Docket No.: A.26-01-009
Exhibit No.: SC-01
ALJ: Jamie Ormond
Witness: Tyson Siegele

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 (Filed January 15, 2026)

DIRECT TESTIMONY OF TYSON SIEGELE ON BEHALF OF SIERRA CLUB

AUGUST 20, 2026

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1. INTRODUCTION

I evaluated the Southern California Gas Company's ("SCG" or "SoCalGas") application proposing to increase the storage inventory at the Aliso Canyon Gas Storage Facility. Throughout my testimony, I identify several problems with SoCalGas' application and recommendations, and I provide analysis explaining why the Commission should reduce gas storage inventory at Aliso Canyon and further refine the Biennial Assessment process. My qualifications are described in my resume, attached as Exhibit SC-03.

In Sections 2 through 4 of my testimony, I evaluate the reliability need for Aliso Canyon, the economic need for Aliso Canyon, the energy insecurity that accompanies continued reliance on natural gas, and the modeling criteria that govern the Aliso Canyon biennial assessment process. In Section 5, I review the Biennial Assessment process including the biennial modeling criteria detailed in Decision ("D.") 24-12-076's Attachment A, the Biennial Assessment Report Inputs and Methods ("Biennial Modeling Criteria").[1] That section focuses on:

- The amount by which Energy Division may recommend reducing the Aliso Canyon maximum storage inventory;
- The source of the 1-in-10 gas demand forecast used in the demand reduction analysis;
- The use of SoCalGas-defined inputs elsewhere in the modeling criteria;
- The individual modeling inputs specified in Table 1 of the Biennial Modeling Criteria; and
- The price inputs used in the economic analysis.

Finally, in Section 6, I examine the Aliso Canyon Disaster Area as defined in AB 157 and quantify the number of disadvantaged communities located within it. This section describes the toxic emissions those communities continue to experience and the ongoing role of Aliso Canyon in producing them.

[1] D.24-12-076, Attachment A, Biennial Assessment Report Inputs and Methods (Oct. 4, 2024) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K129/551129840.PDF [hereinafter "Biennial Modeling Criteria"].

The following is an overview of my findings:

- Energy Division's 2025 Biennial Assessment found that Aliso Canyon inventory could be reduced by 38.4 Bcf while still serving a 1-in-10 peak day, and it reached that result using conservative overlapping assumptions.
- Installed battery capacity in California Independent System Operator ("CAISO") territory has reached 17,125 MW, resolving concerns that closing Aliso Canyon could pose grid reliability shortfalls.
- Load-serving entities added 29,371 MW of renewable, battery, and import capacity between January 2022 and June 2026.
- Controlling for temperature, 2026 gas demand in SoCalGas was the lowest on record, 8.7 percent below 2025 demand across a primary winter temperature band.
- SoCalGas has no data showing that low receipt point utilization reflects low or limited gas supply, and the historical record shows customers scheduled nearly all available capacity when they chose to.
- Since the Aliso Canyon blowout, SoCalGas has never held less than 34.9 Bcf in storage, and it has no record of withdrawing storage to mitigate gas prices during price spikes.
- Unbundled Storage Program subscribers have never filled more than 14.2 Bcf of their 25 Bcf allocation since the re-opening of the program, and a 29 Bcf reduction at Aliso Canyon would not limit their winter withdrawal capacity.
- SoCalGas customers depend on gas that is 95.8 percent imported, delivered through infrastructure largely outside this Commission's jurisdiction.
- The Commission's Safety and Enforcement Division found SoCalGas responsible for both the Aliso Canyon blowout and the Line 235 rupture — two of the highest-volume and longest gas infrastructure outages of the last fifteen years.
- Revised inputs and assumptions for biennial assessment modeling would produce more accurate results.
- The Aliso Canyon Disaster Area encompasses disadvantaged communities that continue to be burdened with the facility's toxic emissions.

The following is a summary of my recommendations to the Commission:

- Aliso Canyon maximum storage inventory should be reduced by 29 Bcf before the upcoming 2027 Biennial Assessment.
- The Biennial Modeling Criteria should allow the Commission's Energy Division to recommend any maximum inventory level, rather than capping its recommendation at a 10 Bcf reduction.
- The 1-in-10 peak day gas demand forecast used in the demand reduction analysis should be produced by the California Energy Commission instead of by SoCalGas to ensure more realistic and reliable projections.
- The Biennial Assessment modeling inputs and assumptions should be produced by independent third parties such as the California Public Utilities Commission or the California Energy Commission instead of by SoCalGas.
- The demand variation input in Biennial Assessment modeling should be based on the most recent ten years rather than 2010 through 2019.
- The pipeline capacity input should be set to the historical winter average, and the receipt point utilization input should be set at no less than 97 percent of total receipt capacity.
- Storage withdrawal and injection rates and the Aliso Canyon maximum inventory input should be proposed by SoCalGas in a formal filing served on the service list each January 1, subject to comments by January 15, with Energy Division determining the values to be modeled.
- The modeling should evaluate the upcoming winter and the following two winters, and the summer modeling requirement should be eliminated.
- The economic trigger comparing Southern California gas prices to Henry Hub should be eliminated.
- The remaining economic trigger should compare the most recent past winter's actual average gas price to a ten-year inflation-adjusted average, rather than comparing a three-winter average to a forward price.

2. ALISO CANYON INVENTORY CAN BE REDUCED WITHOUT IMPACTING GRID OR GAS SYSTEM RELIABILITY, EVEN ASSUMING SOCALGAS'S HIGH 1-IN-10 GAS DEMAND FORECAST.

SoCalGas asks the Commission to retain Aliso Canyon's current maximum inventory level because it claims that reducing it would negatively impact gas and electric reliability in California.[2] However, the application fails to substantiate that request, and multiple analyses (including mine) demonstrate that Aliso Canyon's storage inventory can be reduced without threatening grid or gas system reliability on 1-in-10 peak demand days.

Gas reliability is measured against a defined standard, meeting a 1-in-10 peak gas demand. The independent analyses that have applied that standard — including analyses the Commission itself commissioned — do not support SoCalGas's position.

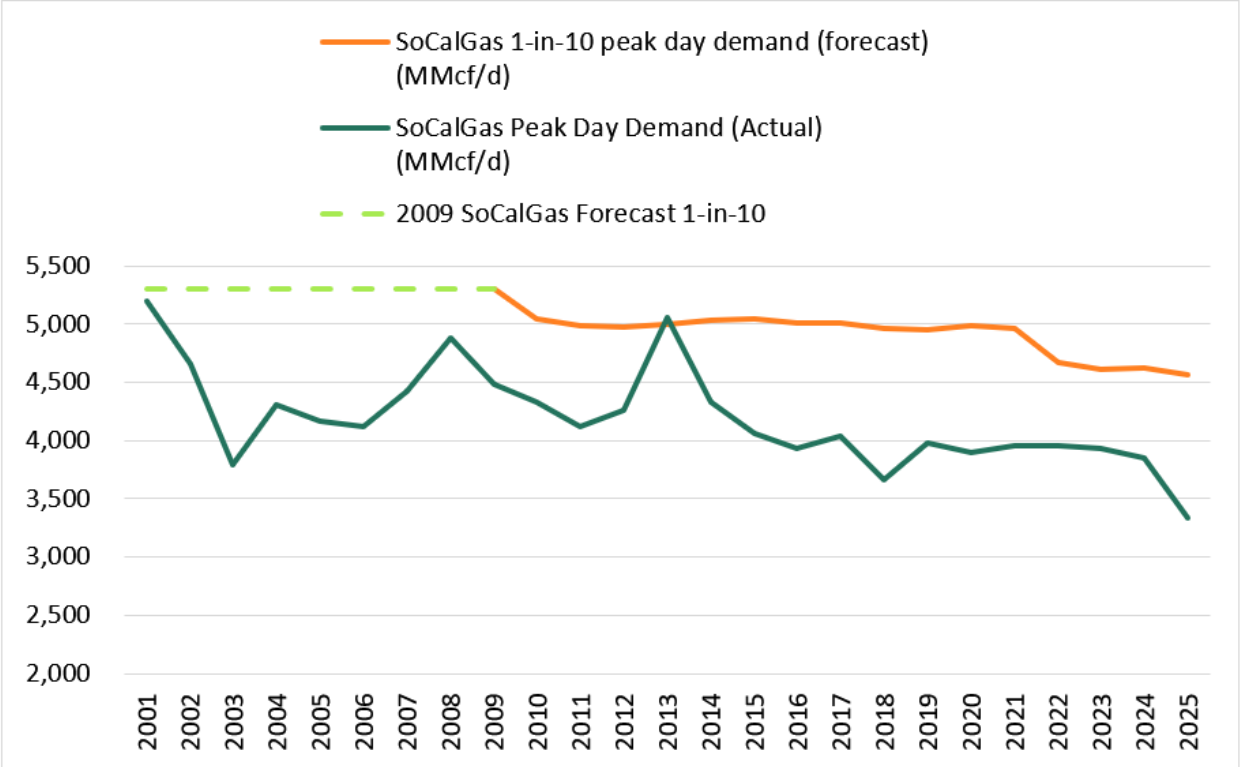
D.06-09-039 defines the 1-in-10 peak demand as the demand of core customers and firm-non-core customers during "a 1-in-10 year cold day event (one curtailment event in 10 years)."[3] Because the Southern California gas system is a winter-peaking system, the 1-in-10 peak cold day event is the highest winter gas demand day to be expected during a typical 10-year period. SoCalGas's 1-in-10 peak day demand is exceedingly conservative, as evidenced by the fact that it has occurred once in the 25 years of gas demand data SoCalGas has on record.[4]

[2] A.26-01-009, Application of Southern California Gas Company (U904G) in Compliance with Ordering Paragraph 6 of Decision 24-12-076, at 1-2 (Jan. 15, 2026) [hereinafter "SoCalGas Application"].

[3] D.06-09-039, Phase 2 Order Addressing Infrastructure Adequacy & Slack Capacity, Interconnection & Operational Balancing Agreements, an Infrastructure Working Group, Natural Gas Supply and Infrastructure Adequacy for Electric Generators, Natural Gas Quality, and Other Matters, at 49–50 (Sept. 21, 2006), https://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/60237.pdf.

[4] *See* Figure 1, below.

Figure 1: SoCalGas Peak Annual Demand and SoCalGas 1-in-10 Peak Day Forecast[5]



The sub-sections below review the reports, studies, and data that bear on whether Aliso Canyon is needed to serve peak gas demand. First, Energy Division's 2025 Biennial Assessment found that the Commission could reduce Aliso Canyon's maximum inventory by 38.4 Bcf while still serving a 1-in-10 peak day.[6] Second, while the Commission's consultant, FTI Consulting, Inc. ("FTI"), previously identified a three-hour, 3,176 MW electricity shortfall without Aliso Canyon,[7] installed battery capacity in CAISO service territory now stands at 17,125 MW, which

[5] SoCalGas Envoy, Daily Operations, https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternalDailyOperations.getDailyOperation; California Gas Reports 2008-2024, 1-in-10 gas demand forecasts, https://www.socalgas.com/regulatory/cgr; Exh. SC-05-CONF: SoCalGas Confidential Supplemental Response to Sierra Club Data Request 2-10 - Written Response (July 6, 2026); Exh. SC-18-CONF: SoCalGas Confidential Supplemental Response to Sierra Club Data Request 2-10 - Excel File (July 6, 2026) (only for data points regarding peak gas demand for years 2001-2004).

[6] California Public Utilities Commission ("CPUC") Energy Division, Energy Resource Modeling, *2025 Aliso Canyon Biennial Assessment Report Pursuant to D.24-12-076*, at 2, 4 (Oct. 1, 2025), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/2025_aliso_canyon_biennial_assessment.pdf [hereinafter "2025 Biennial Assessment"] (Aliso Canyon's maximum inventory of 68.6 Bcf).

[7] Investigation ("I.") 17-02-002, *Aliso Canyon I.17-02-002 Phase 3 Report: Assessment of Portfolio Solutions for Eliminating the Use of the Aliso Canyon Natural Gas Storage Facility by 2027 of 2035*, at

is 6,275 MW more than was needed to close the shortfall. Third, CAISO's 2023 study analyzed those findings and concluded that, if FTI's projected gas shortfall occurred on the peak gas demand day, 56 gas power plants could be curtailed and CAISO would still have sufficient resources to serve all electricity demand on that winter day, despite the curtailment of those gas plants. Fourth, between 2017 and 2021, the Commission and its staff found on five separate occasions that a fraction of Aliso Canyon was sufficient to maintain reliability — findings made before load-serving entities added 29,371 MW of renewable, battery, and import capacity. Finally, SoCalGas's own Envoy data show that temperature-controlled gas demand is declining, CAISO's monthly reports show renewable generation serving a growing share of peak demand, and SoCalGas's receipt point utilization ("RPU") data show that customers schedule nearly all available capacity when they need it. Each of these sources — the Commission's staff, the Commission's consultant, the grid operator, and SoCalGas's own operating records — supports a reduction in Aliso Canyon's maximum inventory. SoCalGas's application, which opposes any reduction, stands alone against them.

2.1. Every reliability assessment in this section, including the Biennial Assessment, finds that Aliso Canyon inventory can be reduced and still meet SoCalGas's forecast peak demand.

Three independent entities have evaluated whether Aliso Canyon inventory can be reduced without impairing electric reliability: Energy Division, CAISO, and the Commission's consultant. Each proceeded from SoCalGas's own forecast of 1-in-10 peak demand rather than from a lower planning forecast, and none found that its currently authorized inventory level results in grid reliability issues. Their findings are addressed in turn below.

2.1.1. Energy Division's 2025 Biennial Assessment found that the Commission could reduce Aliso Storage Capacity by 38.4 Bcf while serving the 1-in-10 peak demand.

In the 2025 Biennial Assessment, Energy Division completed an analysis of an outage scenario to evaluate the ability of SoCalGas's infrastructure to serve the 1-in-10 peak day

25, Figure 8 (Dec. 31, 2021) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M443/K009/443009051.PDF [hereinafter "I.17-02-002 Phase 3 Report"].

demand. Energy Division's 2025 Biennial Assessment produced an extremely conservative reliability assessment because its modeling depends on the overlap of several conservative inputs. The following table shows a selection of Energy Division assumptions for the report and quantifies the conservativeness of the input.

Table 1: 2025 Biennial Assessment Modeling Inputs

2025 Biennial Assessment Inputs	Input Conservativeness
SoCalGas 1-in-10 gas demand forecast	The peak day gas demand has exceeded SoCalGas's 1-in-10 forecasts on one day in 25 years.[8]
2,800 MMcfd pipeline flowing capacity	3,286 MMcfd: Average flowing capacity Dec–Feb, 2004-2025.[9] Average flowing capacity exceeds Energy Division's input.
Winter 2025-2026 battery and renewable capacity	Energy Division IRP staff expect 6,563 MW of new battery and renewable capacity by Dec 31, 2026,[10] (Energy Division's input was correct, but the 2025-2026 winter is now over and new resources are being added).

The 2025 Biennial Assessment scenario reflects inputs so rare that the hypothetical scenario has never occurred. The only day that SoCalGas customer gas demand exceeded SoCalGas's 1-in-10 peak demand forecast was January 14, 2013, when SoCalGas' total receipt capacity was 3,634 MMcfd.[11] However, the Biennial Report's low RPU assumptions effectively suggest SoCalGas' system has only 2,800 MMcfd in Total Receipt Capacity. The only time gas demand has exceeded SoCalGas's 1-in-10 peak demand forecast, the pipeline flowing capacity was more than 800 MMcfd higher than the 2025 Biennial Assessment's flowing supply

[8] *See* Figure 1.

[9] Exh. SC-06: SoCalGas Response to Sierra Club Data Requests 2-13 and 2-14 (May 28, 2026).

[10] *See* Table 2. *See also*, CPUC Staff Report, Resource Tracking Data, Data current as of June 2026, at 15, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-june-2026-release.pdf.

[11] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (On January 14, 2013, SoCalGas' reported Total Receipt Capacity was 3,740,193 Dth, equivalent to 3,634 MMcfd assuming 1,029.3 Dth = 1 MMcf.).

assumption.[12] Many, if not all, of the assumptions used by Energy Division in the 2025 Biennial Assessment were requirements established by the Commission in D.24-12-076, Attachment A. Those inputs should be updated and are discussed further in Section 5.

In the 2025 Biennial Report's modeling scenario that is so conservative that it has never occurred in real life, Energy Division found that gas demand could be served by SoCalGas's storage infrastructure at 44% of the current Aliso Canyon maximum inventory limit.[13] That equates to a new Aliso Canyon inventory limit of 30.2 Bcf and a storage capacity reduction of 38.4 Bcf.[14]

2.1.2. CAISO's 2023 reliability analysis found that electricity reliability would be maintained without Aliso Canyon.

CAISO completed an analysis in 2023 that found gas and electric reliability could be maintained without Aliso Canyon.[15] The CAISO analysis aimed to test an FTI finding that on the 1-in-10 peak demand day, "56 generating facilities would be required to be curtailed in the absence of the Aliso Canyon gas storage."[16] CAISO tested FTI's finding by modeling the identical 56 gas-fired generators named by FTI as curtailed on a 1-in-10 peak demand day.[17]

CAISO found that on a 1-in-10 peak gas demand day, all 56 gas-fired could be curtailed and still all of CAISO electric demand would be served.[18] CAISO assumed the renewable and battery storage resources that had been ordered by the Commission at the point of the study (before 2023) and assumed that all CAISO transmission projects that were scheduled to be completed by 2032 were operational.

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[12] *Id.* (*See* "Total Receipt Capacity" reported for January 14, 2013); *See also*, footnote 162; Calculation 3,634 MMcfd – 2,800 MMcfd = 834 MMcfd.

[13] 2025 Biennial Assessment at 12, Table 4.

[14] *Id.*; Calculation: 68.6 Bcf – 30.2 Bcf = 38.4 Bcf reduction.

[15] 2022-2023 ISO Transmission Plan, Appendix K: Informational Special Study of Reduced Reliance on Aliso Canyon Storage – Assumptions, Study Results and Alternative Analysis at K-6 (May 10, 2023), http://www.caiso.com/Documents/Appendix-K-Revised-Draft-2022-2023-Transmission-Plan.pdf [hereinafter "CAISO Aliso Special Study"] ("2032 Winter peak load conditions did not result in transmission reliability concerns in the LA Basin and San Diego-Imperial Valley area, provided that the remaining gas-fired generation resources are available.").

[16] *Id.* at K-3.

[17] *Id.* at K-4, K-5.

[18] *Id.* at K-6.

In contrast, FTI assumed battery storage capacity in 2027 that is less than half the battery storage capacity that is currently online in CAISO's service territory.[19] If FTI had modeled the grid's current battery storage capacity, it would have found no gas shortfall during the 1-in-10 peak demand day in 2027.[20] Regardless, CAISO's study assumed the inaccurately low FTI battery inputs to determine if FTI-outputs requiring the curtailment of 56 gas-fired power plants would result in an electricity shortfall.

Electricity demand in California peaks during the late summer, yet even on those summer days, demand for gas is much lower than on peak winter days. Gas demand for winter space heating plus winter gas-fired electricity generation significantly exceeds the gas demand for gas-fired generators on peak summer days. For example, CAISO reports the highest-ever instantaneous load on its system occurred on September 6, 2022, reaching 52,061 MW.[21] SoCalGas reports gas demand for that same day was 3,235 MMcfd,[22] which is 68% of SoCalGas's 2026 forecast of the 1-in-10 peak gas demand of 4,758 MMcfd (a forecast for gas demand on a winter day).[23]

New clean grid resources are further eroding the grid's need for Aliso Canyon. In recent years, CAISO data shows generation from solar resources has steadily increased, while gas plant

[19] *See* Figure 2; FTI's supporting materials in the file "Detailed Power Market Modeling Inputs and Results" projected 7,673.79 MW of battery storage in 2027 when summing the "2027 Max Power (MW)" column of the Base Batteries sheet, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/fti-phase-3-final-report-supporting-materials.zip. CAISO reports 17,125 MW of installed battery capacity. CAISO, *Key Statistics*, July 2026, at 2, https://www.caiso.com/documents/key-statistics-jul-2026.pdf. Calculation: 7,673.79 MW ÷ 17,125 MW = 0.448 = 45%.

[20] *See* Figure 3, below (the 3,176 MW of four-hour battery capacity required to cover the three-hour shortfall FTI identified); I.17-02-002 Phase 3 Report at 25, Figure 8.

[21] CAISO, *Key Statistics*, July 2026, at 1, https://www.caiso.com/documents/key-statistics-jul-2026.pdf ("Peak Demand 52,061 MW Sept. 6, 2022 at 4:57 p.m").

[22] SoCalGas Envoy, Daily Operations, https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternalDailyOperations.getDailyOperation (3,330,000 Dth, converted to 3,235 MMcfd using 1,029.3 Dth/MMcf conversion factor. This conversion factor is used throughout my testimony unless noted otherwise); Southern California Gas Company, *2026 California Gas Report* at 129, Table 38 (July 1, 2026) https://www.socalgas.com/sites/default/files/2026-07/2026_California%20_Gas_Report.pdf [hereinafter "2026 California Gas Report"].

[23] Calculation: 3,235 MMcfd / 4,758 MMcfd = 0.6799075 = 68%.

generation tends to decrease, most noticeably in the spring months.[24] From the start of 2023 through June 2026, California utilities added 25,240 MW of renewable energy, battery storage, and import capacity to the grid.[25] This additional renewable and battery capacity will decrease the need for Southern California gas-fired generation on peak summer electricity demand days compared to prior years.

The 2023 CAISO study lacked inputs on summer gas reductions and acknowledged critical information limitations for properly assessing summer grid reliability. CAISO cautioned the Commission against using the CAISO's Aliso Canyon special study's finding on summer grid impacts, stating that "these results are preliminary, and the usefulness of the study when concluded in March [2023] will remain limited until appropriate inputs are available to the CAISO."[26] The CAISO further noted that "the ISO does not support this [November 17, 2022] presentation or comments made in discussing this presentation with stakeholders being relied upon for decision-making."[27] The letter explicitly states the data it needs to complete a study that could be relied upon:

> [F]or the study inputs, [CAISO] would utilize as much public information as possible, but it might need to fill in gaps with its own assumptions on possible summer gas reductions. Without the appropriate input assumptions on the summer gas reductions specific to the local capacity areas impacted, the CAISO used winter assumptions as a placeholder. Therefore, the special study applies gas limitations in the *winter* to assess potential impacts in the *summer* when the electrical system is at peak.[28]

Thus, out of an abundance of caution, CAISO effectively applied the peak 1-in-10 winter gas demand to summer conditions by curtailing 56 gas-fired generators in Southern California

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[24] U.S. Energy Information Administration, "Solar generation in CAISO surpassed natural gas in the first five months of 2026," (June 16, 2026) https://www.eia.gov/todayinenergy/detail.php?id=67784.

[25] CPUC Staff Report, Resource Tracking Data, Data current as of June 2026, at 6, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-june-2026-release.pdf (*see* row "Total New Resources, including Imports" minus "NATURAL GAS, incl. Alamitos & Huntington Beach" for years 2023-2026).

[26] Exh. SC-08: CAISO Letter from Vice President Neil Millar to CPUC President Alice Reynolds and Administrative Law Judge Zhen Zhang at 3 (Nov. 23, 2022) [hereinafter "CAISO Aliso Letter"].

[27] *Id.* at 1.

[28] *Id.* (emphasis added).

during its summer peak modeling run.[29] Assuming winter gas demand, summer electricity demand, and 56 curtailed generators, CAISO found load-pocket failures would occur during the summer.[30] However, those CAISO assumptions were inaccurate and inappropriate for the summer months as summer gas demand is much lower than winter gas demand. As noted above, gas demand on the record high electricity demand day represented only 68% of the forecast peak winter gas demand.[31] In summary, CAISO found that on a 1-in-10 peak gas demand day, all 56 gas-fired could be curtailed and still all of CAISO electric demand would be served,[32] and its summer input assumptions were not accurate and thus, CAISO stated that they should not be used. The Biennial Assessment however did review summer with appropriate inputs.

The 2025 Biennial Assessment concluded that Aliso Canyon is not needed to sustain summer grid reliability. It found that "[f]or summer 2026, the hydraulic modeling analysis indicates that Aliso Canyon is not needed to maintain gas system reliability."[33] To be clear, the 2025 Biennial Assessment goes on to state "[h]owever, the simulation highlights some difficulties managing the evening ramp, associated with the so-called 'duck curve.'"[34] These ramping concerns are managed today and are decreasing rapidly for multiple reasons. First, CAISO can reliably forecast solar output in advance (i.e. the sun goes down at the same time every day) and enable gas turbines more than sufficient time to ramp to meet projected load.[35] Second, the additional battery capacity over the recent years, which currently exceeds 17,000 megawatts, enables near instantaneous ramping of electricity supply and no longer depends on the multi-hour ramp required by combined-cycle gas-fired resources. The steepest 3-hour ramp

[29] *Id.*

[30] CAISO Aliso Special Study at K-6.

[31] SoCalGas Envoy, Daily Operations, https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternalDailyOperations.getDailyOperation (3330000 Dth, converted to 3235 MMcfd using 1,029.3 Dth/MMcf conversion factor); 2026 California Gas Report at 129, Table 38 (4,758 MMcfd); Calculation: 3,235 MMcfd / 4,758 MMcfd = 0.6799075 = 68%.

[32] *Id.* at K-6.

[33] 2025 Biennial Assessment at 20.

[34] *Id.*

[35] Pascal Decoussemaeker, GE, *Startup Time Reduction for Combined Cycle Power Plants*, 8th International Gas Turbine Conference, at 4 (Oct. 12, 2016) https://etn.global/wp-content/uploads/2018/09/STARTUP-TIME-REDUCTION-FOR-COMBINED-CYCLE-POWER-PLANTS.pdf (cold start: Phase 1, 20–25 min.; Phase 2, 80 min.; Phase 3, 45 min. Warm start: Phase 1, 20–25 min.; Phase 2, 50 min.; Phase 3, 45 min.).

on record is 24,567 MWh.[36] If split evenly across the 3-hour window, the ramp is an increase of 8,189 MW of electricity demand each hour. That means CAISO's battery capacity of greater than 17,000 megawatts can cover any instantaneous shortfall even if CAISO were to wait until the ramp started before it called the first gas-fired power plant.[37] Current data show that CAISO effectively manages the evening ramp without significant difficulty and the summer gas demand can be served without Aliso Canyon.

2.1.3. The Commission's own precedent includes five prior findings that a fraction of Aliso Canyon's storage capacity would maintain reliability.

From January 2022 through June 2026, electricity load serving entities added 29,371 MW of renewable capacity, battery capacity, and import capacity.[38] However, before those new resources started commercial operations, the Commission and Commission staff determined on numerous occasions that just a fraction of Aliso Canyon was needed to maintain energy reliability. Table 2 below shows five of those findings.

Table 2: Chronology of Aliso Canyon Storage Limits

Date	Limit (Bcf)
July 19, 2017	CPUC Executive Director: 23.6 Bcf limit "needed to maintain reliability"[39]

[36] CAISO, *Key Statistics*, July 2026, at 1, https://www.caiso.com/documents/key-statistics-jul-2026.pdf ("Peak Demand 52,061 MW Sept. 6, 2022 at 4:57 p.m").

[37] From a cold start, gas-fired power plants take anywhere from a few minutes to a few hours to ramp depending on the type of plant and the capability of the plant. Some of the slowest gas power plants take hours to fully ramp but ramp relatively quickly after the first two hours of operation. From a warm start or hot start, which is a more reasonable assumption to address a daily ramp, ramp times drop considerably compared to a cold start.

[38] CPUC Staff Report, Resource Tracking Data, Data current as of June 2026, at 6, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-june-2026-release.pdf (*see* row "Total New Resources, including Imports" minus "NATURAL GAS, incl. Alamitos & Huntington Beach" for years 2022-2026).

[39] CPUC Letter from Executive Director Timothy J. Sullivan to SoCalGas Senior Vice President Rodger Schwecke at 1-2 (July 19, 2017) https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/news_room/news_and_updates/7-19-17-cpucltrtor-schweckere-reliability.pdf ("I direct SoCalGas to manage the facility to target a working gas level of 23.6 Bcf and maintain a level above 14.8 Bcf at all times…The updated report found that the range of working gas needed to maintain reliability is between 14.8 Bcf and 23.6 Bcf.").

Dec. 11, 2017	CPUC Executive Director: 24.6 Bcf limit maintains "safe and reliable service"[40]
July 2, 2018	CPUC Executive Director: 34 Bcf limit maintains "safe and reliable service" [41]
Nov. 23, 2020	D.20-11-044 reaffirms a 34 Bcf storage limit maintains reliability[42]
Nov. 5, 2021	D.21-11-008 finds 41.16 Bcf "needed to ensure reliability"[43]

These prior determinations by the Commission are reasonable to consider as the next Aliso Canyon storage limit is established.

The primary reason that Commission modeling continues to find a partial need for Aliso Canyon – despite gigawatts of new renewable capacity and battery storage capacity – appears to be that SoCalGas does not provide an accurate 1-in-10 peak day gas demand forecast. Thus, each time the Energy Division reviews gas and electric system reliability without Aliso Canyon, it evaluates a system to serve the inaccurately high peak gas demand SoCalGas forecasts instead of a reasonable planning forecast and increasingly more conservative planning assumptions, which increase the bar for "reliability." For example, as noted in Section 2.1 above, the 2025 Biennial

[40] CPUC Letter from Executive Director Timothy J. Sullivan to SoCalGas Senior Vice President Rodger Schwecke at 1 (Dec. 11, 2017) https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/news_room/news_and_updates/12-11-17-directive-to-maintain-a-range-of-working-gas-in-aliso.pdf ("I am directing SoCalGas to maintain up to 24.6 billion cubic feet ("Bcf") of working gas at the Aliso Canyon gas storage facility.").

[41] CPUC Letter from Executive Director Timothy J. Sullivan to SoCalGas Senior Vice President Rodger Schwecke at 1-2 (July 2, 2018) https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/news_room/7-2-18-ltr-to-rodger-schwecke-re-aliso-canyon-gas-storage-facility.pdf ("I am directing SoCalGas to maintain up to 34 billion cubic feet (Bcf) of working gas at the Aliso Canyon gas storage facility…The Report finds that SoCalGas should maintain a working gas inventory between zero Bcf and 34 Bcf at the Facility in order to maintain safe and reliable service…").

[42] D.20-11-044, Decision Setting the Interim Range of Aliso Canyon Storage Capacity at Zero to 34 Billion Cubic Feet, at 16 (Nov. 19, 2020) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M351/K840/351840520.PDF ("The interim range of working gas at the Aliso Canyon Natural Gas Storage Facility is between zero and 34 billion cubic feet.").

[43] D.21-11-008, Decision Setting the Interim Range of Aliso Canyon Storage Capacity at Zero to 41.16 Billion Cubic Feet, Finding of Fact 1, at 21 (Nov. 4, 2021) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF.

Assessment evaluates a scenario so rare – a large gas-system outage occurring simultaneously with a 1-in-10 gas demand day – that it has never occurred.[44]

However, it is possible that SoCalGas's gas system is becoming less reliable, with the company suggesting that Energy Division's conservative scenario assumes that SoCalGas's system is more reliable than SoCalGas believes it to be.[45] For example, SoCalGas' testimony projects a January peak-day pipeline supply of 2,416 MMcfd, which represents only 62% of its system nominal capacity during the peak winter months when gas demand is at its highest.[46] Unavailability of 38% of SoCalGas' capacity would reinforce need for Aliso Canyon, but it would also represent a scenario where a significant percentage of SoCalGas's infrastructure is not "used or useful."[47] If only 62% of the utility capacity is available during peak demand, the Commission should consider whether ratepayers should only be responsible for paying for the portion of the gas system that is reliably available during the winter and meets the "used and useful" standard.

For example, while the nominal capacity of the SoCalGas transmission system is 3,875 MMcfd,[48] SoCalGas operated its system during the peak winter months of December-February at a nominal capacity of only 3,204 MMcfd (2024-2025) and has operated its system at lower capacities in other years. One of the main causes of the lower capacity from 2017-2023 was the SoCalGas Line 235 explosion. The Commission's Safety and Enforcement Division determined that the Line 235 explosion and the substantial damage along Line 235 was caused by

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[44] The only day that SoCalGas customer gas demand exceeded SoCalGas's 1-in-10 peak demand forecast was January 14, 2013. On that day, SoCalGas reported its Total Receipt Capacity as 3,740,193 Dth, equivalent to 3,634 MMcfd assuming 1,029.3 Dth/MMcf.

[45] A.26-01-009, Prepared Direct Testimony of Andrew J. Sawin on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-5 (Jan. 15, 2026) ("The Biennial Assessment's conclusions regarding system reliability and reduced reliance on Aliso Canyon are driven by a set of assumptions that materially overstate the availability of flowing supplies.").

[46] *Id.* at AJS-14 (85 percent receipt point utilization applied across all receipt zones except California Producers) and AJS-19 (resulting January peak-day pipeline supply of 2,416 MMcfd). Nominal system capacity of 3,875 MMcfd per 2016-2017 Aliso Canyon Winter Risk Assessment Technical Report, at 8 (Aug. 23, 2016). Calculation: 2,416 MMcfd ÷ 3,875 MMcfd = 0.6235 = 62%.

[47] Cal. Pub. Util. Code § 454.8.

[48] *2016-2017 Aliso Canyon Winter Risk Assessment Technical Report* at 8 (Aug. 23, 2016) https://www.cpuc.ca.gov/regulatory-services/safety/gas-safety-and-reliability-branch/aliso-canyon-well-failure/aliso-canyon-summer-and-winter-reliability-assessments ("The system today has the potential capacity to accept up to 3,875 MMcfd of interstate and local California supplies.").

SoCalGas.[49] Line 235 West partially reopened two years later, but it did not regain its designed operating capacity until November 2023, nearly six years after the rupture.[50]

Figure 2 below shows the daily average receipt capacity of the SoCalGas system during January, February, and December of each year compared to the assumption in the 2025 Biennial Assessment and to the average daily total receipt capacity during those same months across the entire 22-year period.

[49] Exh. SC-09: Safety and Enforcement Division Line 235 Final Report – Redacted, Released Pursuant to CPUC Resolution L-571, at 28 (Oct. 25, 2018) (filed as Attachment A to A.26-01-009, Sierra Club Comments in Response to Prehearing Conference Ruling (Mar. 27, 2026)), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K483/603483126.PDF.

[50] CPUC, *Winter 2023-2024 Southern California Gas Reliability Assessment* at PDF p. 4 (Sept. 15, 2023) https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/2023_winter_reliability_daily_stochastic_mass_balance_model.pdf ("The Northern Zone of the pipeline system is set to regain 175 million cubic feet per day (MMcfd) of receipt capacity in November 2023 when Line (L) 235 west remediation is scheduled to end.").

Figure 2: Historical Total Receipt Capacity (2004-2025) Compared to 2025 Biennial Assessment Total Receipt Capacity

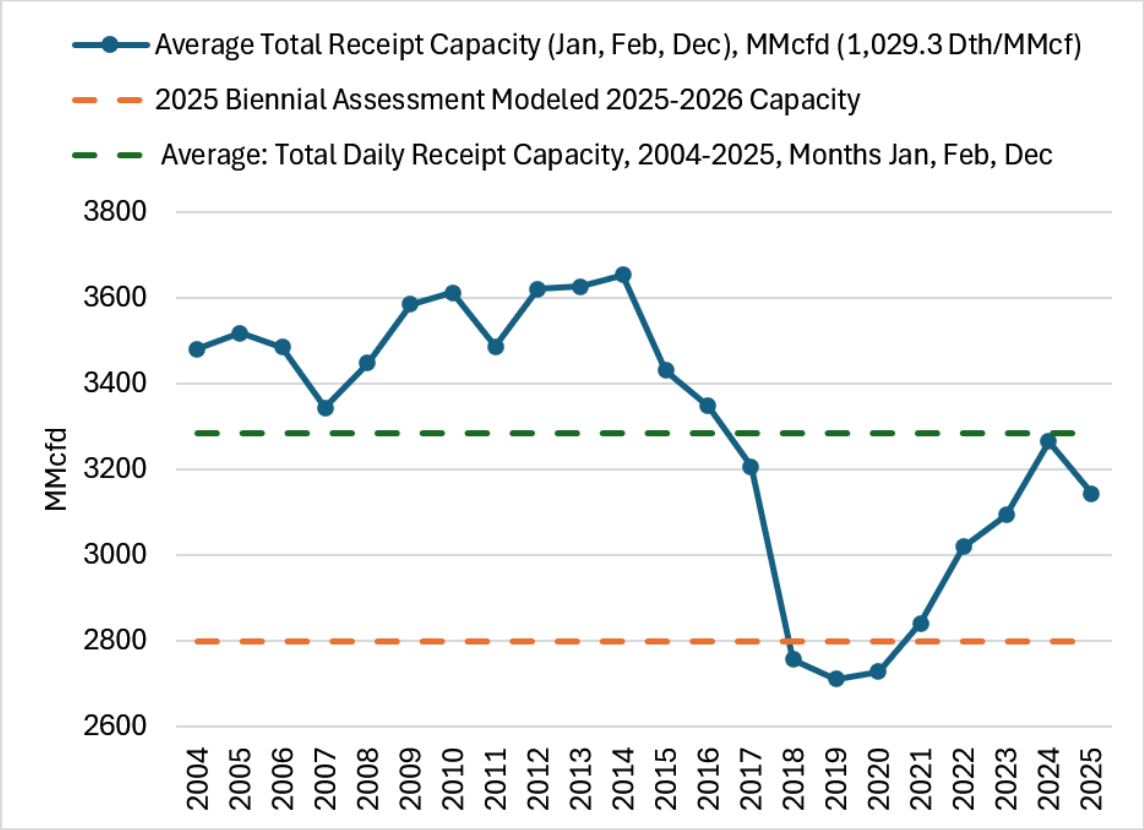


Figure 2 shows that the 2025 Biennial Assessment input a system capacity far lower than the average and in fact far lower than any but the lowest capacity years on record. In other words, the Biennial Assessment models an extremely conservative scenario of SoCalGas' ability to deliver gas. Future biennial assessments should assume typical winter gas system deliverability capacity instead of assuming that a large gas-system outage will overlap with a 1-in-10 gas demand day because a 1-in-10 peak day demand scenario has only occurred on one day in the last 25 years.

2.2. The Application identifies no electric reliability need for Aliso Canyon that battery and renewable resources do not already meet.

In 2021, the Commission's Aliso Canyon modeling consultant, FTI, reviewed whether there would be an electricity supply shortfall on the 1-in-10 peak gas demand day if Aliso Canyon were unavailable. It found that there would be a three-hour shortfall of 3,176 MW on the peak 1-in-10 day in 2027 if the gas shortage were to be attributed to gas-fired electricity

demand.[51] That means the shortfall FTI calculated could be closed with 3,176 MW of 3-hour or greater-duration battery storage. Due to California resource adequacy requirements, utility scale battery storage typically equals or exceeds 4-hours of duration. A 4-hour duration 3,176 MW battery will include an extra hour of duration beyond what is needed to close the 3-hour 3,176 MW shortfall.

In I.17-02-002, Southern California Edison ("SCE") testimony stated that "FTI's analysis includes a total CAISO battery nameplate capacity of 6,505 MW in 2027… SCE concludes FTI's Analysis is missing about 4,000 MW battery storage nameplate capacity, which exceeds its calculated electric shortfall of 3,176 MW."[52] I agree with SCE that FTI did not include all battery storage that was ordered, however, my analysis below proceeds on the assumption that FTI's 3,176 MW shortfall was correct based on the amount of battery capacity that FTI modeled.

FTI assumed a battery storage capacity in 2027 that is less than half the battery storage capacity that is currently online in CAISO's service territory.[53] If FTI had modeled the grid's current battery storage capacity, it would have found no gas shortfall during the 1-in-10 peak demand day in 2027.[54]

I updated FTI's analysis to account for recent resource additions to the grid and found that an electricity supply shortfall for the 1-in-10 peak day would not occur when retaining FTI's other inputs, even if Aliso Canyon were completely unavailable. I aimed to ensure a conservative output by analyzing a shortfall of 3,176 MW at a 4-hour duration, which assumes more battery capacity than in FTI's modeling, which is 3,176 MW at a 3-hour duration. SCE's

[51] I.17-02-002 Phase 3 Report at 16, 50 (Figure 3 at page 16 shows three hours of shortage, and page 50 states that the shortfall is during the "the final three hours of the winter peak day.").

[52] I.17-02-002, Exhibit No. SCE-01, Concurrent Opening Testimony of Southern California Edison Company (U 338-E) On Assigned Commissioner Ruling and Staff Proposal for Portfolio and Next Steps, at 6-7 (Dec. 12, 2022) https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/I1702002/5691/499887635.pdf.

[53] FTI's supporting materials in the file "Detailed Power Market Modeling Inputs and Results" spreadsheet shows 7,673.79 MW of battery storage in 2027 when summing the "2027 Max Power (MW)" column of the Base Batteries sheet, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/fti-phase-3-final-report-supporting-materials.zip. CAISO reports 17,125 MW of installed battery capacity. CAISO, *Key Statistics*, July 2026, at 2, https://www.caiso.com/documents/key-statistics-jul-2026.pdf. Calculation: 7,673.79 MW ÷ 17,125 MW = 0.448 = 45%.

[54] *See* Figure 3, below, (the 3,176 MW of four-hour battery capacity required to cover the three-hour shortfall FTI identified); I.17-02-002 Phase 3 Report at 25, Figure 8.

calculation appears to have only assumed a subset of the batteries listed in FTI's input workbook (i.e., SCE included only 6,505 MW of battery capacity compared to a total of 7,674 MW of battery capacity listed in FTI's input data). To ensure consistency with FTI's battery estimates in its prior calculations, my calculations include all battery capacity that FTI lists in its battery inputs, which totals 7,674 MW of battery storage for 2027.[55]

Figure 3 below shows the FTI assumption of 7,674 MW of battery storage on the 1-in-10 peak day in December 2021. I then add to that FTI's 3,176 MW shortfall to arrive at the total of 10,850 MW of energy storage capacity required to close FTI's calculated electricity shortfall by 2027.[56]

In addition to the FTI assumptions illustrated, Figure 3 below also shows CAISO's monthly-reported installed battery capacity through June 2026.[57] Each month represents a cumulative total reported by CAISO. The latest CAISO report shows 17,125 MW of battery capacity as of June 2026, which is 6,275 MW more than the 10,850 MW of battery capacity that FTI's report claimed would be needed by 2027 to enable the closure of Aliso Canyon.[58]

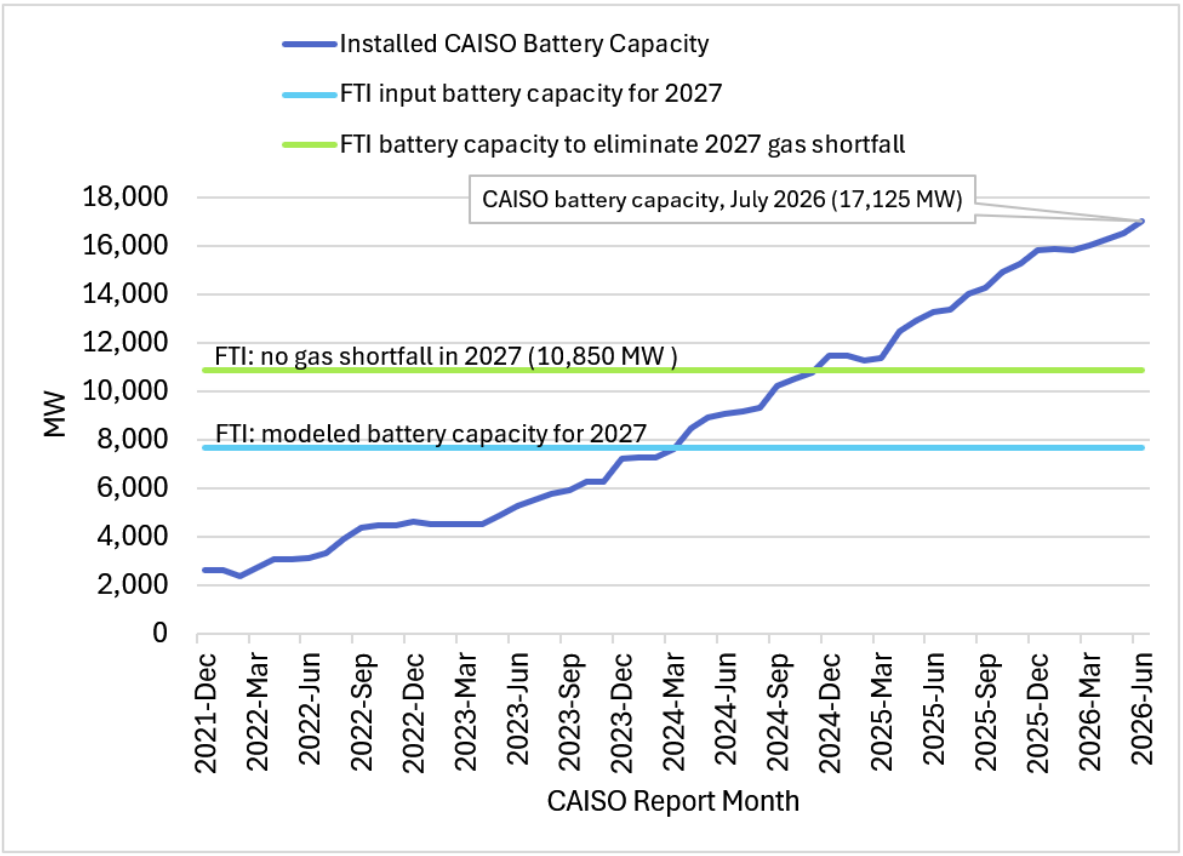
[55] FTI's accompanying supporting materials in file "Detailed Power Market Modeling Inputs and Results" spreadsheet shows 7,673.79 MW of battery storage assumptions when summing the "2027 Max Power (MW)" column of the Base Batteries sheet. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/fti-phase-3-final-report-supporting-materials.zip.

[56] *See* Figure 3; As I noted previously, the actual 4-hour battery capacity is more than the 3-hour capacity shortfall. Thus, the 3,176 MW that I include in the figure above is conservative; I.17-02-002 Phase 3 Report at 25, Figure 8.

[57] CAISO, *Key Statistic*, December 2021 through June 2026, https://www.caiso.com/library/key-statistics. Installed battery capacity is typically listed at page 2 of each key statistics report.

[58] Calculation: 17,125 MW - 10,850 MW = 6,275 MW.

Figure 3: CAISO battery capacity exceeds threshold required for Aliso Canyon closure



The Commission continues to plan for more renewable energy and battery capacity additions to the grid in its Integrated Resource Planning ("IRP") proceeding because significantly more resources are needed to reach the 2035, 2040, and 2045 carbon reduction milestones established in SB 1020 (90%, 95%, and 100% of retail sales by 2035, 2040, and 2045 respectively).[59] Table 3 below shows the battery and renewable resources that the Energy Division's IRP staff expect to enter operation through 2029.

[59] Cal. Pub. Util. Code § 454.53(a).

Table 3: CPUC IRP Staff Analysis of Expected New Capacity in Megawatts (June 11, 2026 – 2029)[60]

Resource Type	2026*	2027	2028	2029	Total
Renewable Capacity	3,516	3,220	3,051	630	**10,417**
Storage Capacity	3,047	3,078	2,773	355	**9,253**
Total Capacity	6,563	6,298	5,824	985	**19,670**

*Note: Data includes projects expected/under contract as of June 11, 2026. Resources online before June 11, 2026 are listed separately by IRP staff.

When the 2025 Biennial Assessment was completed October 1, 2025, it incorporated only a subset of these resources, as Energy Division's IRP team updates the resource reports monthly and not all of these resources would have been included in the modeling inputs for Energy Division's 2025 Biennial Assessment. However, when accounting for only a subset of the future renewable energy and battery capacity, the 2025 Biennial Assessment found no need for Aliso Canyon to maintain reliability during the 2030-2031 winter season.[61] The Biennial Assessment only reported the percentage of Aliso Canyon need for two winter seasons 2025-26 (44% Aliso Canyon need) and 2030-31 (0% Aliso Canyon need).[62] The assessment does not state which winter between those two results was the first year when the need for Aliso Canyon falls to zero.

Based on my analysis above, the data shows that there is sufficient battery storage capacity online in California today to address the 2027 shortfall concern identified by FTI in its 2021 report. The 2025 Biennial Assessment similarly underestimated renewable energy and storage capacity on the grid, making its very conservative projections trustworthy. Accordingly, the Commission should adopt the Biennial Assessment's recommendation to reduce Aliso Canyon's inventory and should begin evaluating closure of Aliso Canyon now and consider a closure date of 2031 or sooner.

I find CAISO's prior analysis reasonable corroboration of the electricity system's ability to meet winter electricity load on a 1-in-10 peak gas demand day, even with 56 gas-fired

[60] CPUC Staff Report, Resource Tracking Data, Data current as of June 2026, at 15, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-june-2026-release.pdf.

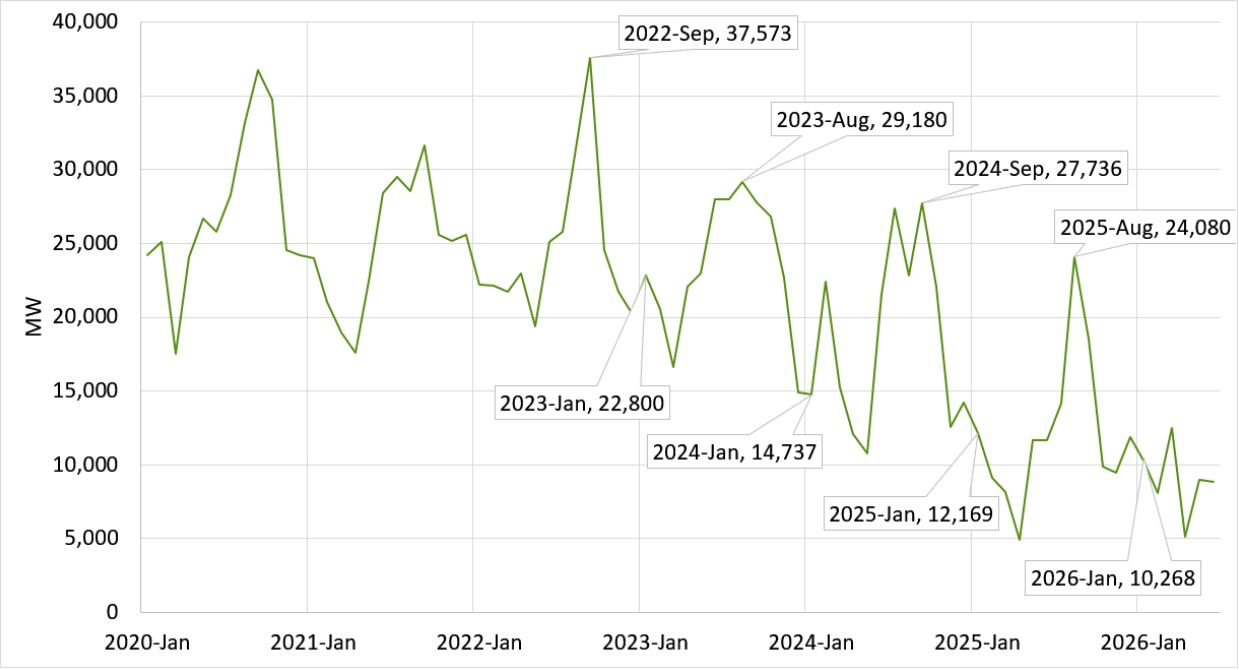
[61] 2025 Biennial Assessment at 12, Table 4.

[62] *Id.*

generators curtailed in SCE and San Diego Gas and Electric (SDG&E) territory on that day. However, my analysis in Section 2.2 demonstrates that if FTI's modeling were updated to reflect the capacity of batteries currently installed on the CAISO system, FTI's modeling would show *no gas shortfall* on the 1-in-10 peak gas demand day in 2027. If the Commission decides it would like CAISO to re-run its analysis to incorporate the data from the 2025 Biennial Assessment that CAISO said it lacked for its 2023 analysis, the Commission could ask CAISO to do so. Such an evaluation would provide the Commission with robust modeling outputs to further reinforce the findings of the upcoming 2027 Biennial Assessment.

To evaluate renewable energy and battery capacity in California, I reviewed the CAISO's key statistics data in its monthly reports.[63] The following figure shows the monthly peak electric demand minus the monthly peak demand served by renewable energy. For that criteria, in Figure 4, below, the last 4 years of summer peaks (September or August) and January peak demand are called out.

Figure 4: Month Peak Demand Minus Month Peak Demand Served by Renewables (MW)



The data show that over the last 4 years renewable energy has served an increasing percentage of the total electricity demand. I expect this trend to continue even as electricity

[63] CAISO, *Key Statistics*, https://www.caiso.com/library/key-statistics.

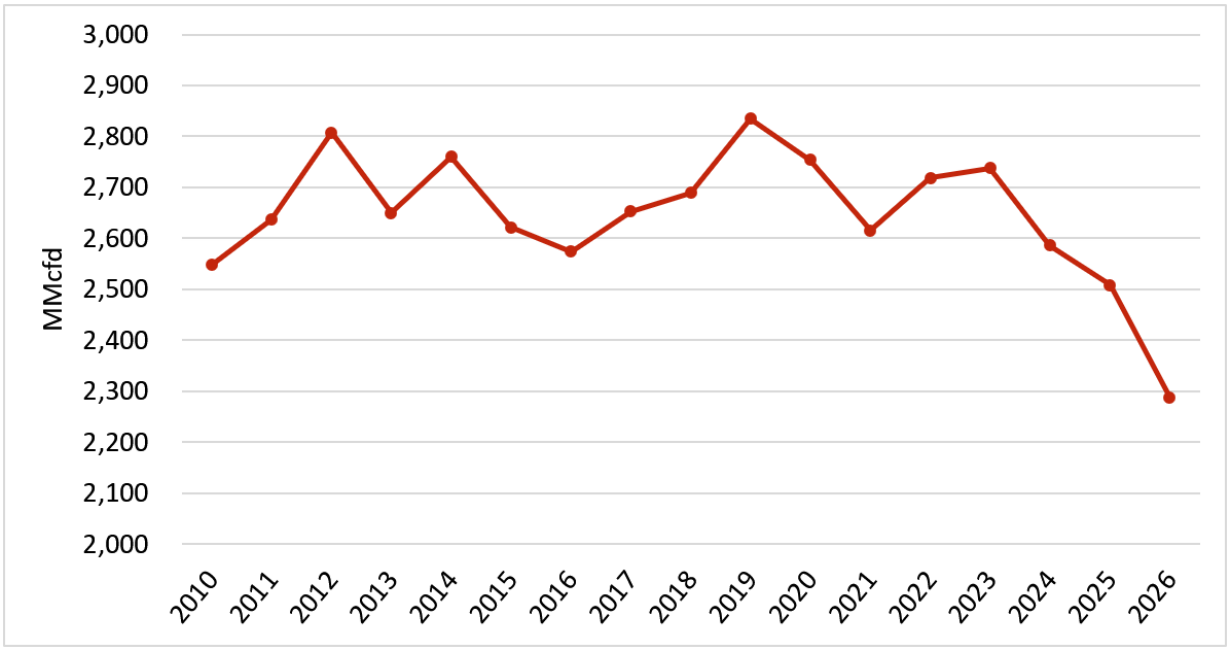
demand increases because the percentage of electricity served by zero-carbon resources continues to increase pursuant to SB 1020. In turn, gas demand will decrease and the need for gas storage will decrease.

2.3. SoCalGas's peak-day forecast is rising, despite its own metered demand falling, even when controlling for higher temperatures.

Using data from Envoy, SoCalGas's reporting platform, I determined that gas demand is decreasing even when controlling for temperature, which directly contradicts SoCalGas's rising peak-day forecasts. To determine whether there has been a decrease in gas demand in SoCalGas territory since electricity providers started significant procurements of renewable energy, batteries, and import capacity, I reviewed Envoy gas demand data (i.e., sendout) during the years 2010-2026 for the months of January-March.[64] Because the average temperature in the most recent year has been higher than normal, simply looking at gas demand will not provide an accurate evaluation of whether gas demand is rising or falling in a typical year. Thus, I reviewed a temperature-controlled series of years during the winter months using SoCalGas's Envoy-reported system-wide average daily temperature (i.e., Composite Weighted Avg Temp). I reviewed only January-March so that I could include winter months during 2026. Each year from 2010-2026 registered at least one day at each temperature from 56 degrees to 60 degrees during the months January-March. Figure 5 below shows the results of the analysis.

[64] The first full year of temperature data in Envoy is 2010.

Figure 5: Temperature-controlled SoCalGas system sendout at 56–60°F, January–March, 2010–2026 (MMcfd)[65]



My calculations, illustrated in Figure 5 above, show that the years 2025 and 2026 are the two lowest demand years on record when controlling for temperature. For temperatures 56-60 degrees, the year 2026 recorded the lowest gas demand year on record by a significant margin– 8.7% lower than 2025.[66] This is an expected outcome based on recent increases in renewable generation and batteries. 56-60 degree days represent 40% of days within the gas withdrawal season (November-March) for the last 10 winter seasons (i.e., winter 2016-2017 through winter 2025-2026). This shows a lower need for gas generally in upcoming seasons and thus a lower need for gas storage.

Despite the decreasing gas demand, SoCalGas has increased its peak demand forecasts in recent years. In the 2024 California Gas Report, SoCalGas forecast a 1-in-10 peak day demand of 4,489 MMcfd for 2026.[67] In the 2026 version of the report, SoCalGas increased its forecast for

[65] Each annual value is the unweighted mean of average daily sendout at each whole degree of Envoy composite weighted average temperature from 56°F through 60°F.

[66] Calculation: 1-(2,288.6 / 2,508.3) = 0.08759 = 8.7%

[67] 2024 California Gas Report, Prepared by the California Gas and Electric Utilities at 159, Table 34, https://www.pge.com/assets/pipeline/docs/library/regulatory/downloads/cgr24.pdf.coredownload.pdf [hereinafter "2024 California Gas Report"].

2026 to 4,758.[68] The 2026 report increases projected demand from electric generation by 168 MMcfd of the 269 MMcfd, making it the single largest driver of the increase in the forecast.[69] This projected increase lacks basis. Electric generation is the category that renewable and storage additions displace, and – as noted in previous sections of my testimony – electric load-serving entities ("LSEs") have made large procurements of batteries, solar, and import capacity in recent years, consistent with Commission planning to decarbonize the grid and comply with state climate and renewable energy targets. Thus, SoCalGas's increasing peak demand forecast conflicts with general trends in grid decarbonization as well as the analyses I have completed.

2.4. Historical Receipt Point Utilization data show that receipt point capacity in gas system modeling should approach 100%.

In addition to the reduction in gas demand, another important input helps to determine whether peak gas demand can be served without Aliso Cayon. That metric is gas flowing supply and gas flowing supply availability is strongly influenced by RPU. There are numerous data points in the historical record demonstrating that high receipt point utilization is achievable and that it occurs on days of high customer gas demand. There is no data in the record, and SoCalGas has stated that it has none, showing that low RPU is caused by a low or limited gas supply or limited availability from out-of-state suppliers. For these reasons and others stated below, the Commission should reject SoCalGas' modeling that uses a 85% RPU assumption[70] and should instead raise the RPU assumption in future biennial assessment modeling to 97%. The Biennial Modeling Criteria address RPU in row 10 "Receipt point capacity."[71]

[68] 2026 California Gas Report at 129, Table 38.

[69] *Id.*

[70] A.26-01-009, Prepared Direct Testimony of Andrew J. Sawin on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-14 (Jan. 15, 2026) ("SoCalGas applied an 85% RPU across all receipt zones, except California Producers, and explicitly modeled the impacts of representative pipeline outages and seasonal constraints.").

[71] Biennial Modeling Criteria at A5, Row 10 (Oct. 4, 2024) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K129/551129840.PDF.

2.4.1. RPU decreases as electrification and renewable energy increase.

The Commission has defined receipt point utilization as "the percentage of available pipeline capacity used by customers at a given time."[72] It is a ratio of what customers schedule to what SoCalGas posts as available. The denominator of that ratio is SoCalGas's total receipt capacity,[73] the term SoCalGas uses for the volume of gas through its receipt points that its system can physically deliver on a given day. It is a measure of SoCalGas's own system rather than of its receipt points, and customers may schedule up to 100 percent of it. Nothing in either part of the ratio measures how much gas exists upstream of the receipt points. RPU is therefore not a measure of upstream supply availability, and the Commission did not adopt it as one.

SoCalGas defines the term slightly differently. When asked to state its definition, SoCalGas responded that it "defines Receipt Point Utilization as the actual physical natural gas supplies received divided by SoCalGas' capacity to receive supplies," illustrating the calculation as "650 MMcfd of actual receipts divided by 765 MMcfd of available capacity is approximately 85% Receipt Point Utilization."[74]

The daily data SoCalGas produced in this proceeding is consistent with that definition. When Sierra Club asked SoCalGas to provide daily receipt point utilization, SoCalGas directed Sierra Club to its Envoy system.[75] The dataset SoCalGas subsequently produced reports total receipt capacity together with a daily volumes column, and the utilization SoCalGas reports equals that column divided by total receipt capacity.[76] The utilization figures used in this section are the figures SoCalGas reported.

In contrast to the discovery-produced definition, SoCalGas has advanced a different meaning, treating low RPU as evidence that supply was unavailable.[77] Indeed, its own witness testifies that "observed [gas] receipt levels can be materially lower due to operational and

[72] D.24-12-076, Decision Adopting Biennial Assessment Process, at 16 (Dec. 24, 2024) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF.

[73] The total receipt capacity can change daily.

[74] Exh. SC-10: SoCalGas Response to Sierra Club Data Request 1-22 (Mar. 20, 2026).

[75] Exh. SC-11: SoCalGas Response to Sierra Club Data Request 1-23 (Mar. 20, 2026) ("Historic receipt point capacity and scheduled volumes are available to download from the archive on ENVOY by selecting Capacity Utilization for the month and year desired").

[76] Exh. SC-06: SoCalGas Response to Sierra Club Data Requests 2-13 and 2-14 (May 28, 2026).

[77] A.26-01-009, SoCalGas Opening Comments on Workshop, at 1.

upstream constraints and/or market economics," citing the 2021 and 2024 Arctic Blasts, when "RPU dropped as low as 47% and 38%, respectively."[78] But when Sierra Club asked SoCalGas to quantify how much gas was actually available from out-of-state suppliers on each historical day, SoCalGas responded that this was "information that is not within SoCalGas knowledge or control"[79] and explained that gas availability "is determined by the actions and decisions of third-party shippers, producers, marketers, and upstream pipeline operators, not by SoCalGas."[80] SoCalGas cannot simultaneously assert that low RPU demonstrates constrained upstream supply and concede that it does not know what upstream supply was available.

SoCalGas's inability to support or quantify its claim of limited upstream supply is not confined to a single data request. Its External Outage Report in this proceeding states that during January 2025 "gas supplies to California became constrained, with interregional gas transfers largely unavailable, and gas markets exhibited reduced liquidity."[81] Sierra Club asked SoCalGas to quantify each of those assertions in MMcfd. SoCalGas quantified none of them, but instead responded that, because average residential demand nationally exceeded demand in the Western Region, "it can be inferred that there was an increase in percentage of natural gas supplies to the Central and Eastern Regions and a decrease in percentage of natural gas supplies to the Western Region,"[82] and that "[t]his inference is further supported in observed pricing in the daily markets with prices higher outside of California and the Western Region for several days during January 2025."[83] Asked separately to quantify the interregional transfers that were "largely unavailable" and the "reduced liquidity," SoCalGas referred back to that same inference and provided no quantified data.[84]

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[78] A.26-01-009, Prepared Direct Testimony of Andrew J. Sawin on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-6 (Jan. 15, 2026).

[79] Exh. SC-06: SoCalGas Response to Sierra Club Data Requests 2-13 and 2-14 (May 28, 2026).

[80] *Id.*

[81] A.26-01-009, Compliance Filing of Southern California Gas Company (U904G) Regarding External Outages at 14 (May 1, 2026) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K451/606451664.PDF.

[82] Exh. SC-12: SoCalGas Response to Sierra Club Data Request 3-22 (Aug. 10, 2026).

[83] *Id.*

[84] *Id.* at subparts (c), (d), and (e); A.26-01-009, Compliance Filing of Southern California Gas Company (U904G) Regarding External Outages at 14 (May 1, 2026) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K451/606451664.PDF.

SoCalGas does not measure physical constraints on gas supply reaching California. It infers a constraint when gas in other markets was more expensive. When shippers deliver gas to the region paying the higher price, those shipments demonstrate a market clearing on price, not necessarily a system with supply disruptions.

The Commission's own consultant reached the opposite conclusion from SoCalGas on the very event SoCalGas relies upon. Analyzing the February 2021 Arctic Blast, FTI found that the "[d]ownward spike in winter RPU did not occur during low temperature / high demand period in California," that the "[d]ownward spike in RPU is a direct response to high gas prices at the SoCal Border," and that the "[d]ownward spike in RPU is not related to availability of takeaway capacity into the SoCal Gas system."[85] Low RPU during that event reflected shippers responding to price, not gas that could not be delivered.

There is a second reason why RPU declines that has nothing to do with supply. As electrification, energy efficiency, and renewable generation reduce gas consumption, customers schedule less gas even when the full infrastructure capacity remains available. In that circumstance, a falling RPU records the success of the energy transition, not a constraint on it. Gas may be fully available at the border while demand simply does not materialize.

2.4.2. On recent high demand days, customers have scheduled nearly all available pipeline capacity and reach nearly 100%.

On the days when customers most need gas, they schedule nearly all the capacity SoCalGas makes available and reach RPUs near 100%.

The Commission's consultant, FTI, quantified this directly. Examining the six highest-sendout days across the winters of 2018-19 through 2020-21, FTI found utilization factors of 92 to 99 percent, averaging 95.69 percent, and concluded that "[o]n the coldest (highest sendout) days of the year from the last three winter seasons, Utilization Factor ('UF') has exceeded 95%."[86]

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[85] Exh. SC-13: I.17-02-002, FTI/Gas Supply Consulting, *Aliso Canyon OII Phase 3 Research, Workstream #2 Approach: Portfolios Framework and Research Methods*, at 32 (Mar. 30, 2021) (filed as Attachment A to A.26-01-009, Sierra Club Reply Comments in Response to Aliso Canyon Biennial Assessment Workshop (May 5, 2026)).

[86] *Id.* at 33.

FTI's seasonal statistics show the same pattern. Average December-February RPU was 97.2 percent in winter 2019-20, with a maximum of 99.9 percent; 93.9 percent in 2018-19; and 90.0 percent in 2020-21.[87]

On that basis FTI recommended that the Commission's modeling use 95 percent RPU, "consistent with recent high demand day experience,"[88] and FTI is not an advocate for reducing gas infrastructure.[89]

These FTI findings align with my own review of the historical RPU data. The data show that SoCalGas customers can use and often have used between 99% and 100% of SoCalGas-offered capacity. Accordingly, I recommend the Commission find the Biennial Assessment's receipt point capacity assumptions reasonable for this cycle and direct Energy Division to assume a 97% receipt point capacity in future Biennial Assessment modeling.

2.4.3. Falling RPU suggests days with excess gas delivery capacity, not a need for gas storage.

Receipt point utilization is a ratio, and a ratio can rise because its numerator grows or because its denominator shrinks. On the SoCalGas system, the denominator has changed; meaning that total receipt capacity has changed. Table 4 below compares December-February days before and after the Line 235 rupture and the associated Line 4000 pressure reductions.

[87] *Id.* at 31, Table – Daily Receipt Point Utilization Statistics (Dec–Feb).

[88] *Id.* at 34 ("For analysis of the Gas Transmission Portfolio – Recommend 95% RPU … 95% RPU consistent with recent high demand day experience"); *id.* at 35 (proposed peak day receipt assumptions of 95% for the Northern and Southern Zones and 100% for Wheeler Ridge). *See also*, *id.* at 30 ("SoCal Gas customers employed 95%+ RPU over past three winters on high sendout days").

[89] Hiroko Tabuchi, *How One Firm Drove Influence Campaigns Nationwide for Big Oil*, New York Times (Nov. 11, 2020) https://www.nytimes.com/2020/11/11/climate/fti-consulting.html.

Table 4: Receipt capacity and RPU, December-February days before and after the SoCalGas Line 235 rupture and Line 4000 pressure reductions

Period	Average posted receipt capacity	Average scheduled volumes	Average RPU
Winters 2005–2017	3,510 MMcfd	2,329 MMcfd	66.70%
Winters 2018–2026	2,940 MMcfd	2,513 MMcfd	86.10%

Scheduled volumes rose about 8% between the two periods. Total receipt capacity fell about 16% even while scheduled volumes increased slightly. Utilization rose from 67 to 86% principally because SoCalGas removed delivery capacity from the market.[90]

The same calculation explains the low utilization figures on the highest-demand days of the earlier period. On January 14, 2013 — the only day in the record when customer demand exceeded SoCalGas's 1-in-10 peak day forecast — SoCalGas posted a total receipt capacity of 3,634 MMcfd, customers scheduled 2,474 MMcfd, and RPU was 68 percent.[91] Utilization was low that day because the total receipt capacity SoCalGas made available substantially exceeded what customers scheduled. The system met the highest demand in its recorded history with 1,160 MMcfd of posted total receipt capacity unscheduled, and RPU was relatively low.

That is the correct reading of a low RPU. When capacity exceeds what customers require, utilization falls, and the appropriate inference is that the delivery system has spare capacity, not that the storage system needs more gas supply. SoCalGas's framing treats every low RPU as evidence that storage must backstop supply, but that logic fails when tested: on the single day demand exceeded the 1-in-10 peak day forecast, utilization was 68 percent because more than a thousand MMcfd of delivery capacity stood unused.

[90] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (months of December, January, and February. Winters 2005–2017 comprise the days before July 1, 2017; winters 2018–2026 the days after).

[91] *Id.* (total receipt capacity 3,740,193 Dth; total scheduled volumes 2,546,970 Dth; reported RPU 0.68, converted at 1,029.3 Dth/MMcf. Calculation: 3,634 − 2,474 = 1,160 MMcfd).

2.4.4. The 2021 event that SoCalGas relies on occurred on one of the lowest-demand days on record.

SoCalGas cites the 2021 Arctic Blast as an extreme weather event demonstrating "the actual availability of supply and customer behavior on a peak day," stating that receipt point utilization "dropped as low as 47%."[92] The lowest utilization SoCalGas reports for February 2021 is 46 percent, on February 15 and 16, 2021.[93]

February 15, 2021 was not a peak demand day. SoCalGas system sendout that day was 2,238 MMcfd, which ranks 1,859th of the 1,926 December–February days in the record — the third percentile, and roughly 750 MMcfd below the December–February average of 2,989 MMcfd.[94] Utilization on one of the lowest-demand winter days SoCalGas has experienced cannot demonstrate what supply is available on a peak day.

The Commission's consultant reached the same conclusion about the same event, finding that the "[d]ownward spike in winter RPU did not occur during low temperature / high demand period in California."[95]

Nor were SoCalGas's own receipt points the binding constraint. SoCalGas posted a total receipt capacity of 2,845 MMcfd on February 15, 2021 and customers scheduled 1,296 MMcfd, leaving 1,549 MMcfd of posted total receipt capacity unscheduled.[96]

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[92] A.26-01-009, Prepared Direct Testimony of Andrew J. Sawin on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-6 (Jan. 15, 2026).

[93] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (February 15, 2021: total receipt capacity 2,845 MMcfd, total scheduled volumes 1,296 MMcfd, reported receipt point utilization 0.46; February 16, 2021: 2,804 MMcfd, 1,295 MMcfd, 0.46), converted from dekatherms at 1,029.3 Dth/MMcf; SoCalGas Envoy, Daily Operations (system sendout of 2,238 MMcfd on February 15, 2021). Rank and percentile calculated across the 1,926 days falling in December, January, and February between September 30, 2004 and December 31, 2025. Calculation: 2,845 − 1,296 = 1,549 MMcfd.

[94] *Id.*

[95] Exh. SC-13: I.17-02-002, FTI/Gas Supply Consulting, *Aliso Canyon OII Phase 3 Research, Workstream #2 Approach: Portfolios Framework and Research Methods*, at 32 (Mar. 30, 2021) (filed as Attachment A to A.26-01-009, Sierra Club Reply Comments in Response to Aliso Canyon Biennial Assessment Workshop (May 5, 2026)).

[96] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (February 15, 2021: total receipt capacity 2,845 MMcfd, total scheduled volumes 1,296 MMcfd, reported receipt point utilization 0.46; February 16, 2021: 2,804 MMcfd, 1,295 MMcfd, 0.46), converted from dekatherms at 1,029.3 Dth/MMcf; SoCalGas Envoy, Daily Operations (system sendout of 2,238 MMcfd on February 15, 2021). Rank and percentile calculated across the 1,926 days falling in December,

2.4.4.1. During the 2024 weather event that SoCalGas relies on, more than 2,000 MMcfd of total receipt capacity went unscheduled.

SoCalGas states that utilization dropped as low as 38 percent during the 2024 Arctic Blast.[97] The lowest utilization SoCalGas reports for January 2024 is 36 percent, on January 13 and 14, 2024.[98]

On January 13, 2024, SoCalGas posted a total receipt capacity of 3,427 MMcfd, and customers scheduled 1,238 MMcfd, leaving 2,190 MMcfd of posted total receipt capacity unscheduled. System sendout that day was 3,261 MMcfd, so the difference between what customers scheduled and what customers consumed was supplied from storage. The following day, the figures were materially identical: total receipt capacity of 3,401 MMcfd; 1,227 MMcfd scheduled; and 2,173 MMcfd of total receipt capacity unscheduled.[99]

Those figures establish that customers did not schedule the total receipt capacity SoCalGas made available, but they do not establish why. Total receipt capacity measures SoCalGas's own system capacity, not the gas supply upstream of it. SoCalGas has not demonstrated whether upstream gas supply existed to fill the remaining 2,190 MMcfd of total receipt capacity. SoCalGas has twice stated that it does not know what upstream supply was

January, and February between September 30, 2004 and December 31, 2025. Calculation: 2,845 − 1,296 = 1,549 MMcfd.

[97] A.26-01-009, Prepared Direct Testimony of Andrew J. Sawin on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-6 (Jan. 15, 2026).

[98] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (January 13, 2024: total receipt capacity 3,427 MMcfd, total scheduled volumes 1,238 MMcfd, reported receipt point utilization 0.36; January 14, 2024: 3,401 MMcfd, 1,227 MMcfd, 0.36; posted total receipt capacity of 3,453 MMcfd on January 12, 3,643 MMcfd on January 15, and 3,462 MMcfd on January 18; reported utilization of 0.72 on January 18), converted from dekatherms at 1,029.3 Dth/MMcf; SoCalGas Envoy, Daily Operations (system sendout of 3,261 MMcfd on January 13, 3,114 MMcfd on January 14, and 2,976 MMcfd on January 18, 2024). Calculations: 3,427 − 1,238 = 2,190 MMcfd; 3,401 − 1,227 = 2,173 MMcfd.

[99] *Id.* (January 13, 2024: total receipt capacity 3,427 MMcfd, total scheduled volumes 1,238 MMcfd, reported receipt point utilization 0.36; January 14, 2024: 3,401 MMcfd, 1,227 MMcfd, 0.36; posted total receipt capacity of 3,453 MMcfd on January 12, 3,643 MMcfd on January 15, and 3,462 MMcfd on January 18; reported utilization of 0.72 on January 18), converted from dekatherms at 1,029.3 Dth/MMcf; SoCalGas Envoy, Daily Operations (system sendout of 3,261 MMcfd on January 13, 3,114 MMcfd on January 14, and 2,976 MMcfd on January 18, 2024). Calculations: 3,427 − 1,238 = 2,190 MMcfd; 3,401 − 1,227 = 2,173 MMcfd.

available on any given day.[100] SoCalGas has failed to produce evidence demonstrating that low RPU suggests constrained upstream supply rather than ample upstream supply that customers simply did not schedule.

2.5. Every analysis of Aliso Canyon's reliability role supports a substantial reduction in its maximum inventory.

The analyses reviewed in this section describe a system that no longer depends on Aliso Canyon in the way SoCalGas's application assumes.

On the electric side, the case is direct. CAISO modeled the curtailment of all 56 gas-fired generators that FTI identified as affected on a 1-in-10 peak day without Aliso Canyon and found that all CAISO electric demand would continue to be served. However, that curtailment should never be needed because the battery capacity FTI treated as necessary to close the resulting shortfall — 10,850 MW by 2027 — is already exceeded by 6,275 MW. Neither finding describes a system that requires Aliso Canyon for electric reliability.

On the gas side, Energy Division's own modeling shows the need declining toward zero. The 2025 Biennial Assessment found that 44 percent of Aliso Canyon's capacity was needed for the 2025-26 winter and that no Aliso Canyon capacity was needed for the 2030-31 winter. The intervening winters were not modeled, but the direction is established, and the resources driving it are already in service: load-serving entities added 29,371 MW of renewable, battery, and import capacity between January 2022 and June 2026.

The remaining evidence points the same way. Temperature-controlled gas demand is falling. Renewable generation serves a growing share of peak electric demand each year. And receipt point utilization data show that SoCalGas's delivery system routinely carries close to 100% of offered capacity, including on the highest demand days.

SoCalGas asks the Commission to hold Aliso Canyon's maximum inventory at 68.6 Bcf. It asserts that any reduction would harm gas and electric reliability. No analysis reviewed in this section supports that position. The Commission staff, the Commission's consultant, and the grid operator have each concluded otherwise, and SoCalGas's operating data shows a declining gas

[100] Exh. SC-06: SoCalGas Response to Sierra Club Data Requests 2-13 and 2-14 (May 28, 2026).

demand. The question before the Commission is not whether Aliso Canyon's maximum inventory can be reduced, but by how much.

I recommend that in this proceeding the Commission reduce Aliso Canyon maximum inventory levels by 29 Bcf to a maximum inventory of 39.6 Bcf. Even though both the 2025 Biennial Assessment found a reliability need at a lower level,[101] and SoCalGas's end of winter season storage level suggest a lower maximum inventory level would be appropriate,[102] my analysis of the current unbundled storage program ("UBS"), *see* Section 3.4 below,[103] shows that a reduction of 29 Bcf to Aliso Canyon's storage capacity will still enable UBS customers access to their current daily withdrawal capacity. Thus, when both the reliability analyses above and the UBS analysis below are considered, a 29 Bcf reduction – while conservative – is a reasonable first reduction to Aliso Canyon's maximum inventory level.

3. ALISO CANYON STORAGE INVENTORY CAN BE REDUCED WHILE MAINTAINING REASONABLE RATES.

This section reviews historical gas storage use and gas prices and compares gas prices to gas storage. For this section, when I refer to gas prices, I refer to SoCal Citygate prices as reported by Natural Gas Intelligence ("NGI") unless noted otherwise. NGI is the gas price data provider that the Commission specified in D.24-12-076 Biennial Modeling Criteria as the official source for the economic analysis.

3.1. Since the Aliso Canyon Blowout in 2015, SoCalGas has always retained at least 34 Bcf of gas in storage.

SoCalGas has four gas storage facilities. Gas is withdrawn from storage during the withdrawal season November 1st – March 31st. Since the Aliso Canyon Blowout, the minimum amount of gas the SoCalGas has had in storage is 34.9 Bcf.[104] Figure 6 below shows the amount

[101] 2025 Biennial Assessment at 12, Table 4.

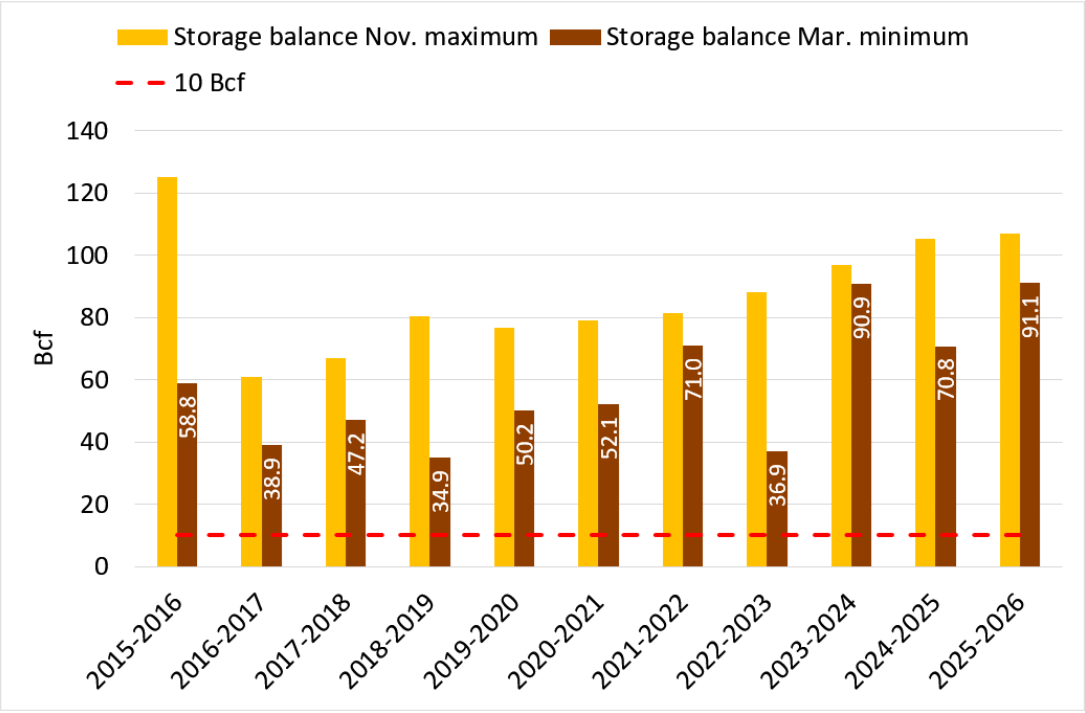
[102] *See* Section 3.1, Figure 6.

[103] *See* Section 3.4; See also footnote 115.

[104] SoCalGas Envoy, Daily Operations, https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternalDailyOperations.getDailyOperation (minimum gas inventory from Winter 2015-2026 occurred winter 2018-2019, reaching 34.9 BCF).

of gas in storage on November 1st and the lowest March gas inventory day for each winter season. The dashed red line shows a 10 Bcf inventory level.

Figure 6: High and Low Gas Inventory in SoCalGas Storage Winter 2015-16 through 2025-26[105]



The figure above shows gas inventory during an 11-year window. That window included the winter with the highest average gas price on record, winter 2022-2023.[106] Despite high gas prices during the 2022-2023 winter season (*see* Figure 7 below), SoCalGas retained 36.9 Bcf in storage at the end of the winter season. Not only did SoCalGas end the season with a 36.9 Bcf in storage, the difference between the November 1st inventory and the March low inventory was 51.1 Bcf.[107] That is 43% of the 119.5 Bcf maximum storage inventory available from all of

[105] *Id.*

[106] According to NGI's full SoCal Citygate price data: 2009-June 2026.

[107] Calculation: 88.0 Bcf – 36.9 Bcf = 51.1 Bcf.

SoCalGas's storage facilities.[108] By the end of the winter season with the highest prices, SoCalGas retained ample remaining gas supply.

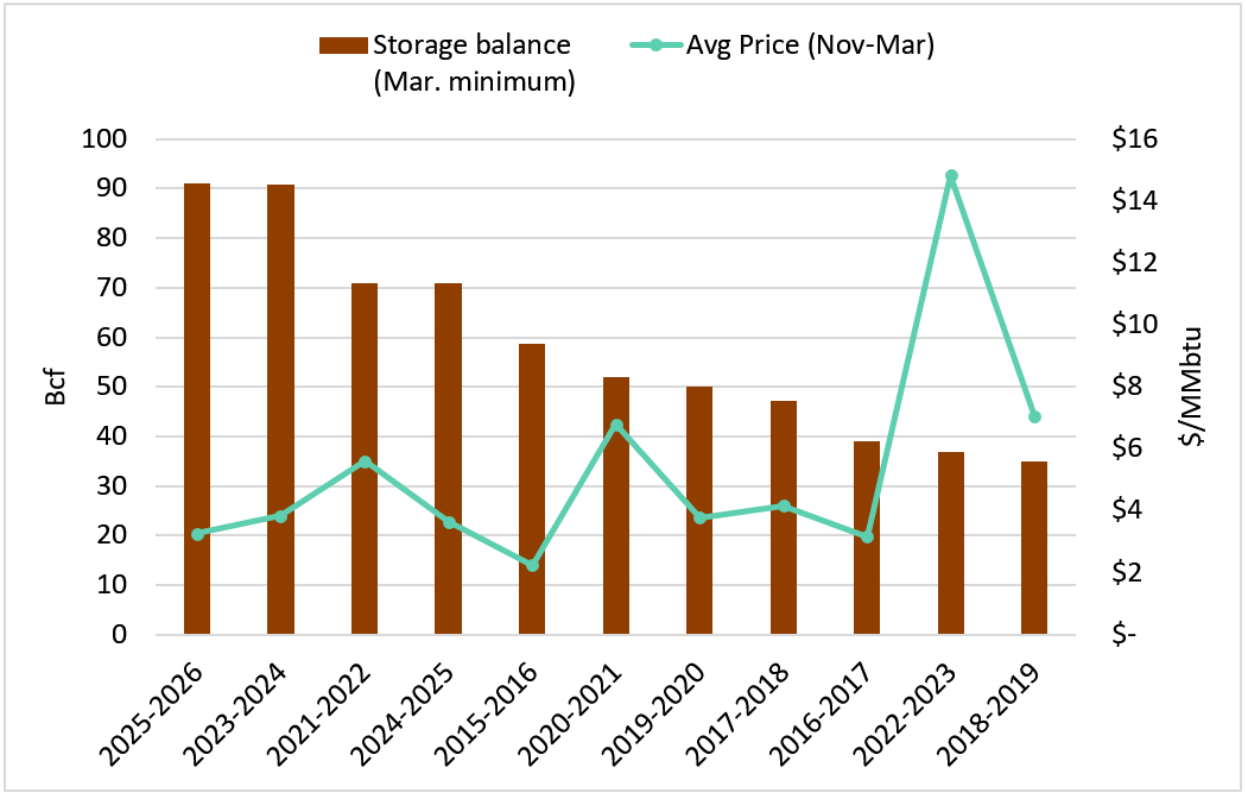
For the last decade, SoCalGas has always retained at least 34.9 Bcf of gas in storage at the end of the winter season, including during a winter with the highest average gas price on record. The Commission should be confident that it can lower the Aliso Storage capacity without fear of system reliability or increasing gas prices.

3.2. SoCalGas operational data suggests that withdrawals are minimally related to price.

In this section, I examine the same 11 years as the previous section: the winter seasons since the Aliso Canyon Blowout in 2015. The Figure below shows the average gas prices for each winter season compared to the March-low gas storage inventory. The winter seasons are arranged in order of highest to lowest March-low gas inventory.

[108] SoCalGas CEC Form 1314 filings after adjusting for Aliso inventory of 68.6 Bcf; *see also* 2026 California Gas Report at 122.

Figure 7: March Low Gas Inventory in SoCalGas Storage and Average Gas Price (Nov-Mar), 2015-16 to2025-2026



The figure shows the last three bars representing the lowest end-of-season storage inventories (the 2016-17, 2022-23, and 2018-19 winter seasons) correspond to average prices that vary significantly. The 2022-2023 season's average price is 4.6 times higher than the 2016-17 season's average price, but the end of season inventories for those two years only vary by 2 Bcf, which is less than a single day's withdrawal capacity. If gas prices were a key factor in SoCalGas' storage withdrawal decision-making, one would expect the green line representing price to decrease in tandem with the brown bars representing season-low inventory. The relationship between storage withdrawals and gas prices are further explored in Sierra Club Dr.

Vincent Berardi's testimony, which also finds a weak relationship between gas withdrawals and gas prices.[109]

3.3. SoCalGas has no record of using its gas storage to mitigate gas prices during gas price spikes.

SoCalGas's Gas Acquisition Department ("SoCalGas Gas Acquisition") procures gas on behalf of core customers. During the winter months, SoCalGas Gas Acquisition receives gas flowing supply from outside of the service territory that it has contracted for in advance. To meet core-customer demand, SoCalGas Gas Acquisition will withdraw gas from storage or inject gas into storage depending on whether the contracted flowing supply is greater or less than the day's core customer demand. The higher the gas demand, the more gas SoCalGas Gas Acquisition withdraws from storage.

In I.17-02-002, SoCalGas has claimed that on occasion it has "redirected some of its firm natural gas supplies to the higher-priced markets that were impacted by the extreme weather conditions, thus helping to support reliability in states east of California while concurrently reducing core procurement ratepayer costs."[110] However, when Sierra Club asked SoCalGas to provide records of redirected gas from 2010-2025, SoCalGas stated that it "is not able to identify redirected supplies in SoCalGas's Gas Acquisition Department transactional data."[111]

There are two reasons that SoCalGas would have no record of redirection gas transactions. First, it is possible that SoCalGas did not redirect gas at the time it claimed and has not redirected gas at any time between 2010 and 2025 (i.e., the time window of SoCalGas's data request response). If that is true, then SoCalGas made a false statement to the Commission in I.17-02-002. Second, it is possible that SoCalGas has redirected gas but failed to record or identify the transactions. If that is true, then there is no evidence to support SoCalGas's assertion that a redirection results in "reducing core procurement ratepayer costs," because there is no

[109] A.26-01-009, Prepared Direct Testimony of Dr. Vincent Berardi on behalf of Sierra Club, at 16-20 (Aug. 20, 2026).
[110] I.17-02-002, Comments of Southern California Gas Company (Apr. 20, 2021). *See also* Exh. SC-14: SoCalGas Response to Sierra Club Data Request 2-6 (May 28, 2026) ("The referenced statement is based on the recollection and knowledge of SoCalGas employees. SoCalGas does not have data specifically showing the redirected natural gas supplies during the 2014 Polar Vortex event.").
[111] Exh. SC-15: SoCalGas Response to Data Request 6, at 2 (Aug. 14, 2026).

record of credits to the core customer trading account. If redirection is happening, but there is no record of credits to the core customer trading accounts, it is unclear where received funds go when gas is redirected.

SoCalGas cannot demonstrate evidence to support its claim that it uses gas storage to mitigate gas prices. There is no record of SoCalGas's Gas Acquisition Department making any redirection trades to protect core customers from gas price spikes. If SoCalGas's Gas Acquisition Department is not making any redirection trades during windows of high gas price, and instead proceeds with its business-as-usual approach (i.e., accepting flowing gas that it procured in advance and supplementing that flowing supply with stored gas to meet core customer demand), then there is no price spike mitigation benefit to core customers from the excess gas storage in Aliso Canyon. Unless SoCalGas can demonstrate how it uses Aliso Canyon storage to mitigate price spikes with tangible data, the Commission should reject SoCalGas's unfounded arguments that an inventory reduction will cause an increase in gas prices.

3.4. A 29 Bcf reduction to Aliso Canyon will not hinder Unbundled Storage Program withdrawals.

A 29 Bcf reduction to Aliso Canyon storage will not impact the Unbundled Storage Program ("UBS") in any material way due to Commission rules regarding UBS operations as detailed in this section.

The UBS-assigned gas storage inventory is 25 Bcf. Over two winters, UBS participants have yet to fill the UBS portion of SoCalGas storage beyond 14.2 Bcf. The Figure below shows the daily inventory level of the UBS program from January 2024 through March 2026.

Figure 8: Unbundled Storage Program Inventory Jan 2024-March 2026[112]

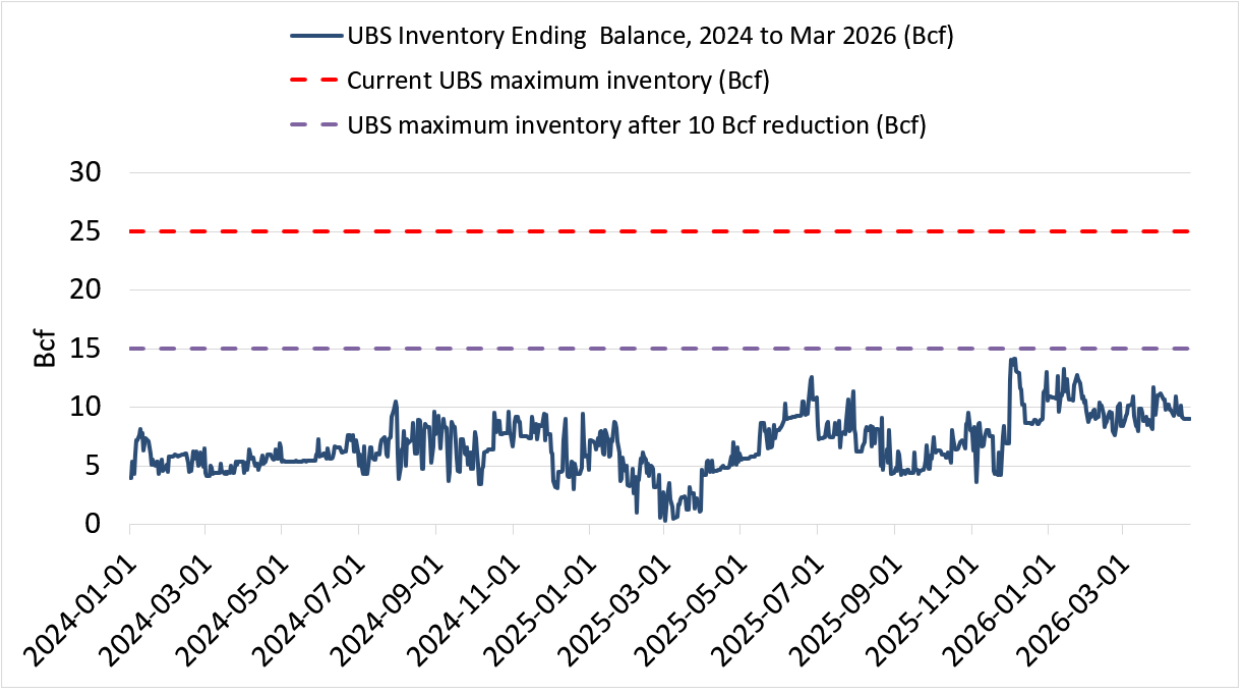


Figure 8, above, shows the only two winters that the UBS program has operated since D.24-07-009 set the maximum inventory and the maximum winter daily withdrawal for the UBS. The winter withdrawal season runs from November 1 – March 31. D.24-07-009 set the maximum winter withdrawal to 50 MMcfd. Thus, if every customer of the UBS withdrew at maximum capacity during each day of the winter withdrawal season, inventory would drop 7,550 MMcf. That shows the Commission could reduce Aliso Canyon capacity until the UBS capacity

[112] Exh. SC-16: SoCalGas Response to Sierra Club Data Request 1-19 (Mar. 20, 2026) (file name: "UBS TBS NonCore Activity_2003-2026"); D.24-07-009, Attachment A at 6, Inventory, Withdrawal, and Injection Table, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K556/536556034.PDF (UBS current maximum inventory, 25 Bcf); (Note, I assumed that inventory was provided in the unit Dth. For that reason, I used the same conversions that I used throughout my testimony of 1029.3 Dth/MMcf and 1000 MMcf/ Bcf).

drops to 7,550 MMcf if it wanted to align UBS inventory with the storage requirement for maximum winter UBS withdrawals.

Table 5: Storage Rights Allocations Regarding SoCalGas Storage[113]

	D.24-07-009					Calculated Percentages	
	Inventory BCF	Withdrawal		Injection		Winter Withdrawal as a % of Total Withdrawal in D.24-07-009 (2400 MMcf)	Winter Withdrawal as a % of SCG 2026 1-in-10 Forecast (4,758 MMcfd)
		Winter	Summer	Summer	Winter		
Core	80.03	1890	606	392	150	78.8%	39.7%
Balancing	12	400	1225	345	345	16.7%	8.4%
UBS	25	50	50	50	50	2.1%	1.1%
Wholesale	2.47	60	19	13	5	2.5%	1.3%
Total:	**119.5**	**2400**	**1900**	**800**	**550**	**100.0%**	50.4%

Table 5 demonstrates that the UBS program makes up only 2.1% of daily withdrawal capacity compared to core and balancing customers, which combined make up 95% of storage withdrawal allocations. The UBS withdrawal capacity is below a level that would impact market prices – especially considering that it is unlikely all UBS customers would withdraw or inject gas on any given day.

In addition to defining total inventory and withdrawal by category, D.24-07-009 defines how the UBS maximum capacity will be reduced as SoCalGas gas storage is reduced. D.24-07-009 states:

> If total available storage inventory levels are reduced by Commission order, the first 10 Bcf in reduction will be applied to Unbundled Storage (UBS), followed by pro rata reductions across all inventory rights down to the following floors: core 72 Bcf, wholesale 2.47 Bcf, and balancing 8 Bcf. Once the floors are reached, any further reductions shall come from UBS.[114]

The table below shows the storage inventory at each successive category floor level and UBS maximum inventory decreasing with each step.

[113] D.24-07-009, Attachment A at 6, Inventory, Withdrawal, and Injection Table, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K556/536556034.PDF (The last two columns of Table 5 above displaying calculated percentages are my own calculations.).

[114] *Id.*

Table 6: Gas Storage Inventory Reductions by Category (D.24-07-009 allocations)

Storage Category	Current Inventory (wholesale at floor level)	First 10 Bcf reduction from UBS	Pro Rata reduction (to core floor)	Pro Rata reduction (to balancing floor)	UBS reduction (to level retaining UBS winter maximum withdrawal)
Core	80.03	80.03	72	72	72
Balancing	12	12	10.80	8	8
UBS	25	15	13.49	10	7.55
Wholesale	2.47	2.47	2.47	2.47	2.47
Total:	**119.5**	**109.5**	**98.76**	**92.47**	**90.02**

Notes

1. All units in Bcf.
2. Floor level hit in column highlighted. According to D.24-07-009, after all categories except UBS hits its floor, "[o]nce the floors are reached, any further reductions shall come from UBS."
3. Figures round in the second decimal place.

While the maximum inventory allocated to each category of storage adjusts in steps, according to total maximum inventory of SoCalGas's storage facilities, the injection and withdrawal limits do not adjust in that way. USB injection and withdrawal limits only adjust according to the total available injection and withdrawal capacities for the given day. Thus, even though the UBS total inventory drops when the Commission reduces the maximum storage inventory levels, the UBS withdrawal capacity remains fixed at 2.1% of total storage withdrawal capacity as calculated in Table 5. 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 result of this analysis is that maximum UBS daily withdrawals (50 MMcfd) during every day of the withdrawal season (i.e., 151 days) would equal 7.55 Bcf of gas storage withdrawals. The Commission would have to reduce total SoCalGas gas storage to 90.02 Bcf for the maximum UBS storage inventory to be limited to 7.55 Bcf. Current SoCalGas storage inventory is 119.5 Bcf. Thus, the Commission could reduce Aliso Canyon storage inventory by 29.48 Bcf before it limits winter storage withdrawals by UBS subscribers.[115] As I noted in Section 2.5, above, when both the reliability analyses are considered and the gas price analyses

[115] Calculation: 119.5 Bcf – 90.02 Bcf = 29.48 Bcf.

are considered – including the UBS analysis – a 29 Bcf reduction is a reasonable first reduction to Aliso Canyon's maximum inventory level.

4. ENERGY INSECURITY CAUSED BY NATURAL GAS INCREASES ENERGY PRICES IN CALIFORNIA.

The ongoing energy transition in California reduces the need for gas storage such at Aliso Canyon. The California Legislature has established that it is "the policy of the state to... [a]chieve net zero greenhouse gas emissions as soon as possible, but no later than 2045[.]"[116] Most people recognize that a transition to net zero will require eliminating a significant amount of natural gas use in the state. That change will reduce air pollution leading to health benefits for Californians. However, the state also gains another benefit from the energy transition: elimination of the energy insecurity that accompanies natural gas.

This section of my testimony addresses opportunities to reduce both the need for Aliso Canyon and the energy insecurity that natural gas creates. I examine California's dependence on imported gas, SoCalGas's gas equipment subsidies, dual-fuel outage exposure, SoCalGas-caused infrastructure outages, and the need for reasonable modeling assumptions that account for that insecurity.

4.1. 95% of the gas SoCalGas customers use is imported from other states, presenting a fundamental energy insecurity.

SoCalGas imports nearly all the natural gas it delivers from other states. The 2026 California Gas Report records that in 2025 California sources supplied 88 MMcf/d of the 2,107 MMcf/d that SoCalGas received, meaning 95.8 percent of its supply originated outside the state.[117] That share has exceeded 95 percent in every recorded year since at least 2021.[118]

SoCalGas does not dispute the point. Its witness testifies that "California currently receives over 95% of its natural gas supply from out-of-state sources," and that "[b]ecause there

[116] Cal. Health and Safety Code § 38562.2(c)(1), ("It is the policy of the state to... [a]chieve net zero greenhouse gas emissions as soon as possible, but no later than 2045").

[117] 2026 California Gas Report at 22, Table 15, Recorded 2025 Statewide Sources and Disposition Summary (Southern California Gas Company, Total row: 1 − (88 MMcf/d ÷ 2,107 MMcf/d) = 0.95823 = 95.8%).

[118] 2026 California Gas Report at 18-22, Table 11-15.

is no meaningful in-state production of natural gas, the SoCalGas system is almost wholly dependent on deliveries of gas from out-of-state through interstate pipelines, which makes the availability of local natural gas storage critical to energy reliability."[119] SoCalGas effectively argues that natural gas is an energy security risk. I agree. Mr. Sawin says Aliso Canyon is critical because the supply is beyond state control,[120] which is an argument for reducing gas dependence, not for storing more gas. The interstate pipelines, out-of-state production basins, and LNG export terminals that determine the price and availability of gas lie almost entirely outside the Commission's jurisdiction, while the renewable generation and battery storage that displace gas demand are frequently in CPUC jurisdiction.

4.2. SoCalGas subsidizes gas use by subsidizing gas equipment, which conflicts with California energy goals, increases ratepayer costs, and extends energy insecurity.

SoCalGas continues to pay its customers to install gas equipment. In response to Sierra Club data request 2-17 asking how much SoCalGas distributed to core customers to reduce the cost of gas appliance purchases in each year from 2015 through 2025, SoCalGas reported rebates totaling $362.5 million over that eleven-year period, an average of $32.9 million each year.[121]

[119] A.26-01-009, Prepared Direct Testimony of Andrew J. Sawin on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-3 (Jan. 15, 2026).

[120] *Id.* at AJS-3 ("California currently receives over 95% of its natural gas supply from out-of-state sources. Because there is no meaningful in-state production of natural gas, the SoCalGas system is almost wholly dependent on deliveries of gas from out-of-state through interstate pipelines, which makes the availability of local natural gas storage critical to energy reliability.").

[121] Exh. SC-17: SoCalGas Response to Sierra Club Data Requests 2-16 and 2-17 (May 28, 2026), Attachment "Sierra Club Data Requests – EE Spend 2015-2025.xlsx," Tab "sc 2-17." (Question 17 asked: "How much money did SCG distribute to core gas customers to reduce the cost of gas appliance purchases in each year from 2015 through 2025?").

Table 7: SoCalGas Gas Equipment Subsidies to Core Customers[122]

Year	Rebates
2015	$31,604,660
2016	$27,233,804
2017	$23,487,502
2018	$28,809,432
2019	$33,684,226
2020	$43,293,866
2021	$39,928,247
2022	$39,935,788
2023	$31,535,670
2024	$31,596,771
2025	$31,438,916
Annual Avg.	**$32,958,989**
Total	**$362,548,882**

That spending has not declined as California's electrification policies have advanced. SoCalGas distributed $31.4 million in 2025, nearly the same amount as the $31.6 million it distributed in 2015.[123] Each subsidized gas appliance installed today commits that customer to gas service for the useful life of the equipment, typically a decade or more. That extends demand for a fuel supply that is 95% imported and largely beyond this Commission's or California's authority. Ratepayers are therefore paying twice: once to subsidize the equipment that sustains gas demand, and again to maintain the storage inventory that SoCalGas claims the gas demand requires.

California's energy agencies have concluded that the state should be working to incentivize electrification instead of gas appliances. In their Joint Agency Staff Gas Transition White Paper, the CPUC, CEC, and CARB found that "[e]lectrification is the best fit for decarbonizing homes and commercial buildings, where gas infrastructure can be fully electrified with technologies such as heat pumps for space and water heating and clothes drying and induction stoves."[124] The same agencies found that "increased electrification will put downward

[122] *Id.*

[123] *Id.*

[124] R.24-09-012, Administrative Law Judge's Ruling Serving Corrected Joint Agency Staff Gas Transition White Paper, Attachment A, CPUC, CEC, and CARB Joint Agency Staff Gas Transition White Paper, at 14, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M550/K500/550500746.PDF

pressure on rates as costs are spread across a greater volume of electricity usage,"[125] and that "[m]inimizing new investments in infrastructure that could become stranded assets is important to reducing ratepayer costs during the gas transition."[126] SoCalGas's incentive spending conflicts with each of those findings. It also conflicts with California's decarbonization policy, which the California Legislature defines in California Health and Safety Code §38562.2(c): "[i]t is the policy of the state to... [a]chieve net zero greenhouse gas emissions as soon as possible[.]"[127]

Returning to Aliso Canyon specifically, gas subsidies to core customers increase the peak 1-in-10 gas demand. Core customer gas use represents 62% of SoCalGas's 1-in-10 peak demand. Electrification – rather than gas equipment subsidies – will help to reduce the 1-in-10 peak demand forecast over time.

4.3. Residential customers lose access to energy during gas outages and during electricity outages.

Dual-fuel homes increase energy insecurity because their energy supply is less reliable than all-electric homes. A residential customer with gas equipment is exposed to two independent causes of service loss rather than one. Gas furnaces and household cooking appliances installed in California may no longer use continuously burning pilot lights, so they depend on electric ignition, and central gas furnaces additionally require electricity to run the air-handler fan that distributes heat and to operate their safety controls.[128] The practical result is that a gas-heated home loses heat during an electricity outage even if gas is still flowing, and it loses heat again whenever the gas system itself is interrupted — two failure points where an all-electric home has one. Restoration is not symmetric either: electric service is restored by repairing shared circuits and can return to thousands of customers at once, while gas service must

[125] *Id.* at 16.

[126] *Id.* at 34.

[127] Cal. Health and Safety Code § 38562.2(c)(1).

[128] California Energy Commission, *2025 Single-Family Residential Mandatory Requirements Summary*, § 110.5 ("Continuously burning pilot lights are prohibited for natural gas: fan-type central furnaces; household cooking appliances (except appliances without electrical supply voltage connection with pilot lights that consume less than 150 Btu/h); pool and spa heaters."), and § 150.0(m)13 (prescribing "an air-handling unit fan efficacy ≤ 0.45 watts per CFM for gas furnace air handlers"), https://www.energy.ca.gov/sites/default/files/2025-04/2025_Residential_Mandatory_Measures_Summary_ADA.pdf. *See also* § 110.5(e) (continuously burning pilot lights not allowed for indoor and outdoor fireplaces).

be restored home by home, with a technician entering each building to relight appliances while the customer is present, which is why gas restoration after a system-wide interruption is measured in weeks or months rather than hours.[129] Electrifying building end uses therefore does not trade one vulnerability for another; it eliminates one of the two causes of service interruption that a dual-fuel household currently carries.

4.4. SoCalGas itself exacerbates energy insecurity through its role in two of the highest volume and longest gas infrastructure outages in the last 15 years.

SoCalGas asks the Commission to maintain a large inventory at Aliso Canyon in part because its system is subject to infrastructure outages. Two of the largest and longest outages on that system were caused by SoCalGas itself, according to the Commission's Safety and Enforcement Division as detailed below.

The first outage was the Aliso Canyon blowout.[130] Well Standard Sesnon-25 ("SS-25") failed on October 23, 2015, and the well vented gas into adjoining residential neighborhoods for 111 days.[131] SoCalGas could not regain control of the well: seven attempts to kill it through the

[129] Commonwealth of Massachusetts, Merrimack Valley Natural Gas Explosions After Action Report at 17 and 66, Figure 8, https://www.mass.gov/doc/merrimack-valley-natural-gas-explosions-after-action-report/download. (Following the September 13, 2018 overpressurization, gas service to affected customers was not substantially restored until mid-December 2018, because each affected premises required individual inspection, line purging, and appliance relighting.); *See also* National Transportation Safety Board, Overpressurization of Natural Gas Distribution System, Explosions, and Fires in Merrimack Valley, Massachusetts, NTSB/PAR-19/02, https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf .

[130] A blowout is "an uncontrolled flow of well fluids and/or formation fluids from the wellbore or into lower pressured subsurface zones (underground blowout)." American Petroleum Institute, RP 64, Recommended Practice for Diverter Systems Equipment and Operations (2d ed. Nov. 2001), as reproduced in International Association of Drilling Contractors, IADC Lexicon, "Blowout," https://iadclexicon.org/blowout/. Blowout, not leak, is the technically correct term for the 2015 SS-25 event. A leak denotes a containment breach in which well control is retained and the release can be isolated by ordinary means; a blowout denotes the loss of well control. Well control at SS-25 was lost: seven top kills through the wellhead failed, and flow ceased only after a relief well intercepted the wellbore at depth. The independent contractor selected by the Commission and the Division of Oil, Gas, and Geothermal Resources (currently CalGEM) to perform the root cause analysis describes the event as "the SS-25 Well blow out." Blade Energy Partners, Aliso Canyon SS-25 Root Cause Analysis (May 16, 2019). Peer-reviewed literature uses the same term. Lehua Pan, Curtis M. Oldenburg, Barry M. Freifeld & Preston D. Jordan, Modeling the Aliso Canyon underground gas storage well blowout and kill operations using the coupled well-reservoir simulator T2Well, 161 J. Petroleum Sci. & Eng'g 158 (Feb. 2018), https://www.sciencedirect.com/science/article/pii/S0920410517309488.

[131] Lehua Pan, Curtis M. Oldenburg, Barry M. Freifeld & Preston D. Jordan, Modeling the Aliso Canyon underground gas storage well blowout and kill operations using the coupled well-reservoir simulator

wellhead failed, and the flow was halted only after a relief well intercepted SS-25 at a depth of approximately 8,400 feet, permitting a bottom kill on February 11, 2016.[132] By the time the well was sealed, at least 109,000 metric tons of methane had been released — the largest uncontrolled release of methane in United States history.[133] The blowout removed the largest storage field in the SoCalGas system from service. The Safety and Enforcement Division concluded that "SoCalGas unsafely managed, unsafely operated, and unsafely maintained its Aliso Canyon facility for multiple decades until Well Standard Sesnon-25 (SS-25) finally failed, all in violation of California Public Utilities Code Section 451."[134]

The second outage was the rupture of Line 235 West on October 1, 2017 at a location west of Newberry Springs.[135] The Safety and Enforcement Division's investigation identified the causes of the rupture as including failed cathodic protection, coating damage during construction, failure to conduct a leak investigation, inadvisable pressure control, and integration and mitigation failures.[136] After the rupture, SoCalGas reduced operating pressure on Line 235 and on the adjacent Line 4000 and posted a capacity reduction of 900 MMcfd to its Envoy maintenance log with no stated end date.[137] Before the rupture, SoCalGas represented that its

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T2Well, 161 J. Petroleum Sci. & Eng'g 158 at 1 (Feb. 2018), https://www.sciencedirect.com/science/article/pii/S0920410517309488 ("Seven attempts to gain pressure control and stop the gas flow by injection of heavy kill fluids through the wellhead failed, a process referred to as a 'top kill.' Introduction of drilling mud when a relief well milled through the casing of SS-25 at a depth of ~8,400 ft ('bottom kill') succeeded in halting the gas flow on February 11, 2016."; "the blowout spanned 111 days.").

[132] *Id.*

[133] California Air Resources Board, *Aliso Canyon Leak Emitted 109,000 Metric Tons of Methane* (Oct. 21, 2016), https://ww2.arb.ca.gov/news/aliso-canyon-leak-emitted-109000-metric-tons-methane; NOAA Climate Program Office, *NOAA and Partners Report the Largest Methane Leak in U.S. History in a Joint Study* (Mar. 4, 2016), https://cpo.noaa.gov/noaa-and-partners-report-the-largest-methane-leak-in-us-history-in-a-joint-study/.

[134] I.19-06-016, Opening Brief of the Safety and Enforcement Division at 4-5 (May 9, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M476/K602/476602876.PDF.

[135] CPUC, *CPUC–CEC Interagency Reliability Workshop, Line 235 Root Cause*, slide 4 (May 23, 2019) ("On October … 2017, L-235 Ruptured at a location west of Newberry Springs").

[136] Exh. SC-09: Safety and Enforcement Division Line 235 Final Report – Redacted, Released Pursuant to CPUC Resolution L-571 at PDF pp. 2-3 (Oct. 25, 2018) (filed as Attachment A to A.26-01-009, Sierra Club Comments in Response to Prehearing Conference Ruling (Mar. 27, 2026)) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K483/603483126.PDF.

[137] SoCalGas Envoy, Operations, Maintenance Schedules, Maintenance Ledger ("Start date: October 15, 2019. End date = TBD. Capacity reduction = 900 MMcfd. Description: Restricted operation of L4000 and L235."), https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome.

system had "the potential capacity to accept up to 3,875 MMcfd of interstate and local California supplies"; three years later the Commission's winter reliability assessment put available capacity at 2,820 MMcfd.[138] The outage was not brief. Eighteen months after the rupture SoCalGas still could not return the line to service: it detected two leak indications on March 23, 2019, two days before the scheduled return-to-service date, two more on April 8, a fifth on April 19, and a sixth and seventh on April 27.[139] Line 235 West did not regain its designed operating capacity until November 2023, nearly six years after the rupture.[140]

SoCalGas's own outage reports show that Aliso Canyon is not a remedy for this record, but a further instance of it. SoCalGas's External Outage Report — covering events SoCalGas attributes to causes outside its service territory — identifies a single curtailment: a Rule 23 curtailment of electric generation customers from February 6 through February 8, 2019, which SoCalGas attributed to forecasted low temperatures and expected high demand from a polar vortex.[141] SoCalGas does not mention that Aliso Canyon failed during that same event.[142] During the event, Aliso Canyon was restricted to 34 Bcf due to the blowout and held 30.4 Bcf on

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[138] *2016-2017 Aliso Canyon Winter Risk Assessment Technical Report* at 8 (Aug. 23, 2016); CPUC, *Winter 2019-20 Southern California Reliability Assessment* at 11, Table 3 (Oct. 24, 2019), https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2019/winter2019-20reliabilityassessment-final.pdf.

[139] CPUC, *CPUC–CEC Interagency Reliability Workshop, Line 235 Root Cause,* slide 7 (May 23, 2019) ("Status of the 7 Leaks on L-235").

[140] CPUC, *Winter 2023-2024 Southern California Gas Reliability Assessment* at PDF p. 4 (Sept. 15, 2023), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/2023_winter_reliability_daily_stochastic_mass_balance_model.pdf ("The Northern Zone of the pipeline system is set to regain 175 million cubic feet per day (MMcfd) of receipt capacity in November 2023 when Line (L) 235 west remediation is scheduled to end.").

[141] A.26-01-009, Compliance Filing of Southern California Gas Company (U904G) Regarding External Outages at 17, 20 (May 1, 2026) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K451/606451664.PDF ("From February 6 at 12:00 AM through February 8 at 11:59 PM, SoCalGas issued a curtailment for electric generation customers under Rule 23 due to forecasted low temperatures and expected high customer demand.").

[142] SoCalGas, *Aliso Canyon Withdrawal Notification* at 2, 7 (last updated Mar. 22, 2019), https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2019/alisowithdrawalsnotification02-10-2019c.pdf (Feb. 4, 2019 Aliso Canyon inventory of 30.416 Bcf; Feb. 5, 2019 reduction of withdrawal capacity by 420 MMcfd "due to unplanned repairs" and issuance of the Rule 23 curtailment effective Feb. 6; Feb. 7, 2019 temporary repair restoring 200 MMcfd; Feb. 8, 2019 termination of the curtailment).

February 4, 2019.[143] On February 5, SoCalGas *reduced Aliso Canyon withdrawal capacity by a further 420 MMcfd* "due to unplanned repairs," and on that same day issued the curtailment of electric generation effective February 6.[144] A temporary repair restored 200 MMcfd on February 7, and the curtailment ended on February 8.[145] Thus, the one curtailment SoCalGas attributes to events beyond California was in fact caused by an unplanned outage at Aliso Canyon — more than three years after the blowout, and after extensive remediation of the field.

Two further facts are relevant. Receipt point utilization averaged 93% from February 4 through February 24, 2019, so flowing supply was available to the system throughout.[146] And although SoCalGas curtailed gas to electric generators during the coldest February in Los Angeles since 1962, CAISO served all electric demand and issued no alert, warning, emergency, or flex alert on any day that month.[147]

These facts relate directly to the relief SoCalGas seeks in this proceeding. SoCalGas cannot maintain both that it is a safe operator that should be trusted to store more gas at Aliso Canyon, and that its system faces so many outages that it must store more gas as insurance against outages. The Commission's own safety division has found SoCalGas responsible for both major outages that define the unreliability SoCalGas now invokes, and SoCalGas's own reporting shows Aliso Canyon failed during the single curtailment it blames on outside forces. Relying on a repeatedly problematic storage facility to back up the rest of SoCalGas's infrastructure, on top of a gas supply that is 95% imported from other states and beyond the Commission's authority, poses energy insecurity risks to California. Additional inventory at Aliso Canyon does not address the cause of these events. It increases the quantity of gas held at the facility whose failure caused the first of the events, does nothing to prevent the kind of maintenance-related rupture that caused the second, and compounds reliance on the very asset that precipitated the third.

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[143] *Id.*

[144] *Id.*

[145] *Id.*

[146] *Id.* at 8.

[147] CAISO, *Grid Emergencies History Report* at 143-145 (Apr. 14, 2026), https://www.caiso.com/documents/grid-emergencies-history-report-1998-to-present.pdf; Alejandra Reyes-Velarde, *February Is Coldest in Los Angeles in Nearly 60 Years*, Los Angeles Times (Feb. 25, 2019), https://www.latimes.com/local/lanow/la-me-ln-cold-february-20190225-story.html.

Accordingly, the Commission should reject SoCalGas' arguments in support of increasing inventory at Aliso Canyon.

4.5. The gas system depends on unreliable infrastructure, but reasonable assumptions must still be applied to modeling.

In its testimony, SoCalGas argues that its infrastructure is becoming less reliable, and asks the Commission to model a winter in which several failures occur at once. For winter 2025-2026, SoCalGas assumes the Northern Zone is "[r]educed to 935 MMcfd for the entire winter season to reflect the pressure derate on Line 4000 and Line 4002 south of Cajon"; the Southern Zone is "[r]educed to 1,060 MMcfd for January 2026 to reflect an assumed unplanned outage on Line 5000 downstream of Blythe Compressor Station"; and the Wheeler Ridge Zone is held at 765 MMcfd.[148] SoCalGas then applies "an 85% RPU across all receipt zones, except California Producers."[149] These assumptions result in a January peak-day pipeline supply of 2,416 MMcfd,[150] which is 62 percent of the 3,875 MMcfd of potential capacity SoCalGas has represented that its system can accept.[151]

I agree that SoCalGas' infrastructure has demonstrated a lack of reliability. As I noted in Section 4.4 above, the Commission's Safety and Enforcement Division found that SoCalGas's own conduct produced both the Aliso Canyon blowout and the Line 235 rupture.[152] But SoCalGas's assumptions regarding flowing pipeline supply do not align with the capacity its system has made available during winter seasons.

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[148] A.26-01-009, Prepared Direct Testimony of Andrew J. Sawin on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-14 (Jan. 15, 2026).

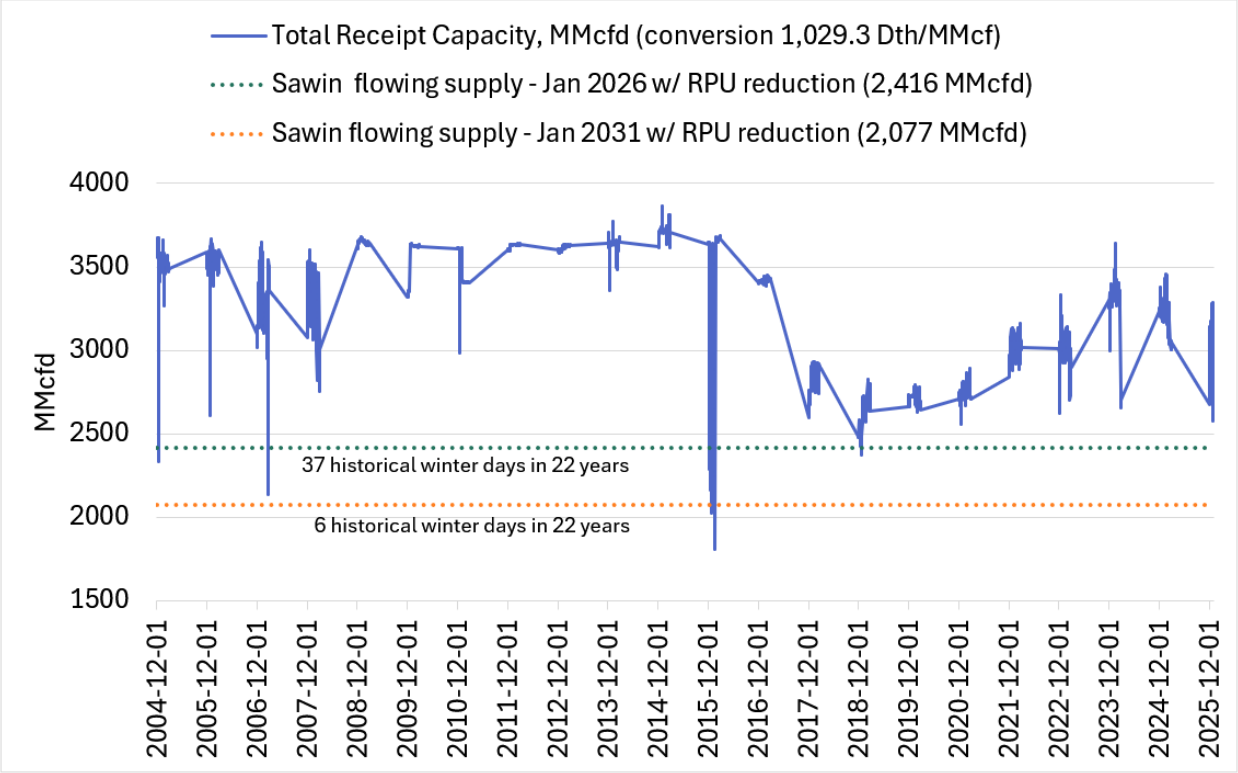
[149] *Id.*

[150] *Id.* at AJS-19.

[151] *2016-2017 Aliso Canyon Winter Risk Assessment Technical Report* at 8 (Aug. 23, 2016) https://www.cpuc.ca.gov/regulatory-services/safety/gas-safety-and-reliability-branch/aliso-canyon-well-failure/aliso-canyon-summer-and-winter-reliability-assessments ("The system today has the potential capacity to accept up to 3,875 MMcfd of interstate and local California supplies."); Calculation: 2,416 MMcfd ÷ 3,875 MMcfd = 0.6235 = 62%. For winter 2030-2031: 2,077 MMcfd ÷ 3,875 MMcfd = 0.5360 = 54%.

[152] *See* Section 4.4, above.

Figure 9: Total Receipt Capacity 2004-2025, (Dec, Jan, Feb)[153]
(Historical capacity shown as posted, without RPU reduction;
Sawin values include his 85% RPU assumption.)



The figure above shows SoCalGas's total receipt capacity for December through February from 2004 through 2025, compared with the January flowing supply used as an input in Mr. Sawin's mass balance analysis, with his RPU assumptions applied.[154] I compared Mr. Sawin's post-RPU input to total receipt capacity because SoCalGas offers its customers 100% of available capacity every day, and the record shows that customers take nearly all of it when they need it. During SoCalGas's 22-year record of receipt point utilization data, customers scheduled

[153] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026); *See also*, A.26-01-009, Prepared Direct Testimony of Andrew J. Sawin on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-14 and AJS-15 (Jan. 15, 2026).

[154] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026), and Attachment. SoCalGas reports total receipt capacity and total scheduled volumes in dekatherms; I have converted to MMcfd using 1,029.3 Dth/MMcf. The series covers September 30, 2004 through December 31, 2025 and contains 1,926 days falling in the months of December, January, and February, spanning 22 winter seasons. All counts and percentages in this section are calculated on those 1,926 days.

97% or more of posted system capacity on 558 days.[155] Utilization is therefore constrained by what customers require, not by what the system can accept.

Measured against the 3,875 MMcfd of SoCalGas nominal capacity, the capacity SoCalGas actually posts during winter is consistently above 70%. Median December–February total receipt capacity across 22 winters is 3,415 MMcfd, or 88 percent of that potential, and the average is 3,286 MMcfd, or 85 percent. The full distribution is as follows.

Table 8: December–February Total Receipt Capacity as a Share of 3,875 MMcfd Nominal System Capacity, 2004–2025[156]

Posted total receipt capacity	Dec-Feb days	Share of Dec–Feb days
≥ 90% of nominal (3,488 MMcfd)	810	42.1%
≥ 85% of nominal (3,294 MMcfd)	1152	59.8%
≥ 80% of nominal (3,100 MMcfd)	1322	68.6%
≥ 70% of nominal (2,712 MMcfd)	1763	91.5%

SoCalGas asks the Commission to plan on 62 percent of nominal capacity.[157] Posted capacity has equaled or exceeded 70 percent of nominal capacity on more than nine of every ten winter days in the record.

SoCalGas' specific assumptions are rarer still. Of the 1,926 December–February days in the record, total receipt capacity was at or below the 2,416 MMcfd SoCalGas assumes for January 2026 on 37 days — 1.9 percent — and at or below the 2,077 MMcfd it assumes for January 2031 on 6 days — 0.3 percent.[158] In summary SoCalGas has asked the Commission to assume that 1-in-10 peak day gas demand overlaps with a gas flowing supply restriction that

[155] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (These day-counts use SoCalGas's calculated RPU% in its response to Sierra Club Data Request 2-8); *See also* Section 5.3.3, below.

[156] *Id.* Nominal system capacity of 3,875 MMcfd per *2016-2017 Aliso Canyon Winter Risk Assessment Technical Report*, at 8. SoCalGas's own operating data corroborates that figure: the highest total receipt capacity in the series is 3,914 MMcfd, and the December–February maximum is 3,864 MMcfd, or 99.7 percent of the stated potential.

[157] As previously explained and cited in Section 4.5 above and in footnotes 148-151.

[158] *Id.* Calculations: 37 ÷ 1,926 = 0.0192 = 1.9%; 6 ÷ 1,926 = 0.0031 = 0.3%.

occurs on 2% of winter days. Assuming those two events are not correlated, then the likelihood of SoCalGas's overlapping scenarios occurring is once every 500 years.[159]

During the 2025 Biennial Assessment workshop, Energy Division asked whether SoCalGas's assumptions should be layered on top of a 1-in-10 demand day forecast, and appeared to imply that they should not.[160] I agree that SoCalGas should not layer its unlikely assumptions because it leads to unrealistic results.

The single day in the record that most closely resembles the demand conditions corresponding to SoCalGas's 62%-of-nominal-capacity proposal is a day with significant capacity availability. January 14, 2013 is the only day on which SoCalGas customer gas demand exceeded SoCalGas's 1-in-10 peak day demand forecast.[161] On that day, SoCalGas posted a total receipt capacity of 3,634 MMcfd — 94 percent of nominal system capacity, and 1,218 MMcfd more than the 2,416 MMcfd SoCalGas now assumes will be available on a comparable day. Customers scheduled 2,474 MMcfd of that capacity, resulting in an actual RPU of 68%.[162]

That comparison requires close consideration, because two different quantities are involved, and the distinction between them is the substance of the disagreement over RPU in this proceeding. SoCalGas's 2,416 MMcfd of modeled receipt capacity is an assumption about the capacity that will exist on a peak day. The 2,474 MMcfd of scheduled capacity on January 14, 2013 represents what customers took, and customers take what they need. They needed 2,474 MMcfd on the highest-demand day in the record because 3,634 MMcfd of capacity stood behind it and storage served the balance. A planning case in which only 2,416 MMcfd of capacity *exists* describes a materially different and far more constrained system than the one that actually served demand above the design forecast in 2013. SoCalGas does not assume that customers will

[159] Calculation: 10 years / 2% = 500 years; If the events are correlated, then the likelihood of SoCalGas's proposed modeling scenario is between 10 years and 500 years depending upon the strength of the correlation.

[160] A.26-01-009, Aliso Canyon Biennial Assessment Workshop (Apr. 15, 2026).

[161] SoCalGas Envoy, Daily Operations, https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternalDailyOperations.getDailyOperation.

[162] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (January 14, 2013: total receipt capacity of 3,740,193 Dth and total scheduled volumes of 2,546,970 Dth, converted at 1,029.3 Dth/MMcf to 3,634 MMcfd and 2,474 MMcfd respectively; reported receipt point utilization of 0.68). Calculations: 3,634 ÷ 3,875 = 0.938 = 94%; 3,634 − 2,416 = 1,218 MMcfd.

schedule 2,416 MMcfd; it assumes the system will be unable to offer more. When the system last faced demand above its design forecast, it offered 3,634 MMcfd in actual total receipt capacity.

Reasonable planning does not require assuming that every unfavorable condition occurs simultaneously. SoCalGas's 1-in-10 peak day scenario combines a demand level observed on one day in 25 years (i.e., actual peak day occurrence)[163] with a capacity level observed on 37 days over the 22 winters (i.e., total receipt capacity) in the evaluation window.[164] Neither assumption is impossible standing alone. However, I disagree with the reasonableness of compounding them, treating the product as the planning case, and then asking the Commission to authorize storage inventory because of it. Accordingly, I recommend the Commission reject SoCalGas' proposal to use both a high 1-in-10 peak day forecast as well as an unrealistically low gas flowing supply in its modeling.

5. UPDATES TO THE BIENNIAL ASSESSMENT PROCESS WILL IMPROVE INPUTS AND RESULTS NEEDED FOR DECISION MAKING.

This section of my testimony reviews the inputs in the D.24-12-076's Attachment A, the Biennial Assessment Report Inputs and Methods ("Biennial Modeling Criteria"). I discuss why the Biennial Modeling Criteria document should be updated to allow Energy Division to propose any level of maximum for Aliso Canyon it deems prudent. I also recommend changes to the four analyses that Energy Division completes for the biennial assessments, which are the (1) demand reduction analysis, (2) hydraulic flow modeling reliability analysis, (3) gas balance reliability analysis, and (4) economic analysis.

5.1. Energy Division should be allowed to recommend Aliso Canyon storage reductions greater than 10 Bcf.

The Biennial Modeling Criteria's introduction notes that the Biennial Assessments may recommend reductions to the Aliso Canyon Natural Gas Storage Facility maximum inventory level of "up to 10 Bcf."[165] I recommend that the Commission update this criterion to allow Energy Division to recommend any maximum inventory level it deems prudent. Otherwise, the

[163] *See* Figure 1, above.

[164] *See* Figure 9, above.

[165] Biennial Modeling Criteria at A1.

Commission will not have written documentation of the Energy Division's understanding of the circumstances and true recommendation. This issue has already come up during the first biennial assessment in which the Energy Division recommends the maximum permissible reduction of 10 Bcf. Because this is the maximum allowed reduction, intervenors do not know if this is where the Energy Division believes the maximum inventory should be adjusted to, or if the Energy Division would have recommended a greater reduction without the 10 Bcf limit. The Energy Division's maximum inventory limit recommendation should be publicly available so that parties can review and discuss that recommendation.

5.2. The demand reduction analysis should use the CEC forecast.

The Biennial Modeling Criteria state that the "the demand reduction analysis will consist of comparing the forecast peak day gas demand (demand) with the 4,121 MMcfd threshold level (threshold) necessary for considering closure of Aliso Canyon."[166] It goes on to state:

> The peak gas day demand for the upcoming year and available future years shall be determined using the level reported in the California Gas Report until such time as the California Energy Commission provides an alternative 1-in-10 winter peak gas day forecast for the SoCalGas service territory and the CPUC adopts its use.[167]

Energy Division reasonably interpreted that to mean it should subtract the threshold level for closure of 4,121 MMcfd from SoCalGas's 1-in-10 peak day demand forecast of 4,618 MMcfd.[168] That resulted is a difference from threshold of 497 MMcfd and none of SoCalGas's future-year forecasts dropped below the 4,121 MMcfd threshold level.

As I discussed in Section 2.2, the rapid growth in battery capacity in California has exceeded the level that FTI determined would be needed for reliability without Aliso Canyon. As I demonstrated with data in Section 2.5, the temperature-controlled gas demand fell in 2025 and fell substantially in 2026. Despite that data, SoCalGas's 1-in-10 gas demand forecast *increased* in the 2026 California Gas Report. The data and analyses I have provided along with Dr. Berardi's testimony chapter demonstrate that SoCalGas's 1-in-10 peak demand forecast is not accurate and should not be considered by the Commission. Instead, the Commission should

[166] *Id.* at A2.

[167] *Id.* at A2-A3.

[168] 2025 Biennial Assessment at 7, Table 1.

adopt the use of the CEC forecast that the Biennial Modeling Criteria lists as an option.[169] The CEC forecast is published annually and could be used immediately.

One concern that has been raised with the CEC forecast is that it does not include future-year forecasts. CEC forecasts only include the upcoming year's forecast of the 1-in-10 gas demand. However, future-year forecasts do not impact the biennial assessment process. The Biennial Modeling Criteria specifically note "[t]he demand reduction analysis will report the forecast peak day gas demand for the upcoming year and *available* future years…"[170] It only requires use of "available" future years. My testimony and Dr. Berardi's testimony[171] together show that SoCalGas's 1-in-10 peak day demand forecast for the current year is inaccurate because it is based on a flawed model that produces inaccurate results. Future-year SoCalGas forecasts are derived from the upcoming-year forecast and are therefore inaccurate as well. It is unreasonable to use inaccurate forecasts produced by a biased party.

CEC forecasts are created using a more appropriate and robust methodology than SoCalGas's forecasts.[172] Moreover, the CEC is a neutral third-party with no market interest, whereas SoCalGas has an inherent bias for higher demand forecasts. The Biennial Modeling Criteria states that:

> When the peak day demand forecast for two years out decreases to 4,121 million metric cubic feet per day and the biennial assessment process shows that Aliso Canyon could be closed without jeopardy to reliability or just and reasonable rates, then the biennial assessment report will recommend opening an Order Instituting Investigation proceeding to review the conclusions of the biennial assessment and to address the relevant issues related to permanent closure and decommissioning.[173]

Because SoCalGas produces the 1-in-10 peak day demand forecast, the Biennial Assessment Criteria establishes SoCalGas as the decision maker. The biennial assessment can only recommend an investigation proceeding for the closure and decommissioning of Aliso Canyon if SoCalGas publishes a forecast below 4,121 MMcfd in its 1-in-10 peak forecast. As

[169] Biennial Modeling Criteria at A2-A3.

[170] *Id.* at A2 (emphasis added).

[171] A.26-01-009, Prepared Direct Testimony of Dr. Vincent Berardi on behalf of Sierra Club, at 2-16 (Aug. 20, 2026).

[172] *Id.* at 14-16.

[173] Biennial Modeling Criteria at A1-A2.

long as the biennial assessment uses the SoCalGas peak demand forecast, SoCalGas has the option to block consideration of Aliso Canyon retirement.

Further, because the biennial assessment only uses future-year forecasts to determine "[w]hen the peak day demand forecast for two years out decreases to 4,121 million metric cubic feet per day,"[174] then the use of the CEC forecast would only potentially reduce consideration of Aliso Closure by two years. In contrast, because SoCalGas has a vested interest against allowing Aliso Canyon to be closed at any time, the use of SoCalGas's forecasts are unlikely to enable the Commission to consider closure of Aliso Canyon. This again shows the reasonableness of using the CEC forecast regardless of whether it is published for just the immediate upcoming season forecast (as it is currently) or if it publishes future-year forecasts as well. Currently, the Commission's regulatory decision making on Aliso Canyon runs through SoCalGas, making it a flawed regulatory process. Accordingly, I recommend the Commission modify the Biennial Assessment to rely on CEC demand forecasts instead of SoCalGas demand forecasts.

5.3. The hydraulic flow analysis and gas balance reliability analysis should rely on inputs produced by CPUC staff or CEC staff.

This section of my testimony reviews the Biennial Modeling Criteria's Table 1: Gas Sufficiency Analysis Inputs, which are used for the Energy Division's hydraulic flow modeling reliability analysis and gas balance reliability analysis**.**

I base my recommendations regarding inputs and assumptions on two fundamental principles. First, SoCalGas, the regulated entity, should not select or influence the inputs and assumptions that the Commission uses in its modeling. If SoCalGas selects the modeling inputs, then SoCalGas controls the modeling outputs. Second, when possible, inputs should be based on historical data suited for the task. Use of historical data as inputs eliminates SoCalGas's ability to influence the input selection unless SoCalGas adjusts its activities over the course of several years of operations.

[174] *Id.*

5.3.1. The biennial assessment modeling should use CEC or CPUC inputs instead of SoCalGas selected inputs (table 1, rows 1, 2, 5, and 6).

Four of the 16 rows of Biennial Assessment modeling inputs list California Gas Report forecasts, which are produced by SoCalGas.[175] Those inputs are:

- Row 1, forecast peak day demand (non-electric);
- Row 2, forecast peak day demand for gas to serve electric generation;
- Row 5, change in annual average demand (nonelectric); and
- Row 6, change in annual average demand for gas to serve electric generation.

As I explained previously in Section 5.2, SoCalGas's demand forecasts are flawed and biased. The Commission does not need to rely on SoCalGas's inputs because each of these forecasts is produced by the CEC or CPUC. The Commission should use data produced by California agencies in modeling that is intended for regulatory decision making.

5.3.2. For the demand variation (table 1, row 4) the historical time horizon should be updated.

The Commission should update its demand variation input to a current time horizon. Row 4 currently describes the demand variation input as:

> Standard deviation of daily gas demand (including for electricity), calculated for each calendar month using historical data from 2010-2019, then used to create a higher standard deviation based on a 95% (1-in- 20) confidence interval for the standard deviation itself, thus representing the most variable year in 20 years. Alternative values may be used for comparison or basis years updated after 2024.[176]

The input should be based on the most recent 10 years instead of an arbitrary 10-year period. The most recent 10 years will reflect the current demand variation. The current demand variation will be different than prior years' because recent years will reflect the impact of renewable generation, battery storage, and increased electric import capacity.[177] These factors

[175] *Id.* at A3-A7.

[176] *Id.* at A4.

[177] These factors reduce gas demand as supported by my analysis in Figure 4 of the 2010-2026 gas demand controlled for temperature.

reduce gas demand as supported by my analysis in Figure 4. Reduced gas demand is likely to reduce variability compared to the historically higher gas demand. Regardless of whether variability is lower, variability will be different, and that will be appropriately evaluated when Energy Division runs a correlation fitted on the most recent 10-year data instead of to the 2010–2019 data to which it is currently fit.

Row 4 should be updated according to my recommendations to avoid modeling conditions that fail to reflect current gas demand conditions.

5.3.3. Pipeline capacity and receipt point capacity (table 1, rows 9-10) should include historical averages and assume an RPU of 97%.

The Commission should update the pipeline capacity input and the receipt point input to the historical average during winter months. Rows 9 and 10 specify specifics for modeling inputs that do not reflect the operational characteristics of the SoCalGas infrastructure or customers' procurement activities.

I reviewed pipeline capacities and receipt capacities in Section 1. My analyses in Section 1 resulted in three important findings on the issues of pipeline capacity and receipt capacity. First, 22 years of average historical receipt capacity exceeds the 2025 Biennial Assessment's modeling capacity by 486 MMcfd.[178] On the single day when demand exceeded SoCalGas's 1-in-10 peak day demand forecast (January 14, 2013), the total available receipt capacity exceeded the 2025 Biennial Assessment's input assumption by 834 MMcfd.[179] Both of these suggest that the Biennial Assessment inputs assume unrealistically severe constraints on SoCalGas' receipt capacity and are too low to represent the likely available capacity during a 1-in-10 peak demand day. If Biennial Assessment modeling stacks below-average pipeline capacity on top of the 1-in-10 peak demand forecast, the modeling is assuming an event that has a far more rare than 1-in-10 likelihood of occurring. Thus, I recommend that the biennial assessment pipeline capacity assumption be changed to the average pipeline capacity of the winter months December-February for the last 20 years. While in other parts of my testimony I recommend using shorter

[178] Calculation: 3,286 MMcfd – 2,800 MMcfd = 486 MMcfd (Dec-Feb winter months).

[179] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026); SoCalGas Envoy, Daily Operations, https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternalDailyOperations.getDailyOperation; Calculation: 3634 MMcfd – 2,800 MMcfd = 834 MMcfd.

historical windows, it is reasonable here to use 20-years because ratepayers are paying for the historical nominal system capacity (3,875 MMcfd) which should be reflected over the full 20-year time horizon.

Second, when SoCalGas customers want gas, they utilize up to 100% of available capacity.[180] According to SoCalGas, its customers have used 97% or more of total receipt capacity on 558 days; including 87 days when customers have used more than 99% of capacity.[181] These data show that total available capacity is the limiting factor, not customers' ability to access 100% of system capacity.

Third, when Sierra Club asked SoCalGas to quantify the amount of gas in MMcfd that is actually available to SoCalGas customers from out-of-state suppliers on each historical day, SoCalGas responded that it could not supply "information that is not within SoCalGas knowledge or control."[182] This conflicts with SoCalGas's claims on numerous occasions including in SoCalGas testimony in the instant proceeding stating that "observed [gas] receipt levels can be materially lower due to operational and upstream constraints and/or market economics. For example, numerous extreme weather events *have demonstrated the actual availability of supply* and customer behavior on a peak day."[183] SoCalGas's response to Sierra Club's discovery request corrected the testimony statement. SoCalGas admits that it does not

[180] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (100% of capacity is according to SoCalGas's RPU calculation where it rounds any number above 99.5% of RPU up to 100%.).

[181] Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (These day-counts use SoCalGas's calculated RPU% in its response to Sierra Club Data Request 2-8).

[182] Exh. SC-06: SoCalGas Response to Sierra Club Data Requests 2-13 and 2-14 (May 28, 2026) ("SoCalGas objects to this request to the extent that it seeks information that is not within SoCalGas knowledge or control. Subject to and without waiving the foregoing objection, SoCalGas responds as follows. The 'actual availability' of gas supply at receipt points on the SoCalGas system is determined by the actions and decisions of third-party shippers, producers, marketers, and upstream pipeline operators, not by SoCalGas. SoCalGas does not possess information to disaggregate the volumes that were 'available' to be delivered from the volumes that were actually delivered based on third-party 'customer behavior,' as the request contemplates.").

[183] A.26-01-009, Prepared Direct Testimony of Andrew J. on Behalf of Southern California Gas Company (U 904 G) (Chapter I — Reliability Impacts), at AJS-6 (Jan. 15, 2026) ("For example, numerous extreme weather events *have demonstrated the actual availability of supply* and customer behavior on a peak day, including during the 2021 and 2024 Arctic Blasts where RPU dropped as low as 47% and 38%, respectively." (emphasis added)).

know how much gas is available to its customers from out-of-state suppliers on any day (as detailed in Section 2.4.1).[184]

To my knowledge, the Commission has no data, historical or otherwise, on gas supply availability from out-of-state suppliers. However, it does have daily data showing that SoCalGas customers have routinely used 97% or more of the capacity that exists. For these reasons, Row 10 of the Biennial Modeling Criteria should be updated to a minimum of 97% of total receipt capacity. Both of my recommendations conform to D.24-12-076 which states "[i]n future assessments, pipeline capacity and other modeling assumptions will be updated to reflect more recent information."[185]

5.3.4. Gas storage operability (table 1, row 12 and 13) should be subject to stakeholder comment and set by Energy Division.

Rows 12 corresponds to the input "[m]aximum gas withdrawal and injection rates for each gas storage field."[186] Row 13 corresponds to "Aliso Canyon maximum inventory."[187] The Biennial Modeling Criteria set both as SoCalGas defined figures. I propose that rather than allowing SoCalGas to define these figures confidentially, that the Commission require SoCalGas propose these figures for biennial modeling in a formal filing served on the instant service list of this proceeding on the first day of January in each year scheduled for biennial assessment. Then, the Commission should allow parties to supply opening comments on that filing by January 15, of the same year, as well as reply comments by January 22. After the opening and reply filings,

[184] Exh. SC-06: SoCalGas Response to Sierra Club Data Requests 2-13 and 2-14 (May 28, 2026) ("SoCalGas objects to this request to the extent that it seeks information that is not within SoCalGas knowledge or control. Subject to and without waiving the foregoing objection, SoCalGas responds as follows. The 'actual availability' of gas supply at receipt points on the SoCalGas system is determined by the actions and decisions of third-party shippers, producers, marketers, and upstream pipeline operators, not by SoCalGas. SoCalGas does not possess information to disaggregate the volumes that were 'available' to be delivered from the volumes that were actually delivered based on third-party 'customer behavior,' as the request contemplates."; *See also,* Exh. SC-12: SoCalGas Response to Sierra Club Data Request 3-22, subparts (c) and (d) (Aug. 10, 2026) (SoCalGas was unable to quantify out-of-state supply unavailability in MMcfd.); *See also,* A.26-01-009, Compliance Filing of Southern California Gas Company (U904G) Regarding External Outages at 14 (May 1, 2026) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K451/606451664.PDF.

[185] D.24-12-076, Decision Adopting Biennial Assessment Process, at 17 (Dec. 24, 2024) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF.

[186] Biennial Modeling Criteria at A6.

[187] *Id.*

Energy Division may determine the rates and levels for row 12 and 13 based on the filings. Thus, while SoCalGas provides input on the storage criteria, it is ultimately the Energy Division that determines the modeling inputs that it will use.

5.3.5. Modeling should evaluate the upcoming winter and the following two winters; summer modeling is not required (table 1, row 15)

Row 15 input is "[f]uture years modeled" and defines the years to model as the "[u]pcoming winter and subsequent summer seasons and five years later."[188] The modeling years should be changed based on the results of the 2025 Biennial Assessment, which found a need for 44% of Aliso Canyon capacity for reliability for 2025-26 winter and found 0% capacity need for the 2030-31 winter.[189] Thus, the Commission needs to have modeling results for the years in between the winters that were already modeled. Energy Division's modeling is updated in each assessment to include the impact of new renewable energy, battery storage, and import capacities that were not known to the Energy Division when it completed the 2025 Biennial Assessment modeling. The 2027 Biennial Assessment should still model the upcoming winter as is currently defined, which would be 2027-28. However, instead of modeling the winter 5-years later (i.e., winter 2031-32) – which I would expect to have the same result of 0% need as the previously completed modeling of winter 2030-31, the Commission should order modeling of the two missing winters between winter 2027-28 and the completed modeling for winter 2030-31. That will provide new information to the Commission, including the first winter during which Aliso Canyon is not needed for reliability according to Energy Division inputs.

Regarding summer modeling, the 2025 Biennial Assessment found that for both summers modeled (i.e., 2026 and 2031) it was able to complete the modeling runs without the need for Aliso Canyon.[190] The addition of renewable generation, battery storage, and import capacity over the coming years continues to reduce the summer high-gas-demand-day forecast making future summer modeling, at best, redundant. Eliminating the summer modeling requirement from the

[188] *Id.*

[189] 2025 Biennial Assessment at 12, Table 4.

[190] *Id.* at 20 ("For summer 2026, the hydraulic modeling analysis indicates that Aliso Canyon is not needed to maintain gas system reliability."), and at 23 ("For summer 2031, the hydraulic modeling analysis indicates that Aliso Canyon is not needed to maintain gas system reliability on a summer high demand day.").

Biennial Modeling Criteria will conserve scarce Commission resources. Further, any changes to summer modeling trends would be flagged in the IRP proceeding's modeling exercises to ensure consistency with long-term grid planning.

5.4. The Economic Trigger Evaluation should incorporate more realistic inputs.

The Biennial Report includes two economic triggers. The first trigger is intended to compare Southern California gas prices to national gas prices (geographic comparison). The second is intended to compare Southern California gas prices to historical Southern California gas prices (historical comparison). The mechanisms are both at least partially flawed and more complicated than necessary to accomplish the Commission's goal of "mitigate[ing] the rate impacts of high Southern California gas prices."[191]

First, the geographic comparison selected an arbitrary price index in Louisiana, Henry Hub, to represent the national price of natural gas.[192] The gas price data provider selected by the Commission, NGI, provides a National Spot Market Average.[193] The goal of comparing Southern California gas prices to national prices would be better completed by comparing the price of Southern California to the National Spot Market Average. However, I recommend removing the geographic comparison entirely because there is no data in the record showing that Southern California natural gas prices have ever tracked a national benchmark. The comparison most relevant to California customers is how gas prices compare to historical prices.

Second, I recommend the economic trigger evaluation incorporate a historical comparison. The Biennial Modeling Criteria defines the historical comparison in this way:

> If the forward price of gas in Southern California for the upcoming winter is 50 percent or more above the bidweek price of gas in Southern California during the previous three winters, the biennial assessment conducted that year will recommend not reducing the maximum storage level at Aliso Canyon during the two-year period covered by the biennial assessment.[194]

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[191] Biennial Modeling Criteria at A7.

[192] *Id.* at A8 ("[T]his calculation, the national gas price for the upcoming winter will be represented by the Henry Hub average forward price of gas").

[193] NGI, Price Index Methodology, Code of Conduct & Point Descriptions at 31 (Oct. 20, 2025) https://apppack-app-naturalgasintel-prod-publics3bucket-8jv5bxjtvpgq.s3.amazonaws.com/documents/documents/documents/documents/documents/NGIMethodology.pdf.

[194] Biennial Modeling Criteria at A8.

Thus, the historical comparison evaluates the prior three-winter gas price to a hypothetical future estimated price determined by gas traders applying a risk premium for the upcoming winter (i.e., forward price). This is not an appropriate metric because the historical prices are not compared to an actual price, but rather to a price that will never materialize and one that is artificially elevated to account for pricing risk. It would be more appropriate to compare the most recent past-winter daily average gas price to a 10-year inflation-adjusted average gas price. That would be a reasonable comparison, because it compares one actual gas price to an average gas price and because it reflects the historical norm. The question to consider is whether the Commission should include the 2022-2023 winter in the 10-year average. I believe it should be included because that winter reflected a gas market scenario which was unable to be mitigated by gas storage.

In summary, I recommend that (1) the Commission remove the comparison of Southern California gas to a national gas price or to a Louisiana gas price, and (2) that the historical price of Southern California gas (i.e., most-recent past winter) be compared to the 10-year inflation-adjusted average. This historical average should be used as the economic trigger instead of comparing a three-year average price to a hypothetical future price inflated to reflect a risk premium.

6. ALISO CANYON CONTINUES TO EMIT TOXINS INTO THE AIR IMPACTING DISADVANTAGED COMMUNITIES.

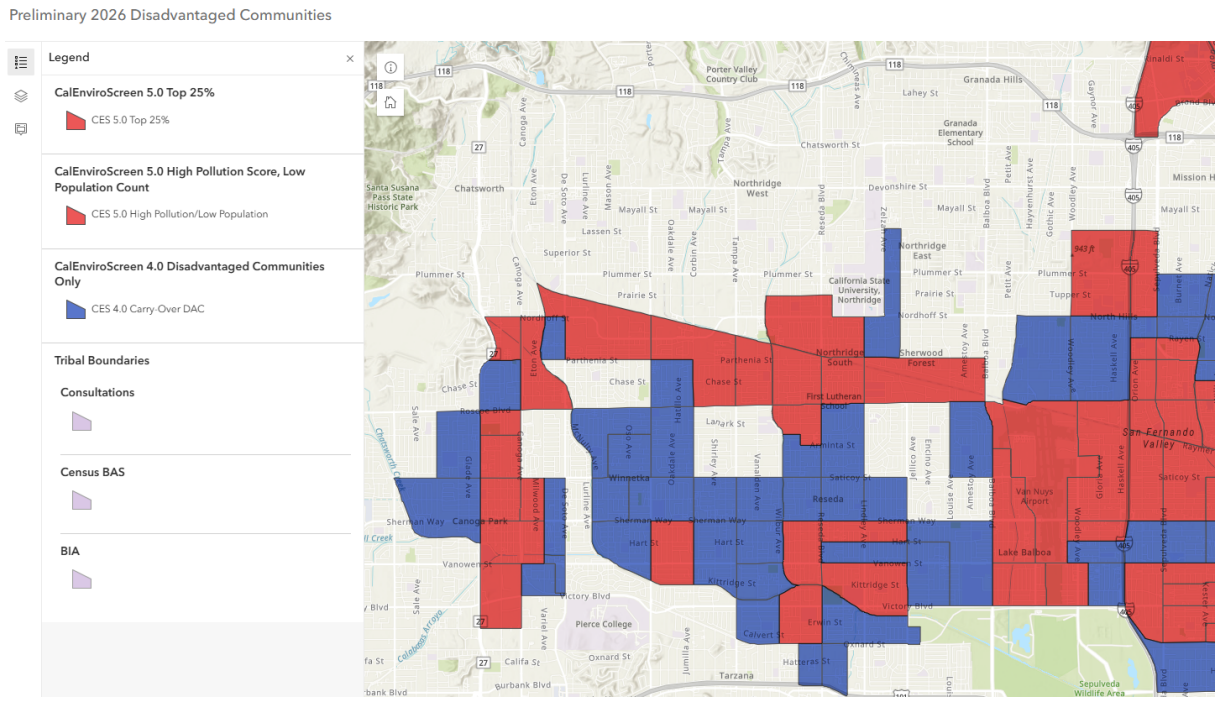
Aliso Canyon negatively impacts disadvantaged communities in the LA area. Because of the impacts of the Aliso Canyon rupture in 2015, AB 157 allocated $40 million to supporting electrification efforts in households near Aliso Canyon.[195] D.25-06-034 directed implementation of a program for comprehensive building electrification "in the Aliso Canyon Disaster Area communities."[196] AB 157 defined the Aliso Canyon Disaster Area as "the City of Los Angeles

[195] AB 157 (Gabriel), Budget Act of 2024 — Stats. 2024, ch. 994, § 99. *See also* Resolution M-4875, p.5 ("Under AB 157, Section 99, the TECH Initiative has been allocated $40 million from the Aliso Canyon Recovery Account to continue incentives for the electrification efforts historically supported by the program.").

[196] D.25-06-034, Phase 4 Track A Decision Establishing New Electric Service Line Upsizing Rules, Modifying Electric Line Extension Rules and Reporting Requirements, and Implementing Assembly Bill 157, at 95 (June 20, 2025) ("While all customers regardless of income status are eligible to receive incentives for [Meter Socket Adapters], smart splitters, and other load management devices using the new AB 157 funding, the [Technology and Equipment for Clean Heating] Initiative implementer shall use the

communities of Porter Ranch, Granada Hills, Northridge, Chatsworth, North Hills, Canoga Park, Reseda, Winnetka, West Hills, Van Nuys, and Lake Balboa."[197] These are the neighborhoods immediately surrounding Aliso Canyon in the San Fernando Valley region and are mapped by the LA Times's neighborhood mapping tool.[198] Of those neighborhoods, eight are fully or partially located in disadvantaged communities according to the CalEnviroScreen 2026 preliminary designation, and 10 of the 11 according to the CalEnviroScreen 4.0 designation.[199]

Figure 10: Aliso Canyon Disaster Area Disadvantaged Communities, CalEnviroScreen 5.0 (screenshot)[200]



Aliso Canyon continues to impact these disadvantaged communities and has a demonstrated track record of harming Californians. A peer-reviewed UCLA study found that

measure list developed for 'comprehensive building electrification' for the CEC's [Equitable Building Decarbonization] program for customers in the Aliso Canyon Disaster Area communities who have incomes at or below 80 percent of area median income.").

[197] *Id.* at 80.

[198] Los Angeles Times, Mapping L.A. Neighborhood Tool, San Fernando Valley, (accessed Aug. 20, 2026) https://maps.latimes.com/neighborhoods/index.html.

[199] CalEnviroScreen 5.0 Preliminary 2026 Disadvantaged Communities map (accessed Aug. 10, 2026), https://oehha.maps.arcgis.com/apps/instant/sidebar/index.html?appid=f6f616c3b8d645489c1090d5292f6546%20.

[200] *Id.*

women in the later stages of pregnancy living near the blowout had nearly a 50% higher-than expected chance of delivering a low-birth-weight baby, a condition associated with increased risk of autism spectrum disorder, ADHD, hypertension, diabetes, and coronary artery disease.[201] Moreover, Aliso Canyon continues to emit toxins, including carcinogens.[202] Those emissions continue daily at Aliso Canyon. However, data shows that the less actively used Aliso Canyon is, the fewer emissions from the facility.[203] Reduction of Aliso Canyon use, or closure of Aliso Canyon would reduce the negative impacts to the disadvantaged communities in the Aliso Canyon Disaster Area.

7. CONCLUSION

My testimony evaluated the reliability need for Aliso Canyon, the economic need for Aliso Canyon, energy insecurity of natural gas dependence, and the Biennial Modeling Criteria for the Aliso Canyon biennial assessment process. The data I provide shows that Aliso Canyon is no longer needed to maintain grid and gas reliability and that a 29 Bcf reduction in Aliso Canyon storage maximum inventory will have no significant impact on gas prices, including gas prices for UBS subscribers. End of winter gas storage has not been lower than 34 Bcf in the last 10 years, and a 29 Bcf reduction would still allow UBS subscribers to withdraw gas at the maximum UBS withdrawal rate on every winter day.

I recommend that the Commission reduce Aliso Canyon storage by 29 Bcf and make the following changes to the Biennial Assessment process:

(1) Allow Energy Division to recommend any reduction amount to the Aliso Canyon maximum storage inventory;

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[201] Kimberly C. Paul et al., *Investigating the Aliso Canyon Gas Blowout Disaster and Adverse Birth Outcomes: A Quasiexperimental Approach*, Sci. Advances, Vol. 11, No. 37, at 5 (Sept. 12, 2025), https://doi.org/10.1126/sciadv.adr6684.

[202] South Coast Air Quality Management District, *FIND Database*, Facility ID 800128, https://xappprod.aqmd.gov/find//facility/AQMDsearch?facilityID=800128 (last visited Aug. 16, 2026); I.17-02-002, Issam Najm Notice of Ex Parte Communication, at Attachment p. 4, PDF p. 7 (Aug. 8, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K768/516768711.PDF.

[203] I.17-02-002, Issam Najm Notice of Ex Parte Communication, at Attachment p. 4, PDF p. 7 (Aug. 8, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K768/516768711.PDF.

(2) Update the demand reduction analysis to use the 1-in-10 gas demand forecast from the California Energy Commission instead of SoCalGas's forecast;

(3) Replace all other SoCalGas-defined inputs with reliable input sources;

(4) Revise the inputs discussed in Section 5.3 to data-backed inputs;

(5) Update the economic analysis to use actual historical gas prices instead of hypothetical future prices as analytical inputs; and

(6) Direct Energy Division to identify steps to reduce the impacts of Aliso Canyon emissions on disadvantaged communities in the nearby area.

This concludes my testimony.