Via email and posting

September 16, 2022

**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 - September 14, 2022 – Responses Related to Item 3a

Dear NAESB Members, GEH Forum Participants and Interested Parties,

Please find below the comments received by the NAESB Office in response to the survey/request for comments that was distributed on September 7, 2022 <https://www.naesb.org/pdf4/geh092322w1.docx>. The following responses were submitted regarding question/topic 3a:

Please provide comments and any specific recommendations for the forum attendees to consider regarding “Which entity 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, 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.”

| **Responses Submitted by September 14, 2022 – 3a** | | | | |
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| **Question/Topic** | | 3a. Please provide comments and any specific recommendations for the forum attendees to consider regarding “Which entity 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, 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.” | | |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | LS Power | Marji Phillips | WEQ – Generator | It is important to distinguish between RTO and non-RTO regions, which are structured in vastly different ways to assure generation performance and adequate fuel supply and ensure that any recommendations respect this. Any additional requirements that result in additional investment must ensure guaranteed cost recovery; ideally it would be through a market mechanism in the RTO regions. In terms of authority, at least with respect to the RTOs, it would be the RTO that would make a tariff fling with FERC to reflect any mandates. Hopefully whatever mandates are produced would be the result of thoughtful consideration of stakeholder concerns, including state and federal regulators.  Obviously pipeline infrastructure build out would be the easiest way to solve many problems, but that is not an alternative in many states that have limited, and plan to eliminate the use of natural gas in their state. From a reliability perspective, this alternative would probably be less expensive. Additionally, it would be ideal if the pipelines could offer more flexible call options at lower costs than exist today.  There are balances to be considered in mandating firm supply or dual fuel capability. First, it may be an unnecessarily broad action. For example, LS Power owns a natural gas peaking plant in New England that because of its location on the pipeline system it does not need firm fuel to perform (as it has, with excellence). To so require firm fuel would unnecessarily increase consumer costs (as that requirement would have to be passed through) with zero incremental reliability gains. So it is important to be very precise on identifying the problem (e.g. where a plant is in relationship to the pipeline). Ensuring the right balance between carrot and stick: incentives and severe penalties for non-performance, is probably the ideal approach.  Finally, we need to consider if the 1 in 10 standard used is appropriate: are we trying to change that standard to a 1 in 20; is it necessary to have a seasonal approach to be more efficient, etc.  These are just some of the issues that need to be considered |
| 2 | Aspen Environmental Group | Catherine Elder | Other/Observer | I recommend FERC direct the independent system operators and RTOs to require evidence of firm supply and transportation or dual fuel capability in order to for that electric generation capacity to count towards resource adequacy – or vehicles such as the proposed Western Resource Adequacy Program submitted to FERC by the Western Power Pool (which may need modification to capture these gas-related issues). From work on a plant near Warner Robbins, I had thought SERC or Georgia had such a requirement but cannot quickly find a reference to it. If confirmed, the SERC requirement could be a potential model for other planning pools. Notably, in states such as California, the PUC has no jurisdiction over generators’ fuel and transportation arrangements. Accordingly, the action must come through FERC’s oversight of electricity markets.  Having worked on fuel arrangements for many merchant generators, I notice it is often over-looked that the reason they rely on interruptible arrangements is that they only have to operate enough to make their debt service payments and they have no obligation to operate. Just as important, those costs cannot be recovered in a marginal-cost bid market. As such, they do not want to commit to paying the reservation charge associated with firm transportation capacity. Capacity payments would be a huge help to solve this problem and it would be comforting to see FERC stop sticking its head in the sand on the symbiotic relationship between gas system reservation charges and electricity marginal cost markets.  In some locations (New England comes to mind) infrastructure buildout would be needed. Those costs should go to electric customers unless the additional capacity benefits all ratepayers but perhaps as a reliability surcharge rather than blending into existing rates. It would be interesting to explore recovery of such costs and any potential premium for firm supply (and maybe even the pipeline reservation charges) as an electricity security charge. FERC could also consider creation of an emergency at-risk provision under which all generators must be prepared to operate under emergency conditions (and governors and/or the President would declare that emergency similar disaster emergency declarations and/or the EEA stages) and impose a negative surcharge on those that fail to certify having made the appropriate arrangements to so operate. |
| 3 | Natural Gas Supply Association | Pat Jagtiani | WGQ Producer | NGSA has a strong preference for relying on competitive market solutions to improve the functioning of the market prior to resorting to out-of-market solutions or government mandates. Therefore, before examining who should mandate fuel procurement practices by generators, NGSA encourages the forum to consider market improvements that will fairly incentivize proper service procurement.  Current market design in organized markets often results in a disincentive for advance contracting and purchases of natural gas, which runs counter to what is required to ensure reliability. In organized power markets, generators face uncertainty about whether they will run until regional operators dispatch them. Consequently, generators in those markets often find it difficult to take on the financial risk of procuring their fuel in advance when they are unsure about how much fuel they need and whether they will be able to recover fuel-related costs. In many instances, generators continue to rely on interruptible transportation and supply contracts (that are typically only available when the gas system is not constrained), and day-of gas purchases that arise to meet electric system balancing requirements that expose generators to more volatility associated with spot market purchases.[[1]](#footnote-1)  Recently, ISO-NE’s problem statement emphasized this point: “Specifically, the electricity markets are not designed to spur investments in supporting infrastructure needed to ensure a reliable clean energy transition. While the region is in the process of developing a plan and cost allocation methodology for assuring investments in the transmission infrastructure required to integrate renewable resources, there is no comparable plan to ensure the region has sufficiently robust, long duration, sources of balancing energy (including for the meantime, sufficient supplies of natural gas). In essence, the prevailing assumption is that the fuel markets will ensure sufficient fuel supply in response to high prices in the electricity markets. For a variety of reasons, this assumption is proving to be flawed.”[[2]](#footnote-2)  NGSA believes that this forum should recommend that FERC and regional operators work with regional stakeholders to develop market design changes that mitigate the financial risk associated with advance fuel procurement and contracting by gas generators by placing more value on reliability. Also, we should explore other ways to encourage improved contracting and fuel procurement practices such as considering greater awareness of generator contractual commitments, power market capacity accreditation enhancements, the timing of day-ahead awards, and new flexible pipeline services. Given that the scope of this forum is not limited to serving power customers that operate only in organized markets, we would also be interested in gaining a better understanding about whether integrated utilities are also experiencing similar issues.  (1) Consideration of Design Changes in Organized Markets.  At a meeting last year, PJM presented a problem statement, which precipitated the creation of Senior Task Force on Gas-Electric Coordination. According to the problem statement, one of the primary problems with market design issues is as follows:  “Under the current wholesale electric market design, the risk/reward that Market Participants with gas generators face discourages fuel procurement at the very time generation is most needed. As need and gas costs rise, the profit margins of Market Participants with gas generators fall, often going negative. At extreme prices, there may even be corporate limitations that prevent fuel purchases altogether (authorization protocols, cashflow requirements, etc.). Also, market design limitations can create perverse generator behavior with respect to the way they use their dual fuel capability. Generators that can maximize profits (or limit losses) will have incentive to burn limited backup fuel resources as gas procurement risk/reward falls. Often this results in backup fuel consumption well in advance of peak weather or need.”[[3]](#footnote-3)  Not only does current market design in organized markets discourage fuel procurement “at the very time” it is most needed, but it also discourages procurement “in advance” of when it is needed, which is ideally when fuel procurement should take place.  Notably, vertically integrated utilities and local distribution companies do not experience the same disincentive to procure fuel and, as a result, do not face the same level of reliability risk that we see in organized markets. Specifically, vertical utilities and LDCs (that have obligation to serve) do not face the same level of exposure because they have cost recovery mechanisms that allow them to actively manage their gas supply and capacity needs and invest in an expansive portfolio of long-term firm contracts and storage that support the level of reliability they require. Not only do advance contractual arrangements support a high level of reliability, but they also help to avoid or minimize the need to purchase large amounts of natural gas in the more volatile spot market, thereby mitigating their cost exposure. Organized markets should strive to replicate these practices to the extent possible through market design changes that value reliability and provide market signals that incentivize enhanced generator procurement practices. While this may appear to be a difficult or expensive undertaking when viewed in isolation, it should be evaluated in the broader context of the benefits derived from avoiding costly, damaging, and life-threatening power outages, as well as supporting the energy transition.  (2) Greater Awareness of Contractual Information and Improved Capacity Accreditation Practices.  NGSA supports recommendations in the FERC-NERC Final Report, such as Recommendations 1.G and 8, that give regional operators greater insight into the types of contracts gas generators have so they have a more accurate understanding of potential vulnerabilities that may exist due to contracting practices. Similarly, ensuring that capacity accreditation is in line with the actual expected availability of generation units for all resources could be a valuable tool for more appropriately valuing advance arrangements for reliable fuel delivery.  (3) Timing of Day-ahead Awards.  To the extent possible, region operators may want to consider whether changing the timing of day-ahead generator awards would assist gas generators in their region by giving them more timely notice about the amount of fuel they will need to purchase during the morning period when the gas market is most liquid. Late day award notifications force generators into the market when most gas has already been sold for the day (generally by 9am ET). This risks gas availability as well as higher priced purchases during illiquid periods. The gas industry does not “set” a time for purchases. Many gas customers purchase on a monthly basis and the percentage sold in the daily market is generally completed in the early morning hours. This also holds true for gas pipeline scheduling where most capacity is scheduled during the timely gas cycle and later cycles are used more for balancing.  (4) Facilitated Discussions to Find Mutually Agreeable Service Options.  A recent ISO-NE study found that, as more renewables are added to the grid and electrification efforts accelerate, natural gas demand will actually increase during cold weather periods when wind and solar resources underperform.[[4]](#footnote-4) When pipeline systems are operationally constrained, whether by higher utilization by firm shippers or increased hourly takes, a gas generator’s ability to attain services and accommodations become more limited. In those instances, there may be (1) insufficient spare capacity to offer firm transportation and storage services to generators if there is an increased demand for those services (as recommended in FERC-NERC report on Uri), (2) less ability to rely on “spare” interruptible capacity, and (3) more limited operational intra-day flexibility to accommodate best efforts swings.  As these new patterns of electricity usage create a need for greater hourly swings by generators to balance the variability of renewable resources, it will be important to assess whether pipeline systems will also have the operational capability to manage the need for increased hourly flows. A pipeline’s ability to provide customers with intra-day flexibility (non-ratable takes) is contingent upon how much physical capacity is actually available in the existing pipe, which is limited by the finite size of the pipeline and its operational parameters. It also depends on how much line pack is available at a certain location in the pipe and how much the pipeline can let certain shippers draw on that line pack without causing an operational issue on the pipeline. During peak weather events, however, sudden unexpected takes can literally drain a pipeline system and impact its pressure – harming system operations and service to all shippers.  If a pipeline has insufficient capacity to provide the level of intra-day flexibility a customer requires, no level of coordination can change that fact.[[5]](#footnote-5) However, given that most pipeline customers currently receive such “services” without additional costs on a best-efforts basis for much of the year, it may be difficult for gas generators to justify paying for flexible services that provides guaranteed hourly flexibility. If generators are compensated for purchasing this needed level of intra-day flexibility, pipelines will have the proper compensation to stand ready to serve through, for example, expanding capacity, increasing line pack in locations of the pipe where it is most needed, calling on increased supplies through OBAs with interconnecting pipelines and pulling on system storage. The costs of providing these services should be properly allocated to ensure that they are not borne by other customers.  While there are a variety of flexible market options available to generators in the gas market today, NGSA believes it would be helpful for this forum to recommend discussions between providers of natural gas services and their power customers to find mutually agreeable service options for flexible pipeline firm transportation and storage services or third-party services that provide the flexibility generators require. While these types of conversations typically occur between a company and its customer, the time may be ripe for a fuller discussion of what prevents such flexible services from coming to fruition and ways to encourage customers to invest in these services rather than relying on pipelines to accommodate those needs on a best-efforts basis. |
| 4 | Process Gas Consumers Group & American Forest Paper Association | Andrea Chambers | WGQ End User | Commenters assert that the FERC is the federal entity that has the authority to require natural gas-fired generators to obtain either firm supply and/or transportation or dual fuel capability to participate in wholesale electricity markets. Indeed, FERC has exercised this authority in the past in response to the Polar Vortex winter event when it approved ISO-NE’s and PJM’s pay-for-performance incentives aimed at ensuring energy resources are ready and able to fulfill their obligations to provide electricity or reduce demand during times of stress on the power system. The New England ISO’s incentive payments have increased over time and are being phased in over the next several years. Because FERC approves tariffs that provide for the payment to electric generators for their supply of electricity and capacity in wholesale markets, FERC is the proper authority to require such generating entities to acquire the necessary firm interstate pipeline transportation or natural gas storage in order to ensure the reliability of the electric grid as a condition to qualify to receive wholesale electric capacity or energy payments.  The FERC has also approved payments to generators, through reliability must run agreements, in cases where a region, like the California ISO, has experienced inadequate reliable generation to serve electric load. As noted in the NERC’s Report on the February 2021 Cold Weather Outages in Texas and South Central United States (the “Report”) discussing the outages during the Uri Storm, natural gas pipeline capacity is certificated to accommodate firm transportation commitments, while many natural gas-fired units rely on non-firm commodity and/or transportation contracts. Commenters believe the answer to electric service reliability issues is to make electric service more reliable by fixing compensation issues in the wholesale electric markets that discourage generators from signing contracts for firm natural gas transportation or storage to serve gas-fired generators. The Commenters believe the resolution is not to make the electric system more reliable by leaning on the existing firm pipeline infrastructure that is built to serve natural gas demand in a way that harms reliability of natural gas service to customers of interstate pipelines who pay for firm transportation service.  Requiring electric generators to purchase firm pipeline transportation to ensure reliability will provide the pipelines with the market demand to support their construction of additional interstate pipeline capacity where it is needed to serve both electric power generation load and natural gas demand for home heating, commercial and industrial load. Without the requirement that natural-gas-fired generators purchase firm transportation, consumers will suffer in the reduction of both reliable electric and reliable natural gas services, which could result in damage to property and health in extreme weather events, as was witnessed with the Uri Storm. Moreover, regions could also see economic and job loss due to industry moving from a region with less reliable electricity and natural gas supplies to another region with more reliable energy resources.  In terms of cost-effectiveness, the cost for natural gas supply to local utilities in Texas in the wake of the Uri storm for a week was more than some utilities budgeted for the year. According to the Report, analyst with the Federal Reserve Bank of Dallas estimate the outages caused direct and indirect losses to the Texas economy of between $80-$130 billion. On top of that, there is the cost of loss of life which is immeasurable. According to the Report, 210 people died during Storm Uri, with most of the deaths connected to the power outages. While the loss of life is more significant than economic losses, manufacturers suffered economic losses from shutting down production and, in cases where replacement gas was available, from the high cost of replacement gas. These additional costs are sometimes recoverable from increasing the cost of manufactured products, but many manufacturers and industrial companies, such as PGC and AF&PA members operate in highly competitive, trade exposed markets and must absorb these increased costs |
| 5 | Enchanted Rock | Joel Yu | WEQ Technology or Service | The challenge with respect to the costs of firm deliveries to electric generation is in the fact that benefits of firm service accrue to electric customers while costs are borne by gas companies. The most cost-effective solution would allow these costs to be reflected in competitive electric markets through requirements on electric generation. Relevant state commissions or FERC should develop rules to require firm natural gas supply and transportation for generation and allow those costs to be recovered through the electric markets without handicapping natural gas generation with respect to other technologies that may not have the same level of flexibility and dispatchability without duration limits. Texas has taken steps to do this through the development of a Firm Fuel Supply Service product. Revenues generated from the electric markets will pass through to the gas companies to deploy for expanded capacity and resiliency investments. Recommendations for electric generation must be paired with recommendations for improving gas facility reliability under topic 2, including potential requirements for gas facilities, like electric compressor stations, to deploy on-site gas-fired generation that can provide backup during grid emergencies and provide support to the electric grid when operating in parallel. |
| 6 | Interstate Natural Gas Association of America | Christopher Smith | WGQ Pipeline | Before reaching the question of authority to impose requirements, there is a threshold question: Why shouldn’t the organized wholesale electric market develop market incentives, products, or services to promote reliable fuel supplies in the first place? In organized power markets, however, uncertainty over whether a generator will be called upon leads to short notice fuel procurement practices that are no longer sustainable given the increased demand for natural gas. Current market design in organized markets often results in a disincentive for advance contracting and purchases of natural gas, which runs counter to what is required to ensure reliability. Market clearing times force gas generators into the gas market to purchase gas after most gas is already sold during the more illiquid times if they wait to know if they clear. Gas generators are most hesitant to purchase gas during tight market conditions, when gas is most needed, because it is more expensive during those times, and they lack confidence in whether they will be compensated for taking an untenable financial risk.  The concern is that calls for more “gas-electric coordination” skirt addressing the fundamental disconnect between electric reliability and organized power markets which dispatch on least cost. While this structure may work well for creating competitive bidding in organized markets, it does not give generators certainty of how often they will be needed; making gas generators hesitant to make advance longer-term arrangements for their fuel supply. Regional operators must be able to provide greater confidence to gas generators so that they are not at risk when contracting for the proper level of commodity, transportation, and storage.  Changes to RTO market structures must be made to instill greater confidence to generators to secure their fuel supply. Organized markets should develop mechanisms that properly value reliability and facilitate power generator investment in the gas services they require, including supporting new gas infrastructure investment when needed. Nonetheless, cost recovery for infrastructure will be difficult when the electricity market structure drives electricity suppliers to short-run marginal costs. One such recommendation to address these concerns, proposed by ISO New England, is to create an energy “reserve.” Such a reserve could be achieved through some or all of the following:  1) State regulated cost-of-service infrastructure investments coupled with contracting for the necessary energy.  2) FERC regulated cost-of-service rates for recovering investments in infrastructure and forward energy supply chain arrangements.  3) FERC regulated wholesale electric market tariffs that rely on uniform clearing price mechanisms to incentivize investments in infrastructure and forward energy supply chain arrangements. |

1. There are a variety of ways that generators, utilities, and industrial users can choose to purchase their natural gas. Generally, natural gas customers purchase their natural gas through a portfolio of products including prearranged contracts set at a pre-determined fixed price or indexed to an agreed variable, along with buying some supply in the daily spot market, where availability and prices fluctuate in response to weather and the availability of infrastructure capacity and storage. Many transactions are made in advance on a monthly. Depending on the location and the relative options available to a generator, relying on interruptible service may not pose issues during peak load conditions. Therefore, it is not always essential for generators to acquire firm capacity to ensure reliable fuel. [↑](#footnote-ref-1)
2. Draft ISO/EDC/LDC Problem Statement and Call to Action on LNG and Energy Adequacy Federal Energy Regulatory Commission New England Winter Gas-Electric Forum, September 8, 2022. [↑](#footnote-ref-2)
3. PJM Markets & Reliability Committee Meeting, Aug. 25, 2021. https://pjm.com/-/media/committees-groups/committees/mrc/2021/20210825/20210825-item-05-2-natural-gas-and-electric-markets-problem-statement.ashx. [↑](#footnote-ref-3)
4. ISO-NE “2021 Economic Study: Future Grid Reliability Study Phase 1, July 29, 2022. [↑](#footnote-ref-4)
5. There are tools in place today that are available to generators that are not often dispatched such as purchasing delivered gas or entering into OBAs or park and loans agreements with pipelines to provide flexibility to the extent that a pipeline system can operationally allow it. [↑](#footnote-ref-5)