Comments of Pacific Gas and Electric Company
CAISO May 15, 2015 Stakeholder Call on FERC 809

Submitted by	Company	Date Submitted
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Pacific Gas and Electric Company (PG&E) offers the following comments on the California Independent System Operator's (CAISO) response to FERC Order 809 and the related stakeholder call on May 15, 2015. CAISO has requested that stakeholders, to the extent possible, provide data to CAISO about potential costs and benefits of the proposed earlier Day Ahead (DA) market. PG&E maintains its objections to moving the DA market process earlier in the day, and provides the following quantitative analysis for the CAISO's consideration.

PG&E's main points are as follows:

- FERC Order 809 does not presuppose CAISO must change the DA market schedule, and explicitly allows for consideration of the benefits, costs, and operational burdens.
- California does not have the gas reliability problems experienced in the Eastern RTOs given our robust gas storage and pipeline capacities.
- A 7:00 am DA market close would decrease market efficiency through more uncertain gas prices, resulting in a risk premium on gas-based bids, while providing questionable volume certainty to gas peaking units.
- PG&E expects the market efficiency gains of post-DA award gas trading under Alternative 1 would be minimal; neither generators nor the CAISO have provided quantitative analysis to show otherwise.
- CAISO should factor into its analysis the negative impacts of an earlier DA market on load, hydro, and VER forecasts, as well as the operational burden on CAISO staff and market participants.

I. FERC Order 809 does not presuppose CAISO must change the DA market schedule, and explicitly allows for consideration of the benefits, costs, and operational burdens.

The CAISO appears predisposed to change the current DA market schedule under the assumption that the FERC expects such a change in response to the April 2016 gas nomination deadline change. However, the FERC Order clearly gives CAISO the option to not change the DA market schedule after considering the benefits, costs, and operational burdens of doing so. The FERC Order states,

> "[T]he individual ISO and RTO section 206 proceedings provide additional opportunities to seek regional solutions. As discussed further below, the 206 Order requires each ISO and RTO to adjust the time at which the results of its day-ahead energy market and reliability unit commitment process (or equivalent) are posted to a time that is sufficiently in advance of the Timely and Evening Nomination Cycles, respectively, to allow gas-fired generators to procure natural gas supply and pipeline transportation capacity to serve their obligations, or show cause why such changes are not necessary. In the Section 206 Order the Commission encouraged each ISO and RTO to consider whether other market reforms would be appropriate.[130]…
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> …[130] For example, RTOs and ISOs could consider the potential benefits, cost, and operational burdens of adjusting the timing of their operating day. Section 206 Order, 146 FERC ¶ 61,202 at P 19 & n.14 ("In addition, we encourage RTOs and ISOs to consider whether other market reforms would be appropriate.")."

PG&E believes that the CAISO should fully consider all the potential benefits, costs, and operational burdens of an earlier DA market that stakeholders have put forth and recommend a course of action based on these factors, rather than a perceived expectation that a DA market change is necessary to comply with FERC Order 809. CAISO has already laid the groundwork for such a response by highlighting the need for regional best practices in coordinating the gas and electricity markets in its February 2015 Fuel Assurance Report to FERC, stating

> "[T]he Commission should forbear from imposing a new uniform fuel assurance strategy across all organized markets. The Commission should instead continue to assess best practices in each region as well as regional differences and coordinate review and approval of market rule changes and other practices developed to address fuel assurance issues in each region."[1]

PG&E believes that sufficient evidence exists to show cause at FERC that CAISO electricity market changes are not appropriate, and that ensuring gas price certainty with the current day-ahead market timeline is the best outcome for the CAISO.

II. California does not have the gas reliability problems experienced in the Eastern RTOs given our robust gas storage and pipeline capacities.

The goal of FERC Order 809 is to "ensure the reliable and efficient operation of both the interstate natural gas pipeline and electricity system"[2]. PG&E maintains that there is no gas reliability problem in California, either under the current nomination deadline or the

[1] Fuel Assurance Report of the California Independent System Operator Corporation, Docket No. AD14-8-000. Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators. https://www.caiso.com/Documents/Feb18_2015_FuelAssuranceReport_AD13-7_AD14-8.pdf, p23-24.
[2] 151 FERC ¶ 61,049, Docket No. RM14-2-000; Order No. 809, p1.

earlier nomination deadline which will take effect in 2016. Therefore, no change to the DA market is necessary to maintain alignment between the gas and electric market from a reliability standpoint. CAISO's own analysis supports this point.

The CAISO's 2015 Fuel Assurance Report to FERC in February 2015 details the robust gas transport capacity in the West, and the benefits of gas price certainty for the electricity market. As CAISO noted in the report, the need for electric market awards to occur before gas trading in the Eastern ISOs/RTOs is driven by gas capacity constraints. As these constraints do not exist in the CAISO, our electricity and gas markets are appropriately aligned based on gas price certainty rather than gas volume certainty.

> "… in contrast to concerns expressed in eastern organized markets, the natural gas supply infrastructure serving gas-fired generators in the CAISO balancing authority is fairly robust."[3]

> "Although the CAISO must continue to assess gas pipeline constraints, according to the 2014 California Gas Report, natural gas utilities, interstate pipelines, and in-state natural gas storage facilities have sufficiently increased their delivery and receipt capacity to meet natural gas demand growth over the last five years."[4]

For example, PG&E's gas system provides more than adequate capacity to reliably serve forecasted peak demand days. As shown in the 2014 California Gas Report[5], PG&E storage resources and pipelines can supply 8.0 billion cubic feet (bcf) of gas per day.[6] This is 40% more supply than is forecasted for the PG&E system on an Abnormal Peak Day (5.7 bcf/day).[7] The Abnormal Peak Day forecast is a projection of demand under extremely adverse conditions. PG&E uses a 1-in-90 year cold-temperature event as the design criterion.[8]

PG&E has seen no evidence from CAISO or other market participants that the natural gas infrastructure in the state has or will become significantly constrained. As such, PG&E does not support a shift away from a price certainty paradigm in California. The benefits of the current electric-gas market alignment, which CAISO describes in its fuel assurance report, will persist regardless of the timely nomination deadline adjustment.

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[3] Fuel Assurance Report, p.2
[4] Fuel Assurance Report, p7.
[5] 2014 California Gas Report. http://www.pge.com/pipeline/library/regulatory/downloads/cgr14.pdf
[6] 2014 California Gas Report. p40
[7] 2014 California Gas Report. p49
[8] This criterion corresponds to a 27 degree Fahrenheit system-weighted mean temperature across the PG&E gas system. The PG&E core demand forecast corresponding to a 27 degree Fahrenheit temperature is estimated to be approximately 3.2 Bcf/day. The PG&E load forecast shown here excludes all noncore demand and, in particular, excludes all electric generation (EG) demand. PG&E estimates that total noncore demand during an APD event would be approximately 2.5 Bcf/day, with EG demand comprising between one-half to two-thirds of the total noncore demand.

> "Unlike the Eastern Interconnection, the timing of the natural gas markets largely allows for price certainty when market participants bid into the CAISO's day-ahead market.[31] The day-ahead market closes after the natural gas timely nomination cycle, so market participants have the opportunity to purchase the bulk of their gas prior to submitting bids into the CAISO market thereby allowing for greater price certainty when scheduling coordinators for natural gas-fired resources submit day-ahead energy bids. When the CAISO issues day-ahead market awards, participants can purchase any incremental natural gas in the evening nomination cycle since CAISO issues day-ahead market results in between these two cycle timings. As a result, operators of natural-gas fired generators generally have a clear understanding of their fuel needs across the entire operating day, including the morning electric ramp. This visibility provides an opportunity for operators of natural gas-fired generators to balance their transportation service over the gas day."[9]

No gas reliability problem exists in California which would be solved by an earlier DA market, and no evidence has been provided by CAISO or other stakeholders that an earlier DA market would improve gas or electric reliability.

III. A 7:00 am DA market close would decrease market efficiency through more uncertain gas prices, resulting in a risk premium on gas-based bids, while providing questionable volume certainty to gas peaking units.

a. Gas Price Uncertainty

An earlier DA market would degrade market efficiency through increased gas prices and costs to load. With the earlier market timeline, resources would be forced to use a lagged gas price from the day before the DA market to create their bids, and likely would add a risk premium on top of that price to account for price uncertainty.

The CAISO's proposed Alternative 1 would move the DA market earlier to begin before timely gas market trading has occurred. This would eliminate gas price certainty for participants bidding into the CAISO DA market. It is unclear exactly how this would change market participant behavior, but it is reasonable to assume that risk adverse participants, not knowing the gas price for the subsequent day, would add a risk premium to their bid.

Under current market rules, participants could submit bids with a risk premium without being mitigated as the default energy bid calculation includes a ten percent adder and the start-up and minimum load calculations include a twenty-five percent adder. It is reasonable to assume these increased market bids will lead to higher market clearing prices, and thus higher costs to electric customers.

[9] Fuel Assurance Report, p22.

PG&E estimated the impact of inflated prices to CAISO load if prices were set by a marginal unit that included a risk premium in its bid (Table 1); assuming a $0.05/MMBtu gas risk premium, **estimated impacts are as high as $220 million annually**. PG&E does not support introducing this level of additional costs to electric customers with no improvement in gas or electric reliability.

Table 1: Estimated Cost to Load from Natural Gas Price Uncertainty

	Units Submitting Bids with a Risk Premium	
Gas Risk Premium	**All Marginal Units**	**Peakers Only**
$0.05/MMBtu	$ 93,636,162	$ 18,054,612
Standard Deviation of Day-over-day Gas Price Change	$ 219,806,223	$ 35,909,426

<u>Methodology</u>

To estimate costs to load, we used day-ahead hourly implied heat rates[10] from 2014 and hourly total CAISO load. We estimated costs under two scenarios:

1. all marginal units used a risk premium and
2. only peakers used a risk premium[11].

We then calculated the total costs as the product of the implied heat rate and the risk premium using four different assumed risk premium values: $0.01/MMBtu, $0.025/MMBtu, $0.05/MMBtu, and the monthly standard deviation of day-over-day gas price changes.

To calculate the monthly standard deviation of day-over-day gas price changes, we used the daily CISO gas price from 2013-2014. The monthly standard deviation of day-over-day gas price variation ranged from $0.039/MMBtu in August to $0.44/MMBtu in February.[12]

[10] The formula for calculating day-ahead implied heat rates is Day-ahead price / (Gas Price + GHG * 0.053072). The assessment used the hourly NP-15 day-ahead energy price, CAISO's daily CISO gas price index, and CAISO's daily GHG index.

[11] To estimate the impact of only peakers submitting bids with a risk premium, we included only those hours with a day-ahead implied heat rate exceeding 10,268 Btu/KWh. This rate is from the California Energy Commission report "Thermal Efficiency of Gas-Fired Generation in California: 2014 Update," available here: http://www.energy.ca.gov/2014publications/CEC-200-2014-005/CEC-200-2014-005.pdf.

[12] The calculation of the standard deviation of day-over-day gas price variation eliminated any days in which the day-over-day gas price change exceeded 25%, as the CAISO tariff currently allows for a manual gas price increase on those days.

b. **Gas Volume Uncertainty**

It is unclear if an earlier DA market will provide peaking units with more gas volume certainty for procurement. Generators, particularly operators of peaking units, are supportive of an earlier DA market to the extent it will enable gas volume certainty for procurement in the Timely gas cycle. However, PG&E understands that real-time dispatch for peaking units regularly differs from their DA award. If this is the case, it is unclear to what level of certainty the peakers can procure gas day ahead if their actual real time dispatch is different. These resources would still true up their gas supply in the intra-day cycles as they do today.

PG&E did a preliminary analysis of our natural gas fleet (including peakers and non-peakers) to compare DA and RT gas usage. Using data from 2013 and 2014, PG&E concludes that the actual electric portfolio daily gas usage deviation from the DA market award is +/- 13% on average. It is reasonable to assume that peaking unit DA v. RT awards could deviate more than baseload units, since they are likely to be on the margin. Given the deviation between DA and RT awards, the benefits of an earlier DA award for peaking resources may not be so straightforward.

PG&E recommends CAISO do its own market-wide analysis of DA v. RT dispatch for peaking units to understand what, if any, level of gas procurement volume certainty could actually be achieved by procuring gas to match the DA award.

IV. PG&E expects the market efficiency gains of post-DA award gas trading under Alternative 1 would be minimal; neither generators nor the CAISO have provided quantitative analysis to show otherwise.

Generators have commented in favor of an earlier DA market so that they can access liquid gas trading in the period of time between the DA market results being published (est. 10 am) and the Timely Nomination Deadline (11 am). This assumes that gas prices in the 10-11am period will be lower than in the later Evening nomination cycles.

However, PG&E has yet to see any quantification of how this change would benefit the CAISO market. What are the efficiency gains of providing for this 10-11am gas trading period? What evidence is there that this period will be more liquid and less expensive than in the evening before the 6 PM nomination deadline? PG&E is concerned that gas traders would increase their prices during this 10-11 am window, with the knowledge that

DA awards have been published and a buyer is motivated to procure before the 11 am Timely Nomination Deadline. Under these circumstances, the elevated gas prices would undermine the generators theoretical benefits of moving the DA market earlier.

V. CAISO should factor into its analysis the negative impacts of an earlier DA market on load, hydro, and VER forecasts, as well as the operational burden on CAISO staff and market participants.

a. **Load, hydro, and VER forecast errors**

CAISO should analyze how DA load, hydro, and VER forecast accuracy would be negatively impacted by an earlier DA market. Minimizing forecast inaccuracies is a high priority for reducing costs to load. Load and renewable forecast errors are the most common driver of very high prices in the real-time market , resulting in estimated costs of upwards of $50 million annually. Significant forecast inaccuracies can also pose reliability concerns.

If the day-ahead market close were moved from 10 AM to 7 AM the day prior to the trading day, the CAISO optimization and market participant's bids would rely on less accurate load and renewable forecasts as less reliable information would be available to produce these forecasts.

CAISO should analyze the accuracy of earlier VER forecasts and quantify the combined effect of VER and load forecast accuracy changes on the CAISO's overall net load forecast as a small change in these forecast accuracies can have a large impact on market efficiency.

b. **Operational burden**

In Order 809, FERC specifically asked the RTO to consider the operational burdens of adjusting the timing of their operating day. PG&E agrees and believes that operational impacts of participating in an earlier DA market are significant. While some of the DA analysis could be done the previous day, there would still be a need for some staff to come in very early in the morning to complete the DA process before 6am. As PG&E described in our comments to FERC on the Gas Day, we have concerns about such an earlier work day start from a safety and logistical perspective. We would also expect some loss of internal coordination between the DA staff and the rest of our procurement organization as work hours for the two groups would have less overlap. Coordination between the DA staff and other procurement staff is highly valuable for PG&E to function effectively.