Application: A.26-01-XXX

Exhibit No.:

Witness: Andrew J. Sawin

PREPARED DIRECT TESTIMONY OF

ANDREW J. SAWIN

ON BEHALF OF

SOUTHERN CALIFORNIA GAS COMPANY (U 904 G)

(CHAPTER I – RELIABILITY IMPACTS)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

January 15, 2026

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PREPARED DIRECT TESTIMONY OF ANDREW J. SAWIN
(CHAPTER I – RELIABILITY IMPACTS)

I. INTRODUCTION

The purpose of my prepared direct testimony is to illustrate how the Energy Division's Aliso Canyon Biennial Assessment (Biennial Assessment) significantly understates the need for Aliso Canyon. My testimony explains why the assumptions used in the Biennial Assessment are inconsistent with observed system performance and operational practice, why Energy Division's own caveats warrant a more conservative interpretation of the Biennial Assessment results, why reducing Aliso Canyon inventory would increase reliability risk, and why SoCalGas's assessment results indicate an increase in Aliso Canyon inventory may be more appropriate. Using corrected and operationally realistic inputs, SoCalGas's assessment demonstrates that Aliso Canyon remains critical to maintain energy reliability.

II. BACKGROUND

In Decision (D.) 24-12-076 (Decision), the Commission established the biennial process for evaluating whether reductions to the maximum allowable inventory at Aliso Canyon can be made while maintaining energy reliability and just and reasonable rates. The Decision adopted a reliability threshold and directed Energy Division to prepare a Biennial Assessment every two years to track progress toward reducing reliance on Aliso Canyon.[1] The Biennial Assessment is intended to provide a preliminary indication, not a definitive determination, of whether conditions may support a change in Aliso Canyon's maximum inventory. If Commission Staff recommend a change to the inventory level, that recommendation serves as a trigger for a formal Commission proceeding, during which the Commission evaluates the recommendation.[2] D.24-12-076 directs Energy Division to include four distinct analyses in each Biennial Assessment: (1) Demand Reduction Analysis; (2) Gas Balance Reliability Analysis; (3) Hydraulic Modeling Analysis; and (4) Economic Analysis.[3] The Biennial Assessment examines both near-term conditions (the upcoming winter and summer) and a forward-looking scenario (five years later).[4]

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[1] D.24-12-076 at 2-3.

[2] *Id*., Ordering Paragraph (OP) 6, at 77.

[3] *Id*., Attachment A.

[4] *Id*.

The Biennial Assessment concludes that, for the upcoming winter of 2025-2026, system demand can be met while maintaining reliability with continued reliance on Aliso Canyon, and that withdrawals of at least approximately 550 MMcfd from Aliso Canyon are required on a 1-in-10 winter peak day to continuously serve demand.[5] The Biennial Assessment provides that, together, the four analyses conducted (demand reduction, gas balance reliability, hydraulic modeling, and economic analyses) for winter 2025-2026 support a Staff recommendation to reduce the Aliso Canyon maximum inventory by 10 Bcf to a level of 58.6 Bcf. However, the Biennial Assessment acknowledges that this recommendation is sensitive to multiple assumptions and conditions, including pipeline availability, storage withdrawal capability, demand forecasts, and infrastructure upgrades.[6] Commission Staff further explain that based on certain factors, a smaller reduction or no reduction in Aliso Canyon's inventory may be more appropriate.[7]

III. SOCALGAS SYSTEM DESIGN AND OPERATION

SoCalGas's natural gas transmission system consists of pipeline and storage facilities spanning an approximately 24,000 square mile service territory. SoCalGas uses this network of pipeline and storage facilities to provide gas service to a population of 21 million people in Southern California. SoCalGas's transmission system receives and delivers gas from the east and north to the load centers in the Los Angeles Basin, Imperial Valley, San Joaquin Valley, north coastal areas, and San Diego County.

SoCalGas operates four storage fields—Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey—as an essential component of its integrated transmission system. SoCalGas uses each of its four storage fields and flowing pipeline supplies to meet customer demand across the system. These storage fields also provide operational resiliency and flexibility for the Southern California energy grid. Aliso Canyon is by far the largest of SoCalGas's four storage fields in terms of inventory, injection, and withdrawal capacity, and plays a key role in SoCalGas's delivery of reliable energy at just and reasonable rates to millions of people, tens of thousands of

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[5] CPUC Energy Division, Aliso Canyon Biennial Assessment Report Pursuant to D.24-12-076, October 1, 2025 (Biennial Assessment), at 4.

[6] Biennial Assessment at 3, 5, 11, 20, 27.

[7] *Id.* at 5.

businesses, and facilities critical to the public welfare such as electric generators, refineries, universities, military and law enforcement installations, and hospitals. Aliso Canyon provides supply to customers in response to daily, hourly, and seasonal gas demand, provides a local and strategic supply source, and increases systemwide capacity and flexibility.

SoCalGas's natural gas transmission and distribution system was designed and has developed based on the availability of both strategically located sources of supply and demand[8] at Aliso Canyon and SoCalGas's other storage fields. As currently configured, SoCalGas's transmission pipelines and integrated storage system cannot reliably function with only pipeline supply—natural gas travels slowly at approximately 20-30 miles per hour and SoCalGas's natural gas receipt points with interstate pipelines, located at the fringes of the service territory, are too far from the load centers to fully support customers' changing needs throughout the operating day. Natural gas supplies are also delivered by interstate pipelines at a uniform hourly rate over the course of each "gas day,"[9] whereas customers' usage (both individually and in the aggregate) rarely happens at a uniform hourly rate throughout the day. This is particularly evident for electric generation (EG) customers. The situation is further complicated by the fact that 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.

SoCalGas's system is also at the terminus of several interstate pipelines delivering gas into California and, as in the past, local underground storage serves as the system's largest contingency resource for flexibility and resiliency and it remains the primary safeguard against curtailments and their associated significant safety and economic impacts. Notably, it is also true that "linepack," the ability to store and use gas supplies in pipeline by operating between minimum and maximum pressures, is not a significant source of storage given SoCalGas's relatively limited extent and diameters of transmission lines between its border sources and internal markets. Further, this limited capacity is dispersed across the entire SoCalGas transmission system, spanning the whole of Southern California, and the availability of linepack

[8] Demand includes the ability to inject gas on a seasonal, daily, and hourly basis when supply is greater than customer demand for use at a later time.

[9] A "gas day" is the 24-hour period from 7 a.m. to 7 a.m. the following day.

to support customer demand in any specific area may be negligible at any given time. Without sufficient natural gas to provide supplies in times of heavy load or low flowing gas availability, SoCalGas loses flexibility and curtailments may occur. Therefore, being able to withdraw sufficient gas from a local storage source is critical to Southern California's energy reliability.

It is important to understand the limitations of out-of-state supplies and the importance of local natural gas storage in providing system reliability, resiliency, emergency response, and incident mitigation capabilities. SoCalGas is more likely to be impacted by upstream events due to its heavy reliance on out-of-state supplies. There are numerous events that could prevent or limit natural gas from reaching California: emergencies such as wildfires, floods and landslides could restrict the capabilities of certain parts of the system; freezing temperatures have caused well freeze offs in producing basins; weather conditions east of California can and has affected the availability to downstream markets (i.e., California) of upstream supplies; increasing demand for gas supplies upstream of California, including increasing exports to Mexico; or operational failure of the interstate pipeline systems supplying southern California. When this happens, California has limited options.

For winter operations, Aliso Canyon provides needed winter gas supply and storage withdrawal services to support SoCalGas's customers including core residential customers. For summer operations, SoCalGas uses Aliso Canyon to provide gas supplies during the peak electric generation demand periods that occur throughout the day. Daily gas supply comes in at a constant hourly rate, but customer demand varies throughout the day. To meet these changes in demand, gas is withdrawn or injected into underground storage. This is essential for maintaining safe operating pressures on the transmission system. Aliso Canyon also provides significant flexibility and resiliency to the system and enables SoCalGas to operate and maintain its transmission system safely and cost-effectively by providing a buffer to protect against transmission line outages, allowing pipelines to be taken out of service for maintenance and repairs, and allowing pipeline pressure to be reduced to enhance the margin of safety.

IV. THE BIENNIAL ASSESSMENT SIGNIFICANTLY UNDERSTATES THE NEED FOR ALISO CANYON

The Biennial Assessment consists of four analyses—demand reduction analysis, gas balance reliability analysis, hydraulic modeling analysis, and economic analysis. My testimony discusses the gas balance reliability analysis and the hydraulic modeling analysis. The gas balance reliability analysis (gas balance) models the ability of the SoCalGas system to provide enough supply to meet daily systemwide demand and throughout a cold and dry winter. The analysis is conducted for the entire upcoming year at the time of the Biennial Assessment and five years later.[10] The hydraulic modeling analysis (hydraulic modeling) 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.

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. These assumptions inflate the volume of gas assumed to be available to the system in the gas balance analysis, which in turn suppresses modeled storage withdrawals and overstates storage inventory and deliverability in the hydraulic modeling. Because these assumptions are carried forward across both the gas balance and hydraulic analyses, their combined effect is to materially understate the system's reliance on Aliso Canyon. The following sections demonstrate why the Energy Division's assumptions are inconsistent with observed operations and why correcting them materially alters the reliability conclusions of the Biennial Assessment.

A. Energy Division's Receipt Point Utilization, Pipeline Outage Assumptions, and Flowing Supplies Are Unrealistic and Overly Optimistic

1. <u>High Receipt Point Utilization Is Unrealistic and Imprudent</u>

For the gas balance analysis, Commission Staff assumed 100% of SoCalGas's firm contracted capacity or the zonal capacities assumed for the hydraulic flow modeling less planned outages, whichever is lower.[11] For the hydraulic flow modeling, Commission Staff assumed 85% of the nominal capacity of the Northern and Southern Zones and 100% of the nominal

[10] This Biennial Assessment analyzes Winter 2025-2026, Summer 2026, Winter 2030-2031, and Summer 2031.

[11] Biennial Assessment at 9.

capacity of the Wheeler Ridge Zone.[12] While the Biennial Assessment assumes 100% Receipt Point Utilization (RPU), as Commission Staff have recognized, this assumption does not reflect actual system operations during the entire operating season. As Commission Staff have explained, "CPUC staff will also lower the upper bound of the sensitivity analysis on RPU to 95 percent instead of 100 percent, since the latter requires "perfect" forecasting and fuel burn."[13] In reality, observed 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, including during the 2021 and 2024 Arctic Blasts where RPU dropped as low as 47% and 38%, respectively.

Thus, while assuming a high RPU may be useful to demonstrate the theoretical capabilities of the system, it does not depict the actual operations and customer behavior, and the gas balance's unrealistic and overly optimistic RPU assumption overstates the amount of supply available to the system. Because total flowing supplies are overstated, the mass balance analysis correspondingly understates the volume of storage withdrawals required to meet daily demand. Those storage assumptions are then carried forward into the hydraulic modeling as input assumptions, resulting in higher modeled inventory and withdrawal availability at the non-Aliso storage fields than would exist under realistic receipt conditions. As a result, the hydraulic modeling incorrectly shows reduced reliance on Aliso Canyon because supply is overstated in the preceding mass balance analysis.

2. <u>Pipeline Outages Were Not Accounted for Properly</u>

The Biennial Assessment incorporates pipeline outages (planned and unplanned) into the gas balance and hydraulic modeling. In the gas balance, pipeline outages are reflected through zonal derating assumptions that reduce total available receipt capacity based on planned outages identified at the time of modeling—pressure reductions on Line 4000 and Line 4002, which were modeled as a 655 MMcfd reduction in the Northern Zone capacity for winter 2025-2026.[14] The hydraulic modeling represents outages as location-specific physical constraints on individual

[12] *Id.*

[13] I.17-02-002 Phase 2: Further Hydraulic Modeling Explanation and Updates at 2.

[14] Biennial Assessment at 9.

pipeline segments. For winter 2025-2026, this includes the Line 4000 and Line 4002 pressure reductions and a required 101.5 MMcfd unplanned outage modeled on a segment of Line 5000 in the Southern Zone, which Commission Staff concluded did not reduce overall zonal deliverability due to parallel pipeline capacity.[15] For winter 2030-31, the required 101.5 MMcfd unplanned outage was instead placed on Line 235 West, east of Quigley Regulator Station, and modeled through reduced pressure constraints while still allowing delivery of the assumed zonal supply.[16]

In the hydraulic modeling, Energy Division incorrectly reflected capacity reductions by lowering pressure constraints on affected pipeline segments while continuing to assume that supplies could be delivered up to the modeled receipt levels so long as minimum operating pressures were maintained. For the pressure reductions on Line 4000 and Line 4002, as well as the simulated outages on Line 5000 and Line 235, Energy Division did not physically limit the volume of supplies entering the system in a manner consistent with actual scheduling restrictions. In addition, for Line 235 West, Commission Staff did not isolate (i.e., physically remove) that asset from the model to reflect the outage, but instead allowed supplies to continue flowing subject only to pressure constraints.

While this approach may demonstrate feasibility within the model, it does not reflect how receipt capacity is determined or managed in actual operations. In practice, receipt capacity is established based on a combination of upstream delivery pressures, the physical design and interconnectivity of the transmission system (including pipelines, compressors, and valve stations), minimum and maximum operating pressure limits, the geographic distribution of customer demand, the availability of supplies, and the system's ability to absorb those supplies through demand or injection. When any of these parameters change, the system must be rebalanced to preserve pressure margins, which typically requires a corresponding reduction in posted receipt capacity.

That operational reduction is reflected through capacity postings on SoCalGas's Electronic Bulletin Board (ENVOY), at which point shippers are no longer permitted to schedule volumes in excess of the reduced capacity. Accordingly, while the model may reflect that

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15 *Id.* at 14.

16 *Id.*

pressure constraints can be satisfied at higher receipt levels, actual system operations require capacity reductions that limit scheduled receipts in order to maintain required system conditions.

The Biennial Assessment's assumption that supplies could be delivered up to the modeled receipt levels so long as minimum operating pressures were maintained allows system pressures to decline toward the minimum operating threshold before constraining receipts. By contrast, in actual operations, a prudent system operator must intervene before pressures approach minimum limits in order to continue maintaining reliability. Maintaining reliability may require curtailing customers (because there is insufficient system pressure to support their demand) and issuance of High Operational Flow Order (OFO) (to encourage customers to bring in fewer supplies onto the system given the curtailment of customers).

Furthermore, receipt capacities posted to the market as a result of facility outages must remain valid throughout the term of the outage under all demand conditions. While additional supplies in excess of the posted receipt capacity may at times be received when customer demand is high enough, that same level of supply would not be able to be transported to customer demand centers under a lower demand condition – system pressures would soon approach their maximum operating limits. Receipt capacities must therefore reflect what SoCalGas can consistently receive. And while SoCalGas can and has increased receipt capacity at specific receipt points on an "as-available" or "interruptible" basis when demand or pipeline outage conditions warrant, those times are unpredictable and upstream suppliers may be unable or unwilling to increase deliveries. For these reasons, the inclusion of this "as-available" capacity would not be valid or prudent for system planning purposes.

In addition, corrections are needed to the Biennial Assessment's treatment of unplanned pipeline outages in the hydraulic modeling. D.24-12-076 prescribes an "unplanned outage of 101.5 MMcfd" for hydraulic flow modeling.[17] As SoCalGas has stated previously, "[t]he unplanned outage value is overly specific and undervalued as capacity impacts from unplanned outages can be significantly greater than 101.5 MMcfd. Therefore, the biennial assessment should determine the appropriate value for unplanned outages for each biennial assessment

[17] D.24-12-076, Attachment A.

performed."[18] Applying a single, fixed, statistically averaged outage value is not appropriate for peak-day hydraulic reliability analysis, because actual unplanned outages can cause materially larger and operationally consequential capacity losses. The Biennial Assessment itself demonstrates that reality. Specifically, pressure reductions on Line 4000 and Line 4002 were associated with reductions far greater than 101.5 MMcfd—the capacity reduction was posted for a loss of 655 MMcfd on June 30, 2025.[19] The capacity reduction for Line 5000 also assumed to be 101.5 MMcfd, despite the capacity reduction of 150 MMcfd posted on December 8, 2025 for a similar outage.[20] Using a fixed "average" outage value therefore understates outage severity and underestimates storage withdrawals needed to maintain reliable service under realistic outage conditions.

A second issue is the placement of the assumed unplanned outage. For winter 2030-2031, Commission Staff placed the 101.5 MMcfd outage on Line 235 West east of Quigley. That segment is not representative of a materially constraining outage so long as parallel paths (e.g., Line 335) remain in service, because flows on that path are typically limited and readily re-routed. Energy Division should be aware that this segment is not a meaningful proxy for outages that materially affect receipt deliverability or customer reliability so long as parallel paths, such as Line 335, remain in service. As a result, the modeling outcome, which produced no meaningful operational or customer impacts, is largely a function of outage placement rather than an indication that unplanned outages are inconsequential to system reliability. Energy Division itself recognizes this limitation. As noted in the Biennial Assessment, if an unplanned outage were to occur on a more critical location on the system, continued reliance on Aliso Canyon could be required to meet demand and maintain linepack.[21] This acknowledgment underscores that the minimal impact observed in the hydraulic modeling is driven by the assumed outage location and magnitude, rather than an absence of operational risk. To better

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[18] Joint Opening Comments of Southern California Gas Company (U 904 G) and San Diego Gas and Electric Company (U 902 G) On Proposed Decision Adopting Biennial Assessment Process, December 3, 2024, at 6.

[19] SoCalGas ENVOY Critical Notice, Northern Zone Operational Restrictions, April 11, 2025.

[20] SoCalGas ENVOY Event ID 8283 and 8299, L5000 Maintenance.

[21] Biennial Assessment at 20 ("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).").

reflect reliability risk, the assumed unplanned outage should be assumed on a major pipeline with demonstrated systemwide significance, such as Line 4000 or Line 225. As recently as December 27, 2025, SoCalGas posted a 650 MMcfd capacity reduction at its Wheeler Ridge Zone due to a force majeure event on Line 225.[22] Only two months before this incident, another unplanned outage on Line 225 occurred north of the Honor Rancho Storage Field and south of Saugus Station, impacting both the Wheeler Ridge Zone and Honor Rancho Storage Field and La Goleta Storage Field withdrawal.[23]

Had pipeline outages been reflected in a manner consistent with operational capacity reductions, the pipeline receipts assumed in the hydraulic modeling would decrease from 3,215 MMcfd to 2,800 MMcfd—a reduction of approximately 415 MMcfd. Correcting for pipeline outages and receipt point utilization will only increase this shortfall. On a peak demand day, this shortfall would necessarily be met through increased withdrawals from storage, including Aliso Canyon, to maintain system reliability.

3. Energy Division Fails to Acknowledge the Potential Impact of the Energía Costa Azul LNG Export Facility on Flowing Supplies

The Biennial Assessment highlights the economic impacts associated with the upcoming Energía Costa Azul (ECA) liquified natural gas (LNG) export terminal,[24] including increased competition for regional gas supplies. However, beyond price effects, ECA also presents a material operational risk to flowing supplies on the Southern System that is not reflected in the modeling assumptions. ECA's export capacity is expected to reach up to 425 MMcfd,[25] which could effectively reduce available supplies to the Southern System from 1,210 MMcfd to 785 MMcfd—65% of the nominal capacity of the Southern System, which is far below the 85% RPU assumed in the Biennial Assessment. Moreover, the Southern System is underutilized as customers seek to schedule supplies at other receipt points, resulting in an even greater supply reduction.

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22 SoCalGas ENVOY Event ID 8309 L225 Force Majeure.

23 SoCalGas ENVOY Event ID 8210 and related events for L225 Necessary Remediation.

24 Biennial Assessment 26-27. However, the North Baja expansion approved by FERC specified a capacity of 0.495 billion cubic feet per day, or nearly 500 MMcfd: https://www.reuters.com/business/energy/ferc-approves-tc-energys-us-mexico-north-baja-natgas-pipe-expansion-2023-05-30/.

25 *Id.* at 27.

While physical withdrawals from Aliso Canyon cannot directly serve the Southern System, storage withdrawals play a critical operational role by preserving Southern System receipts for serving demand on the Southern System and enabling the diversion of supplies from the Northern System to support Southern System demand. If Southern System supplies are reduced due to LNG export activity at ECA, increased reliance on storage, including Aliso Canyon, would be necessary to maintain system reliability. Accordingly, assumptions that maintain Southern System receipts at levels well above those that may realistically be available under ECA export conditions further understate the operational value.

B. Concerns Regarding the Electric Generation Summer Demand Forecast

The electric-generation summer demand forecast used in the Biennial Assessment is materially lower than the electric-generation demand presented in the 2024 California Gas Report (CGR). Moreover, the Biennial Assessment does not provide details or adequately explain why this reduced forecast should be viewed as representative of realistic operating conditions. As described in the Biennial Assessment, Energy Division developed an hourly electric-generation gas burn forecast for the summer hydraulic analyses using production cost modeling, and then selected a single "high demand" summer day to test system performance.[26] However, the resulting daily and hourly electric-generation demand levels (i.e., gas demand) are meaningfully lower than those shown in the CGR. This divergence is particularly concerning given recent experience demonstrating that lower summer electric-generation forecasts have not reliably captured actual system conditions.

Specifically, in the 2022 CGR, summer electric-generation demand was similarly forecast at lower levels, yet actual peak-day demand over an extended period materially exceeded those forecasts,[27] requiring subsequent revisions in the 2024 CGR. In the 2022 CGR, summer demand projections were revised downward based on a set of assumptions related to increased renewable generation and building electrification. These assumptions were based on California Energy Commission (CEC) recommendations, and SoCalGas, San Diego Gas and Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) jointly adopted a common set of

[26] *Id.* at 15, 20-24.

[27] California Gas and Electric Utilities, *2023 California Gas Report Supplement*, at 21-24, available at https://www.socalgas.com/sites/default/files/Joint_Biennial_California_Gas_Report_2023_Supplement.pdf.

assumptions representing the mid-point scenario regarding demand reduction. As a result, the 2022 CGR projected substantially lower summer demand than prior forecasts, with the higher summer sendout day demand forecast approximately 20% lower than the corresponding forecast in the 2020 CGR. However, actual system conditions did not align with those assumptions. During the summer 2022 heatwave, electric-generation and total system demand on the SoCalGas system regularly exceeded the 2022 CGR projected high summer day demand levels. This divergence indicates that the assumptions underlying the reduced summer forecast did not fully account for sustained extreme heat events or for the operational realities (e.g., renewable generation or imported power).

This experience demonstrates that reductions to summer demand forecasts can materially understate actual operating conditions. Accordingly, reliance on similarly reduced summer electric-generation demand assumptions in the Biennial Assessment raises concern that high demand summer conditions may not be fully captured, further understating the operational reliance on storage, including Aliso Canyon, to maintain reliability. Any reduction in demand used to minimize or eliminate Aliso Canyon, or any natural gas infrastructure, must be based on actual displaced demand, that is sustained over time, and is permanent.

C. Storage Assumptions Are Unrealistic and Overly Optimistic

For the reasons discussed herein, including optimistic RPU and limited and unrepresented pipeline outages, the storage inventory and withdrawal assumptions used as inputs in the hydraulic modeling are overly optimistic and do not reflect realistic operating conditions. These assumptions materially affect the conclusions drawn regarding system reliability and the use of Aliso Canyon. The Biennial Assessment derives storage inventory levels and withdrawal capabilities from the gas balance reliability analysis and applies those values directly in the hydraulic modeling, using February 15 as the representative winter peak date. However, as SoCalGas has previously stated, the 1-in-10 year cold day is expected to occur in December or January, not mid-February.[28] By February 15, storage inventories may be higher or lower than during the actual peak period depending on prior withdrawals to serve earlier cold events or injections during intervening periods. As a result, using February 15 conditions does not reliably

[28] Joint Opening Comments of Southern California Gas Company (U 904 G) and San Diego Gas and Electric Company (U 902 G) On Proposed Decision Adopting Biennial Assessment Process, December 3, 2024, at 6.

capture the most constrained operating scenario under which peak demand would be served. A more appropriate approach would evaluate the lowest available storage inventory and withdrawal capability observed across the entire December-January period.

This concern is further reinforced by inconsistencies in the non-Aliso storage inventories calculated in the Biennial Assessment. Specifically, the Biennial Assessment reports a combined non-Aliso inventories of 52 Bcf, which exceeds the maximum physical capacity of those fields of 50.9 Bcf. While the numerical value is modest, the discrepancy highlights the sensitivity of the hydraulic modeling inputs to upstream assumptions and raises questions regarding the accuracy and robustness of the storage inventory calculations used to inform the Biennial Assessment's conclusions.

The Biennial Assessment also assumes that, for the winter 2030-2031 peak day, non-Aliso storage fields begin at 100% inventory. That outcome flows from the same optimistic assumptions identified above, including RPU, pipeline outage treatment, and the selection of February 15 inventory levels. When these assumptions are corrected to reflect realistic receipt availability, outage severity, and peak-period timing, non-Aliso storage inventories on a winter peak day are likely to be materially lower than assumed in the Biennial Assessment.

V. SOCALGAS'S ASSESSMENT DEMONSTRATES THAT THE MAXIMUM INVENTORY LEVEL AT ALISO CANYON SHOULD NOT BE REDUCED AND INDICATES AN INCREASE IN ALISO CANYON INVENTORY MAY BE MORE APPROPRIATE

SoCalGas prepared its own mass balance analysis and peak day analysis using operationally realistic inputs. SoCalGas's assessment demonstrates that, under realistic assumptions, Aliso Canyon's inventory should not be reduced. SoCalGas's assessment corrects key upstream assumptions used in the Biennial Assessment, including RPU, outage magnitude and placement, peak period timing, and starting storage inventories. SoCalGas's assessment incorporates: (1) a mass balance to assess systemwide supply (demand feasibility and storage drawdown over time), and (2) hydraulic modeling to evaluate peak-day deliverability under constrained conditions. Together, these analyses provide a realistic depiction of system performance during winter peak conditions and demonstrate the continued and increasing operational value of Aliso Canyon.

A. SoCalGas's Mass Balance

SoCalGas performed a mass balance analysis to evaluate the system's ability to meet customer demand and the impact on storage inventory and withdrawal capacity under realistic winter operating conditions. Unlike the Biennial Assessment, this analysis reflects realistic pipeline supply constraints, representative outage conditions, reduced RPU, and storage inventories consistent with examining the impact on its storage supplies, the ability to meet customer demand, and the ability to maintain minimum storage inventory and withdrawal requirements. The mass balance analysis compares forecasted monthly demand in a cold and dry year from the CGR with assumed supplies. In the mass balance, SoCalGas applied an 85% RPU across all receipt zones, except California Producers, and explicitly modeled the impacts of representative pipeline outages and seasonal constraints. The analysis was performed for both winter 2025-2026 and winter 2030-2031, as described below.

1. Winter 2025-2026 Assumptions

SoCalGas's made the following assumptions for winter 2025-2026:

- **Northern Zone:** Reduced to 935 MMcfd for the entire winter season to reflect the pressure derate on Line 4000 and Line 4002 south of Cajon, which corrects the Biennial Assessment outage that assumed 1,352 MMcfd received.
- **Southern Zone:** 1,210 MMcfd for the winter season
    - Reduced to 1,060 MMcfd for January 2026 to reflect an assumed unplanned outage on Line 5000 downstream of Blythe Compressor Station, which corrects the Biennial Assessment outage that assumed no impact from the outage.
- **Wheeler Ridge Zone:** 765 MMcfd capacity for the entire winter season.[29]
- **Aliso Canyon:** Starting inventories of 58.6 Bcf, 68.6 Bcf, or 86.2 Bcf.
- **Non-Aliso Storage Fields:** Starting the winter at full inventory.

2. Winter 2030-2031 Assumptions

SoCalGas's made the following assumptions for winter 2030-2031:

- **Northern Zone:** 1,590 MMcfd for the entire winter season.
- **Southern Zone:** Reduced to 535 MMcfd of flowing supplies for the entire winter season attributable to ECA.[30]

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[29] With the appropriate 85% RPU applied, unlike the Biennial Assessment assumption of 100%.

[30] Reduced from a recent high-supply day at Ehrenberg of 960 MMcfd – 425 MMcfd = 535 MMcfd.

- RPU is irrelevant to the Southern Zone in this scenario; while export operations at ECA will result in a supply loss to the Southern Zone, SoCalGas does not anticipate reducing its receipt capacity at Ehrenberg. SoCalGas would still make 1,210 MMcfd of receipt capacity available to its customers at that location should the supply be available. 535 MMcfd of expected flowing supplies with ECA operations in this scenario is well below the available receipt capacity and no further reduction is warranted.

- **Wheeler Ridge Zone:** 765 MMcfd for the entire winter season, reduced to 120 MMcfd to reflect an unplanned outage on Line 225 north of the Honor Rancho Storage Field and south of Saugus Station in January, moving the insignificant outage from Line 235 in the Biennial Assessment to an impactful pipeline.
  - Peak day capacity of 185 MMcfd to match higher demand.
  - Honor Rancho and La Goleta withdrawal is limited to a combined total 535 MMcfd for the Line 225 outage.
  - RPU not applied to the Wheeler Ridge Zone because capacity is restricted to the local demand.
- **Aliso Canyon:** Starting inventories of 58.6 Bcf, 68.6 Bcf, or 86.2 Bcf.
- **Non-Aliso Storage Fields:** Starting the winter at full inventory.

3. Mass Balance Results and Key Findings

The mass balance results demonstrate a direct and material relationship between Aliso Canyon and inventory levels and systemwide withdrawal capability during peak winter conditions. As Aliso Canyon starting inventory increases, total available storage withdrawal on the winter peak day increases meaningfully, providing critical operational flexibility when pipeline supplies are constrained. For winter 2025-2026, the available storage withdrawal on a January peak day is approximately 1,815 MMcfd with Aliso Canyon starting at 58.6 Bcf, 1,975 MMcfd with Aliso Canyon starting at 68.6 Bcf, and 2,260 MMcfd with Aliso Canyon starting at 86.2 Bcf (*see* Tables I-1-a through I-1-d). Similarly for winter 2030-2031, the withdrawal rate on a January peak day increases as Aliso inventory increases, with approximately 1,740 MMcfd with Aliso Canyon starting at 58.6 Bcf, 1,890 MMcfd with Aliso Canyon starting at 68.6 Bcf, and 2,165 MMcfd with Aliso Canyon starting at 86.2 Bcf (*see* Tables I-2-a through I-2-d). Importantly in 2030-2031, the withdrawal capacity at the Honor Rancho Storage Field and the La Goleta Storage Field are severely restricted due to the assumed unplanned outage on Line 225, further increasing the value of Aliso Canyon. The mass balance shows that the inventory at Aliso Canyon has a significant impact on available withdrawal during the peak demand period of December and January.

Table I-1a
Mass Balance Analysis – Winter 2025-2026 – Supply & Demand

Month	Units	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
Northern Zone	MMcfd	935	935	935	935	935
Southern Zone	MMcfd	1210	1210	1060	1210	1210
Wheeler Ridge Zone	MMcfd	765	765	765	765	765
CA Producers	MMcfd	70	70	70	70	70
Receipt Point Utilization	%	85%	85%	85%	85%	85%
Pipeline Monthly Supply	MMcf	76305	78849	74896	71218	78849
CGR Monthly Demand	MMcf	74490	96999	89559	77028	73811
Storage Withdrawal (+) / Injection (-)	MMcf	-1815	18151	14663	5810	-5038

Table I-1b
Mass Balance Analysis – Winter 2025-2026 – End-of-Month Inventory & Withdrawal Capacity, Aliso Maximum Inventory 58.6 Bcf

Month	Units	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
Aliso Inventory	Bcf	58.6	58.6	48.7	40.8	37.6	39.6
Non-Aliso Inventory	Bcf	50.0	50.0	41.7	35.0	32.4	35.4
Total Inventory	Bcf	108.6	108.6	90.4	75.8	70.0	75.0
Aliso Withdrawal	MMcfd	---	1073	968	912	873	903
Non-Aliso Withdrawal	MMcfd	---	1323	1057	900	840	949
Total Withdrawal	MMcfd	---	2396	2025	1812	1713	1852

Table I-1c
Mass Balance Analysis – Winter 2025-2026 – End-of-Month Inventory & Withdrawal Capacity, Aliso Maximum Inventory 68.6 Bcf

Month	Units	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
Aliso Inventory	Bcf	68.60	68.60	58.02	49.49	46.14	48.15
Non-Aliso Inventory	Bcf	50.00	50.00	42.42	36.29	33.84	36.87
Total Inventory	Bcf	118.60	118.60	100.44	85.78	79.98	85.02
Aliso Withdrawal	MMcfd	---	1215	1106	1050	1009	1039
Non-Aliso Withdrawal	MMcfd	---	1323	1070	924	868	977
Total Withdrawal	MMcfd	---	2538	2176	1974	1877	2016

Table I-1d
Mass Balance Analysis – Winter 2025-2026 – End-of-Month Inventory & Withdrawal Capacity, Aliso Maximum Inventory 86.2 Bcf

Month	Units	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
Aliso Inventory	Bcf	86.2	86.2	74.7	65.3	61.7	63.7
Non-Aliso Inventory	Bcf	50.0	50.0	43.4	38.1	35.9	38.9
Total Inventory	Bcf	136.2	136.2	118.1	103.4	97.6	102.6
Aliso Withdrawal	MMcfd	---	1466	1352	1300	1257	1287
Non-Aliso Withdrawal	MMcfd	---	1323	1089	957	909	1017
Total Withdrawal	MMcfd	---	2789	2441	2257	2166	2304

Table I-2a
Mass Balance Analysis – Winter 2030-2031 – Supply & Demand[31]

Month	Units	Nov-30	Dec-30	Jan-31	Feb-31	Mar-31
Northern Zone	MMcfd	1590	1590	1590	1590	1590
Southern Zone	MMcfd	535	535	535	535	535
Wheeler Ridge Zone	MMcfd	765	765	120	765	765
CA Producers	MMcfd	70	70	70	70	70
Receipt Point Utilization	%	85%	85%	85%	85%	85%
Pipeline Supply	MMcf	78203	80809	64372	72989	80809
CGR Monthly Demand	MMcf	65310	86087	84320	73500	70990
Storage Withdrawal (+) / Injection (-)	MMcf	-12893	5278	19949	511	-9819

Table I-2b
Mass Balance Analysis – Winter 2030-2031 – End-of-Month Inventory & Withdrawal Capacity, Aliso Maximum Inventory 58.6 Bcf[32]

Month	Units	Oct-30	Nov-30	Dec-30	Jan-31	Feb-31	Mar-31
Aliso Inventory	Bcf	58.6	58.6	55.8	45.0	44.7	50.2
Non-Aliso Inventory	Bcf	50.0	50.0	47.6	38.4	38.2	42.5
Total Inventory	Bcf	108.6	108.6	103.3	83.4	82.9	92.7
Aliso Withdrawal	MMcfd	---	1223	1209	1035	995	1122
Non-Aliso Withdrawal	MMcfd	---	1431	1415	703	1279	1408
Total Withdrawal	MMcfd	---	2654	2624	1738	2274	2530

[31] RPU not applied to the Southern Zone, or the Wheeler Ridge Zone in January as supply is required to meet demand.

[32] Non-Aliso withdrawal is limited in January due to the assumed unplanned outage on Line 225.

Table I-2c
Mass Balance Analysis – Winter 2030-2031 – End-of-Month Inventory & Withdrawal Capacity, Aliso Maximum Inventory 68.6 Bcf[33]

Month	Units	Oct-30	Nov-30	Dec-30	Jan-31	Feb-31	Mar-31
Aliso Inventory	Bcf	68.60	68.60	65.55	54.01	53.71	59.32
Non-Aliso Inventory	Bcf	50.00	50.00	47.77	39.36	39.15	43.37
Total Inventory	Bcf	118.60	118.6	113.3	93.4	92.9	102.7
Aliso Withdrawal	MMcfd	---	1385	1372	1185	1139	1276
Non-Aliso Withdrawal	MMcfd	---	1431	1417	706	1309	1411
Total Withdrawal	MMcfd	---	2816	2788	1891	2449	2687

Table I-2d
Mass Balance Analysis – Winter 2030-2031 – End-of-Month Inventory & Withdrawal Capacity, Aliso Maximum Inventory 86.2 Bcf[34]

Month	Units	Oct-30	Nov-30	Dec-30	Jan-31	Feb-31	Mar-31
Aliso Inventory	Bcf	86.2	86.2	82.9	70.2	69.9	75.6
Non-Aliso Inventory	Bcf	50.0	50.0	48.1	40.7	40.6	44.7
Total Inventory	Bcf	136.2	136.2	130.9	111.0	110.5	120.3
Aliso Withdrawal	MMcfd	---	1500	1500	1455	1400	1500
Non-Aliso Withdrawal	MMcfd	---	1431	1419	711	1351	1416
Total Withdrawal	MMcfd	---	2931	2919	2166	2751	2916

Importantly, under no modeled scenario are the non-Aliso storage fields at 100% inventory during the December – January peak demand period. This demonstrates that storage availability during peak conditions is materially more constrained than assumed by the Biennial Assessment when realistic supply, outage, and utilization assumptions are applied. These results confirm that reducing Aliso Canyon inventory would erode peak day withdrawal capability and increase reliability risk, while maintaining Aliso Canyon at higher inventory levels maintain system reliability and resilience under realistic operating conditions.

B. SoCalGas's Peak Day Analysis

Building on the mass balance analysis, SoCalGas performed a peak day analysis to evaluate whether the system can physically deliver sufficient gas to meet a 1-in-10 winter peak demand under realistic conditions. Consistent with the mass balance, SoCalGas reflected representative outages and derates, applied realistic RPU assumptions, and limited storage withdrawals based on available inventory and field-specific performance.

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33 Non-Aliso withdrawal is limited in January due to the assumed unplanned outage on Line 225

34 Non-Aliso withdrawal is limited in January due to the assumed unplanned outage on Line 225.

1. Winter 2025-2026

For winter 2025-2026, SoCalGas's peak day analysis applies the same pipeline outages and RPU reflected in the mass balance and then physically constrains interstate pipeline supplies to those levels. When these realistic constraints are applied, the resulting storage withdrawal requirement on a winter peak day is materially higher than that reflected in the Biennial Assessment. On a 1-in-10 Year Cold Day, total system demand is forecast to be 4,562 MMcfd.[35] With pipeline supplies of 2,416 MMcfd, the system requires a minimum storage withdrawal of approximately 2,146 MMcfd to maintain reliability. This required withdrawal is approximately 700 MMcfd greater than the withdrawal found in the Biennial Assessment Energy Division,[36] a difference that follows directly from applying more realistic assumptions regarding RPUs and pipeline outages. Table I-3 shows the supply shortfall or surplus at each of the starting inventory for Aliso Canyon, with the resulting storage withdrawal capacity obtained from the mass balance.

Table I-3
Peak Day Analysis – Winter 2025-2026 – Peak Day Supply & Demand (MMcfd)

Aliso Starting Inventory (Bcf)	58.6	68.6	86.2
January End-of-Month Storage Inventory (Bcf)	75.8	85.8	103.4
1-in-10 Year Peak Day Demand Forecast	4562	4562	4562
Pipeline Supply	2416	2416	2416
January Minimum Available Withdrawal	1813	1974	2258
Supply Shortfall (-) / Surplus (+)	-333	-172	112

SoCalGas's analysis shows that this level of withdrawal cannot be supported when Aliso Canyon is limited to a maximum inventory of 58.6 Bcf. Under the realistic pipeline delivery assumptions reflected in the mass balance, storage is projected to have approximately 75.8 Bcf of inventory during the December – January peak period, which corresponds to a maximum withdrawal capability of 1813 MMcfd. This is roughly 333 MMcfd short of what is required to

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[35] The California Gas and Electric Utilities, 2024 California Gas Report, at 159, available at https://www.socalgas.com/sites/default/files/2024-08/2024-California-Gas-Report-Final.pdf.

[36] Biennial Assessment at 16. 896 MMcfd from the non-Aliso storage fields + 550 MMcfd from Aliso Canyon = 1446 MMcfd.

meet the peak day demand, resulting in an inability to meet the Commission's mandated design standard for core and noncore service.[37]

By contrast, when Aliso Canyon begins the winter season at its maximum inventory of 86.2 Bcf, the required peak day withdrawal can be achieved and system reliability is maintained. To maintain continuous service on a peak day with Aliso Canyon limited to the currently authorized 68.6 Bcf, RPU would need to increase to approximately 91% on that day, which may be achievable on a peak day if customers and shippers respond to the issuance of an OFO. However, if Aliso Canyon were reduced to 58.6 Bcf, RPU would need to approach approximately 97%, a level that is operationally unrealistic and inconsistent with historical performance. These results demonstrate that reducing Aliso Canyon inventory materially increases reliance on near-perfect pipeline performance and leaves the system with little to no margin to manage uncertainty during peak winter conditions.

Table I-3 shows that with these assumptions in place, both cases—with Aliso Canyon operating at either 58.6 Bcf or 68.6 Bcf—would be infeasible on a peak day. Therefore, SoCalGas used these assumptions for RPU, pipeline outages, and available storage withdrawal, with Aliso Canyon at a maximum 86.2 Bcf, to perform a hydraulic analysis and confirm that the peak day demand could be met under these conditions. For a simulation to be considered successful, all facilities must operate within established capacities, all system pressures must remain between minimum and maximum operating pressures, and linepack must be restored across the entire system. This confirms that the peak day demand could be met multiple days in a row if required. SoCalGas's analysis indicates that on a peak day, these requirements can be satisfied and service can be maintained during the 1-in-10 year cold day demand forecast, even with these assumed pipeline outages, so long as Aliso Canyon is operating at a maximum inventory of 86.2 Bcf.

2. Winter 2030-31

For winter 2030-31, SoCalGas evaluated a peak day scenario reflecting both representative outages and emerging supply risks. Specifically, the analysis assumes an outage on Line 225 north of the Honor Rancho Storage Field and north of Quigley Station, impacting

[37] In D.06-09-039, the Commission affirmed a 1-in-35 year cold day condition as the design criteria for core service and a 1-in-10 year cold day design criteria for noncore firm service. In D.16-07-008, "firm" and "interruptible" service designations were eliminated for noncore service with the approval of new curtailment procedures. These design standards were once again affirmed in R.20-01-007.

Wheeler Ridge receipt capacity and the Honor Rancho Storage Field and the La Goleta Storage Field withdrawal capacity. These simultaneous outages occurred recently (October 2025) and demonstrate what happens when an outage occurs on a major transmission pipeline. As a result of these outages, the Wheeler Ridge Zone is limited to only bringing in supply to meet local demand of approximately 185 MMcfd, and Honor Rancho Storage Field and La Goleta Storage Field withdrawal is limited to local demand and the coastal valve station capacity of approximately 535 MMcfd. In addition, the analysis assumes that ECA LNG export operations reduce supplies available to the Southern System by diverting gas that would otherwise flow through the Ehrenberg Receipt Point to serve California demand. As ECA exports increase, gas that historically entered the SoCalGas system may instead be redirected to support LNG exports, reducing the volume available to the Southern System. The analysis assumes a reduction of up to 425 MMcfd, corresponding to the expected ECA export capacity. Together, these reductions reduce total system pipeline receipts to 2,142 MMcfd. Table I-4 shows the supply shortfall or surplus at each of the starting inventory for Aliso Canyon, with the resulting storage withdrawal capacity obtained from the mass balance.

Table I-4
Peak Day Analysis – Winter 2025-2026 – Peak Day Supply & Demand (MMcfd)

Aliso Starting Inventory (Bcf)	58.6	68.6	86.2
1-in-10 Year Peak Day Demand Forecast	4197	4197	4197
January End-of-Month Storage Inventory (Bcf)	83.4	93.4	111.0
Pipeline Supply	2142	2142	2142
January Minimum Available Withdrawal	1738	1891	2166
Supply Shortfall (-) / Surplus (+)	-317	-164	111

Under these conditions, SoCalGas's analysis shows that the system can meet a 1-in-10 winter peak demand day of 4,197 MMcfd only when Aliso Canyon begins the winter season at a maximum inventory of 86.2 Bcf. Even at this inventory level, the Southern System experiences limited operating margin and exhibits stress in maintaining delivery to customers, underscoring the critical role of Aliso Canyon in supporting peak day reliability. Any reduction in Aliso Canyon inventory under these conditions could materially increase the risk of service impacts during peak demand events.

Table I-4 clearly shows that with these assumptions in place, both cases with Aliso Canyon operating at either 58.6 Bcf or 68.6 Bcf would be infeasible on a peak day. Therefore, SoCalGas's analysis again assumed that Aliso Canyon was allowed to operate at a maximum inventory of 86.2 Bcf. Even with the severe outages on L225 and the supply constraint on the Southern System, SoCalGas's analysis indicates that on a peak day, all forecasted demand could be served, so long as Aliso Canyon is operating at a maximum inventory of 86.2 Bcf.

SoCalGas's analysis confirms that Aliso Canyon plays an indispensable role in maintaining winter reliability under realistic future operating conditions, particularly as uncertainty increases around pipeline outages frequency, location, and Southern System supply availability. Reducing Aliso Canyon inventory could materially erode system reliability and resilience, compress operating margins, and increase the likelihood of curtailments during peak demand winter events, and increasing its authorized inventory capacity could be the most cost-effective and timely means to offset losses in supply resulting from ECA's export operations.

3. Summer Analysis

While SoCalGas does not have a summer design standard, it does review the ability to meet a peak day during the summer. Using the peak summer demand forecast from the 2024 CGR, SoCalGas expects to meet the 2026 demand forecast of 3,169 MMcfd and the 2031 demand forecast of 2,685 MMcfd.

VI. THE COMISSION SHOULD CAREFULLY CONSIDER ENERGY DIVISION'S CAUTIONS AND UNCERTAINTIES

The Biennial Assessment itself identifies multiple sources of uncertainty and operational risk that materially affect system reliability. Rather than supporting a firm conclusion that Aliso Canyon inventory can be reduced, Energy Division qualifies its findings based on dynamic pipeline conditions, emerging supply risks, reliance on future infrastructure, and operational constraints that could alter system performance. The Commission should heed these caveats and uncertainties and exercise caution.

A. Conditions are Dynamic and Uncertain

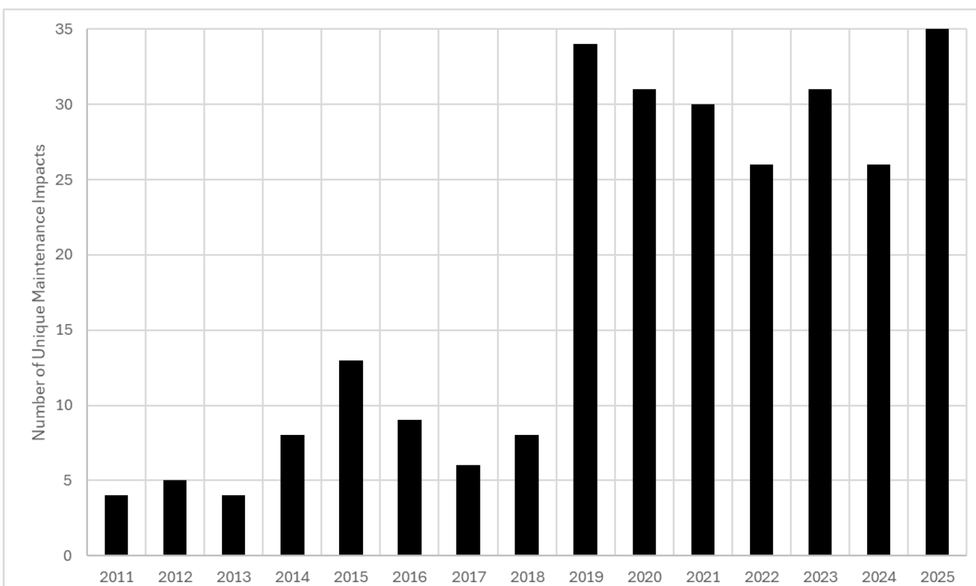
In the Biennial Assessment, Energy Division explicitly recognizes that conditions are subject to change and that future system performance cannot be predicted. For example, Energy Division states that "[t]his unexpected change to pipeline capacity underscores the uncertainty surrounding future pipeline conditions that California must be prepared to manage."[38] Energy Division further acknowledges that modeling does not account for withdrawals occurring for

[38] Biennial Assessment at 3.

price mitigation, which may result in lower storage inventory throughout the study period,[39] and 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).[40] In addition, the Energy Division notes that ECA will increase competition for limited interstate pipeline capacity from gas production basins in Texas and New Mexico,[41] introducing further uncertainty regarding available flowing supplies.

As demonstrated in SoCalGas's assessment, these caveats should not be ignored. Accounting for outages at critical pipeline locations highlights the importance of maintaining sufficient storage inventory and withdrawal capability to manage reliability risks. Pipeline outages are becoming more common as pipelines age, inspection methods enhance, and regulations change. A review of unique maintenance impacts on ENVOY illustrates this trend in Figure I-1, with the average number of annual capacity reductions increasing from seven in 2011-2019 to 30 in 2020-2025.[42]

Figure I-1
Annual Number of Capacity Reductions, 2011 through 2025



[39] *Id.* at 11.

[40] *Id.* at 20.

[41] *Id.* at 27.

[42] In 2019, the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted Part 1 of the Gas Transmission Safety Rule, which substantially expanded integrity management, inspection, and risk assessment requirements for gas transmission operators, driving increased inspection and inspection activity and related maintenance outages. *See* 84 Fed. Reg. 52180 (Oct. 1, 2019).

Similarly, recognizing withdrawals from price mitigation demonstrates that non-Aliso storage fields are unlikely to be at maximum inventory levels on a peak day. Increased competition for interstate supplies associated with ECA not only raises the likelihood of additional price mitigation withdrawals, further lowering inventories, but may also reduce flowing supplies altogether, increasing reliance on storage during peak conditions.

B. Pending Projects

Although the Biennial Assessment does not rely on the winter 2030-2031 and summer 2031 analyses for its recommendation, Energy Division explicitly acknowledges that the findings for those periods are contingent on "significant changes to the physical capabilities of the SoCalGas gas system, particularly in the Northern Zone[.]"[43] As described in the Biennial Assessment, Energy Division's modeling for 2030-2031 assumed the completion of multiple system upgrades, including upgrades to the Quigley Regulator Station, additional wells at Honor Rancho, and the Honor Rancho Compressor Station Modernization Project.[44] Another critical pending project—the Ventura Compressor Modernization Project (VCM)—is necessary to confirm that the La Goleta Storage Field can be reliably filled every summer, even in scenarios where inventory is fully depleted. This capability is particularly important under conditions such as the assumed outage on Line 225 in SoCalGas's analysis, or other outages that would render the coastal region dependent on withdrawals from the La Goleta Storage Field. Both the Biennial Assessment and SoCalGas's assessment assume that the La Goleta Storage Field begin the winter season at full inventory, an assumption that may not be realized absent completion of the VCM project. Critically, assumptions about future infrastructure cannot substitute for demonstrated, in-service capability. Until these projects and others are completed, tested, perform reliably under peak conditions, and demonstrate reduced reliance on Aliso Canyon, it would be premature to make changes to Aliso Canyon inventory.

C. Operational Complexities and Realities

The Energy Division also acknowledges significant operational complexity in its summer analysis. Specifically, the Biennial Assessment finds that storage fields must frequently switch between injection and withdrawal within the same day to fully utilize pipeline supplies and meet

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[43] Biennial Assessment at 19.

[44] The Honor Rancho Compressor Modernization Project does not increase storage inventory or withdrawal capability; it supports injection reliability.

demand.[45] Such operating patterns are not desirable, place additional strain on storage facilities, and may be infeasible in practice. These rapid operational transitions could increase the occurrence of both high and low OFOs within the same day. This acknowledge complexity underscores that modeling solutions that rely on frequent storage mode switching may not be practically achievable and should not be used to support conclusions that reduce Aliso Canyon inventory.

VII. CONCLUSION

The Biennial Assessment's recommendation is driven by a set of optimistic assumptions that overstate flowing supply availability and underrepresent outages. When those assumptions are corrected to reflect realistic RPU, representative pipeline outages, credible electric generation demand forecasts incorporating market observations, and peak period storage conditions, the system's reliance on Aliso Canyon increases materially. SoCalGas's mass balance and peak day hydraulic analyses show that reducing Aliso Canyon inventory would risk reliability, particularly as uncertainty grows around supply availability and outage frequency and location. The decision to reduce the inventory of a critical asset must be grounded in realistic conditions and not aspirational assumptions or best-case conditions. For these reasons, it would be imprudent for the Commission to reduce the authorized inventory capacity at Aliso Canyon at this time. Indeed, SoCalGas's assessment indicates that increasing the maximum inventory level may be more appropriate.

This concludes my prepared direct testimony.

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[45] Biennial Assessment at 23.

VIII. WITNESS QUALIFICATIONS

My name is Andrew J. Sawin. I am employed by SoCalGas as a Principal Engineer in the Gas Transmission Planning department. My business address is 8101 South Rosemead Blvd, Pico Rivera, California 90660-5100. I received a Bachelor of Science degree in Mechanical Engineering in 2011 and a Master of Science degree in Mechanical Engineering in 2017 from the California State University at Northridge. I am a Registered Professional Engineer in the State of California since 2017. I have been employed by SoCalGas since 2011 and have held positions in the Gas Transmission Technical Services and the Gas Transmission Planning departments.

I have held my current position since September 2015. My current responsibilities include system design and analysis of SoCalGas and SDG&E's gas transmission and storage systems. As such, I am responsible for: analyzing the transmission system capacity under CPUC-mandated design standards for core and noncore service; recommending improvements and additions as necessary; monitoring system conditions and changing operating dynamics; performing short-term capacity analyses for customer service requests from the transmission system; and evaluating system impacts from new product offerings to customers.

I have previously testified before the Commission.