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March 30, 2012

Commissioner Philip Moeller
Suite 11A
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Docket No. AD12-12-000

Dear Commissioner Moeller:

Enclosed are comments in response to your February 3, 2012 notice regarding the Coordination between the Natural Gas and Electricity Markets.

Regards,



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**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Coordination between)	Docket No. AD12-12-000
Natural Gas and)	
Electricity Markets)	
Request for Comments)	

The Emerging Need for Greater Gas-Electric Industry Coordination

Comments by

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of The Brattle Group

March 30, 2012

We are pleased to submit comments in the Commission’s docket (AD12-12-000) on coordination between natural gas and electricity markets.¹ We are submitting these on our own, without sponsorship. Our comments address our perceptions of why this is an important issue, and what the elements of a possible system for increased coordination could look like.

Increasing Reliance on Gas-Fired Generation

The issue of coordination between the natural gas and electric power industries is emerging as a very important one. This need is not indicated by a crescendo of unfortunate events from lack of coordination, though there have been a few times in the last decade (e.g., the 2004 New England winter and the February 2011 Southwest U.S. cold snap) when the risks were strongly revealed.²

1 The authors are principals and associates in the natural gas and electricity industry practices of The Brattle Group. The views expressed herein are those of these specific authors and are not offered as the position of The Brattle Group or any of its clients.

2 The Brattle Group recently analyzed the reliability implications of the New England electric grid’s reliance on natural gas in the 2012 Integrated Resource Plan for Connecticut. See Appendix B (Resource

The coordination risks these events exemplify will likely become more material in the future, assuming 1) that the current trends of significant coal plant retirements, expansion of renewable resources, and the availability of low cost natural gas continue, and 2) that the current procedures and economic signals for cross-industry coordination are not enhanced.

Gas-fired generation has been the dominant source of natural gas demand growth for the past several years, and it is likely to represent almost the entirety of net growth for the next decade. Currently, gas-fired generation requires about 21 Bcf/d out of total average annual demand of around 67 Bcf/d, and electric sector gas demand is forecasted by NERC to grow to about 30 Bcf/d by 2020.³ This growth will come from both new plants and increased use by existing plants. In the last five years, the average capacity factor on natural gas combined-cycle units (CCs) has increased from 35% to 44%, such that in some areas, plants that were previously at the middle of the dispatch ladder are running as baseload units.⁴

This expected future increase in usage means that gas-fired generation will soon require more supply and perhaps more transportation capacity than has been needed to date. Some pipelines already have electric loads with peak day gas needs that represent 30% or more of their design capacities.⁵ If this capacity is needed by peakers running only a few hours per day, it could effectively require almost all of the ratable capacity of the pipeline for that time period. Equivalently, it might consume all of the few hours of linepack that can be stored the night before if the need was foreseen and nominated, which will not always be the case due to the erratic nature of real-time electric demands for gas-fired generation. Exposure to this kind of situation is not evenly distributed across the nation — power needs for gas are strongly concentrated in a few regions — but it will become more widespread.

A major cause of increasing natural gas usage is that coal-fired power plants are retiring due to low wholesale power prices (reflecting low gas prices) and the tightening EPA regulations on SO₂, NO_x, mercury and acid gases, ash handling, and cooling water. To date, about 25 GW of coal plants have announced their intentions to retire over the next 3-4 years, and that number is likely to grow substantially.⁶ Several industry studies conducted in 2011 found that 40-70 GW

Adequacy) to the “Draft 2012 Integrated Resource Plan for Connecticut,” The Connecticut Department of Energy and Environmental Protection, January 2012, pp. B-30 to B-36.

³ Total natural gas consumption and natural gas consumed by the power sector in 2011 obtained from EIA. Projected 2020 natural gas consumption by the power sector obtained from “2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States,” NERC, December 2011, figure 4-15.

⁴ According to EIA, capacity factors between 2005 and 2010 have gone from 26% to 32% during off-peak hours and from 40% to 50% during on-peak hours.

⁵ Algonquin Gas Transmission reported peak day gas demand by generators on its system of roughly 0.5 Bcf/d and 0.74 Bcf/d during winter and summer respectively compared to 2.5 Bcf/d of system capacity. See “Spectra Energy’s Perspective on Natural Gas Service to Electric Generation during the Winter,” presented by Rich Paglia at the NECPUC Meeting, 03/24/11.

⁶ “Upcoming, recent coal-fired power unit retirements,” SNL Energy, 03/28/12.

of coal (out of a base of about 315 GW) were then perceived as likely to retire due to compliance costs in excess of operating margins – and since that time, gas and power prices have fallen materially, putting more economic pressure on coal plants.⁷ Thus, it is likely that many more coal units are yet to announce their retirements, and some of those will be replaced with gas. 60 GW of coal being replaced by gas could add 5-6 Bcf/d to gas demand, about the throughput capacity of some of the larger national pipelines.

In addition, the integration of renewable resources onto the electric transmission grid is becoming more challenging and important, both due to the increased reliance on intermittent resources needing backup capacity and ancillary services, and due to the retirement of coal plants that have traditionally provided some of that support. Since gas-fired combustion turbines are capable of rapid increases and decreases in output, they are very attractive for this purpose. The implication is increased variability and uncertainty in the usage of gas-fired generation, complicating the gas supply and transportation capacity planning and coordination problem.

In sum, even if we have not yet experienced widespread, frequent system performance difficulties from gas-electric coordination, the market trends are such that we are more likely to face such problems (to varying degrees in different regions of the country) in the future.

Causes of the Potential Problem

The growing need for natural gas service to electric generation, by itself, is largely desirable from a public policy perspective. It involves greater use of a relatively clean, low carbon, and now apparently abundant and inexpensive local fuel, and convenient reliance on low-cost but flexible peaking generation to support renewables. However, we believe that gaps in cross-industry planning and scheduling, as well as inadequate pricing and contracting incentives to let the market internalize and fix the problem if/when it becomes more acute, create the risk of potentially inadequate supply or deliverability to electric generation. This, in turn, could cause reliability problems or unnecessary, extreme price spikes affecting both the gas and electric industry.

The problem could arise if a prolonged, severe cold weather snap or a major, unplanned outage of non-gas base load power plants (such as nuclear units) were to occur, causing unusually high gas demand by power generators, that the gas infrastructure may not be able to support.⁸ The

⁷ See “Potential Coal Plant Retirements Under Emerging Environmental Regulations,” by Metin Celebi, Frank C. Graves, Gunjan Bathla and Lucas Bressan, The Brattle Group, Inc., 12/08/10. Also see “Potential Coal Plant Retirements in U.S. and Impact on Gas Demand,” presented by Metin Celebi at CERI Conference in Calgary, Alberta, 02/27/12.

⁸ This can be described as a “common mode failure” whereby several facilities face a shared risk that they will experience jointly. This is potentially a riskier situation than having each plant have primarily unique

risks of a severe cold snap and generation outages are already considered by the electric industry in its reliability planning, but the sufficiency of fuel supply generally is not. Moreover, a gas supply curtailment could trigger a multiple contingency electricity reliability problem (“N-n”) if many regional gas-fired power plants were simultaneously affected and curtailed.

The concern arises in part because many, if not most, gas-fired generators do not hold firm upstream gas transportation capacity, because their demands are uncertain (or low during some periods of the year) and the costs of firmness may be quite high and difficult to recover. Instead, many generators opt to hold interruptible gas transportation capacity or procure gas from other gas market participants with firm transportation capacity. Historically, this did not tend to create problems, since in many regions the gas demand by generators was highest during the summer electric peak, which is typically a time of slack on the gas infrastructure side. However, as the electric system becomes more gas-dependent, those generators may (at some point) have difficulty obtaining natural gas supplies during periods of peak gas demand, and in some cases could even create a new peak in gas demand. If they (or their utility systems) do not then have other means of backing up their performance — such as with dual-fuel capability that allows them to switch to fuel oil — significant outages could occur.⁹ For the individual generators, this may or may not be a big problem. They are likely to face penalties for not being available, but these might not be as large as the avoided fixed pipeline costs. But collectively, this risk may be very costly and even unacceptable, because it could happen to lots of generators simultaneously. RTOs may not be fully aware of this exposure, or they may have insufficient penalties and alternatives. Likewise, this problem does not necessarily impinge on the financial health of the upstream pipelines. Their ability to earn an adequate return on and of their investments may not depend heavily on whether there is swing capacity available to the electric generation sector under infrequent, extreme conditions. Pipelines are generally sized and expanded for the needs of their long term firm customers.

While some regions and some pipelines have introduced innovative improvements to their scheduling, pricing and information exchange between pipelines or gas local distribution companies (LDCs) with downstream RTOs and electric utilities to address these concerns, that process has not been systematic or comprehensive. To some degree, this problem is everyone’s problem, hence no one’s problem. It lies between the spheres of control and responsibility for the pipelines, the gas LDCs, the merchant generators, the utilities, the system operators and the RTOs. The following are some of the institutional arrangements that make this an externality to many of the participants in the industry (in no particular order of importance):

performance risks that are uncorrelated and reduced by diversity (e.g, steam tube outages). Another example of this is correlated swings in output from renewable resources.

⁹ Recently, new natural gas plants are being built with dual-fuel capability in some pipeline constrained power markets.

- *Pipeline expansion only if/when the pipelines have firm long term contracts for the new facilities* – As noted above, most of the future growth in gas usage will come from power plants. However, electric generators tend to be reluctant to sign long-term firm transportation contracts, due to their uncertain long-term annual gas needs, the often off-peak nature of their demand (i.e., greater usage in summer which traditionally has been off-peak in the gas market), inability to reflect the fixed costs of firm transportation contracts in their energy offer prices, the difficulties/riskiness of recovering the costs from occasional price spikes in wholesale markets, and their ability to design the plant so it can switch to fuel oil if natural gas is curtailed.
- *Very tolerant pipeline balancing rules and small penalties* – Some pipelines only require balancing of net demands over a month-long horizon, when the operational difficulties could arise within a single day.
- *Primarily “plain vanilla” services on many pipelines* – That is, some pipelines do not distinguish between relatively flat and predictable average daily usage vs. extremely spikey, unpredictable usage having a similar average need. Similarly, they also do not have an ability to base their interruptible rates on less than 100% load factor imputed usage. On electric systems, distinctions in the costs of service between different locations and times are routine and important, e.g., LMPs that can change quickly and vary significantly throughout the day, or ancillary services that are procured to provide the required system flexibility.
- *Lack of gas industry regional reliability oversight or standards* – There is no natural gas industry counterpart to electric RTOs or NERC. This may not be a problem in regions where there are only one or two large pipelines serving a large geographic area, but when several pipelines share upstream responsibility for a material gas-fired generation load, a greater degree of regional coordination of linepack, forecasting, etc., across pipelines would be helpful.
- *Scheduling inconsistencies between gas and electric organizations* — The “gas day” is typically from 9:00 a.m. Central Clock Time (CCT) to 9:00 a.m. (CCT) the following calendar day, while the “electric day” operates on different, region-specific schedules. This results in some minor misalignment, as some portion of the electric needs for gas (e.g., the morning ramp-up) must be forecasted ahead of the day they are actually scheduled by the electric operators. One helpful fix for this may be to allow more intra-day re-nomination times, some of which could be flexible rather than fixed times.
- *Lack of fuel-firmness standards for capacity recognition and reliability planning by the electric industry* – While RTOs impose penalties (such as derated capacity payments) for inability to respond to performance requests of generators, the authors are not aware of any

RTOs that seek or require upstream proof of fuel deliverability or that routinely confirm or test the viability of dual-fuel capabilities. Penalties, by their nature, are ex-post remedies, and they may not be large enough to motivate the ex-ante commitment to years of payments for firm transportation or gas supply that might be needed to avoid them. More information collection and coordinated scheduling with generators and pipelines when an unusual level of need is anticipated (e.g., a long cold snap is being forecasted) may be a better solution.

- *Reductions in dual-fuel capability and its economic and environmental feasibility of use* – For the last few years, natural gas supply prices have been quite low relative to oil; the two markets have decoupled in the U.S., because gas is a domestic market while oil is international and facing large demands from other countries. As a result, oil usage in dual-fueled power plants is very expensive, to the point that its use has become virtually non-existent, and this may affect the readiness to deploy that capability on short notice or for prolonged periods of time. Environmental constraints on oil usage are also increasing, so its viability as a swing fuel (to avoid gas price spikes or shortages) has declined significantly.

Possible Solutions

The biggest need associated with addressing gas-electric coordination is first to better understand it; the Commission should develop a thorough evidentiary foundation of the nature of the risks facing each region. To the extent there are emerging problems or risks, these are very likely to be quite distinct by region, for several reasons. First, there are varying amounts and extents of reliance on gas-fired generation, gas heating load, and depth and diversity of pipeline service, and seasonality and timing of gas and electric loads in various parts of the country. Second, some regions have larger or smaller electric reserve margins and differing exposure to extreme weather or major contingencies and to the availability of other types of generation. Third, the regions differ in the type and extent of flexible mechanisms they already have (or could have) for protecting local reliability, such as market-area gas storage, curtailable electric or gas loads, and the extent to which dual-fuel capability exists within the natural gas generation fleet. The Commission should develop an analytical template to evaluate region-specific conditions.

For example, we suggest that the Commission ask all the RTOs and balancing areas and major pipelines with material gas-fired electric loads to produce five-year outlooks of their average and peak deliverability needs for gas for electric generation, coupled with analysis of how this need compares to projected average and peak (intraday, hourly) capability, expansion plans and contracting for firm supply. The needs foreseen by the pipelines should be compared to the needs as viewed by the electric users, to see if they are similar in size, timing and location. It is likely there will be some differences, due to the pipelines being mostly aware of committed plans of their generation customers, while the RTOs will have a broader view of potential needs due to coal retirements, increased ancillary services to support renewables, their own demand response, hydroelectric variability, and so on. RTOs should also seek information on the firmness of

upstream fuel and transportation commitments by their gas generators, including the extent to which generators are relying on interruptible transportation, and the capabilities the dual-fuel units have to turn to their alternative fuel if need be (e.g., is it operationally ready on short notice, and for how long could it be used given typical fuel oil inventories and environmental permits). The extent of limits on oil usage as well as the practical (likely quite high) costs of relying on it should also be reviewed to see if they could create an intolerable situation.

The Commission should also seek to understand the region's gas network characteristics. For each pipeline within a region, what proportion of the pipeline's capacity serving that region is represented by average day and peak day deliveries to gas-fired generators? To what degree is high deliverability storage available? What are the balancing rules in effect on the region's pipelines? What are the flow patterns (is the region situated at the origin, center, or terminus of the pipelines which serve it)? Are these flow patterns changing as a result of the shifting North American gas supply picture?

For those regions that identify a potential risk of un-served gas demands, the second stage will be to design tactical solutions to the problem, customized again to the specific region and causes of the problem. It is very likely that this will include requiring some degree of more regular planning and information sharing between gas and electric market participants, possibly new obligations on electricity market participants to have firm gas supply or other firm, flexible alternatives available during peak gas demand periods, different kinds of contingency (risk) planning, and more nomination opportunities on pipelines.

The necessary solutions are also likely to involve new kinds of pricing for both electric and gas systems. However, careful analysis is required to sort out viable price regimes from those that are impractical or unrealistic, even if desirable in principle, and hence unlikely to succeed. For example, very flexible intraday pricing of deliverable gas could, in principle, solve the problem of ensuring that electric market participants contract for adequate firm gas capacity. There would be high prices for gas on extremely tight gas days (already seen to a degree currently, but not to the extent or magnitude that is likely needed to stimulate contracting for significant quantities of new, firm gas capacity). Demand-response and fuel-switching natural gas users would relinquish their firm claims in exchange for this high spot price for regional gas, in sufficient numbers to allow enough gas-fired generators to use the diverted gas to keep the lights on. Spot wholesale power prices (e.g, LMPs) would spike as well. This would cause generators who had previously arranged for long-term firm capacity to earn large margins, justifying the fixed costs of those rights. As a result, contracting for long term firm gas supply and transportation would likely increase.

In practice, it is doubtful that this ideal of strong reliance on very flexible intraday pricing can be achieved. One weak link in the chain is the assumption that it would be politically acceptable to let prices spike high enough to do their job. Experience in the electric industry indicates we are often uncomfortable with prices that reflect the true value of scarcity (or we cannot readily

distinguish them from market power abuses) — which led to the imposition of price caps and the need for other mechanisms, such as capacity markets, to support investments and assure system reliability. Even if very high short-term prices for gas and electricity were allowed, electric investors are likely to be quite leery of the prospect of recovering large, ongoing fixed costs for upstream firmness via very occasional bonanzas of short-term profits during extreme events. There is too much uncertainty about when or whether these events would occur. To help work around this, it is possible that fixed costs of fuel supply firmness need to become part of allowable bids into capacity markets and/or part of the uplift payments to units that are committed but fail to recover all of their start costs in the energy markets.

Second, the flexible intraday pricing model assumes that there is a sufficient base of demand-responsive gas customers (on peak gas days) to accommodate the electricity market's need for gas, but this could be far too much for some systems. As noted earlier, the electric load can be a significant part, or even the majority, of short term deliverability on a major pipeline, and that is even more likely for a smaller pipeline (with smaller diameter, less linepack, and lower pressure). However, steps probably could be taken to enlarge the pool and the responsiveness of natural gas customers willing to reduce usage.¹⁰

Finally, this approach transfers all of the short-term value of deliverable gas to the pipeline capacity holders, and none to the pipelines (unless and until they obtain future long term contracts for pipeline expansions, which as just noted might not occur due to the riskiness of cost recovery for the electric market participants). If some of this value was captured by, or at risk to, the pipelines, they would have incentives to do more active management of the exposure, and indeed they may be the parties most able to anticipate and mitigate it. In some ways, the burden of sudden gas supply usage on the pipelines is analogous to the burden of sudden renewable generation usage (or cessation) on electric transmission grids. In that setting, we have acknowledged that new, more expensive ancillary services and better forecasting are needed, and that the grid managers and RTOs must be involved in the design, procurement and deployment of those products and controls. By analogy, it is possible that the pipelines should be offering new ancillary services with more efficient short-term time pricing to discipline and manage the variability and risks that large, sudden, or unexpectedly protracted electric gas usage could impose on their systems.

Thus, while prices are likely to play an important part in the solution, they likely cannot play the only part. A more viable and prudent strategy may be to encourage the stakeholders in electricity markets who have resource adequacy obligations to create performance obligations,

¹⁰ A study by Brattle in 2011 found that if residential gas customers in Massachusetts were incentivized to reduce their winter thermostat settings by 1 degree, this would reduce their gas demand by about 60 MMcf/d. That is enough gas to serve a 200 MW to 300 MW gas peaking plant, which could be a non-trivial resource in ISO-NE under tight electric supply conditions. See “ISO New England Strategic Planning Discussion - Considerations and Recommendations,” by Metin Celebi, Judy Chang, Mark Sarro and Jurgen Weiss, 10/11/11, slide 40.

backed up by financial rewards and penalties, for generators to have reliable access to fuel (whether through firm fuel supply and transportation contracts, demonstrable, multi-day dual-fuel capabilities, or agreements with non-electric customers that have firm gas contracts to reduce their gas demand). If this is a requirement with financial incentives (again, only where the initial investigations identified a material need), then market mechanisms can be tapped to find the least cost solutions.

Conclusions

We are fortunate to have a domestic energy system that is enjoying the sudden emergence of abundant, low cost natural gas. However, it is possible that the transition to exploiting this abundance could be disruptive and lead to performance problems in some regions that are especially reliant on natural gas for power generation and which have not yet developed coordination mechanisms and economic methods of adjusting under duress. The timing of the Commission's investigation is attractive, because it will take a couple of years of careful analysis to diagnose where the problems, if any, are located, and what the best solutions are likely to be. Some of those solutions may require new systems that will also take a year or two to be developed and installed. That time frame corresponds roughly to when gas generation is likely to be taking a large step upwards in its importance to our electric system.

Commenter's Certification

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.



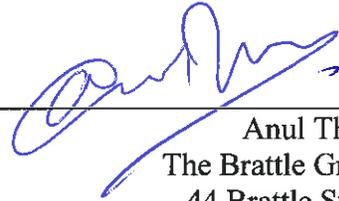
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