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**TO:** NAESB Gas-Electric Forum and Interested Parties

**cc:** NAESB Board of Directors, Executive Committee (EC) Members, EC Alternates, Members, and Advisory Council

**FROM:** Rae McQuade, NAESB President & Jonathan Booe, NAESB Executive Vice President & COO

**RE:** NAESB Gas-Electric Forum Survey Responses – January 31, 2023

Dear NAESB Members, GEH Forum Participants and Interested Parties,

Please find below the comment received by the NAESB Office in response to the survey/request for comments that was distributed on January 23, 2023 related to the Summary of Comments by Topic Areas Identified by FERC and NERC Staff - January 23, 2023: <https://www.naesb.org/pdf4/geh020223w3.docx>.

|  **Responses Submitted by January 31, 2023** |
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| **Question/Topic** | Please review the Summary of Comments by Topic Areas Identified by FERC and NERC Staff (<https://www.naesb.org/pdf4/geh020223w1.docx>) and respond to the following questions. 1) Are there areas or proposals outside of those included in the discussion paper that the Forum should consider? If so, what are they?2) Do you have any comments on the categorizations and summaries provided in the discussion paper? |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1  | Interstate Natural Gas Association of America | Christopher Smith | WGQ Pipeline | INGAA appreciates the opportunity to comment on NAESB’s compilation of comments received from participants in the Gas-Electric Harmonization Forum as well the accompanying summary. Participants have submitted a substantial number of proposals that implicate many areas of the electric and natural gas industries. As the Forum Panel reviews the comments and determines which proposals warrant further consideration and discussion, INGAA urges the Panel to keep in mind FERC’s and NERC’s charge to develop “plans for implementing concrete actions to increase the reliability of natural gas infrastructure system necessary to support the Bulk Electric System” as well as the fundamental regulatory tenet that those receiving the benefit should be the ones to pay for it. The Panel should identify—and Forum participants should discuss—only those proposals that meaningfully improve the reliability of the Bulk Electric System in an economic manner and that assign the cost of those proposals to the electric customers who benefit from enhanced electric reliability. The Forum should not devote its time and resources to exploring proposals that provide marginal improvements to the reliability of the Bulk Electric System (or no improvements at all) or that impose substantial burdens on natural gas customers to benefit electric customers. INGAA looks forward to working with the Forum Panel and other Forum participants to develop practical, effective actions to enhance the reliability of the Bulk Electric System. |
| 2 | Xcel Energy Services, Inc. | Terri Eaton | WEQ Marketer/Broker | I. IntroductionWe appreciate the North American Energy Standards Board's (NAESB's) initiative to evaluate potential mechanisms to better align the needs of the gas supply industry, the gas transportation industry, and the electric industry. Alignment is needed to improve timeliness and reliability of access to both gas and electricity to support public health and safety and power our economy.Our comments below are intended to frame our view of the issues and potential solutions between and among the three discrete industry segments identified above. In addition, we are approaching our comments with the understanding that the final output of this effort will be a report containing policy considerations and recommendations and that existing laws and rules do not necessarily bound the scope of potential solutions to be evaluated. Wherever possible, our recommendations are focused on solutions that are fundamentally market-based.We engage in this debate as an entity with affiliates that own and operate:* gas distribution facilities (LDCs) in Colorado, Michigan, Minnesota, North Dakota, and Wisconsin
* electric utilities in the Midcontinent Independent System Operator (MISO) market, the Southwest Power Pool (SPP) market, and Colorado
* gas and LNG storage facilities in Colorado, Minnesota. and Wisconsin
* a small suite of inter and intrastate pipeline facilities

We have significant experience as a gas commodity purchaser, transportation capacity purchaser and operator for both LDC and electric generation needs, and an owner and operator of electric generation and transmission resources. Further, we are at the forefront of efforts to integrate renewable and other zero carbon resources into our power generation fleet. As such, we acutely understand many of the challenges associated with aligning the needs of the gas and electric industries.II. Recommendations Regarding Gas Supplya. Weatherization of Gas WellsAvailability of reliable gas supplies is critical to health, safety, convenience, and the economy. No amount of gas-electric "harmonization" efforts will work absent a reliably available gas supply, especially during extreme conditions. Unfortunately, experiences with Winter Storms Uri and Elliott expose that gas supply is not immune to changing weather patterns that are driving more severe and more protracted extreme weather events and have significant impacts on the heating and electric generation markets. While Uri may have led some to believe the issues with well freeze-offs are limited to climates that have historically been relatively warm across winter months, Elliott clearly demonstrates that even production in colder climates is at risk.We consider the standard NAESB gas purchase contract forms a disincentive to proper weatherization of gas wells. The standard NAESB gas purchase contract forms include a blanket *force majeure* out for gas suppliers who have not adequately weatherized their equipment:*Force Majeure shall include but not be limited to the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of re pairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption of firm transportation and/ or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, or regulation promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance. (highlight added)*This language should be removed from the contract and replaced with language that imposes a reasonable design standard for weatherization.In addition, greater transparency about freeze-offs might also move this issue forward in a positive direction. Specifically, we recommend that all gas suppliers be required to annually post data showing the level of well freeze-offs experienced during cold winter periods. This would give purchasers more information about where they can source gas that is less susceptible to freeze-offs and potentially result in greater weatherization across the board for suppliers to remain competitive.We also note that we generally disagree with comments that have been made in this proceeding that purchasers can get greater access to gas if they are willing to pay more. The NAESB standard purchase contract simply does not provide for varying levels of firm supply service at any price. Further, these suggestions misinterpret the existing NASEB contract. Under the existing agreement, sellers already commit to providing firm gas supply service, and purchasers pay for that service. The answer is not to extract higher payments out of purchasers; it is that sellers should live up to the contractual commitments they make.b. Purchase Horizon for Weekends and HolidaysFor all practical purposes, the market to procure natural gas for weekends and holidays is only in advance of the event. The effect of this is that, for weekends, gas must be procured on Friday for the following Saturday, Sunday, and Monday, and for long holiday weekends, gas must be procured on Friday for the following Saturday, Sunday, Monday, and Tuesday. While there are limited transactions that occur during weekends and holiday periods, there is not a sufficiently liquid market to enable a user to effectively procure needed supply over the weekend or holiday period, particularly when weather results in increased demand for natural gas.Further, gas suppliers rarely differentiate in quantities across a weekend or holiday period - meaning purchases are generally "ratable" or equal for each day. So, the largest amount of gas a purchaser needs for the period sets the purchase amount for every day of the period. Over a holiday weekend, if a purchaser's peak gas usage is forecasted to occur on Saturday, it must purchase the same amount of gas for Saturday, Sunday, and Monday. Because there are effectively no exceptions to this practice, purchasers are required to over-procure gas over weekends and holidays. This over-procurement can increase costs to customers, create excess demand for gas, and in some cases (such as Winter Storm Uri, when gas prices rose dramatically in advance of the long weekend), saddle customers with significant costs for gas they may not strictly need.More flexibility is needed for purchases across weekend and holiday periods. We encourage leadership of the Gas-Electric Harmonization (GEH) forum to address this issue. Our preferred approach would be regulations prohibiting gas suppliers from requiring ratable purchases across weekend and holiday periods, but we are open to more market-based solutions that would be widely adopted.c. Shared gas supplyWe have listened with interest to discussions about centralized procurement and storage of gas supply for generation resources. This concept may be attractive to some purchasers, and we would support development of this concept on a voluntary basis. The focus of the NAESB effort, in our view, would be a full evaluation of barriers to such an approach.III. Gas TransportationGenerally speaking, we agree with commenters that have advocated for increasing transportation capacity for pipeline customers willing to pay for such expansions. The cost of such expansions should be borne by those customers needing the increased transportation capacity. Customers already holding adequate transportation capacity should not be asked to share in those costs.In terms of policy recommendations, we think it would be useful to explore whether permitting requirements could accommodate greater flex or speculative capacity that would help create more headroom in the system to accommodate extreme demands. Second, we agree with commenters who have suggested that a relatively simple system be developed to allow users to sell excess supply-and its associated transportation-in anticipation of or during an extreme event. Regulators should evaluate rules to eliminate barriers to such sales and facilitate ease of transaction by entities with such excess capacity.We do not support suggestions that transportation for specialized needs should somehow be able to trump purchased firm transportation. As a consumer of gas we strategically purchase firm gas transportation for our business needs. Any mechanism that would undermine the value of our firm transportation would undermine the contractual expectations of parties and likely result in less firm transportation purchases than exist today because firmness would lose its value. Additionally, any such mechanism would negatively impact the human needs we directly serve and potentially the sources of supply delivering gas to us. In our view, such an outcome would be harmful to the gas transportation industry.IV. RTO and ISO MarketsSince the first NAESB GEH forum in the early 201O's, we have been thinking about how to better align the gas and electric days in their respective markets. After much internal deliberation, we have not identified any solutions that would bring meaningful change. There is a fundamental chicken and egg problem that is largely insurmountable within the context of the normal gas and electric operating days. A generator operating in an organized market doesn't know how to price its offers until it knows the cost of gas. The cost of gas isn't known until purchases are made. But generators take on gas cost risk if they purchase gas before they know whether their units will run. The issue is circular, and it is not clear to us what mechanisms there are to effectively break this cycle. Further, we estimate that usage of gas for generation amounts to about 20% of the gas market, on average. We question whether it makes sense to fundamentally alter the existing market to meet the needs of 20% of the gas market when the other 80% of the gas purchase market seems comfortable with that market.On a normal day, these chicken and egg issues are largely manageable. But when extreme weather is forecasted, the financial risks of buying gas in advance of commitments become much harder for generators to take on.In our review, ISOs and RTOs need to rethink the notion that market forces should be the exclusive driver of outcomes when extreme conditions are projected. In these situations, it may be that RTO and ISO markets should shift to a different mindset, an event-driven mindset, and deploy a forward commitment process that lines up units well in advance of the gas purchase horizon. Make-whole payments would be needed to protect the generators against gas price volatility and against a change in circumstance that obviates the need for generation.We note we have also heard some commenters argue that markets should take steps to further incent firm gas transportation capacity, potentially through performance penalties or other financial consequences of non-performance. If all generators were allowed by their organized markets or state regulatory agencies to recover the fixed costs of firming up transportation capacity, then we would expect to see much more firm capacity in use. While such mechanisms could help drive reliability of the system, no incentive/penalty structure is going to completely solve the gas supply availability problem if gas suppliers are not incented to weatherize their equipment. In our view, the more cost­ effective solution is to implement requirements that mandate weatherization and require transparency about gas supply performance during extreme events.We appreciate due consideration of our recommendations.\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_The following commentary is provided by reference to the sections in the Summary of Comments by Topic Areas Identified by FERC and NERC Staff.1a) Generally these comments support transparency, which we support. Many of the recommendations are recommendations that are already employed in various regions. We do not believe that regulatory/policy mandates are needed to further transparency in these areas.1b) We generally do not favor regulatory/policy mandates surrounding issues identified in this section. Individual market participants have the ability to implement such programs. We oppose 2b5). Back-up services are no substitute for delivery/deliverability of gas.1c) See our comments submitted on January 27, 2023.2a) We generally favor transparency. Many of the recommendations provided already apply to interstate pipelines. We support expanding this type of transparency to intrastate pipelines. We oppose, however, 2a6 and 2a9. LDCs are already subject to stringent regulation and further regulatory requirements we view as unhelpful.2b1 and 2) See our comments submitted January 27, 2023.2c) We oppose as discussed in our comments submitted January 27, 2023.3a) We generally believe that firm contractual rights should be respected and enforced as discussed in our January 27, 2023 comments.3b) We support temporary waivers of the Jones Act.3c) Firm contractual rights should be respected and enforced.3d) We support resource accreditation policies that factor in fuel firmness, fuel redundancy, etc.3e) Some process should be developed to lift air emissions limits during emergencies. Emergency operations may result in increased emissions that erode the ability of units to operate within permitted limits after the emergency has expired. A tool that allows such emissions to be tracked but not counted against permit limits would be extremely helpful in managing cost and reliability.3f) We support these recommendations.3g) We support these recommendations, provided that they are voluntary.3h) The availability of peak shaving plants can be addressed through resource accreditation requirements.4) We strongly oppose the recommendations to require RTOs/ISOs to create capacity markets. The need for and structure of capacity markets should be left to the discretion of the applicable regions. |
| 3 | Natural Gas Supply Association | Pat Jagtiani | WGQ Producer | Given the short amount of time to review the list of recommendations in the discussion paper, our comments here may not be exhaustive. However, NGSA offers two additional recommendations that we believe are essential parts of the review.1. There should be a specific proposal included in the discussion paper that recommends examining the various natural gas industry product offerings that already exist in the market that can help gas generators meet their just-in-time procurement needs, including increased reliance on Asset Management Agreements, no-notice type services and call options. The issue of whether gas generators are willing and able to pay for these services is a separate yet equally important part of this topic. 2. Also, the discussion document should include a recommendation to review the need for credit and collateral reforms to ensure that gas generators are sufficiently set up in advance to transact with a diverse number of counterparties on short notice. \_\_\_\_\_\_\_\_\_\_Comments & Specific Recommendations: The NAESB forum has resulted in a very comprehensive list of proposals that NAESB has posted for the upcoming meeting on February 2. As NAESB and the co-chairs work toward the preparation of a report back to FERC and NERC, it will be critical to find a balanced and collaborative approach that allows for meaningful input to ensure that the report provides guidance that is not only useful, but that provides a roadmap that leads us to focusing on those areas that will be the most impactful in improving gas generators’ ability to procure fuel when needed. To that end, NGSA suggests that the co-chairs consider the following:* Request a short list (3 to 5) of top priority issues from each stakeholder and compile those priorities by quadrant.
* Allow ample time (4 weeks) for feedback on a draft paper.

Prior to a prioritization request, it would be useful to narrow the list of proposals to something more manageable. To accomplish this, we suggest eliminating recommendations for actions that: (1) already exist and/or are already possible (such as LNG call options and weekend scheduling), (2) would have adverse impacts on most gas generation (such as eliminating the no-bump rule), and (3) are not permitted under law (such as reprioritizing customers and disregarding contractual arrangements). Also, it may be helpful to further categorize these topics into: (1) meeting daily needs, (2) meeting needs during critical events, and (3) meeting future gas generation needs (due to increased ramping requirements to support growth in variables energy resource integration).  |
| 4 | Vermont Public Power Supply Authority | Brian Evans-Mongeon | WEQ - Generator | Background In July 2022, FERC and NERC requested NAESB to establish a forum to investigate and consider approaches that would provide for a more integrated, or harmonized, structure for the operational interdependencies of the gas and electric industries. Issues relating to the lack of coordination have existed and has transcended many years, however, the weather event known as “Winter Storm Uri” exposed the critical and essential needs for gas and electric coordination. NAESB agreed to conduct a number of working sessions to examine the circumstances and bases for the inherent natures of the two industrial constructs. The sessions gave various segments within each industry the opportunity to present the historical operating structures, characteristics, and protocols for conduct in today’s environment. The GEH Forum’s Steering Group has identified 10 essential elements of the two industries that would need to be factored into any solution going forward. Each of the industries has profound reasons for their inherent structures, all predicated upon the commercial business needs of the industry members. And while the respective industry members overlap between the two industries, the operational structures, today, do not allow for a combined optimized effort for harmonization. I believe that consensus of the participating interests in the GEH Forum would say that securing a solution in today’s environment would be unlikely to succeed given the historical investments made to get the industries to where they are today. Thus, I believe that we need to create a new environment where we blend the cultures and create a single environment to would provide benefits to an integrated system and still provides value to the industries involved. Proposal Based upon prior paradigm changes, I believe that the parties of the two industries, state and federal regulators, and consumers need to acknowledge that the change must come from a mutual agreement to alter the operating environment. Back in the 1990’s, through rough starts and system changes, the electric industry modernized its grid approach from one that had entities conducting themselves more independently to a centralized system operations with independence created at the heart of the operations. I believe that a derivative of this approach could be the model for our future. One of the primary keys to this approach would be to set a future date for which a temporary “Gas Electric Council” would have oversight to create and construct the set of operating parameters for integrated gas and electric operations. Through the identification of the 10 working areas established by the GEH Forum, the GEC would create working groups of industry and regulatory professionals to examine, design, develop, and eventually implement processes, protocols, and procedures to adjust the current designs of operating systems of the gas and electric industries to those that would be needed in the future. The temporary nature of the GEC is to provide for the transition of the current industries to a future design. Ultimately, the GEC would continue for a short period beyond the start date of the integrated environment, as the traditional industrial structures could then resume the advocation for their respective realms. The key elements on this are to secure buy-in from a majority of the gas and electric stakeholders and state and federal regulators, as well as setting of a future date (it could take from 3 to 6 years) to begin the new operational paradigm. I believe that we must set aside our current and embedded biases for the historical structures and look to create a new design that will provide for greater integration between the two industries. In light of the future environment where gas and electric need to work together for the betterment of our society in the areas electric service, heating, and transportation, this proposal seeks to offer a vision on how we can advance our efforts.  |
| 5 | Texas Competitive Power Advocates (TCPA) | Michele Richmond | WEQ – Generator | Texas Competitive Power Advocates (TCPA) is a trade association representing power generation companies and wholesale power marketers with investments in Texas and the Electric Reliability Council of Texas (ERCOT) wholesale electric market. TCPA members[[1]](#footnote-1) and their affiliates provide a wide range of important market functions and services in ERCOT, including development, operation, and management of power generation assets, power scheduling and marketing, energy management services and sales of competitive electric service to consumers. TCPA members provide more than 54,000 MW of generating capacity in ERCOT, representing approximately two-thirds (2/3) of the non-wind electric generating capacity in ERCOT and more than eighty-two percent (82%) of all-natural gas generating capacity in ERCOT. TCPA member- owned gas plants in ERCOT are mostly situated with access to intrastate pipelines only (77%). TCPA members have invested billions of dollars in the state and employ thousands of Texans.GENERAL COMMENTSTCPA appreciates the opportunity to provide comment on the NAESB Gas-Electric Harmonization Forum Discussion Paper. TCPA does not make comment on the summary of comments received, assuming the staff summary is consistent with the comments received from stakeholders. Lack of comment on the summary should not be construed on TCPA verifying accuracy of other stakeholder comments nor should it be construed as agreement with positions taken by other stakeholders. TCPA stands by its comments throughout the forum, many of which disagree with positions regarding the availability of firm fuel on intrastate Texas pipelines, as well as with positions taken by Texas intrastate pipelines regarding the competitiveness of that market and the robustness of the regulatory oversight.Section II. Comments on Discussion PaperThe summary of comments and topic areas identified by the FERC and NERC Staff discussion paper are fairly comprehensive, in scope. The Forum should, in considering the topics and proposals in each, bear in mind the differing state and regional contexts as well as the incentives and tensions that each proposal would have on both resource adequacy and operational reliability objectives. For example, while proposals to require generators to obtain firm gas service or to otherwise “back-up” its output capability might have some simplistic appeal from an operational standpoint, the cost of such proposals for generators is likely untenable in many instances (assuming the options are even available), which would be net negative from a resource adequacy standpoint. Since a smaller resource pool both reduces the ability to meet peak load needs and reduces optionality to grid operators in managing non-peak (but still critical) operational needs, such as net load ramping capabilities or non-spinning reserves, the Forum should over- weight potential negative impacts to resource adequacy in its consideration of the various proposals. The analysis should also not unnecessarily cause unit exits when they are needed for periods without gas scarcity (e.g., Summer). Policies which unnecessarily punish assets, may counterintuitively reduce reliability by causing premature exits when those units would have been regularly available and needed to meet peak Summer demand. That said, to the extent that any policies are pursued that would require generators to obtain firm gas or otherwise “back-up” its output capability, it would become even more critical that all such resources have a mechanism to be compensated for the fuel security they are compelled to provide.\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_Section 1(a) in the summary is framed only in terms of sharing aggregated gas system information with Bulk Electric System (BES) operators; while BES operators certainly have an interest in receiving better information about the natural gas system, all shippers on the natural gas system (including natural gas-fired generators on the BES) would benefit from additional visibility into real-time or near real-time information about the natural gas system (e.g., aggregate production/processing volumes and curtailments; storage capacity & withdrawal levels; transportation flows and available capacity). The Forum should consider revising Section 1(a) to read “Whether and how natural gas information could be aggregated on a regional basis for sharing with Bulk Electric System operators and generators in preparation for and during events in which demand is expected to rise sharply for both electricity and natural gas, including whether creation of a voluntary natural gas coordinator would be feasible.”Section 2(a) in the summary is framed solely around the “reliability of the intrastate natural gas pipelines…” but the underlying comments also highlight the importance of financial incentives and having a functional market for natural gas that supports and is aligned with reliability needs. No other section seems to squarely address this objective, so the Forum should consider either moving/copying some of those comments to a new section that directly addresses it or alternatively revising the description of Section 2(a) to read “Additional state actions (including possibly establishing an organization to set standards, as NERC does for Bulk Electric System entities, and market oversight and design frameworks, as FERC does for interstate gas sales) to enhance the reliability of intrastate natural gas pipelines and other intrastate natural gas facilities and the ability for intrastate gas markets to align with reliability needs.”Section 2(c) in the summary is focused on prioritization of critical natural gas infrastructure load (for electric load shed planning), but some of the underlying comments are focused on the prioritization of critical electric infrastructure (for gas curtailment planning). Therefore, the description should be revised to reflect both considerations – e.g., “Methods to streamline the process for, and eliminate barriers to, identifying, protecting, and prioritizing critical natural gas and electric infrastructure load for respective curtailment prioritization.”Section 3(a) in the summary seems to presuppose that requiring natural gas generators to obtain firm gas supply or dual fuel capabilities should be pursued by regulatory authorities. However, as noted in the response to survey question (a) above, such requirements could ultimately have net negative consequences for BES reliability if its effect is to heap costs upon generators unless generators are also assured a mechanism to be compensated for the fuel security they would be compelled to provide. Accordingly, the Forum should revise the section description to read: “Which entity, if any, has authority to require certain natural gas-fired generating units to obtain either firm supply and/or transportation or dual fuel capability, under what circumstances such requirements would be cost-effective or consistent with resource adequacy and other reliability objectives, and how such requirements could be structured, including associated compensation mechanisms, whether additional infrastructure buildout would be needed, and the consumer cost impacts of such a buildout.”Section 3(c) in the summary asks which entities have authority to give electric generation priority “second only to residential heating load,” but there may be rare instances where the public interest warrants further prioritization of electric generation above residential heating (e.g., avoidance of a black start event, where gas residential heating abilities would be impaired by lack of electricity anyhow and the societal costs of the black start event would outweigh the LDC outage recovery costs). Accordingly, the “second only to residential heating load” distinction should be struck from the section description.CONCLUSIONThe lack of transparency of information on intrastate pipelines creates a significant barrier for both generation owners and independent system operators to ensuring gas supply to generation resources is reliable and will be delivered as contracted. The nature of generation dispatch makes it difficult to contract for exactly the amount fuel and fuel delivery needed because some markets, such as ERCOT, compensate generators only for fuel burned to produce power. Without the presence of either a make-whole mechanism to compensate generators for gas contracted for but not burned due to lack of dispatch, or a capacity release requirement coupled with transparency of activities on the intrastate pipelines, firm fuel commodity and delivery will remain uneconomic up to a generator’s high sustained limit (HSL) on a year-round, daily basis. The opacity of the intrastate delivery and storage markets and the lack of meaningful competition in certain geographic areas threatens the reliability of the grid overall and increases consumers’ end costs unnecessarily. TCPA recommends the NAESB GEH Report make recommendations to reliability entities and state legislatures as well as to NERC and FERC for specific changes to facilitate a transparent, competitive marketplace for gas delivery and storage on intrastate pipelines. TCPA appreciates the robust discussions during the GEH Forum and looks forward to working with participants to ensure a reliable and affordable electric and gas system regardless of location or type of pipeline serving resources. |
| 6 | Railroad Commission of Texas | Natalie Dubiel | RMQ End Users/Public Agencies | IntroductionThe Railroad Commission of Texas (“RRC”) appreciates the invitation to submit written comments to the North American Energy Standards Board (“NAESB”) Gas-Electric Harmonization Forum. The RRC is the State of Texas’ oldest regulatory agency. The RRC has regulatory jurisdiction over the oil and natural gas industry, pipeline transportation, natural gas and hazardous liquid pipeline industry, natural gas utilities, the LP-gas industry, and coal and uranium surface mining operations. The RRC thanks Chairman Gee for expressing the desire to hear from the agency on certain intrastate gas regulation matters that are being actively discussed at the forum.The RRC notes that there are a wide variety of misconceptions and inaccuracies that are being stated both at this forum and generally regarding the RRC’s jurisdiction over intrastate natural gas transportation rates and services. These written remarks attempt to clear up those inaccuracies and respond to written and verbal comments made at the forum.The RRC, through authority granted in the Texas Utilities Code, has jurisdiction over the *rates and services of natural gas utilities*. The RRC does not have authority over gas marketing companies[[2]](#footnote-2) and does not have authority over the price of natural gas that is, as with any other fungible commodity, determined by the economic forces of supply and demand. There seems to be a common misconception that the RRC is vested with the authority to otherwise interfere with the private, bilateral contracts between a gas utility pipeline and its customers. This is not accurate. Rather, the RRC’s jurisdiction to examine or modify certain contractual terms is limited to contractual terms involving rates or services that fall within the RRC’s jurisdiction.Any statements that the RRC has failed to exercise its authority to meet its statutory duties as set by the Texas Legislature are inaccurate and hyperbolic. The RRC, on a daily basis, carries out its statutory duties to regulate the rates and services of gas utilities within the clear parameters of law. A state regulatory agency cannot act outside of its statutory authority—as much as it may be desired by other industry segments—and in fact, to do so, would result in legal action against the state. An overview of the RRC’s jurisdiction over the rates and services of natural gas utilities follows.RRC JurisdictionChapters 101-105 of the Texas Utilities Code, the Gas Utility Regulatory Act (“GURA”), provide the RRC with authority to set cost-of-service based rates for a gas utility. GURA is, by and large, utilized to set rates for local distribution company (“LDC”) gas utilities that provide low pressure, natural gas service to downstream end-users, such as homes and businesses.Chapter 121 of the Texas Utilities Code, formerly known as the Cox Act, provides the RRC with jurisdiction to regulate gas pipelines on a variety of levels, including for pipeline safety. However, most transmission gas pipelines utilize what is colloquially referred to as the “negotiated rates” statute, Tex. Util. Code § 104.003, for transportation rates. Section 104.003(a) states that the RRC shall ensure that each rate a gas utility charges is “just and reasonable”. Importantly, the statute presumes that a rate that is negotiated between two parties, as long as it meets certain parameters,[[3]](#footnote-3) is just and reasonable. The negotiated rates statute has been effective law in the State of Texas since 1979.[[4]](#footnote-4) A pipeline utilizing negotiated rates, unlike FERC interstate pipelines and intrastate gas utilities that have cost-of-service based rates (which include a rate of return component), forgoes the opportunity to earn an established rate of return.The negotiated rates statute allows the RRC to address any purported issues on a case-by- case basis, rather than setting broad-reaching, state-wide cost-of-service rates that treat all gas utility pipelines in the same manner from a rates perspective. The statute also prevents the RRC from establishing a cost-of-service rate each time a gas utility pipeline negotiates a rate with an existing or new customer.[[5]](#footnote-5) There is a large universe of negotiated rates charged by approximately 200 intrastate gas utility pipelines with thousands of receipt and delivery points within the state to accommodate the large universe of suppliers and end-users of natural gas in Texas. There are approximately 10,000 active negotiated rate tariffs currently on file with the RRC. These tariffs include thousands of customers, and many include multiple receipt and delivery points.Since Winter Storm Uri, the negotiated rates statute has been frequently misunderstood and often overlooked. Any statement that the RRC is “hands off” and fails to adequately regulate pipeline gas utilities is simply ignoring the negotiated rates statute. The RRC does not set cost-of- service based rates for every gas utility in the state because the Texas Utilities Code expressly provides for willing parties to negotiate rates and terms between themselves—in fact, it requires the RRC to presume just and reasonable rates when they are negotiated and agreed by two parties. It is not a statute that the RRC can disregard, and neither should those who are actively, loudly, and inaccurately proclaiming that the RRC is not doing its job.Section 104.003 is the statute from which the oft-referred “complaint-based process” derived its existence. The just and reasonable presumption described above does not apply if “a complaint is filed with the railroad commission by a transmission pipeline purchaser of gas sold or transported under the pipeline-to-pipeline or transportation rate”.[[6]](#footnote-6) Therefore, a shipper that has signed a contract with a gas utility pipeline may file a formal complaint with the RRC alleging that a pipeline transportation rate does not comply with section 104.003, and this ability exists even if the particular transportation rate was agreed to by both parties to a contract.The RRC also separately created what is known as the “informal complaint” process. The informal complaint procedure applies to informal complaints within the RRC’s jurisdiction regarding natural gas purchasing, selling, shipping, transportation, and gathering practices.[[7]](#footnote-7) The informal complaint rule states that the RRC “encourages affordable, expeditious, and fair settlement and resolution of disputes regarding natural gas purchasers, sellers, transporters, and gatherers.”[[8]](#footnote-8) Under the informal complaint procedure, a shipper or seller may file an informal complaint at the RRC and a staff mediator or a mediator of the parties’ choosing will mediate the complaint. Filing an informal complaint is not a prerequisite to filing a formal complaint.Eliminating the existing law permitting negotiated rates would most likely require cost-of- service based transportation rates for every gas utility in the state, and there is no evidence to suggest that such action would have a beneficial impact on reliability or increase access to pipelines. It would, however, require more state resources, more time in administrative hearings, increase costs to both pipelines and their customers, and ultimately create a less efficient marketplace. Statements regarding the efficiency of the formal complaint process are addressed in the responses to comments below.Response to Written and Verbal CommentsThe following responses to certain written and verbal comments made in this forum are supported by the jurisdiction of the RRC that is outlined above. That is, the responses point out the inaccuracies or misstatements in those comments based on the clear parameters of the RRC’s existing authority.The Formal Complaint ProcessAs discussed above, the formal complaint process for resolving transportation rate disputes between a gas transmission pipeline and a customer was put into place by statute. Pursuant to statute, a gas utility pipeline or customer of a gas utility pipeline may file a formal complaint at the RRC regarding a section 104.003(b) rate. The RRC will promptly docket the case and adjudicate it in accordance with the Administrative Procedures Act,[[9]](#footnote-9) as it is required to do by law.Supplemental written comments filed in the forum regarding the RRC’s formal complaint process stated the following:*The informal and formal complaint processes established by the Texas Railroad Commission (TRC) are generally viewed by most market participants as being slow and expensive processes that benefit the pipelines and not the customers. Contractual disputes are routinely referred to the courts rather than being resolved by the TRC. These facts discourage customers from filing complaints with the TRC.*[[10]](#footnote-10)Additionally, the following verbal comments were made at the December 5, 2022 forum meeting:*Uh, Mr. Mann talked about the complaint process that is in place by the Railroad Commission. If you look at the history and I think there is some data out there about how many complaints are filed, they are very few and far between and even fewer by power generators. The reason for that is the complaint process that the Railroad Commission has is basically useless. It takes a lot of time, a lot of money, there is no transparency, no one sees the content of those complaints or the resolution. Or, a customer that wants to file a complaint and look for fair and reasonable rates to similarly situated customers—there’s not transparency in the tariffs or anything like that that provides the shipper or customer to go in and file a complaint to be successful. Typically, a complaint takes a year to process with very little probability of success from the shipper’s standpoint. And, as Mr. Mann pointed out, most of these disputes end up in the courts.*[[11]](#footnote-11)Formal complaint dockets at the RRC are public dockets. With regard to the allegation that “no one sees the content of those complaints or the resolution”, any member of the public can access the RRC’s Case Administration Service Electronic System (“CASES”)[[12]](#footnote-12) and view the pleadings and associated documents in a pending or past formal complaint docket, includingAdministrative Law Judge (ALJ) rulings. The hearing on the case itself is open to the public. The resolution of a formal complaint docket is also made readily available to the public as the Commissioners must vote on a final order in an open meeting in accordance with the Open Meetings Act.[[13]](#footnote-13)Further, the length of time a formal complaint takes to process is determined by the facts and circumstances specific to the case. Every formal complaint is different in terms of number of parties, issues in dispute, and complexity. This is a well-known fact both at the administrative level and in the courts. Even still, a vague reference to “some data out there” can be put to rest: since 2008, thirty-eight formal complaints have been filed at the Commission, which averages to 2.53 cases per year. The average length of a formal complaint over that 15-year period is 1.27 years; a duration that is largely due to participating parties seeking procedural schedule extensions. Further, since the RRC has implemented CASES,[[14]](#footnote-14) the average length of a formal complaint is reduced to 179.57 days.In response to the statement that the formal complaint process “generally” favors the pipelines and not customers—the RRC is baffled that such a statement would be made in a public forum with no documentary support. Out of the thirty-eight formal complaints that have been filed since 2008, 52.6 percent have reached settlement and/or were withdrawn by the complainant without the need for adjudication by the RRC. While the assertion is that there are not more formal complaint filings because the process is viewed as “useless” by potential parties, there is nothing to suggest, other than written and verbal comments given without evidentiary support, that this is the case. In fact, the likely reason that there are not more formal complaints is because pipelines and shippers are typically able to resolve their disputes through negotiations and view filing a formal complaint as a last resort.[[15]](#footnote-15) The statistics on the rate of settlement support that fact.Additionally, the RRC does not “routinely” refer cases “to the courts” rather than resolving them at the agency. In fact, the RRC does not have the authority to refer a case involving a matter within its jurisdiction to the courts instead of adjudicating it at the agency, and to even suggest that it does is completely inaccurate. The RRC has repeatedly exercised jurisdiction over complaints involving matters within its purview despite efforts by parties to have such matters dismissed and resolved by the district courts. Thus, any suggestion to the contrary is misleading. Finally, it should be noted that it is the plaintiff to any action that decides the forum in which to file its contractual disputes, not the RRC.The Need for More Pipeline InfrastructureAs the state continues to grow, the need for more pipeline infrastructure increases. The RRC has heard and read multiple references to the fact that there are power generation plants in the state that only have access to one pipeline and/or do not have access to firm service. The RRC is aware of very limited instances of this occurrence in the state. This is a lack of infrastructure problem, not an issue of geographic monopoly. Power generation plants with only one pipeline connection have the ability to work with pipeline companies to build more access to more pipeline interconnections.The following supplemental written comments were filed by a commenter regarding “geographic restrictions” of intrastate pipelines:*The Railroad Commission has relied on market competition between pipelines to ensure a level playing field and competitive rates. By and large, this competition works reasonably well in areas where there are multiple pipelines for customers to choose from. This is particularly true along the gulf coast areas of the state. However, in other areas of the state, particularly North Texas, the intrastate pipeline and storage system is a geographic monopoly with limited market competition. This allows some pipelines to exert market power to the detriment of their pipeline customers and ultimately to electric power customers particularly during extreme weather events.*[[16]](#footnote-16)Power generators, like any other pipeline customer, may choose to contract with one or several pipeline companies to build additional pipelines so that there is increased opportunity to obtain the desired products. However, in an area where there is market demand for additional pipeline transportation capacity, there might be many reasons why a customer chooses not to expand its options. In a competitive wholesale power market, a gas-fired generator is paid by the amount of energy it sells, which may not be enough to recover the costs to have additional pipeline connections. In any event, a gas utility pipeline in the State of Texas is bound to follow the Texas Utilities Code and the RRC’s regulations prohibiting discrimination against similarly situated shippers, and the RRC remains prepared to adjudicate complaints.ConclusionThe RRC will continue to execute its statutory duties as set forth in the Texas Utilities Code with regard to the regulation of intrastate natural gas utilities. The RRC notes that one of the forum’s stated outcome goals is “[c]oncrete actions to increase reliability of the natural gas infrastructure system necessary to support [the] Bulk Electric System.”16 The RRC would note that its regulations encourage any pipeline customer that requires reliable service to contract for firm service. To the extent market participants feel that they are being discriminated against according to existing law and RRC regulations, the RRC encourages informal and formal complaints.The RRC appreciates the opportunity to file comments and will continue to work with stakeholders and the state legislature when requested on issues affecting the intrastate natural gas transportation market in Texas. |

1. TCPA member companies participating in these comments include: Calpine, Cogentrix, Constellation (formerly Exelon), EDF Trading North America, Luminant, NRG, Rockland Capital, Shell Energy North America, Talen Energy, Tenaska, TexGen Power, and WattBridge. [↑](#footnote-ref-1)
2. Entities that are not gas utilities that arrange for the purchase and sale of natural gas on behalf of a third party. [↑](#footnote-ref-2)
3. Tex. Util. Code § 104.003(b). [↑](#footnote-ref-3)
4. Tex. Util. Code § 104.003 was originally enacted in 1979 as Section 38 of the Public Utility Regulatory Act (“PURA”), the predecessor to GURA. [↑](#footnote-ref-4)
5. In fact, the ability to presume rates are just and reasonable without a cost-of-service justification was, in part, due to the fact that the establishment of cost-of-service rates was considered unnecessarily expensive in situations in which two sophisticated parties can agree to a transportation rate. “Basically, [the bill] says that [eligible] transactions if they meet the just and reasonable standard do not have to go through costly ratemaking proceedings.” Sen. Peyton McKnight, Transcript of Senate State Affairs Committee hearings on CSHB 2090, 67th Leg. 1 (May 11, 1981). [↑](#footnote-ref-5)
6. Tex. Util. Code § 104.003(c)(1). [↑](#footnote-ref-6)
7. 16 Tex. Admin. Code § 2.1(a). [↑](#footnote-ref-7)
8. 16 Tex. Admin. Code § 2.1(c)(1). [↑](#footnote-ref-8)
9. Texas Government Code, Chapter 2001. [↑](#footnote-ref-9)
10. TCPA Follow-up Comments from November 8, 2022 NAESB GEH Forum, page 4 (November 28, 2022). [↑](#footnote-ref-10)
11. These verbal comments were made by Mr. Paul Sierer, a representative of TCPA. [↑](#footnote-ref-11)
12. <https://rrc.texas.gov/hearings/rrc-cases/>. [↑](#footnote-ref-12)
13. Texas Government Code, Chapter 551. [↑](#footnote-ref-13)
14. The public has been able to view dockets in CASES since August 2019. [↑](#footnote-ref-14)
15. The most recent formal complaint docket filed by a power generation company against a gas utility pipeline was settled in less than a year without the need for a formal administrative hearing. [↑](#footnote-ref-15)
16. TCPA Follow-up Comments from November 8, 2022 NAESB GEH Forum, page 4 (November 28, 2022). [↑](#footnote-ref-16)