Session Title:
Competing Claims: Gas and Electric Scheduling
Mismatches and Capacity Release Issues

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

I. Introduction

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

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

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

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

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4 Daily gas basis is defined here as the difference between the daily Algonquin Citygates price and the daily spot Henry Hub price. The Cromwell compressor station on the Algonquin pipeline is located in Connecticut, on the main pipeline bringing gas from the Mid-Atlantic region into New England. Figure from EIA, “Short-Term Energy Outlook: Constraints in New England likely to affect regional energy prices this winter”, January 18, 2013.
Similar charts for many other parts of the country would show lower utilization on average across the year on key pipelines, and dramatically lower basis prices. While broad policy issues exist across the U.S., the details and impacts are quite regionally specific.

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

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

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

II. Potential Sources of Market Failure

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

Imperfect information and transactions costs

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

See for example the comments of PJM Interconnection Inc. filed in FERC Dockets AD12-12-000 and RM96-1-037.
commitment and dispatch. The information from generators comes in to the RTO in the form of price-quantity offers which are necessarily conditioned on the information available about gas prices and transportation capacity in the market. If this gas information is insufficient or stale, the offers of generators will affect power market operations through a variety of means:

- Generators may assess that gas pipeline capacity is unavailable – based on available pipeline data and market prices – when capacity in fact will be available. Conversely, a generator could be exposed in the day-ahead market if it made a commitment to generate when in fact insufficient gas was available.

- As we discuss later in this paper, gas trading volumes in regional daily spot markets are generally constrained to a relatively small time window, which may not correspond to the period when generator offers are created. Spot gas prices used by generators could therefore be stale or otherwise not representative of current forecast weather, pipeline and other conditions. This could affect the allocative efficiency of power market outcomes or require generation offers to include risk premia over the short-term volatility in local gas prices.

- Outside of high liquidity trading windows, daily gas prices (and we expect intra-day prices) show considerable bid-ask spreads, reflecting weaker liquidity, lower price transparency and the inability of market participants to hedge these temporal risks physically. If generators are required to transact out of liquid periods, these spreads could contribute to higher transactions costs and ultimately higher prices.

**Unpriced constraints**

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

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

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

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6 As is widely recognized, the unique characteristics of AC electric systems, with their inherent need for very short-term balancing of supply and demand, make a large degree of central control necessary. This is common to RTO and non-RTO systems.
(LMPs). Transmission, load, generation and contingency constraints are modeled in the SCUC software so that the resulting operational schedules and LMPs are consistent with the known operating physical constraints on the bulk power system. During real-time operations, the RTO operate a centralized security-constrained economic dispatch (SCED) and a real-time LMP market, which reflects load, generation and transmission constraints at the time.

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

Table 1: Attributes of US gas and SMD power markets

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

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

Broadly speaking, under the gas model capacity commitment and allocation decisions are made individually, and in a decentralized fashion. While the rates and operating practices of pipelines are subject to regulation, individual shippers decide when to use gas transportation services and pipelines have only the responsibility to make these services available under the terms of their tariffs. Commitments are contractual between parties and it is the responsibility of end users to contract and pay for sufficient gas resources (commodity, transportation or
storage) to meet their requirements. The US natural gas industry has been remarkably successful in evolving a market structure to meet these requirements with a minimum of top-down “design”.

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

Figure 2: Stylized operation of a SMD power market

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

Under SMD, the primary mechanism for ensuring operational reliability (as opposed to longer-term generation resource adequacy and electrical transmission deliverability of that generation) is incorporating all resource constraints – including transmission constraints which affect the location of potential incremental generation, temporal constraints such as minimum on
and off-times and ramp rates, and security constraints such as maintenance of reserves and frequency – into the security-constrained commitment systems which compute both day-ahead schedules and day-ahead LMPs. In this way, a single-shot, single-clearing price auction mechanism (the SCUC) can create a set of schedules which is feasible given known constraints. Given the information set provided in the day-ahead market (e.g., generator bids and availabilities, transmission constraints, and contingency constraints) the RTO can be confident that the operating schedule meets reliability standards for the following operating day.

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

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

**Pricing gas constraints in the SMD framework**

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

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

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

8 Electricity transmission systems are generally operated on an N-1 contingency basis, which requires that system operational reliability be preserved on the loss of the single largest impact constraint (which could be the loss of a generator, a transmission line, etc.). Additionally, there are reliability requirements setting the minimum levels of various grades of operating reserves.
that there are electrical constraints on the grids which prevent all generation from serving all load. However, such capacity mechanisms do not consider gas pipeline constraints that might also impact generation capacity availability and deliverability. Nor do the RTOs generally perform any contingency analysis of the gas system to establish whether the mix of available generation resources is robust to the loss of an element of the pipeline system. As such, important elements of assessing future resource adequacy may be missed and therefore not priced.⁹

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

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

- For example, at one time it was fairly common for new combined cycle gas turbine units to have liquid fuel backup. This is now less common, given the gap in natural gas and oil prices, and the unclear path for monetizing the capability without some pricing of the reserve capacity. If the gas availability constraint was priced, dual-fuel units could be paid as a form of ancillary services, calculated during the day-ahead SCUC run.¹¹

- Liquefied natural gas (LNG) peak shaving facilities are one method for meeting peak day demands. These facilities liquefy natural gas and store it cryogenically on site or transport it to remote locations by truck for regasification. Additional regional or plant site-regasification could be economically sensible if the standby capacity was priced.

- Finally, as the Energy Information Administration has noted, some of New England’s recent supply issues have been intensified by lack of foreign LNG cargoes being brought in to US and Canadian regas terminals, due to the large price differentials between US

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

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

¹¹ The authors thank Bill Hieronymus for his suggestion that dual-fired capacity could be priced as an ancillary service under the SMD framework.
regional and foreign destinations in Europe and Asia. The economics of bringing in limited additional cargoes could be bolstered as high deliverability reserves if there was a counterparty available who could profitably sell backstopped gas capacity into the power market.

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

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

III. Scheduling mismatches and market timing

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

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


¹³ All times are Eastern Prevailing Time.
Figure 3: Simplified SMD power market and gas nomination timelines

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

**Timing of next-day gas trading**

Electric power in an SMD market is traded in hourly blocks (day-ahead and real-time) and also in forwards markets (which are typically financial swaps against RTO prices and not for physical power). In the gas market, the primary spot market liquidity is in the next day product for delivery at a specific hub, which is traded, for example, on Tuesday morning for delivery on Wednesday starting at 10:00 A.M. This “next day” gas is traded on exchanges such as the Intercontinental Exchange (ICE) and also on an over-the-counter (OTC) basis. Market transparency on ICE-traded gas is high, which aids efficient price discovery. During active trading periods bid-ask spreads – a measure of transaction costs – are low.
In addition to the next day market, intra-day gas is also traded, generally on an OTC basis. Volumes and liquidity tend to be low and transparency is substantially weaker. While there is little or no public data available on OTC intra-day trades, spreads are generally expected to be substantially higher.

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

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

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

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15 The analyses reported in this section of the white paper were undertaken by the authors on behalf of the New England Power Pool (NEPOOL) in connection with ISO New England Inc.’s (ISO NE) proposed resetting of the timing for offers into the day-ahead market. Both NEPOOL and ISO NE submitted to the Federal Energy Regulatory Commission (FERC) alternative proposals to modify New England’s market rules for earlier clearing of the DA energy market and earlier completion of ISO NE’s reserve adequacy analyses (“RAA”). Our results were incorporated in prepared testimony filed by NEPOOL in support of its alternative proposal. Both alternative proposals are pending before the FERC in Docket No. ER13-895-000.
We recognize that ICE is not the only method of next day trading at Algonquin Citygates, and that additional trading occurs on an OTC basis. However, ICE is a major trading platform in the next day gas market, and the timing of trades on ICE is generally believed to be representative of all Algonquin Citygates next day gas trades.\(^\text{16}\)

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

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\(^{16}\) The analyzed transactions reflect only next-day trades, and exclude trades before weekdays and holidays. Since the gas market does not trade on the weekends and holidays, larger time lags can occur on these days.
Figure 5 combines the power market timeline of Figure 3 (representing current ISO NE offer practices) with the next day Algonquin Citygates transaction volume data in Figure 4 – shown here as downward columns representing frequency of transactions. As can be seen in the figure, market volume (and hence price discovery) is strongest mid-morning, allowing current next day gas market prices to be incorporated into generator offers into the day-ahead power market.

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

\textsuperscript{17} Speech at the New England Society Dinner, 1876.
If offers into the day-ahead market cannot be based on current gas prices, there may be quite limited price information on which to develop offers, and previous day prices are a poor substitute as shown in the figure. It thus appears likely that short-term inefficiencies will be created and that generators who have to make firm offers into the gas market will introduce a risk premium to compensate for their additional trading risks.

IV. Conclusions

More than a decade ago, the development of US power markets was faced with a question: Should American electricity markets follow the centralized operations of traditional electric utilities, the “tight pools” such as PJM, NEPOOL and the New York Power Pool (plus the British-inspired “PoolCo” model), or should they follow the largely decentralized example of the American gas industry, which had already been successfully deregulated. The ensuing debate –
which perhaps provided more heat than light – shifted over time towards a centralized view of power operations and markets. Today, most US power markets are based on the “standard market design” with LMP pricing. This approach includes centralized security-constrained unit commitment and security-constrained economic dispatch under which the RTO controls system operations. Only the Southeast and the West (outside California) retain the remnants of the bilateral power market model, and most loads in these regions are served by vertically-integrated and regulated utilities.

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

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

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

Potential avenues and further questions

Providing definitive solutions for this complex problem is outside the scope of this paper, and will require a more detailed quantitative understanding of the specific issues affecting major gas and power market regions. We can however identify some potential approaches that might be explored further for addressing operational (rather than planning or investment) solutions for SMD markets dependent on gas.
RTOs could aim to have mechanisms that would trigger when total pipeline capability was becoming very constrained, given that having every generator nominate and confirm capacity before offers are submitted is impractical given market timelines. A “tight market” market signal could perhaps be developed which would trigger on expectations of very high aggregate regional gas demand. This gas market signal might be used to schedule non-gas-fired resources or gas-fired resources on pipelines with spare capacity in the SCUC which could then be reflected in day-ahead LMPs.

These resources, which could include dual-fueled units, or units with secured gas supply or storage, might be made available to the RTO under an ancillary service-type reserve payment. These payments could provide incentives for generators to contract for short-term storage, gas transportation or dual-fired capability to meet RTO requirements.

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