Staff Report on Gas-Electric Coordination Technical Conferences (Docket No. AD12-12-000)

November 15, 2012

This report was prepared by the staff of the Federal Energy Regulatory Commission.
This report does not necessarily reflect the views of the Commission.

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I. Introduction

In recent years, reliance on natural gas as a fuel for electric generation has steadily increased. This trend is expected to continue in the future, leading to greater interdependence between the natural gas and electric industries. In some areas of the country, questions have been raised regarding whether adequate market structures and appropriate regulations are in place to support this increasing reliance on natural gas-fired generation. To explore these issues, the Commission convened five regional conferences throughout the month of August 2012, in advance of the winter heating season, to solicit input from both industries regarding the coordination of natural gas and electricity markets. The conferences were structured around three sets of issues: scheduling and market structures/rules; communications, coordination, and information-sharing; and reliability concerns.

A cross-section of industry representatives participated and/or attended the regional conferences, with total attendance exceeding 1,200 registrants. Perspectives varied by region and across industry sectors as to the issues confronting the industries and actions to be taken. Information gathered at the conferences confirmed that gas-electric interdependence concerns are more acute in some regions than others, with the discussion at each conference focusing on the particular circumstances and needs of each region. Notwithstanding the regional focus of the discussions, recurring themes across the conferences were that more attention needs to be paid to gas-electric interdependence issues and that some matters are appropriate for generic consideration while others are more appropriate for individual regions to address.

This report focuses on several topics that were common to multiple regions. First, conference participants in many regions sought confirmation that sharing information in furtherance of enhancing gas-electric coordination would not run afoul of the Commission's Standards of Conduct or be construed as engaging in undue discrimination or preference.[1] Second, a number of concerns were expressed regarding the misalignment of gas and electric scheduling practices, as well as application of the no-bump rule and pipeline capacity release rules. Third, questions were raised in several regions regarding whether generators have appropriate incentives to deliver firm energy. Finally, industry representatives in multiple regions are considering appropriate steps to take to address reliability considerations in the context of gas-electric coordination. Staff addresses these issues by providing guidance where possible and highlighting relevant activities taking place in individual regions.

As the discussion below indicates, significant industry attention and resources are being dedicated to address these and a host of gas-electric coordination issues. Several regions have implemented or are developing practices to improve coordination and communication between the industries during normal operations as well as in emergency situations. Some regions are considering changes to electric market rules to address increased reliance on gas-fired generation, while pipelines have developed flexible products and scheduling protocols for their customers. These efforts have helped participants in each industry identify improvements that can be made to support effective operations within both industries.

By focusing on the subset of cross-cutting issues identified above, staff seeks to support the progress being made on gas-electric coordination matters. Staff understands that there are a number of other issues unique to each region that must be addressed to

[1] The Standards of Conduct govern communications between interstate natural gas pipelines and their affiliates that engage in marketing functions, and public utilities that own or operate electric transmission facilities and their affiliates that engage in marketing functions. 18 CFR § 358.1(a) and (b) (2012). See discussion in Section IV of this Report, below.

improve coordination across the gas and electric industries. Moreover, staff appreciates that gas-fired generators are only one of many users of the interstate natural gas pipeline system and that any changes to practices or rules within a particular region or the natural gas industry more broadly must be informed by the needs of a broad range of customers. With these considerations in mind, staff will be actively monitoring and engaging industry regarding progress being made in each region to ensure that gas-electric coordination issues are identified and addressed.

II. Background

On February 15, 2012, the Commission issued a notice in Docket No. AD12-12-000 requesting comments on various aspects of gas-electric interdependence and coordination in response to questions posed by Commissioner Philip Moeller and Commissioner Cheryl LaFleur.[2] Recognizing the electric industry's increased reliance on natural gas to generate electricity now and into the future, Commissioners Moeller and LaFleur pointed out the critical importance of the interface between the electric and natural gas industries. In order to better understand that interface and identify areas for improvement, Commissioners Moeller and LaFleur sought comments on a variety of topics including market structure and rules, scheduling, communications, infrastructure and reliability.

The Commission received comments from seventy-nine entities. The commenters raised a wide variety of issues regarding gas-electric interdependence. Many of the commenters asserted that the issues differed on a regional basis and requested that the Commission convene regional technical conferences.

On July 5, 2012, the Commission responded and issued a notice of a series of regional technical conferences to explore coordination between the natural gas and electric industries.[3] During the month of August 2012, Commission staff held five

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[2] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12-12-000(Feb. 15, 2012) (Notice Assigning Docket No. and Requesting Comments) (*available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12893828). *See also* Commissioner Philip D. Moeller, *Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets* (Feb. 3, 2012), *available at* http://www.ferc.gov/about/com-mem/moeller/moellergaselectricletter.pdf; Commissioner Cheryl A. LaFleur, *Statement regarding Standards for Business Practices for Interstate Natural Gas Pipelines* (Feb. 16, 2012), *available at* http://www.ferc.gov/media/statements-speeches/lafleur/2012/02-16-12-lafleur-G-1.asp.

[3] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12-12-000 (July 5, 2012) (Notice of Technical Conferences) (*available at*

(continued)

regional technical conferences for the Central, Northeast, Southeast, West and Mid-Atlantic regions. Each conference had a staff-led roundtable discussion of the following topics: scheduling and market structures/rules; communications, coordination, and information sharing; and reliability concerns.

III. Summary of Regional Conferences and Ongoing Initiatives to Address Gas-Electric Coordination

Before turning to the discussion of concerns common across multiple regions, staff provides a summary of general observations at each conference (not in chronological order) and information gleaned from publicly available sources. Each regional summary includes identification of initiatives to address gas-electric coordination issues that are either underway or in the planning stages in each region.

A. Northeast Region[4]

Several participants in the Northeast Region conference stated their views that the region is in need of additional pipeline infrastructure. It was noted that New England historically has had strong fuel diversity and dual-fuel capability,[5] and that this region will depend on dispatching generators with alternate fuel sources out of economic order to protect reliability in the face of possible natural gas delivery concerns.

Several pipeline participants reported that their systems within the Northeast are consistently running near their design capacities. According to statements made at the conference, some of the major existing pipelines serving the New England region are

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http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13023450); 77 Fed. Reg. 41,184 (July 12, 2012) (*available at* http://www.gpo.gov/fdsys/pkg/FR-2012-07-12/pdf/2012-16997.pdf).

[4] The Northeast region technical conference was held August 20, 2012 in Boston, Massachusetts, and included natural gas and electric entities from an area defined by the corporate boundaries of ISO New England Inc. (ISO-NE) and the States of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

[5] According to a recent report by ISO-NE, as recently as the 1990s the region's electricity was produced primarily by oil, coal and nuclear generating plants, with little gas-fired generation. In contrast, by 2011, approximately 51% of the electricity consumed in New England was produced by gas-fired generation. ISO New England, *Addressing Gas Dependence*," at 3 (July 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/ strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf.

nearly fully subscribed or constrained at specific points on their respective systems. The lack of available capacity may limit regional pipeline flexibility, and frequently results in flow restrictions and strict balance requirements. Both gas and electric industry participants stated that relatively little gas-fired generation in New England is backed by primary firm pipeline transportation contracts. Instead, participants stated that generators typically rely on released secondary firm or, to a much lesser extent, on interruptible transportation (IT) pipeline capacity. Some participants also discussed the roles of marketers in procuring both pipeline transportation service and gas supplies.

Conference participants reported that under the current market structure, generators have few incentives to obtain long-term primary firm pipeline service, invest in alternate fuel capabilities, or take other steps to ensure fuel availability. A representative of ISO-NE reported that several proposed revisions to its forward wholesale electric capacity market are being developed. ISO-NE's representative and other conference participants also discussed a proposal to allow hourly re-offers in the real-time energy market, and revisions to ISO-NE's price mitigation rules to allow bids to be adjusted to reflect actual fuel costs.[6]

Several conference participants indicated that options are limited for addressing the natural gas pipeline infrastructure issue in the near term. A representative of ISO-NE discussed its intentions to review generators' plans for the winter and determine whether individual generating units would be able to continue operating during a cold snap similar to that of January 2004. Pipelines stated their focus for the upcoming winter would be to maximize utilization of existing pipeline capacity to ensure reliability.

In the intermediate term, an ISO-NE representative noted ISO-NE's plans to propose adjustments to the electric market day-ahead scheduling and resource adequacy assessment process. Under its proposal, day-ahead awards may be released as early as 30 hours prior to the start of the electric day, and well in advance of the North American Energy Standards Board (NAESB) timely nomination deadline for gas pipeline capacity. ISO-NE stated its belief that the current timeline leaves it with too little time to mitigate generation supply risks before the start of the operating day. Some conference participants voiced support for such a change, while others stated that it would reduce, but not eliminate, the risk exposure of the generators.

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[6] ISO-NE is proposing to allow hourly offers and intra-day re-offers so that generators would be able to adjust their bids to reflect changes in fuel costs closer to real time. "Accordingly, resources that must buy intra-day gas will be able to reflect their true costs, and generators that might not be able to get gas in real-time and want to switch to oil will have the ability to reflect the cost of switching." ISO New England, *Addressing Gas Dependence*, at 15.

Some electric utility and gas local distribution company (LDC) participants suggested that further, coordinated studies of regional gas and electric infrastructure are needed. A few electric industry participants offered the idea of a regional gas infrastructure planning effort, similar to how the region already performs regional electric infrastructure planning. Gas industry participants did not express support for this idea.

Commentary of participants suggested that they are generally comfortable with the quality of communications between the pipelines, generators, and ISO-NE. Some observed that the communications currently occur on a largely *ad hoc* basis, and suggested that efforts to further formalize the communications procedures could be beneficial.

Northeast Regional Initiatives

Many technical conference participants supported the idea of forming a steering committee to address concerns about gas-electric coordination in the Northeast. The steering group would consider changes to the electric day, maximizing assets in the region through maintenance planning, and changes to ISO-NE's market rules, scenario planning, and funding mechanisms.

Participants at the conference discussed the need for improved coordination of maintenance outages among electric and natural gas industry participants. Representatives of pipelines and LDCs offered that the Northeast Gas Association is willing to lead the efforts to develop communication protocols governing gas and electric maintenance-related outage coordination.

As noted above, and according to the ISO-NE participants at the conference, ISO-NE is considering several potential modifications to its tariff, some to take place sooner than others. In the near-term, ISO-NE is considering a plan to conduct a supplemental procurement for natural gas, liquefied natural gas, or back up oil supplies to ensure adequate supplies over 2013 and 2014. Longer-term, ISO-NE plans to develop certain tariff revisions to move up the timeline for day-ahead unit commitment and the resource adequacy assessment process in an effort to provide additional time to ensure that gas-fired generators may procure gas supplies and delivery services so that adequate generation capacity is available in real time.[7] Further, ISO-NE is considering several

[7] ISO-NE is proposing to move the day-ahead market back so that generators can buy gas and pipeline capacity while the market is still liquid and so that it has more time to call on generators. *See* Janine Dombrowski, *Moving the Day Ahead Market & Reserve Adequacy Assessment Clearing Times*, ISO New England (Aug. 7-8, 2012), *available at* http://www.iso-

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changes to the market rules to allow energy and capacity prices to better reflect the risk of generator interruptible vs. firm gas procurement, including changes to the capacity product definition, changes to the resource adequacy assessment process, and a review of the consequences of generator non-delivery. ISO-NE is also considering a proposal to modify the real-time energy market and bid mitigation rules to allow generators to update bids to reflect changes in natural gas prices. [8]

B. Mid-Atlantic Region[9]

According to some participants representing generators in the Mid-Atlantic region, power markets provide no incentive to purchase firm contracts for pipeline transportation. Various other participants in the Mid-Atlantic Region conference pointed out that there are multiple ways a gas-fired generator can firm its fuel supplies—through firm contracts for pipeline transportation, dual fuel, storage contracts, and access to more than one pipeline. A North American Electric Reliability Corporation (NERC) representative noted the appeal of a requirement for generator "firmness" that would account for the multiple ways to firm-up fuel supply, and identified a potential firmness requirement as an item more suited for an RTO/ISO proposal rather than a NERC standard.

The prevalence of dual fuel capability in both the NYISO and PJM regions was noted. Participants stated that both the PJM and NYISO markets provide some incentive or requirement for dual fuel. A representative of PJM said that its Reliability Pricing Model (RPM) uses a dual fuel reference unit to determine the Cost of New Entry for the wholesale electric capacity market demand curve, which helps set the price of capacity. In NYISO, according to conference participants, generators in downstate New York (New York City and Long Island) are required to have alternate fuel capability under state reliability requirements. Participants generally indicated that gas markets in PJM are more liquid than those in NYISO given the availability of various pipelines and storage.

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ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/aug782012/a07_iso_presentation_08_07_12.ppt.

[8] *See* ISO New England, *Addressing Gas Dependence, supra* n. 5.

[9] The Mid-Atlantic Region technical conference was held August 30, 2012 and included natural gas and electric entities from an area defined by the corporate boundaries of New York Independent System Operator Inc. (NYISO), PJM Interconnection, L.L.C. (PJM) and related areas, including the States of Delaware, Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia and West Virginia.

While many representatives of generators indicated that they currently are able to secure pipeline capacity, several pipelines noted that liquidity and flexibility experienced thus far in the Mid-Atlantic region are not necessarily indicative of the flexibility that will be available in the future as gas-fired generation grows. Representatives of an LDC and a pipeline also argued that cost causality needs to be matched with cost responsibility. An LDC representative asserted that today certain costs of serving generators' variability and hourly flows are being paid by LDCs.

The issue of the use of secondary firm contracts and recallable capacity release contracts (rather than primary firm contracts) as a means of serving gas-fired generation was discussed. Several contend the practice of relying on types of transportation services other than primary firm transportation to fuel gas-fired generation is not a reliable solution given the higher rate of curtailment of secondary firm customers. Some pipeline participants also noted that while producers have funded some new pipeline capacity, these pipelines only extend far enough to get the natural gas from the producing region to a liquid pooling point, and there is still a need to build infrastructure to get natural gas from the supply area to generators. Some LDC representatives noted that for generators behind their citygates, even if the generator has firm gas contracts on an interstate pipeline, it still needs firm natural gas delivery capacity on the LDC's system.

Several participants also raised concerns about planning—whether the planning horizon is long enough and whether market participants are planning appropriately. Noting the differences between electric and gas planning horizons, a pipeline noted that pipelines do not plan for growth; rather they build to accommodate firm customers. An industrial participant argued that market signals are not a substitute for planning and contended that the region may need a longer-term planning horizon. A generator noted that while a long-term electric planning process exists, what is missing is consideration of fuel security.

There was no consensus among Mid-Atlantic conference participants as to the best way to address the gas-electric scheduling mismatch. A representative of NYISO stated that it currently releases its day-ahead dispatch results earlier (10 a.m. EST) than PJM does (4 p.m. EST). NYISO's representative noted that the earlier release allows gas-fired generators to be better informed for the first timely pipeline nomination cycle which occurs at 11 a.m. (CST). Feedback from participants representing generators on whether they preferred the earlier release or later release was mixed. NYISO's representative also reported that it is considering moving the day-ahead dispatch results release to earlier than 10 a.m. (EST) (when gas markets are more liquid) or later (to facilitate better gas supply and transportation price certainty when bidding), and will continue to explore scheduling through its stakeholder process. Conference participants noted that in PJM, where the natural gas market is relatively liquid and there are many pipelines and storage reservoirs, generators thus far have been able to acquire natural gas supplies and pipeline capacity in later pipeline nomination cycles. Conference participants noted that in

NYISO where the gas market is less liquid it is not always easy to acquire gas after the first timely pipeline nomination cycle.

With regard to the process for allowing generators to modify bids to reflect actual fuel costs, NYISO permits it if a generator had to switch fuels or procure more expensive intra-day gas if the ISO increased its dispatch level. According to the PJM representative, PJM does not currently permit this, but PJM would be open to considering it.

Some participants representing generators encouraged the creation of more nomination cycles. Pipeline representatives noted that some pipelines in the region already offer hourly nomination cycles and stated that more frequent nominations will not help if there is inadequate pipeline capacity.

Regarding communications, a representative of NYISO noted that it does not necessarily understand how pipeline outages impact the electric system and which generators will be affected. Representatives of PJM and a pipeline mentioned a partnership which would include exchanging control room operators. They expect that spending time in each others' control rooms will help to bridge the language gap and learn about each other's industry. Various conference participants also noted their interest in tabletop exercises that simulate reliability scenarios. A representative of NYISO noted that several combined gas-electric utilities, along with certain pipelines within its area, recently ran a useful tabletop exercise.

Conference participants indicated that there is no formal outage coordination process across industries, but some expressed support for a formalized process. Some conference participants noted there is a tension between wanting to openly discuss publicly available information on outages and the impact on operations, and concern about whether unit-specific discussion would violate regulations against undue preference or discrimination. Pipeline representatives noted reluctance to discuss granular impacts at the level of individual shippers beyond the information the pipelines make publicly available on electronic bulletin boards. One participant noted that enhanced outage coordination gives rise to heightened concern over manipulation. Various participants indicated concern about specifying shipper-level information in discussions.

Participants from both the natural gas and electric industries suggested clarification of the Standards of Conduct and Natural Gas Act Section 4b undue preference and anti-manipulation rules would be helpful.[10] One participant suggested

[10] N. 35, *infra*.

"common sense leeway" to the Standards of Conduct rules in emergencies. A pipeline trade association representative noted that some RTOs/ISOs have adopted the Standards of Conduct in their tariffs and RTOs/ISOs are concerned about sharing information with pipelines. PJM's representative asked whether it can tell pipelines which generator units will be dispatched.

Participants articulated different views on the markets' ability to send appropriate signals. One pipeline representative argued that electric market signals do not factor in reliability and another participant argued that generators in unregulated markets have no incentive to contract for firm pipeline transportation. A PJM representative noted that its wholesale electric capacity market does not pay generators if they do not run and capacity factors[11] decline if generators do not run. A generator representative stated that PJM's capacity market sends the right signals, while a pipeline representative argued that PJM's nonperformance penalties are weak and do not justify paying for fuel security. A NERC representative noted that many capacity market incentives, such as Equivalent Forced Outage Rate—demand (EFORd)[12] penalties, are problematic because they are retrospective and the impact arrives three years later.

In general, participants in this technical conference urged the Commission to "be patient" and check back with the regions to see that they continue to make progress on most issues involving gas-electric coordination, although there was interest in having the communications issues clarified.

Mid-Atlantic Regional Initiatives

A representative of NYISO noted that NYISO, PJM, ISO-NE, the Ontario Independent Electricity System Operator (IESO), and possibly also Midwest Independent System Operator (MISO) are planning a comprehensive study across pipelines serving these regions that would incorporate retirements and infrastructure changes over five to ten years. The study will examine planned generation retirements, new transmission lines, and new pipelines for the next five to 10 years and try to identify any electric reliability problems. The study is expected to be available sometime in 2013.

On communications between the RTOs/ISOs and the pipelines in coordinating outages, representatives of PJM and NYISO discussed educational processes and

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[11] Capacity factor refers to the ratio of a plant's output during a period of time to its potential output if it had operated at its full nameplate capacity.

[12] EFORd is a measure of the probability that a generator will not meet its demand periods for generating requirements.

operator training and exchange programs, and the development of protocols for the sharing of maintenance schedules.[13] As mentioned above, several combined utilities went through a tabletop reliability scenario exercise with several pipelines, where they examined different scenarios based upon loss of supply.

C. Central Region[14]

Many participants in the Central Region conference stated that gas-electric coordination in the region is not currently a problem. However, a representative of MISO suggested that this could change in 2013-2015 when it expects approximately 30,000 MW of coal-fired generation to either be retired or taken off line for retrofits to meet emissions standards over the 2012-2015 period. MISO's representative anticipates this will result in a greater reliance upon gas-fired generators, and said that it is particularly concerned about the unavailability of coal units during the December – April period, when natural gas demand is highest.

Participants came down on all sides of the gas-electric scheduling question. Some suggested that both markets would benefit if the market schedules were more aligned: if the electric market cleared earlier in the day and the timely (first) gas nomination cycle occurred later in the day, market participants would be able to make gas supply arrangements at a time when the natural gas market is more liquid, based upon knowing earlier which generation plants were going to run. Others asserted that the earlier day-ahead electric commitments are made, the less accurate the load and price forecasts become. Some firm gas pipeline shippers expressed concern about the impact of increased gas-fired generation upon the quality of their firm pipeline services. Suggestions to improve gas pipeline flexibility include revisiting the "no-bump" rule and making intra-day capacity release more flexible. A few shippers noted what they

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[13] *See, e.g.*, NYISO, NYISO Tariffs, OATT, § 34, Attachment BB, New York State Gas-Electric Coordination Protocol (*available at* http://www.nyiso.com/public/webdocs/documents/ tariffs/oatt/oatt_attachments/att_bb.pdf). The protocol applies where a gas system event would likely lead to a loss of firm electric load on either bulk or local power system; applies in emergency situations only and not to situations where a generator is derated for economic reasons.

[14] The Central Region technical conference was held August 6, 2012 in St. Louis, Missouri, and included natural gas and electric entities from an area defined by the corporate boundaries of MISO, Southwest Power Pool, Inc. (SPP), and Electric Reliability Council of Texas (ERCOT). It included the states of Arkansas, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin.

described as the high quality and flexibility of their pipeline transportation services. One pipeline representative expressed a willingness to continue to create flexible services for customers, including offering short-term capacity and volumetric rates.

Participants generally reported that there is little direct communication between the pipelines and electric system operators in this region. Many participants asserted that responsibility for information-sharing lies with the generator, and that generators should be responsible for communicating and sharing outage, capacity, and expected gas burn information with both the pipelines and the RTOs/ISOs. Several participants suggested that information sharing could be improved by having RTOs/ISOs provide the gas pipelines with hourly generator commitments, so that pipelines would know in advance which gas-fired generators are likely to run. Many expressed concern, however, about the market sensitivity and the potential for violations of the Commission's regulations prohibiting undue discrimination or preference associated with sharing such information. They suggested that adequate protections would need to be in place to ensure such information was confined only to operating personnel and not shared with marketing departments.

Another example identified at this conference was gas-electric communications during emergencies and peak demand situations. While generators often provide the pipelines with a day-ahead hourly burn profiles as required by NAESB gas-electric business standards,[15] pipelines suggested more real-time information would also be useful, especially during electric contingencies that could affect gas facilities such as electric compression, production or storage. Again, concerns were raised about violating the Commission's regulations against anti-competitive conduct.

Addressing reliability concerns, it was suggested that entities responsible for resource adequacy should evaluate fuel availability in their loss of load probability (LOLP) studies for both winter and summer planning. MISO's representative suggested that this could be accomplished by including unavailability due to lack of fuel in the generators' forced outage rate. However, there was concern expressed that the forced outage rates are historical and do not reflect the expected unavailability due to increases in capacity factors of gas-fired generation.

Central Regional Initiatives

[15] *See* Order No. 698. Order No. 698 mandates that communication protocols be established between interstate pipelines, power plant operators, and transmission owners/operators, and among other things requires power plant operators to provide their projected hourly natural gas flow rates to directly-connected pipelines upon request.

A representative of MISO noted that it is continuing to refine and update an October 2011 study,[16] which looked at whether current generation capacity is sufficient given planned coal plant retirements and planned retrofit outages expected in the 2013-2015 period. MISO's representative committed to working with the pipelines that serve the generators in its control area and obtaining a more definitive planned outage/maintenance schedule from coal-fired generation as they move into the 2013-2015 time period. In addition, he noted that MISO recently formed a task force to work on general gas-electric coordination issues.[17]

A representative of ERCOT suggested it could act as a host for tabletop exercises for RTOs/ISOs and pipelines to review emergency procedures and discuss communication issues and risks on the bulk power and natural gas systems.

D. West Region[18]

Participants at the West technical conference discussed many subregional differences within the region, including resource mix, market structure, and degree of dependence upon natural gas for electric generation. There was general agreement that the West as a whole will have a greater reliance on natural gas for electric generation in the future. Some participants expect the burn profile for natural gas used for electric generation to become more volatile, due both to the normal variation in electric demand and the increased use of gas for balancing, resulting from the increase in renewable generation in the region.

Representatives from both natural gas and electric entities in the West stated that most of the natural gas-fired electric generation in the West region (outside of the

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[16] *See* MISO, *EPA Impact Analysis: Impacts from the EPA Regulations on MISO* (Oct. 2011), *available at* https://www.midwestiso.org/Library/Repository/Study/MISO%20EPA%20Impact%20Analysis.pdf.

[17] MISO's Natural Gas Coordination Task Force was recently formed to address these issues. *See* MISO, Steering Committee Meeting Minutes (Sept. 20, 2012), *available at* https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/Steering%20Committee/2012/20121018/20121018%20SC%20Item%2001b%20Minutes%2020120920.pdf.

[18] The West Region technical conference was held August 28, 2012 in Portland, Oregon, and included natural gas and electric entities from an area defined by the Western Interconnection, and included the States of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

California Independent System Operator Corp. (CAISO)) is backed by firm gas transportation contracts. Natural gas-fired electric generators served by the LDCs within CAISO mainly use interruptible gas transportation contracts on the LDCs' distribution systems, but this service reportedly performs like firm because gas pipeline infrastructure within CAISO is expanded in anticipation of load, as opposed to responding to long-term firm contracts.

Some conference participants stated that gas-electric coordination issues could be alleviated by having more efficient electric markets in the West region. An energy imbalance market was explicitly mentioned as one way of achieving additional efficiencies. A representative of CAISO indicated that it has no mechanism to look at firmness of fuel, and believes that it should not have a mechanism for this purpose. He noted that CAISO's market has a penalty for non-performance.

Several conference participants requested more opportunities for intra-day nomination adjustments on pipelines, but a few pipelines clarified that these additional nomination opportunities would have value only if they resulted in actual physical changes; actual changes in pipeline flow can only occur if gas can be purchased and injected into the pipeline to accommodate the revised nomination and then delivered. The appropriateness of the "no-bump" rule was challenged on multiple occasions. A few participants from the Southwest opined that both the gas and electric scheduling days should go until midnight local time.

Regarding communications, CAISO's representative discussed recent Commission-approved revisions to its tariff to permit sharing generation and transmission outage information with utilities that operate pipelines and/or deliver gas to gas-fired generators, pursuant to non-disclosure agreements. Additionally, a few participants both inside and outside California currently send estimated burn profiles for electric generation to the pipelines on a day-ahead basis.

Representatives of several pipelines in the region discussed their efforts to improve communications with generators and electric balancing authorities, including updating points of contact and communication methods, conducting regional table top exercises, and reviewing emergency procedures. For example, one pipeline hosted a mock gas supply emergency exercise following the February 2011 cold weather event, and another plans to host a similar mock emergency drill in 2013. Pipeline representatives added that both gas and electric operators could benefit from education about the other's system, in particular how to interpret and determine the important information from the notices and information that is provided, especially given the sheer volume of postings from both sides. The pipeline representatives also described efforts between the RTOs/ISOs and the Interstate Natural Gas Association of America (INGAA), as well as operator training programs that can provide that education. For example, in the wake of the February 2011 Southwest cold weather event, a number of entities participated in the electric and natural gas interdependency conferences at the Western Electricity Institute, which focused upon educating the electric and gas companies about how the other functions.[19]

Several participants stated that FERC's Standards of Conduct are a barrier to communications. For example, the representative of a utility in the Northwest described a tabletop exercise in that region during which it was discovered that some organizations have employees with considerable operational experience within marketing groups. This gave rise to the concern that the Standards of Conduct would prohibit these employees from being involved with efforts to resolve operational problems or emergency situations.

Some participants stated that the Northwest needs to improve gas-electric coordination and communication during normal operating conditions, but noted that there are agreements in place to help during emergency situations. One example mentioned as a model for such coordination is the Northwest Mutual Assistance Agreement (NMAA), which aids coordination between utilities during gas-related emergency situations by maintaining updated emergency contact information, and conducting semi-annual planning meetings and periodic emergency exercises for utilities.[20] Some participants at the technical conference believe that this type of agreement should be extended to the rest of the West region. It was mentioned that the Western Energy Institute maintains the Western Region Mutual Assistance Agreement, but this agreement only covers crew assistance during emergencies.[21]

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[19] FERC Office of Electric Reliability Staff recently conducted technical conferences in Texas and New Mexico (Docket No. AD11-9-000) to discuss actions taken in response to the August 16, 2011 *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*. *See* FERC and NERC, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011* (Aug. 2011), available at http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

[20] Signatories to the NMAA agreement are defined as entities that utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest. The membership includes pipelines, LDCs, combined utilities, and electric-only utilities. An emergency is defined as "an unplanned event [that] causes, or is likely to cause, a supply shortfall to firm customers or markets beyond the abilities of a Member to manage." *See* Western Energy Institute, *Northwest Mutual Assistance Agreement,* http://www.westgov.org/wieb/meetings/crepcfall2012/briefing/NWmaa.pdf

[21] http://www.westernenergy.org/WRMAA/wrmaa.htm.

The importance of gas storage, especially during emergency situations, was expressed by multiple participants. Representatives of several utilities in Arizona noted that that state has been attempting to get market area storage, without success, for many years. CAISO's representative stated that long-term electric contracts may be needed to finance and construct market area gas storage facilities.

Representatives of several Southwest utilities suggested a regional gas sharing pool or pooling mechanism for pipeline capacity, in which members of the pool could give up pipeline capacity to help a generator that requires more gas. One pipeline representative at this conference commented that this already occurs in the market through capacity releases.

Several participants from the electric industry confirmed that pipeline contingencies are not currently included in planning studies. One participant argued that the probability of an event on the gas side is so low that it is negligible, but others still want it quantified because it may be within the risk parameters that are planned for on the electric side.

West Regional Initiatives

Participants representing entities in the Northwest described regional efforts by the Pacific Northwest Utilities Conference Committee (PNUCC), the Northwest Power and Conservation Council (NPCC), and the Northwest Gas Association (NWGA) to look at long-term resource adequacy needs through analyses of utility integrated resource plans.[22]

Representatives of two utilities in the Northwest discussed regional emergency coordination efforts, including the Northwest Mutual Assistance Agreement described above, that provides procedures to address anticipated cold weather events and critical situations leading to loss of pressure on a pipeline or storage facility. These utility representatives believe that such efforts have led to improved coordination and cooperation among regional entities, but that communications with the Bonneville Power Administration (BPA) could be improved because they are not a customer of any pipeline. A representative of BPA noted that the mutual assistance agreement works well

[22] *See* PNUCC, *Northwest Regional Forecast of Power Loads and Resources, 2013–2022*, (Mar. 2012), *available at* http://www.pnucc.org/ sites/default/files/file-uploads/2012%20Northwest%20Regional%20Forecast.pdf. This report indicates that while natural gas currently is used primarily for peak demand needs, utilities in the region expect most of the generation added in the next 10 years to be natural gas-fired, followed by wind.

in dealing with emergencies but does not address non-emergency situations. BPA's representative added that the Western Electric Coordinating Council also maintains a "merchant alert protocol" that facilitates communications and coordination between merchant generators and reliability entities prior to an emergency situation occurring.[23]

A representative of CAISO stated that California entities talk frequently and meet at least quarterly to examine outages and coordinate generation and transmission. According to CAISO's representative the result has been that even major pipeline outages have not led to electric outages, and the electric and gas systems within California have been robust enough to weather an extended outage at Southern California Edison Company's San Onofre nuclear plant.

The Northwest transmission planning group, ColumbiaGrid,[24] announced on August 28, 2012, that it has formed a study team to analyze potential impacts of a gas supply limitation in the Interstate 5 corridor area of Oregon and Washington.[25] ColumbiaGrid stated that the study is an exploration of possible consequences if something happened to the natural gas supply system in a way that limited supply to the electric generating stations. Columbia Grid will coordinate the study with PNUCC and NWGA.[26]

In October 2012, members of the Committee on Regional Electric Power Cooperation and State-Provincial Steering Committee formed a task force to identify and study issues at the interface of the gas and electric industries. The Task Force is currently

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[23] *See*, *Merchant Alert Protocol (MAP) Guideline*, WECC (April 20, 2011), *available at* http://www.wecc.biz/committees/StandingCommittees/MIC/Shared%20Documents/Guideline%20-%20Merchant%20Alert%20Protocol.pdf.

[24] ColumbiaGrid is a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. The corporation itself does not own transmission, but its members and the parties to its agreements own and operate an extensive network of transmission facilities. ColumbiaGrid has substantive responsibilities for transmission planning, reliability, Open-Access Same-Time Information System (OASIS), and other development services.

[25] The area is home to about 4,400 MW of natural gas-fired generation that serves the Portland and Seattle areas.

[26] *See* ColumbiaGrid, http://www.columbiagrid.org/GasElectric-overview.cfm.

engaged in outreach to determine the scope of its work and potential for collaboration with others, with the goal of providing direction to states and provinces as they consider the interface issues most important to the West.

E. Southeast Region[27]

While some participants in the Southeast Region had specific concerns about certain current gas scheduling rules, they generally did not believe that the reliability of natural gas service for electric generation was an issue in their region. Conference participants explained that in this region, most of the entities use integrated resource planning, examining both transmission and generation jointly with expected load growth to determine areas where either transmission or generation capacity is required. These studies also include fuel supply interactions for generation. Generators in this region typically have firm pipeline transportation service, and utilize a combination of released firm or IT service to meet peak needs. For example, a utility representative noted that it requires all new gas-fired generation capacity additions to have firm gas transportation and storage. A Florida utility representative noted that Florida entities use similar processes, although it was noted that a third natural gas pipeline into Florida would enhance reliability.

Many of the Southeast technical conference participants agreed that weather driven electric load variations will increasingly be supplied by gas generation. They also agreed that the need to rely upon gas-fired generation to meet daily and hourly variations is not consistent with interstate pipelines' standard firm transportation service, including the timely nomination cycle and the no-bump rule. Some representatives of generation owners with firm pipeline capacity stated that they would like the ability to use the firm service as flexibly as possible. For example, one electric utility representative stated that it often is not able to use its firm capacity to make nomination changes because of the no-bump rule and other service priority rules. Other participants stated that they have not experienced the same limitations, in part due to completing their electric day analysis before gas prior day timely nominations must be submitted.

In contrast, representatives of some gas shippers, such as industrial users, argued in favor of retaining the no-bump rule. They stated loss of the no-bump rule could cause

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[27] The Southeast region technical conference was held August 23, 2012 and included natural gas and electric entities from an area defined by the corporate boundaries of Southern Company, Tennessee Valley Authority, and other areas south of PJM and east of SPP and ERCOT. It included the States of Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, and Tennessee.

fewer shippers to use IT, resulting in lower overall utilization of pipeline capacity and a greater share of fixed costs allocated to firm shippers.

A utility representative also asserted that the present analysis used to determine nominations in gas system operations (forward haul and back haul pipeline capacity, storage, and LDCs' local capabilities) "leaves too much on the table" by not allowing utilization of dynamic gas system capabilities. The representative further stated that gas-fired electric generators need to supply the net electric demand over a short time frame without impacting operational flexibility on the gas system.

Several generator representatives stated that they rely upon marketers and asset managers, who hold a mix of firm and interruptible transportation and storage services to manage their load swings throughout the day. They believe that additional flexibility could be achieved through FERC changes to the capacity release rules, which in turn could result in more efficient pipeline capacity utilization.

Participants stated that communications between the major electric entities and pipelines in the region are robust. For example, during a cold weather event in January 2010, an electric utility shifted away from gas generation to allow pipeline packing for use on the coldest day. This allowed the utility to stay within its long term contractual withdrawal limits while allowing sufficient withdrawals to occur on the critical electrical demand day. Participants stated that gas and electric entities share locations of electric driven natural gas compressor stations, which account for usually less than 20% of the flow capacity on the pipelines. However, one participant identified that there are critical locations that are supplied by electric-only compressor stations.

Participants stated that maintenance outages on the electric and gas systems are informally coordinated between major entities, resulting in selected changes in the timing of maintenance on both systems. They state that this is accomplished through a number of informal meetings per year. Participants also agreed that the communications that take place between the pipelines and their customers, including power generators, have been adequate to address reliability concerns both day-to-day and during emergencies. No concerns were expressed regarding the Standards of Conduct.

One utility representative stated that his utility plans its system to include gas system limitations and selected contingencies. This includes the complete outage of a single pipeline (and all generation attached). This utility has sufficient generation supplied by other fuels and the transmission to deliver that generation to be able to supply firm load for at least one to two days.

Southeast Regional Initiatives

According to participants, the Florida Reliability Coordinating Council (FRCC) created a flow model of the pipelines in Florida. FRCC also created a Fuel Reliability Working Group (FRWG) that reports to the FRCC Operating Reliability Subcommittee on matters relating to fuel and impacts to Bulk Electric System reliability. Specifically, the FRWG provides the administrative oversight of a regional fuel reliability forum that studies the interdependencies of fuel availability and electric reliability and supports coordinated regional responses to fuel issues and emergencies.[28]

At least one pipeline in the region offers an enhanced nomination service, and others are contemplating a similar service.

IV. Topics Common to Multiple Regions

The conferences summarized above were planned as a series of regional discussions given that the particular circumstances and needs of each region are distinct. Notwithstanding the regional focus of the discussions, a recurring theme across all of the conferences was that more attention needs to be paid to gas-electric interdependence issues. Participants in multiple conferences also stressed that some matters may be more appropriate for generic consideration while others are more appropriate for individual regions to address. In addition, several topics were of particular interest to participants across the conferences. The discussion below focuses on these topics:

- communications, coordination, and information sharing, including the Standards of Conduct and prohibitions on undue preference and discrimination;
- scheduling-related issues, including the no-bump rule and pipeline capacity release policies;
- electric resource adequacy, including RTO and ISO wholesale electric capacity markets; and
- reliability issues.

Industry representatives participating in the technical conferences described ongoing efforts to address each of these topics, noting that some issues implicate rules of general applicability while others are tied more closely to market structures or the resource mix of a particular region. For example, conference participants generally stated that communications and coordination improvements could be made on a regional basis, but that generic guidance regarding Commission rules and policies would facilitate progress. Similarly, while electric scheduling practices within a particular region can be

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[28] *See* FRCC, Scope of FRCC Fuel Reliability Working Group (Feb. 1, 2008), https://www.frcc.com/FRWG/ Shared%20Documents/ FRCC%20FRWG%20Scope%2002-01-08.pdf.

refined to better align with gas scheduling opportunities, changes to gas scheduling rules would require national coordination given the way pipeline systems are operated. In comparison, resource adequacy and reliability issues are often tied to the structure and performance of the electric system in a particular region.

Staff discusses on-going efforts in each of these cross-cutting areas below. Where relevant, staff provides guidance regarding applicable Commission rules and policies and highlights regional activities that will be monitored for progress.

A. Communications, Coordination, and Information-Sharing

Gas and electric industry representatives participating in the technical conferences described a variety of actions that are being taken to improve communications and information sharing between their industries. However, participants at multiple conferences expressed concern that Commission rules and policies could be impeding further efforts to improve communication between the industries. Industry representatives asked that the Commission provide guidance regarding application of the Standards of Conduct and prohibitions on undue discrimination and preference in the context of gas-electric coordination. After reviewing actions already being taken across the regions, relevant Commission regulations and precedent are discussed and opportunities for further progress are highlighted below.

Groups have been formed in multiple regions to enhance communication and coordination across the gas and electric industries. For example, in the Northeast, ISO-NE, representatives of its stakeholders, the Northeast Gas Association, and pipelines serving the region have formed a working group/steering committee to foster improved communications within the region.[29] NYISO formed an Electric Gas Coordination Working Group earlier this year,[30] and in August the MISO announced a taskforce to

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[29] In the wake of the 2004 cold snap in New England, ISO-NE and the Northeast Gas Association formed the Electric/Gas Operations Committee (EGOC), consisting of representatives from the regional pipelines and gas LDCs as well as ISO-NE, NYISO and PJM. The EGOC is responsible for cross-training of electric and gas system operators, establishing emergency communications protocols and procedures, assessing coordination of electric and gas system maintenance requirements, and other common issues. *See* ISO New England, Electric/Gas Operations Committee, http://www.iso-ne.com/committees/comm_wkgrps/othr/egoc/index.html.

[30] *See* NYISO, Electric Gas Coordination Working Group, http://www.nyiso.com/public/committees/documents.jsp?com=bic_egcwg&directory=2012-03-05.

work on general gas-electric coordination issues.[31] In the West, the Northwest Mutual Assistance Agreement aids coordination between utilities during gas-related emergency situations by maintaining updated emergency contact information and conducting semiannual planning meetings.[32]

Several regions have conducted emergency exercises to test inter-industry coordination and communication. In New York, pipelines, LDCs and generators conducted a "tabletop" reliability exercise under different loss of supply scenarios. Signatories to the Northwest Mutual Assistance Agreement periodically undertake emergency exercises that prepare participants to take timely and effective action when an emergency does occur. One pipeline in the Southwest hosted a mock gas supply emergency exercise in the fall of 2011, and another plans to host a similar mock emergency drill in 2013.

Responding to issues arising from outage coordination, CAISO amended its tariff to enhance communications on gas-related maintenance activities within California.[33] The CAISO tariff now specifically authorizes the CAISO to share outage information with natural gas pipelines, with or without notice to the affected market participant. This includes, but is not limited to, the identity of individual natural gas-fired generation resources that are needed to support reliability of the CAISO balancing authority area in the event of a natural gas shortage, natural gas pipeline testing and maintenance, or other curtailment of natural gas supplies. ISO-NE has announced that it is considering revising its policies to allow sharing of real-time operational information with gas pipeline operators.[34]

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[31] MISO's Natural Gas Coordination Task Force was recently formed to address these issues. *See* MISO, Steering Committee Meeting Minutes (Sept. 20, 2012), *available at* https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/Steering%20Committee/2012/20121018/20121018%20SC%20Item%2001b%20Minutes%20120920.pdf.

[32] *See* Western Energy Institute, *Northwest Mutual Assistance Agreement*, *available at* http://www.westgov.org/wieb/meetings/crepcfall2012/briefing/NWmaa.pdf.

[33] *See Cal. Indep. Sys. Operator Corp.*, Docket No. ER12-278-000 (Dec. 8, 2011) (delegated letter order).

[34] *See* John Norden, *Information Policy Changes to Facilitate Electric and Gas Coordination*, ISO New England (Oct. 11, 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/oct10112012/a13_iso_presentation_10_11_12.ppt.

At multiple conferences, however, gas and electric industry representatives questioned whether the FERC Standards of Conduct are impeding further efforts to improve communication between the industries. For example, one entity at the West technical conference raised the concern that information-sharing in an emergency situation could be a problem for companies where employees with operational knowledge are also wholesale merchant function employees. Many entities requested that the Commission provide clarity about what types of information can be shared and when.

Some pipelines and RTOs/ISOs also noted at the technical conferences that, although they make significant amounts of operational information publicly available, there is reluctance to share information on a more granular level because of concerns about violating statutory prohibitions against undue preference for any customer or customer class.[35] So, for example, in response to one RTO/ISO's comment that it was not able to interpret a pipeline's posted outage information in terms of which specific generators would be affected, several pipelines expressed discomfort with going beyond what was publicly posted.[36] Pipelines also noted that, in situations where information regarding pipeline capacity limitations has been posted, they typically will be queried on how much interruptible or secondary transportation is available, but they are not required to provide more specific information beyond their public postings.[37]

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[35] Both the Federal Power Act (FPA) and the Natural Gas Act (NGA) prohibit undue discrimination or preference. See 16 U.S.C. § 824d(b); 15 U.S.C. § 717c (b). Section 205(b) of the FPA provides that no public utility

> shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

Nearly identical language is contained in section 4(b) of the NGA, 15 U.S.C. § 717c(b).

[36] *See* 18. C.F.R. § 284.13 (2012) (Reporting requirements for interstate pipelines).

[37] Pipelines are required to post estimates of their operationally available capacity based on prior schedules. They are not required to separately report how much interruptible or secondary firm transportation is available. *See* 18 C.F.R. § 284.13 and NAESB Version 2.0 WGQ Standard No. O.4.2.

At several conferences, pipelines indicated a desire to receive timely information from RTOs/ISOs about the dispatch of the gas-fired generation fleet and the expected impacts after generation forced outages. Some RTOs/ISOs expressed interest in knowing whether the gas-fired units scheduled in the day-ahead market have the necessary gas supply and transportation arrangements in place. While several generators and RTOs/ISOs expressed concern about the market sensitivity of sharing such information, at least one generation operator stated that generation plant operating profiles are regularly communicated to the pipelines to which they are attached, which facilitates those pipelines' ability to accommodate the generators' needs for flexible services. Several entities noted that the Commission's issuance of Order No. 698,[38] which requires generators to provide pipelines with hourly gas burn estimates upon request, has improved gas-electric communications for normal operations.

Subsequent to the August conferences, staff conducted additional outreach to solicit more specific feedback from pipelines, RTOs/ISOs and generators about concerns with information sharing. Pipelines and RTOs/ISOs would like to exchange information that allows each to operate their systems more efficiently and reliably. Generally, this would include information about pipeline capacity scheduled (for generation) and available, individual generator's expected burn rates, quick notice of significant changes in capacity or operations, and coordination of maintenance planning and scheduling.

One RTO suggested some form of a "one call" system so that it could quickly and efficiently inform all relevant gas industry participants supplying a particular generator (or a specific group of generators) of an unexpected change in electric system operations.[39] Some natural gas-fired electric generators would like assistance in perfecting nominations for gas flow, especially later in the day after earlier nominations were rejected due to insufficient available pipeline capacity. Some generators are

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[38] *Standards for Business Practices for Interstate Natural Gas Pipelines; Standards for Business Practices for Public Utilities*, Order No. 698, FERC Stats. & Regs. ¶ 31,251 (2007), *order on clarification and reh'g,* Order No. 698-A, 121 FERC ¶ 61,264 (2007) (collectively, Order No. 698). Order No. 698 mandates that communication protocols be established between interstate pipelines, power plant operators, and transmission owners/operators, and among other things requires power plant operators to provide their projected hourly natural gas flow rates to directly-connected pipelines upon request.

[39] Regional cooperation and appropriate contractual measures would appear to be required to accomplish any form of "one call" system such as this. Staff does not address this suggestion further in this report.

concerned that information exchanged between a pipeline and an RTO/ISO may lead to unilateral action by either the pipeline or the RTO/ISO which could cause competitive harm to the generator, or may act as a conduit for third parties to gain access to information about a specific generator causing competitive harm to the generator in the marketplace.

In response to concerns expressed by industry representatives at the technical conferences and in subsequent outreach, staff takes this opportunity to provide its views regarding application of the Commission's Standards of Conduct and statutory restrictions on undue preference or discrimination.[40] The discussion of these issues at the conference was general in nature and, therefore, so is staff's response. To the extent a natural gas pipeline or electric transmission operator has questions regarding the application of Commission rules or regulations in specific circumstances, it should seek appropriate guidance from the Commission or staff.[41]

Standards of Conduct

The Standards of Conduct govern communications between interstate natural gas pipelines and their affiliates that engage in marketing functions, and public utilities that own or operate electric transmission facilities and their affiliates that engage in marketing functions.[42] In other words, the Standards of Conduct apply to communications only within the same organization (*i.e.*, between the affiliated entities of a single corporate family). The Standards of Conduct do not apply to communications between two different natural gas and electric transmission organizations. By their terms, then, the Standards of Conduct do not limit communications between natural gas pipelines and electric transmission operators. Moreover, under section 358.1(c) of the Commission's regulations, the Standards of Conduct do not apply to Commission-approved RTOs or ISOs.[43]

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[40] Under section 358.7(a) of the Commission's regulations, a transmission provider must provide equal access to non-public transmission information disclosed to its affiliated merchant function, to all its transmission customers. 18 C.F.R. § 358.7 (2012). *See also*, n.35 *supra*.

[41] *Obtaining Guidance on Regulatory Requirements*, 123 FERC ¶ 61,157 (2008).

[42] 18 C.F.R. § 358.1(a) and (b) (2012).

[43] 18 C.F.R. § 358.1(c) (2012).

In those situations where the Standards of Conduct govern the disclosure of non-public transmission information between the transmission function and marketing function of an organization, the Commission's regulations already permit communications during "emergency circumstances," such as hurricanes or earthquakes, when information is needed to comply with reliability standards or to maintain/restore system operations.[44] Two sections of the Standards of Conduct specifically authorize communications that may be necessary to address emergency conditions: (1) section 358.7(g)(2) authorizes transmission providers to suspend posting requirements in an emergency; and (2) section 358.7(h)(2) permits communication among employees needed to comply with reliability standards, restore system operations and provide for generation dispatch.[45] These sections provide relief from the Standards of Conduct rules, including the Independent Functioning Rule, the No-Conduit Rule, and the Transparency Rule.[46]

Given that the Standards of Conduct do not govern communications or coordination between a natural gas pipeline and an electric transmission operator, and that exceptions to the Standards of Conduct already are provided to allow communications between the merchant function and transmission function of the same organization during emergencies, staff believes that further discussion with industry is necessary to address the continuing perception that the Standards of Conduct can act as a barrier to effective coordination of the gas and electric industries. In addition, Staff encourages industry representatives to contact staff with specific questions regarding application of the Standards of Conduct in the context of gas-electric coordination.

Undue Discrimination or Preference

Separate questions have been raised by industry representatives regarding whether sharing of certain types of information between natural gas pipelines or electric utilities could be viewed as unduly discriminatory or preferential, triggering questions regarding compliance with NGA section 4 and FPA section 205.[47] Staff notes that a number of

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[44] 18 C.F.R. § 358.7(g)(2), (h)(2) (2012).

[45] 18 C.F.R. § 358.7(g)(2), 358.7(h)(2) (2012). *See Standards of Conduct for Transmission Providers*, Order No. 717, FERC Stats. & Regs. ¶ 31,280 (2008), *order on reh'g*, Order No. 717-A, FERC Stats. & Regs. ¶ 31,297, *order on reh'g*, Order No. 717-B, 129 FERC ¶ 61,123 (2009), *order on reh'g*, Order No. 717-C, 131 FERC ¶ 61,045 (2010), *order on reh'g*, Order No. 717-D, 135 FERC ¶ 61,017 (2011) (collectively, Order No. 717).

[46] 18 C.F.R. §§ 358.5, 358.6, 358.7 (2012).

[47] *See* n.35 *supra*.

communication protocols already have been adopted to facilitate the exchange of information between the industries and additional enhancements are being considered by many regions. For example, typical day-to-day practices within each industry provide for the sharing of transmission information among natural gas pipelines, and among electric transmission operators. Pipelines routinely exchange information with other pipelines and other upstream and downstream entities needed to confirm transportation nomination requests, and to coordinate flows between each other. Transmitting electric utilities routinely share eTag information, scheduled interchanges, and related operational data to ensure the safe and reliable transmission of electric power across a region.

As between industries, natural gas pipelines and electric generators have established protocols for sharing a significant amount of information pursuant to Order No. 698. Under the North American Energy Standards Board (NAESB) Wholesale Gas Quadrant (WGQ) Version 2.0 Business Practice Standard 0.3.12, a generator and its directly connected natural gas pipeline(s) "should establish procedures to communicate material changes in circumstances that may impact hourly flow rates." These communications can help natural gas pipelines anticipate problems, devise solutions and take timely action to avoid operational problems.[48] NAESB WGQ Version 2.0 Business Practice Standard 0.3.14 further provides that a pipeline "should provide Balancing Authorities and Reliability Coordinators" and generators with notification of operational flow orders and other critical notices. NAESB Wholesale Electric Quadrant (WEQ) Version 002.1 Business Practice Standard 11.1.4 states that RTOs and ISOs "should sign up to receive" these pipeline notices. These communications can help electric transmission operators better manage their systems by reallocating resources in response to changing conditions on natural gas pipelines.

As noted above, CAISO has begun sharing with natural gas pipelines information regarding outages of generation or transmission facilities within its footprint. Specifically, CAISO is authorized to provide outage information to natural gas pipelines for their use in managing, coordinating, planning, forecasting, and/or scheduling outages, maintenance, repairs, and/or curtailment of their gas transmission pipeline or storage systems.[49] This allows CAISO and natural gas pipelines to coordinate outages and

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[48] Anecdotal evidence from the technical conferences and staff outreach suggests that this practice may not be in widespread use among pipelines nationwide, notwithstanding the opportunity provided by the NAESB standards.

[49] Cal. Indep. Sys. Operator Corp., *Business Practice Manual for Outage Management*, at section 4.2.1.2 (Apr. 30, 2012) (setting forth the terms of a non-disclosure and use of information agreement), *available at* https://bpm.caiso.com/bpm/bpm/doc/000000000001211.

maintenance of generation and transmission resources necessary to ensure the safe and reliable operation of the natural gas system.[50] In recognition that the information exchanged can be sensitive, CAISO requires natural gas pipelines to execute non-disclosure agreements that define the purposes for which information may be used and affirms the pipeline's commitments to follow the Commission's Standards of Conduct with regard to further communication of the information.

Industry participants at multiple technical conferences expressed a desire for inter-industry communication of the sort currently engaged in by CAISO and natural gas pipelines. The CAISO tariff provisions and non-disclosure agreement serve as an example to other electric transmission operators seeking to implement communication protocols with natural gas pipelines. Other types of information may be useful for natural gas pipelines to share with electric transmission operators. For example, information regarding generators' scheduled natural gas flow, alternatives where available pipeline capacity would allow deliveries to flow to natural gas-fired generators not yet scheduled, and future available capacity alternatives may assist electric transmission operators respond to changing system conditions more efficiently and maintain reliability of the electric transmission grid. A natural gas pipeline wishing to exchange non-public capacity-related information with electric transmission system operators without subjecting itself to possible future complaints of undue discrimination or preference might also look to the CAISO outage management model, with its non-disclosure agreement and reliance on the Commission's Standards of Conduct to ensure that any information shared is appropriately used and protected.

As with concerns related to the Commission's Standards of Conduct, staff appreciates that representatives from both the natural gas and electric industries seek additional comfort that enhanced communication and coordination practices will not violate statutory prohibitions on undue discrimination or preference. Staff believes that further discussion with industry is necessary to identify and address concerns in this area. Conference participants described a number of initiatives to improve inter-industry communication and coordination, including:

- Development of communication protocols governing gas and electric maintenance-related outage coordination, suggested by MISO and pipeline and LDC members of the Northeast Gas Association;
- ISO-NE's consideration of revised policies to allow sharing of real-time operational information with gas pipeline operators;

[50] *See* Cal. Indep. Sys. Operator Corp., Docket No. ER12-278-000, Oct. 31, 2011 Filing at 2.

- The possibility of brief exchanges of pipeline and electric transmission provider control room operators, for cross-training purposes, as noted by PJM and a Mid-Atlantic pipeline;
- The development of a "one call" system to allow an RTO/ISO to inform relevant gas industry participants of unexpected changes in electric system operations;
- Enhancement of inter-industry communication and coordination during normal operating conditions under the Northwest Mutual Assistance Agreement; and,
- The use of tabletop exercises in multiple regions to examine different scenarios based on loss of supply.

Staff will monitor progress being made on these and other initiatives, and provide guidance where possible to ensure that concerns regarding Commission rules and policies do not hinder industry progress.

B. Scheduling-Related Issues

Several conference participants raised issues related to gas and electric scheduling and pipeline capacity release.[51] Generators participating in the RTO/ISO markets stated that managing fuel procurement risk can be a challenge because the operating days between the natural gas and electric industries are not aligned, and the timeframe for nominating natural gas transportation service, including pursuant to a capacity release, is not synchronized with the timeframe during which generators receive confirmation of their bids in the day-ahead electric markets. While electric scheduling practices and market rules within some regions are being refined to better align with gas scheduling opportunities, changes to gas scheduling practices can have national implications given the way pipeline systems are operated. As a result, whether gas scheduling practices need to be changed and, if so, what changes are warranted has been a matter of debate among the industries for a number of years.

Scheduling Practices

Standard pipeline services are generally designed as daily services, and the gas day covers a 24-hour period beginning at 9:00 a.m. Central clock time (CCT). For most rate schedules, tariffs provide that the pipeline may insist that gas be taken on a uniform hourly rate of flow although the pipeline tariffs generally provide that the pipeline permits fluctuations in flow on a best efforts basis. The NAESB gas standards, which the

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[51] The Commission rules governing capacity release on interstate pipelines are at 18 C.F.R. § 284.8 (2012).

Commission regulations incorporate by reference, currently provide shippers one day-ahead nomination opportunity, the Timely Nomination Cycle (11:30 a.m. CCT the day prior to gas flow), and three opportunities to revise that nomination, one in the day-ahead (the Evening Nomination Cycle (6 p.m. CCT the day before gas flow) and two within the gas day (the Intra-Day 1 (10 a.m. CCT the day of gas flow) and Intra-Day 2 (5 p.m. CCT the day of gas flow)). In the event a pipeline cannot fulfill all service requests, the pipeline allocates capacity according to its nomination priorities. As a general matter, (1) nominations of firm transportation service from "primary" points of receipt to "primary" points of delivery, which is termed "primary firm" service, have the highest priority; (2) nominations from alternative or additional "secondary" receipt or delivery points, which is termed "secondary firm service," is next in priority and (3) interruptible service is the lowest priority.

Schedules made during the Timely Nomination Cycle establish the allocation of pipeline capacity for the next gas day. In this cycle, the priorities listed above apply so primary firm nominations have priority over all other nominations. During the next three cycles, primary and secondary point nominations are treated equally, so a request to change quantities at a primary point will not bump already scheduled secondary firm service. A revised firm nomination during the Evening and Intra-Day cycles, however, can bump already scheduled interruptible service from prior cycles. During the final Intra-Day- 2 cycle, primary and secondary firm nominations cannot bump already scheduled interruptible service. Pipelines are permitted to offer additional nomination opportunities.

In contrast, electric generators are dispatched during the operating day hour-by-hour. A gas-fired generator may operate for many hours throughout the day or may operate only during peak hours. Increasingly, gas-fired generators are being dispatched as flexible resources, ramping up and down within the hour and across the day to help balance the electric system.

There is no defined electric day, but for most entities the standard 24-hour calendar day begins at 12:00 a.m. local time. Similar to the gas industry, electric generators in wholesale electric markets bid into the market prior to the given electric day, commonly known as the day-ahead market. For these generators, the time to obtain the best natural gas prices is typically before the Timely Nomination Cycle, because the gas markets would be most liquid at this time.[52] However, an electric generator's day-

[52] Natural gas is traded in bilateral markets. Daily transactions are mostly consummated in the morning hours before the first timely day-ahead pipeline nomination deadline. The ability to find willing buyers and sellers to act as counterparties of a commodity transaction is greatest during these normal trading periods; the gas market is "liquid" during this time of the day.

ahead electric bids generally are not confirmed by the RTO/ISO until after the Timely Nomination Cycle for pipeline service.[53]

Various generators participating in the RTO/ISO markets noted that these differing timelines result in significant price and/or supply risk for gas-fired generators because, to obtain the best gas price, the generators would need to nominate pipeline transportation service before they know if their electric bid has been confirmed. Generators also noted that, given the operating day mismatch, a pipeline nomination will cover parts of two electric days and therefore involve multiple iterations of the unit commitment process as day-ahead commitments turn into real time dispatch and the day-ahead commitments for the next electric day.[54] Concern also was expressed about whether the standard gas nomination schedule provides sufficient ability for generators to revise their nominations as needed by dispatch requirements, whether located within or outside RTO and ISO markets.

Representatives from the gas and electric industries participating in the conferences offered different perspectives on whether changes need to be made in either industry's scheduling framework. As several pipeline representatives pointed out, some pipelines offer to shippers more than the NAESB standard four daily nomination cycles. For example, in March of this year, the Commission approved a proposal by Texas Gas Transmission LLC (Texas Gas) to allow firm shippers contracting for Enhanced Nominations Service an additional eleven nomination cycles each gas day.[55] Some pipelines offer a firm no-notice service under which firm shippers can receive delivery of gas on demand up to their firm entitlements on a daily basis, without incurring daily scheduling and balancing penalties. The purpose of no-notice service is to enable firm shippers to meet unexpected requirements such as sudden changes in temperature. Some pipelines also offer firm shippers enhanced services that allow for greater flexibility in the rate at which their gas can flow. This service, as well as the no-notice service described above, is provided at a higher rate.

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[53] Electric scheduling timelines are set forth in the respective RTO/ISO tariffs and are not uniform across entities.

[54] Conversely, an electric generator may seek to procure gas during two successive daily cycles to accommodate the needs of a single electric day.

[55] *See Texas Gas Transmission LLC*, 137 FERC ¶ 61,093 (2011), *order on compliance filing*, 138 FERC ¶ 61,176 (2012) (collectively, *Texas Gas*) (offering enhanced nomination service with bumping of interruptible service permitted until 5 p.m.).

Also, representatives of the NYISO and ISO-NE present at the conferences stated that they have considered ways to change the schedule of the day-ahead unit commitment process to better coincide with the gas timely nomination cycle. For example, ISO-NE is considering moving up the timeline for day-ahead unit commitment and the resource adequacy assessment process in an effort to provide additional time to gas-fired generators to procure gas supplies and transportation services so that adequate generation capacity is available in real time.[56] However, it was pointed out by several participants at the conference that one disadvantage of moving the day-ahead unit commitment timeframes closer in time to the gas Timely Nomination Cycle and therefore, further from the real time, is that electric load forecasts become less accurate. Some conference participants also indicated that one reason it has been difficult to change the day-ahead unit commitment process is the absence of a standardized electric schedule across markets, similar to the standardized gas day.

A related scheduling issue raised by conference participants involved the service priorities for transportation services offered by interstate pipelines and the "no-bump" rule.[57] As noted above, primary and secondary nominations cannot bump already scheduled interruptible service during the final Intra-day 2 cycle, which is at 5 p.m. CCT.[58] Discussion at some of the technical conferences indicated that the general consensus supporting the no-bump rule may no longer exist. Some generators with firm pipeline service stated that they would like to see additional nomination opportunities and in some cases, elimination of the no-bump rule. They contended that the current gas nomination cycles do not provide sufficient flexibility to generators facing weather-driven electric load variations, and the no-bump rule impedes their ability to use their firm service flexibly. However, other firm gas shippers, such as industrial users in the Southeast, argued in favor of retaining the no-bump rule. They stated that elimination of

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[56] ISO-NE is proposing to move the day-ahead market back so that generators can buy gas and pipeline capacity while the market is still liquid and so that ISO-NE has more time to call on generators. *See Moving the Day Ahead Market & Reserve Adequacy Assessment Clearing Times*, ISO New England (Aug. 7-8, 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/aug782012/a07_iso_presentation_08_07_12.ppt.

[57] As noted above, at the Intra-Day 2 cycle, a firm nomination will not bump already scheduled interruptible service. This is referred to as the "no-bump" rule.

[58] *Standards for Business Practices of Interstate Natural Gas Pipelines*, Order No. 587-G, FERC Stats. & Regs. ¶ 31,062, at 30,670-72 (1998). This rule also applies to those pipelines that offer enhanced nomination services.

the no-bump rule could cause fewer shippers to use interruptible transportation, resulting in lower overall utilization of pipeline capacity and a greater share of fixed costs allocated to firm shippers.

As noted by many conference participants, prior efforts of NAESB participants did not reach consensus on the creation of a unified gas and electric timeline,[59] revisions to the gas nomination schedule to permit additional intra-day changes, or elimination of the no-bump rule. Several participants maintained that these changes were not a high priority and accordingly, should not be a priority for the Commission. To the extent changes are made, most conference participants agreed that these issues are interrelated and cannot be considered in isolation, and that any changes would need to be implemented in a way that makes sense for both industries from both regional and national perspectives.

Staff believes that further discussion is necessary to explore whether coordinated refinements to gas and electric scheduling rules are appropriate. Existing Commission policies and regulations provide a certain degree of flexibility in the near term for utilities to address coordinated scheduling issues on a regional basis and for pipelines to provide enhanced scheduling. As noted above, several RTOs/ISOs are considering or have refined their market practices and some pipelines have modified services and nomination cycles to meet the needs their customers. These efforts improve operations across both the gas and electric industries and should continue to be pursued. However, they do not address whether industry-wide changes would be appropriate to improve the longer-term harmonization of gas and electric operations. Taking a broader view of gas-electric scheduling issues could lead to greater operational efficiencies in both industries.

To that end, staff will continue to engage industry on gas and electric scheduling issues, including the effect of the Commission's no-bump rule. During this outreach, staff will monitor the progress being made on the following activities highlighted by conference participants:

- ISO-NE's consideration of moving the timeline for its day-ahead unit commitment and resource adequacy assessment process and allowance of bid adjustments and hourly re-offers;
- NYISO's consideration of moving releasing day-ahead dispatch results to early than 10 AM (EST), when gas markets are more liquid; and,
- The ability of natural gas pipelines to offer additional nomination opportunities after 5 PM or provide for electronic scheduling that could be completed faster than the current four hour processing time.

[59] *Standards for Business Practices for Interstate Natural Gas Pipelines*, Order No. 587-U, FERC Stats. & Regs. ¶ 31,307 at P 27 (2010).

Progress on these nearer-term activities may facilitate greater coordination between the gas and electric markets while longer-term initiatives are being evaluated.

Capacity Release

In many regions, natural gas LDCs contract for firm long-term pipeline service based on their winter peak demand. Consequently, those LDCs generally have excess natural gas transportation capacity in the summer when gas demand is lower. In contrast, gas-fired electric generation in most, but not all, regions experience demand peaks in the summer time when LDC use of pipeline capacity is relatively low.[60] As a result, gas-fired generators have generally been able to utilize released pipeline capacity from the LDCs to meet their gas delivery needs.[61]

As the relative amount of gas-fired generation increases, some contend that in the future these dynamics will no longer hold true. Gas-fired generation has increased to an extent that some pipelines are operating at increasing load factors, with diminishing availability of capacity to serve new gas-fired generation needs. For example, in New England, which experiences relatively high winter electric demand, gas-fired generators are increasingly competing with LDCs for pipeline capacity.

In response to these concerns, participants at every technical conference expressed a desire for more flexible capacity release on pipelines. Issues raised included a desire for more opportunities for intra-day releases and short-term or even hourly releases, enhanced ability to facilitate pre-arranged bilateral release deals, and more streamlined processing of capacity release transactions. In some cases, technical conference participants discussed “gas demand response,” but did not specify what that meant or how it could be implemented on the gas pipelines. In at least one case, a large generator with firm gas contracts suggested that more transparency regarding how pipelines analyze their systems to determine available pipeline capacity would be desirable.

The Commission’s current pipeline capacity release program is designed to permit expeditious and flexible releases.[62] A firm shipper (releasing shipper) sells its capacity

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[60] Gas-fired generators in other regions of the country, particularly the Southeast, do not rely on interruptible transportation or capacity release to ensure reliability, but contract directly for firm primary point transportation service with the pipelines.

[61] The Commission rules governing capacity release on interstate pipelines are at 18 C.F.R. § 284.8 (2012).

[62] 18 C.F.R. § 284.8 (2012).

by returning its capacity to the pipeline for reassignment to the buyer (replacement shipper).[63] Released capacity is offered for bid on the pipeline's website and awarded to the highest bidder. Firm shippers may also enter into a pre-arranged release directly with a replacement shipper. If the prearranged release is for a term of one month or less it need not be posted for bidding. The replacement shipper may pay less than the pipeline's maximum tariff rate, but not more for releases that are long term in nature. Short term releases, those for one year or less, are not subject to price limitations tied to a pipeline's maximum tariff rate.[64] Many pipelines also permit replacement shippers to prequalify for releases, which expedites the assignment of capacity.

With respect to the flexibility of releases, the regulations provide that releasing shippers can release capacity at any time and that "pipelines must permit shippers acquiring released capacity to submit a nomination at the earliest available nomination opportunity after the acquisition of capacity."[65] Under the regulations, the pipelines must process these releases in one hour. As a consequence of the Commission's posting and bidding rules, an LDC and a generator, for example, could negotiate a short term release at a market-determined rate at any nomination cycle permitted by the pipeline, including releases during the intra-day process.[66] In addition to capacity release, shippers can make bundled gas sales to third-parties.[67]

The Commission's capacity release regulations, including the NAESB WGQ standards, therefore provide shippers with considerable flexibility to acquire released capacity or obtain gas on a timely basis. However, the implementation of a capacity release remains subject to the scheduling opportunities available. As a result, it may be

[63] The pipeline contracts with, and receives payment from, the replacement shipper and then issues a credit to the releasing shipper.

[64] The results of all releases are posted by the pipeline on its Internet web site and made available through standardized, downloadable files. 18 C.F.R. § 284.13(b)(1) (2012).

[65] 18 C.F.R. § 284.12 (b)(1)(ii)(A) (2012).

[66] In the intra-day process, shippers are permitted to release the unused portion of their contract demand.

[67] For example, an LDC could sell its gas to an electric generator. Under the Commission regulations, a holder of pipeline capacity can redirect that capacity without a requirement for rescheduling that supply, so long as the original contract provides for service beyond any constraint point. NAESB WEQ Standard 1.3.80.

that the concerns expressed by conference participants are driven more by the desire for greater pipeline scheduling flexibilities, or by an unwillingness of firm transportation contract holders to release capacity, than the Commission's capacity release rules. Staff notes that no specific reforms in the area of capacity release were suggested by conference participants, nor was the relationship between capacity release and underlying pipeline scheduling opportunities generally discussed. Nonetheless, given the significant number of conference participants that raised capacity release rules as an issue to be address, staff believes is it necessary to continue to engage industry with respect to this issue.

C. Electric Resource Adequacy

The question of whether generators in a particular region have appropriate incentives to deliver firm energy was raised at several of the technical conferences. At every conference, natural gas pipeline representatives emphasized that they are in the business of delivering gas to meet customer needs, but that the customers themselves must arrange for gas supplies. There were differences of opinion, however, with regard to the perceived need for firm delivery arrangements from natural gas pipelines as between electric industry representatives at the conferences.

In the Southeast, characterized by electric service being provided by vertically-integrated electric utilities, firm natural gas pipeline arrangements appear to be the norm. As a result, in this region, there appears to be little concern about ensuring adequate pipeline infrastructure.[68] In regions with restructured electric markets and an RTO or ISO, natural gas-fired generators appear to rely more heavily on pipeline capacity release and interruptible services for delivery of gas supplies. Some contend that this practice appropriately reflects the variability with which gas-fired generators are dispatched in RTO/ISO regions, while others suggested the practice indicates a need to provide greater incentives to generators to arrange for fuel supplies in a way that ensures reliability. Conference participants suggesting enhancements to RTO/ISO market rules generally focused on the terms of organized wholesale electric capacity markets and performance incentives for resources clearing in those markets. Several participants at the Northeast conference stated there is a need for additional pipeline infrastructure but there was also recognition that options are limited for addressing the gas infrastructure issue in the near term and that, under current market structures, generators have few incentives to obtain long-term primary firm pipeline service or invest in alternative fuel capabilities.

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[68] The exception to this is Florida, which is highly dependent upon gas for electric generation. Some Southeast regional conference participants identified a need for a third natural gas pipeline into Florida for reliability purposes.

Most organized wholesale electric capacity markets provide no more than a one-year or seasonal price. Various technical conference participants noted the tension between a short-term one-year price from capacity markets and the long-term decision to contract for firm fuel supply. Representatives from the RTOs and ISOs with organized capacity markets indicated that they are aware of this tension and are exploring potential market design changes. PJM stakeholders are considering multi-year pricing mechanisms, including a voluntary long-term auction.[69] A recent letter from PJM indicated that stakeholders are still discussing long-term options and noted that stakeholders agreed to attempt to develop business rules for a multi-year pricing mechanism in time for a May 31, 2013 filing, which could be applied to the May 2014 auction.[70]

Participants in some regions questioned whether the incentives, penalties, and/or participation requirements in the organized wholesale electric capacity markets are adequate to incent performance and ensure a firm fuel supply. Participants in virtually all regions with capacity markets indicated that their capacity markets do not consider the firmness of a generator's fuel supply when clearing resources. At the Northeast conference, a representative of ISO-NE indicated that a generator's Forward Capacity Market (FCM) penalties for not showing up are too low, though one generator argued that forward capacity market nonperformance penalties are substantial. ISO-NE's representative indicated that its Strategic Planning Initiative includes plans to strengthen capacity market performance incentives. On October 22, ISO-NE shared with stakeholders a white paper on FCM performance incentives that included a proposal to make FCM resources' revenue contingent on performance during scarcity conditions.[71] Stakeholders are currently considering these proposed modifications.

In the Mid-Atlantic region, one gas company in PJM argued that PJM's Reliability Pricing Model (RPM)[72] nonperformance incentives are too weak to encourage a

[69] PJM Multi-year Pricing Mechanism, http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={B709F188-450F-4A06-A5EB-BD61B601C9EF}.

[70] PJM Interconnection, L.L.C., Docket No. ER12-513-000, July 31, 2012 Supplemental Information Filing, available at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13038241.

[71] ISO-NE, *FCM Performance Incentives* (Oct. 2012) *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.

[72] RPM refers to PJM's capacity market.

generator to pay for firm contracts or dual fuel; the gas company argued that PJM should consider increasing penalty provisions or treating a capacity resource as a limited capacity resource. A representative of PJM, however, noted that a generator with an RPM commitment that fails to perform will be penalized with an Unforced Capacity (UCAP)[73] reduction and thus earn less in future years. A NYISO representative indicated that they could consider improving their UCAP nonperformance penalty. A representative of NERC noted that because many capacity market incentives such as Equivalent Forced Outage Rate (EFORd)[74] penalties are retrospective, the penalty's impact does not arrive until three years later. The NERC representative noted that this may be a concern given not only the longer-term dependence on gas, but the near-term dependence on gas because in the next three years a substantial number of coal units will be going offline for retrofit.

Discussion at the conferences affirmed that each region meets resource adequacy requirements in its own way. Focusing on the RTO/ISO markets that rely on capacity market constructs regulated by the Commission, a number of issues have been raised regarding whether and how to structure gas-fired generator's performance incentives. PJM, ISO-NE and NYISO each have somewhat different market designs and each has commenced work to evaluate performance incentives in their respective regions. MISO continues to study the issue, with plans to refine and update studies evaluating whether generation capacity is sufficient. In CAISO, conference participants stated that gas infrastructure is expanded in anticipation of load (as opposed to responding to firm contracts) and CAISO's non-performance penalties are adequate.

Staff believes that resource adequacy issues in these markets should continue to be addressed in the first instance by market participants, states, and other stakeholders in each region. Unlike the communication and scheduling issues discusses earlier in this report, generic guidance may not be helpful at this time for regions considering how to structure market rules to ensure that generators have appropriate incentives to deliver firm energy. Significant attention and resources are being devoted to these matters, concrete issues have been identified, and responses to those issues are being formulated.

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[73] UCAP refers to installed capacity adjusted by forced outage rates. UCAP represents the amount of MWs a resource can sell into a capacity market. For instance, a 100MW resource with a 20% forced outage rate would have its installed capacity (100 MW) reduced by its 20% forced outage rate so that the resource could only sell 80 MW of unforced capacity into a capacity market.

[74] Equivalent Forced Outage Rate (EFORd) refers to the probability that a generator will not be available due to forced outages or forced deratings when there is demand for the unit to generate.

Staff will monitor progress on these initiatives and encourages industry representatives to contact staff if guidance is required.

D. NERC Activity

A representative of NERC discussed its efforts to study gas electric interdependency reliability issues at several of the conferences, including a potential need to revise reliability assessments such that the assessments would take fuel supply into account. NERC's representative also indicated that it will complete phase 2 of its Gas-Electric Interdependency Study by the end of 2012[75] and suggested that recommendations in the phase 2 of the report would include the creation of a taskforce to further identify potential revisions to NERC standards. NERC's representative also stated that factors associated with the loss of gas lines (such as a gradual loss of gas pressure) may exempt this scenario from the planning standards requirements regarding surviving the loss of the single largest contingency (N-1).[76]

Participants in several conferences suggested that gas-electric coordination and fuel availability problems could be addressed, in part, with the development of new NERC Reliability Standards or modifications to existing standards. Other participants, such as ISO-NE and PJM, stated that they are addressing electric system performance within their respective regions, whether performance is adversely impacted by fuel supply issues, and what might be needed to address those impacts. Some participants suggested approaches that would establish requirements to study fuel availability and other gas-electric interdependency issues, without mandating specific changes to resource procurement. In the Southeast region, for example, at least one utility indicated that its contingency planning already considers the loss of a single natural gas facility. Other participants expressed concern that fuel supply or resource adequacy requirements could intrude on traditional areas of state jurisdiction.

Staff looks forward to the results of NERC's interdependency study and the consideration by industry of what additional steps are appropriate to take to address reliability considerations in the context of gas-electric coordination. Staff will monitor the progress of this initiative and encourages active industry participation.

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[75] *See* North American Electric Reliability Corporation, *2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* (Dec. 2011), *available at* http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf.

[76] TPL-002.

V. Closing

As indicated in the discussion above, significant industry attention and resources are being dedicated to a host of issues related to the coordination of the gas and electric industries. While the focus of this report is on the coordination, scheduling, resource adequacy and reliability issues that were common to multiple technical conferences, Staff appreciates that there are a number of other issues unique to each region that must be addressed to improve coordination across the gas and electric industries. Staff will be actively monitoring and engaging industry regarding progress made in each region to ensure that gas-electric coordination issues are identified and addressed.