UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF
THE
AMERICAN GAS ASSOCIATION

Dated: November 28, 2014

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Pursuant to the "Notice of Proposed Rulemaking" issued in the above-referenced proceeding,[1] and the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. Part 385, the American Gas Association ("AGA") respectfully submits these comments regarding the proposed regulatory changes in the NOPR.[2]

I. SUMMARY

AGA supports the Commission's efforts to improve coordination between the electric and natural gas industries and shares the Commission's ultimate goal of ensuring that natural gas service is reliable and efficient. However, AGA urges the Commission to weigh proposed changes to the rules governing natural gas scheduling with the overarching goal of maintaining and improving the reliability of the natural gas system for all customers, including existing non-electric generation as well as electric generation customers. The Commission should only take steps that will improve the reliability and efficiency of the current natural gas transmission system for all gas customers. Changes to the national gas nomination schedule should not be

[1] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 79 Fed. Reg. 18223 (Apr. 1, 2014), FERC Stats. & Regs., Proposed Regs. ¶ 32,700 (2014) ("NOPR").
[2] AGA member - Exelon Corporation - does not support AGA's position as to the start of the gas day.

made at the expense of the quality or quantity of service currently available to natural gas customers. The Commission should be particularly responsive to those proposed changes for which a clear consensus exists for a change in the national gas regulations.

In light of these principles, AGA supports the recommended standards developed by the North American Energy Standards Board ("NAESB")[3] that move the timely nomination deadline from 11:30 am Central Clock Time ("CCT") to 1:00 pm CCT. AGA also supports NAESB's recommendation for two bumpable intraday cycles during normal business hours. AGA further supports NAESB's recommendation for a third intraday cycle closer to the end of the gas day. AGA believes that these changes will provide significant benefits to electric generators by enhancing their ability to participate in the natural gas scheduling process.

AGA, however, does not support a change to the current 9:00 am CCT start of the gas day. As demonstrated in the reports submitted by NAESB, none of the options considered to change the start of the gas day, including the Commission's proposed 4:00 am CCT start time, received consensus support among the NAESB participants. Changing the start of the gas day is unnecessary. NAESB's recommended standards address the electric reliability issues the Commission identified in the NOPR, and there are far better ways to address the reliability needs of highly variable loads like gas-fired electric generators than changing the gas day start time. Moreover, the burden on the gas industry of moving the start of the gas day would outweigh the potential benefits of the change. Prior to issuing a final rule that moves the gas day start time, the Commission should perform a thorough cost-benefit analysis that considers the potential

[3] *See* NAESB filing submitted on September 29, 2014, in Docket No. RM14-2-000 ("NAESB September 2014 Filing"). *See also Report of the North American Energy Standards Board*, filed June 18, 2014, in the same proceeding ("NAESB June 2014 Report").

adverse consequences, in terms of cost and changes in operations, to AGA members of requiring any change to the gas day start time.

AGA does not support the alternative proposals put forth by the Desert Southwest Pipeline Stakeholders because they are inconsistent with the recommended standards developed by NAESB with wide-spread support from market participants and would dramatically revise the Commission's "no-bump" policies. The Commission should not adopt a nation-wide standard that adversely impacts the gas industry to address a regional problem.

AGA believes that in order to maximize the benefits of any change to the gas nomination schedule, such changes must be coordinated with the changes to the electric scheduling practices. Accordingly, AGA urges the Commission to coordinate the changes to both the gas and electric schedules and only require modifications to the gas nomination schedule as part of a final rule in this proceeding to be implemented contemporaneously with the modifications to electric schedules required in Docket Nos. EL14-22-000, *et al*.

Finally, AGA supports the Commission's proposal to permit pipelines to provide for multi-party transportation contracts, subject to the implementation of that policy through individual pipeline tariff filings after consultation with customers.

II. COMMUNICATIONS

All pleadings, correspondence and other communications filed in this proceeding should be served on the following:

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III. IDENTITY AND INTERESTS

The AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 71 million residential, commercial and industrial natural gas customers in the U.S., of which 94 percent — more than 68 million customers — receive their gas from AGA members. AGA is an advocate for local natural gas utility companies and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international gas companies and industry associates.[4]

AGA's member local distribution companies ("LDCs") take service from virtually every interstate natural gas pipeline regulated by the Commission under the Natural Gas Act ("NGA"). As customers of jurisdictional pipelines, AGA members are directly affected by the rates, terms and conditions of the transportation and storage services provided by jurisdictional pipelines and storage providers, including rules affecting the reliability of the natural gas system and the coordination between the natural gas and electricity markets. In many cases AGA's members provide natural gas service to gas-fired electric generating facilities and/or are part of larger utility entities that provide electric power and transmission services. AGA's members, therefore, have a direct and substantial interest in the issues raised in this proceeding.

AGA actively participated in Docket No. AD12-12-000, in which the Commission began its assessment of the need for new and additional regulations to facilitate gas-electric coordination and to most effectively meet the growing need for gas as a fuel for electric generation loads.[5] In addition to submitting comments, AGA's representatives took an active

[4] For more information, please visit www.aga.org.

[5] *See e.g.*, *Comments of the American Gas Association*, Coordination Between Natural Gas and Electricity Markets, Docket No. AD12-12-000, filed Mar. 30, 2012; *Comments of the American*

role in the regional conferences held in that docket, as did representatives from numerous member companies. As described in NAESB's September 29, 2014 Filing in this proceeding, AGA's members played a very active role in the development of the recommended standards submitted by NAESB at the direction of the Commission.[6]

AGA believes that the Commission should strike the right balance between the desire to change the rules for natural gas pipelines as part of an effort to improve coordination with power generators, and the need to ensure continued secure, safe and efficient transportation of natural gas to all of the gas-consuming public.

IV. INTRODUCTION

A. Background and Guiding Principles

1. This rulemaking is part of a larger effort to improve reliability.

This proceeding arose from two broad concerns: (1) a lack of synchronization between the operating procedures and timetables of natural gas pipelines and those of regional electric transmission entities ("RTOs/ISOs");[7] and (2) the potential that these differences might exacerbate difficulties in electric generators scheduling natural gas supplies when they are needed. In the NOPR, the Commission cited examples of serious stress for the electric system and natural gas supplies,[8] and suggested that improved coordination would mitigate the potential for future complications in operations between the two industries.

In the NOPR, the Commission recognized that the proposed rules are part of a broader effort by the Commission to take steps to encourage greater harmonization between the natural

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Gas Association on Communications and Information Sharing, Docket No. AD12-12-000, filed Jan. 7, 2013.

[6] NAESB September 2014 Report at pp. 3, 6, Appendices A and C.

[7] NOPR at PP 5 – 6.

[8] *Id.* at P 5, esp. fn. 8 through fn. 10.

gas and electric industries. Commencing with the hearings and reports resulting from the Docket No. AD12-12-000 proceeding,[9] the Commission has undertaken other steps, including its "show cause order" issued in Docket No. RP14-442-000[10] regarding pipeline compliance as to posting offers to buy capacity (recently the subject of an omnibus order on compliance filings);[11] its revisions to the regulations governing communication of transmission information in Order Nos. 787 *et al*.;[12] its ongoing monitoring of power markets;[13] and its oversight orders regarding tariff actions by RTOs and ISOs as to the reliability of winter service.[14] The Commission's staff provided an overview of the steps taken to improve reliability in its October 2014 Reliability Report, ranging from this proceeding to waivers, capacity market enhancements, provision of additional market incentives, oversight conferences and enforcement staff review of market performance.[15] The rulemaking in this proceeding, therefore, is only one part of a broad series of steps being taken by the Commission to adjust the tariffs of both jurisdictional natural gas companies and public utilities to improve reliability.

The record in this proceeding, as well as in the Commission staff's market reports and comments in various settings relating to gas-electric coordination, strongly demonstrates that the

[9] The NOPR cites relevant results of that proceeding at P 6, fn. 11 and fn. 12.
[10] *Posting of Offers to Purchase Capacity*, 146 FERC ¶ 61,203 (2014).
[11] *B-R Pipeline Co., et al*., 149 FERC ¶ 61,031 (Oct. 16, 2014).
[12] *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, Order No. 787, 78 Fed. Reg. 70,163 (Nov. 22, 2013), FERC Stats. & Regs. ¶ 31,350 (2013), *order on reh'g*, 147 FERC ¶ 61,228 (2014).
[13] *E.g*., Commission Staff Report, *Summer 2014 Energy Market and Reliability Assessment*, May 15, 2014; Commission Staff Report, *Gas-Electric Coordination Quarterly Report to the Commission*, Sept. 18, 2014; Commission Staff Report, *Winter 2014-15 Energy Market Assessment*, Oct. 16, 2014 ("2014-2015 Winter Assessment").
[14] *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, et al*., 149 FERC ¶ 61,145 (Nov. 20, 2014).
[15] Commission Staff Report, *Commission and Industry Actions Relevant to Winter 2013-14 Weather Events*, Docket No. AD14-8-000 (Oct. 16, 2014) at p. 5 ("Reliability Report").

reliability issues faced by electric generators and RTO/ISO operators vary substantially among regions of the country, both as to the nature and scope of the problems. The Commission staff's reports strongly indicate that a substantial underlying constraint in growing electric reliance on natural gas as a fuel is the robustness of each region's natural gas infrastructure and other fuel security measures, such as dual-fuel capability, to support increased power sector demand.[16] Further, Commission staff's October 2014 Reliability Report did not conclude or suggest that coordination of scheduling between the natural gas and electricity markets appeared to be a significant factor in the severe electric reliability challenges of 2013-2014. Instead, the report focused on more basic infrastructure and electric market design problems. Indeed, the Commission recently identified fuel assurance – generator access to sufficient fuel supplies and the firmness of generator fuel arrangements – as a significant issue contributing to poor generator performance and inefficient market operations.[17]

AGA believes that the Commission's recent orders and the reports of its staff reflect that reliability problems in the electric industry resulting from increased use of natural gas to generate electricity stem from a wide range of factors, including a number already being addressed by other, ongoing Commission initiatives. Ultimately, the principal determinants of the reliability of gas-fired electric generators will be adequate natural gas infrastructure (and/or dual-fuel capability) and appropriate electric market design rules and incentives to develop such infrastructure or capability – not refinements to the rules governing the operation of the gas transportation market, or even improving scheduling coordination. AGA contends that the

[16] 2014-2015 Winter Assessment at 2 (despite abundant national supplies and additional pipeline construction, "there are still restrictions in New England. In some regions, there is an increased reliance on natural gas for electricity generation.").
[17] *Centralized Capacity Markets*, 149 FERC ¶ 61,145 at P 5.

subject matter of this rulemaking is therefore one part, and a relatively minor part, of a wide-ranging Commission effort to improve reliability. Thus, the uncertain benefits and increased costs of the proposed actions should be viewed and weighed in this context.

2. The Commission should approach gas-electric coordination with the goal of improving reliability for both natural gas and electricity customers.

The purpose of this proceeding is to consider whether the Commission should make certain changes to the business practices of interstate natural gas pipelines in order to better coordinate their operations with those of the electric industry. The Federal Power Act is not the basis or authority for the proposed regulation, nor is security of natural gas supply for the electric power industry the only factor that the Commission must consider in any final rule in this proceeding. The proposed regulations are being issued under the Commission's authority to implement the provisions of the NGA.[18] In exercising that authority, the Commission must consider its fundamental duty under the NGA, which makes protection of the ultimate consumers of natural gas the principal obligation of the Commission.[19] While improving new and expanded use of the gas transmission system by electric generators is important for the reasons set out in

[18] 15 U.S.C. Section 717, *et seq.*

[19] *Atlantic Refining Co. v. Public Service Commission,* 360 U.S. 378, 388 (1959). *See also Maryland People's Counsel v. FERC,* 761 F.2d 780, 781 (D.C. Cir. 1985); *City of Mesa v. FERC,* 993 F.2d 888, 895 (D.C. Cir. 1993). *See also Sunray Mid-Continent Oil Co. v. FPC,* 239 F.2d 97, 101 (10th Cir. 1956) ("No single factor in the Commission's duty to protect the public can be more important to the public than the continuity of service furnished."), *rev'd on other grounds,* 353 U.S. 944, 1 L. Ed. 2d 794, 77 S. Ct. 792 (1957); *cf. Texas Power Corp. v. FERC,* 285 U.S. App. D.C. 239, 908 F.2d 998, 1003 (D.C. Cir. 1990) ("The public interest that the Commission must protect always includes the interest of consumers in having *access* to an adequate supply of gas at a reasonable price."). Notably, according to the Energy Information Administration, non-electric generation gas demand comprised about 2/3 of the national total. *See* http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm. The needs of non-electric generation end-use natural gas customers require appropriate consideration in this proceeding along with those of gas-fired electric generators.

the NOPR, the Commission must ensure that the resulting business standards advance the core obligations of the NGA. As AGA stated in its comments at the commencement of the Docket No. AD12-12-000 process, the Commission's pursuit of improved coordination between the natural gas and electric industries should adhere to principles that reflect the underlying statutory and policy goals of the NGA, as well as the complex and varying realities in the industries, *viz.*:

- The overall goal of gas-electric coordination efforts should be to preserve and, where appropriate, enhance reliability for all customers, both gas and electric.
- Gas and electric stakeholders must collaborate to meet this overall objective.
- Policymakers and industry leaders should initiate a dialogue that addresses the reliability of both the gas and electric systems in a coordinated manner, not one at the expense of the other. In that regard, the Commission should have a bias toward enabling creative market solutions to enhance coordination between the natural gas and electricity markets, and not merely establish additional regulatory requirements.
- The Commission should establish a clear policy framework that reflects variations in reliability issues at the regional level in terms of infrastructure, scope and timing. Priority should be given to those regions where the need is most urgent. The Commission must provide policy guidance in advance of others moving to implement specific solutions.
- The Commission should recognize ongoing regional efforts to address reliability issues, draw on stakeholders' existing knowledge of regional operations and promote continued collaboration among all stakeholders on a regional basis.
- The immediate priorities should be to take steps that will improve reliability during periods of peak demand, system constraints or supply or transportation disruptions on the gas systems.

These principles should continue to guide the Commission's consideration of the proposed rules in this proceeding. Achieving these goals places a premium on both: (1) relying on steps broadly supported by market participants of both industries, *i.e.*, on not imposing burdens or one-sided operational changes on one industry in an attempt to address reliability concerns in another industry; and (2) on being mindful of the differences in operational circumstances, market needs and reliability issues that exist among geographic regions and even on individual pipeline systems, where appropriate. Thus, even though the impetus for this rulemaking (and the other steps described above) has been to improve rules to increase the availability of natural gas service to meet electric generation needs, the rules need to ensure that both industries, in all regions, are benefitted by the new regulations.

3. The final rule must meet its goals without imposing substantial costs and risks on the natural gas industry.

Any final rule in this proceeding should address: whether the Commission's goals – relating, as discussed above, to both the natural gas and electric industries – would be significantly advanced by the proposed changes; whether the changes may have other impacts on natural gas operations; and whether the potential negative impacts of any aspect of the proposed changes might outweigh the potential benefits of the proposed changes. The need to balance such values is integral to the Commission's obligations under the NGA and the Administrative Procedure Act.[20]

The Commission recognized this tension in the NOPR, stating that it is proposing "actions that provide for better coordination in scheduling between the industries, *while respecting the differences between the industries* in their operational and business needs."[21] Elsewhere, the Commission concluded that:

> the adjustments to the Gas Day and interstate natural gas pipeline nomination timeline proposed herein promise to provide significant assistance in helping to improve coordination of the natural gas and electric nomination and scheduling systems, while maintaining the substantial efficiencies gained through standardization of the natural gas scheduling system. The Commission intends that these reforms, along with the additional actions we propose in Docket Nos. EL14-22-000, *et al.* and RP14-442-000, will serve to

[20] *See e.g.*, *National Fuel Gas Supply Corp. v. FERC*, 468 F. 3d 831 at 840-844 (D.C. Cir. 2006).
[21] NOPR at P 27 (emphasis added).

> *better ensure the reliable and efficient operation of both interstate natural gas pipeline and electricity systems*.[22]

Whether the final rule achieves both goals will require a careful cost-benefit analysis of the expected and potential results of implementing the proposals. That review should be guided by the Commission's own stated goal of improving reliability and operational efficiency in both industries, which in turn will require a careful analysis of the impacts of the proposed changes on all segments of the natural gas industry, including LDCs. In that regard, one indication that a proposed change in operations and/or business practices is to the benefit of both industries is whether that change has met with consensus approval by market participants among both industries. If so, the changes are more likely to produce net benefits; if not, the changes are more likely to produce unreasonable adverse impacts.

4. The natural gas industry provided reliable service during the winter of 2013-2014.

In considering these goals of improved reliability and operational efficiency, the Commission should take note of the current robustness of the natural gas system in this country. As the past winter of 2013-2014 demonstrates, the natural gas production and delivery system in the United States is remarkably reliable, and it performed well during a period of unprecedented demand. The winter of 2013-2014 was the second coldest winter in the United States since 1985, and set natural gas consumption records, presenting the U.S. natural gas delivery system with a historic stress test.[23] The natural gas industry came through, demonstrating the resiliency

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[22] *Id.* at P 34 (emphasis added).

[23] Although it was a cold winter, it was not, in many regions, a design winter, nor did it include a design day. For example, in the Washington, DC area, the coldest day experienced this past winter was January 22, 2014, which had an average temperature of 16.1 ° F – 11.1 ° F above design conditions for the region.

and robust nature of our nation's natural gas infrastructure. From production to delivery, all parts of the value chain performed as they were expected to.

A significant weather system – the polar vortex – impacted large parts of the country and pushed the natural gas markets to unprecedented levels. According to the National Climate Data Center, energy demand in the continental U.S. was 27 percent higher than average during the 2013-2014 winter. According to Bentek Energy, seven of the top ten highest natural gas demand days in U.S. history occurred in January of 2014 (January 6, 7, 8, 22, 23, 24, and 28). On January 7, the country set a new demand record of 139 Bcf of natural gas.[24]

Residential and commercial customers used more natural gas than ever to keep warm. Weather-driven residential and commercial demand exceeded 65 Bcf per day for eight days in January alone, representing an extraordinary amount of demand load. Power generators pulled record volumes of gas to maintain electric system reliability. Industrial demand for natural gas increased, and even exports of natural gas to Mexico remained strong. It was an exceptional winter for natural gas deliveries.

Despite the extreme conditions and often with only a few days' notice, the entire natural gas value chain was able to meet the demand due to extensive system planning and the flexibility and efficiency of our nation's natural gas infrastructure. Natural gas storage was leveraged like never before to help meet customer needs last winter. More than 3 Tcf of working gas was supplied to the pipeline grid from November 2013 through March 2014 – a winter heating season record. These withdrawals were underpinned by a decade of growth in storage infrastructure. Our nation's storage capacity has increased by more than 18 percent since 2002. And, despite

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[24] As a point of reference, total U.S. natural gas consumption on a warm day in March 2014 was 68 Bcf.

the significant drawdowns last winter, storage reserves have been replenished for this winter largely due to production increases this summer. The United States is currently producing approximately 4 Bcf per day (about 6 percent) more than it did last year. The existing network of more than 300,000 miles of natural gas transmission pipelines has enabled the U.S. to benefit quickly from the shale gas revolution. Due to natural gas supply abundance, robust storage assets, a vast network of transmission and distribution pipelines, and prudent planning by utilities and portfolio managers, the natural gas industry performed to expectations last winter delivering natural gas to those who needed it.

Moreover, despite the extreme conditions of last winter, natural gas prices remained relatively low and stable throughout the winter period, particularly in contrast to price fluctuations experienced over the past decade. *See* Figure 1 below.

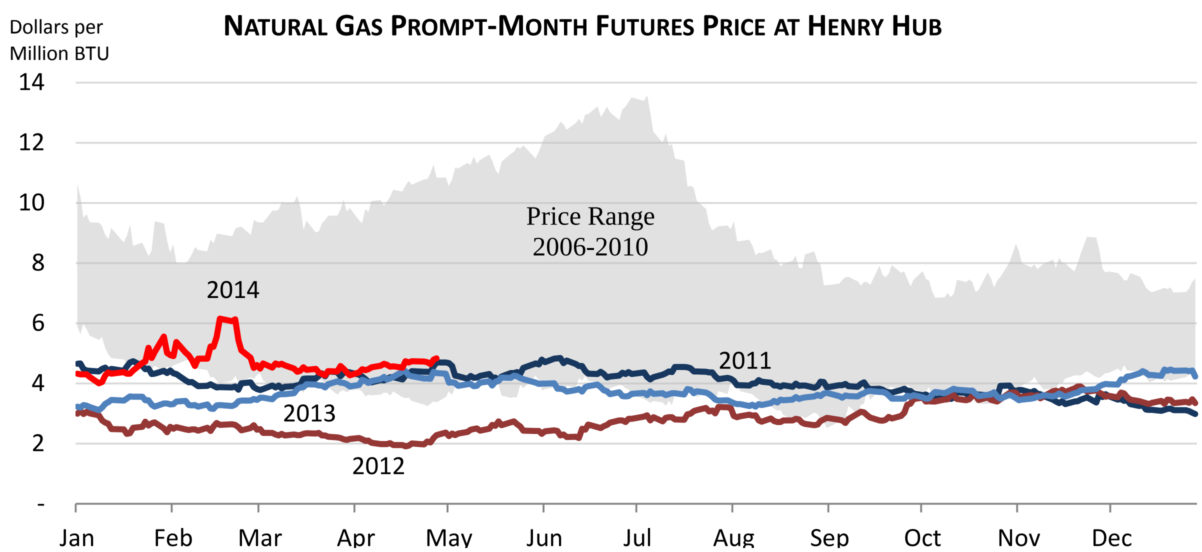

Fig. 1

This relative stability does not imply that price movements were non-existent. For several days in February 2014, natural gas futures prices sat above $6 per MMBtu due to persistent high demand, temporary disruptions to flowing gas and, in some cases, constrained storage supplies; however, futures prices fell quickly back down to the $4 range. Local cash prices jumped temporarily in the Northeast and parts of the Southeast due to basis differential blowouts. Notably, the extreme price movements experienced in those areas signal a need for additional natural gas infrastructure in those regions or other steps to improve generator fuel security. Yet, even in New England where pipeline capacity constraints posed real challenges in satisfying peak winter demand, customers that had purchased gas supplies through term contracts (rather than on the New England spot/cash market) paid prices close to Henry Hub prices at the time (*i.e.*, in the \$4.50 - \$5.50 per MMBtu range). Moreover, spot market prices reflect the price of gas delivered to the point of use. In other words, paying a high spot market price only when needed must be compared to paying an average commodity price together with the cost of holding firm pipeline capacity year-round. Thus, high prices on a limited number of winter peaking days is not necessarily a reliability issue or a market dysfunction; rather, it may simply reflect the economic choices of market participants in sourcing their gas supplies.

Despite the challenges presented this past winter, the natural gas industry responded. Customers were served. Reliability and safe delivery were maintained. Overall, the natural gas system performed as expected. Given our abundant natural gas supplies and robust natural gas infrastructure, the U.S. natural gas industry is poised to meet the needs of the nation's natural gas customers, including demand growth from the power sector. Thus, contentions that the natural gas industry is unreliable or unable to meet the needs of the electric industry are simply erroneous.

B. History of Proceeding

As described in the NOPR, the Commission has engaged in an extensive dialogue with both the natural gas and electricity industries on various aspects of gas-electric interdependence.[25] With respect to the coordination of the timelines for nominating and scheduling natural gas and electricity service, the Commission held a technical conference in April 2013 to consider issues related to whether and how additional harmonization could be achieved.[26] According to the Commission, the specific issues involving differences between the gas and electric scheduling processes that could affect reliability were identified as follows: (1) the discontinuity between the operating days of electric utilities (often midnight local time) and the standardized gas day (starting at 9:00 am CCT)); (2) the lack of coordination between the day-ahead process for nominating natural gas service and the day-ahead process for scheduling electric generators for dispatch, particularly in RTOs and ISOs; and (3) the lack of intraday nomination opportunities on interstate pipelines that would allow gas-fired electric generators to revise their nominations during their operating day.[27]

1. The NGC Process

Following the April 2013 technical conference, the Natural Gas Council ("NGC") embarked on an initiative to examine changes to the standardized gas nomination schedule that could improve coordination in the schedules between the natural gas and electricity industries. The NGC brought together system operators and gas traders from the major sectors of the industry (producers, marketers, interstate pipelines, distributors, industrial end-users, *etc.*) who were knowledgeable as to the gas scheduling and nomination rules to reach consensus to the greatest degree possible on potential modifications to the Commission's policies regarding the standardized gas nomination schedule to help facilitate enhanced coordination between the natural gas and electricity markets.

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[25] *Id.* at P 22.
[26] *Id.* at P 25.
[27] *Id.*

After much deliberation and debate, the NGC was able to achieve consensus on a framework of changes supported by the natural gas industry that could be used to engage in further dialogue with electric stakeholders. In particular, the NGC's consensus framework proposed to move the deadline for the Timely Nomination Cycle from 11:30 am CCT to 1:00 pm CCT, to have three intraday nomination cycles with deadlines in the morning, afternoon, and evening, such that the morning and afternoon intraday cycles would occur during normal business hours and allow firm transportation nominations to bump flowing interruptible service. Although the members developed and analyzed the consequences of several alternative schedules based on different gas day start times, there was no consensus among the participants to change the start of the gas day from its current 9:00 am CCT start time.

2. The NOPR

In the NOPR, the Commission recognized that industry participants were best positioned to work out the details of how changes in the scheduling practices can most efficiently be made and implemented.[28] The Commission, therefore, afforded industry participants an opportunity, working through NAESB, to reach consensus on modifications to the proposed gas nomination schedule.

In the NOPR, the Commission provided policy guidance to assist the industries in moving forward on coordination of scheduling practices. Specifically, the Commission proposed, among other things, to: (1) move the start of the gas day from its current 9:00 am CCT to 4:00 am CCT; (2) move the Timely Nomination Cycle deadline from 11:30 am CCT to 1:00 pm CCT; (3) provide four standard intraday nomination cycles at 8:00 am CCT, 10:30 am CCT, 4:00 pm CCT, and 7:00 pm CCT with the last intraday cycle remaining a no-bump cycle; and (4)

[28] NOPR at P 10.

clarify its policy regarding the ability of a firm shipper to bump a lower priority shipper during enhanced nomination cycles provided by pipelines.[29]

Under the Commission's proposal, the gas nomination schedule would be as follows:

Gas Nomination Schedule Proposed in the NOPR						
Cycle	**Nomination Deadline**	**Confirmation**	**Schedule Issued**	**Start of Gas Flow**	**Remaining Gas Day**	**Firm Bumping Rights**
Timely	1:00 p.m.		4:30 p.m.	4:00 a.m.	n/a	n/a
Evening	6:00 p.m.		10:00 p.m.	4:00 a.m.	n/a	Bumpable
Intraday 1	8:00 a.m.		11:00 a.m.	12:00 p.m.	16 hours	Bumpable
Intraday 2	10:30 a.m.		2:00 p.m.	4:00 p.m.	12 hours	Bumpable
Intraday 3	4:00 p.m.		6:00 p.m.	7:00 p.m.	9 hours	Bumpable
Intraday 4	7:00 p.m.		9:00 p.m.	9:00 p.m.	7 hours	No bump

In particular, the Commission proposed to move the start of the gas day to better accommodate the load increase in the morning for electricity systems. It found that moving the start of the gas day earlier would address instances in which gas-fired generators find themselves running out of scheduled natural gas capacity during the morning ramp-up period.[30] The Commission added that, based on an analysis of electric ramp periods in all time zones, moving the start of the gas day to 4:00 am CCT would allow generators in all regions to approach the morning electric peak as well as most of the morning ramp period with new daily nominations.[31] While the Commission recognized that moving the start of the gas day to 4:00 am CCT might result in increased staffing and other costs, including actions to be taken to mitigate potential safety issues associated with employees conducting manual operations in the dark, the Commission stated that the frequency under which those circumstances occur was unclear.[32]

[29] *Id.* at PP 8-9.
[30] *Id.* at P 39.
[31] *Id.* at P 40.
[32] *Id.*

The Commission believed that on balance the overall benefits to both industries of moving the gas day to include the morning ramp-up period in a single gas day outweighed the potential for increased costs.[33]

The Commission proposed to move the timely nomination deadline to 1:00 pm CCT to provide sufficient time for electric utilities to complete their process for selecting generating resources prior to the most liquid time in the natural gas supply and transportation markets.[34] In doing so, the Commission stated that in order to ensure that RTO and ISO clearing processes sufficiently align with the proposed Timely Nomination Cycle deadline, it has initiated investigations of all of the RTO and ISO tariffs to make sure the RTOs and ISOs modify their dispatch instructions in sufficient time to allow generators to acquire natural gas supplies and arrange transportation prior to the new timely nomination deadline.[35]

The Commission proposed to modify the gas nomination schedule to provide for four standard intraday nomination cycles in order to enhance shippers' ability to make significant changes to their nominations and provide greater flexibility to adjust to system conditions and changes in load throughout the day.[36] In that regard, under the Commission's proposal, the first three Intraday Nomination Cycles would be bumpable, but the no-bump rule would be retained for the last Intraday Nomination Cycle.[37] In retaining the no-bump rule for the last intraday cycle, the Commission expressed its belief that making the last intraday nomination opportunity no-bump adds stability to the nomination system and provides a reasonable balance between the

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[33] *Id.*
[34] *Id.* at P. 48.
[35] *Id.* at P 49.
[36] *Id.* at P 63.
[37] *Id.* at P 64.

needs of firm and interruptible shippers.[38] The Commission clarified that under its proposal, pipelines offering enhanced nomination opportunities should be permitted to bump interruptible shippers at least until the time when the bumping notice is provided under the last Intraday Nomination Cycle so that a bumped interruptible shipper will have an opportunity to re-nominate at the last Intraday Nomination Cycle.[39]

3. The NAESB Process

As detailed in NAESB's June 18, 2014 report to the Commission in this proceeding, NAESB's Gas-Electric Harmonization Forum convened in March 2014 to address the Commission's requests included in the NOPR.[40] As part of the effort, NAESB issued an industry-wide call for presentations offering alternatives to the Commission's proposals in the NOPR. Significantly, AGA member companies, the NGC, as well as the Desert Southwest Pipeline Stakeholders ("DSPS") and the Southwest Customer Group submitted presentations in the NAESB process.[41] NAESB participants met April 22-23, 2014, to review the presentations, and again May 5-6, 2014, to discuss issues and voting rules.

During the May 22-23, 2014 meeting, the NAESB participants developed and voted on nine separate alternatives, with variations to the gas day start time, number of cycles, cycle nomination deadlines, *etc.* Through a process of elimination, the NAESB participants narrowed the alternatives to four, all of which proposed a 1:00 pm CCT Timely Nomination Cycle deadline, a 6:00 pm CCT Evening Nomination Cycle deadline, three Intraday cycles at 10:00 am CCT, 2:30 pm CCT, and 7:00 pm CCT with the last cycle being non-bumpable. The only

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[38] *Id.* at P 69.
[39] *Id.* at P 71.
[40] NAESB June 2014 Report at p. 3.
[41] *Id.* at p. 5.

variation among the alternatives was the start of the gas day. The gas day start times for the four alternatives included 4:00 am CCT, 6:00 am CCT, 7:00 am CCT, and 9:00 am CCT.[42]

At the June 2-3, 2014 meeting, the NAESB participants used a series of binding votes where the alternative receiving the least amount of support was eliminated from further voting. The alternative based on a 6:00 am CCT gas day start time was eliminated first, and the alternative based on a 7:00 am CCT gas day start time was eliminated by the second binding vote.[43] With only two alternatives remaining, and in order to determine if participants could operationally support both options rather than merely communicating a preference, participants were asked not only whether they support their preferred alternative, but also whether they could support what for them was the less attractive alternative. While neither option garnered a supermajority of support, on a cumulative percentage basis, the alternative based on the current 9:00 am CCT gas day start time received the most support. The alternative based on a 4:00 am CCT gas day start time received 69 percent support from electric industry participants and just 28 percent support from gas industry participants, while the alternative based on the 9:00 am CCT gas day start time received 38 percent support from electric industry participants and 82 percent support from gas industry participants.[44]

A final binding vote was taken on the alternative based on the 9:00 am CCT gas day start time to determine if consensus support could be achieved. In that vote, 43 percent of electric industry participants and 86 percent of gas industry participants voted that they can support the alternative, while 39 percent of electric industry participants and 80 percent of gas industry

[42] *Id.* at p. 8.
[43] *Id.*
[44] *Id.*

participants voted that they do support the alternative.[45] Thereafter, the NAESB participants voted on an alternative that included the changes to the gas nomination schedule but did not specify a gas day start time. As to that alternative, 49 percent of electric industry participants and 82 percent of gas industry participants voted that they *can* support the alternative, and 45 percent of electric industry participants and 78 percent of gas industry participants voted that they *do* support the alternative.[46]

On June 4, 2014, the NAESB Board of Directors reviewed the results of the voting and agreed that although a NAESB-defined consensus had not been reached on a complete alternative, there was broad support from participants in both the gas and electric industries for the changes to the day-ahead and intraday nomination schedule.[47] The NAESB Board, therefore, directed the Wholesale Gas Quadrant ("WGQ") Executive Committee to develop standards to reflect the changes to the timely, evening, and intraday nomination cycle schedules consistent with the voting. Working through the appropriate NAESB committees, the WGQ developed standards as directed, which were approved by the WGQ Executive Committee on August 21, 2014, and ratified by the NAESB WGQ membership on September 22, 2014.[48] In particular, the NAESB WGQ supported the following changes in the gas nomination and scheduling standards:

- on the day prior to gas flow, the Timely Nomination Cycle would begin at 1:00 pm CCT and conclude at 5:00 pm CCT with scheduled quantities resulting from this cycle becoming effective at the start of the next gas day;

- the start of the Evening Nomination Cycle would remain at 6:00 pm CCT but would conclude at 9:00 pm CCT with scheduled quantities resulting from this cycle becoming effective at the start of the next gas day;

[45] *Id.*
[46] *Id.* at p. 10.
[47] *Id.*
[48] *See* NAESB September 2014 Filing at p. 3.

- the start of the Intraday 1 Nomination Cycle would remain at 10:00 am CCT but would conclude at 1:00 pm CCT with scheduled quantities resulting from this cycle becoming effective at 2:00 pm CCT on the current gas day;

- the start of the Intraday 2 Nomination Cycle would begin at 2:30 pm CCT and would conclude at 5:30 pm CCT with scheduled quantities resulting from this cycle becoming effective at 6:00 pm CCT on the current gas day;

- the new Intraday 3 Nomination Cycle would begin at 7:00 pm CCT and would conclude at 10:00 pm CCT with scheduled quantities resulting from this cycle becoming effective at 10:00 pm CCT on the current gas day;

- under the revisions to the nomination cycles, bumping would be allowed during the Intraday 2 Nomination Cycle in addition to the Evening Nomination Cycle and the Intraday 1 Nomination Cycle; and

- the NAESB proposed nomination cycle timeline would not be dependent upon any specific start time to the gas day.[49]

Thus, the standards developed by NAESB reflect the following agreed-upon changes:

NAESB Proposed Schedule						
Cycle	**Nomination Deadline**	**Confirmation**	**Schedule Issued**	**Start of Gas Flow**	**Remaining Gas Day**	**Firm Bumping Rights**
Timely	1:00 p.m.	4:30 p.m.	5:00 p.m.	?		n/a
Evening	6:00 p.m.	9:30 p.m.	10:00 p.m.	?		Bumpable
Intraday 1	10:00 a.m.	12:30 p.m.	1:00 p.m.	2:00 p.m.	?	Bumpable
Intraday 2	2:30 p.m.	5:00 p.m.	5:30 p.m.	6:00 p.m.	?	Bumpable
Intraday 3	7:00 p.m.	9:30 p.m.	10:00 p.m.	10:00 p.m.	?	No bump

V. COMMENTS

A. AGA supports NAESB's recommended revisions to the gas nomination schedule.

AGA supports adoption of NAESB's recommended revisions to the gas nomination and scheduling standards as being "consistent with the policies" of the NOPR while reflecting the broad support of natural gas and electricity industry participants regarding the best steps in

[49] *Id.* at p. 4.

improving the gas nomination scheduling standards. As the Commission recognized, broad industry support better reflects the facts and perceptions of those active in the natural gas and electric industries. Such is the case here.

NAESB's recommended revisions regarding the timely and intraday nominations cycles would also address the problems identified by the Commission that can be addressed through changes to the gas nomination schedule. If, for example, the RTOs/ISOs issue their day-ahead commitments prior to 1:00 pm CCT, moving the timely nomination cycle deadline to 1:00 pm CCT would allow an electric generator to make a timely gas nomination, thus providing it with a better opportunity to participate in the day-ahead nomination cycle during the most liquid time in the natural gas supply and transportation markets. By increasing the number of intraday cycles to three, having two intraday cycles during normal business hours in which firm transportation service would bump flowing interruptible service, and having a third, non-bumpable intraday cycle in the evening, together with the day-ahead evening cycle would address concerns that electric generators do not have sufficient opportunities during the gas day to make changes to their nominations to address changes in demand.

In addition, NAESB's recommended revisions address the ability of electric generators to meet their obligations during the morning electric ramp period by providing sufficient opportunities to schedule gas to cover that period on a planning basis. To the extent that the Commission remains concerned that electric generators and/or RTOs/ISOs need to be able to respond quickly to changes in power sector demand during the morning electric ramp period, AGA submits that that issue is not properly addressed through changes to the gas nomination schedule. Rather, the needs of large, highly variable loads are best served reliably by a portfolio of assets and services or alternative fuel requirements that can accommodate changes of significant volume on short notice. Spot market purchases at a generator's delivery point may also be used to cover changes on short notice; however, such purchases can be costly if the changes occur at times of lower gas market liquidity, *e.g.*, during the early morning hours of the electric ramp period, and may not be available at all during periods of peak natural gas demand. Thus, NAESB's recommended revisions to the standard gas nomination schedule satisfactorily address the Commission's concerns raised in this proceeding to the extent such concerns are best addressed by changes to the gas nomination schedule. For all these reasons, therefore, AGA urges the Commission to adopt NAESB's recommended revisions.

B. AGA does not support changes to the gas day start time.

1. No industry consensus supports changing the start of the gas day.

The most contentious change proposed in the NOPR was the suggested change in commencement of the gas day from 9:00 am CCT to 4:00 am CCT.[50] The Commission tasked NAESB with achieving, if possible, a consensus proposal to implement the elements of the NOPR, and NAESB succeeded with respect to revising the timely, evening and intraday nominations and related aspects of the scheduling cycles. In doing so, the NAESB participants agreed that the proposed nomination timeline changes would not be dependent upon a certain start time to the gas day. Such agreement was reached because there was no consensus to change the gas day start time.

As detailed in the NAESB June 2014 Report, a series of ballots were taken regarding changes to the start of the gas day, and a process of elimination method was used to determine support for the various alternatives. The start times of 6:00 am CCT and 7:00 am CCT were eliminated with little support from participants in either the electric industry or natural gas

[50] NOPR at P 9.

industry. A series of votes were then taken in which the 9:00 am CCT start time was preferred over the 4:00 am CCT start time. As NAESB reported, "[o]n a cumulative percentage basis, however, the package including the 9:00 am CCT start to the gas day received the most support."[51] Later in that meeting, the participants voted on packages based on a 9:00 am CCT start time with overwhelming gas industry support and low electric industry support; however, no consensus was achieved.[52]

The results of the votes at NAESB reflect a profound difference in the assessment of the merits of changing the existing gas day start time as between the electric industry and the natural gas industry – with large, supermajority levels of support among the electric industry participants for changing it, and large, supermajority levels of opposition among the gas industry participants. This difference does not merely display a difference of view, but a deep division. Thus, the fact that the gas industry so strongly opposes a change to the start of the gas day should lead the Commission to more closely review the concerns of the gas industry over the potential effects of the proposed change. It is, after all, a consensus standard to be set for the gas industry.

The Commission should not view alternative times such as 6:00 am CCT or 7:00 am CCT as potential compromise outcomes. Importantly, the participants at NAESB considered these alternative times, but found that there was no consensus in favor of any alternative start time. Indeed, the 6:00 am CCT and 7:00 am CCT alternatives were the first to be eliminated. As a result, attempting to split the difference between the two industries by adopting a gas day start time between 4:00 am CCT and 9:00 am CCT has even less support among both industries than either the Commission's proposed time or the current time. Moreover, a gas day start time

[51] NAESB June 2104 Report, p. 9.
[52] *Id.*

between 4:00 am CCT and 9:00 am CCT would complicate matters during the morning gas ramp period of AGA members, particularly in the Central and Eastern time zones. While the NOPR analyzes the morning ***electric*** ramp period, it is noticeably silent – prejudicially so – with regard to the morning ***gas*** ramp period.[53] There is no record support or basis to move the start of the ***gas*** day during the morning ***gas*** ramp period. Accordingly, AGA supports retention of the current gas day start and urges the Commission to make no change to the start of the gas day.

2. Changing the gas day start time is unnecessary to improve reliability.

As noted above, NAESB's recommended revisions to the gas nomination schedule address the reliability issues identified in the NOPR that can be addressed through changes to the gas nomination schedule. To the extent the Commission remains concerned about the ability of electric generators, with highly-variable loads, to be able to arrange for gas supplies on short notice during the morning electric ramp period, AGA contends that such issue is better addressed by means other than changing the start of the gas day.

LDCs have been reliably meeting the needs of highly variable loads on short notice for decades. LDCs use a portfolio of assets including firm gas supplies from diverse sources and peaking gas supply contracts, coupled with firm pipeline transportation and storage services, pipeline no-notice services, as well as on-system storage and other facilities such as LNG or propane air storage to meet the peak demands of their customers. Storage and no-notice services are particularly effective in responding to load variability on short notice, especially during periods of low liquidity in the natural gas markets. As some LDCs have found, using spot market purchases to address changes in demand, even for a limited number of peak demand

[53] *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983) (requiring agencies to examine the relevant data and articulate a satisfactory explanation for its action that draws a rational connection between the facts found and the choices made).

days, is far less effective and may be costlier than purchasing additional storage or pipeline capacity. Indeed, changing the start of the gas day will not enable those paying high spot market prices to access the relatively low-priced markets upstream of a pipeline constraint.

There are far better ways to address the reliability needs of highly variable electric generator loads than changing the start of the gas day. A more productive approach would be to examine how the RTO/ISO markets can incentivize and compensate generators to purchase natural gas services that provide for the flexibility to make changes on short notice or to consider other steps to enhance fuel security, such as improving dual fuel capability. Pipeline no-notice or imbalance services allow generators to withdraw gas to meet their load requirements and then supply (pay back) the gas during a liquid period and at a grid-wide nomination cycle. These types of services, supported by the construction of appropriate gas infrastructure to support them, would be far more effective in meeting the reliability needs of electric generators than trying to force wholesale changes to the natural gas markets and the gas nomination schedule on an unwilling gas industry to accomplish the same result for some generators in some regions during some hours of the day at certain times of the year.[54]

3. The burden on LDCs of moving the start of the gas day would outweigh the potential benefits of the change.

Changing the start of the gas day from the current 9:00 am CCT to 4:00 am CCT would entail a number of costs and potential reliability and even safety-related risks adverse to LDCs,

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[54] The natural gas supply and transportation markets have demonstrated a willingness and aptitude in offering innovative services to meet the needs of customers. To the extent service gaps still exist AGA encourages the Commission to foster dialogue among industry participants to determine what additional services are required. In that regard, if new services are needed requiring additional gas infrastructure, the dialogue should include removing impediments to generators' contracting for such services in order to fund the necessary investments. As the Commission recently noted, for greater fuel assurance, it may be appropriate to adjust electric market mechanisms to include cost recovery for investments required for fuel assurance. *Centralized Capacity Markets*, 149 FERC ¶ 61,145 at PP 17-18.

though these would vary among regions and among LDCs. While not all LDCs will experience the same effects or to the same extent, the need for a change to the gas day start time must be assessed in light of the potential for these adverse effects to occur.[55]

Cost. Based on comments provided to NAESB and input from AGA's member companies, AGA submits that the proposed rule would impose significant costs on numerous members of the natural gas industry. The impact of the proposed change to the gas day would vary substantially by geographic region and within regions by companies. While some LDCs and other gas industry participants may not experience major additional costs, many LDCs do anticipate that they will, and such costs may be substantial depending on the operating circumstances and system configuration of the particular LDC.

For example, many LDCs expect that changes to the gas nomination schedule may entail significant costs in terms of re-programming of citygate stations, meters, and SCADA equipment. The costs incurred by LDCs, as well as costs incurred by interstate pipelines and flowed through to LDCs, would all be borne by end-use gas customers. Changing the gas day start time may result in increased costs for many LDCs in terms of additional staffing required during overnight or early morning hours for gas controllers, traders, and IT support. For some LDCs, both the one-time implementation costs as well as the on-going annual costs are projected to be in the millions of dollars. In addition, LDCs may be required to incur costs to recalculate design peak day and peak hour needs potentially necessitating changes to LDC supply portfolios.

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[55] A more complete description of the impacts set forth in this section can be found in *Analysis of Potential Impacts to LDCs on Changes to the Gas Day Start Time,* dated November 5, 2014, prepared by the AGA Gas Control Committee. The Analysis can be found at http://www.aga.org/our-issues/RatesRegulatoryIssues/gas-and-electric-interdependency/other-resources-library/AGA/Documents/AGA%20Paper_%20Analysis%20of%20Potential%20Impacts%20to%20LDCs%20on%20Changes%20to%20the%20Gas%20Day%20Start%20Time.pdf.

Changing the gas day start time may also require LDCs to revise or renegotiate customer and gas supply contracts and/or tariffs that reference the current gas day start time or require or allow for actions to take place keyed to the start of the gas day.

Potential reliability- and safety-related risks. A number of AGA's member companies have expressed concern as well regarding the potential for adverse impacts on reliability and the danger of increased operational risk, given their geographic location, operational status and procedures. In particular, some members believe that increased field work during the night, including undertaking valve and station work in the dark, may potentially add operational risks. AGA notes that depending on system operational configurations and geographic location, these issues may not affect all LDCs; however, a survey of LDCs revealed that 19 out of 53 LDCs conduct manual operations hourly, and that another 19 LDCs conduct manual operations daily.[56]

Many significant LDC activities occur just before or at the start of the gas day that would be difficult or costly to do if the gas day start time were moved to 4:00 am CCT. Examples include updating weather forecasts, forecasting demand from various customer groups (including gas-fired generators), forecasting interruptible service requirements, verifying volumes from interconnected pipelines, evaluating supply options, evaluating balancing needs, and coordinating storage injections or withdrawals. In addition, LDCs are concerned that the reliability of upstream flows from non-regulated production, processing, gathering entities, marketers as well as intrastate pipelines and interstate pipelines, may not be able to match shifts in demand by the LDC on a real-time basis at the earlier hours. In that regard, some LDCs are concerned that if upstream entities (producers, processors, pipelines, *etc.*) forego night-time manual operations, downstream supply shortages may ensue. Not all LDCs have on-system

[56] *Analysis* at p. 2.

storage or compressor stations; they therefore rely on upstream pipeline pressures to ensure reliable service to customers.

In addition, LDCs on some pipelines make “true-up” or “clean-up” nominations for the prior gas day during the early morning hours when other gas traders, controllers, and operations personnel are available to provide critical information, make corrections, and compare nominations and contractual limits to actual receipts and deliveries. As currently structured with a 9:00 am CCT start to the gas day, traders and schedulers arriving for work in the early morning hours (*e.g.,* at 6:00 am CCT) still have time to make adjustments to the prior gas day, since they would still have, in this example, three more hours until the end of the gas day. Personnel at other companies are typically also on duty at that hour, enabling the parties to address any overnight developments or imbalances that may have arisen, reduce imbalances, and otherwise resolve issues pertaining to the prior day’s business, to the benefit of all parties. Under a 4:00 am CCT gas day model, it would be exceedingly difficult to replicate this type of business activity in the 1:00 am CCT timeframe, since key decision-makers would not be on duty at that hour. Thus, moving to a 4:00 am CCT gas day would certainly undermine this key benefit for the gas and electric industries, while it is still unclear whether any of the desired benefits for electric generation would in fact be realized.

Further, many LDCs with pipeline operations rely on the early morning hours to pack their systems in anticipation of the morning load. Currently, early morning flows are predictable in that scheduled quantities are known through the 9:00 am CCT hour. Moving the start of the gas day earlier, with the attendant need to change flows in the middle of the night, would create uncertainty as to the changes that will occur in the middle of the night and hence whether the LDC will be adequately prepared for the morning peak. This could potentially lead to less system flexibility, increased issuances of OFOs, or load shedding. Notably, if load shedding is required, it is likely that large customers, including electric generators, could be affected. In other words, changing the gas day start time could adversely affect the very entities the Commission is most attempting to help.

The proposed changes in the gas day could also have an impact on the entire natural gas value chain of producers, gathering systems, processors, intrastate pipelines, interstate pipelines, and LDCs, based on the fact that these segments and participants need to coordinate operations. The vast natural gas infrastructure (plants, compressors, thousands of wells and millions of miles of pipelines encompassing gathering, transmission and distribution) is, in many instances, unmanned and not supported electronically, thus often requiring the dispatch of personnel to remote worksites to make the necessary physical changes to maintain services and operations.[57] This aspect of the gas industry is not likely to change, and physical, manual operations will remain common. Even the redirection of flows resulting from a new batch of nominations that are so common at the start of a new gas day may require manual intervention. Changing the gas day start time to nighttime would raise significant operational and financial concerns, including the potential for shipper imbalances to become more difficult to manage.[58]

The Commission's proposed 4:00 am CCT gas day would place the gas day start time during a crucial gas load ramp-up period for many LDCs in the Eastern and Central time zones, while at the same time moving all the activity associated with the start of the gas day to the very time of day when personnel working for LDCs in the Pacific and Mountain time zones are, due to their circadian rhythms, at their lowest level of attention. Human behavior experts believe that

[57] See *Assessment of Gas Scheduling Changes to Assist Power Customers*, Presentation of Natural Gas Council to NAESB, Apr. 22, 2014.
[58] *Id.* at pp. 4, 16.

reaction times, hand-eye coordination, simple math calculations, driving and flight simulations are all at their minimum from 12:00 midnight to 7:00 am, with a 15 to 30 percent performance drop at 3:00 am from peak operator performance.[59] As a result, both the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and the National Transportation Safety Board have recognized the effects of human fatigue and natural circadian rhythms on pipeline operations. PHMSA requires transmission pipeline operators to employ fatigue mitigation tactics during shifts or times of increased fatigue, including "any and all hours worked between 2:00 am and 6:00 am."[60] As NAESB recognized in its June 2014 report, entities in the Western United States, including not only LDCs, but also gas end-users and electric generators, objected to the proposed 4:00 am CCT gas day start, which would be 2:00 am Pacific Time.[61]

The current start of the gas day was adopted by the gas industry as a compromise proposal from a decade and a half ago and has proven to be a time that the industry can work with both efficiently and reliably. Changing the gas day start time to 4:00 am CCT will create significant costs and risks, all for the uncertain goal of enhancing the reliability of some electric generators on some days during the morning electric ramp period. For the reasons discussed above, the other changes in timely, evening and intraday nomination schedules address much of those generator concerns, while not facing the opposition of a supermajority of the gas industry, as NAESB found. Because the benefits of the proposed change to the gas day start time appear so limited, and the costs potentially substantial, and in light of broad gas industry opposition, AGA submits that the Commission should not change the gas day start time in this rulemaking.

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[59] *See* Circadian Technologies, Inc. (2005) *Safety & Alertness in the Post HoS Environment: Practical Performance Based Measures*. (Presentation).
[60] *See* http://primis.phmsa.dot.gov/crm/docsf/faq.pdf.
[61] NAESB June 2014 Report at pp. 6-7.

In light of these factors, the record in this proceeding does not support the Commission's tentative conclusion in the NOPR that, "the overall benefits to *both industries* of moving the Gas Day earlier so that the morning ramp period for gas-fired generators and other gas consumers is included in a single Gas Day outweigh the potential for increased costs that may be incurred."[62] AGA contends that the record – including the presence of widespread opposition in the gas industry, lack of a cross-industry consensus on an alternative to the current 9:00 am CCT gas day start time, and the strong evidence of potential costs and adverse impacts on reliability and safety particularly for LDCs – strongly suggests that there is an insufficient basis to change the start of the gas day at this time.

C. AGA does not support the Desert Southwest Pipeline Stakeholders' proposals.

In its October 14, 2014 Notice in this proceeding, the Commission observed that the Desert Southwest Pipeline Stakeholders ("DSPS") has submitted an alternative proposal to NAESB and that comments in this proceeding should address such proposal. The DSPS proposed to the Commission to move the Evening Nomination Cycle deadline from NAESB's proposed 6:00 pm CCT to 7:00 pm CCT, and to modify the Commission's bumping policy to allow firm transportation service from a primary receipt point to a primary delivery point to bump secondary firm nominations in the Evening Nomination Cycle.

AGA does not support these proposals because they are inconsistent with the recommended standards developed by NAESB with wide-spread support from market participants and would dramatically revise the Commission's "no-bump" policies. In particular, having the evening cycle overlap with the Intraday 3 Cycle (both nomination deadlines occurring at 7:00 pm CCT) would be unwise. Requiring gas schedulers to make both day-ahead and

[62] NOPR at P 40 (emphasis added).

intraday nominations at the same time is likely to result in confusion and error. Moreover, under the Commission's current "no-bump" policies, a nomination of firm transportation service on a secondary basis that is made and accepted in the timely nomination cycle cannot be bumped in later cycles. Such a policy effectuates the Commission's flexible receipt and delivery point policies as set forth in Order Nos. 636 and 637, and underpins much of the value shippers derive from firm transportation service. Further, the proposals would adversely impact gas customers by devaluing capacity release and reducing revenues from secondary market sales that are used, particularly by LDCs, to mitigate the costs of holding firm capacity. The Commission should not entertain such a dramatic change in its policies simply because one class of shippers in one region of the country asked NAESB to consider an alternative proposal.[63]

At the heart of the DSPS's proposals lies a set of regional problems. Significant reliance on renewable resources together with the lack of natural gas storage infrastructure and the economic and environmental challenges in building storage infrastructure in the desert Southwest United States are driving the DSPS's proposals. Clearly, these problems do not obtain in other parts of the U.S., nor is there any record basis to conclude that they will, which the DSPS acknowledge. The Commission should not adopt a nation-wide standard that impacts the gas industry across the entire country in an attempt to address what has only been shown to

[63] During the NAESB process, the DSPS proposed to modify the NAESB standards so that pipelines with enhanced nominations could allow firm transportation service to bump flowing interruptible service even in the last NAESB intraday cycle if the pipeline offered a subsequent no-bump cycle. AGA similarly does not support this alternative proposal because it is inconsistent with the principles and standards developed during the NAESB process and would dramatically revise the Commission's current "no-bump" policies to the detriment of gas customers. Allowing flowing interruptible service to be bumped in the last intraday nomination cycle would raise implementation issues, particularly for deliveries using multiple pipelines. All of the interconnected pipelines downstream along the delivery path would need to support a subsequent no-bump cycle in order to provide interruptible service an opportunity to make alternate arrangements.

be a regional issue. Accordingly, AGA urges the Commission to not adopt the DSPS's proposals at this time.

D. The Commission should implement changes to the gas nomination schedule contemporaneously with changes to the electric schedules.

In the NOPR, the Commission contemplated that it could incorporate by reference in a final rule the consensus standards that NAESB develops.[64] The Commission also noted that it was instituting proceedings under Section 206 of the Federal Power Act to coordinate the day-ahead scheduling of the RTOs/ISOs with the revised gas nomination schedule.[65] As stated in the NOPR, the purpose of such proceedings is to ensure that RTO/ISO market clearing processes will sufficiently align with the revised gas nomination schedule. In particular, RTOs/ISOs will be required to provide their generators with dispatch instructions in sufficient time for the generators to be able to acquire natural gas and transportation service by the timely nomination deadline, and complete their supplemental reliability dispatch in sufficient time for generators to use the evening cycle.[66]

AGA believes that in order to maximize the benefits of any change to the gas nomination schedule, such changes must be coordinated with the changes to the RTO/ISO scheduling practices. Consequently, the Commission should only implement the changes that it makes to the gas nomination schedule through a final rule in this proceeding contemporaneously with any changes to RTO/ISO scheduling practices ordered in the FPA Section 206 proceedings in Docket No. EL14-22-000, *et al*. In order to achieve the goal of improved electric reliability through greater generator participation in the gas scheduling process, changes to gas scheduling processes must be coordinated with the changes in the electric scheduling processes.

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[64] NOPR at P 11.
[65] *Id.* at P 2. FERC Docket Nos. EL14-22-000, *et al*.
[66] NOPR at P 49.

As the Commission recognized in the NOPR, in order for electric generators to obtain the value in terms of enhanced reliability of moving the timely nomination deadline to 1:00 pm CCT, the generators should receive their dispatch instructions in sufficient time to acquire natural gas supplies and transportation service by the nomination deadline.[67] It thus makes little sense for the Commission to require the entire natural gas industry to incur the expense and disruption of changing the gas nomination schedule, if the RTO/ISO scheduling practices do not allow electric generators to take advantage of the changes.

As the Commission should recall from the implementation of Order No. 637, significant changes to the gas nomination schedule can be a massive undertaking requiring all natural gas market participants to undergo review and modification of business practices and technology systems, which cannot be done overnight or even in a few months. It is reasonable to expect that the changes to electric scheduling practices and the stakeholder processes required to identify and effectuate such changes will be no less of an undertaking. AGA believes that the Commission should not require changes to the gas nomination schedule until all of the implementation issues are examined and addressed, including the required changes to the electric schedules in order for electric generators to obtain the benefits of the changes to the gas nomination schedule. Accordingly, AGA urges the Commission to coordinate the changes to both gas and electric schedules and to require modifications to the gas nomination schedule as part of a final rule in this proceeding to be implemented contemporaneously with the modifications to RTO/ISO schedules required in Docket Nos. EL14-22-000, *et al*.

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[67] *See id.*

E. AGA supports the use of multi-party contracts, if implemented in individual pipeline proceedings with input from customers.

Finally, the Commission proposed changes to the open access regulations to permit transportation contracts in which multiple shippers could "share interstate natural gas pipeline capacity under a single service agreement," with the goal of ensuring greater efficiency in the utilization of pipeline capacity.[68] The specific language proposed in the NOPR would constitute, in effect, an exception to the Commission's shipper-must-have-title policy and its requirement that capacity be made available by one shipper to another only under the uniform capacity release program.[69] The Commission stated the expectation that, although open to all shippers, gas-fired generators might find greater access to firm capacity by means of multi-shipper agreements in company with LDCs or industrial customers having complementary needs, thus potentially better aligning supplies to generators.[70]

As discussed in the NOPR, the Commission has accepted multi-party contracts voluntarily filed by a number of pipelines since 2008.[71] The tariff requirements of Gulf South Pipeline Company appear to be typical of the current multi-shipper contracts and require the multiple shippers to demonstrate that each shipper is jointly and severally liable for all obligations and that they collectively meet the Commission's shipper-must-have-title requirements.[72] The Commission has already clarified that the "joint and several liability" and

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[68] NOPR at P 76.

[69] *Id.* at P 77. The proposed text is as follows:

> "(v) A pipeline must allow multiple shippers associated with a designated agent or asset manager to be jointly and severally liable under a single firm transportation service agreement, subject to reasonable terms and conditions."

[70] NOPR at P 79.

[71] *See, e.g.*, NOPR at PP 77-78, fn. 107 through fn. 110. *See also*, Elba Express Company L.L.C. and Gulf South Pipeline Company, LP.

[72] Gulf South Pipeline Company, LP, FERC NGA Gas Tariff, Seventh Revised Volume No. 1, Terms & Conditions, Section 6.21.13.

demonstration of being able to "collectively meet" the shipper-must-have-title requirement adequately address its title policy. In the NOPR, the Commission suggested that the new, mandatory right to use a multi-party firm transportation service might have two conditions: (1) that the shippers and agent demonstrate their agency relationship in writing; and (2) that the shippers be willing to be treated "collectively as one shipper for nomination, allocation, and billing purposes under the contract."[73] The Commission thus sought comment on whether pipelines should be required to offer multi-party interruptible service.[74]

AGA generally supports the proposed regulation, consistent with AGA's long-standing support for maximizing the ability of firm shippers to use and manage their contract entitlements thus maximizing the value of such entitlements.[75] AGA further agrees with the Commission that shippers may benefit from broader access to multi-party contracts, whether to permit sharing of capacity with electric generators, other LDCs, or other shippers, as long as service to existing shippers is not degraded. Greater flexibility as to firm capacity may lead to greater efficiency in pipeline capacity use and greater value for firm shippers, consistent with the goals expressed in the NOPR.

AGA, however, recommends that the Commission permit pipelines to implement this regulation through tariff filings to be considered in individual proceedings, with sufficient latitude for pipelines to work with their customers to tailor the specific tariff terms and scope of the new provisions to their varied individual circumstances. Despite some commonality of

[73] NOPR at P 80.
[74] *Id.* at P 81.
[75] For example, AGA supported the Commission's efforts to lift the price cap for short-term releases and to provide for appropriate exceptions to the bidding and posting requirements for asset managers and state-approved choice programs, among other changes, in Order No. 712. *Promotion of a More Efficient Capacity Release Market*, Order No. 712, FERC Stats. & Regs. ¶ 31,271, *order on reh'g*, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008).

conditions for the current multi-party contracts, all of the tariff provisions for such contracts are voluntary, and are not identical in scope and characteristics – *e.g.*, some extend to firm service, while some extend to rate schedules such as IT, PAL, pooling and ICTS (Transco), and others permit small customers to use the multi-party contract option while still maintaining their small customer FT charge (Southern). In addition, despite the authorization of a number of such tariff provisions, not all pipelines have sought such authority.

Moreover, the pipeline tariffs differ somewhat regarding the scheduling priorities for firm contracts. Typically each contract only has one primary receipt and one primary delivery point, or has limited primary points. Fitting multi-party contracts into different pipelines' scheduling systems may require some system-by-system variations. Individual pipelines may need to address system-specific issues in implementing a mandatory multi-party tariff provision in consultation with their customers, given the differing operational and tariff provisions among the various pipelines.

Consequently, AGA supports the language of the proposed rule, but recommends that the Commission provide in the final rule that pipelines should make individual filings implementing any necessary tariff revisions in consultation with customers, and consider the relevant circumstances of each pipeline in addressing each pipeline's compliance filing.

VI. CONCLUSION

For the reasons provided in detail above, the AGA recommends that the Commission issue a final rule in this proceeding that adopts the recommended revisions to the gas nomination schedule set forth in the standards developed by NAESB, that does not change the start of the gas day from its current 9:00 am CCT start time, that does not change the gas nomination schedule or capacity allocation rules as proposed by the Desert Southwest Pipeline Stakeholders, that requires any modifications to the gas nomination schedule as part of a final rule in this proceeding to be implemented contemporaneously with the modifications to RTO/ISO schedules required in Docket Nos. EL14-22-000, *et al*., and that permits pipelines to implement multi-party transportation contracts, through individual tariff filings after consultation with customers.

Respectfully submitted,

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