Shell Energy North America (US), L.P.

Comments to CAISO Aliso Canyon Gas-Electric Coordination Issue Paper, March 17, 2016

Mike Evans, Shell Energy, michael.evans@shell.com, 858-526-2103

March 29, 2016

Shell Energy appreciates the opportunity to provide comments on impacts and options to address the proposed 5% daily balancing requirement in the Southern California Gas Company and SDG&E ("the gas companies") gas service areas. Shell Energy desires both a reliable electric grid, and a reliable gas supply system, and understands the association between both systems. Shell Energy remains available to discuss possible solutions to ensure safe and reliable operations at the lowest sustainable cost to California consumers.

Historically, the electric system has relied on the gas balancing provisions to have gas available for real time (RT) dispatch. The possible reduction of flexibility in the gas system will have a corresponding effect on RT dispatch in the affected gas service area. We encourage the CAISO to continue to work with the gas companies to verify that these stringent requirements are necessary, as they are expected to result in much higher costs to California consumers on both the gas and electric sides.

<u>The proposed tariff requires adherence to a +/- 5% gas scheduling tolerance.</u> - An important clarification is that the gas companies have filed a revised tariff; a new Rule No. 30 "Transportation of Customer-Owned Gas". This rule states in part: "Customers will be required to deliver (using a combination of flowing supply and storage withdrawl) at least 95% and no more than 105% of their usage each day (+/-5%) (Daily Transportation Tolerance)." The ISO must recognize that its dispatch orders to power plants can place generators in violation of the proposed Rule No. 30. While there are then associated penalties (150% of the highest daily border price index at the SoCal border) for being out of tolerance, notwithstanding, the CAISO should not design its market to intentionally cause generation to violate Rule No. 30. Indeed, the gas company has represented that its system will be in jeopardy and reliability will suffer if entities scheduling gas on their system are outside of this tolerance. While the actual limits of the gas system are subject to a separate proceeding at the CPUC, the gas companies, by filing this revised tariff, have stated that their systems cannot manage gas deliveries beyond these parameters. Consequently, it would be inappropriate for the CAISO to put generators in between a gas system that now has very limited flexibility and an electric grid operator that desires greater flexibility. The ISO will likely require several changes in operations to accommodate this new limitation.

<u>The ISO will have to schedule energy further in advance.</u> - In conforming to the new limits and gas nomination cycles, the ISO conducts its daily Integrated Forward Market (IFM) from 10 a.m. to 1 p.m. and publishes DA schedules at 1:00 p.m. or shortly thereafter, which is after the 11 a.m. timely gas nomination cycle. Suppliers will need to procure gas in anticipation of a Day Ahead (DA) schedule, and then re-sell gas intraday, in time for the 4:00 p.m. evening gas nomination deadline. This will allow a

final gas schedule for the next gas day (7 a.m. to 7 a.m.). The ISO must either estimate and add RT dispatch to the DA schedules for Hour Ending (HE) 01 through HE12 or not dispatch those units beyond a 5% tolerance because the next as nomination cycle is intraday 1 at 8:00 am, which is effective at 12 noon. (As of April 1, with the new nomination schedules). Suppliers have two opportunities to trade in liquid intraday markets to support ID1 at 8:00 a.m. and ID2 at 12:30 p.m. As was discussed on the ISO call, gas is very difficult to obtain after 2 p.m. for the current 3 p.m. ID2 gas nomination deadline. When ID2 is moved back to 12:30 p.m., it is expected that this will be the last effective trading period of the day. It would be most helpful for the ISO to finalize all of its RT dispatch to support the new ID2 gas nomination deadline at 12:30 p.m., meaning that any RT dispatch needs would need to be issued by 10:30 a.m. to procure intraday gas and get it scheduled. It is unknown how liquid the gas market will be for the new ID3 at 5:00 p.m., as this is essentially after-hours for a majority of the market.

The ISO may wish to consider the value of moving earlier in the morning its Integrated Forward Market (IFM) and compressing the scheduling period from 3 hours to 2 hours. The ISO may consider a new IFM schedule to require bids at 8:00 a.m. and to publish DA schedules at 10:00 a.m. (instead of the current 10:00 a.m. to 1:00 p.m. schedule). In this way, the ISO could accommodate normal bilateral sales and imports, generally transacted earlier in the morning, and then market participants would have a sense of costs for bidding into the 8:00 a.m. deadline. Market participants would then have time after the 10 a.m. publishing of DA schedules to procure additional gas and submit gas nominations that are consistent with the DA schedule for the generator at the 11 a.m. timely gas nomination cycle.

Consider retaining in-state transmission capacity - The ISO may need to set aside in-state transmission capacity to procure ancillary services and real time energy dispatch from generators located in areas outside of the gas companies' service areas (i.e. where generators are not exposed to 5% daily balancing). The ISO must then forecast the range of RT dispatch that could be needed and keep transmission capacity, such as imports from Palo Verde, and flows on Path 26, available for RT dispatch. In the Day Ahead scheduling process, the ISO may need to dispatch units in the gas companies' service areas to meet both reliability requirements, generally at least 25% generation, and to meet the forecasted net load curve The ISO may need to compensate schedules decremented to hold capacity available in the real time.

Re-evaluate dispatch of peakers. - The ISO often will dispatch peaking units late in the day, typically to Pmin, in the anticipation that the small "dispatchable" quantity remaining ("Pmin to Pmax") might be dispatched in the RT market. With the new Rule No. 30, it will be nearly impossible to obtain gas for these late dispatch notices. The ISO will need to review its DA forecast for net load carefully to see how to commit units so that they can obtain gas in a sufficient time frame. The ISO has asked for feedback as to the importance of keeping units on line pursuant to the DA IFM schedules. Because gas is procured and scheduled well in advance of the RT, and the penalties for over or under are so high ($4.50/mmbtu penalty for $3.00 gas price results in a $7.50/mmbtu cost for over or under usage), it is critical for both the reliability of the gas system, per the motion, and the financial exposure of the generator that the ISO operate the unit per the DA dispatch schedule. For example, the ISO may need to dispatch peakers in the DA market from 4 p.m. to 10 p.m. each day, and to operate those units according to their DA dispatch schedules, regardless of RT economics. While this is an unfortunate outcome that may result in more greenhouse gas emissions, it will ensure the reliable operation of the gas network system and comply with the new, rather stringent, mandatory tariff requirements.

The ISO may also see value in determining that resources that can start in 10 minutes can set a Pmin to 0, and then dispatch the unit to its Pmax when needed. The ISO will benefit as it will not consume Pmin energy from a typical use limited resource, the state of CA will benefit from lower GHG emissions from running a peaker at "minimum load". The consumer will benefit when peakers can operate only when needed for peaking service.

<u>LMPs should reflect costs at nodes</u> – The CAISO should be careful to not shift costs to uplifts, and to dispatch units economically such that LMP prices reflect costs. To that extent, the ISO should consider increasing bid caps for the Default Energy Bid (DEB) until such time as the ISO can implement appropriate market power mitigation mechanisms, such as a "conduct and impact test" to ensure competitive markets.

<u>Consider raising Bid Caps.</u> – For the situations in which the ISO causes generators to incur excess costs for intraday gas procurement or gas transportation penalties, the ISO should increase bid caps to allow cost recovery. While the ISO has proposed a cumbersome and lengthy process for an affected generator to file for cost recovery at FERC, the ISO should also realize that the non-compliance and other gas charges such as the commodity cost are due at the end of the month. Cost recovery from FERC takes much, much longer.

<u>Gas Outage Cards are needed.</u> – The ISO should have a mechanism for the generator to advise the ISO as of a certain time that the remaining gas is limited, and only sufficient to meet the DA schedule for the remainder of the day. The generator is precluded from any additional dispatch due to gas supply limitations, otherwise, any additional dispatch would place the generator in violation of the Rule No. 30 gas tariff and jeopardize the reliability of the gas network system. This mechanism will allow the generator to help the ISO manage dispatch around the multiple constraints that are being imposed with the new Rule No. 30. It is unlikely that the ISO will manage the gas supply to each plant as closely as the owner, who will experience the penalties and possible other consequences of violating the gas companies' tariff, and it is critical that a "gas outage card" provision allow a generator to lock in its schedule. Unfortunately, the gas companies' new rule also limits decremental instructions, so that flexibility is further constrained, however, this further invokes the need for the gas outage card. A gas outage card should not impact RA. In other words, no RAAIM charges or other unavailability charges should be assessed, unless the full output of the unit was not available to the ISO in the DA scheduling process.

<u>Managing to a MWhr daily dispatch</u> – The ISO might consider that it can move MWhrs around on a generator, and to manage a generator based on MWhrs per daily dispatch. The ISO would likely have to provide compensation to the generator if the LMP's were different in the hours that the energy redispatch occurred. While this would have a significant impact on dispatch software, the concept aligns with the gas companies requirement for daily balancing.

Shell Energy appreciates the difficulty of this situation and the effort that the ISO is expending to address the immediate problem. The issues above highlight the difficulty of accommodating a 5% gas balancing requirement and the concomitant obligation onto the ISO. Shell Energy encourages the ISO to continue to work with the other state agencies and the gas companies to determine the actual need for any changes in gas scheduling, and we encourage the ISO to oppose a daily balancing requirement, as this will likely result in higher GHG emissions and higher consumer costs.