California Public Utilities Commission

2025 Aliso Canyon Biennial Assessment Report Pursuant to D.24-12-076

ENERGY DIVISION

Energy Resource Modeling

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Contents

Executive Summary

Background

This report is an outcome of the California Public Utilities Commission's (CPUC) Investigation (I.) 17-02-002. The purpose of the investigation was to determine the feasibility of minimizing or eliminating the use of the Southern California Gas Company's (SoCalGas) Aliso Canyon natural gas storage field (Aliso Canyon) while still maintaining energy and electric reliability for the region and just and reasonable rates. In December 2024, the CPUC issued Decision (D.) 24-12-076, which established a reliability threshold for considering the closure of Aliso Canyon and a biennial process for considering reductions to the field's maximum inventory.[1] The decision's Attachment A describes in detail the four analyses that Energy Division staff (Staff) are to include in each *Aliso Canyon Biennial Assessment Report (Biennial Assessment Report)* to track progress toward closure.[2]

The decision further outlined how the four analyses will lead to a recommendation of either no change or changes to the storage limit (such as a decrease), which is the trigger for a formal CPUC proceeding. If the trigger is met, SoCalGas shall file an application within 90 days of the issuance of the *Biennial Assessment Report* and request the CPUC to review the recommended actions as set forth in the biennial assessment. Then, SoCalGas is required to hold a workshop within 90 days of filing the application during which Staff will present the *Biennial Assessment Report,* and SoCalGas will present its application.

Staff will reassess the Aliso Canyon maximum inventory in the *2027 Biennial Assessment Report*.

Overview of Methodologies

The *Biennial Assessment Report* consists of four analyses that are designed to provide a preliminary indication of when Aliso Canyon can be closed without jeopardy to reliability or just and reasonable rates: demand reduction analysis, gas balance reliability analysis,[3] hydraulic modeling analysis, and economic analysis. Each analysis looks at the potential impacts of Aliso Canyon closure from a different perspective. These analyses focus on the upcoming year and five years later, covering both the winter and summer seasons as described below.

- **Demand reduction analysis:** compares the forecast demand on the coldest day in 10 years, or 1-in-10 peak day gas demand, with the 4,121 million cubic feet per day (MMcfd) reliability threshold established in the decision. If demand exceeds the threshold, Aliso Canyon should not be closed. The comparison is made for all future winters included in the "SoCalGas Winter 1-in-10 Year Cold Day Demand" forecast table in the *California Gas Report*. For this report, these include winters 2025-26 through 2030-31.[4]

[1] D.24-12-076: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF.

[2] D.24-12-076, Attachment A: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K129/551129840.PDF.

[3] The gas balance reliability analysis was referred to as the "feasibility analysis" or the "daily stochastic mass balance model" in previous reliability assessments.

[4] *2024 California Gas Report,* Table 34, p. 159: 2024-California-Gas-Report-Final.pdf.

- **Gas balance reliability analysis:** models the ability of the SoCalGas system to provide enough supply to meet daily systemwide demand throughout a cold and dry winter.[5] The analysis is conducted for the entire upcoming year and five years later.
- **Hydraulic modeling analysis:** tests the ability of the SoCalGas system to continuously deliver enough gas to all demand locations and maintain operating pressures within set boundaries to meet fluctuations in demand on the coldest day in 10 years and be prepared to do the same the next day. The winter season assessment is based on the projected inventory in the gas storage fields on February 15 while the summer season assessment is based on inventory on August 15. Analysis is provided here for the upcoming year and five years later.
- **Economic analysis:** compares the current expected price for gas in Southern California during the upcoming winter to set national and historical thresholds. The analysis is required only for the upcoming winter. However, Staff performed additional analyses for winter 2026-27 due to concerns about the potential for gas prices increases next year.

Overview of Current Context

The analyses conducted by Staff focus primarily on the reliability of the natural gas system, with a limited economic test that indicates whether gas commodity prices are currently high compared to national and historic benchmarks. This simple economic analysis does not allow Staff to predict the impacts of reducing the Aliso Canyon maximum inventory on gas commodity prices. Appendix A also does not include a model that forecasts withdrawals from gas storage for economic, rather than reliability, purposes. Historically, having sufficient gas in storage has tended to prevent or mitigate the impact of high or volatile gas commodity prices.[6]

There are events on the horizon that have the potential to increase gas commodity prices, particularly for winter 2026-27, which is beyond the time period required to be considered in the economic analysis. Nationally, liquified natural gas (LNG) exports are forecast to rise 34 percent from 2024 to 2026, outpacing growth in U.S. natural gas production. The U.S. Energy Information Administration (EIA) forecasts that average annual gas prices at Henry Hub, the national benchmark, will rise from $2.20 in 2024 to $4.90 in 2026 due to exports rising faster than production.[7] Closer to California, Sempra's Energía Costa Azul LNG export facility is expected to begin operations in spring 2026, increasing competition for interstate pipeline capacity to Southern California.

Staff's economic analysis also does not capture the impact of reductions to the Unbundled Storage Program. When there is enough gas storage inventory capacity available, SoCalGas sells storage to noncore customers through the Unbundled Storage Program. Having gas in storage provides these customers with an alternative to purchasing pipeline gas in the spot market on days when prices are

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[5] The gas winter is November 1 through March 31. The gas summer is April 1 through October 31.

[6] See the Staff white papers *High Natural Gas Prices in Winter 2022-23: Parts I and II* for additional discussion on the impact of storage on gas commodity prices. *Part I:* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K897/556897040.PDF. *Part II:* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M567/K955/567955443.PDF.

[7] EIA, *Short-Term Energy Outlook,* June 10, 2025: Short-Term Energy Outlook - U.S. Energy Information Administration (EIA).

high.[8] Gas-fired electric generators are noncore customers, and their ability to lower their exposure to high gas prices directly impacts electric ratepayers.[9] Staff note that gas prices stabilized after the CPUC's August 2023 decision to increase Aliso Canyon's maximum inventory from 41.16 Bcf to its current level of 68.6 Bcf, following extreme price spikes in winter 2022-23.[10]

Pipeline conditions have also evolved since modeling was conducted for this assessment. On April 11, 2025, SoCalGas announced that it would reduce the pressure on Lines 4000 and 4002 from July 1, 2025, through November 1, 2026, to complete testing required by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA). SoCalGas stated that this pressure reduction would result in a 655 million cubic feet per day (MMcfd) reduction in pipeline capacity in its Northern Zone.[11] Staff at that point used the assumption that this pressure reduction would be in place for the winter 2025-26 modeling.

On September 4, 2025, after Staff's full modeling was completed, SoCalGas announced that the pressure reduction would instead end at midnight on September 5, 2025.[12] On September 11, SoCalGas further explained that it was able to complete its assessment early due to improvements to the company's data analytics and threat evaluation processes that stem from updates to PHMSA's regulations and advisory bulletins.[13] This unexpected change to pipeline capacity underscores the uncertainty surrounding future pipeline conditions that California must be prepared to manage.

While this is a change in pipeline capacity compared to Staff's assumptions, it has a limited impact on the modeling results, and it does not change Staff's recommendation. Any change in pipeline capacity impacts the gas balance reliability and hydraulic modeling analyses, which are interrelated. Increased pipeline capacity would typically result in less need for Aliso Canyon in the gas balance reliability analysis. Since Staff modeled many different scenarios, this report already includes a scenario that is close to the current pipeline conditions of Line 4000 and 4002.

The gas balance reliability analysis predicts the available withdrawal capacity from the non-Aliso fields,[14] which is an input to the hydraulic modeling. While reflecting this increase in pipeline

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[8] SoCalGas discontinued the Unbundled Storage Program after the Aliso Canyon gas leak because there was insufficient gas storage inventory to support it. The utility reinstated the program in fall 2023 after the CPUC increased the Aliso Canyon maximum allowable operating pressure to 68.6 Bcf in D.23-08-050: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M519/K806/519806122.PDF. See also Advice Letter 6185-G: Advice Letters | SoCalGas.

[9] See the Staff white paper *High Natural Gas Prices in Winter 2022-23: Part II,* pp 30-43.

[10] D.23-08-050: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M519/K806/519806122.PDF.

[11] See the Critical Notice posted to SoCalGas' electronic bulletin board, ENVOY, on April 11, 2025: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternalEbb.getMessageLedger?ledgerType=message&Page=filter&datePosted_from=04%2F11%2F2025&datePosted_to=04%2F11%2F2025&keyword=&folderId=1.

[12] SoCalGas ENVOY, September 5, 2025: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternalEbb.getMessageLedger?ledgerType=message&Page=filter&datePosted_from=09%2F04%2F2025&datePosted_to=09%2F04%2F2025&keyword=&folderId=1.

[13] SoCalGas ENVOY, September 11, 2011: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternalEbb.getMessageLedger?ledgerType=message&Page=filter&datePosted_from=09%2F11%2F2025&datePosted_to=09%2F11%2F2025&keyword=&folderId=1.
SoCalGas ENVOY, September 5, 2025: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternalEbb.getMessageLedger?ledgerType=message&Page=filter&datePosted_from=09%2F04%2F2025&datePosted_to=09%2F04%2F2025&keyword=&folderId=1.

[14] The non-Aliso Canyon gas storage fields are Honor Rancho, La Goleta, and Playa del Rey.

capacity in the gas balance reliability analysis will project higher non-Aliso storage inventory available for the hydraulic modeling analysis, based on the analysis conducted in this report, an increase in the available withdrawal capacity from the non-Aliso fields as a result of the recent increase in pipeline capacity would not result in a substantial decrease in withdrawals needed from Aliso Canyon due to other constraints on the system.[15] Similarly, the increase in pipeline capacity would have a limited impact on the hydraulic modeling itself because, on a high demand day, Staff were able to bring more gas into the model than expected. In fact, Staff were able to stay within the normal supply parameters outlined in Attachment A.[16]

Summary of Results and Staff Recommendation

Winter 2025-26 and Summer 2026

The results of the four analyses conducted for winter 2025-26 and summer 2026 hydraulic modeling analysis are as follows:

- **Demand reduction analysis:** The forecast 1-in-10 peak demand for winter 2025-26 is 4,562 MMcfd, exceeding the threshold for considering closure of Aliso Canyon by 441 MMcfd and indicating that Aliso Canyon should not be closed.
- **Gas balance reliability analysis:** An Aliso Canyon inventory of at least 44 percent of capacity (30.2 billion cubic feet or Bcf) is needed to reliably serve daily demand throughout winter 2025-26 when 2,800 MMcfd of pipeline supply assumed in the modeling is available and there are no unplanned storage outages. At the current pipeline capacity of roughly 3,200 MMcfd, 1 percent of Aliso Canyon capacity would be required if there are no unplanned storage outages or changes to the interstate or intrastate pipeline systems similar to the previous reductions on Lines 4000 and 4002.
- **Hydraulic modeling analysis:** The winter assessment shows that fluctuations in demand can be served continuously throughout the coldest day in 10 years with a minimum of 550 MMcfd of withdrawals from Aliso Canyon. In the summer assessment, demand can be met on a high demand summer day without Aliso Canyon, despite challenges with keeping the gas system in balance throughout the day due to the limited injection capacity at the non-Aliso storage fields.[17]
- **Economic analysis:** Gas commodity forward prices in Southern California for the upcoming winter do not exceed the national and historical price thresholds set in the decision. That is, forward prices are less than 50 percent above national and historical levels.

Staff Recommendation

Decision 24-12-076 directs Staff to recommend whether to change the Aliso Canyon maximum inventory based on the analyses. Staff may recommend an increase, no change, or a reduction of up

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[15] Specifically, the pipelines between Honor Rancho and the Northern city gate and the limitations of the Northern city gate itself.

[16] Attachment A, Table 1, Row 10 requires Staff to assume 85 percent pipeline capacity in the Northern Zone, which Staff were able to do, even with the pipeline outages.

[17] The non-Aliso Canyon gas storage fields are Honor Rancho, La Goleta, and Playa del Rey.

to 10 Bcf.[18,19] Together, the four analyses conducted for winter 2025-26 support a Staff recommendation to reduce the Aliso Canyon maximum inventory by 10 Bcf to a level of 58.6 Bcf. However, given current forecasts for higher gas commodity prices in winter 2026-27, which are not captured in the economic analysis but are discussed in the Current Context section of this report, a smaller incremental or no reduction may be appropriate.

Forward Look: Winter 2030-31and Summer 2031

The results of the analyses conducted for winter 2030-31and summer 2031 are intended as a preview of future progress towards reducing reliance on Aliso Canyon but are not factored into Staff's recommendation. These results depend on the following assumptions: natural gas demand declines significantly, as forecast in the *2024 California Gas Report* due to building electrification and reduced demand from electric generation; planned upgrades to the natural gas system are in service before winter 2030-31; and outages to pipelines, storage wells, or other infrastructure do not exceed those planned and modeled.

- **Demand reduction analysis:** The forecast 1-in-10 peak demand for winter 2030-31 remains 76 MMcfd above the threshold required for considering Aliso Canyon closure, indicating that Aliso Canyon is still needed to meet projected demand.
- **Gas balance reliability analysis:** Aliso Canyon is not needed if at least 3,000 MMcfd of pipeline supply and at least 60 percent of non-Aliso storage withdrawal capacity (approximately 890 MMcfd) is available. At lower levels of pipeline supply or non-Aliso storage inventory, withdrawals from Aliso Canyon would be needed.
- **Hydraulic flow modeling analysis:** If planned infrastructure upgrades are in place, the hydraulic flow modeling indicates that Aliso Canyon is not needed in winter 2030-31. However, if these upgrades are not in-service by winter 2030-31, Aliso Canyon may still be needed. Aliso Canyon is not needed on a high demand day in summer 2031, however, it may be challenging from an operational perspective for the utility to meet the ramping needs and inject into the non-Aliso fields on the same day as assumed in the model.

The analyses for winter 2030-31 that result in a reduced need for Aliso Canyon remain contingent on assumed reductions in gas demand and completion of planned infrastructure improvements. As noted above, the economic analysis is only conducted for the upcoming winter. Staff will verify whether the forecasts and infrastructure upgrades modeled for 2030-31 are on track in the *2027 Biennial Assessment Report*.

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[18] The CPUC cannot approve an Aliso Canyon maximum inventory that exceeds the maximum pressure level determined to be safe by the California Geologic Energy Management Division (CalGEM).

[19] D.24-12-076, pp. 51, FOFs 8-10, OPs 3, 5-7: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF.

Demand Reduction Analysis

Methodology

The demand reduction analysis consists of comparing the forecast demand on the coldest day in 10 years, or 1-in-10 peak day gas demand, with the 4,121 MMcfd threshold established for considering closure of Aliso Canyon.[20] The threshold represents the daily gas demand that the system can serve without Aliso Canyon. The demand reduction analysis reports the forecast peak day gas demand for the upcoming winter and available future winters, the adopted maximum storage level, and the threshold in a table for comparison purposes.[21] The peak day gas demand forecast is currently based on the most recent *California Gas Report.*[22] However, in the future, the CPUC may adopt a 1-in-10 winter peak day forecast developed by the California Energy Commission.[23]

Relationship Between Inventory and Withdrawal Capacity

Inventory is the volume of gas stored in a gas storage field and is usually reported in billion cubic feet (Bcf). Withdrawal capacity is the amount of gas that can be withdrawn in one day and is usually reported in million cubic feet per day.[24] As a storage field's inventory level decreases, the pressure in the storage field also decreases, which in turn decreases the field's withdrawal capacity.

Storage inventory is usually highest at the start of each winter season (November 1). Customers typically try to fill their inventory capacity during the injection season (April-October) and then withdraw gas over the course of the winter to meet demand and to manage price fluctuations. As inventory declines, pressure decreases. A storage field's withdrawal capacity can thus be significantly lower at the end of winter than at the beginning. The amount of daily gas demand that can be reliably met by the gas system depends on numerous factors including combined storage inventory and withdrawal capacity, conditions in the gas production basins, global and national competition for natural gas, and whether there are outages on the interstate or intrastate pipeline systems. There is thus not a simple relationship between daily demand and Aliso Canyon's maximum inventory. The assumptions and modeling underlying the 4,121 MMcfd threshold were conducted by FTI Consulting[25] during the Aliso Canyon proceeding,[26] reviewed by parties, and approved in D.24-12-076.[27]

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[20] D.24-12-076, Finding of Fact 13, p. 72: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF.

[21] In later biennial analyses, this table will also include peak day gas demand level(s) shown in previous *Biennial Assessment Reports.*

[22] *2024 California Gas Report,* Table 34, p. 159: 2024-California-Gas-Report-Final.pdf.

[23] Attachment A pp. A2-A3

[24] "Ratable" means that the same amount of gas is withdrawn every hour. Because gas demand varies throughout the day, higher withdrawal rates may be needed in the morning and evening than during the rest of the day. If storage is not withdrawn consistently, the total amount of gas actually withdrawn from a field over a 24-hour period may be less than the maximum withdrawal rate.

[25] FTI Consulting and Gas Supply Consulting, Inc.: *Aliso Canyon I.17-02-002 Phase 3 Report*, December 31, 2021: fti-aliso-canyon-i1702002-phase-3-report.pdf.

[26] I.17-02-002: https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:I1702002.

[27] D.24-12-076, Finding of Fact 13: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF.

Results of Demand Reduction Analysis

The peak day demand forecasts from the *2024 California Gas Report* decline over time. These declines are largely driven by reductions in residential customer demand due to building electrification and a drop in demand from gas-fired electric generators. All forecasts through 2030-31 are above the 4,121 MMcfd threshold, as shown in Table 1 below. The gas demand reduction analysis thus indicates that Aliso Canyon is still necessary for natural gas and electric reliability.

Table 1: Peak Day Demand Forecast for Winters 2024-25 through 2030-31

Winter	1-in-10 Peak Day Demand Forecast (MMcfd)	Threshold for Considering Aliso Canyon Closure (MMcfd)	Difference from Threshold (MMcfd)	Aliso Canyon Maximum Inventory (Bcf)
2024-25	4,618	4,121	497	68.6
2025-26	4,562	4,121	441	TBD
2026-27	4,489	4,121	368	TBD
2027-28	4,435	4,121	314	TBD
2028-29	4,377	4,121	256	TBD
2029-30	4,295	4,121	174	TBD
2030-31	4,197	4,121	76	TBD

Source: *2024 California Gas Report* and D.24-12-076

Gas Balance Reliability Analysis

Methodology

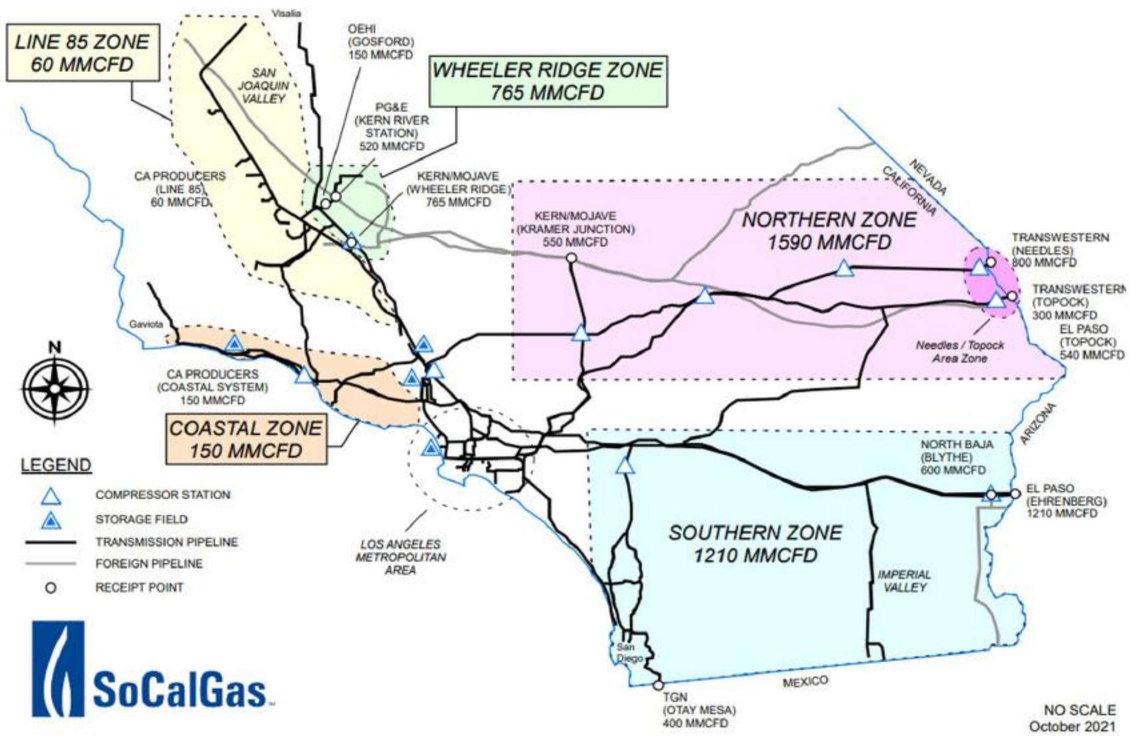
The gas balance reliability analysis assesses the ability of the gas system to meet daily demand over the course of the winter and the following summer. To do so, it uses a model that represents daily gas supply and demand across a range of variable conditions.[28]

Modeled gas supplies consist of interstate pipeline supplies, California gas production, and SoCalGas underground storage. Some initial conditions are drawn from information that Staff requests from SoCalGas via confidential data requests. Assumptions input to the model include: expected storage inventories on November 1, the beginning of the winter season; capacity reductions from planned pipeline outages occurring during the winter season; storage withdrawal and injection curves; and planned outages for gas storage wells. Assumed California Production is based on the combined gas supplies from the Coastal and Line 85 Zones, where in-state production wells in the SoCalGas service territory are located. Gas production in California has declined significantly over time, so

[28] This methodology was referred to as the "Feasibility Assessment" in phase 1 and 2 of the OII. It was also referred to as the "daily stochastic mass balance model" in past seasonal assessments of the SoCalGas pipeline network. The model was developed by Staff during phase 2 of the OII.

Staff assume a total of 70 MMcfd for California Production.[29] The assessment also uses data regarding nominal zonal capacity on the SoCalGas system, which is summarized in Figure 1 below.

Figure 1: SoCalGas Receipt Point and Transmission Zone Nominal Capacity



Source: SoCalGas

Modeled gas demand is based on forecasts obtained from the *2024 California Gas Report* as well as historical data. The gas balance reliability analysis forecasts the gas demand each day during the study period using stochastic, or random, draws from a distribution of gas demand. This distribution uses historical and forecasted data and is designed to represent a cold and dry year, not an average year. The model then seeks to balance that daily demand with available gas supplies each day. Any day on which demand exceeds the supplies is identified as an imbalance day and represents a potential curtailment.

Stochastic modeling is conducted in which each scenario is randomly simulated 100 times to recover the whole assumed distribution of the gas demand and obtain statistically convergent results. The results of the 100 simulations are then averaged.

Input Parameters: Attachment A Assumptions and Additional Scenarios

Attachment A to D.24-12-076 directs Staff to use certain assumptions and inputs for this assessment. In addition to modeling the assumptions outlined in Attachment A, however, Staff simulated multiple scenarios in order to cover a wider range of possibilities over the study period by varying the pipeline supply, storage well utilization factor, and Aliso Canyon maximum inventory.

[29] See Data Request 2, Question 2, in link to data requests about the Ventura Compressor Station, which shows that Coastal Production declined by 90 percent between 2011 and 2020: [Natural Gas and Oil Pipeline Regulation](#).

We first present the assumptions outlined in Attachment A. This is followed by a description of the additional analysis performed by Staff.

Attachment A Assumptions: Pipeline Capacity

Attachment A anticipates the possibility of planned pipeline outages and provides the following direction for assuming pipeline capacity:[30]

- For the gas balance analysis, 100% of SoCalGas' firm contracted capacity **or** the zonal capacities assumed for the hydraulic flow modeling less planned outages, whichever is lower.

- For hydraulic flow modeling, 85% of the nominal capacity of the Northern and Southern Zones and 100% of the nominal capacity of the Wheeler Ridge Zone.

At the time this analysis was conducted, SoCalGas had reduced the pressures on Lines 4000 and 4002 to conduct required testing. The utility expected the reductions to continue throughout winter 2025-26 and to result in a 655 MMcfd decrease in Northern Zone capacity. The 85 percent pipeline utilization specified in Attachment A was intended to capture potential reductions in interstate gas supply upstream of California. Since the planned outages on Lines 4000 and 4002 were on the intrastate pipeline system, any potential upstream interstate capacity disruptions were likely to be less than the intrastate outages on the Northern Zone. For this reason, Staff assumed that total Northern Zone capacity in winter 2025-26 was reduced by the amount of the capacity reductions on Lines 4000 and 4002 (655 MMcfd or about 58 percent) and did not assume an additional 15 percent reduction in the Northern Zone. In contrast, since there were no major planned outages in the other zones, Staff assumed 85 percent pipeline capacity for the Southern Zone, the 100 percent nominal capacity available for Wheeler Ridge, and the assumptions for California Production as directed by Attachment A.

The resulting assumptions for derated Zonal Capacity used in the gas balance reliability assessment are summarized in Table 2 below. Total derated pipeline capacity for winter 2025-26 was assumed to be 2,798.5 MMcfd, which Staff round up to 2,800 MMcfd for the gas balance reliability analysis. Without the pressure reductions on Lines 4000 and 4002, the Northern Zone would be modeled at 85 percent pipeline capacity as specified in Attachment A, and the total Zonal Capacity for 2025-26 would total 3,215 MMcfd.

For winter 2030-31, planned outages have not yet been determined and SoCalGas's firm contracted capacity is not yet known.[31] Staff therefore assumed a total derated pipeline capacity of 3,215 MMcfd, based on zonal capacity assumptions for hydraulic flow modeling specified in Attachment A.

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[30] See Row 10 of Table 1.

[31] SoCalGas holds periodic Open Seasons during which customers can purchase Backbone Transmission Service on the intrastate pipeline system. The next Open Season is scheduled to be held in summer 2026: https://www.socalgas.com/business/energy-market-services/backbone-transportation.

Table 2: Nominal and Derated Zonal Capacity (MMcfd)

Zone	Nominal Capacity	2025-26 Derates	2025-26 Derated Capacity	2030-31 Derates	2030-31 Derated Capacity
Wheeler Ridge	765.0	0	765.0	0	765.0
Cal Production	70.0	0	70.0	0	70.0
Southern	1,210.0	85%	1,028.5	85%	1,028.5
Northern	1,590.0	-655	935.0	85%	1,351.5
Total	3,635.0		2,798.5		3,215.0

Attachment A Assumptions: Storage Withdrawal Capacity

Attachment A states that Staff should base storage withdrawal capacity on an "Annual data request to SoCalGas for forecast daily or monthly withdrawal and injection rates, which vary based on number of wells out of service for maintenance and other storage facility conditions." An assumption of 100 percent storage utilization facture captures reductions in withdrawal capacity due to planned well maintenance but not unplanned outages.

Additional Analysis

Staff simulated multiple scenarios in addition to those required in Attachment A, to cover a wide range of possibilities over the study period by varying the pipeline supply, storage well utilization factor, and Aliso Canyon maximum inventory. To account for possible unplanned infrastructure outages, Staff varied the available pipeline supplies from 2,700 MMcfd to 3,500 MMcfd in 100 MMcfd increments to show the effect of changes to pipeline capacity. This range encompasses both values resulting from Attachment A (2,800 MMcfd) and the current situation (3,200 MMcfd). As noted previously, the assumptions outlined in Attachment A required using a pipeline capacity of 2,800 MMcfd for the primary analysis, while the pipeline capacity is closer to 3,200 MMcfd as of September 5, 2025.

Staff also varied the storage utilization factor, which accounts for changes in the storage fields' withdrawal capacity due to unplanned well outages and shut-ins. Starting from the assumption of 100 percent (no unplanned outages or shut-ins), Staff modeled decrements of 20 percent storage utilization factor down to 60 percent.

Finally, Staff varied the Aliso Canyon inventory from zero to the current maximum of 68.6 Bcf. At the lower end, Staff varied the maximum inventory in increments of 1 Bcf to account for Aliso Canyon's relatively high injection and withdrawal rates when the field is nearly empty. At the high end, Staff varied the inventory by 5 Bcf. In the mid-range, Staff varied the inventory by 20 Bcf.

Altogether, Staff modeled 324 scenarios using different combinations of these input assumptions.[32] Table 3 below summarizes the range of parameters used to create all the scenarios.

Table 3: Range of Parameters for Gas Balance Reliability Analysis

Parameter	Minimum	Maximum	Increment	Number of Values
Pipeline Supplies (MMcfd)	2,700	3,500	100	9

32 Recall that each scenario is simulated 100 times to obtain statistically convergent results

Storage Utilization Factor	60%	100%	20%	3
Aliso Canyon Maximum Inventory (Bcf)	0	68.6	1, 20, 5	12[33]

Use of the Gas Balance Reliability Analysis

Before discussing the results, it is important to mention the limitations of the model used in the gas balance reliability analysis. The model offers many advantages and is a necessary test of the reliability of a gas system, but it is not sufficient and its results should be interpreted in conjunction with hydraulic modeling.

First, the gas balance reliability model does not have any geographic dimension, which means withdrawals from any underground storage field are assumed to be able to meet supply shortages in any area served by the pipeline network without considering network constraints and energy conservation principles. This is because the model balances only mass, while higher order models, such as hydraulic modeling with Synergi Gas, balance both mass and energy. Second, the model does not account for hourly variations in the flows on the gas system that may lead to overpressures or underpressures, which hydraulic modeling captures. Third, the model does not account for withdrawals occurring for price mitigation, which may result in lower storage inventory levels throughout the study period.[34]

Therefore, while the gas balance reliability analysis is an important check to determine whether there is sufficient gas in storage to reliably supply customers throughout a cold and dry winter, hydraulic modeling analysis of peak day demand must also be conducted to ensure that the gas system can supply fluctuating demand continuously throughout the day across the entire SoCalGas service territory. That hydraulic modeling analysis, which is the subject of the next section, uses outputs from the gas balance reliability analysis. These outputs include the inventories of Aliso Canyon and the non-Aliso fields—Honor Rancho, La Goleta, and Playa del Rey—on the dates for which hydraulic modeling is conducted.

Results of Gas Balance Reliability Analysis

Minimum Required Inventory in Aliso Canyon Field

Staff ran scenarios for both study periods (November 1, 2025, through October 31, 2026, and November 1, 2030, through October 31, 2031).

For 2025-26, Staff assume pipeline supplies of 2,800 MMcfd based on the derated zonal capacities explained previously and a 100 percent storage well utilization factor.[35] The 100 percent storage well utilization factor reflects planned storage outages but assumes no unplanned storage outages. Using these assumptions, the gas balance reliability analysis finds that a minimum of 44 percent (30.2 Bcf) of Aliso Canyon's inventory is required to meet daily demand in winter 2025-26.

[33] The specific values modeled are 0, 1, 2, 3, 4, 5, 10, 30, 50, 58.6, 63.8, and 68.6 Bcf.
[34] None of the analyses included in Attachment A and used in this *Biennial Assessment Report* models withdrawals from storage for price mitigation.
[35] Aliso Canyon I.17-02-002 Phase 2: Modeling Report, Attachment A filed 3/8/2021, page 83 item 3

For 2030-31, staff assume pipeline supplies of 3,215 MMcfd and a 100 percent storage well utilization factor. Using these assumptions, the gas balance reliability analysis finds that Aliso Canyon inventory is not needed for reliability.

Table 4: Minimum Aliso Canyon Inventory Using Attachment A Assumptions

Winter	Pipeline Supply (MMcfd) (assumed)	Storage Well Utilization (assumed)	Percentage of Aliso Canyon Capacity (result)	Aliso Canyon Inventory Level (Bcf) (result)
2025-26	2,800	100%	44%	30.2
2030-31	3,215	100%	0%	0

As noted above, Staff also modeled a range of scenarios to show the impact of potential variations in pipeline and storage availability in both 2025-26 and 2030-31. The results from the range of scenarios are shown in Table 5, with results corresponding to the Attachment A assumptions highlighted in yellow. The results corresponding to the updated pipeline capacity are highlighted in blue and show a need for a 1 percent inventory level at Aliso Canyon when there are no unplanned storage outages. In general, the additional scenarios indicate that, as storage well utilization decreases, with the assumed pipeline capacity required by Attachment A, the maximum capacity required at Aliso Canyon to support reliability increases.

Table 5: Minimum Percentage of Aliso Canyon Capacity Needed Across a Range of Scenarios

	Storage Well Utilization Factor (Percent) 2025-26			**2030-31**		
Pipeline Supply (MMcfd)	**60%**	**80%**	**100%**	**60%**	**80%**	**100%**
2,700	Failure	85%	44%	44%	1%	0%
2,800	Failure	73%	44%	15%	0%	0%
2,900	100%	44%	44%	1%	0%	0%
3,000	85%	44%	1%	0%	0%	0%
3,100	73%	15%	1%	0%	0%	0%
3,200	73%	4%	1%	0%	0%	0%
3,300	44%	1%	0%	0%	0%	0%
3,400	15%	1%	0%	0%	0%	0%
3,500	1%	0%	0%	0%	0%	0%

Non-Aliso Field Levels on February 15

The gas balance reliability analysis is used to estimate the inventory in the non-Aliso fields (Honor Rancho, La Goleta, and Playa del Rey) on February 15. These outputs are used as an input into the hydraulic modeling analysis. Based on the outage assumptions in this report, which result in 2,800 MMcfd of available supplies, the combined inventory level of the non-Aliso fields on February 15 is 35 Bcf. If those pipeline outages were not modeled, resulting in 3,200 MMcfd of available supplies, the combined inventory level at the non-Aliso fields would be higher at about 52 Bcf on February 15, 2026.

For winter 2030-31, the gas balance reliability analysis shows that the non-Aliso fields are full (at 100 percent) by February 15, 2031. This increase in inventory compared to winter 2025-26 is a result of the forecast decline in gas demand. However, since storage fields are almost never filled to 100 percent capacity in order to leave room for daily balancing injections, Staff assume that the non-Aliso fields are at a 95 percent inventory level for the hydraulic modeling assessment. Staff thus base the available withdrawal rates on 95 percent inventories. Together, the non-Aliso fields would provide an estimated 1,457 MMcfd of withdrawals on February 15, 2031. The much higher withdrawal rates compared to winter 2025-26 are partly due to the higher inventory levels at the non-Aliso fields and partly due to anticipated upgrades at Honor Rancho.

Hydraulic Modeling Analysis

Methodology for Winter and Summer Analyses

The hydraulic modeling analysis tests whether gas demand can be met continuously during a 1-in-10 cold and dry peak day if it falls on February 15 as well as a high demand summer day if it falls on August 15. Attachment A requires these dates because storage fields are typically at lower inventory levels late in the winter season and the weather is typically hot in August. The pressure in storage fields declines as inventory declines, so fields with lower inventory have lower withdrawal capacity. Therefore, to conduct the winter hydraulic modeling analysis, Staff use the estimated inventory levels of Aliso Canyon and the non-Aliso fields on February 15 from the gas balance reliability analysis as an input to determine withdrawal rates of the non-Aliso fields, which change depending on their inventory levels. The hydraulic modeling analysis also tests whether swings in gas demand can be met during a summer high demand day if it falls on August 15.

As required in Attachment A, Staff conducted hydraulic modeling for the upcoming winter 2025-26 as well as winter 2030-31.[36] Staff also conducted hydraulic modeling for summer 2026 and summer 2031 during high demand days. Staff performed hydraulic modeling first without Aliso Canyon and then with various withdrawal rates of Aliso Canyon until the modeling run succeeded in meeting peak-day demand. To run successfully, the gas system must be able to recover the same amount of gas in the pipelines by the end of the day that it started with, to be ready to serve demand the following day. This is modeled as the system ending the 24-hour simulation with as much linepack, or gas in the pipelines, as it had at the beginning of the simulation. This approach uses Synergi Gas software to model the flows of gas into and within the SoCalGas system to ensure that adequate gas pressure on each SoCalGas network element is maintained throughout the day. This modeling is critical because gas demand fluctuates significantly throughout the day, with peaks in the morning and evening, while pipeline supply is ratable (constant) throughout the day.

Input Parameters: Attachment A Assumptions

Attachment A includes Table 1, which contains 16 inputs to be used in the model, including the forecast peak day demand, demand variation, demand shapes, pipeline capacities, gas in storage, and

[36] D.24-12-076, Attachment A, Table 1, pp A6: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF.

withdrawal and injection rates.[37] Row 9 of Attachment A discusses how to set pipeline outages internal to SoCalGas system for hydraulic modeling as follows:

> Actual operating capacities, as reported in advice letters regarding pipeline capacity submitted in compliance with D.22-07-002, less unplanned outage of 101.5 MMcfd for hydraulic flow modeling, less planned outages reported by SoCalGas in twice annual data requests for the gas balance analysis.

While Attachment A does not clearly indicate whether Staff should include planned outages in the hydraulic modeling analysis, Staff did not think it prudent to disregard a then-known outage. Therefore, for winter 2025-26, Staff included SoCalGas's planned pressure reductions on Lines 4000 and 4002 in the hydraulic modeling assumptions, which SoCalGas expected to last from July 1, 2025, through November 1, 2026.[38] SoCalGas provided the expected pressure reductions to Staff for use in the model via data request response. However, the corresponding loss in capacity did not reduce the Northern Zone capacity by the amount reported on Envoy (655 MMcfd) under the peak day conditions assumed in the hydraulic modeling, and Staff was still able to bring in 85 percent of the Northern Zone nominal capacity. In other words, Staff's simulation shows that the impact of the planned outages on the Northern zonal capacity during a 1-in-10 peak did not reduce capacity below the 85 percent utilization specified in Attachment A.

In addition, for winter 2025-26, Staff assumed an unplanned outage of 101.5 MMcfd on a 23-mile segment of Line 5000 in the Southern Zone. There are multiple pipelines carrying gas from the border in the Southern Zone, and it was not clear prior to running the hydraulic simulation whether the reduction on this segment would lead to a capacity reduction in the zone as a whole. Staff therefore modeled the system to determine whether this unplanned outage would reduce the zonal capacity. It did not. Specifically, Staff reduced the upstream pressure on a segment of Line 5000 just downstream of the Blythe Compressor station to correspond to a reduction in the flow rate capacity of 101.5 MMcfd on this segment from its maximum or nominal flow capacity. The pressure reduction on the upstream end of this segment is insignificant, while the capacity loss is recovered by the twin Lines 2000 and 2001 resulting in no zonal capacity loss. Accordingly, Staff assumed no further unplanned outages or capacity reductions beyond those required by Attachment A.

In summary, for the winter 2025-26 1-in-10 peak day simulation, 3,215 MMcfd of ratable supplies are available during the entire day (inclusive of 70 MMcfd of California Production).

For winter 2030-31, Staff modeled only a 101.5 MMcfd unplanned outage as required by Attachment A since there are currently no planned outages for that winter. The outage was assumed to be located on Line 235 West, extending from west of Kramer Junction to just east of Quigley Station. To include the 101.5 MMcfd outage as a constraint in the hydraulic model, Staff performed the following calculations:

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[37] Ibid, pp. A3-A7

[38] ENVOY is SoCalGas' electronic bulletin board. Information about the pressure reduction on Lines 4000 and 4002 was posted to ENVOY'S Critical Notices on April 11, 2025: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternalEbb.getMessageLedger?ledgerType=message&Page=filter&datePosted_from=04%2F11%2F2025&datePosted_to=04%2F11%2F2025&keyword=Northern%20Zone&folderId=1.

1. Assume maximum allowable operating pressure (MAOP) at the upstream end of the pipeline (near Kramer Junction).
2. Assume the pressure at the downstream end of the pipeline to be equal to the MAOP of the pipeline just downstream of Quigley Station (i.e. inside the LA basin).
3. Calculate the flow rate based on the pressure difference above.
4. Decrease the flow rate until no MAOP violations are occurring. This is the maximum possible flow rate in this segment of the pipeline.
5. Once the flow rate in Step 4 is determined, subtract 101.5 MMcfd from it and assume that flow rate as a source at the upstream of the pipeline.
6. Find the corresponding pressure distribution on this segment of the pipeline.
7. Use the pressure distribution in Step 6 as the new pressure constraint (or reduced MAOP) for the peak day demand simulation.

As for the summer hydraulic modeling analysis, Staff used the same outage assumptions outlined above for the winter hydraulic modeling analysis. In addition, to obtain hourly fuel burn forecasts needed to model the electric generators, Staff performed Production Cost Modelling for calendar years 2026 and 2031 using its Strategic Energy Risk Valuation Model (SERVM) based on the most current Integrated Resource Planning (IRP) cycle assumptions.

SERVM is normally run using a range of weather years, hydro years, and other input parameters. Therefore, a selection must be made as to which of these weather and hydro years is most appropriate to forecast the hourly fuel burn by the electric generators that will be used in the hydraulic modeling analysis. Since natural gas forecasts are mostly concerned with cold and dry years, Staff proceeded with the selection of 1-in-10 cold weather years and a 1-in-10 dry hydro year. The weather years selected for modeling were historical 2000 and 2003 respectively due to their weather patterns and gas demand being overall in the 90th percentile among the entire weather history used for PCM. This selection was based on Table 6.1 from SoCalGas' Workpapers for the *2024 California Gas Report*. On the other hand, the hydro year selected was 2007, which was based on Staff analysis of drought metrics, namely the Modified Palmers Drought Severity Index.[39]

The results obtained from the production cost model were analyzed and processed to obtain the maximum demand by the electric generators in the SoCalGas region during the summers of 2026 and 2031 (July, August, and September). The dates of maximum summer fuel burn were August 2, 2026, and July 18, 2031. The demand forecasted by the production cost model is 1,671 MMcfd and 881 MMcfd for summers 2026 and 2031 respectively. In addition, Staff used the Small Electric Generators[40] forecasts from the SoCalGas model, which show demand of about 66.5 MMcfd and 65.5 MMcfd in 2026 and 2031 respectively. The hourly profiles of the natural gas power plants

[39] Another approach would be to use a 1-in-10 hot year for fuel burn by the electric generators. However, the 1-in-10 hot year forecasts for other customer classes, such as noncore, non-EG are not available. This approach would also complicate how the gas balance reliability analysis is performed since this analysis require a full year of forecasts and was never used to combine forecasts from multiple weather years such as a Typical Meteorological Year

[40] These are generators located, for example, at Home Depot, Walmart, or AT&T.

serviced by SoCalGas[41] were extracted on those dates and mapped to their physical locations and corresponding Synergi nodes in the hydraulic model.

A more in-depth description of methods to perform hydraulic modeling analysis can be found in Staff's Aliso Canyon I.17-02-002 Phase 2: Modeling Report from March 2021.[42]

Results of Hydraulic Modeling Analysis

Winter 2025-26 Peak Day

For winter 2025-26, the hydraulic modeling analysis indicates that a withdrawal rate of 550 MMcfd from Aliso Canyon is needed on a peak day to maintain gas system reliability.

Figure 2 below shows the results of two simulations performed for the winter 2025-26 assessment. One simulation uses withdrawals from Aliso Canyon to meet gas demand, while the other does not.

A successful simulation is defined as one that restores the linepack (the amount of gas in pipelines) to its initial level by the end of the simulation as well as ensures that pressures on all pipelines and stations remain above minimum operating pressure and below maximum operating pressure. Restoring linepack means that the system could continue serving that level of demand for many days. Linepack loss directly correlates with loss of pressure on the transmission system. If the pressure drops below the minimum allowable operating pressure (MinOP), customer curtailments are likely to occur, and compressors start to shut off. Failure to restore linepack means that the system would likely drop below the minimum operating pressure, resulting in curtailment of gas for some customers.

For the simulation that does not use Aliso Canyon, represented below by the red line, linepack does not return to its original level, resulting in a failed simulation. In that scenario, linepack falls from 2,618.6 MMcf at the beginning of the simulation to 2,071.5 MMcf at the end, a 547.1 MMcf linepack loss, meaning that supply from Aliso Canyon is needed. The amount needed from Aliso Canyon is approximately equal to the 547 MMcf linepack loss resulting from the failed simulation

In the scenario that uses withdrawals from Aliso Canyon, represented below as the blue line, linepack is restored by the end of the day. This result supports the conclusion that withdrawal from Aliso Canyon (a positive number adding to total supplies) is needed to provide reliable service and meet gas demand (labeled as loads and shown as a negative number) on a 1-in-10 peak winter day.

In both simulations, withdrawals from the three non-Aliso fields have been maximized between the hours six and 26, using the full 896 MMcfd of available withdrawal capacity predicted by the gas balance reliability analysis for February 15, 2026. The maximum withdrawal from Aliso Canyon was 550 MMcfd and started at hour six till the end of the simulation. In total, 3,215 MMcfd of ratable supplies are available during the entire day (inclusive of 70 MMcfd of California Production).

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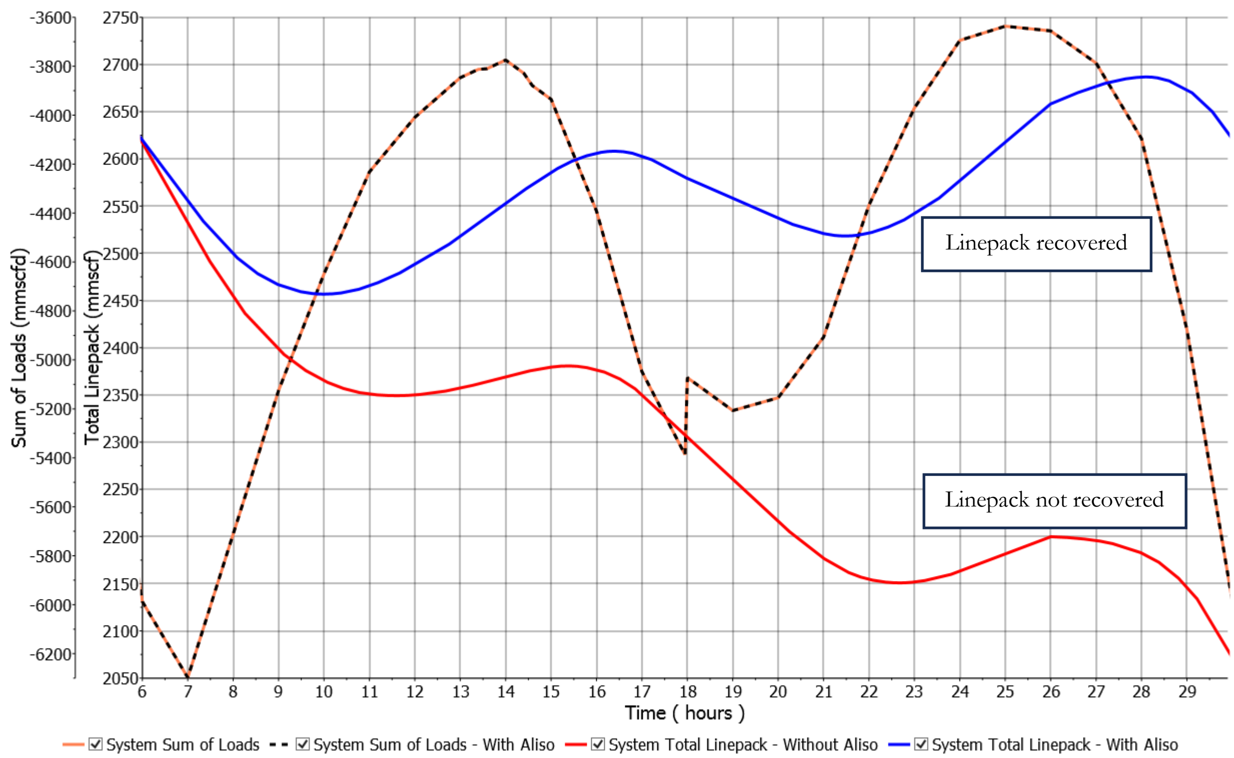
[41] Some power plants in Southern California are not serviced by SoCalGas. They are known as "bypass" powerplants. Predicted generation and gas demand from these generators is left out of the hydraulic model.

[42] See *Aliso Canyon I.17-02-002 Phase 2: Modeling Report,* 3-8-2021 page 31: [i_1702002_phase2modelingreport_3-8-21_unredacted.pdf]().

Figure 2: Winter 2025-26: Linepack and Gas Demand with and without Aliso Canyon



Winter 2030-31 Peak Day

For winter 2030-31, the hydraulic modeling analysis indicates that Aliso Canyon is not needed to maintain gas system reliability provided that planned gas system upgrades are completed, gas demand declines as forecasted, and there are no unplanned outages more disruptive than what was modeled.

Figure 3 shows some of the results of the winter 2030-31 hydraulic modeling analysis including the total linepack, total supplies, and total load throughout the day. The simulation shows that demand was met during the entire 24 hours without withdrawals from Aliso Canyon and without minimum or maximum pressure violations or violations of any other constraints on the system, such as the maximum flow rates at the citygates. Linepack was restored by the end of the simulation and follows the typical daily trend, i.e., decreasing during the morning and evening ramps and recovering during periods of lower demand in the afternoon and at night. The linepack recovery occurs when hourly supplies are higher than the hourly demand.[43]

For winter 2030-31, Staff placed the required unplanned outage of 101.5 MMcfd on Line 235 West, east of the Quigley Regulator Station. Despite the pressure reduction on Line 235 West, modeling indicates 3,215 MMcfd of ratable supplies can be brought into the SoCalGas pipeline network. A

[43] There are about three hours of phase lag on the SoCalGas pipeline network, however, where demand and linepack are misaligned by three hours due to how slowly gas moves throughout the system.

combined non-Aliso maximum withdrawal rate of 1,012 MMcfd was used during the simulation, leaving about 444 MMcfd of unused non-Aliso withdrawal capacity.[44]

Figure 3: Total Linepack, Total Supplies, and Total Load During a 1-In-10 Peak Day in Winter 2030-31

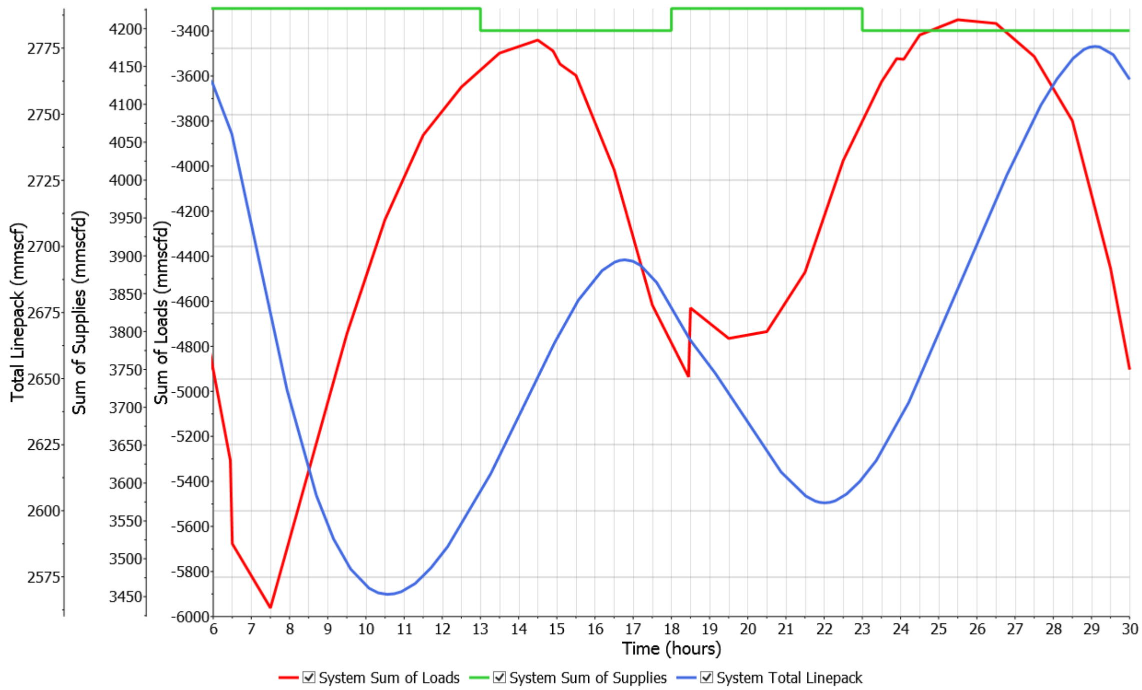
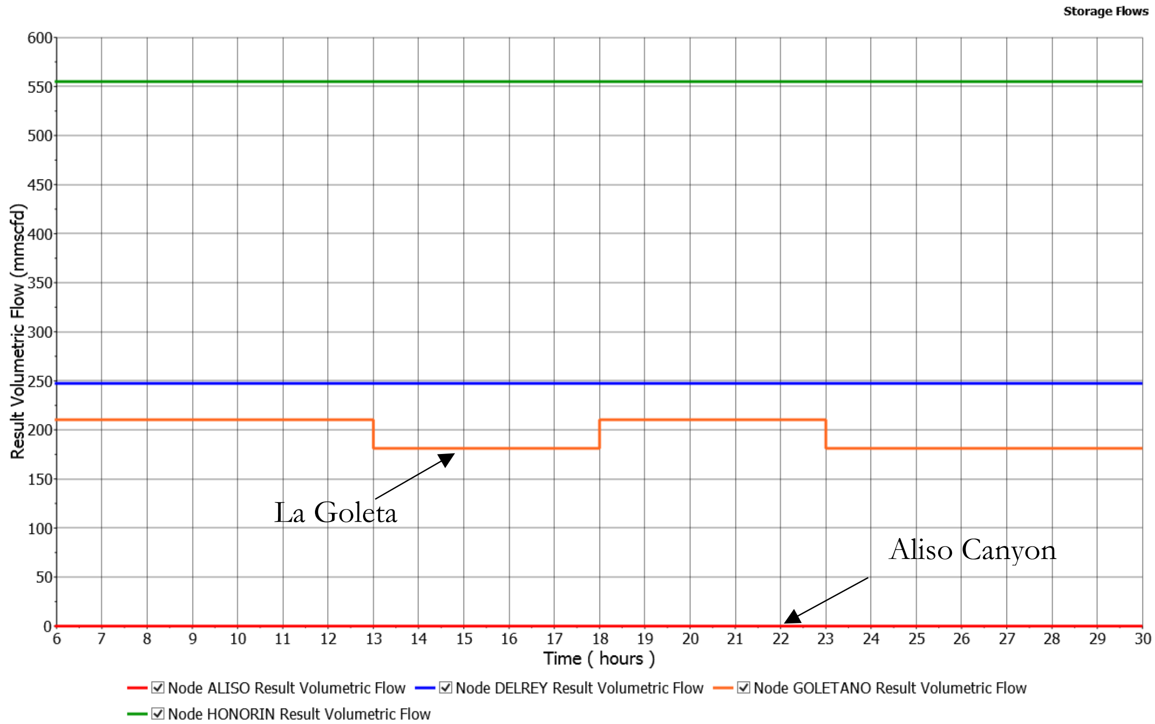


Figure 4 shows withdrawals from the non-Aliso storage fields—Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey—throughout the day. (There are no withdrawals from Aliso Canyon.) Withdrawals from Honor Rancho, SoCalGas' second-largest field, remain constant throughout the day at 550 MMcfd. Withdrawals from La Goleta, located near Santa Barbara, are maximized except during the down ramps when withdrawals are reduced to avoid MAOP violations in the coastal area. Finally, withdrawals from Playa del Rey, which is SoCalGas' smallest gas storage field but situated near demand centers in the LA basin, are maximized throughout the day.

Figure 4: Withdrawals from Storage During a 1-In-10 Peak Day in Winter 2030-31



The finding that reliability can be preserved in winter 2030-31 with no withdrawals from Aliso Canyon rests on significant changes to the physical capabilities of the SoCalGas gas system, particularly in the Northern Zone, as well as significant declines in the peak day demand forecast. SoCalGas is planning three upgrades to the SoCalGas system that together reduce the need for Aliso Canyon but increase the critical significance of Honor Rancho and surrounding transmission pipeline capacity to gas system reliability.

The first is an upgrade to the Quigley Regulator Station. Currently, the total combined Wheeler Ridge pipeline capacity and Honor Rancho withdrawal capacity cannot be brought into the Los Angeles basin given the capacity of the Quigley Regulator Station. SoCalGas plans to increase the flow capacity at the Quigley Regulator Station prior to 2027, which will reduce the need for Aliso Canyon.

Second, SoCalGas plans to drill additional wells at Honor Rancho by 2030, which will increase the field's withdrawal capacity, complementing the increased flow capacity created by the Quigley Regulator Station upgrade.

Third, SoCalGas' ability to reliably inject gas into Honor Rancho should also be improved when it completes the Honor Rancho Compressor Station Modernization Project. The Compressor Station project was updated in SoCalGas' most recent general rate case and is expected to be fully commissioned in 2027.[45]

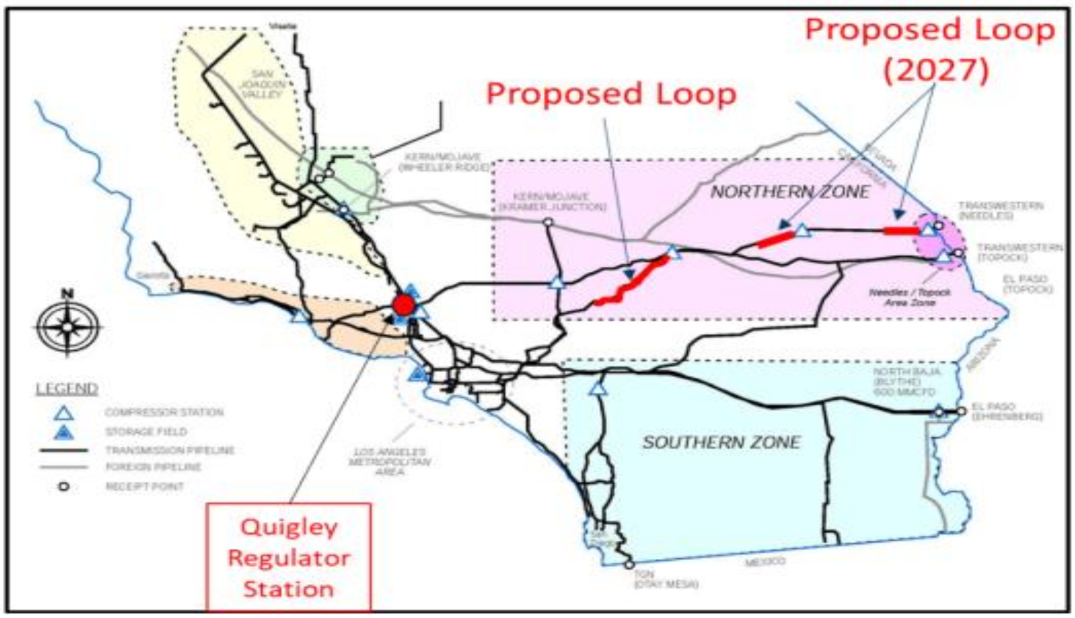
Upgrades performed to Honor Rancho and the Quigley Regulator Station have the benefit of allowing higher flows from Honor Rancho to the northern part of the Los Angeles basin, which is

[45] D.24-12-074, pp. 285-88: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf.

the closest citygate to Aliso Canyon. This explains the decreased need for Aliso Canyon withdrawals. Thus, until the constraint at Quigley is alleviated, flows from Aliso Canyon are necessary to support demand variability in the LA Basin, downstream of Quigley.

While demand reduction and electrification have received most of the attention in attempts to reduce reliance on Aliso Canyon, these planned gas system upgrades are critical to the observed reduction in the need for Aliso Canyon in the winter 2030-31 simulation. It is also worth noting that while these upgrades will decrease the need for Aliso Canyon, they will increase the gas system's reliance on Honor Rancho and the surrounding transmission pipelines.

Figure 5: Location of Quigley Regulator Station



Source: *Aliso Canyon I.17-02-002 Phase 3 Report.*

One final nuance to consider regarding the 2030-31 hydraulic modeling analysis is the location of the assumed unplanned outage. As described above, in this analysis, Staff assume an outage on Line 235 West, east of the Quigley Regulator Station. However, if an outage were to occur at a more critical point on the SoCalGas system, continued operations at Aliso Canyon could be required for the simulation to succeed (i.e., to meet demand and restore linepack).

In the *2027 Biennial Assessment Report,* Staff will verify whether the planned infrastructure upgrades have been fully commissioned and whether the peak day forecast is declining as expected.

Summer 2026 High Demand Day

For summer 2026, the hydraulic modeling analysis indicates that Aliso Canyon is not needed to maintain gas system reliability. However, the simulation highlights some difficulties managing the evening ramp, associated with the so-called "duck curve."

For summer 2026, the forecast demand on a high demand day is 3,110 MMcfd which translates to an average hourly demand of 130 million cubic feet per hour (MMcfh). Similar to the winter 2025-26 simulation, 3,215 MMcfd of ratable supplies are available, which translates to 134 MMcfh.

Furthermore, the peak hourly demand on that summer day is 171 MMcfh (4,105 MMcfd) (at 6:00 PM), while the minimum hourly demand is 108 MMcfh (2,592 MMcfd) (around midnight).[46] Without any reliance on linepack, this hourly variability in the demand indicates a maximum need for 63 MMcfh or 1,513 MMcfd in withdrawal capacity to balance the load.

Preliminary simulations showed that if the supplies are assumed at 3,215 MMcfd, there isn't enough injection capacity to balance the system. Overpressures occur throughout the SoCalGas pipeline system, especially in the SDG&E service territory and on Lines 4000 and 4002. Therefore, Staff had to lower the supplies to match the demand as a first measure to avoid overpressures.[47] In other words, supplies are assumed to be 3,110 MMcfd, which is a reduction of 105 MMcfd compared to the winter 2025-26 simulation. Part of this reduction was to California Production in the San Joaquin Valley, which had to be lowered from 50 MMcfd to 40 MMcfd to avoid overpressures in the Line 85 Zone due to lower summer demand.

Even with supplies at 3,110 MMcfd, there was a critical need to balance the system using underground storage. Since the gas reliability analysis shows that storage is full by August 15, 2026. Staff assumed 95 percent inventory levels for all storage fields, which resulted in only 254 MMcfd of combined injection capacity available from the non-Aliso fields. The available injection capacity (254 MMcfd) is small compared to the variability in demand (1,502 MMcfd).

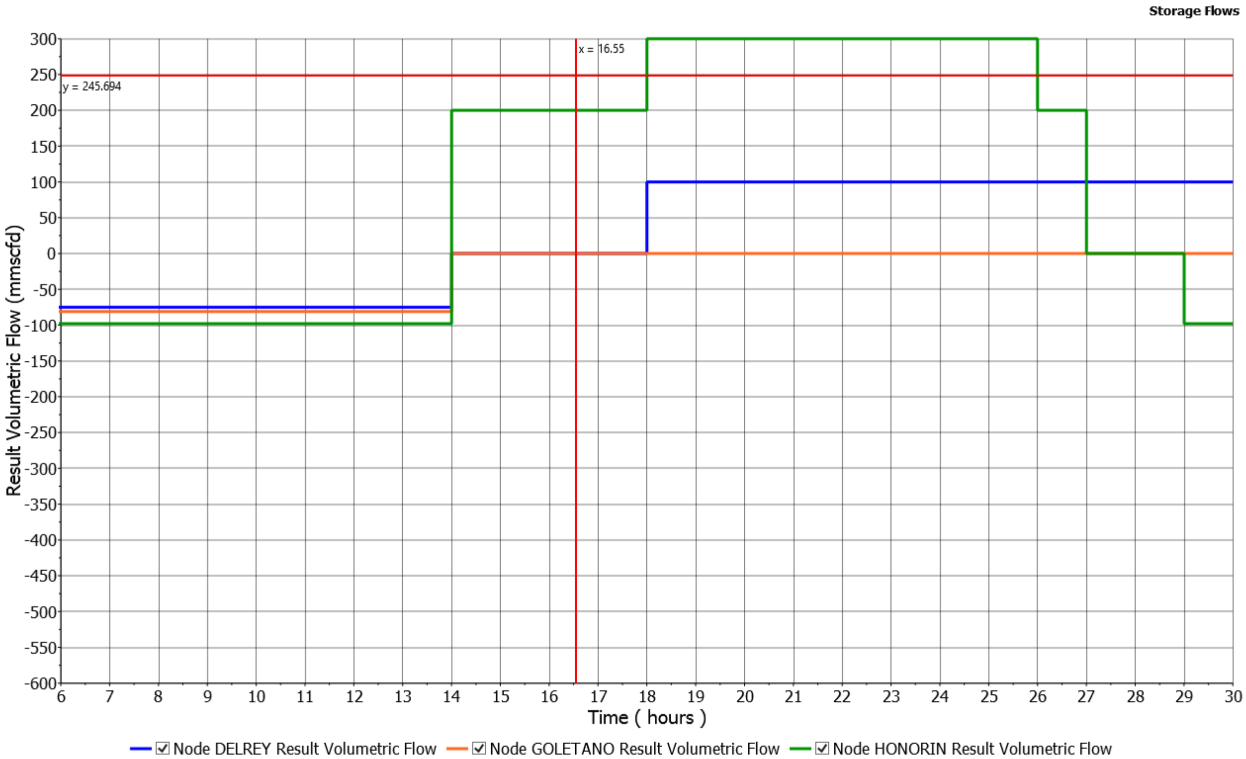
The summer simulation presented different challenges than that for winter. First, morning hourly load is much lower than the peak load. Specifically, the load between 6:00 AM and 12:00 PM averages 3,009 MMcfd, which is substantially below the peak load of 4,095 MMcfd. Therefore, Staff injected into all the non-Aliso fields at the maximum available injection rate (254 MMcfd) during the morning and up to 2:00 PM. Despite maximizing injections into the non-Aliso fields, the linepack kept increasing until 12:30 PM, when the demand started to ramp up. Had the supplies been any higher, the SoCalGas pipeline network would have been "over-packed" by 12:30 PM, and overpressures would have been occurring.

A second challenge was managing overpressures in the SDG&E area. SDG&E has a relatively low amount of linepack and does not allow much load variability without having to rely on the rest of the Southern Zone, which in turn does not have direct access to underground storage. Keeping the Moreno Compressor on bypass (offline) for much of the day resulted in a small increase in the Southern Zone linepack but not to the level that would cause overpressures. All other systems had near constant linepack.

The combination of the load curve and the supplies assumed resulted in injections into all three non-Aliso fields from 6:00 AM to 2:00 PM. By 6:00 PM, two of the storage fields were already being used for withdrawals to meet the steep evening ramp. The withdrawals peaked at 400 MMcfd between 6:00 PM and 2:00 AM the next day to avoid minimum pressure violations on the Northern Zone and to restore the linepack in both the Northern and Southern Zones. The storage flows used to balance the load are shown in Figure 6.

[46] Hourly demand is often referred to in whole-day terms rather than in the actual hourly demand number. In this case, at 6:00 pm, hourly demand is equivalent to what it would be on a day with 4,095 MMcfd in demand, if gas demand was the same in every hour.
[47] As opposed to injecting to Aliso Canyon.

Figure 6: Injection and Withdrawals from Storage During a 2026 Summer High Demand Day



While balancing the pipeline system using both injections and withdrawals on the same day is not typical, this occurred due to two reasons. First is the set of assumptions described in Attachment A of D.24-12-076, which prescribes higher-than-typical interstate summer supplies. Second is the steep evening ramp resulting from the Electric Generation. Furthermore, it is important to note that Staff presents one of many possible solutions that do not rely on Aliso Canyon, and it reflects a modeling assumption that may be challenging for the utility to implement. Other solutions exist that are less challenging operationally. For example, it is possible to bring more supplies into the Northern Zone and less supplies into the Southern Zone (although the assumed outages may prohibit that), similar to the seasonal load restrictions implemented by SoCalGas during the summer. Delivering more gas to the Northern Zone would potentially allow for more variability in the pressures in the SDG&E territory, thereby absorbing down ramps but increasing the risk of minimum flow violations.[48,49]

One may think of the linepack in the Southern Zone as SDG&E's own gas storage, except that this storage is inside the pipelines rather than underground. The linepack of the Southern Zone as a

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[48] In the model, regulator and compressor set points govern how much gas is delivered to which system. In reality, gas customers decide how much gas they will deliver and where they will deliver it. The utility's System Operator has to respond to customers' decisions and keep the system balanced in real time.

[49] Customers have a tendency to deliver less gas to the Southern Zone than they use in that region, which leads to periodic local shortages. Because under-deliveries to the Southern Zone are a long-standing problem, the CPUC has given the System Operator authority to purchase gas to meet the minimum flow requirement on an as-needed basis. The costs for these purchases are recovered via Tier 3 Advice Letters on the Annual Compliance Report on Utility System Operator's Southern Zone Reliability Purchases and Sales, e.g., Advice Letter 6219-G: https://tariffsprd.socalgas.com/scg/filings/content/?utilId=SCG&bookId=GAS&flngStatusCd=Approved.

whole is about six to eight times that of SDG&E alone. The reliance on the linepack of Lines 2000, 2001, and 5000 to meet SDG&E's load variability is also complicated by the Southern Zone's lack of access to nearby underground storage and the fact that Southern Zone supplies are needed support to the Los Angeles basin on peak days.

Another challenge with this simulation is switching underground storage fields from injection to withdrawals on the same day, which may be operationally difficult. The solution to that problem would be to decrease supplies even further so as not to need injections during the morning hours.[50] However, higher withdrawals would then be needed to meet the evening ramp and restore the linepack. In essence, using this strategy, the flows shown in Figure 6 would shift upwards resulting in no injections between 6:00 AM and 2:00 PM and higher withdrawals after 2:00 PM.

To conclude, this simulation shows that Aliso Canyon may not be needed in summer 2026. However, the simulation also highlights some of the difficulties in operating the pipeline system on a high demand day with a steep evening ramp when supplies are precisely equal to demand. These difficulties are exacerbated by the nearly full non-Aliso storage fields. Filling non-Aliso gas storage early in the season may not be the optimal strategy for meeting demand on high demand summer days because of the need for injection as well as withdrawal. Of course, in reality, the inventory of the gas storage fields on a high demand summer day is not optimized by the utility but rather depends on customers' injection decisions earlier in the season.

Summer 2031 High Demand Day

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. Specifically, Aliso Canyon is not needed to balance the ratable supplies with the variable demand.

For summer 2031, the high demand day forecast is only 2,305 MMcfd.[51] Similar to the winter 2030-31 simulation, 3,215 MMcfd of ratable supplies are available (inclusive of 70 MMcfd of California Production), which is much higher than the demand. Only 254 MMcfd of injection capacity is available since the non-Aliso fields are nearly full and assumed to be at 95 percent inventory levels. Therefore, if supplies are assumed at 3,215 MMcfd, the SoCalGas pipeline network will certainly violate the MAOP or cause violations on upstream interstate pipelines.

Therefore, and similar to the summer 2026 simulation, Staff assumed supplies that are equal to the sum of the demand and the available injection capacity, which is 2,559 MMcfd.[52] After lowering the supplies to match the demand and the injection capacity, the receipt point utilization of the Northern, Southern, and Wheeler Ridge zones is 70 percent, 52 percent, and 98 percent respectively. Only 60 MMcfd of California Production was needed.

The simulation shows that the maximum injection rate was needed to balance the pipeline network system. Injection into all three non-Aliso fields was needed from 6:00 AM to 5:00 PM. This result was expected, since Staff set the supplies higher than the demand by an amount equal to the

[50] Appendix A does not include any direction for this situation.

[51] Staff obtained the forecasts for electric generation demand from ED Production Cost Modeling. The forecasts for all other customer classes are from the *2024 California Gas Report*.

[52] 2,305 (load) +254 (injection capacity) = 2,559 MMcfd

available injection capacity. At 5:00 PM, injection into Playa del Rey ceased in order to avoid minimum pressure violations and help restore the linepack.

Staff notes that this is but one solution for the given set of assumptions. However, it shows that there will be an ongoing need for storage to balance hourly variation in demand especially around the evening hours when demand from gas-fired electric generators peaks.

Economic Analysis

Methodology

The economic analysis compares expected natural gas prices for the upcoming winter in Southern California to national and historic levels. If prices exceed specified threshold levels, Staff may recommend that the Aliso Canyon storage level remain unchanged, or even be increased, to mitigate the rate impacts of high Southern California gas prices.

There are two price comparisons. The first compares expected Southern California gas prices for the upcoming winter to national prices, and the second compares them to actual historical prices.

Threshold: Comparison with National Prices

If the price of natural gas in Southern California for the upcoming winter is 50 percent or more above the national price of natural gas for the upcoming winter, it exceeds the threshold.

The Southern California gas price for winter 2025-26 is represented by the SoCal Citygate average forward fixed price of gas for the upcoming December, January, and February, as published by Natural Gas Intelligence, averaged across the values published on each date from March 1 through May 31, 2025.

The national gas price for winter 2025-26 is represented by the Henry Hub average forward gas price for the upcoming December, January, and February, published by Natural Gas Intelligence, averaged across the values published on each date from March 1 through May 31, 2025.

Threshold: Comparison with Historical Prices

If the forward price of gas in Southern California for the upcoming winter is 50 percent or more above the bidweek[53] price of gas in Southern California during the previous three winters, it exceeds the threshold.[54]

For this calculation, the Southern California gas price for the upcoming winter is as described in the comparison with national prices above. The Southern California historical price of gas during the previous three winters is represented by the SoCal Citygate average bidweek price, as published by Natural Gas Intelligence, averaged across the values for December, January, and February delivery in

[53] Monthly gas contracts for the upcoming month are often purchased during bidweek. Bidweek is a trading period that includes the first three of the last five gas trading days before the new month begins, where a trading day is defined as any day the Intercontinental Exchange (ICE) is trading physical natural gas. Long-term gas contracts are often indexed to the average or midpoint bidweek price, meaning the contract is not for a fixed gas price but a price that fluctuates with bidweek prices. For a more in-depth discussion of gas contracting, see the CPUC Staff White Paper *High Natural Gas Prices in Winter 2022-23: Part I:* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K897/556897251.PDF.

[54] For more detail, see D.24-12-076, Attachment A, pp A7-A9.

the preceding three winters (2022-23, 2023-24, and 2024-25), excluding December 2022 because it represents an exceptional data point.

Results of Economic Analysis

Current gas prices expected in Southern California for winter 2025-26 do not exceed the threshold levels set by D.24-12-076. Therefore, the results of the limited economic analysis do not override the results of the other analyses.

Comparison with National Prices

Southern California natural gas prices for the upcoming winter are about 39 percent above national gas prices, as represented by Henry Hub. Therefore, they are not more than the threshold level of 50 percent above national prices.

Table 6: Comparison of Winter 2025-26 Forward Prices at SoCal Citygate and Henry Hub

Average SoCal Citygate price for the upcoming winter	Average Henry Hub price for the upcoming winter	SoCal Citygate price percentage above Henry Hub
$6.86	$4.94	+39%

Source: Staff analysis based on Natural Gas Intelligence data.

To provide additional information, Staff conducted the same comparison for winter 2026-27. SoCal Citygate forward prices for winter 2026-27 were more than 50 percent above Henry Hub prices during the trade dates used in the above analysis but have since declined to below the threshold. Forward prices for that winter will be more certain by next year.

Table 7: Comparison of Winter 2026-27 Forward Prices at SoCal Citygate and Henry Hub

Trade Dates	Average SoCal Citygate price for the 2026-27 winter	Average Henry Hub price for the 2026-27 winter	SoCal Citygate price percentage above Henry Hub
March 1 – May 31, 2025	$7.37	$4.70	+57%
September 1, 2025	$6.34	$4.47	+42%

Source: Staff analysis based on Natural Gas Intelligence data.

Comparison with Historical Prices

Southern California natural gas prices for the upcoming winter are not above the threshold level of 50 percent above historical Southern California prices for the previous three winters.

Table 8: Comparison of Winter 2025-26 SoCal Citygate Forward Prices with Previous Three Winters

Average SoCal Citygate price for the upcoming winter	Average SoCal Citygate bidweek price for the past three winters	Upcoming winter gas price percentage above past three winters
$6.86	$11.48	-40%

Source: Staff analysis based on Natural Gas Intelligence data.

Staff conducted an additional comparison in recognition that gas prices in winter 2022-23 were exceptionally high.[55] Excluding that winter from the analysis, the bidweek gas price for the past two winters (2023-24 and 2024-25) is $5.03. Prices for winter 2025-26 are thus 36 percent higher than the preceding two winters and do not exceed the 50 percent threshold.

Table 9: Comparison of Winter 2025-26 SoCal Citygate Forward Prices with Previous Two Winters

Average SoCal Citygate price for the upcoming winter	Average SoCal Citygate bidweek price for the past two winters	Upcoming winter gas price percentage above past two winters
$6.86	$5.03	+36%

Additional comparison of prices for winter 2026-27 shows that they are still well below the average for the past three winters.

Table 10: Comparison of Winter 2026-27 SoCal Citygate Forward Prices with Previous Three Winters

Average SoCal Citygate price for winter 2026-27	Average SoCal Citygate bidweek price for the past three winters	Winter 2026-27 gas price percentage above past three winters
$7.37	$11.48	-36%

Comparing with the past two winters, forward prices are still below the 50 percent threshold. These results reflect the volatility of gas prices, the potential for gas prices to increase in 2026-27, and that even then, expected prices are still well below recent highs.

Table 11: Comparison of Winter 2026-27 SoCal Citygate Forward Prices with Previous Two Winters

Trade Dates	Average SoCal Citygate price for the 2026-27 winter	Average SoCal Citygate bidweek price for the past two winters	Winter 2026-27 gas price percentage above past two winters
March 1 – May 31, 2025	$7.37	$5.03	+47%
September 1, 2025	$6.34	$5.03	+26%

Source: Staff analysis based on Natural Gas Intelligence data.

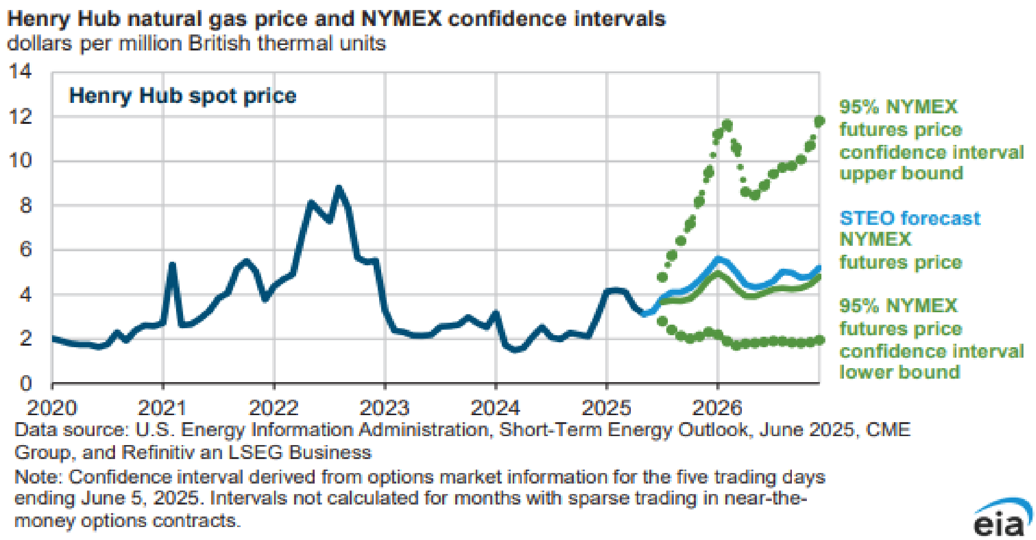
Current Context

There are events on the near-term horizon that have the potential to increase gas commodity prices, particularly for winter 2026-27, that are not reflected in Staff's economic analysis. Issues of concern include a national increase in exports of liquified natural gas and the start-up of the Energía Costa Azul LNG facility in Baja California.

[55] For more information, see Investigation 23-03-008: https://apps.cpuc.ca.gov/apex/f?p=401:5::::RP,5,RIR,57,RIR::.

Nationally, LNG exports are expected to ramp up as more LNG export facilities begin operations. U.S. LNG exports are predicted to increase from 11.9 billion cubic feet per day (Bcfd) in 2024 to 14.6 Bcfd in 2025 and 16.0 Bcfd in 2026, outpacing growth in U.S. natural gas production. The EIA cites this combination in its prediction that average natural gas prices at Henry Hub, the national benchmark, will increase from $2.20/MMBtu in 2024 to $4.00/MMBtu in 2025 and $4.90/MMBtu in 2026.[56]

Figure 7: Henry Hub Gas Prices and NYMEX Confidence Intervals[57]



Source: EIA

One LNG export facility will have a localized impact on the SoCalGas service territory: Sempra's Energía Costa Azul. Expected to go into service in spring 2026, the Baja California facility is expected to increase gas demand in the region by 425 MMcfd. Energía Costa Azul will increase competition for limited interstate pipeline capacity from gas production basins in Texas and New Mexico. In May 2025, Natural Gas Intelligence reported that fixed forward prices at the SoCal Citygate were $4.77/MMBtu for summer 2025 and $5.41/MMBtu for summer 2026.[58,59] The impact of Energía Costa Azul is expected to be felt most strongly in SoCalGas' Southern Zone (see Figure 1 above and Figure 8 below), which includes San Diego, Riverside, and Imperial Counties. The Southern Zone has no gas storage facilities and limited connections to the rest of the SoCalGas system.

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[56] EIA *Short-Term Energy Outlook*, June 10, 2025, pp 3, 12-13, and Table 5a: https://www.eia.gov/outlooks/steo/archives/jun25.pdf.

[57] The New York Mercantile Exchange (NYMEX) allows the sale of natural gas contracts for future delivery using Henry Hub as the delivery site: Natural Gas Prices - American Gas Association

[58] Natural Gas Intelligence, "Sempra Moves to Realign Mexico Natural Gas Assets as ECA LNG Nears Completion," May 12, 2025.

[59] Natural Gas Intelligence, "With Summer Around the Corner, How Will Mexico Compete With California for Permian Natural Gas Supply?," April 25, 2025.

Figure 8: Gas Production Basins and Pipelines Serving Energía Costa Azul

Source: *2024 California Gas Report*

Staff's economic analysis also doesn't capture the impact of reductions to the Unbundled Storage Program, which is currently allocated 25 Bcf in inventory. The program provides an opportunity for noncore customers, including electric generators, to purchase gas storage to help meet their demand. SoCalGas suspended the program after the Aliso Canyon leak because there was not enough inventory capacity to support it. The utility reinstated the program in 2023 after the CPUC increased Aliso Canyon's maximum inventory to 68.6 Bcf. Per D.24-07-009, the inventory allocated to the Unbundled Storage Program will be reduced in response to any reduction in the Aliso Canyon maximum inventory. A 10 Bcf reduction in Aliso Canyon inventory would reduce the inventory capacity allocated to the Unbundled Storage Program to 15 Bcf.[60]

If the Unbundled Storage Program is reduced, noncore customers will have less opportunity to purchase gas storage in Southern California and therefore may be more vulnerable to volatility in the gas spot market. In turn, spot market prices may become more volatile because sellers of the gas commodity would know noncore customers have limited alternatives to pipeline supplies. With less access to storage, noncore customers, including electric generators, could be exposed to higher gas prices, which could in turn increase electric rates.

[60] The Settlement Agreement for D.24-07-009 allocates storage inventory capacity and determines how each storage use category will be cut if total inventory capacity is reduced. "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.": https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K556/536556034.PDF.

Recommendation and Next Steps

Following the direction set in D.24-12-076, together, the four analyses conducted for winter 2025-26 support a Staff recommendation to reduce the Aliso Canyon maximum inventory by 10 Bcf to a level of 58.6 Bcf. However, given current forecasts for higher gas commodity prices in winter 2026-27, the CPUC may wish to consider a smaller incremental reduction. As noted above, the simple economic analysis conducted for this report demonstrates only that forward gas prices in Southern California for winter 2025-26 are not above the thresholds established in D.24-12-076 (based on national forwards and historic averages) at the current Aliso Canyon inventory level. The economic analysis does not predict the impact on gas commodity prices of decreasing the Aliso Canyon maximum inventory.

Per D.24-12-076, if the *Biennial Assessment Report* recommends changes to the storage limit and/or the reliability or economic analyses, then it triggers a formal proceeding process with opportunities for discovery, testimony, and cross-examination. Therefore, SoCalGas is required to file an application within 90 days asking the CPUC to review Staff's recommendation as well as SoCalGas' recommendations, if any. Within 90 days of the filing of the application, SoCalGas is required to hold a workshop during which Staff will present the *Biennial Assessment Report,* and SoCalGas will present its application. The Aliso Canyon maximum inventory will remain at 68.6 Bcf unless and until a change is required by a decision in that proceeding.