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VIA E-MAIL

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

Re: Southern California Publicly Owned Utilities Informal Comments on the July 28, 2020 Workshop on Production Costs Modeling Results, Hydraulic Modeling Results, and Capacity Studies.

Dear Energy Division:

The Southern California Public Owned Utilities ("SCPOU")[1] appreciates the presentations by the Energy Division and by the Los Alamos National Laboratory ("LANL") at the July 28, 2020 workshop in Investigation ("I.") 17-02-002, and SCPOU appreciates the opportunity to submit these informal comments on the workshop presentations.

For the reasons discussed below, SCPOU respectfully requests that the Energy Division make publicly available each of the scenarios with its underlying assumptions that the Energy Division ran for simulations 01-06 (winter 2020,[2] summer 2020, winter 2025, summer 2025, winter 2030, and summer 2030). SCPOU further respectfully requests that, upon making publicly available the scenarios that the Energy Division ran for each of the six simulations, the Energy Division and LANL hold a further workshop for discussion of the scenarios and to discuss which of the scenarios should drive the simulation results S01-S06 that LANL displayed in abbreviated form in LANL slide 14. The scenario and assumptions were different for each of the six simulations shown in LANL slide 14.

SCPOU also respectfully requests that the Energy Division provide an explanation about how the Energy Division knows that production cost modeling for the Unconstrained Gas Scenarios for 2022, 2026, and 2030 was "not significantly different" from production cost modeling of the Minimum Load Generation scenario for 2020, 2025, and 2030, given the difference in years studied. Additionally, SCPOU respectfully requests that the Energy Division make available the Electric Generation (EG") demand in MMcfd assumed for the Minimum Load Generation scenarios for each of the years 2020, 2025, and 2030.

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[1] The members of SCPOU are are Burbank Water and Power, City of Anaheim, City of Pasadena, City of Vernon, and Glendale Water and Power.

[2] SCPOU assumes that winter 2020 covers the months of November through March, 2019-2020. The workshop slide decks do not explicitly state the period represented by Simulation 01.

Lastly, although the scope of the workshop covered primarily production cost modeling and hydraulic modeling results, the last Energy Division speaker and slide deck suggested that the Southern California Gas Company ("SoCalGas") increase Northern Zone capacity from a nominal capacity of 1,590 MMcfd to 2,243 MMcfd. SCPOU assumes this would be accomplished by building new pipelines. SCPOU is deeply concerned about the ratepayer impact of constructing new pipelines on a gas system for which the Commission and the public foresee declining throughput.

I. SCPOU REQUEST FOR HYDRAULIC MODELING SCENARIOS FOR SIMULATIONS 01-06.

The presentation by the LANL representatives at the July 28, 2020 workshop demonstrated that the Energy Division and LANL ran a variety of scenarios for each of the Simulations 01-06 that the Energy Division and LANL presented at the workshop. The fact that a variety of scenarios were run for each of the simulations was demonstrated by LANL slides 10-13 showing demand assumptions, pipeline supply assumptions, and storage assumptions which resulted in slide 14 showing Simulation 01through 06 results. The summary LANL slide 14 is below:

SIMULATION RESULTS

	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
MAX WD RATE	1,330	1,329	1,329	1,116	2,594	527
MAX INJ RATE	368	368	368	442	368	184
Pressures above MinOP?	NO	YES	NO	YES	NO	YES
Pressures below MOP?	YES	YES	YES	YES	YES	YES
Linepack recovered?	NO	YES	NO	YES	YES	NO
Facilities operated within capacity?	YES	YES	YES	YES	YES	YES

These are the criteria for success or failure of the simulation.

UNCLASSIFIED 14

SCPOU respectfully requests an explanation about how the Energy Division and LANL decided which of the scenarios would have the scenario results chosen for presentation in slide 14 for each of the Simulations 01through 06. As LANL slides 10 through13 demonstrate, each of the simulation results shown on slide 14 are driven by different scenarios with different assumptions. Each of the simulation results for each of the time periods covered by each of the simulations reflect differing assumptions, resulting in slide 14 showing simulation results for each of the six time periods being an "apples to oranges" comparison.

A. Demand Assumptions Fluctuate Inexplicably for Scenarios 01-06.

Demand assumptions varied for each of the Simulations 01through 06. SCPOU recognizes that it is reasonable to assume that over the ten years from winter 2020 to summer 2030 there would be variations in demand. However, the EG and non-EG demand levels shown in LANL slide 10 fluctuate inexplicably without any self-evident pattern. Slide 10 shows the following:

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**

UNCLASSIFIED 10

Core winter demand declines linearly from winter 2020 to winter 2030 for S01, S03, and S05. However, the non-EG noncore demand bounces non-linearly down from 1,048 MMcfd in winter 2020 to 900 MMcfd in winter 2025 and then back up to its highest level, 1,122.6 MMcfd, in winter 2030.

The winter demand for the non-EG non-core is also non-linear, although the fluctuations are not as pronounced and go in the opposite direction in comparison to the EG demand levels. Non-EG non-core demand starts at 654 MMcfd in winter 2020, goes up in winter 2025, and then goes down in winter 2030, the opposite of the pattern for EG demand.

B. The Assumed Pipeline Supply Fluctuates Inexplicably for Each of the Scenarios 01-06.

The pipeline supply shown in slide 11 assumed for each of the six simulations is inexplicable. Slide 11 is the following:

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.

UNCLASSIFIED 11

For the Northern Zone, which includes pipelines that receive gas at the North Needles, Topock, and Kramer Junction receipt points, the modelers assumed that 1,250 MMcfd would be available for winter 2025 and winter 2030. However, without explanation, the modelers assumed no gas would be delivered from North Needles and Topock during summer 2025 and summer 2030. Kramer Junction would be permitted to increase to from 550 MMcfd to 700 MMcfd during each of those summers, but the total Northern Zone capacity still drops by 500 MMcfd for both summer 2025 and summer 2030 to Kramer Junction's 700 MMcfd.

Also, the Wheeler Ridge Zone is assumed to operate at 765 MMcfd for every one of the scenarios except summer 2025 and summer 2030, when, without explanation, capacity drops to 600 MMcfd. Likewise, California production is assumed to be the same for each of the years covered by the simulations except for summer 2025 and summer 2030 when, without explanation, the modelers assume that no gas would be taken from California production.

C. Storage Withdrawal Rates Vary Inexplicable.

Lastly, 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:

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

UNCLASSIFIED 12

As shown on LANL slide 12, the modelers omit Aliso Canyon from each of the simulations except winter 2030, when Aliso Canyon is shown to operate at a 1,265 MMcfd withdrawal rate. The explanation in the slide says that S05 includes Aliso Canyon and "determines the minimum amount needed from Aliso." However, the slide appears to fail to meet its objective, because in the simulation results shown on LANL slide 14 pressures above minimum operating pressures are not achieved during winter 2030. Failure to achieve minimum operating pressures demonstrates that the 1,265 MMcfd shown in Slide 12 as the withdrawal rate from Aliso Canyon is insufficient to maintain pressures above minimum operating pressure. Thus, it appears that the assumption that Aliso can operate in winter 2030 but not for any of the other simulations fails to show the minimum amount needed from Aliso, contrary to the explicit claim made in slide 12.

Lastly, inexplicably, for S06, summer 2030, the modelers assumed that <u>both</u> Honor Rancho and Aliso Canyon would be out of operation. Honor Rancho is the biggest SoCalGas storage field aside from Aliso Canyon that is proximate to the Los Angeles Basin. The modelers do not explain the rationale for excluding Honor Rancho from Simulation 06. In the slide 14 showing simulation results, a "no" appears in the S06 column for "line pack recovered?" If the more reasonable assumption were made that Honor Rancho would be available in summer 2030, it seems reasonable to assume that line pack would be recovered in summer 2030 just as it was in summer 2025. Both winter 2025 and summer 2030 would show green in all slide 14 boxes.

The hydraulic modeling results are critical for making reasoned decisions about the future operations of Aliso Canyon. Accordingly, SCPOU respectfully requests that the Energy Division make publically available all the scenarios with all assumptions for each of the simulations 01-06. In particular, SCPOU requests that the Energy Division make publicly available the sensitivity analyses for each year where the Energy Division studied the results of changing only one variable. Also, SCPOU respectively requests that the Energy Division and

LNAL hold a further hydraulic modeling workshop on the simulations presented on July 28, 2020, after the requested additional data is released to the public.

II. SCPOU REQUESTS INFORMATION AND AN EXPLANATION ABOUT THE PRODUCTION COST MODELING RESULTS THAT THE ENERGY DIVISION PRESENTED AT THE WORKSHOP.

At the workshop, the Energy Division staff presented production cost modeling results for two scenarios. The first scenario was the Unconstrained Gas Scenario. The Energy Division staff said that, for the Unconstrained Gas Scenario, staff modeled all regions in the Western Electric Coordination Council ("WECC") but presented results only for the California Independent System Operator ("CAISO") balancing area.[3] Under the Unconstrained Gas Scenario, the staff assumed that there would be no EG curtailment.[4]

Second, the Energy Division staff modeled the Minimum Local Generation scenario in which "Electric Generation in SoCalGas system curtailed down to the minimum needed to meet Local Reliability Criteria according to FERC."[5] The Energy Division staff said, "This scenario simulates the expected electric reliability effect in the event of a significant curtailment of the availability of gas to supply generation in the SoCalGas gas network."[6] SCPOU requests information and an explanation about the production cost modeling.

A. SCPOU Requests Information about the Level of EG Demand Assumed for the Minimum Load Generation Scenario for the Years 2020, 2025, and 2030,

SCPOU respectfully requests that the Energy Division present the level of gas demand in MMcfd that was served under Minimum Local Generation scenario. Absent further information from the Energy Division, SCPOU assumes that the minimum amount of gas-fired generation that would be required on a 1-in-10 year cold day to maintain electric system reliability would be similar to the minimum amount that was determined by the Joint Agencies (CPUC, Energy Commission, CAISO, and LADWP) in their technical reports on gas supply issues caused by the October 23, 2015, Aliso Canyon gas leak.

The Joint Agencies concluded that only 96 MMcfd of gas burn was required by EGs in the SoCalGas and San Diego Gas and Electric Company ("SDG&E") service territories to provide local generation to meet electric requirements in a post N-1contingency event, and only 22 MMcfd would be needed under normal pre-contingency conditions.[7] The Joint Agencies

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[3] Slide 15.

[4] Slide 19.

[5] Slide 16.

[6] *Ibid.*

[7] Aliso Canyon Winter Risk Technical Assessment Report, CEC Docket No. 16-IEPR-02, pp. 4-5 (August 22, 2016).

cautioned, however: "Although the electric system can operate with extremely low gas consumption during the winter months, doing so would result in increased dispatch costs."[8]

Given the findings of the Joint Agencies in their Technical Assessment for winter 2016-2017 and in subsequent Joint Agencies technical reports, SCPOU requests that the Energy Division release to the public the Minimum Local Generation Demand that the Energy Division's production cost modeling shows would have to be met in 2020, 2025, and 2030.

B. SCPOU Request an Explanation about the Asymmetry in Years Studied for the Unconstrained Gas Scenario and the Minimum Local Generation Scenario.

In addition to requesting information about the EG demand assumed in the Minimum Local Generation Scenario, SCPOU requests an explanation about the asymmetry between the years modeled for the Unconstrained Gas Scenario in comparison to the Minimum Local Generation Scenario years.

The Energy Division staff explained that the staff used the results of the IRP proceeding Reference Plan as a basis for the Unconstrained Gas Scenario. Staff modeled three study years, 2022, 2026, and 2030 for the Unconstrained Gas Scenario.[9] However, for the Minimum Local Generation Scenario, the staff modeled a different set of study years, 2020, 2025, and 2030. The staff said that the asymmetry between the set of years studied for the Unconstrained Gas Scenario and the set of years studied for the Minimum Local Generation Scenario "did not produce significantly different results."[10] Slide 22.

It is unclear to SCPOU how the staff could conclude "Differences in study years did not produce significantly different results" without modeling for 2020, 2025, and 2030 for the Unconstrained Gas Scenario or, conversely, modeling for 2022, 2026, and 2030 for the Minimum Local Generation Scenario. Thus, SCPOU requests an explanation about how the Energy Division reached its conclusion that asymmetry in the study years "did not produce significantly different results."

III. SCPOU OPPOSES THE SUGGESTION THAT SOCALGAS INCREASE ITS NORTHERN ZONE CAPACITY TO 2,243 MMCFD.

In addition to presenting the results of its production cost modeling and hydraulic modeling, the staff concluded the July 28, 2020 workshop by presenting a slide deck on capacity studies.[11] In slide 62, the staff said that that the Northern Zone capacity could be increased to 2,243 MMcfd, much higher than the Northern Zone nominal capacity of 1,590 MMcfd or the capacity of 990 MMcfd that SoCalGas is currently making available in August 2020 in its Backbone Transportation Service open season.

[8] *Ibid*, p. 5.

[9] Slide 21.

[10] Slide 22.

[11] Aliso OII I.17-02-002: Workshop Three Input Data Development and Capacity Studies.

The staff explains that the higher Northern Zone capacity would be "due to the removal of the competition from the Wheeler Ridge Zone, which competes at least on L235, L335, L1185, and L4002, and the Northern Citygate."[12] That elimination of competition would presumably result from the addition of pipeline capacity to the capacity currently available on Lines 235 and 335 between Quigley and the Adelanto compressor station and on Lines 1185 and 4002 between the Adelanto compressor station and Chino.

Without further information, it appears the addition of capacity by looping Lines 235 and 335 and by looping Lines 1185 and 4002 would be a massive pipeline project that would put a heavy burden on gas ratepayers who are already stretched thin by, among other things, the enormous expenditures of SoCalGas and SDG&E on their Pipeline Safety Enhancement Plan. SCPOU caution the Commission against an expensive pipeline capacity expansion for a gas system that is expected to serve decreasing gas demand during the coming decades.

IV. CONCLUSION.

For the reasons discussed above, SCPOU respectfully requests that the Commission provide the additional information and explanations requested by SCPOU and convene a further workshop on the hydraulic modeling results presented on July 28, 2020. SCPOU looks forward to continued involvement in the important investigation in I.17-02-002.

Sincerely,

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cc:

[12] *Ibid* (emphasis in original)>