**Gas-Electric Harmonization Problem Statements and Proposed Problem Resolutions**

**Problem Statement 1:**

On the gas side of the gas-electric energy market, while there may be any number of perceived and real problems accompanying the interface between the gas delivery and electric generation businesses, the following, albeit simplified statement, seems to encapsulate the most frequently expressed one:

“To get firm gas, they have to have firm Service. We can give them firm… They just have to pay for it.”

**Problem Statements 2 & 3:**

On the electric generation side of the gas-electric energy market, again, while there may be any number of perceived and real problems accompanying the interface, the following, simplified statement, seems to encapsulate the most frequently expressed one:

“All we want is assured fuel, at a price, when we want to burn it to meet electrical demand.”

Still on the electric side, and with respect to the RTO/ISO and balancing authority components, again, while there may be any number of perceived and real problems accompanying the interface, the following, simplified statement, seems to encapsulate the most frequently expressed one:

“We need to be able to rely on the MWs of capacity under our control to generate electricity when needed to meet demand.”

**Observation 1:**

Over 90% of the time, on an operational, hour by hour, day over day basis, the two industries make the gas move, get it delivered to the generators when and in quantities they need and as a result, the two industries present to its participants and to the public a view of an integrated system that is working. Electricity is generated and paid for, gas is delivered and paid for, plus, the respective transportation of the gas and transmission of the resulting electrons are effectuated.

**Observation 2:**

We are here yet again dealing with gas-electric harmonization because there are increasingly frequent intervals of time that the hour by hour, day by day harmony ceases; and the integrated and interdependent systems break down; leading to economic dislocations and loss of life.

**The Essential Conundrum Facing Gas-Electric Harmonization**

The rest of this document starts with discussing the essential conundrum facing NAESB; followed by the essential conundrum facing the gas and electric industries as it relates to the ultimate goal of harmonization 100% of the time.

Then, starting from the point where the two industries work in operational harmony and providing a rationale for why it works -- when it works; I outline a suggested reason underlying the why the interface between the two markets breaks down and “doesn’t work” when things “don’t work”.

Following a discussion of what is “missing” when it doesn’t “work”, I start the identification of problem-resolution with identifying certain un-priced and yet valuable services provided by pipelines to generators and proposing relatively small, incremental, changes that can be made. The order of presentation here is gas then electric. Nevertheless, I suggest that the implementation of changes be coterminous.

Following the what and how portions of resolution presentation, I provide some discussion about why making those changes will start the two industries on the path to eventual realization of 100% gas-electric harmonization; a realization that starts with small policy changes and which realization is then spurred along by market forces seeking revenue enhancement, operational efficiency, and optimized asset utilization.

Lastly, I discuss how, taken together, the resulting competitive responses by market participants to: 1) changes regarding what services are charged for on the gas-side; and, 2) minor policy change(s) to market operations in RTO/ISO organized markets can together enhance the long-term reliability of the gas side in a manner that reinforces reliability of the electric side and thus mutual reliability reinforcement.

**Bedrock Problem Facing NAESB**

The bedrock problem NAESB keeps facing every time that this matter is brought up is directly and inextricably linked to the bedrock problem at the core of disharmony -- economic and policy differences and shortcomings in one, the other or both industries that come into conflict at their interface during times of stress. That bedrock NAESB problem is that participants predominantly state: “we are a standard setting organization not a policy setting organization”; and “we standardize once FERC has set the policy”.

It is unlikely that any proposed changes that increase, decrease, or change the flow of dollars in or between the two industries will be agreeable enough to all segments of the two industries that standards approval thresholds would be surmounted.

Moreover, I would suggest that there is no threshold surmountable standard(s) that would – by it/themselves achieve 99+% harmonization, let alone eventual 100% harmonization; thus, the proposed approach of: 1) crafting problem identification-problem resolution pairs and their policy choices; and, 2) putting them before FERC to choose among, modify, combine, or set their own preferred course.

**Introduction to the Bedrock Problem Facing the Gas-Electric Market’s Interface:**

Viewed from a low-earth orbit level, Gas-Electric Harmonization/Coordination, when it flounders, does so in, and adjacent to, RTO/ISO markets because the respective industries’ fundamental, long-term, economic business models are incompatible. That said, viewed at ground level, as stated above, 90%+ of the time, the two industries respective operations are well coordinated. Gas gets moved to generators, generators operate, electricity is produced and consumers’ demands are met.

**Operational Coordination between the Industries Occurs 90+%of the Time – Today**

This operational level, ground level, operational coordination occurs even though the two industries’ price formation models differ, their economic days differ, their scheduling processes differ, their contracting processes differ, their long-term planning processes differ; and I will submit, their respective views on what should “change” to make coordination work -- 100% of the time – are not shared.

**What is Working and Why is it Working?**

When gas price plus the gas capacity to deliver that price (or a closely and predictably related price) to one or more generators; enables such generators to clear the electric side’s price formation process; gas moves, electrons and/or electric side ancillary services are created, electrons and/or electric services are paid for; delivered gas is paid for and run-of-the-mill pipeline usage charges are paid for. This is what happens over 90% of the time when the two industries interface.

**What’s Missing When It is Not Working and Why is it Missing?**

Given that since passage of the NGPA, the solution of the gas price problem has assured north Americans that we have not, do not, and will not face a gas supply problem. The “problem” -- when coordination at the interface[[1]](#footnote-1) is not working -- is a capacity problem. The capacity may start as an hourly capacity deficit; may progress from hourly to daily; and/or may persist seasonally. In any event, absent temporary loss of facilities or capability, capacity problems require capacity solutions, and thus, expensive long-term solutions.

Why is the capacity missing? Simply put, under the business model paradigm in effect since industry restructuring; and in fact, since the introduction of gas transportation services alongside merchant services, new gas capacity gets built when someone agrees to pay for it (and legacy customers are not required to subsidize its’ costs). So, the capacity is missing because absent an assured revenue source to ensure cost recovery, the new capacity will not be forthcoming capacity.

As a result, and until there is a mechanism to provide revenues underwriting new capacity, the “capacity problem” will not only persist, but will likely increase in frequency and duration.

In short, a revenue model that works with how the two industries currently operate is needed before experience with that revenue model can inform; and, be relied upon to fund, mid-term and long-term facilities enhancements purposed for serving the needs of electric generation; and addressing what is “missing” when things don’t work.

**Drawing on a Recent Paradigm Codified by FERC with respect to the Electric Industry**

Recently, FERC, in an order concerning compensation, in the electric industry, for a generation asset’s “fast start services”, basically said that pricing for this service should be commensurate with its value and be coincident with the dispatch of this service. In this way, FERC found that it is better to align pricing and dispatch intervals.

So, while on the electric-side, aligning the value provided by a fast start generator should be recognized and aligned with the dispatch of that generator’s fast start service, the same recognition is not present on the gas side for the service delivered by the pipeline of providing that generator the fuel that enables its fast start.

In essence, the pipeline, not the shipper, is providing the non-ratable, and often quick start, delivery service; and, is doing so, for no additional charge -- in short, that crucial pipeline service is an uncompensated service.

While the electric side is imparting value to and explicitly recognizing the value of the generator’s fast start service, the gas side’s quick-response, non-ratable delivery service (without which the fast start cannot be realized) is not receiving commensurate recognition.

**Demand for Valuable, Un-Priced, Pipeline Services is, and will Continue to be, “Infinite”**

It is important to note here, that there is, and will be, infinite demand for a valuable service that is unpriced at (or during) the interval over which it is demanded. Likewise, there are no economics which could call forth “more” of a demanded service when that service is unpriced and incremental investment is required to provide the “more” of that service.

**Where to Start: One Example of Un-Priced Service -- Penalties Do Not Substitute for the Pricing of Actually Provided Services**

During times of gas-side system stress, the pipelines currently have only coarse, behavior-based, tools to invoke in response to the service they are providing. That tool, the tool that made the pipeline-as-merchant to pipeline-as-transporter transformation even possible, was and is, the OFO and associated OFO, SOC and COC penalties.

One problem with continuing, as-is, with this historic and coarse formulation is that the pipeline is still providing the service, even under these strained conditions; however, because penalties’ revenues from offending shippers are flowed back to non-offending shippers, the pipelines that actually provided the “penalized service” remain uncompensated even though they provided the service.

**Keep Penalties and Institute Charges for Services Provided**

I am neither suggesting here that pipelines not charge penalties, nor am I suggesting that pipelines retain penalty revenues; rather, what I am suggesting is that pipelines collect, in addition to the penalty revenues; service revenues for the service actually provided. Further, those services provided should be defined and when provided, whether during conditions of stress or, for that matter, in the normal course of business, those service revenues should be collected and retained by the pipelines. There should still be penalties to discourage behavior outside of contractual parameters, and there should be prices for services provided.

**Providing Volumetrically Priced Services for Non-Ratable Deliveries from Firm Contracts**

Current “Authorized Overrun Services” – services provided *outside of* contracted quantities -- are volumetrically priced at rates derived from the 100% load factor of the rates charged for “within contract services”.

Analogously, there should be rates for “Unauthorized Overrun” services. These “Unauthorized Service” rates can and should be charged at rates reflecting 10%-20% load factor rates; or stated another way, these services, once taken, should be volumetrically charged at rates that are 5 to 10 times the Authorized Overrun rates. In this way, the stage is set for having known and knowable variable rates charged to generators that can be recovered in the electric market; and, with a volumetric structure tied, of course; to both the hour of use and the quantity(ies) of service provided, such volumetric rates can reflect the value of the service provided by the pipeline/gas market to the electric market.

These prices (rates) can also be tiered so that during those hours -- where the pipeline is providing the most service (in relation to/relative to) and in excess of contract rights – deliveries are charged more per unit of service than those hours of lesser service relative to contract rights. One way to visualize this service would be that a 6% hour (where 6% of daily quantity is taken in one hour) would be charged, in such hour, at a lower rate than would takes at a 15% hour, 25% hour or other non-ratable hourly take level.

**Historic Precedent for Volumetrically Priced Firm Services**

Since the 1990’s period of pipeline service restructuring, pipelines have had a portion of their firm transportation services priced volumetrically. Those services were primarily services to municipal gas and electric entities. The original impetus for this pricing structure was that these generally “small entities’” markets experienced very low load factor demands and there would be a commensurate, “unfair” relative, economic burden on them if they were subjected to annual fixed reservation charges. So, the bargain was struck that the gas-side would continue with volumetrically based services to these entities.

Today, a similar economic burden is expressed by generators in their ISO, RTO, and BA markets where fixed firm reservation charges from pipelines are not recoverable under current electric market price formation/dispatch mechanisms. Instituting volumetrically-priced service from pipelines provided to, and for the benefit of, generators addresses this facet of price formation in RTO, ISO and BA markets that discourages the vast majority of generators from subscribing to firm pipeline service; precisely because such services are priced on a fixed reservation charge basis and such “fixed” costs are not recoverable in electric market energy prices.

**Gas Market Services are also being Provided when Scheduled Gas is Not “Taken”**

The reader should keep in mind, as well, that the pipeline is not only providing service(s) when takes exceed contracted MDTQ and/or contracted ratable takes, but also when the generator is taking below ratably (or even taking zero gas in an hour but is taking gas during the day). This is due to the fact that to the extent the generator is scheduling gas, that gas comes into the pipeline ratably, and when the generator is taking no gas or is taking at less than ratable levels, the pipeline has to use its horizontal and vertical storage assets to find a place to put the unburned gas; as well as, a place from which to take the gas when it is burned above ratable levels.

This operational fact and service provided also leads to the corollary economic fact that when the pipeline were to charge for this service, it should collect these volumetric, non-ratable, service charges only when the generator is burning (i.e., taking gas) above ratable so that the generator can collect these variable/volumetric charges as part of its energy charge compensated in the electric market.

**What can this Service and Revenue Configuration Lead to on the Gas-Side?**

Over time, for the pipelines, they will gain experience with the frequency of service delivery as well as the magnitude of the associated revenues; and for the generators, the same experience and the incentive to avoid penalties will likely lead to fashioning of and subscription to services that provide firm, volumetrically priced services at price and revenue levels sufficient to support existing and, if demanded, *additional services effectuated through additional facilities*.

**The Path To, and Possible Vehicle for, Moving Forward**

How, contractually, can pipelines introduce and charge for these services with a minimum of gas market disruption?

At the core, these services are provided by pipelines to the entity/facility they are directly connected to – i.e., the generator. At the same time, these hourly load-following services are not services spelled out in, or required to be provided under, run-of the-mill FT contracts. Rather they are effectuated by the masterful operational knowledge associated with asset utilization optimization while simultaneously maintaining services contracted for by firm shippers. These firm services that are “maintained” also include those contracted FT agreements into which gas is received ratably and from which deliveries to generation locations are scheduled ratably; but from which the gas is actually delivered non-ratably.

In short, non-ratable service consumes capacity not contracted for, but created and effectuated by pipeline operations, operations that should be compensated in a manner that their value is communicated to and becomes part of price formation in the electric markets.

At present, the vast majority of generators get their gas delivered off of firm contracts held by marketers, LDCs and others using secondary delivery rights; or in some cases off of generators’ own FT contracts with primary delivery rights. Here, the FT contracts that I am talking about are FT contracts from supply points, from (or passing) liquid trading points or pools and passing by; or (i.e., in the case of generators with FT contracts), running to the generation location. I am not including generators’ lateral only contracts which simply run from a mainline to the plant.

Leaving the rates and operations of these FT contracts discussed above alone, there is a way to economically connect the generator receiving the non-ratable service with the pipeline whose assets and operator skills are effectuating the non-ratable, load following, service. This “way” of economically connecting the physically connected parties could be through amendment of the Operational Balancing Agreement (OBA) between the pipeline and the generator.

**Focus on the OBA**

OBAs are used to both keep shippers’ scheduled quantities “whole”; and, to have a mechanism for resolving and keeping physical differences between scheduled and burned volumes as a matter that just between the physically connected parties. These volume “differences” can be settled in kind or by means of cash-out; and with few exceptions they are settled monthly. As currently structured, OBAs can be and anecdotally, frequently are, “abused” by the connected, non-pipeline, party. In the case of generators, this “abuse” can be price-based/motivated or operational (for example taking non-ratably, taking when not scheduled, or not taking when scheduled).

**Update the OBA**

By employing updated OBAs as the means for compensating pipelines for valuable but currently uncompensated services, and using volumetrically based charging mechanisms, the value of services provided by pipelines will be communicated to the electric market and foster both economic efficiency and/or economic substitution in that market as a competitive response to appropriate price signals. The result will be that the two markets, at the most granular daily and hourly level, the level that they are most coordinated today will finally have the short-term price signals that will inform both medium and long-term investments in both markets.

**Also Look to Updating the Electric-Side**

Is it *sufficient* to introduce these changes to the gas side?

No.

Would such changes *alone* bring about better and more pervasive gas-electric harmony?

Additional harmony, yes, pervasive enough to address all coordination breakdowns? No.

Are there commensurate market operation changes on the electric side that can institutionalize and support development of these gas-side services and lead to prevention of coordination breakdowns?

Yes.

**What Change on the Electric Side Complements and Reinforces Increased Coordination and Reliability?**

One such enhancement would be to have the ISOs, RTOs, and outside of these, the Balancing Authorities (BAs) make one change to the way they conduct price formation and attendant dispatch.

**Adopt a “Firm-Fuel-First” Paradigm**

At a high, and simplistic level, after RTOs, ISOs and BAs identify total demand to be met, as is done today, they would identify zero fuel cost generation and the predictable MWs from such generation and then identify the clearing price of all generation with “firm fuel” needed to satisfy that hours’ projected demand. Then, for each hour it would schedule that generation and to the extent additional generation was required, schedule the next increment of firm-fuel generation bid in and clearing that hour at the firm-fuel clearing price. If this combination of generation meets projected demand, then stop. If these two tranches, (i.e., zero cost generation plus firm fuel generation) are insufficient to meet projected demand, then; to the extent additional generation was/is required, identify the new, third tranche’s, higher clearing price and schedule the remaining required generation along with the other two tranches; and pay all generators at this final clearing price.

The same Firm-Fuel Paradigm would also apply in real-time markets where incremental firm fuel generation would have a dispatch preference and non-firm fuel generation would face decremented dispatch first.

**Pricing Levels of Volumetrically Priced Firm Services**

Would all volumetrically priced firm service be priced the same?

It is not likely that pipelines would provide volumetric firm services at the same price to all generators. That is because the load factors of operation differ among gas-fired generators based upon a slew of factors; primary among them being heat rate and location relative to demand nodes. Because differing generators operate at different load factors, rates will, (at least it would be logical that such rates), be structured so as to recover pipelines’ costs over generators’ respective, projected, load factors of operation.

**Beneficial, Market-Driven, Effects of “Firm-Fuel-First” Scheduling on the Electric-Side**

The effect of this enhanced RTO/ISO and BA clearing and scheduling process would be to increase reliability of generation within the electric grids. A Firm-Fuel-First price formation and scheduling paradigm will also incentivize both the gas transportation and gas-fired generation sectors to have and contract for, respectively, firm fuel; enabled by volumetric firm service offerings.

And, for the pipelines; knowing that firm services, (both reservation-based and volumetric-based services), will receive scheduling priority from the electric-side means that such priority will serve to provide additional assurance of volumetric revenue realization.

Associated with greater assurance of scheduled volumetric service, the electric-side scheduling priority will incentivize pipelines to offer volumetric firm services. As a consequence, and additionally, services like those identified above where the pipeline firms-up and prices “Authorized Service” to generators by means of firm OBA mechanisms; and, where pipelines also price “Un-Authorized Service” while maintaining penalties for Un-Authorized Service will generate, for pipelines, revenues that otherwise would not be available.

**Benefits to Electric-Side of Firm Fuel First**

Firm Fuel First price formation and scheduling, whether in an energy-only market or a market with a capacity-market component, increases the reliability of energy production and provides a known and knowable measure of reliable capacity[[2]](#footnote-2) for planning and operations purposes. Giving a preference to firm fuel provides to generators an incentive to be counted among; and, dispatched ahead of, non-firm fuel generators; thus, providing precisely the incentive to generators to obtain firm capacity service that underpins firm fuel. This incentive, coupled with volumetric firm offerings by pipelines will, over time, achieve, by market mechanisms, the reliability needed to effectively meet demand while managing generation.

Finally, because the value to the electric industry of non-ratable delivery service will be reflected both in energy prices on the electric side and revenues on the gas side, market forces will work to constantly adjust to what is and will continue to be a dynamically changing integrated and interdependent energy market. It will take time, but absent out-of-market solutions (OOMS) imposed on both the gas-side and the electric-side (which OOMS will face their own timelines and delays) it would seem preferable to make the policy changes needed to spur along desired market developments which will harness and motivate mutually reinforcing responses on and in both the gas and electric sides.

**Next Steps:**

Surely, this proposal is not and will not be the only Problem-Solution offering from among NAESB participants. There may and likely will be other views as to how to achieve better and more comprehensive harmonization. Indeed there may be complimentary offerings and contrary offerings. In either and both events, providing comprehensive proposals for paths forward will provide FERC with choices of policy direction that, once made by FERC, can form the basis of NAESB’s efforts to craft implementation standards.

1. When the problem is un-weatherized generators, the policy changes associated with resolving this problem are not addressed in this writing. When the problem is un-weatherized gas production, gathering or processing facilities, the policy and market rules changes called for herein will increasingly eliminate the ability to blame the pipelines for not being able to perform under standard NAESB contracts and will lead to increases in physical risk mitigation responses to production loss so as to reduce and eliminate the impact on sellers of NAESB Contract “keep whole” risk vis a vis their customers. [↑](#footnote-ref-1)
2. Both gas delivery capacity and generation capacity. [↑](#footnote-ref-2)