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Date: October 8, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U904G) in Compliance with Ordering Paragraph 6 of Decision 24-12-076	)	Application 26-01-009

Rebuttal Testimony of

Brian C. Collins

On behalf of

Indicated Shippers

October 8, 2026

Project 12089

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Rebuttal Testimony of Brian C. Collins

I. INTRODUCTION AND PURPOSE

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME BRIAN C. COLLINS WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A Yes. I filed direct testimony on behalf of the Indicated Shippers ("IS") on August 20, 2026, and an errata to that testimony on September 15, 2026 (Exhibit IS-01E, "Collins Direct").[1] My qualifications are described in Appendix A to my direct testimony.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A My rebuttal testimony responds to the August 20, 2026 direct testimony of Sierra Club witnesses Tyson Siegele (Exhibit SC-01, "Siegele Direct") and Dr. Vincent Berardi (Exhibit SC-02, "Berardi Direct"), and to the August 20, 2026 opening testimony of Public Advocates Office ("Cal Advocates") witness Christian Lambert ("Lambert Direct").

Specifically, my rebuttal testimony focuses on the two issues identified in the Assigned Commissioner's July 8, 2026 Scoping Memo and Ruling ("Scoping Memo").

[1] The Indicated Shippers represent the natural gas non-core customer interests of California Resources Corp., Chevron U.S.A. Inc., Marathon Petroleum Company LP, and PBF Holding Company in this proceeding.

Those issues are: (1) whether the Commission should maintain the current 68.6 billion cubic feet ("Bcf") maximum inventory at the Aliso Canyon Natural Gas Storage Facility ("Aliso Canyon") or order Southern California Gas Company ("SoCalGas" or "Company") to reduce it; and (2) whether the Commission should modify the biennial assessment framework in Attachment A to Decision ("D.") 24-12-076 (the "Decision").[2]

Sierra Club recommends that the Commission reduce the Aliso Canyon maximum inventory by 29 Bcf, to 39.6 Bcf, before the 2027 Biennial Assessment.[3] Cal Advocates recommends that the Commission maintain the current 68.6 Bcf maximum inventory at Aliso Canyon.[4]

SoCalGas served rebuttal testimony on September 17, 2026 that addresses the recommendations of Sierra Club, including the California Gas Report ("CGR") peak-day forecasting methodology, the FTI Consulting, Inc. ("FTI") Phase 3 report, the California Independent System Operator ("CAISO") study, and the hydraulic modeling results.[5]

Where I do not address a particular argument made by Sierra Club or another party, my silence should not be read as agreement with it.

II. SUMMARY OF REBUTTAL CONCLUSIONS

Q PLEASE SUMMARIZE YOUR REBUTTAL CONCLUSIONS AND RECOMMENDATIONS.

A I recommend that the Commission maintain the Aliso Canyon maximum inventory at 68.6 Bcf and reject Sierra Club's proposal to reduce it by 29 Bcf, to 39.6 Bcf, as well as

[2]Scoping Memo at 4-5.

[3]Siegele Direct at 3, 33.

[4]Lambert Direct at 1-1, 1-5, 1-10.

[5]Prepared Rebuttal Testimony of Andrew J. Sawin on behalf of SoCalGas (September 17, 2026) ("Sawin Rebuttal") at AJS-2 to AJS-6; Prepared Rebuttal Testimony of Eduardo J. Martinez on behalf of SoCalGas (September 17, 2026) ("Martinez Rebuttal"); Prepared Rebuttal Testimony of Stacy Chang on behalf of SoCalGas (September 17, 2026) ("Chang Rebuttal").

Energy Division's proposed up to 10 Bcf reduction. Sierra Club's proposal is nearly three times the 10 Bcf per-cycle maximum limit the Commission adopted in the Decision. My conclusions are as follows:

1. A 29 Bcf reduction, as proposed by Sierra Club's Mr. Siegele, falls first on the noncore customers' share of storage capacity. Under the storage allocation rules the Commission adopted in D.24-07-009, reducing total SoCalGas storage inventory by the 29.48 Bcf Mr. Siegele analyzes, from 119.5 Bcf to 90.02 Bcf, reduces the Unbundled Storage ("UBS") Program from 25 Bcf to 7.55 Bcf, a cut of about 70% that absorbs about 59% of that reduction.

   Mr. Siegele presents this result as a reason the reduction is harmless. However, his proposal would harm customers because it would remove about 70% of the UBS inventory capacity that noncore customers, including the electric generators that serve CAISO load, hold to manage supply and price risk during extreme events, and it would reduce the UBS revenues that are credited to ratepayers.

2. With respect to Aliso Canyon storage inventory, Sierra Club would have SoCalGas plan for the average day. This is an incorrect and imprudent approach. Four of Mr. Siegele's key analytical choices regarding Aliso Canyon replace an extreme but probable condition with an average one: average historical receipt point capacity in place of the outage-reduced capacity the SoCalGas system has actually experienced during system stress events; demand on 56 to 60 degree Fahrenheit days, rather than demand at the 42.3 degree 1-in-10 design temperature, to conclude that demand is falling; end-of-March inventory instead of inventory available during a January cold week; and a probability calculation that treats cold weather and loss of flowing supply as independent events when the record shows they often occur together. Storage inventory is the system's insurance against extreme, multi-day weather and grid reliability events, and insurance coverage sized to an average does not provide protection when it is needed most.

3. Since the Decision was issued, the insurance that Aliso Canyon inventory represents and provides has been called upon, including during the Line 225 outage from December 2025 to August 2026 and during Winter Storm Fern in January 2026, when storage supplied nearly 60% of system demand at the peak while interstate deliveries fell to as little as 25% of available receipt point capacity. The record shows the insurance provided by inventory was valuable and effective, not going unused.

4. The storage inventory margin that Sierra Club would further reduce is already thin. In its winter 2025-26 peak-day analysis, SoCalGas calculated that serving the 1-in-10 peak day with Aliso Canyon inventory at 68.6 Bcf requires about 91% receipt point utilization ("RPU"), and that a reduction to 58.6 Bcf would require about 97% RPU, a level that the

Company describes as operationally unrealistic.[6] Sierra Club's 29 Bcf reduction goes well beyond that.

5. Sources that Sierra Club references support maintaining the current inventory level at Aliso Canyon for this 2025 Biennial Assessment. For example, the California Energy Commission ("CEC") winter assessment containing the forecast Sierra Club asks the Commission to adopt clears the 1-in-10 day only with storage withdrawals comprising about one-third of demand, starting from assumed 100% full storage that includes 68.6 Bcf at Aliso Canyon.

6. Cal Advocates concludes that the 2025 Biennial Assessment economic results and the higher 2026 CGR forecast support keeping the current 68.6 Bcf limit, and selects the zero-reduction end of Energy Division's proposed range of reduction.[7] I reach the same conclusion, for the reasons in my direct testimony and below.

7. Given the reliability and price benefits provided by gas storage, I recommend that Attachment A remain forward-looking and gradual: forward-looking in that the economic trigger compares forward prices for the coming winter, and gradual in that any single reduction is limited to 10 Bcf per assessment cycle. The Commission should keep the 10 Bcf per-cycle limit and the Henry Hub pricing economic trigger, reject Sierra Club's proposed 97% RPU and historical-average pipeline capacity assumptions, and adopt the corrections to the reliability analysis that Indicated Shippers and SoCalGas both recommend.

8. The timing of the next biennial assessment matters. The corrections to Attachment A that I support require Energy Division to build new modeling inputs, and if this proceeding is decided in the first half of 2027, little or no time would remain to incorporate them into a June 15, 2027 Biennial Assessment report. An assessment prepared in 2028 on corrected inputs, as requested in the joint petition for modification that Indicated Shippers and SoCalGas filed in Investigation ("I.") 17-02-002, would be more useful to the Commission than a 2027 Biennial Assessment that repeats the flawed 2025 inputs.

[6]Prepared Direct Testimony of Andrew J. Sawin on behalf of SoCalGas, Chapter I (January 15, 2026) ("Sawin Direct") at AJS-18 to AJS-20 and Table I-3; Sawin Rebuttal at AJS-9; Collins Direct at 32.

[7]Lambert Direct at 1-1, 1-5 to 1-10.

III. SIERRA CLUB'S PROPOSED 29 BCF REDUCTION FALLS FIRST AND HARDEST ON THE NONCORE CUSTOMERS' SHARE OF STORAGE

A. The Settlement Allocates Most of Any Large Reduction to the UBS Program

Q HOW IS SOCALGAS STORAGE INVENTORY CURRENTLY ALLOCATED AMONG CUSTOMER GROUPS?

A The current allocation is set by the settlement the Commission adopted in D.24-07-009 (the "Settlement"). Of the 119.5 Bcf of total approved SoCalGas storage inventory, 80.03 Bcf is allocated to core, 12 Bcf to load balancing, 25 Bcf to the UBS Program, and 2.47 Bcf to wholesale. The UBS Program carries a firm withdrawal right of 50 million cubic feet per day ("MMcfd") in both winter and summer.[8]

The Settlement also specifies how a Commission-ordered reduction in total inventory will be allocated. The first 10 Bcf of any reduction will come from the UBS Program. The remainder will be applied pro rata across all inventory rights, down to floors of 72 Bcf for core, 2.47 Bcf for wholesale, and 8.0 Bcf for load balancing. Once the floors are reached, all further reductions will come solely from the UBS Program.[9]

Q WHAT HAPPENS TO THE UBS PROGRAM UNDER THE 29 BCF REDUCTION MR. SIEGELE PROPOSES AT PAGES 3, 33 AND 40-41 OF HIS TESTIMONY?

A Mr. Siegele recommends a 29 Bcf reduction and calculates that total SoCalGas storage inventory could be reduced by 29.48 Bcf, from 119.5 Bcf to 90.02 Bcf, before UBS winter withdrawals would be truncated.[10] Applying the Settlement rules to that 29.48 Bcf reduction:

[8] D.24-07-009, Attachment A (Settlement), Section II.E(1)(a) at 5-6; Collins Direct at 22.

[9] Settlement, Section II.E(1)(b) at 6. Mr. Siegele quotes the same provision. Siegele Direct at 40.

[10] Siegele Direct at 41 and fn. 115. "For the purposes of this exercise, I'm assuming the withdrawal rate listed in D.24-07-009 of 50 MMcfd to calculate the floor level for retaining UBS maximum winter withdrawal shown in Table 6."

- The UBS Program inventory capacity falls from 25 Bcf to 7.55 Bcf, a reduction of 17.45 Bcf, or about 70%.
- Core inventory capacity falls from 80.03 Bcf to its 72 Bcf floor, a reduction of 8.03 Bcf, or about 10%.
- Load balancing inventory capacity falls from 12 Bcf to its 8 Bcf floor, a reduction of 4 Bcf, or about 33%.
- Wholesale inventory capacity remains unchanged at 2.47 Bcf.

The UBS Program is currently fully subscribed,[11] and would absorb 17.45 Bcf of the 29.48 Bcf reduction, about 59% of the total. Mr. Siegele's Table 6 reaches the same 7.55 Bcf UBS result.[12] Where we differ is in what the result means. Mr. Siegele incorrectly asserts that a 29 Bcf reduction "will not hinder" UBS withdrawals because 50 MMcfd of withdrawal over the 151-day withdrawal season equals 7.55 Bcf.[13] I conclude that removing about 70% of the UBS inventory capacity is itself the hindrance: noncore customers would have far less gas in storage to draw on, even though the daily withdrawal right is unchanged.

Q WHY IS THE "50 MMCFD TIMES 151 DAYS" TEST MR. SIEGELE APPLIES AT PAGES 39 AND 41 OF HIS TESTIMONY THE WRONG MEASURE?

A It is the wrong measure because inventory and withdrawal rate serve different purposes. For the UBS Program, the Commission-adopted Settlement pairs 25 Bcf of inventory capacity with 50 MMcfd of firm withdrawal capacity, which is 500 days of withdrawal at the maximum rate. The inventory is not a multiple of the daily rate; it is the volume that noncore customers hold to hedge their supply reliability and price exposure, injected

[11] Chang Rebuttal at SCC-7.

[12] Siegele Direct at 41 and Table 6.

[13] Siegele Direct at 38-39, 41.

when prices are low and available when they are not. As SoCalGas explains, UBS Program customers actively cycle gas into and out of storage throughout the year.[14] They use the program for injections, withdrawals, and imbalance trades, so the value of the inventory does not depend on withdrawing gas at 50 MMcfd every day of the winter.[15] Mr. Siegele's test would be equally satisfied by a program of 7.55 Bcf. It measures the pipe, not the tank.

Q WHAT ARE THE CONSEQUENCES FOR CUSTOMERS OF A UBS PROGRAM REDUCTION OF THIS SIZE?

A I described the consequences in my direct testimony and they remain unchanged here.[16] The UBS Program is fully subscribed, and 100% of net UBS revenues are credited to ratepayers.[17] Customers are therefore harmed twice: noncore customers, including the electric generators that serve CAISO load, would lose much of the hedge value and be more exposed to higher and more volatile prices, and all customers lose much of the revenue credit. Energy Division acknowledged in the 2025 Biennial Assessment that its economic analysis does not capture the impact of reductions to the UBS Program and that, with less access to storage, noncore customers including electric generators could be exposed to higher gas prices, which could in turn increase electric rates.[18] Cal Advocates makes the same point with respect to Energy Division's up to 10 Bcf proposal, which could remove 40% of the UBS Program inventory capacity.[19] Sierra Club's proposal removes about 70%.

[14] Chang Rebuttal at SCC-7 to SCC-9.

[15] Chang Rebuttal at SCC-7 to SCC-9.

[16] Collins Direct at 22-25.

[17] Chang Rebuttal at SCC-7; Lambert Direct at 1-6; Prepared Direct Testimony of M. Michelle Dandridge on behalf of SoCalGas, Chapter II (January 15, 2026) ("Dandridge Direct") at MMD-7.

[18] CPUC Energy Division, 2025 Aliso Canyon Biennial Assessment Report Pursuant to D.24-12-076 (October 1, 2025) ("2025 Biennial Assessment") at 28; Lambert Direct at 1-5 to 1-6.

[19] Lambert Direct at 1-1, 1-5.

Q AT PAGES 48-49 OF HIS TESTIMONY, MR. SIEGELE CITES THE FEBRUARY 2019 RULE 23 CURTAILMENT AS EVIDENCE THAT ALISO CANYON IS UNRELIABLE. HOW DO YOU RESPOND?

A From February 6 through February 8, 2019, SoCalGas curtailed electric generation customers under Rule 23 after a necessary and unplanned maintenance outage reduced Aliso Canyon withdrawal capacity by 420 MMcfd, while the field held about 30 Bcf under a 34 Bcf cap.[20] Receipt point utilization averaged 93% from February 4 through February 24, 2019, so the curtailment was not a flowing-supply problem, and the customers curtailed were electric generators. The event shows that storage deliverability margin, in addition to flowing supply, determines whether noncore customers are curtailed during a cold event, and that margin depends on withdrawal capacity, which declines as inventory and reservoir pressure decline.[21]

B. <u>The Price Exposure Noncore Customers Face When Supply Tightens</u>

Q IS THERE RECENT EVIDENCE OF THE PRICE EXPOSURE THAT STORAGE INVENTORY HEDGES?

A Yes. SoCalGas reports that between August 20 and August 31, 2026, during a regional summer heat event, it purchased Southern System reliability gas at prices reaching $30 per million British thermal units ("MMBtu"), buying more than 2 million MMBtu for a total cost exceeding $25 million.[22] Energy Division and SoCalGas both expect liquefied natural gas exports from Energia Costa Azul to increase competition for pipeline capacity serving Southern California, and SoCalGas expects the cost of Southern

[20] Siegele Direct at 48-49 and fns. 141-142, 146-147; Collins Direct at 7-8, 42, 49.

[21] Sawin Rebuttal at AJS-17.

[22] Chang Rebuttal at SCC-13.

System procurement to rise significantly, potentially two or three times its current level, as it competes with export markets for the same gas.[23]

The winter 2022-23 experience remains the record example of the costs imposed on customers by constrained storage inventory. SoCalGas and San Diego Gas & Electric Company ("SDG&E") estimated that natural gas cost their customers about $307 million more to procure that winter than it would have if the Aliso Canyon maximum inventory had been 68.6 Bcf rather than 41.16 Bcf, an estimate the Commission reiterated in D.23-08-050 and D.24-12-076.[24] In addition, the Commission staff white paper reports CAISO day-ahead market costs of about $5 billion in December 2022 against about $1 billion in the same month of the prior and following years.[25]

IV. SIERRA CLUB IMPRUDENTLY PLANS FOR THE AVERAGE DAY; THE SYSTEM MUST BE PLANNED FOR THE EXTREME BUT PROBABLE MULTI-DAY EVENT

A. Each of Sierra Club's Analytical Choices Substitutes an Average for an Extreme

Q WHAT IS THE CENTRAL PROBLEM WITH THE RELIABILITY ANALYSIS MR. SIEGELE PRESENTS AT PAGES 15 THROUGH 35 OF HIS TESTIMONY?

A Sierra Club measures the need for Aliso Canyon storage inventory against conditions that are typical, then concludes any inventory capacity above that level that is held for extreme but probable conditions is excess and unneeded.

Sierra Club makes the same error at least four times over. First, Mr. Siegele uses the historical average of pipeline receipt capacity to set the pipeline capacity input. Second, he uses demand on 56 to 60 degree Fahrenheit days to conclude that demand is falling. Third, he uses end-of-March inventory balances to conclude that residual

[23] 2025 Biennial Assessment at 2; Dandridge Direct at MMD-5; Chang Rebuttal at SCC-12 to SCC-13; Collins Direct at 38.

[24] D.23-08-050 at 10-11; D.24-12-076 at 30; Collins Direct at 9, 40.

[25] I.23-03-008, Staff White Paper on High Natural Gas Prices in Winter 2022-23: Part II (Updated) (October 28, 2025) at 36 and Figure 13; Collins Direct at 40.

storage inventory is neither needed nor valuable. Fourth, he treats a cold day and a loss of flowing supply as independent events to conclude that their coincidence is a once-in-500-years occurrence. None of these assumptions describes the risks of extreme weather and grid reliability events that storage inventory exists to mitigate.

As I explained in my direct testimony, reliability planning is not conducted for average conditions. Systems are planned to the modeled need under adverse conditions, and the relevant question is not what the system averages across a winter but what supply actually arrives when the regional gas system is stressed.[26] SoCalGas makes the same point in rebuttal.[27]

Q AT PAGES 16 AND 59-60 OF HIS TESTIMONY, MR. SIEGELE PROPOSES THAT PIPELINE CAPACITY BE SET AT THE HISTORICAL AVERAGE OF RECEIPT POINT CAPACITY. PLEASE ADDRESS THAT ASSUMPTION.

A Mr. Siegele would wrongly set the incoming pipeline capacity input at the historical winter average of total receipt capacity, which he calculates exceeds the capacity modeled in the 2025 Biennial Assessment by 486 MMcfd, on the grounds that the 2025 Biennial Assessment assumed a system capacity "far lower than the average."[28] He adds that future assessments should assume typical winter deliverability rather than assume that a large gas-system outage will overlap with a 1-in-10 peak winter demand day.

The winter that just ended shows why average available pipeline capacity is the wrong input. Line 225, a roughly 650 MMcfd pipeline moving gas from the Wheeler Ridge Zone to the Los Angeles Basin, was taken out of service by a force majeure event

[26]Collins Direct at 34.

[27]Sawin Rebuttal at AJS-7 to AJS-9, AJS-14 to AJS-15.

[28]Siegele Direct at 3, 16, 59-60.

on December 27, 2025 and did not return to service until August 2026.[29] SoCalGas's Summer 2026 Technical Assessment, issued in April 2026, assumed Line 225 out of service through July.[30]

SoCalGas's Winter 2025-26 Technical Assessment, issued in November 2025, had Line 4000 under remediation into mid-December and stated firm flowing supply of up to 3,775 MMcfd, not the 3,875 MMcfd nominal figure Mr. Siegele uses.[31] A capacity input built from the average of the winters since 2004[32] would not have represented the system as it stood for most of winter 2025-26, including during Winter Storm Fern.

The pipeline capacity input should reflect the system as it is, not as it is hoped to be, because the system can change quickly and in both directions.

For example, the 2,800 MMcfd used in the 2025 Biennial Assessment reflected a 655 MMcfd reduction on Lines 4000 and 4002 that SoCalGas had announced for July 2025 through November 2026. After Staff's modeling was complete, SoCalGas ended that reduction on September 5, 2025, and Energy Division observed that the unexpected change underscores the uncertainty surrounding future pipeline conditions.[33] Less than four months later, the Line 225 force majeure removed about 650 MMcfd of capacity for about seven months. Within a single year, available capacity moved by more than 600 MMcfd in each direction.[34] The corrections in Section VII of my rebuttal testimony

[29]SoCalGas Compliance Filing Regarding Outages Within Its Service Territory (May 15, 2026) ("SoCalGas Internal Outage Report") at 4 and Appendix A at 27 (Event 8414); 2025 Biennial Assessment at 19; Collins Direct at 6, 28 and fn. 56. SoCalGas, Castaic Line Break Repair (last updated October 2, 2026) (pipeline returned to service August 1, 2026); SoCalGas ENVOY, Event ID 8800 (Line 225 force majeure capacity reduction of 490 MMcfd at the Wheeler Ridge Zone through August 12, 2026).

[30]SoCalGas, Summer 2026 Technical Assessment (April 16, 2026) at 2-3, 6.

[31]SoCalGas, Winter 2025-26 Technical Assessment (November 6, 2025) at 1-2; Sawin Rebuttal at AJS-26.

[32] Siegele Direct at 7, 16, 51-52.

[33] 2025 Biennial Assessment at 3.

[34]2025 Biennial Assessment at 3 (655 MMcfd pressure reduction on Lines 4000 and 4002 announced April 11, 2025 for July 1, 2025 through November 1, 2026, reflected in the 2,800 MMcfd assumption; reduction ended September 5, 2025 after Staff's modeling was complete), 4, 12 and Table 5; SoCalGas Internal Outage Report (May 15, 2026) at 4 and Appendix A at 27 (Line 225).

therefore urge Energy Division to model the outages the system actually experiences rather than to assume they will not recur. If flowing capacity is higher when the next assessment is prepared, the model will show it. If it is not, an inventory that has already been reduced likely cannot be restored within the season.

Q THE 2025 BIENNIAL ASSESSMENT ITSELF STATES THAT AT A PIPELINE CAPACITY OF ROUGHLY 3,200 MMCFD, ONLY 1 PERCENT OF ALISO CANYON CAPACITY WOULD BE REQUIRED. DOES THAT STATEMENT SUPPORT SIERRA CLUB'S POSITION THAT THE ASSESSMENT SHOULD ASSUME MORE PIPELINE CAPACITY AND THAT ALISO CANYON INVENTORY CAN BE REDUCED BY 29 BCF?

A No. It shows how sensitive the gas balance result is to the outage assumptions. The Assessment reports the 1 percent figure with a condition attached: it holds only if there are no unplanned storage outages and no changes to the interstate or intrastate pipeline systems similar to the previous reductions on Lines 4000 and 4002.[35] The assessment's Table 5 shows the rest of the range. With 2,700 to 2,800 MMcfd of pipeline supply and a 60 percent storage well utilization factor, the model reports failure; with 3,200 MMcfd of pipeline supply and no well outages, it reports 1 percent. Even at 3,200 MMcfd, the storage capacity requirement rises to 73 percent if storage well utilization falls to 60 percent.[36] The Aliso Canyon inventory capacity did not change between those scenarios; the outage assumptions did. The Line 225 outage previously described is the kind of change the assessment's own caveat describes as not being contemplated by

[35] 2025 Biennial Assessment at 4.

[36] 2025 Biennial Assessment at 10, 12 and Table 5. The storage well utilization factor accounts for reductions in the storage fields' withdrawal capacity due to unplanned well outages and shut-ins. Id. at 10.

the 1% result. The conclusion here is that outage inputs must reflect what the system actually experiences, and a fixed 101.5 MMcfd[37] unplanned outage allowance does not.

Q AT PAGES 22-23 AND FIGURE 5 OF HIS TESTIMONY, MR. SIEGELE FINDS THAT 2026 GAS DEMAND WAS THE LOWEST ON RECORD. PLEASE ADDRESS THAT ANALYSIS.

A Mr. Siegele finds that 2026 gas demand was the lowest on record when controlled for temperature, and that the finding shows a lower need for storage.[38] His analysis is limited to days with system-average temperatures between 56 and 60 degrees Fahrenheit. SoCalGas's 1-in-10 peak-day design temperature is 42.3 degrees Fahrenheit and its 1-in-35 design temperature is 40.6 degrees.[39] Demand on a mild day tells the Commission little about demand on the design day for which the system is planned, and Sierra Club witness Dr. Berardi's own analysis finds that demand becomes less predictable as temperatures fall.[40]

Q AT PAGES 33-36 AND FIGURES 6 AND 7 OF HIS TESTIMONY, MR. SIEGELE IMPROPERLY RELIES ON END-OF-WINTER INVENTORY LEVELS. PLEASE ADDRESS THAT ANALYSIS.

A Mr. Siegele asserts that, since the 2015 Aliso Canyon incident, SoCalGas has never had less than 34.9 Bcf of gas in storage, and mistakenly presumes that the Commission can reduce Aliso Canyon inventory without concern for reliability or price impacts.[41]

End-of-March inventory, however, is the wrong measure. Reliability is determined during a cold week in December or January, and inventory that remains at the end of

[37] D.24-12-076, Attachment A at A-5 (Table 1, Row 9); 2025 Biennial Assessment at 14; Sawin Rebuttal at AJS-28.
[38] Siegele Direct at 2, 22-23 and Figure 5.
[39] Martinez Rebuttal at EJM-11; Berardi Direct at 3.
[40] Berardi Direct at 16.
[41] Siegele Direct at 2, 33-36 and Figures 6 and 7.

March is the reserve that was available for a second cold event or a pipeline outage that did not occur. SoCalGas explains the relationship between inventory and withdrawal capability in its rebuttal.[42]

I add one additional point. For much of the period Mr. Siegele examines, withdrawals from Aliso Canyon were restricted by the Aliso Canyon Withdrawal Protocol, which Energy Division removed only on September 15, 2023.[43] Inventory remaining at the end of those winters reflects a restriction on access to the Aliso Canyon storage field, not a finding that the residual March inventory was unnecessary.

Q AT PAGE 53 OF HIS TESTIMONY, MR. SIEGELE CALCULATES THAT A PEAK DEMAND DAY AND A LOW-CAPACITY DAY WOULD COINCIDE ONCE EVERY 500 YEARS. PLEASE ADDRESS THAT CALCULATION.

A Mr. Siegele incorrectly calculates that the combination of a 1-in-10 peak demand day and a low-capacity day would occur once every 500 years, on the uninformed assumption that the two events are not correlated.[44] His own footnote concedes that if the events are correlated, the likelihood falls to somewhere between once every 10 years and once every 500 years.[45]

The record demonstrates that losses of flowing supply are correlated with regional cold weather. Several of the major upstream supply losses in the record occurred during regional cold extremes: Winter Storm Uri in February 2021, the January 2024 Arctic Blast, and Winter Storm Fern in January 2026, which arrived while Line 225 was out of service.[46] Cold weather in the producing basins is what reduces production

[42]Sawin Rebuttal at AJS-16 to AJS-18, citing D.26-02-058 at 156; Chang Rebuttal at SCC-10 to SCC-12.

[43]Letter from Leuwam Tesfai, CPUC Energy Division, to Rodger R. Schwecke, SoCalGas, regarding the Aliso Canyon Withdrawal Protocol (September 15, 2023).

[44]Siegele Direct at 53 and fn. 159.

[45]Siegele Direct at 53, fn. 159.

[46]Collins Direct at 7-10, 27-35; Sawin Rebuttal at AJS-13 to AJS-15; Siegele Direct at 52-53.

and diverts supply away from California to other markets. Mr. Siegele's count of low-capacity days also uses posted receipt capacity, but in SoCalGas's analysis, 2,416 MMcfd is flowing supply rather than capacity. His count therefore misses days such as those during Winter Storms Uri and Fern, when capacity was posted but the gas did not arrive and storage was drawn heavily even though Southern California weather was mild. Regional cold weather and low flowing supply are not independent events. Mr. Siegele's independence assumption does not hold.

Q AT PAGES 2 AND 5-8 OF HIS TESTIMONY, MR. SIEGELE ARGUES THAT ENERGY DIVISION'S GAS BALANCE ANALYSIS SHOWS ONLY 30.2 BCF OF ALISO CANYON INVENTORY IS NEEDED. DO YOU AGREE?

A No. A gas balance is a daily volume calculation; it asks whether enough gas exists over the winter withdrawal season. It does not ask whether the gas can be delivered at the rate the system needs on the peak day. Energy Division's hydraulic model, which does ask that question, required a 550 MMcfd withdrawal from Aliso Canyon on the winter 2025-26 peak day; without that withdrawal, system linepack fell by 547.1 million cubic feet, which Energy Division found would likely have caused pressures to drop below minimum operating levels.[47] Deliverability falls as inventory and storage reservoir pressure fall, so a field held at 39.6 Bcf would have less ability to sustain that withdrawal rate over a multi-day event than a field held at 68.6 Bcf. Energy Division does not appear to have read the 30.2 Bcf gas balance result as supporting a 38.4 Bcf reduction. Rather, after considering all four of its analyses (demand reduction, gas balance reliability, hydraulic modeling, and economic) Energy Division recommended a reduction of up to

[47] 2025 Biennial Assessment at 16; Sawin Rebuttal at AJS-2 to AJS-3.

10 Bcf and noted that, given forecasts of higher gas prices for winter 2026-27, the Commission may wish to consider a smaller reduction or no reduction.[48]

B. Extreme Events Are Multi-Day Supply-Loss Events, and Supply Loss Coincides with Regional Cold Weather

Q WHY SHOULD THE ANALYSIS OF ALISO CANYON INCLUDE A FOCUS ON MULTI-DAY EVENTS?

A Because storage inventory, which is distinct from daily withdrawal capacity, is what a multi-day event consumes. A one-day cold snap is served by the withdrawal rate from storage. However, a nine-day event such as the recent Winter Storm Fern is served by robust storage inventory: withdrawal must be sustained day after day while reservoir pressure declines, and the field must still have enough gas and pressure at the end of the event to respond to whatever comes next. Sierra Club's UBS analysis treats storage as a daily-rate resource and asks only whether a storage customer's daily capacity withdrawal right survives a reduction in inventory.[49] That framing misses the function of the inventory at Aliso Canyon, which is to supply gas for as long as an extreme event lasts, not just on its first day.

Q WHAT DID WINTER STORM FERN SHOW?

A Winter Storm Fern is the most recent example of a multi-day event that demonstrates the value and importance of storage inventory. From January 23 through January 31, 2026, nine consecutive days, SoCalGas withdrew more than 8 Bcf from its storage fields. Storage supplied nearly 60% of system demand at the storm's peak, and Aliso Canyon alone supplied about 30% of all gas delivered to the SoCalGas and SDG&E system at the peak. SoCalGas reports that, instead of purchasing gas in the market at

[48] 2025 Biennial Assessment at 1, 5, 28-29; Sawin Rebuttal at AJS-3.

[49] Siegele Direct at 38-41.

about $30 per decatherm during the storm, it supplied customers with gas that had been stored when prices were about $3 per decatherm, and it estimates that storage helped customers avoid more than $120 million in potential energy costs.[50] The volume withdrawn is not the measure of the need. Aliso Canyon could supply about 30% of deliveries at the peak because the field was full enough to sustain high withdrawal rates day after day; withdrawal capability depends on reservoir pressure, which in turn depends upon inventory.[51]

The supply side of the Winter Storm Fern event is equally important. System-wide RPU fell to about 25%, with the Northern Zone at 9% and the Wheeler Ridge Zone at 69%, while Line 225 was still out of service.[52] The joint staff review of the winter 2026 Arctic events by the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation found that near-record natural gas storage withdrawals supported electric reliability.[53] Southern California weather during Winter Storm Fern was comparatively mild. Had the same loss of flowing supply coincided with a Southern California cold event, the draw on inventory would likely have been larger, not smaller.

[50]SoCalGas, Regional Natural Gas Storage Helped Southern Californians Avoid Over $120 Million in Energy Costs During Winter Storm Fern (April 1, 2026); Chang Rebuttal at SCC-3 to SCC-4 and Figure 2; Collins Direct at 10.

[51]Sawin Rebuttal at AJS-17.

[52]Sawin Rebuttal at AJS-10 and Figure 1, AJS-15; SoCalGas Compliance Filing Regarding External Outages (May 1, 2026) at 15-17; Collins Direct at 34.

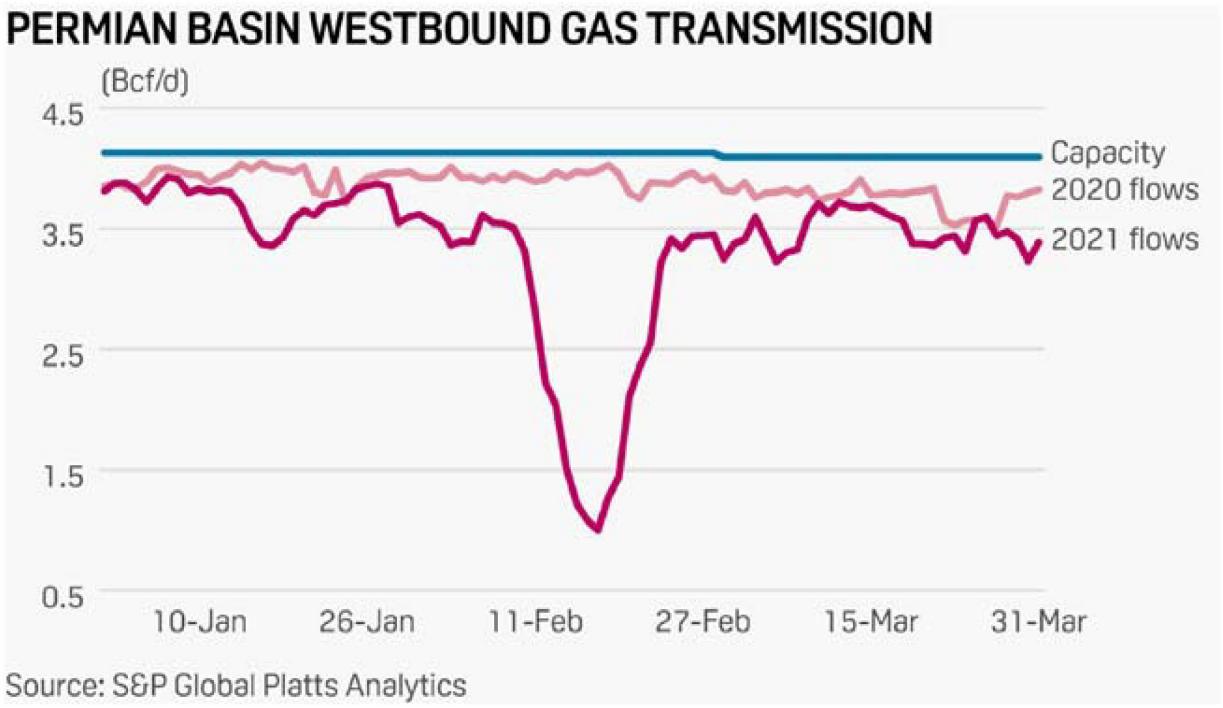
[53]FERC, NERC and Regional Entities, Winter 2026 Arctic Events: A System Performance Review (September 10, 2026) at 27, 36, as quoted in Sawin Rebuttal at AJS-10, fn. 41.

Q AT PAGES 27-28 AND 32 OF HIS TESTIMONY, MR. SIEGELE ARGUES THAT LOW RPU REFLECTS CUSTOMER SCHEDULING CHOICES RATHER THAN A LACK OF SUPPLY. HOW DO YOU RESPOND?

A I respond with the evidence from Winter Storm Uri in February 2021, which I presented in my sur-rebuttal testimony in I.17-02-002 in response to the same argument.[54] During Uri, westbound gas transmission out of the Permian Basin, which normally had a capacity of more than 4.0 Bcf per day, dropped to approximately 1.0 Bcf per day. Figure 1 below reproduces the S&P Global Platts chart of Permian westbound flows during that event.

[54] I.17-02-002, Sur-Rebuttal Testimony of Brian C. Collins on behalf of Indicated Shippers, Exhibit IS-3 (February 8, 2023) ("IS-3") at 7-8 and Figure 1.

Figure 1: Permian Basin Westbound Gas Transmission, February 2021



Source: Exhibit IS-3 at 8, Figure 1 (S&P Global Platts, SoCal Gas summer 2021 forward curve hits 3-year high amid mounting supply concerns, March 31, 2021).

Commission staff reported after the Winter Storm Uri event that gas suppliers sourcing from the Permian Basin did not fully deliver their firm supply contracts, leaving their customers with less gas than expected, and that the impact on Southern California was reduced gas availability and dramatically higher spot prices for several days.[55] System RPU fell to 47%.[56] Aliso Canyon withdrawals during the Winter Storm Uri event reached 508 MMcfd on February 15, 2021, under a 34 Bcf inventory cap.[57]

Firm contracts that are not delivered are not a scheduling choice. Mr. Siegele's own source makes the point. He relies on the finding in the FTI Phase 3 research

[55]CPUC Staff, Summer 2021 Southern California Gas Reliability Assessment (May 17, 2021) at 7; see also CPUC Staff, Winter 2020-2021 Southern California Gas Conditions and Operations Report (October 24, 2022) ("Winter 2020-21 Operations Report") at 4.

[56]Sawin Direct at AJS-6.

[57]Summer 2021 Southern California Gas Reliability Assessment at 3, 9, Table 3.

presentation (Exhibit SC-13) that the February 2021 drop in RPU was "a direct response to high gas prices at the SoCal Border."[58] A price response of that kind is exactly what happens when the producing basins are cold and supply is bid away to other markets. Whether the gas was not delivered to California because it froze off, because it was diverted, or because a customer declined to pay the price, the operational result is the same: it did not enter the SoCalGas system, and storage inventory was used to serve the load.[59] The high border prices that FTI identified and the reduced supply that Commission staff reported are the same event seen from two sides. When Permian production fell and the remaining supply was bid to other markets, less gas was available to reach California and the price of the gas that did arrive increased significantly. Commission staff described the two together, reporting reduced gas availability and dramatically high spot prices for several days.[60]

V. STORAGE INVENTORY AND PRICES

A. Insurance Has Value When It Is Not Used

Q AT PAGES 38-39 OF HIS TESTIMONY, MR. SIEGELE ARGUES THAT UBS PROGRAM INVENTORY HAS NEVER EXCEEDED 14.2 BCF. WHAT IS YOUR RESPONSE?

A To use the insurance analogy, Mr. Siegele's argument measures the value of insurance provided by Aliso Canyon by the claims paid, not by the risk that was mitigated by the insurance. Mr. Siegele's 14.2 Bcf figure is a maximum end-of-day balance over two

[58]Siegele Direct at 27, citing Exhibit SC-13 at 32.

[59]Sawin Rebuttal at AJS-8.

[60]Summer 2021 Southern California Gas Reliability Assessment at 7; Winter 2020-21 Operations Report at 4 (Permian Basin production dropped by 25 percent, and with supply down and demand up, spot prices rose to historic highs) and 5 (reductions in noncore demand reflected shippers' economic response to the interaction of price and availability, resulting in gas directed away from California to higher-price areas); IS-3 at 8.

winters.[61] It does not ask what the inventory was worth on the days it was not drawn. The Commission answered that question when it adopted the biennial assessment framework: natural gas storage functions as an insurance policy, or buffer, against high market prices during high-demand periods, even when it is not utilized to its fullest extent.[62] A policyholder who did not file a claim last year did not waste the insurance premium.

I also note that the 14.2 Bcf figure rests on Data Request 1-19 data, certain of which SoCalGas has since stated require correction and supplementation.[63] Even on the data as provided, the picture is one of active use of storage inventory rather than idle inventory: over the period Sierra Club analyzed, UBS customers injected more than 49 Bcf, withdrew more than 52 Bcf, and conducted more than 11 Bcf of net trade injection and withdrawal activity.[64] An end-of-day inventory balance is a snapshot; it does not record the total volume of gas that was cycled.

Q AT PAGES 33-37 OF HIS TESTIMONY, MR. SIEGELE ARGUES THAT THE PRICE HISTORY SINCE 2015 SHOWS INVENTORY CAN BE REDUCED WHILE MAINTAINING REASONABLE PRICES. WHAT DOES THE MOST RECENT WINTER SHOW?

A Low prices in a winter that began with full storage are what the inventory is supposed to produce. The Energy Information Administration found that higher-than-average storage levels in the Pacific region contributed to California's relatively low natural gas prices in early 2026. A forward price set in the spring, when the market can see that the fields will

[61]Siegele Direct at 2, 38-39 and Figure 8.

[62]D.24-12-076 at 29-30, 72 (Finding of Fact 14); see also id. at 17, fn. 30; Collins Direct at 9.

[63]Chang Rebuttal at SCC-8, fn. 12 (SoCalGas Supplemental Response to Sierra Club Data Request 1-19, April 24, 2026).

[64]Chang Rebuttal at SCC-9 to SCC-10 and Figures 4 and 5.

be full, reflects the same thing: the market prices the scarcity that robust storage removes. The record example of the consequences of low storage is winter 2022-23, for which SoCalGas and SDG&E estimated, in figures the Commission recited in D.24-12-076, that the lower inventory limit cost customers about $307 million in additional gas procurement.[65] Reading a low price as a reason to reduce the inventory that helped produce it reverses cause and effect.

B. Dr. Berardi's Findings

Q WHAT DOES THE ANALYSIS OF DEMAND PREDICTABILITY AT PAGES 16-17 OF DR. BERARDI'S TESTIMONY SHOW?

A Dr. Berardi fits a regression of daily demand on heating degree days for ten winters and finds that the model's prediction errors increase significantly as heating degree days increase; in his words, gas demand becomes measurably less predictable as temperatures grow colder.[66] His finding supports the opposite conclusion from the one Mr. Siegele draws. If demand on the coldest days is harder to forecast, the system needs more margin on those days, not less. SoCalGas makes the same observation.[67]

Q WHAT DOES THE WITHDRAWAL REGRESSION AT PAGES 20-25 OF DR. BERARDI'S TESTIMONY SHOW?

A Dr. Berardi regresses daily storage withdrawals on daily demand and on daily price for each of 18 winter seasons, and in a combined model, and finds that demand explains far more of the variation in withdrawals than price does. He concludes that Aliso Canyon inventory has very limited impact on price.[68]

[65]Chang Rebuttal at SCC-2, citing EIA, California natural gas prices reach historic lows in early 2026 (June 2, 2026); D.23-08-050 at 10-11; D.24-12-076 at 29-30.

[66]Berardi Direct at 16.

[67]Martinez Rebuttal at EJM-10 to EJM-11.

[68]Berardi Direct at 20-25.

That conclusion does not follow from the analysis. No party disputes that withdrawals follow demand. Storage is withdrawn when customers need gas. The question in this proceeding is whether the inventory available to be withdrawn affects the price customers pay, and a regression of withdrawals on price does not test that question. In my view, the inventory's effect on price operates primarily through supply optionality during stress events, when market participants know that stored gas is available and price the scarcity accordingly. On the days Dr. Berardi's regression treats as ordinary observations, the inventory is silently doing its price mitigation work without being withdrawn.

Dr. Berardi's own results and SoCalGas's operating data point the same way. Although demand explains more of the day-to-day variation in withdrawals than price does, Dr. Berardi's regressions find that the relationship between withdrawals and price is statistically significant in 15 of the 18 winter seasons he examined.[69] SoCalGas's operating data, which compare each winter's average scheduled withdrawals with scheduled withdrawals on that winter's highest-priced day, show that withdrawals are generally higher on the peak-price day, indicating that customers draw on storage when prices are elevated.[70] In short, on the highest-priced days, customers drew more gas from storage, not less. Inventory definitely has an impact on pricing, and vice-versa.[71]

[69]Berardi Direct at 21, 23 (Figure 3).

[70]Chang Rebuttal at SCC-5 and Figure 3.

[71] 2025 Biennial Assessment at 2 ("Historically, having sufficient gas in storage has tended to prevent or mitigate the impact of high or volatile gas commodity prices."); D.24-12-076 at 29-30 and 72 (Finding of Fact 14); Chang Rebuttal at SCC-2 to SCC-3 and Figure 1; Berardi Direct at 21, 23.

VI. SIERRA CLUB'S OTHER EVIDENCE DOES NOT SUPPORT A REDUCTION, AND CAL ADVOCATES AGREES

A. Batteries and Resource Additions

Q AT PAGES 5 AND 17-19 OF HIS TESTIMONY, MR. SIEGELE CONTENDS THAT INSTALLED BATTERY CAPACITY HAS RESOLVED THE ELECTRIC RELIABILITY CONCERN. DO YOU AGREE?

A No. A four-hour battery does not serve a nine-day gas event; it shifts electric energy within a day, and it must be recharged before it can discharge again. SoCalGas addresses the FTI report and CAISO study that Sierra Club relies upon.[72] In summary, SoCalGas explains that in D.24-12-076 the Commission found the FTI shortfall analysis outdated, that Energy Division's own Phase 2 Additional Modeling Report found the withdrawal capacity needed from Aliso Canyon to be 177 to 277 MMcfd higher than FTI's shortfall, and that CAISO cautioned against relying on its 2023 special study for decision-making and the Commission did not rely on it.[73]

Q AT PAGES 2, 5 AND 17-19 OF HIS TESTIMONY, MR. SIEGELE POINTS TO 17,125 MEGAWATTS ("MW") OF INSTALLED BATTERY CAPACITY AND MORE THAN 29,000 MW OF RENEWABLE, BATTERY, AND IMPORT ADDITIONS SINCE 2022. DO THOSE RESOURCE ADDITIONS REDUCE THE NEED FOR ALISO CANYON INVENTORY?

A Not in any quantified or verifiable manner. First, electric generation is a large and continuing share of gas demand, and much of the installed gas-fired capacity is located within urbanized local capacity areas where siting of battery resources and transmission expansion is challenging. In Southern California, gas-fired generation is about 29

[72] Siegele Direct at 5-6, 16-19; Sawin Rebuttal at AJS-3 to AJS-6, AJS-20 to AJS-21.

[73] Sawin Rebuttal at AJS-4 to AJS-6, citing D.24-12-076 at 25 and 72 (Finding of Fact 11).

percent of forecast 2026 average-year throughput; statewide, utility-served electric generation is about a third of utility gas requirements.[74] On the 1-in-10 peak day, electric generation is roughly a quarter of SoCalGas system demand: 1,067 MMcfd of 4,504 MMcfd in the CEC's Winter 2025-2026 California Gas Reliability Assessment ("CEC Winter Assessment") and 1,201 MMcfd of 4,758 MMcfd in the 2026 CGR.[75]

Second, the battery and renewable resource additions Mr. Siegele describes are already inside the gas forecast the Commission uses. SoCalGas's electric generation forecast in the 2026 CGR is a power market simulation that assumes most of the Commission-adopted 2025 Preferred System Plan elements. It includes a significant amount of energy storage as well as significant renewable resources, and it uses the CEC's adopted 2025-2045 electricity demand forecast from the Integrated Energy Policy Report process. The CGR also notes that the 2025 Integrated Energy Policy Report projects increasing electric load driven by data center growth.[76] With those additions accounted for, the 2026 CGR electric generation peak-day forecast for the next two winters is 16 percent higher than the 2024 vintage, and it rises again from winter 2028-29 through 2030-31.[77]

[74]2026 California Gas Report at 7 (Table 1) and 10 (Table 4). In Southern California, electric generation served by SoCalGas (509 MMcfd) plus electric generation served through SDG&E, Vernon, and Ecogas (124 MMcfd) is 633 MMcfd of 2,207 MMcfd of total 2026 average-year requirements, or about 29 percent; the corresponding cold-year figures (Table 9 at 15) are 657 MMcfd of 2,299 MMcfd. Statewide, utility electric generation is 1,478 MMcfd of 4,281 MMcfd of utility requirements, about 35 percent.

[75]CEC, Winter 2025-2026 California Gas Reliability Assessment, CEC-200-2025-025 (October 2025) ("CEC Winter Assessment") at 25 (Table: noncore electric generation 1,067 MMcfd of 4,504 MMcfd on the 1-in-10 peak day); Lambert Direct at 1-8 to 1-9, Tables 1 and 2 (2026 CGR: 1,201 MMcfd of 4,758 MMcfd for winter 2026-27).

[76]2026 California Gas Report at 113-115 (SoCalGas electric generation forecast: power market simulation of all electric generation resources in the SoCalGas service territory; base case assumes most of the Commission-adopted 2025 Preferred System Plan, including Mid-Term Reliability compliance and "an aggressive amount of energy storage resources along with significant renewables resources"; electricity demand from the CEC's California Energy Demand Forecast, 2025-2045, adopted January 2026, mid demand case) and 44-45 (2025 Integrated Energy Policy Report Planning Scenario captures increasing electric load driven by data center growth; statewide modeling assumes 2026-2030 resource additions of about 6.5 GW per year based on 2024-2025 actual additions); Lambert Direct at 1-7 to 1-9, Tables 1 and 2.

[77]Lambert Direct at 1-9 and Table 2. The 2026 CGR electric generation peak-day forecasts for winters 2026-27 and 2027-28 are 16 percent above the 2024 vintage, and the forecast rises from winter 2028-29 through 2030-31, ending 34 percent above the 2024 vintage for 2030-31.

Higher electric generation demand is the primary reason the near-term gas forecast went up, not down, and the electric generators that meet that load are the noncore customers whose storage access is reduced first under Sierra Club's proposal.

B. The CEC Forecast Sierra Club Asks the Commission to Adopt

Q AT PAGES 55-57 OF HIS TESTIMONY, MR. SIEGELE RECOMMENDS THAT THE BIENNIAL ASSESSMENT USE THE CEC'S 1-IN-10 PEAK-DAY FORECAST INSTEAD OF THE CGR. WHAT DOES THE CEC FORECAST SHOW?

A It shows a system that needs storage inventory. The CEC Winter Assessment forecasts a SoCalGas 1-in-10 peak day of 4,504 MMcfd for winter 2025-26 and 4,531 MMcfd for 2026.[78] That is about 1% below the 2024 CGR forecast of 4,562 MMcfd used in the 2025 Biennial Assessment, and roughly 380 MMcfd above the 4,121 MMcfd threshold established for considering closure of Aliso Canyon.[79] Substituting the CEC forecast would not change the 2025 Biennial Assessment demand reduction analysis result.

More important is how the CEC clears the design day. In its peak-day gas balance for SoCalGas, total demand of 4,504 MMcfd against available pipeline capacity of 3,035 MMcfd leaves 1,469 MMcfd, about one-third of demand, to be met from storage withdrawals; the CEC assumes 2,000 MMcfd of withdrawal capability and finds no net shortfall.[80] That result assumes that SoCalGas's fields are at full capacity at the start of winter, which the CEC notes includes the 68.6 Bcf working gas limit at Aliso Canyon authorized in D.23-08-050.[81] The CEC also credits the increase from 41.16 Bcf to 68.6 Bcf as a step taken to support reliability and price stability, and identifies severe weather

[78] CEC Winter Assessment at 18 (Table), 25 (Table) and Appendix (1-in-10 forecasts for 2025 and 2026).

[79] 2025 Biennial Assessment at 6, 7 and Table 1; Siegele Direct at 55-57.

[80] CEC Winter Assessment at 25.

[81] CEC Winter Assessment at 20-21 and Table 11.

and unplanned pipeline outages as the events that could significantly affect prices.[82] The CEC assessment that contains the forecast Sierra Club prefers reaches its no-shortfall result with Aliso Canyon at 68.6 Bcf.

C. FTI's Receipt Point Utilization Statistics

Q AT PAGES 27-28 AND 59-61 OF HIS TESTIMONY, MR. SIEGELE RELIES ON FTI'S FINDING THAT RPU AVERAGED 97.2% IN WINTER 2019-20 TO SUPPORT A 97% RPU PLANNING ASSUMPTION. HOW DO YOU RESPOND?

A First, FTI's statistics are seasonal averages and high-sendout-day averages from the winters of 2018-19 through 2020-21.[83] Averages across those winters describe typical conditions; they do not describe what the system delivered during a regional supply-loss event. The same FTI analysis explains that the February 2021 drop in RPU was a direct response to high border prices,[84] which is the supply-loss event. Second, the entire FTI period was under the Aliso Canyon Withdrawal Protocol, when Aliso Canyon withdrawals were restricted and the system relied more heavily on flowing supply; the Protocol was removed in September 2023.[85] Third, Energy Division's own Phase 2 Modeling Report observed that receipt point utilization tended to decrease on high demand days.[86]

Mr. Siegele's 97% proposal is also consequential in a way his testimony does not acknowledge. SoCalGas's peak-day analysis for winter 2025-26, which tests whether the system can serve a 1-in-10 cold day of 4,562 MMcfd, indicates that serving the 1-in-10 day at 68.6 Bcf already requires about 91% RPU, and that a reduction to 58.6 Bcf

[82]CEC Winter Assessment at 2, 29, 32.

[83]Siegele Direct at 27-28, citing Exhibit SC-13 at 30-35.

[84]Siegele Direct at 27, citing Exhibit SC-13 at 32.

[85]Sawin Rebuttal at AJS-8; Letter from Leuwam Tesfai, CPUC Energy Division, regarding the Aliso Canyon Withdrawal Protocol (September 15, 2023).

[86]I.17-02-002, Aliso Canyon Phase 2 Modeling Report (January 26, 2021) at 84, as cited in Sawin Rebuttal at AJS-8.

would require about 97%.[87] A 97% assumption therefore does not describe the system; it describes the performance that would be required only after the storage inventory margin has been removed. The events I describe in Section IV.B, with RPU at 47% in February 2021 and 25% in January 2026, are the reason that the 97% RPU assumption should not be used.

D. Cal Advocates' Testimony

Q WHAT IS CAL ADVOCATES' POSITION?

A Cal Advocates appropriately recommends that the Commission retain the current 68.6 Bcf maximum inventory.[88] Mr. Lambert makes four cogent points. First, the economic trigger in Attachment A is one-directional. If forward Southern California prices for the coming winter are 50% or more above Henry Hub prices or above prices in recent winters, Energy Division must recommend no reduction, but falling short of 50% does not require a reduction. The 2025 Biennial Assessment found forward SoCal Citygate prices for winter 2025-26 about 39% above Henry Hub and 36% above the prior two winters, which are substantial premiums. I would add that Staff's supplemental comparison for winter 2026-27 showed a 57% premium over Henry Hub during the same trade dates, and while Staff then reported a decline to 42%, SoCalGas indicates this reflects use of the wrong months; where the December through February basis the Decision prescribes is utilized, the September 1, 2025 premium was about 56%.[89] Second, a 10 Bcf reduction would eliminate 40% of a fully subscribed UBS Program, and the market impacts of that loss, including on wholesale electricity prices, are not

[87] Sawin Direct at AJS-18 to AJS-20 and Table I-3; Sawin Rebuttal at AJS-9.

[88] Lambert Direct at 1-1, 1-5.

[89] Lambert Direct at 1-5 and fn. 37; 2025 Biennial Assessment at 24-26 and Tables 6 through 9; Dandridge Direct at MMD-3; Collins Direct at 18-19.

captured by the economic analysis.[90] Third, the 2026 CGR raises the near-term peak-day forecast, and the increase is driven primarily by electric generation demand, which relies on the UBS Program for access to storage.[91] Fourth, the zero-reduction end of Energy Division's 0-10 Bcf range is the prudent choice.[92]

With Cal Advocates, Indicated Shippers, and SoCalGas all recommending no reduction, Sierra Club's 29 Bcf proposal stands apart from those parties, and it stands outside the 10 Bcf per-cycle limit the Commission adopted in the Decision.

VII. ATTACHMENT A AND THE BIENNIAL ASSESSMENT FRAMEWORK (SCOPED ISSUE 2)

Q AT PAGES 54-55 OF HIS TESTIMONY, MR. SIEGELE PROPOSES TO REMOVE THE 10 BCF PER-CYCLE LIMIT ON ENERGY DIVISION'S RECOMMENDATIONS. DO YOU AGREE?

A No. The Commission adopted the 10 Bcf increment to avoid shocks to the market, fuel costs, and customer rates.[93] The limit matters because an inventory reduction is, as a practical matter, likely not reversible within a season. The 2023 correction is the example: the joint petition to raise the cap was filed on April 19, 2023, the Commission acted on August 31, 2023 in D.23-08-050, and the relief was only realistically available for the following 2023-2024 winter. The estimated $307 million in additional procurement cost from winter 2022-23 had been incurred before the petition was filed.[94] Injection-season physics and the length of the Commission's process mean that a mistake made in the fall is paid for all winter. A framework that limits each inventory capacity step-down to 10 Bcf limits the size of that mistake.

[90] Lambert Direct at 1-1, 1-5 to 1-7.

[91] Lambert Direct at 1-7 to 1-10 and Tables 1 and 2.

[92] Lambert Direct at 1-10.

[93] D.24-12-076 at 51; Siegele Direct at 54-55.

[94] D.23-08-050 at 4, 10-11; Collins Direct at 9, 18-19, 28.

Q AT PAGES 63-64 OF HIS TESTIMONY, MR. SIEGELE PROPOSES TO ELIMINATE THE HENRY HUB TRIGGER AND REPLACE THE FORWARD-PRICE TRIGGER WITH A COMPARISON OF LAST WINTER'S REALIZED PRICE TO A TEN-YEAR INFLATION-ADJUSTED AVERAGE. DO YOU AGREE?

A No. The Henry Hub comparison measures the scarcity premium that Southern California pays relative to the national market, which is the premium storage inventory insures against; Mr. Siegele's objection that Southern California prices have not tracked a national benchmark is a description of that premium, not an argument against measuring it.[95] The forward-price comparison is forward-looking by design: it asks what the market expects the coming winter to cost before the inventory decision for that winter is made. Mr. Siegele's proposal would compare last winter's realized price to a ten-year average, which detects a price spike only after customers have paid it.[96] The early-2026 price record discussed in Section V.A shows the same problem in reverse: a realized-price trigger would read low prices produced by full storage as a reason to reduce the inventory that produced them. Cal Advocates correctly observes that the existing trigger is one-directional and that the 2025 Biennial Assessment's 39% and 36% results,[97] while below 50%, are large.[98]

SoCalGas also proposes enhancements to the economic analysis, including summer-winter spread analysis, comparisons of SoCal Citygate to western basin benchmarks, and predictive price and storage-behavior analyses.[99] Those three

[95]Siegele Direct at 63; D.24-12-076, Attachment A at A-7 to A-8.

[96]Siegele Direct at 64.

[97] [97]Lambert Direct at 1-3. Forward SoCal Citygate prices were 39% higher than forward Henry Hub benchmark prices for winter 2025-26. Forward SoCal Citygate prices for winter 2025-26 were 36% higher than the previous two winters.

[98]Lambert Direct at 1-5 and fn. 37, 1-7.

[99]Chang Rebuttal at SCC-15 to SCC-16.

proposals are consistent with my recommendation that the economic analysis evaluate the price exposure of noncore customers and the UBS Program.

Q WHAT MODIFICATIONS TO THE RELIABILITY ANALYSIS DO YOU SUPPORT?

A The corrections that SoCalGas proposes in rebuttal are consistent with the recommendations in my direct testimony: apply RPU to the available receipt point capacity that remains after accounting for outages, rather than to nominal capacity; set the unplanned outage capacity reduction value in each assessment cycle rather than fixing it at 101.5 MMcfd; model outages by removing the affected assets from the hydraulic model and carrying the associated capacity reductions into the gas balance analysis; and evaluate December and January peak conditions, when the winter peak actually occurs.[100] The Line 225 outage, which removed about 650 MMcfd for about seven months, is the reason a fixed 101.5 MMcfd unplanned outage assumption is inadequate.

Q DOES THE TIMING OF THE NEXT ASSESSMENT AFFECT THE VALUE OF THESE CORRECTIONS?

A Yes. The corrections only help if Energy Division has them in hand well before the next biennial assessment report is prepared. The 2025 Biennial Assessment was due June 15, 2025 and was issued October 1, 2025, using the inputs Attachment A prescribes today; even so, the economic analysis did not evaluate the UBS Program, the supplemental winter 2026-27 forward price comparison appears to have used the wrong months, and the reliability analysis used the fixed outage allowance discussed above. The corrections in this section require Energy Division to build new inputs: outage cases in the hydraulic model, a per-cycle capacity outage value, and December and January

[100]Sawin Rebuttal at AJS-28 to AJS-29; Collins Direct at 6, 46-47; D.24-12-076, Attachment A at A-4 to A-5 (Table 1, Rows 3, 9 and 10).

peak conditions. If this instant proceeding is decided in the first half of 2027, little or no time would remain to do that work before a June 15, 2027 report deadline.[101] From a planning standpoint, an assessment prepared in 2028 on corrected inputs is more useful to the Commission than an assessment prepared in 2027 that repeats the flawed 2025 inputs. That is a basis for the one-year adjustment Indicated Shippers and SoCalGas have jointly requested in the petition for modification filed in I.17-02-002.

Q WHAT IS YOUR RESPONSE TO THE REMAINING ATTACHMENT A PROPOSALS AT PAGES 57-63 OF MR. SIEGELE'S TESTIMONY?

A Sierra Club also proposes that the storage withdrawal and injection inputs be set by Energy Division after stakeholder comment, that the modeling cover the upcoming winter and the two winters that follow in place of the winter five years out, and that summer modeling be eliminated.[102] SoCalGas explains that the storage injection and withdrawal curves reflect the physical characteristics of the fields and contain confidential operational data that Energy Division already obtains and evaluates, and that the existing framework already pairs the upcoming winter and summer with a preview approximately five years out.[103] SoCalGas does not address the proposal to eliminate summer modeling, and I add one point: summer modeling should be retained, because it is not rendered redundant by the addition of energy storage and renewable resources, despite the claims of Mr. Siegele.[104] The August 2020 and September 2022 heat events,

[101] D.24-12-076 at 77 (Ordering Paragraph 4, June 15 report date); 2025 Biennial Assessment (issued October 1, 2025) at 28 (economic analysis does not capture the impact of reductions to the UBS Program); Dandridge Direct at MMD-3 (apparent inconsistency in the forward price data set); Sawin Rebuttal at AJS-28 to AJS-29; Collins Direct at 46-47. The joint petition for modification filed by Indicated Shippers and SoCalGas in I.17-02-002 on August 21, 2026 requests that the next assessment be due June 15, 2028.

[102] Siegele Direct at 3, 61-63.

[103] Sawin Rebuttal at AJS-26 to AJS-27.

[104] Siegele Direct at 62.

and the August 2026 purchases described in Section III.B, all occurred in summer, when electric generation demand for gas is high.[105]

VIII. CONCLUSION

Q PLEASE SUMMARIZE YOUR REBUTTAL RECOMMENDATIONS.

A Regarding Scoped Issue 1, the Commission should maintain the Aliso Canyon maximum inventory at 68.6 Bcf. Since the Decision was issued, the insurance that Aliso Canyon inventory represents has been called upon at least twice during extreme events: by the Line 225 outage from December 2025 to August 2026, and by Winter Storm Fern in January 2026, when storage supplied nearly 60% of system demand at the peak while interstate deliveries fell to as little as 25% of capacity. The record shows the inventory has great reliability and price mitigation value, which is being used.

The Commission should reject Sierra Club's proposal to reduce the Aliso Canyon maximum inventory by 29 Bcf, to 39.6 Bcf. That proposal is imprudent because it rests on average conditions, exceeds the 10 Bcf per-cycle limit the Commission adopted, and would remove about 70% of the UBS inventory that noncore customers rely upon. Energy Division's up to 10 Bcf proposal should also be rejected for the reasons in my direct testimony.

On Scoped Issue 2, the Commission should keep the 10 Bcf per-cycle limit and the Henry Hub trigger, reject the 97% RPU and historical-average capacity assumptions, and adopt the corrections to the reliability analysis described in Section VII. Because those corrections require new modeling inputs, an assessment prepared in 2028 on corrected inputs, as requested in the joint petition for modification that Indicated

[105] Collins Direct at 49 (August 2020 heat event and September 2022 heat wave); Chang Rebuttal at SCC-13 (August 20-31, 2026 purchases).

Shippers and SoCalGas filed in I.17-02-002, would be more useful to the Commission than a 2027 assessment that repeats the flawed 2025 inputs.

Q WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION AND DIRECTION?

A Yes.

Q TO THE EXTENT IT REFLECTS A PROFESSIONAL OPINION, DOES IT REFLECT YOUR BEST PROFESSIONAL OPINION?

A Yes.

Q IS IT TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A Yes.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.