UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Coordination of the Scheduling Processes	)	**Docket No. RM14-2-000**
Of Interstate Natural Gas Pipelines and	)	
Public Utilities	)	
	)	

COMMENTS OF THE ENVIRONMENTAL DEFENSE FUND,
CONSERVATION LAW FOUNDATION,
THE SUSTAINABLE FERC PROJECT AND THE CLEAN ENERGY GROUP

The Environmental Defense Fund ("EDF"), Conservation Law Foundation ("CLF"), Sustainable FERC Project and the Clean Energy Group (collectively, the "Commenters") respectfully provide the following comments in response to the Notice of Proposed Rulemaking ("NOPR") issued on March 20, 2014 by the Federal Energy Regulatory Commission ("FERC" or "Commission") in this proceeding regarding proposed revisions to the scheduling practices used by interstate natural gas pipelines to schedule natural gas transportation services. [1]

I. Introduction

The rules governing the wholesale gas market design are outdated and no longer align with contemporary energy supply, demand or policy trends. Dramatically changed circumstances since the current natural gas market construct was adopted (in 1995) include new gas supplies from unconventional resources, substantially increased gas demand from gas-fired electric generators, the integration of renewable resources, the evolving characteristics of a more dynamic the electricity grid, new smart energy management technologies providing for transactive interaction in the electricity markets by customers, duly adopted legal requirements and policies implementing the imperative to reduce greenhouse gas ("GHG") emissions from the

[1] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities,* 79 Fed. Reg. 18, 223 (April 1, 2014) ("NOPR").

energy sector. Any two of the foregoing could be cause for re-examination of current natural gas market operations; taken together, they pose potentially daunting implications for a natural gas market organized primarily around monthly and daily changes in supply and demand. At present and going forward the natural gas market faces a major shift in the manner that gas is used, and will require that the gas supply chain adapt its operations to provide new and more granular services to meet current and evolving energy customer needs.

The Commission's recognition of misalignment between the wholesale gas and electricity markets, as embodied in the NOPR, is a helpful start. But it is only a start. Through the NOPR and the Commission's recent related actions, the Commission can and should resolve the inefficaciousness resulting from a gas market that too often undermines the effectiveness of the electric market, as tangibly demonstrated during this past winter's Polar Vortex episodes. The NOPR's suggestion of a more coordinated inter-market and cross-market approach can facilitate greater customer and public benefits by eliminating constraints arising at the gas / electric interface.

In addition, as the Commission proceeds it should continue to be cognizant that the two markets are very differently organized – and each has its separate advantages which can be utilized to common benefit. The natural gas market is first and foremost a bilateral market where nearly all price signals, contracts, transactions, operational activities and obligations are bilateral and one-to-one in nature. In contrast, the electric market has been largely organized around one-to-many and many-to-one relationships with centrally planned and organized operations, agreements, obligations, and locational price signals. These differences often lie at the heart of the conflicts between the two markets and give rise to the misunderstandings and inapplicability of one's solution set to the other.

Against this divergent backdrop, natural gas can enable the electric grid to operate dynamically and to manage load fluctuation in real time. The current number, frequency and duration of nominating cycles, however, imposes limits on the role of gas as an enabler of a more dynamic grid. These constraints undercut the liquidity necessary to align the gas market design with the wholesale electric energy markets, which schedule and dispatch supply on sub-hourly bases. Notwithstanding the Commission's longstanding efforts to improve efficiency by functionally unbundling both the gas and electric wholesale markets, natural gas services do not reflect the variation in offerings, pricing and duration seen in the wholesale electric markets. A synergistic gas market must allow shippers, to the extent of available pipeline capacity, to vary receipts in concert with deliveries constituting non-ratable flows, to enable and support the variable sub-day demands for (and duration of) gas-fired generation. There cannot be a "smart" interactive grid unless the business rules governing the means by which gas is traded and dispatched are in sync with the evolving needs of the electric markets, and the needs of gas shippers and end users who are electric market participants. The Commission's actions to harmonize the gas and power markets will be successful if and when the market design creates better price formation for the provision of enhanced scheduling <u>and shorter duration services as the norm, rather than the exception</u>, in the gas markets.

The Commission's observations and suggestions in the NOPR for adding flexibility to shippers are justified, sensible and derive from the sound principles underpinning the market design: open access, functional unbundling, efficient price formation and transaction duration. Since the Commission wisely initiated technical conferences and review of gas / electric coordination in 2012, customers have been subjected to at times unconscionable price impacts occasioned by illiquidity and insufficient gas responsiveness during periods of peak simultaneous gas-fired heating and gas-fired electrical demand. While the NOPR's proposal to revise the operating and scheduling practices is a productive step in the right direction for more efficient and dynamic energy markets, the Commenters urge the Commission to initiate the next step towards a truly responsive gas market, and as necessary to serve public welfare and public policy goals.

The Commenters strongly support the Commission's efforts in this and in other proceedings to synchronize the gas and electric markets and to update the gas market design. In particular, Commenters recommend adding standardized intraday nomination cycles for pipelines to provide up to twelve cycles per day, shifting the nomination schedule to allow for electric generators to finalize their commitments before making gas purchase arrangements, and requiring pipelines to schedule and deliver non-ratable quantities and services as described in greater detail below. Making these changes would improve liquidity and flexibility of the gas market and would help ensure just and reasonable rates.

II. Description of the Commenters

The Commenters are non-profit organizations advocating for energy policies and market designs which accelerate deployment of renewable energy and low carbon-resources to reduce GHG emissions and mitigate other adverse impacts from energy production, transportation/transmission, distribution and use.

Environmental Defense Fund is a membership organization whose mission is to preserve the natural systems on which all life depends. Guided by science and economics, EDF seeks practical solutions to resolve environmental problems. EDF uses the power of markets to speed the transition to clean energy resources, seeking to change outdated market rules to modernize the energy grid so it can support the ongoing deployment of renewable energy resources and energy efficiency. EDF works collaboratively market participants sharing these goals and is a member of the North American Energy standards Board ("NAESB").

CLF is a public interest advocacy organization with offices and members in the states of Maine, New Hampshire, Vermont, Rhode Island and Massachusetts. A substantial component of CLF's work is directed at influencing energy policy in order to ensure that the region achieves its collective goal of reducing GHG emissions and avoiding or limiting the significant impacts of climate change. The role of natural gas as an energy resource is a central component of this work. CLF has been a vocal advocate for electric and gas market changes that will ensure maximum efficiency in the use of existing natural gas pipeline capacity and for fully utilizing gas storage, LNG and other available approaches to gas supply and management prior to expanding existing or developing new gas infrastructure. CLF is an active participant in the market design initiatives of ISO-NE and is a member of NAESB. CLF participated in NAESB deliberations on issues raised in this docket by submitting and presenting a proposal for revised timelines and practices applicable to the natural gas pipelines in order to better coordinate scheduling between the natural gas and electric industries.

The Sustainable FERC Project, housed within the Natural Resources Defense Council, is a coalition of state, regional and national environmental and other public interest organizations. The Project advocates at FERC and works with FERC-regulated regional grid organizations and utilities to help remove barriers to deploying renewable energy, energy efficiency, demand response, energy storage and other clean energy resources into America's electricity transmission grid. The Project's interest in this proceeding is in ameliorating inefficiencies imposed at the gas-electric interface so that wholesale markets can operate more flexibly and with fewer constraints on clean energy resources.

Clean Energy Group is a national nonprofit organization that works to accelerate the commercialization of clean energy technologies in order to strengthen the economy and stabilize GHG emissions. In support of this work, it produces data and analysis on opportunities, barriers, and emerging markets for clean energy technologies. It works with public clean energy funds, financing institutions and clean energy companies to promote effective clean energy policies, technology innovation strategies and public finance tools. And it assists local, national, and international governments to create and implement innovative public funding programs to advance clean energy markets and project deployment; develops new finance and commercialization tools; and creates networks of U.S. and international funders and policymakers to solve climate change. CEG also manages the Clean Energy States Alliance, the national organization of state officials who manage system benefit charge funds that invest in clean energy projects and companies.

III. Comments

A. Scheduling Changes And Additional Intraday Nominating Cycles Are Necessary to Better Harmonize the Gas and Electric Markets

The NOPR provides a cogent explanation for the need to revise the natural gas scheduling system to enhance coordination between the gas and electric industries, and to increase flexibility by adding intraday nomination cycles. In the recent NAESB process there was widespread recognition that the market timelines of the gas and electric systems are not in sync. As has been pointed out by numerous RTOs, it is inefficient and problematic when a unit's day-ahead market ("DAM") bid is accepted after the first timely nomination cycle for gas delivery has passed. When capacity is constrained, the current sequencing often results in generators seeking to nominate transportation by pipelines *after* the market has become illiquid, a process which is at best inefficient and at worst threatens reliability when generators are unable to perform due to gas scheduling constraints. The timelines adopted by NAESB provide a pathway for RTO-operated DAMs to clear before the timely pipeline nominating cycle begins.

At the crux of the NOPR's call for better synchronized timing between the two markets is the need for greater clarity with respect to generator fuel arrangements. As the Commission recently observed, "fuel assurance is a key to ensuring generator performance, which directly contributes to the overall reliability of the grid and just and reasonable rates." [2] The NOPR explains that,

> [] if gas-fired generators know whether they were committed in the day-ahead electric market prior to the Timely Nomination Cycle, these generators may have a greater opportunity to procure natural gas transportation in the Timely Nomination Cycle—when there is the greatest opportunity to procure pipeline capacity. This, in turn, could reduce the potential for gas-fired generators to engage in costly actions that raise real-time energy market prices.[3]

By moving back the timely day-ahead nomination deadline from 11:30 AM to 1:00 PM (Central Prevailing Time) as agreed at NAESB, the RTOs and ISOs will have opportunity to clear bids in the DAM in a timeframe that maximizes opportunities to procure gas and schedule accordingly. So long as RTO's modify their market timelines as the Commission envisions, the NAESB-approved schedule should better harmonize the timing between the two markets providing efficiency, synergy and lower rates to customers. [4]

That said, better synchronized timing alone (i.e., without additional action by the Commission), however, will not be sufficient to alleviate disharmony between the markets and to foster just and reasonable rates. The problems that came to light during the severe cold weather

[2] *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators,* Order on Technical Conferences at p. 4, (November 20, 2014).

[3] NOPR at 18234, par. 53.

[4] The Commission initiated a separate action under Section 206 of the Federal Power Act to ensure that RTOs modify their respective DAM timelines so that generators understand dispatch instructions and output expectations before the start of the timely nomination cycle.

events experienced in the winter 2013-2014 (the "Polar Vortex") which raised challenges far beyond synchronization of timelines and illuminate several additional improvements needed within the gas / electric interface.[5] In the NOPR, the Commission expresses concern that,

> existing interstate natural gas pipeline scheduling practices and the application of some of the Commission's regulations by pipelines may not provide sufficient flexibility to meet the needs of natural gas-fired generators, and could be limiting the efficient use of existing pipeline infrastructure, thereby making less capacity available to shippers (including natural gas-fired generators). Specifically, the limited number of standard intraday nomination cycles for interstate natural gas pipeline transportation may not be sufficient to meet the needs of gas-fired generators to obtain capacity to deliver additional natural gas supplies during the electric operating day.[6]

The extent of illiquidity in the gas markets during periods of high demand will not be resolved *only* by aligning the timing between the two markets; additional nomination cycles are needed. Although NAESB largely implemented the Commission's directive regarding optimizing the timeline between the two markets, it did not agree to the Commission's prescription for providing four intraday nominating cycles, instead reaching agreement for only three.

Gas trading and market outcomes in the PJM Interconnection region during the Polar Vortex are informative and demonstrative of the lack of flexibility inherent to the current gas market design. The evident transparency and price formation problems arising when the gas delivery system *appeared* to be constrained by cold weather illuminate a fundamental question raised in the NOPR: is the gas market providing necessary incentives for pipelines to maximize the efficient use of their existing infrastructure?[7] PJM's *Analysis of Operational Events and Market Impacts During the January 2015 Cold Weather Events* (May 8, 2014) (the "PJM Winter Analysis")[8] provides a thesis on inefficiency and incongruity between the manner in which gas is

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[5] See, NOPR at 18224, n. 10 (discussing system-wide effects of the Polar Vortex episodes).
[6] NOPR at 18229-30, Par. 33.
[7] *Id.*
[8] Available at http://www.pjm.com/~/media/documents/reports/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

traded and the needs of electric generation, and the resulting adverse effects. PJM notes that during the January 17-29 event,

> [t]he scheduling of natural gas-fired resources became increasingly difficult because of the rigid and expensive terms and conditions generators needed to accept in order to procure gas. Certain gas-fired generators notified PJM that they could get gas only if they committed to operate at fixed output for an extended period of 24 hours or more in some cases. The fact that the period included two weekends – one of them a holiday weekend – exacerbated the fuel procurement-related situation. [] Meanwhile, spot natural gas prices soared; for example, on January 22 spot natural gas prices were 27 times the previous four months average.[9] [10]
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> Generation owners told PJM that they needed to know on Friday, January 17, whether their units would be scheduled to run in order to ensure that they had gas for Tuesday and Wednesday mornings. Although in some instances the units were needed only to cover the morning peak from about 5:00 a.m. to 9:00 a.m., the units had to buy 24 hours worth of gas.[11]
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> Generators told PJM that, because of gas market constraints, their gas-fired resources in some cases had to be operated at full output each hour and for a longer duration than PJM required them – which created extremely high uplift costs especially because of the extremely high prices for natural gas.[12]
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> Generators warned that they likely would not be able to procure gas without some certainty on their commitment period in advance of the typical scheduling windows and some accounting for extraordinary scheduling restrictions such as 24-hour ratable takes and multi-day commitments. Often, operators were forced to commit to these units several days in advance to ensure a reliable level of unit commitment prior to the close of the day-ahead market. [13]

PJM and FERC Staff (in its presentation on April 1, 2014, Docket No. AD14-8-000) observed the consumer cost implications of disharmony. Natural gas trades on January 21 for January 22 delivery in eastern PJM spiked to over $120/MMBTu and power prices above $1000/MWh.

PJM's observations and the experiences of natural gas-fired generators during the Polar Vortex are a stark testimonial to the lack of transparency and flexibility inherent to the current

[9] PJM Winter Analysis at p. 31.

[10] Note that one of the central issues raised by PJM's comments is to the "duration" of the required scheduling (i.e., at least 24 hours). Commenters address this "duration" issue in their recommendations below.

[11] *Id.* at p. 35.

[12] *Id.* at p. 44.

[13] *Id.* at p. 47.

wholesale gas market design. To develop a more precise and data-based understanding of market efficacy (or lack thereof), CLF engaged a consultant, Skipping Stone, to undertake an analysis of daily nominations and throughput for the various pipelines serving eastern PJM during January 2014, including the Polar Vortex events. Several relevant conclusions derive from Skipping Stone's analysis. Notably, with respect to the NOPR, review of timely nominated quantities and end of day deliveries in comparison to each pipeline's total contracted quantities (as a conservative surrogate for physical capacity) unequivocally validate the verity that pipelines offering a greater number of and more frequent intraday nominating cycles experienced significantly greater utilization than those pipelines largely abiding by the minimum FERC-approved NAESB standard timelines (two timely, and two intraday).[14]

The NOPR recognizes that "some pipelines offer additional intraday nomination cycles" but that "these nomination opportunities are not standardized across the nation, however, and therefore are not available to all shippers." [15] It goes onto state that the benefits of additional intraday nomination opportunities are vitiated for transactions requiring transportation on more than one pipeline "because pipelines without enhanced opportunities may not confirm nominations" for transportation nominated for pipelines providing hourly nomination opportunities. [16]

Within eastern PJM, both TETCO and Transco offer enhanced intraday nominating cycles, as frequently as hourly nominating. Skipping Stone's analysis concludes that scheduled and delivered quantities from TETCO and Transco *exceeded* each of their respective total

[14] The analysis prepared by Skipping Stone reviewed and sorted publicly posted data from each of the following pipelines: Columbia Gas Transmission (TCO), Dominion Transmission (DTI), Texas Eastern Transmission (TETCO), Tennessee Gas Pipeline (TGP), and Transcontinental Gas Pipe Line (Transco). An Excel file presenting Skipping Stone's pipeline utilization data in eastern PJM for each day of January 2014 is attached as Attachment 1. Notes prepared by Skipping Stone describing its methodology for the analysis are provided in Attachment 2.
[15] NOPR at 18235, par. 56.
[16] *Id.*

contract quantities during the periods of highest demand in January 2014. In other words, during the Polar Vortex, shippers nominated and scheduled a greater volume of gas transportation than the base amount provided for in the aggregate of firm contracts, and deliveries by TETCO and Transco (in comparison to their respective total firm contracted quantities) far exceeded that of other pipelines serving eastern PJM. In addition, TETCO and Transco scheduled and delivered more gas to their consumption locations by the end of day, compared to the quantity of timely nominated deliveries –a clear indication of greater intraday utilization (and liquidity) in comparison to the other three pipelines serving eastern PJM.[17]

In comments in a related docket, both ISO-NE and NYISO have suggested that "the lack of nomination opportunities impacts their ability to use gas-fired generation capacity to respond to real time events."[18] Commenters assert that the Skipping Stone analysis provides undeniable support for additional standardized intraday nomination opportunities to allow gas users, including gas-fired generators, to better respond to real-time changes in their need for natural gas.

Staff for several of the Commenters participated in the detailed and thorough stakeholder deliberations conducted by NAESB. In those discussions, the less-inclined pipelines did not provide a reasonable or plausible justification for why they are unable to offer hourly nomination schedules, instead of limited intraday cycles. Objections based on the cost of upgrading back-office processes and / or staffing to provide more frequent nominating cycles ring hollow in comparison to the burden imposed on ratepayers, as much as $8 billion in excess costs alone in

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[17] Skipping Stone's analysis also unequivocally demonstrates that each of the DTI, TGP and TCO systems had unused and available capacity during the most constrained days in January when basis and resulting wholesale electric clearing prices within PJM East skyrocketed. The significant magnitude of that excess capacity supports the conclusion that during the Polar Vortex events, market illiquidity diminished the efficiency of price formation (and buyer price discipline) at the expense of customers. While stakeholders may not agree about the extent of new pipeline capacity necessary to add efficiency and liquidity to the gas supply chain, it is axiomatic that without efficient price signals, there will not be a right-sized or cost-effective market response to the need for more pipes.

[18] NOPR at 18235, par. 58 (citing ISO-NE and NYISO Comments, Docket No. AD12-12-000).

PJM during January 2014 due in some measure to illiquid conditions that would be mitigated by additional scheduling cycles. Changing the amount, frequency and permitting shorter duration standardized gas scheduling opportunities would expand the efficiency benefits from the minority of pipelines providing enhanced opportunities (especially for transactions involving more than one pipeline), and would allow RTO's and gas generators to refine schedules and obtain confirmations more often based on contemporaneous market and operational information.

The NOPR squarely frames the need to increase intraday nominating cycles, and it is apparent that the benefits of doing so demonstrably outweigh any associated costs. As PJM noted in recent comments, "no showing has been made to the Commission why these services cannot be provided on other pipelines."[19] Although the NAESB outcome would add one additional intraday cycle, Commenters urge the Commission to standardize the voluntary enhanced practices of pipelines including Texas Gas, Gulf South and TransCanada and establish up to twelve intraday nominating and gas capacity trading (capacity release) cycles.

In addition to better syncing with electricity market conditions, additional cycles would increase the responsiveness of the gas market and infrastructure to variable renewable generation, distributed energy resources, demand response, and peak load management services which are and will become increasingly prevalent in the electricity markets. While additional nomination cycles and sub-day scheduling of gas capacity, in and of themselves will not "create

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[19] Comments of PJM Interconnection L.L.C. (October 1, 2014), *Commissioner Phillip D. Moeller's Inquiry Into the Trading of Natural gas, and the Proposal to Establish an Electronic Information and Trading Platform,* Docket No. AD14-19-000. Commenters strongly agree with PJM's suggestion (at p. 4) that,

> [g]iven the increased demand for services that meet the needs of both local distribution companies as well as generation owners, Commission review of this regulated service [hourly nomination schedules] would help to address differences in pipeline service that do not necessarily mesh with customer need of cannot otherwise be justified in today's changing environment.

capacity" (where capacity is fully utilized), such additional cycles and sub-day schedules will lead to better price formation which can call forth the right-sizing of capacity and services to meet increased demands. Without such price signals, the bilateral gas market will not respond with either new services or right-sized capacity because it is those price signals which give confidence to both pipelines and shippers that it is economical to respond.

B. To the Extent of Available Capacity and Matching of Receipts to Deliveries, Non-Ratable Sub-Day Services Should be Required from the Gas Market to Optimize the Gas / Electric Interface

The NOPR represents another refinement in a long standing and beneficial Commission policy to ensure adequate supplies of natural gas by encouraging market forces and fostering competition within the gas supply chain. For example, FERC Order 436[20] established a program for non-discriminatory open access for pipeline transportation services, while retaining and revising utility-type cost-of-service (and rate of return) regulation over the interstate natural gas transportation function. At its core, Order 436 required that pipelines honor requests to transport to the extent of available capacity. FERC Order 636[21] (and its progeny) furthered the move towards open access by mandating functional unbundling, establishing a capacity release market, and standardizing a new rate design whereby customers contracting for firm service pay to reserve pipeline capacity through a demand charge,[22] and customers of interruptible service pay for the transportation of gas primarily through a commodity charge based on the volume of gas transported to an end user. [23] Thus, interruptible customers purchasing supply from the spot

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[20] 50 Fed. Reg. 42,408 (October 18, 1985) *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol.*
[21] 57 Fed. Reg. 13,267 (April 16, 1992) *Pipeline Service Obligations and Revisions Governing self-Implementing Transportation.*
[22] The demand charge rate is fundamentally established by totaling the fixed costs for the pipeline divided by the sum of firm service capacity reservation and the volumes projected to be transported by interruptible service customers for the following year.
[23] In effect, firm customers largely cover a pipeline's fixed costs. Interruptible customers may pay a portion of fixed costs depending on the extent to which the service is discounted by shippers releasing capacity or pipelines, but are generally exposed to the vagaries of the spot market value for transportation services.

market essentially assume the "basis" as the all in cost of the natural gas including the value of transportation service for the gas.

The focus of the Commission's past efforts to introduce market forces was weighted towards fostering competition in natural gas production and supply. At the core of functional unbundling was the need to convert the firm *supply* rights of the local distribution companies ("LDCs") into firm *transportation* rights. By empowering LDCs to reserve pipeline capacity and use that capacity as they choose, LDCs are able to purchase the gas of their choosing and transport that gas on the lowest-cost pipeline provider. On the flip side, the assumption was that by establishing a market-based pricing regime for interruptible service reflecting a volumetric charge, pipelines would have an incentive to increase the volumes of gas they transport, because the more a pipeline transports, the greater its profits. As it relates to the NOPR, among the most notable aspects of the gas market design is that it was not conceived with an eye towards serving the current and growing magnitude of natural gas-fired electric generation as a major customer for gas supply and transportation services. In the present docket, the Commission is expanding policy focus on gas *delivery responsiveness* to electricity market participants, more so than LDCs obtaining supply.

On a timeframe parallel to its efforts to encourage market forces in the gas supply chain, the Commission has similarly advanced competitive market designs and removed some of the barriers to competition within the wholesale electric market. A series of Commission orders beginning with Order 888[24] have successfully promoted competition and functionally unbundled the wholesale electric market. Competition and lower cost domestic gas production have combined to increase the proportion of electricity generated from natural gas-fired power

[24] 75 FERC 61,080 (1996) *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities.*

plants.[25] This proportion is likely to increase as the US Environmental Protection Agency implements policies seeking to reduce GHG emission, including by replacing coal fired power plant output with electricity from natural gas and renewable resources.

In addition, federal and state policies have helped unleash a technological revolution, where wind and solar power, distributed energy resources, demand response and new intelligent energy management tools are remaking the composition of the electricity grid. Natural gas *can* provide a complimentary and synergistic role with these new technologies by increasing its flexibility to the benefit of all shippers including those which provide fuel to serve the electricity grid, through firming variable resources, and in providing critical reliability services. But it will effectively serve these beneficial roles only if the wholesale gas market design operates efficiently and facilitates the capabilities of gas as an enabler of new technologies and GHG reductions.[26] There cannot be a "smart" interactive grid unless the business rules governing the means by which gas is traded are in sync with the evolving needs of the electric markets.

The NOPR recognizes the value of flexibility provided by pipelines including the benefits of "enhanced services that permit shippers to subscribe to services providing more variable hourly rates."[27] But as PJM recently observed,

> [t]oday's natural gas market appears to lack sufficient tools and services to dynamically respond to the reliability needs of gas-fired units servicing electric load. [] RTO markets are willing to pay for enhanced services over and above what those gas-fired units are receiving today, *but* for the payments to be worthwhile, the new services offered must provide flexibility and value that is needed to help address electric reliability in a

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[25] According to recent Energy Information Agency data, natural gas generation amounted to 27% in 2013.

[26] Although beyond the scope of the NOPR, it is critical that emissions of methane, a potent GHG, be substantially reduced across the entire gas value chain. In this regard, Commenters support the Commission's proposed policy statement to establish mechanisms for pipelines to recover costs associated with replacing old compressors, leak prone pipes and other infrastructure improvements to enhance the safety and environmental performance of the pipeline system. Docket No. PL15-1-000, *Cost Recovery Mechanisms for Modernization of Natural Gas Facilities* (November 20, 2014).

[27] NOPR at 18229, n. 42.

> dynamic wholesale electric market paradigm. The current array of pipeline services offered today simply falls short.[28]

At present, natural gas services do not reflect the variation or duration in services and pricing seen in the electric markets and necessary to effectively interact with the more dynamic service offerings to electric customers. Unless and until the gas market design enables sub-day services and the price formation that will attend to such services, the necessary price signals to market participants and innovators to invest capital will not be forthcoming.

To address the present day obstacles to efficient price formation, the Commenters strongly urge the Commission to require that:

> To the extent of available capacity and the matching of receipts to deliveries, pipelines should schedule sub-day transportation of natural gas.

As compensation for such service, pipelines should be permitted to charge the applicable commodity (usage) rate for transportation within the shipper's contractually ratable amount for the period and for usage above such ratable amount in the period, an overrun rate commensurate with a 100% load factor rate of a pipeline designated service not to exceed the 100% load factor amount of its most recent recourse rate for capacity on its system. Finally, to provide a competitive check on such rate, shippers with firm capacity that they have not nominated or scheduled should be permitted to release their unutilized capacity on a sub-day basis to those wishing to augment their ratable capacity with such released capacity. In addition, any tariff restrictions which might result in restricting one pipeline from projecting its no-notice service onto another pipeline should be eliminated.

By putting in place the foregoing components of service, market participants can obtain experience with non-ratable service offerings, their pricing and market mechanics; and, most

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[28] Comments of PJM Interconnection L.L.C. (October 1, 2014), *Commissioner Phillip D. Moeller's Inquiry Into the Trading of Natural gas, and the Proposal to Establish an Electronic Information and Trading Platform,* Docket No. AD14-19-000.

importantly, the Commission can assess the resulting utilization and price information to monitor the utility and viability of such sub-day service offerings. From this information and price formation activity in the primary and secondary market, more granular and robust services within the gas supply chain will arise and customers will: a) continue to experience the benefits from better utilization of pipeline capacity; and, b) avoid the adverse effects of disharmony and inefficiency in the gas / electric interface.

The present assumption (if not requirement) of ratable takes prevalent in pipeline tariffs is a legacy that impedes the ability of the gas pipelines to serve electricity market participants. The needs of electricity customers increasingly require more flexible, non-ratable quantities provided through sub-day scheduling mechanisms to meet the variation in, and duration of, generation load profiles now and into the future. As implied in the NOPR (noting that "[s]ome pipelines" provide for "variable hourly flow rates"), the provision of these services differs among pipelines with no clear standardization by the Commission or otherwise.[29] As a consequence, currently there is no partial-day non-ratable take "market" for gas. At present, there are no price signals to inform exactly what combination of natural gas facilities and services are required to meet the variable demands for and duration of natural gas-fired generation – demands that will only increase as the electric grid integrates more renewables and relies more heavily on natural gas generation to support and firm variable supply and demand for electricity. Moreover, on the pipeline side, potentially available part-day pipeline capacity goes unutilized and demand that could be served by renewable and/or lower-carbon generation goes unserved. Because presently, short-notice, non-ratable natural gas delivery service is largely unavailable at any price, there is no targeted gas market response to provide such service(s) and by which market-based price formation could develop.

[29] NOPR at 18229, n. 42.

In numerous past instances, the Commission has adapted its regulation of natural gas to contemporaneous economic and marketplace conditions. Indeed, the underpinnings of the current market design were in response changes in the supply and demand dynamic in the 1980's which resulted in gas wells being "shut in" and unnecessarily limited opportunities to purchasers of natural gas. The market design revisions embodied in Orders 436 and 636 largely required the pipelines to modify their business practices to extract greater efficiency throughout the supply chain. In this respect, the impetus for again refining current pipeline practices is analogous.

The NOPR appropriately would require revisions to the prevalent business and scheduling practices of the natural gas industry to provide greater flexibility to shippers operating in the interface between the gas and electric markets. In summary, Commenters urge the Commission, in its final order in this proceeding, to remove the unnecessary scheduling obstacles to harmonized markets by:

- Requiring pipelines to schedule non-ratable flows for durations as short as one hour provided there is available pipeline capacity and subject to verification of supply and demand matching the scheduled quantities and duration;

- Permitting pipelines to charge "overrun" rates to compensate them for facilitating and providing non-ratable capacity that exceeds a shipper's ratable contracted capacity. One formula for setting a maximum rate for such service would be to allow the pipeline to set the hourly rate as no greater than the 100% load factor of the highest recourse rate currently in effect of the system. For instance this could be the overrun rate of a recourse rate associated with an incrementally priced expansion;

- Permitting sub-day capacity releases to compete with pipeline "overrun" service on non-ratable flows;

- Removing any tariff provisions which would inhibit the projection of No-Notice Service from one pipeline onto another; and,

- Removing any tariff provision which would inhibit third-party storage or other facility operators from offering No-Notice Service onto a connected facility to the extent of available capacity and flow rate verification by means of electronic flow measurement.

As discussed above, the foregoing refinements can and will remain faithful to the fundamental underpinnings of the market design: open access, functional unbundling, and market-based price formation amounting to a logical progression of FERC's oversight of transactions in the gas market to increase liquidity and better respond to customer needs in light of changed market conditions.

Customers, pipelines, public welfare and the environment will benefit from more granular service offerings. To the extent transaction durations can better facilitate shorter periods of time, then pricing of such shorter duration transactions will better reflect the least cost combination of assets, products and services to meet those demands. Such price signals will not only increase liquidity but will cause the introduction and proliferation of tailored products and services around the provision of just the sort of non-ratable services and products that are needed to provide flexibility associated with firming variable generation. By pricing non-ratable services, pipelines can generate additional revenue with existing facilities and better price transparency will call forth the right mixture of assets, products and services to serve demands within the gas / electric market interface. As the grid continues to deploy new and evolving technologies, better price signals coming from shorter duration gas-for-electric-generation services will improve price signals to renewable resources, demand response and energy storage (both gas and electric) products.

Efficient price signals require price formation that is tailored to the infrastructure trends and demands on the system. Better price signals coming from shorter duration gas-for-electric-generation services will call forth competitive offerings in shorter term capacity release, third-party and pipeline no-notice services, and incremental pipeline expansions (e.g., looping and compression) which will institutionalize such sub-day services. Unless and until the market design is more responsive to current and future electric customer needs, the economic impetus for new infrastructure will be opaque and ineffective, if not disjointed, as is currently the case in several regional energy markets. The Commission can unleash, on the gas side, a similar wave of innovation and customer-focused products and services, as those available to electric customers, by refining requirements for nondiscriminatory access including for the widespread scheduling of non-ratable quantities by the pipelines.[30]

IV. Conclusion

Commenters strongly support the Commission's efforts to reform scheduling and the businesses practices for natural gas transportation service, and suggest that the Commission take a holistic view of the powerful commercial, technological and policy impetuses at work in the energy grid, both gas and electric. Commenters agree with the NOPR's recommendations to increase flexibility and liquidity in the gas market design, and then appropriately refine electric markets to optimize the gas / electric interface. While the NAESB process and outcome validate the need for scheduling changes to better sync the markets, more needs to be done to foster and facilitate efficient interaction between the gas and electric sectors. We appreciate the Commission's efforts in this and related dockets and thank the Commission for considering these comments as it finalizes beneficial market refinements.

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[30] Establishing and refining standards within the rubric of nondiscriminatory access in order to enhance system efficiency fits squarely within the Commission's authority under the Natural Gas Act ("NGA") (15 U.S.C. §§ 717-717w) and its responsibility to ensure "access to an adequate supply of gas at a reasonable price." *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1003 (D.C. Cir. 1990).

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the service list compiled by the Secretary in this proceeding either by U.S. Mail or electronic service, as appropriate. Dated at Lebanon, New Hampshire, this 28th day of November, 2014.

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