created between the next day gas and power markets

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## 6. Impact on day ahead market

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.

Natural gas is a major generation fuel in New England, and any proposal which raises the economic price of gas used by generators will impact DA electricity prices. For estimation purposes we translated our impact on natural gas prices to DA electricity prices using simple regressions of daily New England hub power prices (peak and off-peak) versus the volume weighted average daily Algonquin

Citygate next day price, where such a price was available. For peak periods, the regression shows a clear relationship and a coefficient on the gas price of 6.59 – similar to the heat rate of an efficient combined cycle generation plant of 7100 btu/kWh (7.1 mmbtu/MWh). For the off-peak periods, the coefficient was much lower at 4.72. We used these regression results and the risk premium per mmbtu of gas to estimate a risk premium adder to the power price, using 2012 data on actual DA energy in MW to estimate impacts on peak and off-peak prices separately. This calculation provides an estimated additional cost of power of $0.33 to $0.79/MWh for peak periods and $0.24 to $0.57/MWh for off-peak periods.

To complete this admittedly simplified analysis, we multiplied these per MWh cost impacts by day ahead demand in each period in 2012. The final estimated cost impact to the New England power market these calculations produce is approximated to be between $36 million to $86 million per annum. This is a price impact on the order of 1% to 2% of energy costs, based on estimated total electric energy costs of $5.2 billion in 2012.

While the exact value of the risk premium and its potential impact on energy prices is subject to model uncertainty, we believe this simplified model provides a reasonable and likely low estimate of the costs of a price risk premium associated with moving the day ahead offer time to 9:00 A.M. as proposed by ISO-NE. Whatever an actual risk premium would prove to be, there can be little doubt that there will be a risk premium and that the impact of that premium on the market would be significant.

As indicated above, the original discussion as to the timing of market closure for ISO NE was the subject of two competitive filings at the FERC. ISO NE arguing for 9am and the NEPOOL group arguing for 10. [1] On April 24, 2013 the Commission found in favor of NEPOOL and the market timing was reset to a close of 10am EST as opposed to 9am EST.[7] Based on the authors analyses, this represented a significant savings to consumers in New England of between $36 and $86 million annually in risk premiums not included in offers of generators.

The authors have not, to date, undertaken a parallel analysis for other RTO/ISO regions. Gas-electric scheduling and coordination issues may be significant in other markets as well, however.

The New York ISO (NYISO) has a close of 5am EST well before there is any information available from the next day gas market. While there are multiple trading hubs for gas in New York, at least some of those hubs are in pipeline-constrained regions facing broadly similar issues as New England. In addition, the New York market is similar to the New England market in terms of its dependence on natural gas; gas generation that accounted for 50% of capacity in 2012 with the percentage likely to increase over time.

A logical question is “given the analysis from New England and assuming similar gas and power markets, what is the likely price risk premium being incorporated into the New York market in generator offers.?” Using a quoted average cost in 2012 of $45/MWH and 163,300GWH of delivered energy the total generation bill in 2012 was roughly $7.4 billion.[4,5] Applying the New England value of 1 to 2% of total cost, the impact on New York consumers is (given these assumptions) between $70 and $140 million per year. This represents a significant price to pay unless it can be shown to represent an equal or greater savings in terms of units not available to the day ahead market because of start-up constraint

## 8. Conclusion

The debate concerning the coordination of natural gas and electric markets is ongoing and likely to continue for some time. The coordination issues arising in gas and power arise from the different fundamental structures of these markets, with the power sector relying a centralized scheduling and operating institution (the RTO/ISO) running single-shot clearing markets, while the gas market depends on decentralized scheduling by users of transactions on individual pipelines. Gas markets, in contract to the single-shot power auctions, are continuous-time bid-ask markets operating through electronic exchanges or on an over-the-counter basis.

So far, however, the discussions on price impacts of coordination effects between power and gas markets have been largely qualitative. In this paper we have presented a quantification of one specific risk issue in one market. This analysis showed that the risk and price impacts could be significant and require further attention from market designers and regulators.

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