Summary of I.17-02-002: Workshop #3 Informal Comments

The following is a summary of comments received on August 13, 2020, in response to the July 28, 2020, Aliso Canyon Modeling Results Workshop #3 held remotely. Staff has considered all feedback and suggestions from the written comments and workshop in the responses provided.

Name/Organization: Protect Our Communities

Comments/Questions:	CPUC Staff Responses:
1. Has the Commission evaluated the actual core, electric generation (EG), and non-electric generation (non-EG) demand on these peak winter days in 2015-2020 to assess the actual demand patterns between these principal gas demand categories? If not, can the Commission provide this information to the parties to I.17-02-002 so they can independently assess these patterns? Of particular interest is the actual core and EG demand on these peak winter days, compared to the modeled projections of core and EG demand at 1-in-10-year conditions. 2. The Commission is using the last 10 years of actual demand data in its regression analyses to verify its modeling. There are no temperatures below 44°F in this 10-year record. Why is 42.3°F continuing to be used to represent a the 1-in-10-year event and not 44°F? 3. Is the Commission using raw reported Sempra Envoy send-out volumes in its regression analyses to support its hydraulic modeling? The Sempra Envoy data is often inaccurate and high on peak days based on my analysis.	1. Staff evaluated historical data for these customer classes from ENVOY and AMI data and validated SoCalGas's forecasts. Staff presented results in November 2019 and are confident the patterns we are using in the modeling represent historical trends. In particular, EG demand from 2016 onward was reduced due to low OFOs and voluntary and mandatory curtailments. 2. The purpose of the regression analysis is to validate the demand at the Peak Day Design (PDD) Temperature and not the PDD temperature itself. Refer to California Gas Report 2018 Workpapers pages 318-326, on how the minimum value theory was used to generate a cumulative density function based on *50 years* of historical data, which is typical for climate change studies.[1] 3. Yes, staff is using data from ENVOY. Staff received POC's prior comments dated March 20, 2020, where it was indicated that on only four specific peak days, ENVOY data did not match CGR 2018 recorded data.[2] The historical data

[1] https://www.socalgas.com/regulatory/documents/cgr/2018CGR_SoCalGAs_Redacted_Workpapers_revised_8_13_18.pdf

[2] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M335/K836/335836721.PDF

4. I analyze the one actual core data point that exceeds 2,400 MMcfd in the 10-year record used in the regression analysis to model core load. This data point appears to be erroneous, as it is 300 MMcfd higher than any other data point in the database. The reasons this data point – and several other winter peak demand day send-out volumes addressed in my reply comments (Table 1, p. 2) – appears erroneous is explained in detail in my March 30, 2020 reply comments (attached). Can the Commission verify this outlier data point is: 1) accurate or 2) erroneous. 5. Assuming the data point in Question 4 is erroneous and when corrected is no greater than 2,400 MMcfd, there is no core demand in the last 10 years that exceeds 2,400 MMcfd. The limited data seems to indicate that once the ambient temperature reaches 47°F, the core demand flat-lines at about 2,400 MMcfd or less even as the ambient temperature drops to 44°F (lowest in 10-year record). The Commission is currently assuming that core demand at the 1-in-10 year will be ~2,600 MMcfd (42.3°F), and ~2,850 MMcfd at the 1-in-35 year (40°F). Has the Commission considered the possibility that the maximum core demand at any temperature at or below 47°F is ~2,400 MMcfd, that the physical limitation of the space heaters serving SoCalGas core load is ~2,400 MMcfd?	used by staff included about 3,650 points, therefore, it is unclear how POC arrived at the conclusion that ENVOY is "often" inaccurate. Additionally, in comparing ENVOY data with CGR data, POC appears to have made a unit conversion error. (Table 1, column units should be MDth, not MMcfd). 4. Staff reviewed the data submitted by SoCalGas in DR6 and found no errors in processing it. Furthermore, if one were to exclude this data point, it does not have an effect on the regression analysis. 5. This regression was done using hundreds of points and one outlier will not affect the polynomial fit. It is inaccurate to exclude data points for temperature below 47°F, and a horizontal line fit for the 44°F -47°F range will result in an extremely poor correlation coefficient. For POC's claim to be correct, all connected equipment will have to be running at full load for 24 hours at 44°F, not just space heaters, but also water heaters, gas used for cooking, drying, grilling. And one would be assuming no new meters or customers join SoCalGas service territory. See CGR 2018 workpapers page 111 for long term forecasts and how equipment, their efficiencies, and penetration rates are modeled.
Name/Organization: SoCalGas	
Comments/Questions:	CPUC Staff Responses:
1. The analyses presented appear to confirm that Aliso Canyon is needed for reliability and reduces energy costs, lowers core customer gas bills, and mitigates gas price volatility.	1. Staff's final analysis is still in progress, but modeling results indicate that under a 1-in-10 hydraulic modeling and given current system infrastructure,

2. Production costs for the Min Local Gen Scenario was $121 MM higher than the Unconstrained Scenario in 2030; however, the analysis focuses on the production cost (price to produce electricity) rather than the market price (price customers will pay to purchase electricity), which understates the economic impact. SoCalGas recommends that Energy Division (ED) consider the market price impact. Additionally, SoCalGas recommends other potential costs that may arise, to avoid understating the economic impact (points to Wood Mackenzie Gas-Electric study which found Aliso Canyon's retirement could lead to a $30 billion economic-impact event). 3. ED staff stated that to keep every load online and to avoid blackouts or brownouts, the calculated minimum generation would need to be higher. SoCalGas agrees with this; the number should be revisited and increased. 4. The assumption that 90% of non-Aliso inventory is available during a peak event is extremely optimistic and does not reflect recent winters. As explained by Michael Bednorz of DNV GL on behalf of Indicated Shippers, 100% or 90% is not realistic because it cannot last for multiple days. 5. As recognized in the California Council on Science and Technology (CCST) Study, there is a need for fast-ramping dispatchable generation to deal with demand spikes or impacts that last over multiple days. Multiple cold days and multiple warm days should be incorporated into ED's analysis. 6. ED should consider impacts to the entire western U.S. Decisions on Aliso Canyon impact prices and reliability in neighboring states.	there are needs for Aliso Canyon, particularly in the winter. 2. Staff did not study other types of costs outside of production cost. 3. Staff followed the directives of the Scenarios Framework; while it is accurate to state that additional online capacity must be preserved above the Minimum Local Generation in order to prevent unacceptable loss of load, staff were not calculating that additional level in the Minimum Local Generation Scenario. 4. As outlined in the Scenarios Framework, the feasibility assessment is meant to determine if the minimum inventories required under other analyses are feasible over an entire season. Staff will also present sensitivities testing a lower level of non-Aliso storage inventory on required inventory at Aliso at the October 15, 2020 workshop. 5. The IRP proceeding studies different weather patterns, including multiple day heat waves, multiple days of low wind and solar, and investments made in the IRP were expected to meet needs caused by variability in weather patterns such as described by SoCalGas. Additionally, staff is completing sensitivity analysis which captures multiple cold days as part of the feasibility analysis. 6. ED did not attempt to study the effect of Aliso on overall gas prices throughout the west, but ED did attempt to simulate the effect of electric generation decisions made by other Balancing Authorities in the WECC by including projected retirements of coal, increased use of natural gas

7. In Simulation 05, ED requested SoCalGas to minimize the use of Aliso Canyon. However, this input is vague; a determination has to be made as to whether to minimize the volume, withdrawal rate, or time. SoCalGas cautions that a more complete assessment is required to determine the minimum amount required from Aliso Canyon. Also, this simulation is overly optimistic and assumes no transmission facility outages, supplies equal to full receipt capacity, and high inventory levels.	generation, and increased penetration of renewable energy. This is laid out in the PCM analysis presentations discussing data sources and modeling data. Largely data for the rest of the western US comes from the Anchor Data Set, which is updated annually with IRP plans filed by utilities outside of California. 7. ED agrees with these caveats, and for that reason is now performing sensitivities particularly around non-Aliso storage inventories to inform our recommendation as to required inventory levels at Aliso.
Name/Organization: Center for Energy Efficiency and Renewable Technologies (CEERT)	
Comments/Questions: 1. The power flow modeling was presented as a single number, other information, including which gas plants are critical, was not discussed. CEERT understands the confidential issue but notes that the California Independent System Operator (CAISO) publishes more detail from power flow modeling in the annual Local Capacity Requirement (LCR) and in their Transmission Planning Process (see approved 2019-20 Transmission Plan, Section 4.9, pp. 264-268). 2. The Los Angeles Department of Water and Power (LADWP) discussed information from their annual transmission planning process as well and shared those results on July 9, 2020. Energy Division is using January 2020 power flow information – it is clear that the CPUC is using outdated information for a substantial portion of EG in the Aliso Canyon area. 3. Power flow modeling cannot answer the question about gas-fired generation, as the model is indifferent to source. The model only	CPUC Staff Responses: 1. ED staff discussed data aggregation and public posting requirements with CAISO in advance of showing these results in the workshop on July 28. ED staff will determine if additional data can be released regarding the power flow modeling, likely in a final report on PCM results that is upcoming in the Aliso OII schedule. 2. It is not clear that results from January 2020 and July 2020 will differ as to minimum local generation levels. ED may research this question further. 3. In running the Minimum Local Generation scenario, staff preserved minimum thermal gas fired generation and removed the other gas fired generation that was served by the SoCalGas system. Generators served at SoCal Border were not removed. Additionally, generators served by PG&E's system were not removed, and all non-gas generation was preserved. ED staff considered comparisons

states that a certain amount of real and reactive power must be on the system. The results presented during the July 28 workshop took the minimum required gas generation, then retired all remaining in-basin generation. Thus, the comparison of operating costs between the under-resourced scenario and a fully resourced Integrated Resource Plan is meaningless. 4. There appears to be some bottleneck removal at northern citygate to improve the situation. Hopefully these relatively inexpensive solutions will be detailed in the next round of results. 5. Two caveats: first, no calibration runs against historical events were performed, and none are planned. That is shortsighted. Second, it would be strange if SoCalGas operators are not aware of the pinch points where relief would improve system resilience. There should be time built into the schedule for testimony from grid operators.	with the IRP modeling informative because they indicate that curtailment of gas generation in the event of 1-in-35 conditions would cause electric reliability problems. 4. Staff has not analyzed the cost associated with this potential bottleneck. ED staff notes that this bottleneck may not be sufficient to increase flowing capacity to the basin, and that other downstream pipeline upgrades may be needed. Phase 3 of the Aliso proceeding will provide more information on the costs and overall impacts of this potential mitigation. 5. ED staff disagree that calibration with historical events needs further analysis, because we envision a future of the gas system that will be significantly different from historical operation, due to both impacts of climate change and the increasingly different operation of the electric system. As a means of testing and establishing a common understanding, ED staff collaborated with LANL, and with input from SoCalGas, to determine that the results we presented are realistic.

Name/Organization: Indicated Shippers

Comments/Questions:	CPUC Staff Responses:
1. It appears that without Aliso Canyon, regional reliability, including electric reliability, is at risk. 2. The 1-in-10 cold day event under the Min Local Generation simulation shows that the system cannot provide reliable, cost-effective service without use of Aliso Canyon. 3. Indicated Shippers have been assisted by DNV GL consultants, and the key points are:	1. Our analysis is still in progress, but we have shown that under a 1-in-10 hydraulic modeling and given current system infrastructure, there are needs for Aliso Canyon, in the winter especially. 2. See response #1 3. Responses below: a. Staff has used the assumptions outlined in the Scenarios Framework, which were adopted after

a. Staff should not be overly optimistic in selection of modeling inputs/assumptions. b. Assumptions used should be further refined to increase the reliability and efficacy of the results reached c. Conduct additional investigations to find peak loads for non-core/non-generating demands d. Examine historical and foreseeable future outages on the system beyond Lines 3000, 235-2, and 4000. e. Model inputs should not rely on both Wheeler Ridge and Honor Rancho simultaneously at their individual maximum capacities because historical data shows this is a rare condition. f. Staff should conduct additional sensitivity cases incorporating: 1) the unique arrangements of input-demand flows to test withdrawal capabilities at non-Aliso storage fields; 2) reduced withdrawal at Honor Rancho; 3) the many "zip code" 24-hour core demand shapes; 4) inventory levels of the non-Aliso storage fields. g. Conduct an uncertainty analysis of the results. If the sensitivity cases are not done, at a minimum some level of confidence limits must be provided in the report. This will give critical guidance. h. Study should not use 90% of maximum withdrawal rates for other storage facilities. A prolonged severe winter would prevent 90%. i. Study the increase in GHG emissions outside of CA when imports are used to cure a deficit in in-state generation.	extensive discussions with stakeholders. Since the adoption of the Framework, one assumption has been adjusted, which is the working gas inventory level for each storage field. The Scenarios Framework had proposed 100%, while the simulations used 90%, and less for the summer cases S04 & S06. Staff is also performing sensitivities around S05 (winter 2030) storage levels. b. Staff finds the comment unclear as to which assumptions need to be refined and how could that affect the results or outcome. c. Staff has used AMI data to validate Noncore-Non EG values reported in the California Gas Report 2018, which was presented in Workshop 2. d. Staff found historical outage data insufficient to perform a statistical analysis on unplanned (sometimes called force majeure) outages. Outages modeled for the PDD are unplanned/unexpected in nature, so future predictions of specific outages are not possible as the operator is assumed to maintain the safety of its pipelines. e. Staff is investigating how the natural gas pipeline system could be run without Aliso Canyon, so values that fall outside the historical norm are expected and even desired to highlight potential system changes or weak points. If staff relies only on historical data, then the outcome of this

j. There are outstanding analyses that have not been addressed, including: 1) need for an uncertainty analysis and 2) the need to assess sensitivity of production cost modeling (PCM)-based EG loads in the hydraulic model. 4. See DNV GL attachment for more details.	investigation would be the historical <u>known</u> outcome. f. 1) Storage fields are modeled as sources in Synergi. The withdrawal capabilities of the storage fields were determined from withdrawal and injection curves provided by SoCalGas. Staff is using 85% utilization on the Northern and Southern Zones and 100% on the Wheeler Ridge as per the Scenarios Framework and Workshop 1. With most of the receipt points being far from the load centers, permutations on where the supplies are coming from within a certain zone are unlikely to yield different results (e.g. Kramer vs North Needles vs Topock). With more than 600 ZIP codes, 157 core demand nodes, and many other demand nodes for noncore, performing sensitivities around demand would be prohibitive. The demand configuration of core customers has been verified using 2018 AMI data. 2) Staff is modeling some sensitivities for Winter 2030. 3) Staff has shown that the results are insensitive to using one aggregate profile for CORE customers versus using 157 profiles. 4) Please see response # 2). g. Staff is conducting sensitivities on Winter 2030 results. Staff has also vetted most of the inputs to Synergi especially MOP and MinOP. In addition, the PCM modeling also incorporates sufficient uncertainty, as results are determined from a wide

	range of weather and generator performance scenarios. h. The scenarios framework had all non-Aliso fields assumed at 100% inventory. Staff has reduced this to 90% and 70% for S04 and S06 to stress the summer system. Furthermore, staff is performing additional sensitivities that will be presented at the October 15 workshop. A feasibility study may be able to shed some light on this issue. i. ED staff did not study the GHG results in other Balancing Authorities in WECC. Effects on GHG emissions are likely to be complicated, and staff does not speculate on the net effects. j. Staff performed a sensitivity around EG profiles, compared results with SoCalGas results, and found that the shape of the profiles did not affect results. No differences in results were noted. This indicates that either the results do not appear sensitive to EG shapes of the profiles or the profiles developed by ED are not notably different than what was used by SoCalGas.
Name/Organization: Southern California Public Owned Utilities (SCPOU)	
Comments/Questions: 1. It was stated that a variety of scenarios were run for each simulation. Requests ED make publicly available each of the scenarios with its underlying assumptions for simulations 01-06.	CPUC Staff Responses: 1. Each simulation represents only one scenario, i.e. the six simulations represent only six scenarios. However, assumptions have been changed across simulations to

Then, requests ED and Los Alamos National Laboratory (LANL) hold a further workshop for discussion of the scenarios and to discuss which of the scenarios should drive the simulation results S01-06 that LANL displayed in slide 14. Explain how ED and LANL decided which scenarios would have the results chosen for slide 14.

2. In simulations 01-06, EG and non-EG demand levels on slide 10 fluctuate without any self-evident pattern.

DEMAND (MMCFD)

	S01 WINTER 2020	S02 SUMMER 2020	S03 WINTER 2025	S04 SUMMER 2025	S05 WINTER 2030	S06 SUMMER 2030
Core	3,285	808	3,170.7	808	3034	808
Non-EG noncore	654	718.6	689.2	700.8	664.6	687
EG	1,048 CGR	1,030.2 CPUC	900 CPUC	1,109.6 CPUC	1,122.6 CPUC	1180 CPUC
TOTAL	**4,987**	**2,556.8**	**4,759.9**	**2,618.4**	**4,821.2**	**2675**

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3. In simulations 01-06, pipeline supply on slide 11 fluctuates inexplicably. No gas is assumed from North Needles and Topock during summer 2025 and summer 2030, without explanation. Also, Wheeler Ridge is assumed at 765 MMcfd for all scenarios except summer 2025 and summer 2030, when, without explanation, it drops to 600 MMcfd. No explanation for California Production dropping to zero also.

eliminate redundant or expected results. Please see response #3 below for more information.

2. <u>More detail showing assumptions made for Simulations 1-6 will be included in the upcoming final report on hydraulic modeling being released later in the Aliso OII proceeding.</u> <u>EG:</u> EG numbers are the result of choosing the 90th percentile of monthly fuel burn data resulting from 100 combinations of weather years (20 weather years) and forecast errors (five forecast errors) from ED's own Production Cost Modeling. The summer and winter patterns show an increase in EG demand as shown in the table. Due to time constraints, Simulation 1 was based on SoCalGas' forecasts for winter 2020 (1,048 MMscfd) instead of EDs PCM result of 810 MMscfd, which obscured the overall increasing trend in ED's PCM modeling for both winter and summer seasons. The gradual increase is due to reduced availability of imports and the availability of imported energy across the Western Electricity Coordinating Council (WECC). <u>Noncore, Non-EG:</u> This category contains refineries (no change throughout the three study years), Enhanced Oil Recovery (slight decrease) and Noncore Commercial & Industrial in both SDG&E and SCG (slight increase). Refineries and EOR include both their own facility operations and their cogen operations. Considered together, there is an apparent trend for the summer but not for the winter.

3. Staff intended to have supplies within 5% of demand, when possible. However, since there was little observed variation

PIPELINE SUPPLY (MMCFD)

	S01 WINTER 2020	S02 SUMMER 2020	S03 WINTER 2025	S04 SUMMER 2025	S05 WINTER 2030	S06 SUMMER 2030
DEMAND	**4,987**	**2,556.8**	**4,759.9**	**2,618.4**	**4,821.2**	**2675**
North Needles	340	300	430	0	430	0
Topock	446.25	200	400	0	400	0
Kramer Junction	276.25	550	420	700	420	700
Wheeler Ridge	765	765	765	600	765	600
Kern River Sta.	0	0	0	0	0	0
Ehrenberg	833	750	728.5	920	980	920
Otay Mesa	195.5	50	300	0	50	0
CA producers	70	70	70	0	70	0
TOTAL	**2,926**	**2,685**	**3,113.5**	**2,220**	**3,115**	**2220**

Scenarios S01, S02, S03, S05 model SoCalGas "Best Case" in which Line 235 and Line 4000 operate at reduced pressures and gas receipts at Otay are available. In S04 and S06 these lines are not used.

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4. Slide 12: the maximum withdrawal rates assumed for each of the scenarios vary without explanation. Most importantly, Aliso Canyon withdrawal capacity is omitted from each of the scenarios except winter 2030, and both Aliso Canyon and Honor Rancho are omitted entirely for summer 2030. Slide 12, S05 says Aliso is included to determine the minimum amount needed from Aliso. However, since Aliso is not operating in the other simulations, this slide fails to show the minimum amount needed. Lastly, explain rationale for excluding Honor Rancho in Sim 06.

in the gas demand particularly in summer forecasts across the three study years, a sensitivity-like approach for summer simulations was utilized to avoid redundant work and results. **The summer simulations represented by simulations 02, 04, and 06** were approached as follows. First, S02 (Summer 2020) succeeded with 90% inventory levels at the non-Aliso fields, L235, L4000, and L3000 at reduced pressure, and with no withdrawals allowed from Aliso Canyon. Since S04 (Summer 2025) demand is only 61 MMscfd higher compared to S02 (Summer 2020), S04 would have also succeeded and been redundant. ED and LANL decided to "stress" the summer system by taking L235 and L4000 completely out of service, assuming 70% inventory levels at non-Aliso storage fields, assuming zero CA production, and about a 400 MMscfd supply deficit (corresponding to the worst forecast error based on historical data over the past three summers). Under these stressed conditions, S04 was also a successful simulation without the use of Aliso.

Finally, staff considered that S06 (Summer 2030) demand is only 57 MMscfd higher than S04), so it could be easily deduced that S06 would succeed had the same S04 assumptions been used. In S06, the summer system was further stressed by assuming Honor Rancho at shut-in (a necessary occurrence each year). S06 failed marginally (by about 25MMscfd), signaling the need for Aliso under these "strenuous" conditions. LG and PDR were not sufficient to handle the stressed summer system in S06.

MAXIMUM WITHDRAWAL RATE (MMCFD)

	S01 WINTER 2020	S02 SUMMER 2020	S03 WINTER 2025	S04 SUMMER 2025	S05 WINTER 2030	S06 SUMMER 2030
DEMAND	4,987	2,556.8	4,759.9	2,618.4	4,821.2	2675
PIPELINE SUPPLY	2,926	2,685	3,113.5	2,220	3,115	2220
Aliso Canyon	0	0	0	0	1265	0
Honor Rancho	800	802	802	672	802	0
La Goleta	230	228	228	197	228	228
Playa del Rey	300	299	299	247	299	299
TOTAL	1,330	1,329	1,329	1,116	2,594	527

S05 includes Aliso determines minimum amount needed from Aliso

S06 excludes Honor Rancho and Aliso

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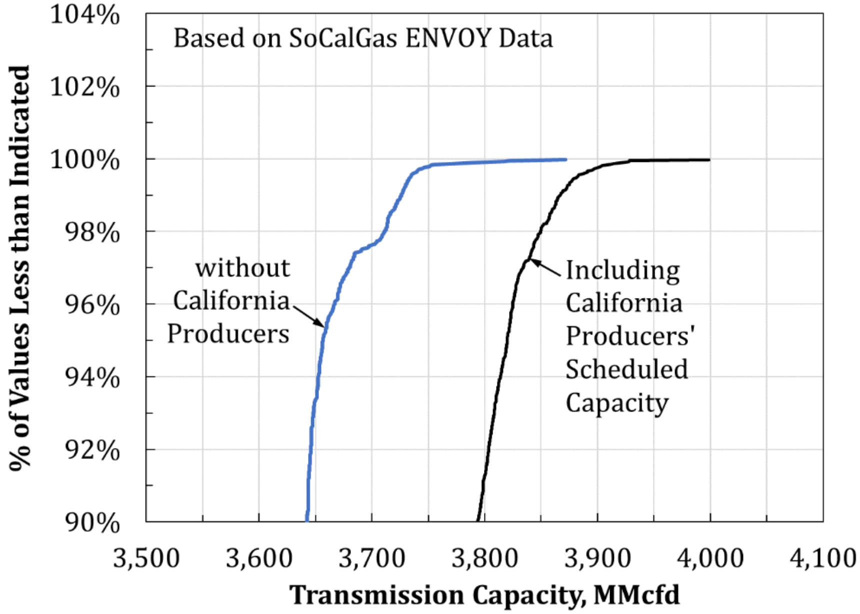
5. Provide an explanation on how ED knows that production cost modeling for the Unconstrained Gas Scenarios for 2022, 2026, and 2030 was "not significantly different" from Min Load Generation scenario for 2020, 2025, and 2030, as the years are different.
6. Requests the electric generation demand in MMcfd for Min Local Gen scenarios for 2020, 2025, and 2030.
7. In the zonal capacity analysis, slides suggested that SoCalGas increase Northern Zone capacity from 1,590 MMcfd to 2,243 MMcfd. SCPOU is concerned about the ratepayer impact of new pipelines and declining throughput.

For the winter simulations (S01, S03, and S05), the same approach could not be used since the first simulation (S01) was a failed simulation and stressing the system more would not have provided any additional insight. For all three winter simulations, an 85% RPU is used for the Northern and Southern Zones and 100% for the Wheeler Ridge Zone. However, due to miscommunication with SoCalGas, S01 RPU was introduced <u>after</u> accounting for the outages resulting in 2,926 MMscfd of supplies, while for S03 and S05, the RPU was applied to the <u>nominal</u> capacity of 3,565 MMscfd resulting in 3,115 MMscfd of supplies. S03 is the key simulation of all three winter simulations because it has the lowest winter demand among the three study years, yet it failed without the use of Aliso Canyon showing that both S01 and S05 would fail without the use of Aliso Canyon. S03 also attempts to bring in more supplies from Otay Mesa, which didn't have much effect on the results compared to S01. Given S03 results, ED and LANL decided that there was no need to repeat S01 with 189 MMscfd additional supplies or to run S05 without Aliso Canyon. Therefore, Aliso Canyon withdrawal was allowed in S05.

4. Please see #3 above. Aliso withdrawal was only allowed in S05. Non-Aliso Inventory levels are at 90% except S04 and S06, where the levels are at 70%.
5. Electric demand forecasts were similar between 2020 and 2022, and between 2025 and 2026. Since Minimum Local Generation results focused on September and December months, Diablo Canyon would already have been retired in

	September 2025 as in 2026. The key difference was the growth of renewable energy facilities, which turned out to be small and mostly composed of solar and battery storage. ED staff assumed that the time of day where LOLE events were seen as well as the magnitude were not likely to be affected much by one year's increase in solar and battery development. 6. This information will be provided in the final results report upcoming in Phase 2 of the Aliso OII proceeding 7. In Phase 2, Staff is not looking into possible mitigations and costs of those mitigations, as per the Phase 2 scoping memo. These issues will be considered in Phase 3. As discussed at the July workshop, the Northern Zone nominal capacity could be 2.2 Bcfd barring any competition from the other two zones.
Name/Organization: Issam Najm	
1. What is the source of the industry standard that referenced a Loss of Load Expectation (LOLE) of 0.1? 2. Inquired into the receipt capacity figures presented during the workshop and suggests that 3.785 Bcfd should be used as the nominal capacity.	1. The North American Electric Reliability Corporation (NERC) is a non-profit which establishes electric reliability standards in the United States, with oversight from the Federal Energy Regulatory Commission (FERC). The LOLE of 0.1 comes from NERC standard BAL-502-RFC-02, which can be found here: https://www.nerc.com/files/BAL-502-RFC-02.pdf. These standards are used in the Aliso OII proceeding, because the California Independent System Operator (CAISO) adheres to standards put in place by NERC. 2. As ED staff indicated at workshop 1, we are using the median or the mode of the historical capacity (without CA



production) which yields ~ 3,575MMscfd (3.7MMDth) in the 1-in-10 simulations. By definition, the median is the most likely value and is unbiased by outliers that could be due to human error, misrepresentation on ENVOY, or temporary interstate pipelines pressure increases above contractual pressure. Median is the most likely value for nominal capacity because it is a statistical measure that is insensitive to outliers. Picking a value at the tail ends is biased especially on a high demand day.