VIA EMAIL ONLY

California Public Utilities Commission
Energy Division
505 Van Ness Avenue
San Francisco, CA 94102

RE: Proposed Scenarios Framework: I.17-02-002 – Comments of Environmental Defense Fund

Dear Energy Division Staff:

Pursuant to the Administrative Law Judge's June 26, 2017 Ruling Requesting Informal Feedback on Energy Division's Initial Proposed Phase 1 Scenarios and Noticing Workshop (Ruling), EDF offers the following informal comments on the Energy Division's (ED's) Proposed Scenario Framework (Scenario Framework), which was attached to the Ruling.

One of the interesting aspects of the analysis scenarios presented by the Commission, and these comments, is the fact that in the time between the request for comments and this filing, the Chair of the California released a statement on a plan to phase out use of Aliso Canyon over the next 10 years, stating "I am confident that through sustained investments in renewable energy, energy efficiency, electric storage technologies and other strategies, we can make this transition a reality." It is therefore against this backdrop that we file these comments – in particular to ensure the Commission's analysis fully takes into account the range of policies and strategies that can and should be implemented on the path toward minimizing or eliminating Aliso Canyon. The policies, some of which have been outlined below, can have the effect of helping support deployment of low carbon energy supplies as well as change the dynamics of natural gas storage demand – thus yielding important results that must be incorporated.

Proposed Scenarios - Near Term, Medium Term, and Long Term

As proposed, the ED scenarios will evaluate the impact of reducing or minimizing the use of Aliso in the near term (2018), medium term (2022), and long term (2027). Since gas usage varies considerably by season, the ED proposal anticipates the model would need to be run for both summer and winter in each of the years mentioned above.

While the timeline for evaluation (next 10-years) appears appropriate, the granularity of the model results, reporting out at only three time intervals seems unnecessarily limited. To the extent feasible, EDF asserts that it would be helpful to see analysis modeled on an <u>annual</u> basis, for each year through 2027. In particular, model results for 2019 and 2020 will be critical to understanding how short term actions can impact reliability needs for the next few summers and winters (and the near term trends associated therewith)– thus giving the Commission and fellow energy agencies a jump on the regional planning and coordination necessary to avoid potential risks. Additionally, a time series analysis comprising of annual results will allow for consideration of time trends, giving a higher degree of awareness of how selected policies impact overall need.

Hydraulic Modeling - Peak Day Forecasts (p. 4-5)

While the use of peak day forecasts as opposed to historical days is important for the purpose of evaluating the conditions more likely to be experienced in the So. Cal. energy system, EDF's evaluation of the proposed analysis uncovers questions which should be answered prior to the model being run. For example, since the 0.6% demand reduction figure provided by SoCalGas is at the heart of the analysis, EDF questions whether there is any way for the Commission to verify the figure to determine if it is an appropriate assumption. In the alternative, if the decline figure cannot be verified to a reasonable degree of certainty, EDF recommends the use of a range of demand reduction scenarios instead of relying on a single figure only, i.e. a low demand reduction forecast, a medium forecast, and a high forecast. Furthermore, EDF recommends the Commission include, within it peak demand forecast, the ability of demand response measures for reducing overall load (e.g. water heater/thermal loading and central control of demand response programs) and the ability of new gas balancing requirements to reduce peak gas demand.

Hydraulic Modeling - Gas receipt point utilization (p. 5)

Given the effectiveness of new balancing rules, the ED proposed Scenarios Framework suggests that 85% receipt point utilization is sufficiently conservative to cover the impacts of under deliveries and planned and unplanned maintenance, despite being higher than the historical average.

While EDF agrees that the market rule changes have seen marked success for reducing system imbalances, the fact that data exists for only one summer and one winter since the new rules were implemented suggests that a longer trend evaluation is needed for making multi-year analysis based on such a limited data set. In particular, the benefits of the market rule changes may be limited since they do not apply to all days. For example. Skipping Stone evaluated the impact and benefit of extending the market rule changes to all days, and requiring system balancing on days even when an Operational Flow Order (OFO) is not called.

According to Skipping Stone, initiating tighter balancing rules for all gas users on all days would have the benefit of impacting the demand for gas storage overall. In short, if California requires the parties that use gas in southern California (including SoCalGas who procures gas for their core customers) to make better demand forecasts and more closely align their purchases to those forecasts, the overall purpose of gas storage will change – reducing our reliance upon it. These policies will have the effect of shifting the function of storage from what it is today (e.g. seasonal supply assurance and price arbitrage) into one that is used primarily to support intermittent renewables until cleaner energy options gain more of a foothold. By changing the role of storage, Skipping Stone predicts that only 25% - 30% of the capacity at non-Aliso storage fields will be used on an average basis, leaving the other 70- 75% to make up for, and exceed the needs for system balancing during more extreme circumstances. As demonstrated on page 5, the proposed analysis misses this point and thus misses the massive storage demand reduction that would accrue from it. However, prior to the model being run, parties to the proceeding should be given information on the deliverability of each storage field subject to "tubing only" requirements.

Hydraulic Modeling - Maximum Tubing-Only Storage Withdrawal from Non-Aliso Fields

EDF finds the proposal to assume the existing production constraints at the other SoCalGas storage fields will be in effect throughout the modeling exercise is prudent.

Hydraulic Modeling - Questions not answered above (p. 6)

- Is the California Gas Report the appropriate source for summer and winter peak day gas demand forecasts?

  Answer: The ED scenarios should augment and adjust the California Gas Report projections with reasonable scenarios that impact gas demand response – such as large scale creation of overnight thermal reservoirs in gas and electric water heaters

- Is it reasonable to estimate 2027 gas demand by reducing the 2022 peak day forecasts by 0.6% per year? If additional mitigation measures are put in place, would they result in a greater than 0.6% annual decline in gas demand? If so, what would be an appropriate method for forecasting future gas demand?

  Answer: In addition to the answer above, the 0.6% decline factor should be augmented by an additional gas and electric demand response/load shifting factor that's takes into account the imposition of additional mitigation measures. Such demand response / load shifting should be assumed to contribute an increasing amount of peak load reduction, starting at 0.5% in year one and increasing 0.5% per year until an aggregate 5% peak load reduction is reached.

- Should historical gas days also be modeled?

  Answer: Historical Days should be used to proportionally create hourly flow patterns from which to derive the hourly flow patterns of the California Gas Report Peak Summer and winter days. To adapt the historical days for longer term scenarios, the ED should layer on top of the historic days (as modified) to be the peak days. In order to make a peak day have an hourly shape, you have to proportionately increase the hourly loads such that the total daily equals the peak day.

- Is 85% gas receipt point utilization a reasonable assumption?

  Answer: The analysis should assume 95% gas receipt point utilization when send out is forecasted to exceed 4 Bcfd. In this circumstance, the 85% assumption is not to be used.

- Are there any other inputs or assumptions that should be considered?

Answer: Notwithstanding that battery installations in Southern California did not reach utility scale deployment until recently, the analysis should assume battery installation grows Assume battery installation grows by 300 MW and 1200 MWH year over year between 2019 thru 2027 – the same size as Long Beach is planning by 2021 per CAISO records. Furthermore, the analysis should assume that LADWP is part of CAISO EIM by 2020 (as currently projected) and remains in the EIM beyond that.

- Are there any other questions that should be considered?

One of the most important questions that the analysis and proposed scenarios do not get into enough depth on is what the potential for market refinements can have on gas storage demand at Aliso Canyon and on storage more broadly. For example, a market design that fosters accurate price formation will optimize reliability, environmental, and economic outcomes – reducing under-optimized energy market scenarios. This fundamental principle must be considered in structuring any analysis conducted to identify the extent to which Aliso Canyon must remain in operation to maintain electric reliability in Southern California. Specifically, this analysis must be rooted in assumptions based on a broader vision for the efficient functioning of California's gas and electric markets into the future.

Broadly speaking, the joint agencies' technical analyses and action plans and other reports issued in the aftermath of the Aliso incident have brought to light the need for gas and electric market refinements in California, going beyond short term fixes, to foster accurate price formation, facilitate greater gas electric coordination, accurately value and price the flexibility attributes of resources offering much needed grid balancing services. CAISO and other California state agencies are considering these issues, particularly in the context of the Aliso Canyon incident, e.g. as part of CAISO's Aliso Canyon Gas-Electric Coordination stakeholder process.

By way of specific example, EDF offers a market refinement policy (and evaluated benefit) that should be incorporated into the ED analysis. Just as new market rules were instituted for OFO days as an immediate response to Aliso, new rules can and should be implemented on all other days to minimize the mismatch between scheduled gas flows and actual burn, (mismatches that can be traced back to outdated operational frameworks that impede accurate forecasting of daily gas demand). Such refinements are easily achieved in the near term, in particular by having all market participants operate by the same rules; and by abiding by the same nominating, scheduling and rules as a first step. Simply put, the SoCalGas Gas Procurement Department (GPD) should be required to closely match its projected demand to actual use across its customer base. This rule would align California with gas markets across the country on this issue, and would see the SoCalGas market transform, as it must, to co-exist with and compliment an ever increasing penetration of renewables.

With needed market refinements, the gas market's responsiveness would learn and adapt to a new, more transparent future in order to keep pace; as to pricing, transactions, and variable flow patterns present in our electric market. The potential for all such market refinements that can be implemented in the near term to inject greater discipline into the functioning of the wholesale gas and electric markets must be considered as part of any analysis that looks at the extent to which Aliso Canyon is necessary to maintain electric reliability.

Production Cost Modeling

Although the ED proposal states that minimizing or eliminating the use of Aliso will reduce the rate of gas delivery to these gas fired electric generators plants, EDF asserts this would not be the case with market refinements identified above. The elimination of Aliso Canyon need not affect the electric system's costs and reliability. Thus, any production cost model or analysis should take these refinements into account. In addition, production cost models should take into incorporate battery growth.

As discussed in the ED proposal, it is important to note that certain plants served by Aliso will be upgraded or retired over the next few years. EDF urges the ED to ensure the model incorporates a scenario that shows a growth of renewables which, when taking into account more efficient natural gas plants, will result in less gas burn.

- What is the best methodology to translate inventory at Aliso, Playa del Rey, and Honor Rancho to withdrawal rates / rate of delivery to the 17 power plants?

  Answer: Public data shows that non-Aliso Canyon storage facilities in Southern California hold nearly 50 Billion cubic feet - gas that can be cycled in and out to meet local needs and alleviate the demand for Aliso Canyon. According to system data, gas can be pulled at about 1 billion cubic feet of gas per day from these other fields, and can recharge them at about 0.4 billion cubic feet per day (when they are at 70% full). At these rates, southern California gas fields can be refilled in about 12 days and discharged in about 4.5 days – allowing them to swing between 70% to 80% full twice in each month and delivering a high level of responsiveness that can make up nearly all of the demand that Aliso Canyon would otherwise provide. Accordingly, the ED production cost model should incorporate model gas market rules that incentivize and require 75% average inventory levels at the other non-Aliso facilities.

Economic Modeling (p. 11-12)

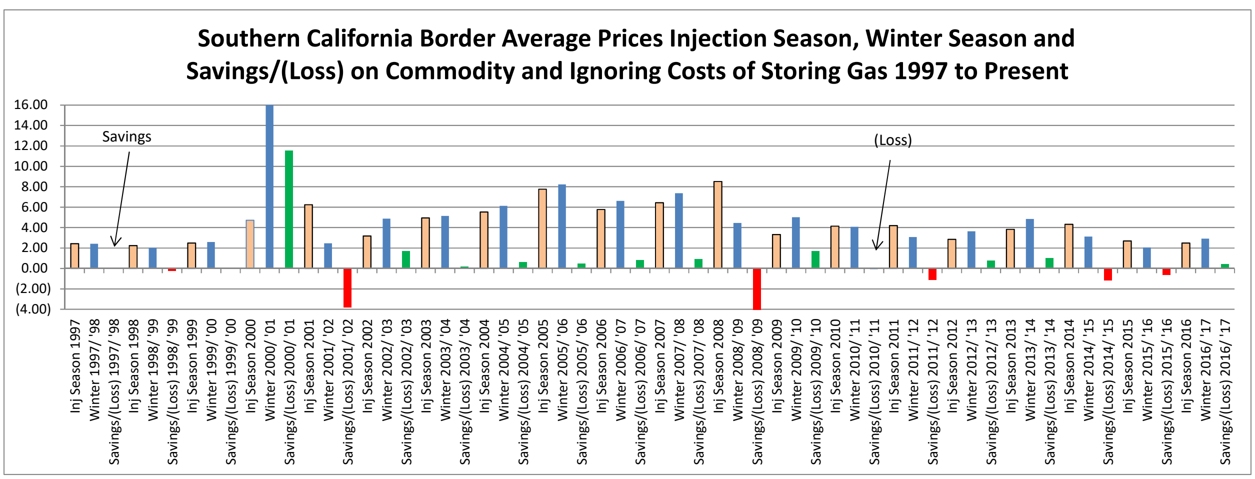
As discussed in the proposed scenario framework, in addition to improving reliability, storage has, at times, been used to reduce the economic impact of fluctuations in natural gas prices. Upon closer examination, while it has been a long held article for faith that injecting natural gas into storage during the spring summer and fall for winter withdrawal provides a price hedge against higher winter prices, it's not always the case. In fact, an analysis of data over the past 20 years, and more particularly over the past 10 years shows a much less consistent pattern. Industry analysts at Skipping Stone did some recent research to see how true this "conventional wisdom" has been for California.

Skipping Stone modeled average prices for each year since 1997. It modeled the average injection period price for April 1 of each year through October 31, of each year; and the average withdrawal period price over the period November 1, of each year through March 31, of the succeeding year.

What it found for the period April 1, 1997 through March 31, 2007 was that 7 out of 10 times the average injection period price was less than the average winter period price. For the 7 times this was true, the average savings was $2.20. For the 3 times that the winter period price was lower (i.e., withdrawing gas on average was more expensive than buying winter period flowing gas) the average "loss" was $1.34. Thus, over that 10 year period on average storage withdrawal would have saved $0.87 over that period.

However, in the past 10 years, the data shows a very different pattern. For the periods from April 1, 2007 through March 31, 2017 injection period gas prices were less than Winter period only half the time (i.e., 5 years of Winter "savings" and 5 years of winter "loss"); and, for the years there were "savings", the average savings over the last 10 years was $0.97 while the average "loss" of the same period was $1.41. Thus over the last 10 years on average storage use as a price hedge would have cost $0.44 – and this is without any consideration of the cost of actually paying for the right to store gas, let alone the cost of injecting and withdrawing the gas.

Why has conventional wisdom changed? Simply put, the reason storage is no longer a guaranteed price hedge is because of several things. First, because of the futures market for gas, where participants can buy "future gas" on the screen and arrange to have it delivered at the agreed price in the future (plus or minus a differential based upon delivery location). Second, there is more than ample storage (both working gas and deliverability) in the U.S. such that there is no longer a demonstrable value to holding (and paying) for storage just to take advantage of potential price differentials between seasons. And third, the U.S. has very ample deliverability of gas from production and for the most part the U.S. has ample pipeline capacity to move that production to a wide variety of markets. In fact, there are now few cases where storage is needed to meet peak day demand, given the amount of pipeline capacity serving most markets. This is also largely true of California which has almost enough pipeline capacity to the state as California needs except on the coldest few days of the year.



- Is there an existing gas price forecast dataset that would be appropriate to use in this model?

  Answer: Skipping Stone recommends using NYMEX Forwards adjusted for negative basis to CA based upon huge uptick in Permian basin supply over the next 6-10 and out years (the Permian basin, which feeds El Paso and Transwestern is undergoing a huge surge in gas production). Much like was witnessed in the Marcellus/Utica, the Permian shale is very prolific and is seeing the same growth curve as was seen in the Northeast. This surge is and will continue to depress prices for years to come. CA is the natural destination for the first 3-5 Bcfd of that gas.

Thank you for your consideration of these comments.

Sincerely

/s/ Timothy O'Connor________________

Tim O'Connor

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