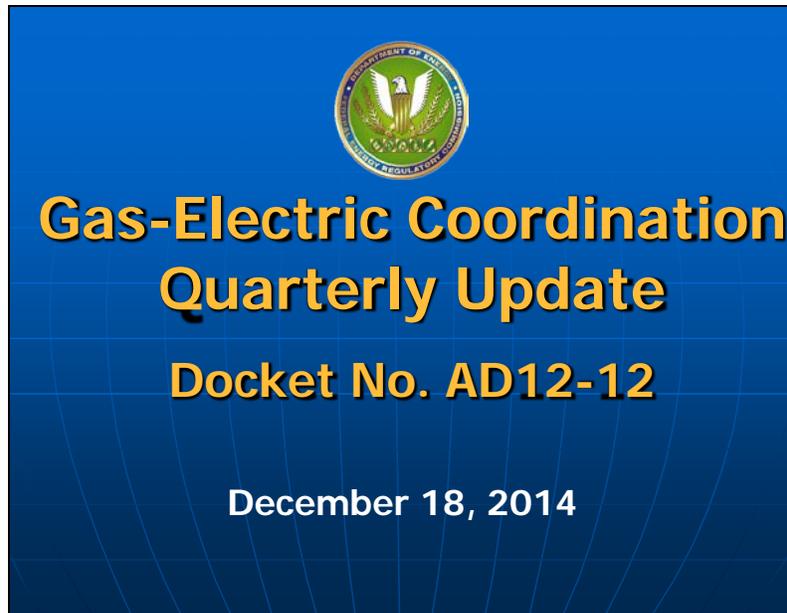




Gas-Electric Coordination Quarterly Report to the Commission

Docket No. AD12-12-000
December 18, 2014

Disclaimer: The matters presented in this staff report do not necessarily represent the views of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.



This report is Commission staff's eighth and final quarterly update on national and regional Gas-Electric Coordination Activities, as directed by the Commission in its November 15, 2012 order in Docket No. AD12-12. This report covers the period September 2014 through December 2014.

This report focuses on significant new national and regional developments since our last report in September 2014, highlights comments filed in response to the Commission's natural gas pipeline scheduling Notice of Proposed Rulemaking (NOPR) in Docket No. RM14-2, and briefly summarizes recent industry applications filed with the Commission.

National Initiatives

- NERC – 2014-2015 Winter Reliability Assessment
- Natural Gas Pipeline Scheduling (Docket No. RM14-2-000)
 - NAESB Response to NOPR
 - Industry stakeholder comments filed on November 28
 - RTO/ISO data request

In November, the North American Electric Reliability Corporation (NERC) published their 2014-2015 Winter Reliability Assessment. NERC's assessment of demand and generation projections for the 2014/2015 winter season indicate adequate resources under normal winter peak demand. However, the assessment states that prolonged and extreme cold weather may prove challenging in parts of North America due to natural gas and coal delivery constraints. NERC also highlighted regional challenges in areas where power generators rely on interruptible gas pipeline transportation, natural gas interstate pipelines are constrained to meet demand beyond firm commitments, and gas use for power generation is increasing. With increased reliance on natural gas-fired generation, NERC suggests additional revisions to assessing reliability in the future. For example, following last winter's Polar Vortex events, NERC developed extreme weather scenarios to assess the potential impacts on reliability. Additionally, going forward, NERC recommends including assessment of fuel availability and deliverability when conducting resource adequacy assessments.

With respect to the Commission's rulemaking on natural gas and electric scheduling practices, on September 29, 2014 NAESB filed a report in Docket No. RM14-2-000 notifying the Commission of the adoption of consensus Wholesale Gas Quadrant (WGQ) standards modifying the nationwide timely and intraday nomination timeline as an alternative to the Commission's proposals in the Notice of Proposed Rulemaking (NOPR) issued March 2014. Under the revised standards, the nomination deadline for the Timely and Evening Nomination Cycles are the same as those proposed in the NOPR—1:00 pm Central Clock Time (Central) and 6:00 pm Central, respectively. The timeline for intraday 1, intraday 2, and intraday 3 varies from that proposed in the NOPR and the nomination deadlines are at 10:00 am, 2:30 pm, and 7:00 pm,

all Central time. The NAESB-revised timeline does not include an intraday 4 cycle as proposed in the NOPR.

The deadline for parties to file comments was November 28, 2014. The Commission received 75 comments in response to the NOPR and Commission staff are now reviewing these comments.

On December 12, 2014, in Docket No. RM14-2-000, requests for data were issued to ISO-NE, NYISO, PJM, MISO, SPP, and CAISO regarding the impact on reliable and efficient operations of natural gas-fired generators running out of their daily nomination of natural gas transportation during the morning electric ramp. RTO/ISO responses to the data requests are due on or before January 12, 2015 and comments on the responses to the data request are due on or before January 22, 2015.



In the Eastern Interconnection, key stakeholders (including ISOs/RTOs, planning authorities, and the states) continue to work collaboratively on an inter-regional basis to study natural gas-electric coordination issues and assess infrastructure adequacy.

The final Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric System Interface Study Target 2 Draft Report, which was originally targeted for release in October 2014, has been delayed. EIPC is continuing to review the draft prior to posting. As previously reported, the Target 2 study evaluated the adequacy of natural gas infrastructure in 2018 and 2023 to meet expected core load and non-core gas-fired generation requirements on a Winter Peak Day and a Summer Peak Day. Work on Target 3, a contingency analysis, is ongoing with discussions continuing through the Stakeholder Steering Committee. Target 3 is planned for completion in the first quarter 2015.

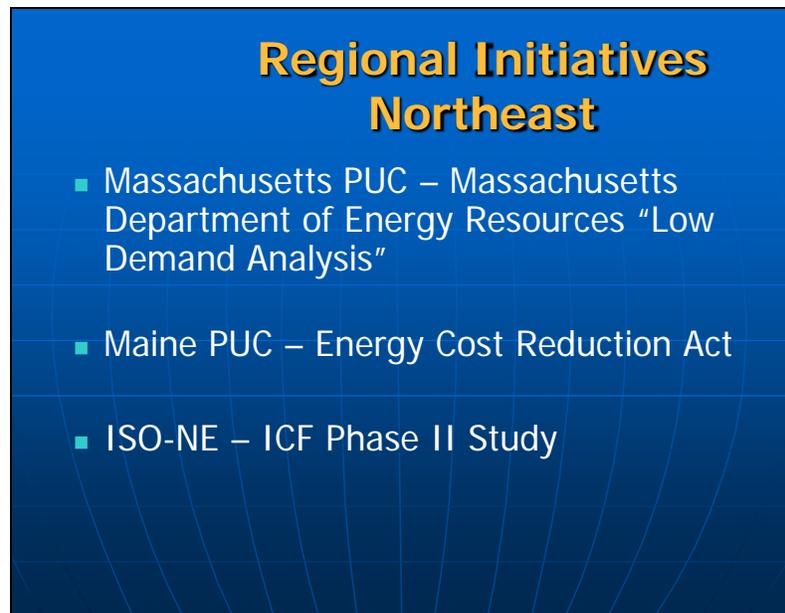
In November, EIPC presented preliminary findings on its Target 4 analysis comparing the relative economics of incremental firm pipeline transportation to dual-fuel capability for a new combined cycle plant or simple cycle gas turbine unit. Key research goals for the Target 4 study include analysis of on-site fuel storage capability for simple cycle and combined cycle generators; dual-fuel operating characteristics and costs; oil market availability and resupply options; fuel switching design and practice; and economic tradeoffs between dual-fuel capable generation and firm pipeline transportation capacity. The final Target 4 draft report was posted in December. Preliminary results indicate that, with few exceptions, the incremental cost of dual-fuel capability for individual generators appears to be much less than the incremental cost of firm transportation on natural gas pipelines as a direct cost strategy to achieve fuel assurance, as defined by the study, for electric reliability within the

Eastern Interconnection. The primary reasons supporting these preliminary study results include, among others: 1) existing pipelines in constrained locations are typically fully subscribed, thereby requiring a pipeline to add expensive new facilities to serve a gas-fired generation plant; 2) generators behind LDC gate stations would be expected to bear the high cost of local facility improvements to ensure year-round service in addition to mainline improvements from the producing basin to the local system; 3) the avoided cost of non-firm transportation is not sufficiently high in most constrained locations to significantly reduce the net cost of incremental firm transportation service; 4) the capital charges, inventory carrying charges and incremental fixed O&M associated with dual-fuel capability are comparatively low; 5) structural change in the distillate oil market has and will continue to simplify the logistics of ultra-low sulfur diesel replenishment during cold snaps or other outages or contingencies. The final draft report notes that locations in MISO, TVA, and some in PJM show relatively low cost for firm pipeline transportation, since recent expansion capacity has been constructed at the system rate, or, in some instances, where existing capacity may not be fully subscribed due to decontracting. The final draft report concludes that despite the ostensible economic superiority of the dual-fuel capable solution to the challenge of maintaining fuel assurance, as defined by the study, for electric reliability, there may be other commercial reasons that otherwise induce generators to invest in firm pipeline transportation. For example, different operating characteristics, margin recoupment from the redeployment of firm capacity rights, and the ability to source gas at a lower price and more stable trading point under firm pipeline service.

The Eastern Interconnection States Planning Council (EISPC) convened a full committee meeting on October 2 and 3, 2014. The objective of the meeting was to examine the impacts of compliance with the Environmental Protection Agency's proposed Clean Power Plan. Panelists provided an overview of the proposal and discussed potential impacts from expected coal plant retirements. Panelists anticipated that although coordination issues between the natural gas and electric industries will be exacerbated as coal plants retire and natural gas demand grows, ultimately, increased reliance on natural gas by the electric industry will incent improved scheduling practices between the two industries and the construction of additional infrastructure. Considering developments into the future, panelists forecasted that growth in the electric power industry will increase on par with national economic growth between now and 2030. Consequently, they cautioned that as natural gas becomes a larger part of the electric generation fuel mix, cold weather impacts will continue to be the principal driver of short-term gas price volatility. Discussions at the full committee meeting highlighted potential policies to address this concern, including policies to facilitate generator owners to recover the cost of firm gas pipeline transportation capacity through the electric markets, as well as costs associated with non-ratable takes. The EISPC convened a full committee meeting in New Orleans on December 11 and 12, 2014. The meeting sessions examined bulk and distribution electric system reliability, transmission security, capacity investment, and grid flexibility achieved from fuel diversity, demand response capabilities and storage. EISPC staff discussed the council's mission and work plan in 2015 and beyond.

The final draft of the ICF-led long-term study of electric and natural gas infrastructure in the Eastern Interconnection, prepared for NARUC and the EISPC, was released in December. The study examines the potential build-out of natural gas infrastructure required to supply power and natural gas customers out to 2030. The final report provides investment expenditure analysis for all aspects of the natural gas sector, from production wells to mainline transportation pipelines, to laterals for delivery to power plants, processing, and storage facilities. The final report concludes that investment in mainline natural gas pipeline is the

largest component of infrastructure expenditures, followed by lateral pipelines, processing, and storage development. The majority of the infrastructure build-out is driven by rapidly expanding production plays in the Northeast (Marcellus and Utica Shales) and the Southwest (Eagle Ford and Haynesville Shales), with the largest concentration of infrastructure investment needed in Pennsylvania and Louisiana. The study finds that total infrastructure costs for the power and natural gas sectors together could be approximately 1.5% lower when the two sectors co-optimize on siting and fuel infrastructure expansion, relative to non-collaborative infrastructure development. However, ICF notes that although both sectors benefit from cost reductions when they co-optimize planning, capital costs for the power sector are slightly higher relative to non-collaborative planning. Going forward, ICF recommends the use the EISPC-developed EZ Mapping Tool, to locate optimal siting locations in relation to environmental regulations, siting and permitting policies, and safety and operational guidelines that pertain to natural gas development.

A blue rectangular box with a grid pattern. At the top, the text "Regional Initiatives Northeast" is written in a bold, orange font. Below this, there is a bulleted list of three items in white text: "Massachusetts PUC – Massachusetts Department of Energy Resources 'Low Demand Analysis'", "Maine PUC – Energy Cost Reduction Act", and "ISO-NE – ICF Phase II Study".

Regional Initiatives Northeast

- Massachusetts PUC – Massachusetts Department of Energy Resources "Low Demand Analysis"
- Maine PUC – Energy Cost Reduction Act
- ISO-NE – ICF Phase II Study

Turning to state and regional initiatives, we begin in the Northeast. The New England States Committee on Electricity (NESCOE) Incremental Gas for Electric Reliability (IGER) proposal is on hold awaiting the completion of study commissioned by the Massachusetts Department of Energy Resources (DOER), which is expected to be publicly released on December 23, 2014. Specifically, DOER has retained Synapse Energy to conduct a modeling analysis of various gas demand scenarios and to evaluate a range of solutions to meet Massachusetts' short and long-term resource needs, while considering greenhouse gas reductions, economic costs and benefits, and system reliability. Since the initial stakeholder meeting to discuss the study in October, Synapse has developed base case and sensitivity assumptions and has conducted a feasibility study of alternative resources in a low energy demand case. The remaining study items include scenario modeling of eight scenario and sensitivity combinations, as well as an assessment of natural gas capacity against demand in a winter peak event.

The Maine Public Utility Commission (Maine PUC) has also continued efforts to advance natural gas infrastructure expansion in New England. In a November hearing, the Maine PUC voted to move forward with a second phase of work under the state's 2013 Energy Cost Reduction Act. The 2013 Act stated that Maine and other New England states could benefit from lower electricity prices through expansions of natural gas pipeline capacity into Maine and the New England states, which would result in lower natural gas prices. The Act authorizes the Maine PUC to execute a contract for up to 200 MMcfd of natural gas capacity, or for an amount of capacity that will not exceed \$75 million in annual costs.

As part of this second phase of work, Maine PUC will conduct a cost-benefit analysis of pipeline project proposals submitted to address Maine's needs for additional capacity. The

analysis will determine whether sufficient benefits would result to Maine consumers of natural gas and electricity. For example, Spectra Energy presented its Access Northeast and Atlantic Bridge projects planned to expand capacity along its Algonquin Gas Transmission and Maritimes & Northeast Pipeline. Spectra plans to develop the Access Northeast project with secured capacity commitments from Northeast Utilities and in collaboration with Iroquois Gas Transmission Systems. Kinder Morgan presented its Tennessee Gas Pipeline Northeast Energy Direct Project which the company is developing with the support of six local distribution companies. Portland Natural Gas Transmission System's project was a third proposal submitted to the Maine PUC. Any interested party may submit testimony until the end of the year in response to the proposals for the Maine PUC to consider. The Maine PUC will review the proposals and testimony in 2015. While Spectra Energy and Kinder Morgan already have firm capacity commitments from LDCs for their projects, additional commitments would be necessary, either from shippers or the state, to expand the projects' planned capacity to supply Maine.

On November 20, 2014, ICF released the Phase II Report on the assessment of New England's natural gas pipeline capacity and its capability to satisfy short and near-term (through 2020) generation needs. Similar to the 2011/2012 Phase I study, Phase II analyzed the potential for shortfalls in natural gas supply to electric generators through 2020 given currently available pipeline capacity and expansion projects likely to come online before 2020. For the Phase II study, ICF performed a new review of pipeline contracts, updated the timing and size of pipeline expansions in New England, as well as revised LNG availability. On the electric side, Phase II provides revised assumptions on power generation retirements and energy efficiency under four generation forecasts. Revised Phase II projections for natural gas supplies available to electric generation throughout the winter 2014/15 average nearly 500 MMcfd lower than projected in Phase I, assuming 2013/14 winter temperatures. In the Phase II report, ICF explores gas supply "deficiency" in terms of availability of pipeline transportation capacity outside of what is contracted and used by firm shippers. It finds that when firm shippers are at or near their full contract limits, there is insufficient interruptible pipeline capacity remaining to meet the overall needs of the electric generators in the region. In addition, ICF finds significant gas supply deficits remain on peak winter demand days from 2014 through 2020 with a gas supply "deficiency" ranging from 40 MMcfd to 1 Bcfd.



In addition to sponsoring meetings for discussion of the EIPC study, the New York Independent System Operator (NYISO) has developed and is now utilizing its Winter Preparedness plan for Winter 2014/2015. As part of the plan, NYISO issued fuel surveys to generators to review the status of their starting oil inventories, oil replacement arrangements, and gas transportation arrangements. NYISO also created a new Control Room gas-electric support position to monitor the status of gas pipeline systems, alternative fuel inventory, and potential emissions limitations. Additionally, NYISO developed a communications protocol to improve the speed and efficiency of submitting generator requests for emissions limit waivers to the New York State Department of Environmental Conservation (NYSDEC), if needed for reliability. NYISO also established a new system that allows generators to update the fuel costs used in the day-ahead reference level calculation, to more accurately reflect market conditions, such as the fuel constraints experienced last winter. In addition, NYISO made improvements to formalize the daily fuel inventory solicitation process and monitor short-term fuel availability on cold days. NYISO also clarified to the stakeholders that natural gas pipeline balancing charges are to be included in reference costs only during periods when nominations are unavailable with authorized gas balancing charges allowed only in real-time market reference cost levels. No gas balancing charges will be allowed in the day-ahead market reference cost levels. Furthermore, NYISO will not permit the inclusion in generator reference cost levels of charges associated with violations of OFOs or instructions restricting the use of gas imbalance service. If an OFO prevents a scheduled generator from securing gas to meet its schedule, and there is no available alternative fuel, the NYISO would expect the generator to take a forced outage.

PJM continues to work with its stakeholders to address a variety of gas-electric coordination issues. For example, since early September, the PJM Operating Committee has provided

education and training sessions to stakeholders on existing business rules for intraday cost-based scheduling submissions, procedures for switching between cost and price-based schedules, and PJM rules for cost reimbursement. During these sessions stakeholders and PJM staff discussed proposed additions to the existing information collected by PJM from generation owners, with the goal of providing both dispatch operators and generating units with more accurate information beyond day-ahead market postings, as well as allowing generation owners more opportunities to submit cost schedules that better reflect the costs of cold-weather operations and fuel market volatility. This resulted in proposed new data fields for generators to submit to PJM, including dual-fuel capability, availability, and fuel-switching transition times, as well as generators' operational restrictions. In addition stakeholders and PJM staff developed proposed adjustments to existing data parameters that would enable generator owners to enter forward data for up to seven days, including as many as 79 hourly intraday cost schedules that can be updated until 6:00pm of the day prior to the potential run-time. On November 20, 2014, the PJM Markets and Reliability Committee voted to endorse all of the proposed changes, which are now incorporated in PJM's Manual for Energy & Ancillary Services Market Operations. These new data collection and cost-schedule updating processes will take effect January 1, 2015, with the new software supporting these changes scheduled for release in early February 2015. In the interim, PJM has released manual directions for members to submit new data and cost-schedule updates.

In addition, PJM has taken a number of key steps to increase winter readiness. In response to last year's Polar Vortex events, PJM has approved Cold Weather Resource Performance improvements to increase resource performance during extreme cold weather events via performance verification and testing of certain resources during cold weather, including testing dual-fuel capability. PJM is also working on improving the tools and processes for two-way communication with the gas industry. PJM has also developed an internal dashboard of electrical interconnection areas impacted by pipeline issues such as capacity constraints or operational issues. This tool provides critical pipeline notifications in one location to enhance PJM's situational awareness and allow PJM to better evaluate the impact of pipeline issues on generators. The dashboard was tested internally at the end of November and is now available to PJM's system operators. Additionally, PJM has instituted weekly system status calls with a number of the prominent pipelines in the PJM footprint.

PJM is also working closely on improving interregional coordination with MISO and NYISO to improve situational awareness during emergencies, and held a number of operations coordination meetings in October and November. PJM holds daily operations conference calls with neighboring ISOs to discuss pressing issues and system status, as well as to share information on gas infrastructure conditions that may be regional in nature.



Moving to the central region, MISO has taken several steps to learn from last winter's gas-electric coordination challenges and better prepare for winter 2014/2015, including hosting a Winter Readiness Workshop with stakeholders. As part of its 2014/15 Winter Resource Assessment released in November, MISO found sufficient resources are available to meet electricity demand this winter, highlighted by over 46 GW of capacity from all resource types in excess of projected peak load, a 45% projected reserve margin. MISO learned that 35 GW out of 69 GW of its gas-fired generation lacks firm natural gas transportation service or dual-fuel capability. Finally, MISO is directing generation owners to prepare for winter based on recommendations from NERC.

In addition, this winter MISO will expand regular communications with pipelines on real-time operating conditions, based on publicly available information, to all pipelines (over 70) serving gas-fired generation in MISO's footprint. Last winter, MISO conducted a field trial of such regular communications with two natural gas pipelines (ANR Pipeline and Northern Natural Gas Pipeline). MISO has also implemented a real-time mapping tool to show MISO system operators all intra- and interstate pipelines in its footprint and the gas-fired units connected to them. The tool consolidates available pipeline information, which will help MISO better anticipate forced outages. In addition, MISO launched a tool on its website to provide information on gas pipelines, including current pipeline conditions and maintenance notices, to its members.

In SPP, the Gas Electric Coordination Task Force (Task Force) is finalizing a proposal to amend the SPP day-ahead market timeline to align with the proposed revised NAESB Timely Nomination Cycle deadline of 1:00 pm Central for scheduling interstate natural gas pipeline

transportation. The proposed changes to the day-ahead market timeline are aimed at maintaining reliability during fuel constraints and ensuring that the day-ahead market timeline compliments gas markets and dispatch scheduling requirements.

SPP completed its 2014/15 winter preparedness plan, and presented the plan to the SPP Balancing Authority Operating Committee on December 4, 2014. The 2014/15 winter preparedness plan describes emergency operating procedures for coordination and communication during critical cold weather events, as well as general best-practices for operations during the winter season. In the new 2014/15 winter preparedness plan, if SPP declares a severe cold-weather event, it may take steps to optimize fuel supply by, for example, 1) appealing to stakeholders to use alternative fuels; 2) conserving fuel in short supply by de-committing resources; and 3) coordinating outages. Additionally, in the plan, SPP identifies various recommendations for improving cold-weather operations, such as winterization, and generation operators notifying SPP of any expected fuel issues during a cold-weather event. During more severe conservative operations SPP will institute daily outreach and coordination calls to share reliability information with impacted generation owners. These multi-party communications protocols of non-public information sharing between dispatch operators, generators, and three natural gas pipelines supplying the majority of fuel to the RTO were first utilized by SPP to ensure reliability during 2013/14 cold-weather events and have since been developed and expanded within the framework of emergency operations for the 2014/15 winter preparedness plan.

Finally, on November 25, 2014, stakeholders agreed to petition the SPP Markets and Operations Policy Committee to both extend the Task Force's charter into 2015 and consider reclassifying the Gas Electric Coordination Task Force as a Steering Committee.



Moving to the West, Phase 2 of the Western Interstate Energy Board’s (WIEB) Natural Gas-Electric and System Flexibility Assessment was finalized last quarter and the Assessment is now complete. The State Provincial Steering Committee (SPSC) directed WIEB Staff to further develop scopes of work for a potential Phase 3 of the Gas-Electric Interdependency Study, focusing on the use of wind and solar forecasts in gas nominations and in communication with pipelines. A potential study on distribution system issues has also been proposed.

ColumbiaGrid is in the process of completing its coal retirement study, which is examining the transmission impacts of replacing coal units with natural gas. The final study report is scheduled for December 2014.

On September 16, 2014 CAISO released an issue paper and initiated a new Natural Gas Pipeline Penalty Recovery stakeholder process to discuss circumstances under which market participants may be able to recover natural gas pipeline penalties through the CAISO bid cost recovery mechanism. The proposal was initially discussed in 2012 within the stakeholder process, but CAISO did not file a proposal with the Commission at that time. Instead, CAISO undertook an outreach effort with intra-state and interstate pipelines to understand and address any potential reliability issues such a cost recovery mechanism might cause pipeline operators. After conducting outreach, the ISO believes it is not prudent to act now to allow recover of natural gas pipeline penalty costs given increased gas and electric coordination efforts, as well as Southern California Gas’ filing to implement in the future operational flow orders similar to those in place at Pacific Gas and Electric. In 2015, CAISO will monitor changes in the gas industry before reconsidering how, or whether, natural gas penalties

should be recovered in CAISO markets. CAISO states that it will continue to work with stakeholders to explore ways to better reflect natural gas costs.

In addition, CAISO and stakeholders will consider longer-term market design changes for both energy and unit commitment cost bids in a more comprehensive bidding rules initiative that began in December 2014. That stakeholder initiative will include discussion regarding greater bidding flexibility to potentially allow bids to reflect intra-day changes in fuel costs.

Relevant Natural Gas Filings

| Region | Pipeline/Association | Capacity/ Initiative | Docket No. | Status |
|--------------|---|---------------------------------|--------------|--------------------------------|
| Southeast | Florida Southeast Connection | Capacity addition 640 MMcfd | CP15-554-000 | Pending 09/26/2014 |
| Northeast | Eastern Shore Natural Gas Company (White Oak Lateral Project) | Capacity addition 55.2 MMcfd | CP13-498-000 | In-service 09/30/2014 |
| Southeast | Southeast Supply Header Expansion Project | Capacity addition 45 MMcfd | CP14-87-000 | In-Service (In Part) 10/1/2014 |
| Southwest | Sierrita Gas Pipeline | Capacity addition 200 MMcfd | CP13-73 & 74 | In-service 10/27/2014 |
| Southeast | Florida Gas Transmission | Capacity addition 25 MMcfd | CP14-21-000 | Approved 10/30/2014 |
| Southeast | NET Mexico Pipeline Partners (Border Crossing Project) | Capacity addition 2.1 Bcfd | CP13-482-000 | In-service 10/30/2014 |
| Mid-Atlantic | Dominion Cove Point LNG (St. Charles Transportation Project) | Capacity addition 132 MMcfd | CP15-22-000 | Pending 12/3/2014 |
| Mid-Atlantic | Dominion Cove Point LNG (Keys Energy Project) | Capacity addition 107 MMcfd | CP15-24-000 | Pending 12/3/2014 |

We now provide an update on relevant natural gas and electric filings submitted to or pending before the Commission, starting with natural gas pipeline filings. As discussed in more detail below, during this quarter the Commission received three new filings to expand pipeline capacity serving electric generation, approved one proposed project, approved the start of operations of four projects, and acted on numerous compliance filings concerning interstate natural gas pipeline compliance with the requirement to post offers to purchase released capacity.

The first new filing proposing to expand pipeline capacity to serve electricity generation was made by Florida Southeast Connection (FSC), which requested authorization on September 26, 2014 to construct facilities spanning from an interconnection with the proposed Sabal Trail Transmission (Sabal Trail) pipeline near Intercession City, Florida to a delivery point serving the Florida Power & Light Company's (FPL) 75-MW solar-thermal Martin Clean Energy Center, near Indiantown, Florida. FSC will have an initial transportation capacity of 640 MMcfd.

Turning to Commission approvals, Eastern Shore Natural Gas Company received approval on September 30, 2014 to go in-service for its White Oak Lateral Project (first filed on June 13, 2013). The proposed project will provide 55 MMcfd of firm transportation service for Calpine Energy Services, L.P. supporting gas-fired generation in Kent County, Delaware.

On October 1, 2014, Southeast Supply Header pipeline (SESH) received approval to place in-service the 45-MMcfd increase in its design capacity of its mainline system. The added capacity will provide firm pipeline transportation capacity from the beginning of SESH's system near Delhi, Louisiana to the end of its system near Coden, Alabama.

On October 27, 2014, Sierrita Gas Pipeline received approval to place into service its 200-MMcf/d facilities located in Pima County, Arizona, while on October 30, 2014, NET Mexico Pipeline Partners received approval to place into service its 2.1-Bcf/d NET Mexico Pipeline Project located in Starr County, Texas.

On October 30, 2014, FGT was granted a certificate of public convenience and necessity to increase the maximum delivery quantity by 25 MMcf/d to FPL through increased compression Broward County, Florida.

On October 30, 2014, NET Mexico Pipeline Partners, LLC (NET Mexico) received approval to place into service the NET Mexico Pipeline Project located in Starr County, Texas. The facility will have a design capacity of 2.1 Bcf/d and will provide supply to the expanding natural gas demand from gas-fired power generation in Mexico.

On December 3, 2014, Dominion Cove Point LNG, LP (DCP) filed an application to construct, install, own, operate, and maintain the St. Charles Transportation Project located in Fairfax County, Virginia and Charles County, Maryland. DCP states that the project will provide 132 MMcf/d of incremental firm transportation service to CPV Maryland, LLC who is proposing to build a 725-MW natural gas-fired combined cycle power plant in Charles County, Maryland known as the "St. Charles Energy Center". DCP also filed to provide an incremental 107 MMcf/d of firm transportation to the Keys Energy Project, a proposed 735-MW natural gas-fired combined cycle electric generating power plant in Prince George's County, Maryland known as the "Keys Energy Center".

Relevant Natural Gas Filings cont'd

| Region | Pipeline/Association | Capacity/ Initiative | Docket No. | Status |
|----------|--------------------------------------|---|---------------------|---------------------|
| National | 157 interstate natural gas pipelines | Order on Filings in Compliance with Order to Show Cause, Posting of Offers to Purchase Capacity | RP13-673-001, et al | Pending |
| West | Cheyenne Plains Gas Pipeline Company | Interruptible parking and lending service | RP15-134-000 | Approved 10/31/2014 |
| National | Kinder Morgan pipelines | Petition for Limited Waiver of No-Conduit Rule adopted in Order No. 787 | RP15-217-000 | Pending |

Addressing compliance, on October 16, 2014, the Commission issued an order on filings in compliance with the previously reported Natural Gas Act section 5 show cause proceeding requiring all interstate natural gas pipelines to either revise their respective tariffs to provide for the posting of offers to purchase released capacity as required by section 284.8(d) of the Commission's regulations, or to demonstrate that their existing tariffs are in full compliance with that section (October 16 Order). The October 16 Order found that out of 157 compliance filings submitted, 64 pipelines revised their respective tariffs in a manner that complies with the Commission's requirement, 23 pipelines demonstrated that their tariffs are in compliance, 1 pipeline requested clarification regarding a previously granted limited waiver, and 69 pipelines do not appear to be in full compliance.

Specifically, the October 16 Order found that potential replacement shippers should be permitted to have their offers to acquire released capacity posted for whatever period of time they desire, subject to a cap of no less than 30 days if the pipeline wishes to impose such a cap. Further, the October 16 Order rejected proposals to assess a separate fee applicable only to posting offers to purchase released capacity. The October 16 Order also clarified a limited waiver for posting website notice of offers to release or purchase capacity, and granted extensions of time to complete and implement website changes. All 69 interstate natural gas pipelines not in compliance have submitted filings to the Commission in response to the October 16 Order. This matter is pending before the Commission.

On October 31, 2014, Cheyenne Plains Gas Pipeline Company, L.L.C. filed revised tariff records to establish an interruptible parking and lending service under a new Rate Schedule PAL. The proposed PAL service will provide shippers a flexible service option to aid in the

management of their imbalances and provide them with an additional tool to mitigate penalties by affording the shippers the ability to leave gas on Cheyenne's system (i.e., park) or to take gas off the system at certain points (i.e., lend). On November 13, 2014, the proposal was accepted for filing by delegated order, effective December 1, 2014

On November 25, 2014, the Kinder Morgan interstate pipelines (KM) requested a limited waiver of the No-Conduit Rule with respect to the disclosure of information received under the rule to shared operational employees. Specifically, KM requests a limited waiver of the No-Conduit Rule adopted in Order No. 787 for operational personnel shared between KM and their affiliated Hinshaw, intrastate, and gathering systems. This matter is pending before the Commission.

Relevant Electric Filings

| Region | Filing Initiative | Docket No. |
|--------|---|---------------|
| NYISO | Pipeline Information-Sharing Changes under Order No. 787 | ER14-2895-000 |
| CAISO | Commitment Cost Enhancements | ER15-15-000 |
| PJM | Capacity Performance Proposal | ER15-623-000 |
| PJM | Additional Remedies to Capacity Performance | ER15-29-000 |
| PJM | Request for Temporary Increase of the System Offer Cap Rule | ER15-31-000 |

Since our last report, five electric tariff filings relevant to gas-electric coordination have been presented to the Commission.

On September 17, 2014, the NYISO submitted, in Docket No. ER14-2895-000, proposed tariff revisions to allow NYISO to share confidential information concerning natural gas-fired generation with the operating personnel of interstate natural gas pipeline companies, intrastate natural gas pipeline companies, and LDCs, to conform with the Commission's regulations adopted in Order No. 787. On November 14, 2014, the Commission accepted the proposed tariff revisions, effective November 17, 2014, subject to conditions and NYISO submitting a compliance filing within 15 days of the date of the order (November 14 Order). The Commission found that NYISO's proposed revisions to allow the sharing of non-public, operational information with interstate natural gas pipeline operators for the purpose of promoting reliable service and operational planning are consistent with Order No. 787, and that its proposal to extend the information sharing provisions to LDCs and intrastate natural gas pipeline operators should ensure cooperation and coordination, thus contributing to the reliable operation of the transmission system. However, the Commission required NYISO to submit a compliance filing to clarify the proposed tariff language prohibiting an LDC or intrastate natural gas pipeline from disclosing, or using anyone as a conduit for disclosure of, non-public operational information received from NYISO to a third party or any affiliate except for the operating personnel of an affiliated interstate pipeline or intrastate pipeline which has a non-disclosure agreement with NYISO.

On December 1, 2014, NYISO submitted a filing to the Commission in response to the November 14 Order. Specifically, NYISO revised its tariff language to (1) clarify that the

operating personnel of interstate pipelines receiving non-public operational information originating from the NYISO, from an affiliated LDC or intrastate pipeline, must comply with section 284.12(b)(4)(ii) of the Commission's regulations; and (2) specify which employees of an LDC or intrastate pipeline are prohibited from receiving non-public operational information from the NYISO. This matter is pending before the Commission.

On October 1, 2014, CAISO filed proposed tariff revisions to allow generators to recover start-up and minimum load costs. CAISO proposes tariff revisions that: (1) increase the existing proxy cost bid cap from 100 percent of the resource's calculated proxy cost to 125 percent; (2) require CAISO to exclusively use the Intercontinental Exchange (ICE) natural gas price index for calculating the natural gas price component if, on the morning of the day-ahead market run, the price reported by ICE exceeds 125 percent of the natural gas price index calculated under CAISO's tariff; (3) eliminate the registered cost option for all resources except use-limited resources; and (4) allow CAISO to switch use-limited resources temporarily from the registered cost option to the proxy cost option whenever the alternative ICE natural gas price is triggered. On November 6, 2014, the Commission issued a deficiency letter requiring CAISO to submit additional information regarding the unit-specific costs that would be included in the calculation of proxy costs. On November 25, 2014, CAISO submitted the additional information requested in the November 6, 2014 deficiency letter. This proceeding is pending before the Commission.

On December 12, 2014, PJM submitted, in Docket No. ER15-623-000, proposed tariff revisions, under section 205 of the Federal Power Act (FPA), to better ensure that committed capacity resources will perform when called upon to meet the reliability needs of the PJM Region (Capacity Performance Filing). The Capacity Performance Filing makes changes to the design of PJM's capacity market, known as the Reliability Pricing Model (RPM), to ensure it provides adequate incentives for resource performance. Specifically, PJM proposes, among other reforms, to: (1) include a new capacity product - the Capacity Performance Resource - that provides greater assurance of delivery of energy and reserves during emergency conditions; (2) redefine its existing capacity product to enhance assurance of delivery of energy and reserves during hot weather operations; (3) eliminate the current excuses for Capacity Resource non-performance, leaving only certain narrowly drawn exceptions for actions specifically approved or directed by PJM; (4) assess charges for poor performance and give credits for superior performance, to provide a strong incentive for performance; (5) change PJM's current capacity sell offer rule to recognize the costs and risks of offering Capacity Performance Resources by increasing the offer-price cap for such resources to the Net Cost of New Entry, while also allowing offers in excess of the Net Cost of New Entry if the seller can demonstrate that the costs of improving resource performance, including firm fuel costs and documented and verifiable expenses solely attributable to the risks of offering Capacity Performance Resources, exceed that value; (6) include a distinct "must offer" requirement specifically for resources capable of qualifying as Capacity Performance Resources, to prevent physical withholding of such resources; (7) revise Load Serving Entity capacity obligations to reflect the reliability value added by resource performance during winter-season emergencies; (8) preserve existing capacity products through May 31, 2020, subject to a reliability-based cap on the quantity of such products that may clear the capacity auctions, to allow market participants time to adapt their resources as necessary to ensure satisfaction of the region's expectation that all committed capacity will deliver energy and reserves during emergencies; (9) provide an allowance for differential price clearing during that transition, to recognize the higher value of Capacity Performance Resources; (10) eliminate the current market rule that intentionally understates the region's reliability needs in the RPM Base

Residual Auction, to eliminate a possible source of under-pricing of any resources in that auction; and (11) make conforming changes to various capacity rules. PJM proposes to implement these changes for the next Base Residual Auction, which is scheduled for May, 2015, and which will procure capacity for the 2018/2019 Delivery Year.

Concurrent with its Capacity Performance Filing, PJM submitted, in Docket No. EL15-29-000, proposed revisions to its Operating Agreement, and related revisions to its tariff, to correct present deficiencies on matters of resources performance, and excuses for resource performance in the PJM markets. Specifically, PJM identified four areas of its current energy market rules that enable, or could enable unreasonable excuses for market participant performance in PJM's markets. Therefore, PJM proposes to: (1) revise the procedure for determining parameter limits for resources, including clarifying that such limits must be based solely on the operating design characteristics of each specific resource (rather than on economic or budgetary concerns), and then clarify that units operating outside of those parameter limitations for reasons other than at PJM direction are ineligible to be made whole through Operating Reserve credits for such operation during specified types of emergencies or alerts; (2) reform PJM's current *force majeure* rules to recognize that participants in PJM's wholesale power markets should be excused from performance only when catastrophic conditions broadly preclude performance by market participants in the PJM Region; (3) reduce opportunities to effectively avoid capacity resource performance by submitting uneconomic (i.e., Maximum Emergency) offers in the Day-ahead Energy Market; and (4) include in the market rules more transparent and rigorous criteria for PJM's consideration and approval of requested planned and maintenance outages, including clarifying PJM's authority to timely rescind a prior approval.

PJM states that while these two concurrent filings provide complementary solutions to the same underlying problem and while both seek the same, April 1, 2015 effective date, the FPA section 205 filing is not dependent upon Commission acceptance of the FPA section 206 filing. These proceedings are pending before the Commission.

On December 15, 2014, PJM submitted, in Docket No. EL15-31-000, proposed revisions to its Operating Agreement and tariff, under section 206 of the FPA, to raise the cost-based energy offer cap from \$1,000 to \$1,800/MWh. The \$1,800/MWh offer cap would apply temporarily, through March 31, 2015, and is intended to address the situation which occurred last year, in which a spike in natural gas prices pushed some generators' costs above \$1,000/MWh, resulting in PJM requesting temporary waiver of the system offer cap rule in Docket No. ER14-1145-000. The proposal would also allow for generator compensation for costs incurred above \$1,800/MWh in the form of after-the-fact make-whole payments. PJM states that the market-based offers will remain capped at \$1,000/MWh, except that if a Market Seller submits a cost-based offer greater than \$1,000/MWh (but below \$1,800/MWh) the Market Seller will be permitted to raise its market-based offer up to a level equal to such cost-based offer. PJM requests a shortened 8-day comment period and expedited action by January 9, 2015, with an effective date of January 9, 2015. This proceeding is pending before the Commission.