Synchronizing Natural Gas & Power Markets

A Series of Proposed Solutions

January 2013

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Synchronizing Natural Gas & Power Markets

Proposed Solutions

Introduction

Whether you call it coordination, harmonization or synchronization, getting the gas and power markets "in sync" is a hot topic. The electric grid's greater dependence on gas-fired generation this past year has fueled the fire. FERC staff has published and held regional technical conferences on the topic, NERC has highlighted the issue in its recent 2012 Long Term Reliability Report and various articles have been written about it. So far we can conclude two things from all this activity:

1. There is a problem and it's serious
2. There is, as yet, no consensus on what to do about it

The gas/power syncing issues have many facets and appear to have regional differences and outlooks; however, this paper is focused on the big picture issues that cross regional lines and on providing a series of proposed solutions for those issues.

The key market synchronization issues as we see them are:

A. Compliance & Definition of Firm Power
B. Economic Syncing
C. Market Timing & Coordination Differences
D. Communication
E. Pipeline Capacity Availability

A. Compliance & Definition of Firm Power

From a system reliability standpoint, we propose that NERC redefine "firm power" on a "fuel neutral" basis. For example, a coal generator would need to verify inventory on site, such as the coal pile size and generating capability in terms of hour. Oil generators would verify tankage, inventory and related generation capacity. For hydro, verification of stored water would be the requirement. Gas fired generators, would need to provide verification (with third party confirmation) of the necessary firm service contracts (i.e., pipeline contract(s) for Firm Transportation Service(FTS)). For gas generators behind city gates, the confirmation would come from the Local Distribution Company (LDC) contracts for either firm LDC transportation or firm sales service or both. The reporting of firm transportation or firm gas service would be coupled with related hourly generating capability.

This redefinition could then be implemented by the market operators and generators, clearing the way for additional market responses to these definitions. In particular, prices bid into the power markets would reflect the costs of firm fuel capacity acquired to meet the "firm power" definition. It is anticipated that demand for pipeline capacity would then be reflected in the secondary market for pipeline capacity. Any signals from that market would be quickly translated into new capacity offerings in the primary market by pipelines responding to the evidenced price signals produced in the secondary market. Pipeline responses in the primary market would be right-sized capacity additions or right-sized service offerings.

Short of a redefinition, there is nothing to compel generators to firm-up their fuel reliability. In our view, this product re-definition coupled with the market syncing proposed herein, would set in motion the market mechanisms, price signals, and market responses needed to make these two markets work in coordination. As a side benefit, power prices reflecting scarce pipeline capacity would also drive the value of fast acting demand response and other ancillary sources of short term power capacity, such as storage.

Two primary areas of compliance, as well as a need for reworking the definition of "firm power," require attention from FERC and NERC. Our analysis suggests that modifying the market rules along the lines of our proposed syncing solutions can be done within the current FERC Standards of Conduct guidelines and that, with perhaps some clarification from FERC, a majority of the markets' concerns on this issue will resolve themselves.

B. Market Timing & Coordination Differences

Given the daily timing differences resulting from the different operational parameters between the gas and power markets, it is amazing the grid hasn't already experienced a train wreck. Whether driven by lower prices, plentiful supply, the retirement of coal plants, or the ever greater amount of intermittent generation resources (i.e., wind and solar) connected to the electric grid, more gas-fired generation is utilized and relied upon by power markets for meeting demand and for assuring reliability. This new inter-market dependency points to an inevitable collision if the two markets don't sync up.

The train wreck theory is based on the fact that much of the "firm" power bid into the real time and day-ahead market by gas generators isn't actually backed by the firm gas pipeline capacity necessary to deliver the gas supply to the generator. It's not that gas generators are intentionally gaming or manipulating the system; rather the industry definition of "firm power" as it relates to gas-fired generation is not conducive to sending economic signals related to the gas pipeline capacity (FTS) which makes the power "firm."

The market timelines of the gas and electric systems, as they are today, don't sync. Today, the gas market's standardized schedule for purchasing, scheduling and confirmation of short term primary or secondary firm pipeline capacity to deliver the required gas supplies generally operates after power bids are due. The potentially devastating effect(s) of nonperformance by gas plants goes beyond basic power system reliability as grid operators increasingly look to dispatch gas generation to offset the expanded use of intermittent renewable generation.

Change the Sequencing of Market Operations to "Gas then Electric"

Once Firm Power means Firm Fuel, the order in which markets operate, that is the *sequencing*, needs to accommodate such change. Today, there are only three ways that a gas-fired generator can obtain the "firmness of their fuel" that the new definition of Firm Power entails. One, have a firm capacity contract with the pipeline serving their load location; two, obtain firm capacity in the secondary (capacity release) market with at least primary zone rights to serve their load location; or three, buy the needed gas on a firm basis from a holder of firm capacity which capacity has at least primary zone rights to serve their load location. Because two of these three ways involve participation in the very liquid secondary capacity or delivered gas sales markets, we propose that the gas markets' clearing sequence (capacity and then sales) be changed so that they occur *before* bids into the power market are made and cleared. For this reason, as proposed below, the on-peak electric market should clear before the off-peak market. With gas market clearing occurring before on-peak electric, and then the off-peak gas and electric markets clearing after the on-peak markets, sellers of power know their cost structure and revenue from the on-peak market and can evaluate whether to be a seller of their off-peak gas and capacity into the off-peak gas market or into the off-peak electric market.

While this sequencing realignment will change the way certain generators, especially peakers, have viewed their participation in the electric market, the fact is that a choice related to reliability and coordination needs to be made. We believe this choice has market synchronization and market reliability benefits that outweigh any impacts these changes might have on peakers.

To put this into perspective, in the future, if a gas generator bids into either the real time or day-ahead power market, they will need proof of contracted firm capacity to assure delivery of gas, and thus, delivery of power. Therefore, unless the generator has acquired long term firm pipeline capacity rights, which today most do not, bidding into power markets will require buying short term pipeline capacity in

the capacity release market. While today, a large proportion of the capacity sold in the short-term capacity release market is "recallable" by the seller, much of this recallable capacity is sold to marketers and others serving load behind the LDC-sellers' city gate points. This is generally not the case with short-term capacity sales where the buyers are purchasing the capacity to serve other markets. As discussed in greater detail below, generators will be acquiring short-term capacity in the capacity release market on a "non-recallable" basis in order to satisfy the requirement that their energy sales be backed by firm pipeline capacity.

In organized markets where renewable generators can bid into day-ahead markets and/or sell into day or "real-time" markets, to "firm up" their day-ahead bids, there are two related potential solutions. One solution is to allow renewable generators to balance their bids with a combination of production and contracted demand response (DR). Contracted DR would kick in as renewable generation dropped below the firm quantity sold to the day-ahead market. To accomplish this, intermittent generators can either aggregate their own load shedding DR portfolios, or more likely, contract with existing DR aggregators. Either way, the DR portfolio backing renewable bids would need to follow the same registration protocols with ISOs that they do now. Each ISO would need to put transaction rules in place to avoid duplicate bidding of DR associated with a specific load, as well as market rules to ensure that ISOs retain event call rights for the DR programs they already have.

Today's Market Timing Differences – An Example

On the gas side of the equation, the NAESB standard or Timely sequence for gas scheduling has nominations for next day delivery due at 11:30 AM Central Prevailing Time (CPT) with scheduled quantity confirmation back from the pipeline at 4:30 PM CPT. Shippers using the Timely scheduling sequence, once scheduled, are not at risk of being bumped when using primary or secondary firm capacity rights. Consequently, Timely nominations are best for assuring delivery of gas for the next day.

While there are other nomination opportunities later in the day, not all of them afford to secondary firm capacity nominations the same bumping rights over interruptible transportation (IT) that they are afforded in the Timely cycle. Thus, today, a within-day "late nomination"[1] of secondary cannot bump previously scheduled IT.

On the power side of the equation, power bids for next day or day-ahead markets are due at an assortment of times. With the exception of NYISO, which closes at 11:00 AM Eastern, scheduling with the other organized ISOs is generally announced at 3:00 PM Central Time[2]. Again, with the exception of NYISO, this is a full 3 ½ hours *after* the natural gas market for day-ahead (Timely) nominations has closed.

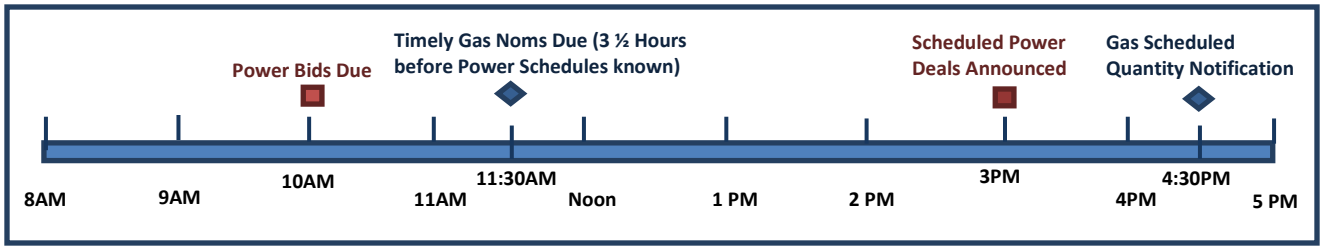
To further complicate matters, the nationwide secondary market for pipeline capacity trading (the capacity release market) opens at 12:00 noon Central, closes at 1:00 PM Central and announces cleared transactions at 4:00 PM Central. Usually pipeline capacity traded in this secondary market is for next day; however, it can be for same day capacity… and same day capacity acquired in the secondary market is at a disadvantage because the "secondary firm rights" are unable to bump previously scheduled IT.

[1] This cycle is referred to as Intraday 2 cycle which has nominations at 5 PM Central with flow at 9 PM during the flow day.

[2] PJM and ISO-NE announce day-ahead market schedules at 4:00 PM Eastern after accepting bids until 11:00 AM and 12 noon Eastern respectively; MISO announces scheduled deals at 3:00 PM Central (4:00 PM Eastern) after accepting bids until 11:00 AM Central (12:00 Noon Eastern); CAISO announces scheduled deals at 1:00PM Pacific (4:00PM Eastern) after accepting bids until 5:00 AM Pacific, NYISO announces scheduled deals at 11:00 AM Eastern, after accepting bids until 5:00 AM Eastern, ERCOT announces scheduled deals at 1:30 PM Central (2:30 PM Eastern) after accepting bids until 10:00 AM Central (11:00 AM Eastern); and both SPP and ISO-NE are in the midst of separate processes to determine which future schedules to implement for their day-ahead transactions (SPP) and what, if any changes are to be made to their day-ahead market schedule (ISO-NE).

The timing differences between gas and power scheduling mean that the markets are not in sync. As the ISO-NE example chart below depicts, gas nominations are due after power bids are due and confirmation of gas schedules occur after power bids are confirmed.

ISO New England: Day-Ahead Market Example
Presented along standard gas timeline – i.e., Central Prevailing Time



How Did We Get Here?

The natural gas and electric power wholesale markets have restructured differently and on separate time lines over the past 20 years. The current wholesale gas market structure, decoupling the pipelines' merchant (supply) role from their transportation (capacity provider) role and the creation of the secondary market in pipeline capacity came about in the mid-90s. The pipeline operational rules for scheduling, confirmation of capacity, etc. were developed shortly thereafter and long before competitive electric power markets were formed.

During the formation of competitive wholesale power market rules, the concept of firm power related more to the presence of a generation unit[3] that bid power supply than to a physical confirmation process. Power markets use penalties for nonperformance and risk of higher power replacement costs as market drivers to assure that generation bidders perform.

The youthful days of both markets experienced huge financial and operational swings that in some cases brought companies to or near bankruptcy. One only need remember the California wholesale power market fiasco of the early 2000s[4] when power traders could bid gas-fired generation into the day-ahead market without actually having supply, causing Real Time prices to go through the roof. Traders have long benefited from the disconnect between the two markets and reaped profit from numerous types of across-market trading mechanisms, such as tolling and reverse tolling which captures the economic value interchangeably between the markets.

Market Timing & Coordination Proposed Solution

Once Firm is Firm, the majority of the syncing issues between gas and power may be solved by fixing the market timing and market coordination rules. While various market participants like to highlight regional differences, we find the following proposed steps will provide a solution that can work on a national basis as well as regionally.

a. More Pipeline Nomination Cycles. While increasing the number of standardized gas scheduling cycles within the day won't truly solve the syncing issue, it would allow gas generators to tweak

[3] A generation unit with Firm electric Transmission Rights ("FTRs") (i.e., takeaway rights) where required, depending on the ISO/RTO. FTRs are distinct from firm transportation rights discussed here. Firm Transportation (i.e., pipeline capacity for fuel) pertains to getting fuel to the plant; whereas Firm Transmission Rights pertain to firm rights to get electric power away from the plant to the location where the bid to sell electricity is considered for clearing the electric market.

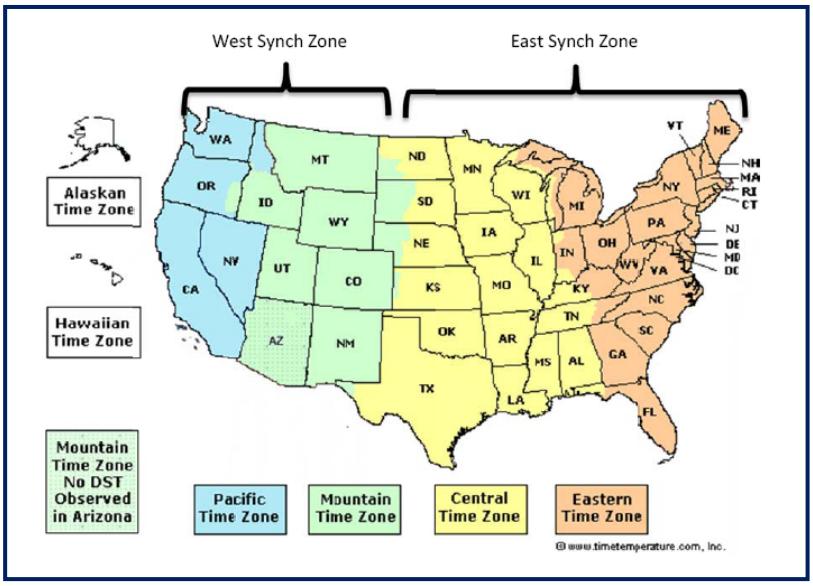
[4] Notably, gas-fired generation then and now constitutes more than 50% of California's generation capacity. Moreover, in most organized electric markets natural gas is the "marginal" fuel from which electricity is generated thus driving market clearing prices for the vast majority of the nation.

schedules and get confirmations more often based on market and operational information. Three major pipelines, Texas Gas, Gulf South, and TransCanada have proven it can be done by voluntarily implementing an increased number of daily cycles.

b. *Raise the Priority of Secondary Firm Above Interruptible in All Gas Nomination Cycles.* Moving secondary firm ahead of IT in the pecking order would enhance capacity release assets for both buyers and sellers and provide real world economic distinction between firm and interruptible service. While this would improve the utility of secondary firm capacity, as well as pipeline capacity reliability, it is still, by itself, not a guarantee of "firmness." Some generators relying on IT will decry the bumping change; however, with the change in definition of firm power and the introduction of the sequencing changes, relying on IT will largely be a thing of the past. Moreover, simply changing the bumping rules without making the other changes may, in fact, make things worse.

c. *Create Two North American Energy Sync Zones.* Today there are at least 4 "Electric Days" and a different "Gas Day" in North America. These multiple and unsynchronized "Days" not only hinder operational coordination, but more importantly they frustrate economic synchronization and coordination. Instead of multiple definitions of a "day," having one "Eastern Energy Sync Zone" and one "Western Energy Sync Zone" would eliminate overlap and establish the foundation for fully synchronizing the two markets. As it stands now, the gas and electric markets are not synchronized and, without establishing the same definition of a "day," it is unlikely they can be. The good news is that the major central and eastern organized electric markets already announce their day-ahead schedules at nearly the same "time," so the adjustment will not be as severe as one might expect.[5] While some, especially those in the gas arena, might think that two energy days is a step backwards, we believe that, again, the benefits of gas-electric coordination outweigh the change. Moreover, as is evident from the hour by hour detail set forth at the end of this article, the 12 sync-up times are all at the same "time," just different clock hours in each time zone.

As illustrated in the following chart, all electric markets and gas pipelines in the respective Zones would have the same "Energy Day."



[5] PJM, ISO-NE, and MISO all announce their day-ahead results at 4:00 PM Eastern (3:00 PM Central). NYISO and ERCOT go "early" announcing at 11:00 AM Eastern (10:00 AM Central) and 1:30 PM Central (2:30 Eastern) respectively. CAISO for its part announces at 1:00PM Pacific (4:00 PM Eastern).

It is proposed that the Central and Eastern Time Zones have one Energy Day, 6:00 AM to 6:00 AM local clock time for the Eastern Time zone and 5:00 AM to 5:00 AM local clock time for the Central Time Zone. In this way, all Eastern Sync Zone Gas and Electric infrastructure would be on the same instantaneous schedule.

The Pacific and Mountain Time Zones are to have another Energy Day: for the Mountain Time Zone, 6:00 AM to 6:00 AM local clock time, and for Pacific 5:00 AM to 5:00 AM local clock time. Like the Eastern Sync Zone, all Western Sync Zone Gas and Electric infrastructure would be on the same instantaneous schedule.

Notably, 154 of 165 FERC regulated interstate "Natural Gas Companies" (i.e., FERC regulated pipelines and storage operators) fit comfortably into these East and West Sync Zones. As part of implementing these two Sync Zones, it is proposed that the remaining eleven FERC regulated natural gas companies, seven of which are storage operators, be allowed to choose in which Sync Zone to participate based on each pipeline's analysis of opportunity to provide incremental service to electric generation markets.

The tables at the end of this article provide an hour-by-hour view of the two Sync Zones and the operational aspects.

C. Economic Synchronization

Once two Sync Zones are in place, a corresponding change in the economic parameters will be required, impacting transactions in both gas and power markets. The following economic sync solutions are proposed:[6]

On Peak

To sync the economics in line with Sync Zones for the power markets, it is proposed that there be an "On-Peak Market" standardized to be 16 hours/day Mon-Fri (excluding holidays). We propose the following sequence of market clearing followed by physical scheduling:

1. The Power Markets start with Requirements Forecasts for Day-Ahead On-Peak hours.
2. Following which, the Gas Capacity Market (Capacity Release) Opens, then Closes and, following Close, Reports cleared capacity deals.
    a. Generators anticipating day-ahead forecasted load and needing Firm can get the Firm they need in this market from:
        i. Capacity Releasers or
        ii. The pipelines who, under our proposal, can offer "Day at a Time" services such as 1) Storage, 2) Firm transmission, 3) Line pack/draft quantities, 4) Primary point rights that adhere to mainline "path rights, and/or 5) non-ratable Hourly Services.

Once the Day-ahead Firm gas transportation capacity market clears, the Electric Day-Ahead On-Peak Market Opens, Closes and Reports. With these two complimentary and interdependent markets

[6] The authors are proposing two distinct economic markets for electric markets, an On Peak and an Off Peak, in order to provide opportunities to separately permit rebalancing (re-release) of pipeline capacity. In particular, capacity procured for On-Peak could, possibly, be traded to different holders for Off Peak electric time periods. While such opportunities may not be necessary or desired by such holders of On Peak pipeline capacity, having the two separate economic markets facilitates such trading. These and many other such details would naturally be worked out in the coming regulatory and NAESB standardization processes. Nevertheless, at this writing, they were deemed a useful, albeit additional set of procedures.

cleared, the gas market proceeds with Day-ahead Nominations being made[7], followed by Confirmations and then Scheduling (Reporting).

Off Peak

In the Electric Markets, it is proposed that there be an Off-Peak Market standardized to be 8 hours/day Mon-Fri and 24 hours/day Sat-Sun and holidays. Like the On-Peak sequencing, Off-Peak sequencing would:

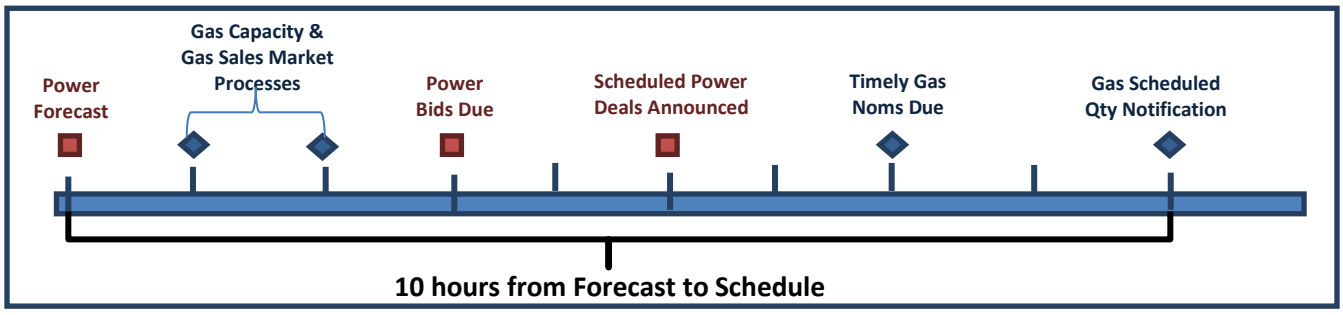
1. Begin with Requirements Forecasting for the Day-ahead Off-Peak
2. Followed by the Gas Capacity Market (Capacity Release) Open, Close and Report.

To the extent generators which obtained full day firm gas transportation capacity in the On Peak wanted to shed capacity in the Off Peak, the "intra-day/balance of the day" capacity release market is available. Likewise, those generators needing balance-of-day firm gas transportation capacity can avail themselves of offerings in the respective capacity release and pipeline "Day-At-A-Time" service markets, consistent with the On-Peak Market mechanics.

Moving the Day-Ahead Capacity Release and Pipeline Day-At-A-Time service markets and clearing times earlier in each Energy Day enables generators to get the Firm they need (assuming they don't already have it) and enables pipelines to offer new Firm Day at a Time services. It also allows firm pipeline capacity holders to more readily respond to power market signals. The pipelines' Day-At-A-Time service offerings may be limited at those times of year when all capacity is anticipated to be fully scheduled, and this would be reflected in price signals in the secondary market, calling forth new capacity additions in the primary market. Otherwise, the Day-At-A-Time or even "Hour-At-A-Time" offerings related to non-ratable service, line pack/draft services, and others as yet unformulated, would be brought to market to serve demonstrated demand.

Likewise, moving Day-Ahead On and Off Peak Electric clearing times sufficiently to sync up with gas markets enables power markets to clear and know that the gas generation that is "bid in" is backed by firm pipeline capacity. And finally, moving the gas nominations mechanics later in the Energy Day permits the physical use of the rights (and obligations) entered into earlier in the Energy Day. While some generators may determine not to purchase their gas supply during the same period they are purchasing their capacity, waiting instead until just before nominations are due, others will make a different determination. In either regard, by having the capacity market clear in advance of power market clearing, generators will have the firm capacity to back their power bids.

Simplified View of Economic Synchronization Sequencing
(See Sync Zone Operational Timeline Implementation Charts for detailed timelines)



[7] In the Gas Market, the deadline for submitting nominations to the pipelines signals the end of the gas trading time interval as all deals for the commodity must be completed prior to such deadline so that the counterparties can submit nominations and conduct confirmations through the pipelines' electronic systems.

Intraday (Real Time)
In addition to the above, and as mentioned in Market Timing Solution #1, we propose that there be the establishment of twelve "Same Day" (i.e., Intraday) Gas Capacity Trading (capacity release) and Gas Nomination Cycles. This increase from the current one Capacity Release and four Nomination cycles[8] would enable significantly tighter syncing to power market real time bidding, clearing and dispatch cycles. A direct benefit would be an increased responsiveness of the gas grid (both the capacity trading and nomination processes) to intermittent renewable generation, demand response (on the electric side), and peak load management by both the gas and the electric distribution segments.

Exceeding the Standard – Other Issues to Be Considered
At present, and quite possibly over time, some ISO/RTOs might be consistently net exporters to the reorganized markets. In those cases, such net exporters may wish to "exceed the standard" timelines set forth here by opening, closing and clearing their markets prior to the timeline(s) above in order to know what is available for export. Such can be accommodated within their market(s)… at least as far as getting firm pipeline capacity is concerned as the authors propose that the pipelines' secondary capacity markets Open, Close and Report every two hours throughout the day. Note that, while this capacity trading would normally be for partial balance of day capacity to meet real-time responses, nothing prevents these markets from conducting day-ahead or other Short-Term pipeline capacity transactions.[9]

D. Communication

One of the keys to syncing the gas and power markets is communication of relevant data between affected parties. Assuming changes in market rules to enable syncing are adopted, communication protocols and processes will undoubtedly need to be enhanced. This is especially true if firm power is redefined to incorporate the generators' fuel source or pipeline capacity.

Currently, no formal method or data transfer process exists to verify firm pipeline capacity between the pipeline, gas generators and power market operators and compliance organizations, such as NERC or FERC. There are several communication issues to consider regarding information transfer.

- Generators or pipelines will certainly voice concerns regarding the extent and proprietary nature of the information that they might be required to disclose.
- Pipeline capacity may change hands in the release market and may not be directly linkable to the generator. For example, a generator may have their "firm pipeline capacity" bundled with the gas supply by capacity and gas trading companies holding the firm pipeline capacity.
- Many generators, especially those located behind the city gate, have options as to which pipeline can serve the LDC serving their facility and may switch the pipelines on which they acquire capacity back and forth based on economic factors or capacity constraints.
- For gas generators that rely on LDCs for delivery of gas supply, the LDC would post the same information as that posted by pipelines related to firm capacity holders.[10]

[8] One Timely cycle and three "intraday" cycles. In the future, there would be fourteen, One Timely On Peak, One Timely Off Peak and twelve intraday.
[9] Here "Short Term" means capacity transactions of less than five months duration. The five-month cut-off is in place in the gas capacity market to provide more days to consider such long term deals. Present rules require that capacity transactions be "available for bid" for at least an hour, currently occurring between 12:00 noon and 1:00 PM Central time. With the changes proposed herein, such "one hour" availability of bidding for full day to five month capacity would be the 12 one hour periods described in the example timelines set forth at the end of this paper.
[10] In the case of behind city gate gas generation, as discussed above, LDCs would likely welcome the additional firm service sales or capacity release to such generators.

We propose to address these communications issues by utilizing the gas and power market information that already exists in each sector. Information on the holders of all firm capacity is already made available by the interstate pipelines[11]. All that needs be done is to associate that information with generators' supply sources.

We further propose that the information regarding pipeline capacity and nominations be shared with market operators on the same cycle as confirmations, without proprietary details such as economic terms. Without the ability to verify firm capacity and match that information to generation bids, market operators cannot properly manage reliability risk.

E. Pipeline Capacity Availability

Regardless of any market based changes to sync the gas and power markets, one of the issues raised in certain regional market areas is the potential of insufficient pipeline capacity, a significant risk for peak winter days or for emergency purposes.

Some market participants have called for gas generators to install duel fuel and onsite storage in anticipation of this deficiency. We don't believe that to be a viable solution on a market-wide basis as there is no economic incentive, and quite possibly environmental disincentives or preclusions, associated with gas generators incurring the additional costs associated with dual fuel. That said, if the market pricing signals and/or future ISO/RTO specified service products warrant the additional investment in dual fuel, no doubt generators will respond. While power markets might change their forward capacity or other pricing mechanics to address this, at the end of the day what is really needed is construction of additional pipeline capacity… and as discussed above, price signals are the best way to incent new pipeline capacity.

We believe that the combination of the redefinition of firm power, market timing and economic syncing will cause true pipeline capacity price signals to create a value for peak and emergency capacity. Pipeline owners have long demonstrated a willingness to build infrastructure to capture economic value.

Alternatively, the demand side of the power grid has already demonstrated it can respond to peak needs. If peak or emergency load requirements can be priced at true market value, programs such as demand response, storage or dynamic pricing will take their rightful place in the market alongside, and in some cases instead of, building pipelines.

In our opinion, placing the burden of having duel fuel for peak or emergency capacity on gas generators is not workable or fair.

The possibility exists that if ISOs are sufficiently concerned about pipe capacity for peak or emergency needs, they might consider buying long term pipeline capacity and creating a generator forward market to resell that capacity. While this might well work, and pipelines would be inclined to build capacity on that basis, we doubt that ISOs are anxious to take on that economic risk.

Implementation

Three high level moving parts are required to implement these solutions. First the regulatory process, beginning with FERC and including NARUC, needs to fully vet these and other solutions. We believe this

[11] Pipelines are required to make reports, referred to as their Index of Customers (IOC), quarterly. In addition Pipelines are required to post prior to gas flow, their sales of Firm Capacity through what is referred to as the FT reports, and finally, capacity release transactions in the secondary market are also made publicly available. The LDC information posting corollary would be similar to the pipelines' IOC postings and FT Reports and, where an LDC accommodates capacity release, a corollary similar to that of SoCal Gas' Firm Access Rights (FAR) trading postings.

issue calls for a FERC NOI followed by a NOPR. Closely aligned within the regulatory process will undoubtedly be NERC and NAESB, as this issue impacts reliability and business rules.

Second, and not insignificant, is the adoption of market synchronization rules by ISOs, RTOs, utilities, generators and pipelines, as well as by retail and wholesale market participants. This will also entail modifications to software and transaction processes, and will alter reporting parameters for all concerned.

Third, as the FERC, NERC, NAESB, the National Petroleum Council and others have observed, there are other gas-electric coordination and "harmonization" issues wanting resolution. These include the necessity for the electric grid, in times of stress, to "share information" in order to keep power flowing to those segments of the gas industry that supply fuel and capacity to the electric grid ensuring that the fuel to run the generators that provide the power and reliability to the electric grid is available.[12]

Last, but not least, is the associated training of the work force to adapt to the new operating rules.

Is it Worth It?

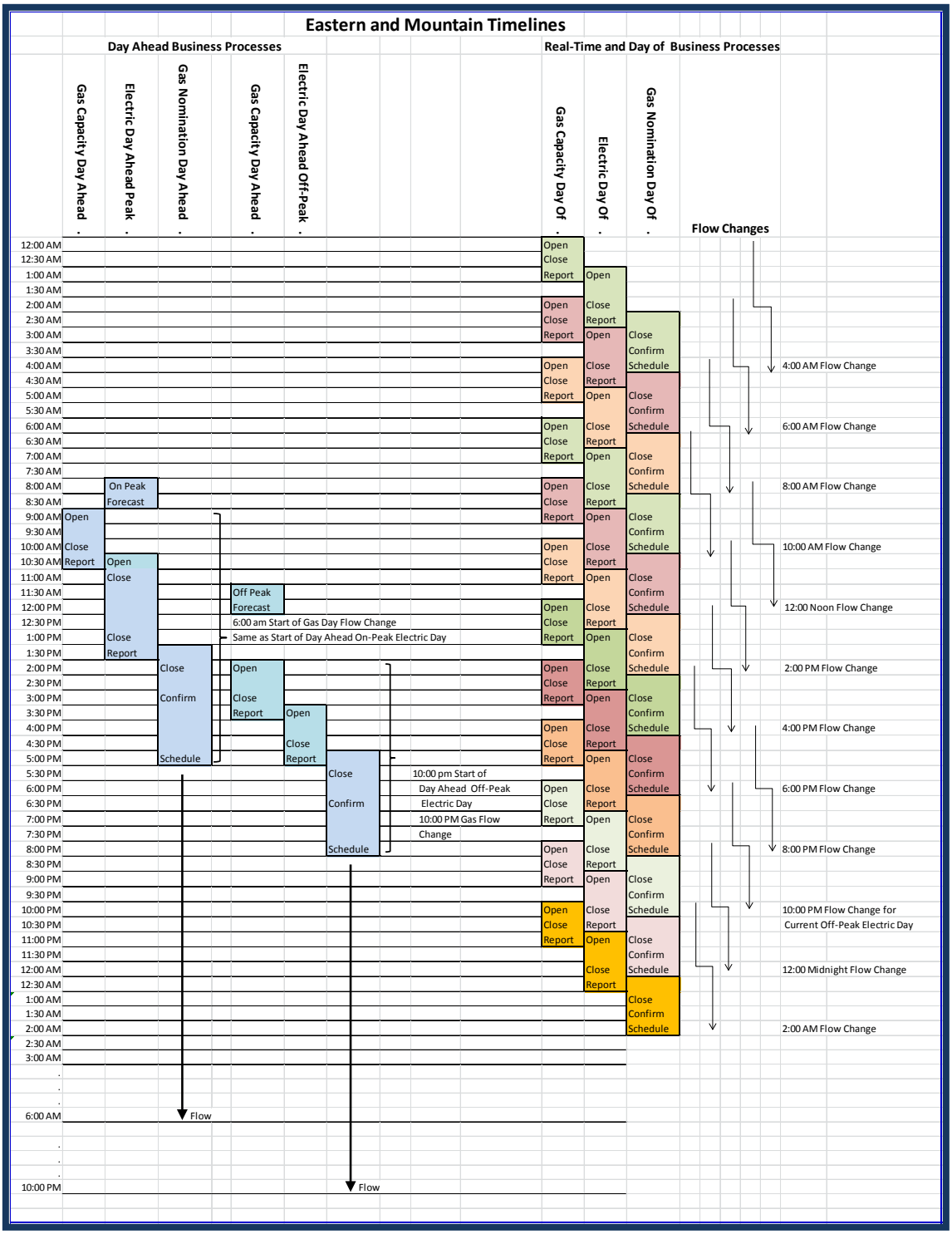
Can there really be a "smart grid" if the business rules for the one generation fuel that enables the grid to manage load in real time – i.e., gas – aren't in sync? Unfortunately the energy industry has a bad habit of fixing things after a catastrophe occurs. Do we really want to explain another blackout, this time because the gas generators were unable to perform because they didn't have pipeline capacity? Do gas generators really want to pay the penalties incurred due to lack of firm capacity when the power grid is depending on them?

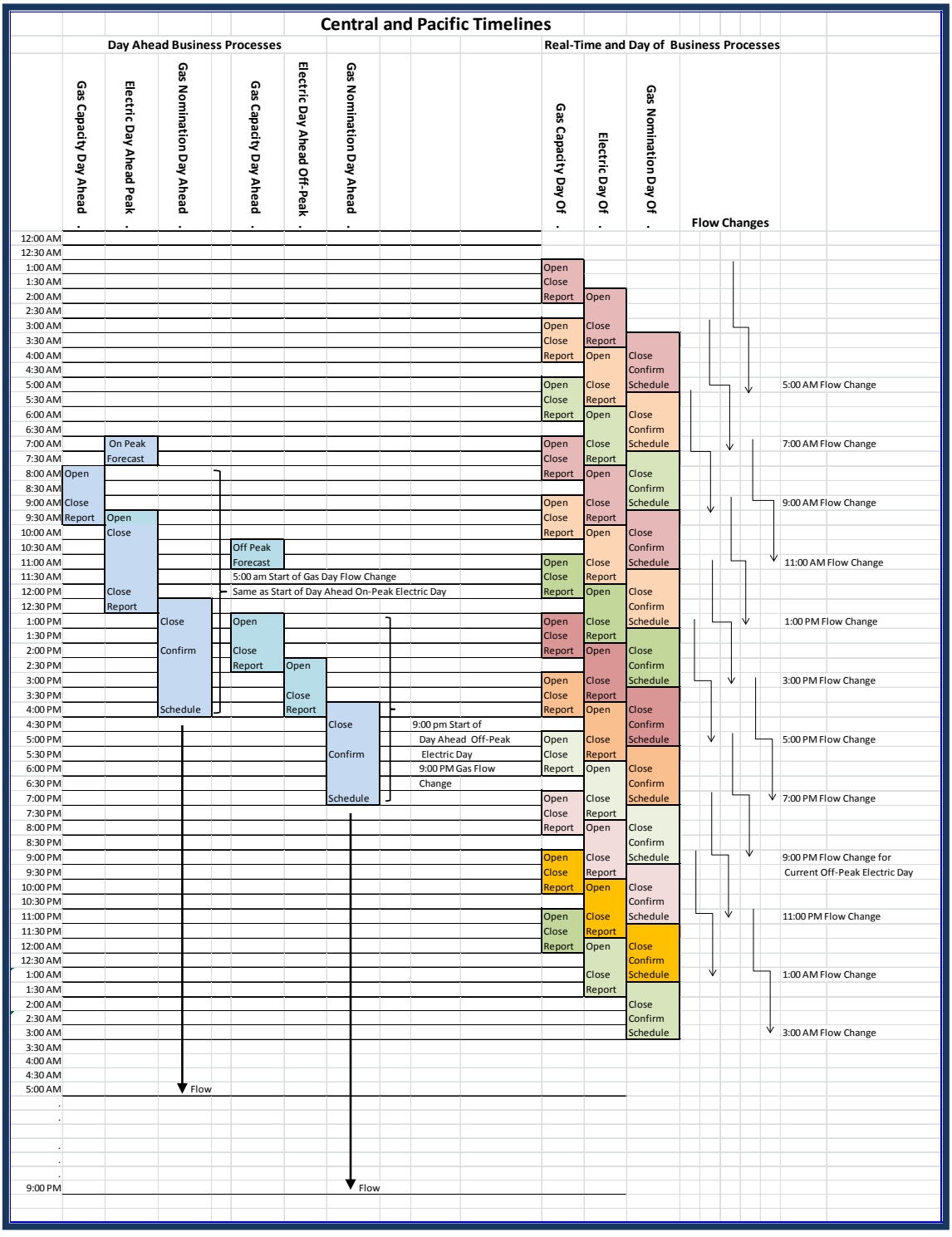
Natural gas has been and, as recently reported by EIA, for the foreseeable future will be a great story for customers, generators, the power grid and the overall economy. In the face of this plentiful resource base, let's not keep outdated market rules in place and risk the wrath of customers, the press and elected officials because we didn't fix the logistics and market structure problems before the train wreck.

[12] To this end, it may be necessary for the gas grid to, in turn, procure "firm power" from the electric grid to the extent portions or segments of the gas industry do not do so today.

Sync Zone Operational Timeline Implementation Charts

The following charts illustrate the proposed Energy Day schedules. As postulated, in order to have the same Energy Day in Central/Eastern and Pacific/Mountain, the instantaneous time would need to be the same in each zone. Since Central "Clock" Time is one hour earlier than Eastern "Clock" Time, and Pacific "Clock" Time is one hour earlier than Mountain "Clock" Time, we have combined Mountain and Eastern (which have the same Clock time schedules) on the first chart and Pacific and Central (which have the same Clock time schedules) on the next. From a real time perspective, of course, the zone schedules are two hours apart.




Central and Pacific Timelines
Day Ahead Business Processes
Real-Time and Day of Business Processes
Gas Capacity Day Ahead
Electric Day Ahead Peak
Gas Nomination Day Ahead
Gas Capacity Day Ahead
Electric Day Ahead Off-Peak
Gas Nomination Day Ahead
Gas Capacity Day Of
Electric Day Of
Gas Nomination Day Of
Flow Changes
On Peak Forecast
Off Peak Forecast
5:00 am Start of Gas Day Flow Change
Same as Start of Day Ahead On-Peak Electric Day
9:00 pm Start of Day Ahead Off-Peak Electric Day
9:00 PM Gas Flow Change
5:00 AM Flow Change
7:00 AM Flow Change
9:00 AM Flow Change
11:00 AM Flow Change
1:00 PM Flow Change
3:00 PM Flow Change
5:00 PM Flow Change
7:00 PM Flow Change
9:00 PM Flow Change for Current Off-Peak Electric Day
11:00 PM Flow Change
1:00 AM Flow Change
3:00 AM Flow Change
Flow
Flow

The authors welcome comments, suggestions and an opportunity to discuss our proposed solutions. Feel free to contact us:

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