Winter 2023-2024 Southern California Gas Reliability Assessment

BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION
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Table of Contents

List of Tables

List of Figures

Executive Summary

Reliability Outlook is Favorable

The winter 2023-24 reliability outlook is favorable for the Southern California Gas Company (SoCalGas) service territory according to modeling conducted by California Public Utilities Commission (CPUC) staff (Staff).[1] With the current natural gas assets and assuming sufficient interstate gas supplies, the model predicts no curtailments or emergency flow orders in winter 2023-2024. The model finds that the SoCalGas pipeline network should be able to meet the demand of a cold winter with dry hydro as well as the 1-in-10 peak day demand, which is forecasted to be 4,612 MMcfd by the 2022 California Gas Report.[2]

Heading into winter, intrastate pipeline capacity in the SoCalGas service territory is higher than in recent years due to completed maintenance and is expected to remain stable. The Northern Zone of the pipeline system is set to regain 175 million cubic feet per day (MMcfd) of receipt capacity in November 2023 when Line (L) 235 west remediation is scheduled to end. This would bring the capacity of the Northern Zone to 1,425 MMcfd for the remainder of the winter, which is almost 90 percent of its capacity prior to the 2017 L235 explosion. Combined with lower demand forecasts than in the past, and few planned outages during the winter, the increased pipeline capacity allows for supply to be higher than demand during every month of the winter. California production remains low averaging around 80 MMcfd last August.

On August 31, 2023, Aliso Canyon Underground Storage Field inventory level was at 99 percent of its maximum allowable inventory level of 41.1 billion cubic feet (Bcf), while the non-Aliso fields needed 11.7 Bcf more to reach their full capacity.[3] On the same date, the CPUC approved a petition to increase the Aliso Canyon maximum allowable inventory from 60 to 100 percent of the 68.6 Bcf limit set by the California Geologic Energy Management Division (CalGEM). The majority of the inventory increase, 27 Bcf, is allocated to the Unbundled Storage Program, which allows large commercial and industrial customers, known as noncore customers, to purchase storage.

The model predicts that the non-Aliso storage fields are on target to fill by October 31 in all three baseline scenarios. Additionally, there is sufficient intrastate pipeline capacity to fill Aliso Canyon by mid-December or mid-January in the best- and mid-case scenarios. In the worst-case scenario, there is only enough pipeline capacity to fill Aliso Canyon by mid-March. However, noncore customers make storage purchase decisions based on market conditions and their own risk analysis, so their economic choices may cause the trajectory of the inventory levels to deviate from the ideal cases simulated by the model.

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[1] The gas winter is from November through March which is covered in this report.
[2] 2022 California Gas Report, p. 181: https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf.
[3] SoCalGas Envoy.

Importantly, since the average daily supply exceeds the average demand, storage is not drawn down during the winter in the baseline scenarios. It is used simply to support higher-than-average demand days, allowing storage levels at the end of the season to equal storage levels at the start of the season.

The model used for this assessment looks only at the physical ability of instate natural gas pipeline and storage infrastructure to deliver sufficient gas to meet demand and does not consider economic factors or the potential for outages on the interstate pipeline system. A high-level overview of unmodeled risk factors is provided at the last section of this Executive Summary.

Methodology, Scenarios, and Sensitivities

This report uses a new modeling method that was developed during the Alison Canyon Investigation (I.) 17-02-002 and first used in its current form in the Winter 2022-23 Reliability Assessment. The new method combines aspects of two previously used analyses: the monthly mass balance and the 1-in-10 peak day analysis. The model uses assumptions about pipeline capacity for each month and randomly selects a demand value for each day of that month that is within the expected probability distribution. Thus, the model includes some days with higher or lower demand than the monthly average.[4] If needed, the model injects excess supply into storage or withdraws from storage to resolve a deficit. Thus, the model both evaluates the potential increase or decrease in storage inventory and the system's ability to meet peak day demand.

Staff modeled three main scenarios based on variations in planned and unplanned outages for maintenance reported to the CPUC by SoCalGas: best-case, mid-case, and worst-case. The average daily pipeline capacity assumed varies from 2,979 million cubic feet per day (MMcfd) for the worst-case scenario to 3,284 MMcfd for the best-case scenario. All three scenarios assume a cold and dry hydro year; high demand variability; no supplies from Otay Mesa, a less-used gas receipt point on the Mexican border; and no restrictions on underground gas storage fields.

Two additional sensitivities have been run, both of which decrease the withdrawal and injection capacity of all underground storage fields by 20 percent to simulate unplanned well outages. In addition, the second sensitivity analysis uses the higher 2020 California Gas Report forecasts for average and peak day demand.[5] The rationale behind this sensitivity is the 2023 California Gas Report Supplement found that the 2022 California Gas Report significantly under-forecasted actual summer peak demand, calling into question its assumptions.[6] However, even when the model was stressed in the sensitivity analyses, there was no degradation in reliability to the SoCalGas pipeline network. Nonetheless, in the higher-demand sensitivity case, the non-Aliso storage levels were drawn down during the winter by 30 percent, while Aliso Canyon never reaches its full capacity.

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[4] Less than half the days of the month will be higher than average due to the right skewness of the Gamma Distribution.

[5] The 2023 peak day forecast in the 2020 California Gas Report is 4,975 MMcfd, p. 140: https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf.

[6] 2023 California Gas Report Supplement pp. 14-16, 22-24: https://www.socalgas.com/sites/default/files/Joint_Biennial_California_Gas_Report_2023_Supplement.pdf.

Unmodeled Risks

There are at least four factors that are not captured by the model which could cause the winter's trajectory to differ from the modeled outcomes. First, noncore customers may not purchase all the capacity newly available to them at Aliso Canyon, reducing the total storage inventory level. Second, any additional out-of-state disruptions to supply, such as an outage on an interstate pipeline, would not be captured. Third, additional unplanned intrastate transmission outages could result in lower flow rates and hence lower injection rates into storage. Finally, high gas prices could cause gas customers to use withdrawals from storage to manage costs as well as reliability, leading to higher withdrawals than forecasted.

Heading into winter 2023-24, the national natural gas market is in better shape than last year, but some risks remain. Internationally, the war in Ukraine continues. While Europe's gas storage fields are over 90 percent full, its efforts to avoid Russian gas have the potential to increase volatility in the liquified natural gas (LNG) market. A cold European winter could deplete storage reserves and increase international LNG prices.[7] While international LNG market prices impact the U.S. market, that impact is limited by the physical capacity of U.S. LNG export facilities.[8]

Nationally, gas storage fields inventory levels are 5.9 percent above the five-year average,[9] which has helped keep prices low across much of the country. High prices in the West have lingered, however, despite storage levels being higher than last year.[10] At the SoCal Citygate, the average futures price for the winter months (November-March) is 19.4 percent lower than this time last year but almost 75 percent higher than Henry Hub, the national benchmark.[11]

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[7] CNBC, "Gas markets are becoming 'extremely difficult' to predict. It's a big problem for Europe this winter," September 12, 2023: https://www.msn.com/en-us/money/markets/gas-markets-are-becoming-extremely-difficult-to-predict-its-a-big-problem-for-europe-this-winter/ar-AA1gAAAX.

[8] U.S. EIA, "Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market," May 23, 2023: https://www.eia.gov/outlooks/aeo/IIF_LNG/.

[9] U.S. EIA Weekly Natural Gas Storage Report, September 15, 2023: https://ir.eia.gov/ngs/ngs.html.

[10] As of September 15, Pacific storage was 11% higher than last year and 0.8% lower than the five-year average. Ibid.

[11] Futures price percentages are based on proprietary data from Natural Gas Intelligence.

Introduction and Modeling Methodology

This report aims to assess the ability of the SoCalGas network to meet the daily gas demand during winter 2023-2024. To forecast supply and demand for each winter day, Staff use demand forecasts based on the utilities' 2022 California Gas Report, historical demand variability, supply assumptions based on utility-reported infrastructure availability, and future wells availability of underground storage. The network is deemed "reliable" if the forecasted supply (i.e., interstate supplies, California production, and underground storage) is always greater than demand.[12] Daily demand is forecasted by drawing from a distribution based on historical variability and forecasted monthly averages, hence this approach is a stochastic daily mass balance model. This model was originally developed by Staff and presented in Workshop #4 of Phase 2 of I.17-02-002 on October 15, 2020.[13]

The stochastic daily mass balance model is more detailed than the monthly balance sheets which were used in previous Reliability Assessments.[14] The model provides valuable insight into the natural gas system without being computationally expensive. The model has been slightly modified from the version presented in the workshop to perform short-term studies, and has been used for winter 2022-2023 and summer 2023 reliability assessments. The use of this model, or a very similar approach, to evaluate whether Aliso Canyon is needed in a given year was included in a staff proposal on September 23, 2022, along with proposed inputs to the model.[15] No decision has yet been made on that staff proposal.

In prior Reliability Assessments, Staff used a monthly mass balance and a 1-in-10 peak day analysis to evaluate system reliability. The monthly mass balance was conducted to see how storage inventory held up over the course of the winter. In that analysis, average demand and supply were assumed for every day of each month. This was coupled with a 1-in-10 peak day analysis, which evaluated whether a peak day could be met in each month given assumed pipeline and storage withdrawal capacity. The storage inventory used in the peak day analysis was determined by the monthly mass balance.

The new stochastic daily mass balance model combines elements of these two previously used analyses. The model uses assumptions about pipeline capacity for each month and randomly selects a demand value for each day of that month that is within the expected probability distribution. Thus,

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12 In very simple terms, the law of conservation of mass states that for any closed system, the mass of the system cannot be created or destroyed, i.e., the mass of the system must remain constant or conserved over time. In natural gas pipelines, this means that supplies must equal demand, with supplies being interstate supplies, California production, or withdrawals from underground storage, and demand being actual customer demand (sendout), or injection into underground storage. In this formulation, the time rate of change of mass within the pipelines is assumed to be zero, which means that the linepack returns to its initial value by the end of the day. Violation of the law of conservation of mass in the pipelines directly translates to an actual problem in the system that will result in either curtailments, over-pressurization, under-pressurization or may even indicate leakage in the system.

13 https://www.youtube.com/watch?v=XcCK2q8quCQ

14 Summer and Winter Reliability Assessments: https://www.cpuc.ca.gov/regulatory-services/safety/gas-safety-and-reliability-branch/aliso-canyon-well-failure/aliso-canyon-summer-and-winter-reliability-assessments.

15 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/aliso-canyon-staff-proposal-2022.pdf.

the model includes some days with higher or lower demand than the monthly average.[16] If needed, the model injects excess supply into storage or withdraws from storage to resolve a deficit. All days throughout the winter are modeled in this manner. The simulation is repeated 100 times to create a probabilistic analysis that includes a spectrum of variations in demand. Thus, the model both evaluates the potential decrease in storage inventory over the course of the winter (or increase during the summer), like the monthly mass balance, and the system's ability to meet peak day demand, like the 1-in 10 peak day analysis.

Input Data and Assumptions

Withdrawal curves, injection curves, and initial inventory level

Previous analyses have used the same withdrawal and injection availability assumptions regardless of the calendar month. These assumptions are referred to as withdrawal and injection "curves," because the withdrawal or injection rate depends highly on the volume of gas in storage and other factors. The relationship between the inventory volume is often described by a graph or "curve." However, maintenance and other factors cause withdrawal and injection curves to vary over time. Therefore, Staff requested that SoCalGas submit forecasted monthly withdrawal and injection curves based on well availability and planned maintenance outages. SoCalGas submitted these curves for the period from October 2023 to March 2024 for all storage fields. These curves were submitted to Staff under a confidentiality agreement and are not available to the public. They are used extensively by the model to calculate the daily available withdrawal and injection capacities.[17] For the months following March 2024, if needed, staff assumed the same withdrawal and injection rates corresponding to March 2024. Similarly, staff assumed September storage and withdrawal curves to be identical to the October ones. The initial inventory level of all four storage fields on September 1, 2023, was obtained from SoCalGas ENVOY.[18]

Supply outlook and assumptions

Unlike previous assessments, staff relied only on publicly available planned outages data that are posted on ENVOY. SoCalGas indicated that planned outages that are published on the maintenance schedules page are finalized and should occur as planned. Other outages summarized in the maintenance outlook[19] of ENVOY are preliminary and may or may not occur due to issues such as a lack of necessary construction permits or labor resource conflicts. As with previous assessments, Staff elected to include the impact of both finalized and preliminary planned outages on the supplies.

The duration of the planned pipeline outages varies from four to 181 days except the outage for L235 operational restrictions, which has an unknown end date.[20] The impact of planned outages on

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[16] Less than half the days of the month will be higher than average due to the right skewness of the Gamma Distribution.
[17] Closed-form integration was performed on the linearly regressed storage curves to obtain accurate inventory volumes
[18] Envoy: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome.
[19] https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternalEbb.getMessageLedger?folderId=18
[20] ENVOY event ID 6245

capacity varies from 50 MMcfd (L2001 remediation) to 630 MMcfd (L5000 leak repair in October, 2023). The planned outages total volumetric impact is approximately 72 billion cubic feet (Bcf) during the study period.[21] Based on the planned outage forecasts, Staff devised the following three scenarios to assess winter 2023-2024 reliability. In all cases, the duration of the outages is rounded to the full calendar month due to current modeling limitations, but this practice could also account for some of the uncertainty associated with the duration of planned outages.

1. Baseline Scenario 1, Best-Case Scenario: planned outages that last fewer than seven days are ignored. Planned outages that last seven days or longer are included, and their duration is rounded to the nearest number of months. This scenario represents an upper bound or a best-case scenario for the winter season.
2. Baseline Scenario 2, Mid-Case Scenario: all planned outages occur as scheduled, and their duration is rounded up or down to full months but lasts at least one month.
3. Baseline Scenario 3, Worst-Case Scenario: all planned outages occur as scheduled and described in Scenario 2. In addition, unplanned outages reduce the Northern Zone receipt capacity by 200 MMcfd during the entire study period. Staff included this scenario to represent the possibility of an unexpected pipeline outage. Scenario 3 represents a lower bound or a worst-case scenario.

All three scenarios assume no supplies from Otay Mesa, which is in the Southern Zone and rarely used. Scenarios 1 to 3 offer very similar average daily supplies over the study period (3,284 MMcfd, 3,179 MMcfd, and 2,979 MMcfd, respectively)[22] with a 306 MMcfd average difference between the highest and lowest monthly average. Depending on outages, the Southern Zone supplies vary from 580 to 1,210 MMcfd, while the Northern Zone supplies vary from 835 to 1,425 MMcfd. Supplies from Wheeler Ridge are assumed to be 765 MMcfd, and California production is 60 MMcfd.

Staff started modeling the three scenarios described above on September 1, 2023. However, an unplanned outage occurred in the Southern Zone the following week, reducing Blythe subzone capacity by 200 MMcfd (ENVOY event IDs 6545 and 6514). To minimize the effect of this force majeure event on system receipt capacity, SoCalGas postponed a planned hydrotest in the Southern Zone that had an impact of 220 MMcfd during September and October. This planned outage (hydrotest) was already accounted for in the three scenarios described above. Given that the difference between the planned and the unplanned outage is only 20 MMcfd, changing the supply assumptions was not necessary especially since the worst-case scenario subtracts another unplanned outage of 200 MMcfd from the system receipt capacity. Should the new outage on the Southern Zone last longer than two months, it is possible that the Worst-Case scenario becomes the Mid-Case scenario unless the operator elects to postpone other planned outages.

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[21]This number is obtained by multiplying the duration of each outage by its impact, then summing the volumes.
[22] The average is weighted by the number of days in a calendar month.

Monthly Demand Forecast and Comparison with Supply

The resulting monthly capacity based on the assumptions listed above is summarized in Table 1. The last row in the table is the sum of available pipeline supplies in Bcf.[23] Noteworthy is that these supplies are only "available," which means they may or may not be used fully depending on the daily demand and the injection capacity available on that day.

The last three columns of the table list the average daily demand by month forecasted by the 2022 California Gas Reports (CGR) for two weather scenarios: average temperature with base hydro and cold temperature with dry hydro as well as the forecasts of a cold temperature and dry hydro year by the 2020 CGR. For all three scenarios, the total available supplies (700 Bcf, 677 Bcf, and 634 Bcf) are higher than the demand forecasted by the 2022 CGR for a cold and dry hydro year (563 Bcf) over the study period. For all months in the study period, the average daily system receipt capacity is *higher* than the average daily demand of the cold temperature, dry-hydro demand scenario. However, when compared with the 2020 CGR forecasts of a cold temperature and dry hydro, the supplies during November and December of scenario 3 are lower. This will be evaluated further in of the sensitivities.

Table 1: System receipt capacity by month for the three scenarios and total gas requirement per the 2022 and 2020 California Gas Report

	System Receipt Capacity[15] (MMcfd) for Scenario			2023-2024 Average Daily Demand [16] (MMcfd) for		
	1	**2**	**3**	**Average Temp Base Hydro**	**Cold Temp Dry Hydro**	**Cold Temp Dry Hydro**
Forecasts Source				**CGR 2022**	**CGR 2022**	**CGR 2020**
Month, Year						
September, 2023	3,065	2,915	2,715	2,189	2,203	2472
October, 2023	3,015	2,655	2,455	2,122	2,147	2325
November, 2023	3,070	2,840	2,640	2,469	2,559	2769
December, 2023	3,460	3,460	3,260	2,982	3,173	3368
January, 2024	3,460	3,460	3,260	2,813	2,987	3058
February, 2024	3,460	3,460	3,260	2,716	2,876	2896
March, 2024	3,460	3,460	3,260	2,457	2,571	2457
Average Daily	**3,284**	**3,179**	**2,979**	**2,536**	**2,645**	**2764**
	Total Available Supplies			**Total Forecasted Demand**		
September-March (Bcf)	**700**	**677**	**634**	**540**	**563**	**589**

[23] Daily supply multiplied by the number of days in a month, summed over the seven-month period divided by one thousand.

This is the first winter since winter 2017-2018 that the available receipt capacity is higher than the *average* demand for a cold and dry hydro year. This is because of the restored capacity of the Northern Zone and the lower forecasts in the 2022 California Gas report. Surprisingly the combination of these supply assumptions and demand forecasts indicates no seasonal or average need for withdrawals from underground storage in order to preserve reliability. However, withdrawals from storage will still be needed to meet daily or hourly demand.

Demand variability

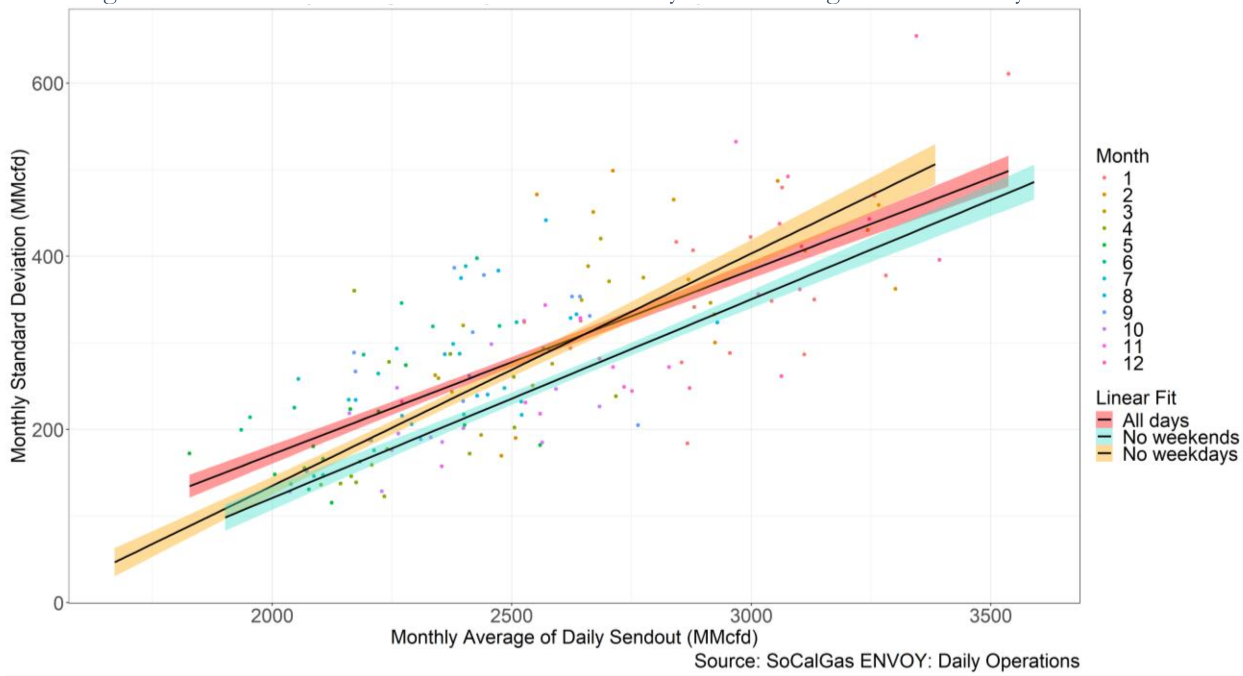
Average monthly demand was obtained from the 2022 California Gas Report, as described above. To quantify the daily variation in demand from the average, historical data was used to calculate the standard deviation (SD) for each calendar month. The historical standard deviation is then used along with the average monthly demand to build monthly Gamma distributions.[24] Three different values of standard deviation were considered. These three standard deviations correspond to the predicted value and the 95 percent confidence intervals arising from the linear regression of the historical average daily demand with the historical standard deviation for a given month. They can be thought of as a proxy for the degree of weather variability or any other variability inherent to the natural gas system such as customer decisions, customer outages, connections or disconnections, and electric generation dispatch. Of these three values, the highest one was used, as discussed below.

Historically, a higher average demand is typically associated with a higher standard deviation, as shown in Figure 1. Therefore, standard deviation was modeled as a function of average demand. To derive the linear regression model between the monthly average of the daily demand and the monthly standard deviation of the daily demand, historical data of daily demand was used. In the previous winter assessment, the historical data ranged from January 2010 to October 2018. For this assessment, the historical data range was extended to April 2023 without special treatment of the warmer years (2014-2018). The inclusion of additional data in the regression model did not result in a better correlation between the two variables but resulted in a negligible decrease in the standard deviation.[25] Furthermore, attempting to correlate the two variables during just weekdays or just weekends did not enhance the regression model nor decrease the confidence intervals of the predicted values of the standard deviation. Figure 1 illustrates the linear regression model for the extended dataset range for weekends alone, weekdays alone, or the entire dataset.

[24] The model uses a Gamma distribution which is a right-skewed distribution because the analysis of historical gas demand data has shown that these distributions are right-skewed, particularly in the winter. Gamma distributions can be generated using two parameters; a mean value and a standard deviation. Gamma distributions are often used to model data that only has positive values such as the daily gas demand. There could be other skewed distributions that fit the historical data.

[25] R-squared for the extended dataset is 0.5254 compared to 0.5606 for the previous dataset. p-values are extremely small for both datasets. Simply put, an R-squared of 0.52-0.56 means that only 52 -56 percent of the variance in the monthly standard deviation can be explained by the monthly average of the daily demand. This is probably due to variations in weather across multiple years. A year can have a consistently hot or average August (which would yield low SD), while another year could have an average August with a heat wave that lasts a week (hence higher SD). Electric Generation demand will also contribute to variability.

Figure 1: Historical standard deviation vs. mean daily volume using 2010-2023 daily demand data



In the feasibility studies performed in Phase 2 of I.17-02-002, Staff concluded that the high standard deviation (corresponding to the upper 95 percent confidence interval) of a cold temperature and dry hydro year forecasted data best mimicked the historical 2013 cold year.[26] Hence, it was used to perform multiple feasibility assessments. For the 2023-2024 winter reliability assessment, Staff continues to use the high standard deviation of a cold temperature and dry hydro year.

Table 2 and Table 3 summarize the Gamma distributions[27] of the daily demand for the period from September 1, 2023, to March 31, 2024, for a cold and dry hydro year, and an average year with base hydro. For example, for a cold and dry year, these distributions forecast 110 and 101 days of demand higher than 2.5 billion cubic feet per day (Bcfd) but lower than 3.5 Bcfd, using the normal and high standard deviations respectively. Similarly, there are almost no days with demand higher than 4.0 Bcfd using the low standard deviation, but approximately one and four days using the normal and high standard deviation of a cold and dry hydro year.

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[26] Year 2013 had 12 days with sendout higher than 4 Bcfd, while the Gamma distribution for a cold 2022-2023 with the upper standard deviation yielded 7.09 days with sendout higher than 4 Bcfd. In comparison, the predicted and lower standard deviations for a cold 2022-2023 yields only 2.67 and 0.27 days respectively. Furthermore, year 2013 had only 1,206 HDDs. A 1-in-10 cold year will have 1,398 HDDs and a 1-in-35 will have 1,476 (CGR 2022).

[27] The model uses a Gamma distribution which is a right-skewed distribution. Gamma distributions can be obtained by using a mean value and a standard deviation. The mean values are obtained from published natural gas demand forecasts such as the California Gas Report, while the standard deviation is obtained using a linear regression model of historical data.

Table 2: Demand distribution for September-March for low, normal, and high standard deviation (variability) of a cold 2023-2024 winter and dry hydro forecast

	Expected Number of Days		
	Low SD	**Normal SD**	**High SD**
Demand Range (Bcfd)			
Higher than 4.612	0	0.04	0.467
4.0 to 4.6	0.085	1.22	3.76
3.5 to 4.0	4.3319	9.73	13.7
2.5 to 3.5	125.2129	110.41	101
Lower than 2.5	83.36967	91.6	94.2
Total	**213**	**213**	**213**
December days above 4,612 MMcfd	**0**	**0.04**	**0.325**
Total days above 4,612 MMcfd	**0**	**0.04**	**0.467**

Table 3: Demand distribution for September-March for low, normal, and high standard deviation (variability) for an average winter 2023-2024 with base hydro forecast

	Expected Number of Days		
	Low SD	**Normal SD**	**High SD**
Demand Range (Bcfd)			
Higher than 4.612	0	0	0.13
4.0 to 4.6	0	0.25	1.59
3.5 to 4.0	0.57	3.9	8.19
2.5 to 3.5	107.99	100.2	94.21
Lower than 2.5	104.44	108.66	108.87
Total	**213**	**213**	**213**
December days above 4,612 MMcfd	**0**	**0**	**0.1**
Total days above 4,612 MMcfd	**0**	**0**	**0.13**

In comparison, the 2022 CGR predicts a 1-in-10 peak demand of 4,612 MMcfd in December 2023 under 1-in-10-year cold and dry hydro conditions. In contrast, the 2020 CGR predicted a 1-in-10 peak demand of 4,975 MMcfd for December 2023 under 1-in-10-year dry hydro conditions, which is about 7.9 percent higher than that forecasted by the newer 2022 CGR. Noteworthy is that in summer of 2022, SoCalGas experienced 21 days when the demand was higher than the summer high demand predicted by the 2022 CGR.[28] The highest recorded demand during that period was 3.2 Bcfd on September 6, much higher than the forecasted high sendout value of 2.579 Bcfd for summer 2022. During these 21 days, the average demand was 2.8 Bcfd.

[28] Two days in July, nine days in August, and 10 days in September

Given the uncertainty in the CGR 2022 forecasts described above, Staff will continue to use the high variability of a cold and dry hydro year to generate the monthly distributions of daily gas demand, which would generate, on average, only four days of demand higher than four Bcfd during the study period. The results of the model are discussed in the next section.

Results of Baseline Scenarios

The analysis finds that all demand can be met throughout the coming winter. There are essentially no days on which demand is not met (imbalance days), and hence no unserved demand or curtailments on those days (Expected Unserved Volume). Since substantial supplies of gas by pipeline are available, at times they exceed what can be injected into storage (Expected Unused Supplies). Unusually, the model does not show storage being drawn down throughout the winter, on average. Rather, average storage levels are maintained throughout the winter, with some storage used to meet fluctuations in daily demand. These results reflect the moderate demand forecast and higher pipeline capacity for this winter.

Daily analysis enables consideration of factors such as the ability to meet demand on days that are higher than average. Results of the analysis are summarized by not only averaging across the winter or its individual months, but by metrics reflecting any days on which a system's balance could not be met. These metrics include Emergency Flow Orders (EFOs), the Expected Unused Supplies (EUS), and the Expected Unserved Volume (EUV). All metrics may be averaged by month or over the whole study period to summarize the results.

Number of imbalance days

The most important metric or outcome for the stochastic daily mass balance model is the number of imbalance days that occur during the simulation. An imbalance day means that the natural gas system could not meet the demand using the supplies available on that day (interstate supplies + California production + available withdrawal capacity). The total number of imbalance days is divided by the number of iterations[29] to obtain the number of imbalance days per study period, or the expected number of imbalance days, which can be disaggregated by month. For all three scenarios, the model predicts a negligible number of imbalance days,[30] even under high demand variability. In other words, based on the model inputs and assumptions, SoCalGas natural gas network should be able to meet customers' demand every day during the entire 2023-2024 winter season, with up to four days of demand above 4 Bcfd and likely more.

Expected Unserved Volume (EUV)

Another simple metric was calculated using the stochastic daily mass balance, which is termed the Expected Unserved Volume (EUV). EUV is the sum of all the imbalance volumes averaged over the number of iterations of the study period. EUV can be reported as a total or disaggregated by month.

[29] Recall that the study period is simulated n=100 times. So, if the model reports 500 EFOs for the study period, this simply means five EFOs per study period on average.

[30] Only Scenario 3 predicts two imbalance days in 100 iterations of a cold and dry hydro year. The demand on these two days was much higher (5.1 and 5.5 Bcfd) than the 1-in-10 peak day demand forecasted by either the CGR 2020 or CGR 2022 (5 and 4.7 Bcfd).

EUV is zero for Scenarios 1 and 2, and negligible for Scenario 3.[31] In other words, no curtailments are expected this winter as long as the model's assumptions hold. Noteworthy is that since the model does not have a geographical dimension, localized events might occur which cause short duration non-core curtailments.

Expected Unused Supplies (EUS)

Another metric was calculated using the stochastic daily mass balance, which is termed the Expected Unused Supplies (EUS). EUS is the sum of supplies that couldn't be injected into storage due to injection limitations or inventory levels reaching their maximum allowed level, averaged over the number of iterations of study period. Similar to the previous metrics, EUS can be reported as a total or can be disaggregated by month or by day if desired. Table 4 shows the monthly EUS for Scenarios 1-3.

Typically, one would expect high EUS during the shoulder months and near-zero EUS during the winter. However, in this assessment, the assumed pipeline supplies are higher than they were in past winters. In addition, the 2022 California Gas Report forecasts are lower than previous forecasts. This results in high EUS during January and February for Scenarios 1 and 2, which could be interpreted as a margin available at the borders to meet a demand that is higher than forecasted. For Scenario 3, the monthly EUS is low and does not exceed a single day's average demand during the period from September to January.

Table 4: Expected Unused Supplies (Bcf) for Scenarios 1-3

		Scenario		
		1	**2**	**3**
Month	**September, 2023**	8.48	5.45	2.26
	October, 2023	14.27	3.22	1.93
	November, 2023	7.7	3.22	0.87
	December, 2023	6.93	4.18	1.31
	January, 2024	13.63	11.64	2.68
	February, 2024	16.6	17.22	4.37
	March, 2024	27.03	27.32	17.4
	Total	**94.62**	**74.24**	**30.82**

Furthermore, the low monthly EUS in Scenario 3 indicates that Scenario 3 is a tipping point. If supplies are lower than what is assumed in that scenario (2,979 MMcfd average), frequent withdrawals and higher withdrawal volumes will be expected, which will result in faster depletion of underground storage. In other words, if the SoCalGas pipeline network suffers a prolonged unplanned outage that has an impact higher than 200 MMcfd, higher dependence on storage and lower inventory volumes by March is expected. However, a prudent operator may elect to cancel or

[31] Less than 1 MMcf, which combined with near zero imbalance days should be ignored.

postpone planned outages, in response to unplanned outages of such magnitude or duration in order to restore the total system receipt capacity.[32]

Inventory tracking

The stochastic daily mass balance tracks the daily inventory level of each storage field. In this section, inventory tracking plots for the three scenarios are shown. Each plot contains four subplots, one subplot for each storage field; Aliso Canyon (AC) on the top left, Honor Rancho (HR) on the top right, La Goleta (LG) on the bottom left, and Play Del Rey (PDR) on the bottom right.

Because of the random draws performed by the model, the daily storage inventory level is not a deterministic value, but rather a probabilistic one, i.e., a distribution.[33] Therefore, each subplot contains five curves that represent the 5th, 25th, 50th (median), 75th, and 95th percentiles of the inventory level of one of the storage fields.

Figure 2, Figure 3, Figure 4 show the inventory tracking plots for Scenarios 1 to 3, while Table 5, Table 6, and Table 7 show the month-end inventories for Scenarios 1 to 3. As summarized in Table 1, Scenarios 1, 2, and 3 have total available supplies of 700 Bcf, 677 Bcf, and 634 Bcf compared to a forecasted demand of 563 Bcf over the study period for a cold and dry year. Scenario 1 represents the best-case scenario, Scenario 2 the mid-case scenario, and Scenario 3 the worst-case scenario. In contrast to recent winter assessments, the assumed supplies for all three scenarios are higher than the demand whether it is total or monthly. In addition, all three scenarios assume a high demand variability (high standard deviation) within a cold temperature and dry hydro year and no supplies scheduled at Otay Mesa. Furthermore, all three scenarios withdraw and inject from all four storage fields using Aliso Canyon last in the sequence.

For both Scenarios 1 and 2, which are shown in Figure 2 and Figure 3, the non-Aliso fields reach their maximum inventory no later than the end of October. On the other hand, Aliso Canyon reaches only 80 percent by the end of October (54.88 Bcf). The model also shows that injection into Aliso Canyon continues throughout the winter and reaches 100 percent of its new maximum allowable inventory (68.6 Bcf) by mid-December for Scenario 1 and by mid-January for Scenario 2. It's worth noting, however, that this outcome assumes that noncore customers purchase gas to inject into storage throughout the winter, which is not typically an economically beneficial strategy.[34]

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[32] Most planned maintenance is required by regulation, so there are limits to how long maintenance can be deferred while still complying with regulatory deadlines.

[33] Since each study period is simulated 100 times, it follows that each day in the study period is also simulated 100 times. In other words, the storage inventory levels on July 1st have 100 values for each scenario and statistics must be drawn to illustrate the results.

[34] The model does not take into account the gas commodity, transmission, and distribution cost. This assumes that reliability is the highest priority. However, sensitivities on the volume subscribed into by the Unbundled Storage Program can be performed and would likely show no degradation in reliability.

Figure 2: Inventory tracking for Scenario 1

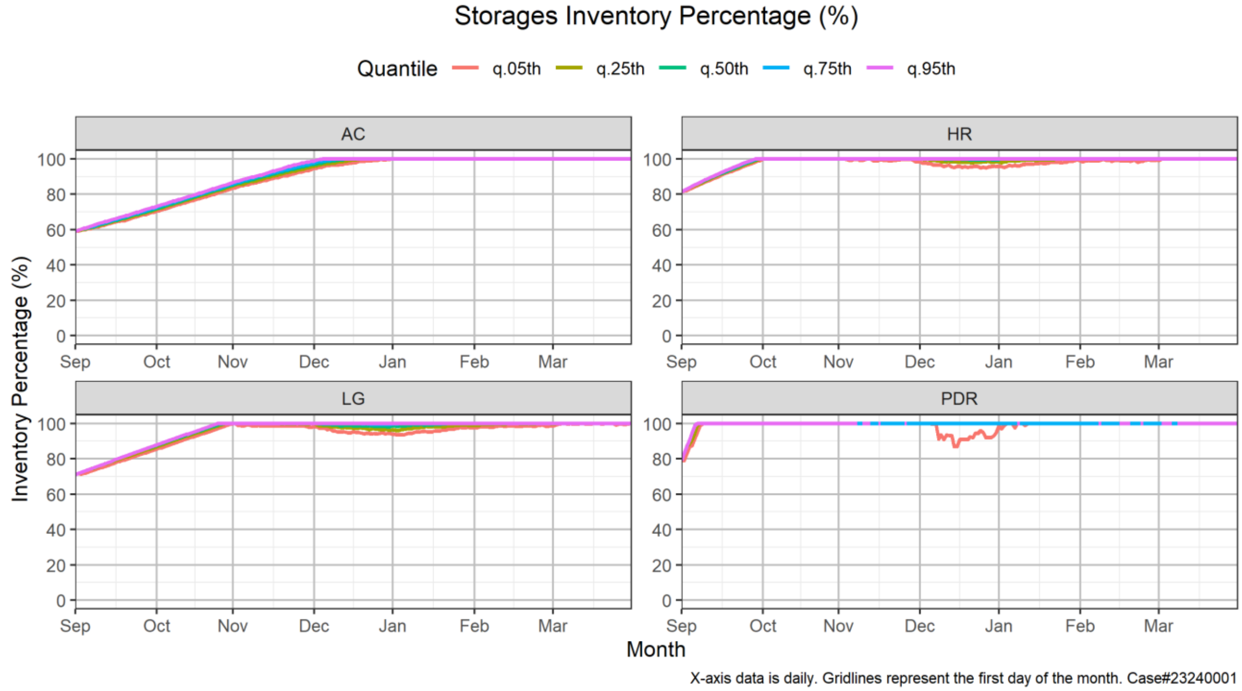
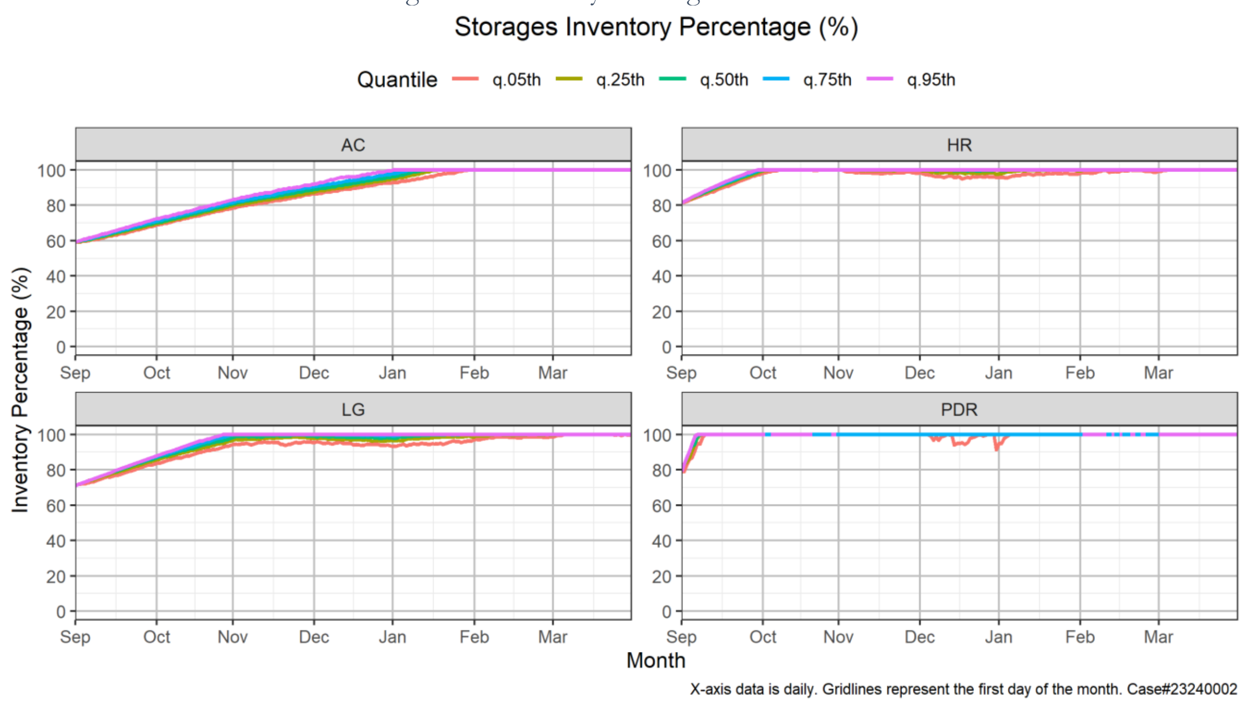
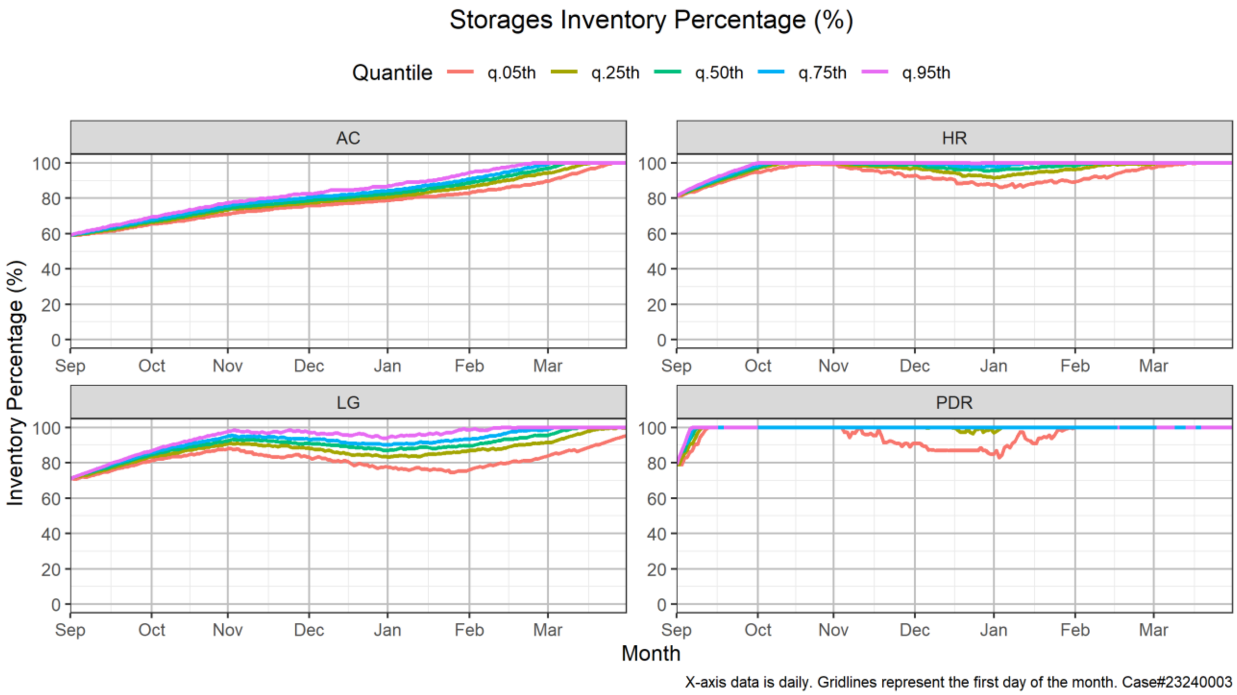


Figure 3: Inventory tracking for Scenario 2



Scenario 3, which is shown in Figure 4 shows more peculiar results. During November and December, the inventory level at La Goleta is slightly decreasing while injection into Aliso Canyon continues. Starting in January, injection into La Goleta resumes. On the other hand, Honor Rancho and Playa Del Rey are near full and are used in the very extreme cases (i.e., during the extreme cases of a cold and dry hydro year). Reviewing the daily results reveals that during this two-month period, and on days when the demand is higher than supplies, withdrawals are occurring from La Goleta and possibly Honor Rancho. On other days, when the supplies are higher than the demand, the model attempts to inject into all storage fields starting with non-Aliso fields. However, because the non-Aliso fields are near full and have a lower injection capacity than Aliso Canyon, part of the imbalance or the excess supply has to be resolved by injecting into Aliso Canyon. Therefore, Aliso Canyon inventory level continues to rise during the winter with little to no withdrawals since it has the lowest priority for withdrawals. This outcome highlights the model's strength in predicting withdrawals and injections within the same month (December) despite average daily supplies (3,260 MMcfd) being higher than the average daily demand (3,173 MMcfd). This behavior also highlights how La Goleta is a "slow" field due to its limited injection capacity, which makes it difficult to fill. This scenario also emphasizes the importance of Aliso Canyon in balancing the system when the non-Aliso fields are near full.

Figure 4: Inventory tracking for Scenario 3



Noteworthy is that during actual operations, Honor Rancho is likely to be used instead of La Goleta due to its proximity to the LA Basin and receipt points and its higher withdrawal and injection rates. When this modeling was conducted, the Aliso Canyon Withdrawal Protocol was still in place.[35] The current model does not include any geographical dimension, and it was not critical to adjust the injection and withdrawal priority as long as Aliso Canyon was set to be used last to account for the Aliso Canyon Withdrawal Protocol. For the future, the model could be updated to reflect the

[35] On September 15, 2023, the CPUC's Energy Division removed the Aliso Canyon Withdrawal Protocol: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/aliso-canyon-withdrawal-protocol-letter-2023-09-15.pdf.

removal of the Withdrawal Protocol and include an optimization scheme, although the optimized variable is not clearly defined.[36]

Table 5: Month-end inventory for Scenario 1 (median)

	Month						
	9	10	11	12	1	2	3
Aliso Canyon	49.11	58.33	66.45	68.60	68.60	68.60	68.60
Honor Rancho	27.00	27.00	27.00	26.85	27.00	27.00	27.00
La Goleta	18.75	21.50	21.50	21.16	21.50	21.50	21.50
Playa del Rey	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Total	**96.76**	**108.73**	**116.85**	**118.52**	**119.00**	**119.00**	**119.00**

Table 6: Month-end inventory for Scenario 2 (median)

	Month						
	9	10	11	12	1	2	3
Aliso Canyon	48.00	55.16	60.82	65.88	68.60	68.60	68.60
Honor Rancho	26.90	27.00	27.00	26.99	27.00	27.00	27.00
La Goleta	18.58	21.05	21.32	21.11	21.50	21.50	21.50
Playa del Rey	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Total	**95.38**	**105.11**	**111.04**	**115.9**	**119.00**	**119.00**	**119.00**

Table 7: Month-end inventory for Scenario 3 (median)

	Month						
	9	10	11	12	1	2	3
Aliso Canyon	45.75	50.98	53.88	56.64	60.76	66.33	68.60
Honor Rancho	26.15	27.00	26.80	25.83	26.6	27.00	27.00
La Goleta	18.02	19.89	19.58	18.72	19.29	20.5	21.50
Playa del Rey	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Total	**91.8**	**99.78**	**102.16**	**103.09**	**108.55**	**115.73**	**119.00**

Furthermore, it is important to note that despite the recent decision to increase the maximum inventory at Aliso Canyon and reinstate the Unbundled Storage Program, customers are not obligated to purchase that capacity. Noncore customers, or large commercial and industrial customers that make their own gas purchasing decisions, are the primary market for this added capacity. They will decide whether to purchase storage based on their own business outlook and risk-management practices. Therefore, it is unknown whether all the newly added 27 Bcf in

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[36] It is not clear if the optimization goal needs to be the minimization of the daily price of gas, minimization of the total cost of gas throughout the winter season, maximizing the total inventory levels throughout the winter, or maximizing the daily withdrawal capacity of the four storage fields or a combination thereof to optimize for reliability and cost together.

Unbundled Storage inventory will be sold, especially since it became available late in the injection season.[37]

It is worth noting that neither the monthly balance sheets, nor the daily mass balance model take into account market decisions made by gas users comparing the price of gas from storage to that of pipeline gas. They also do not factor in the hourly changes in demand that frequently drive storage withdrawals. On the actual gas system, those market decisions and hourly surges in demand may lead to more storage being used than would be forecast based on daily reliability decisions alone.

In summary, the model shows relatively high inventory levels throughout the winter with no imbalance days or curtailments. This is driven by two factors; a higher system receipt capacity that is expected to be restored starting in December 2023 and lower seasonal and 1-in-10 peak day demand forecasts by the 2022 California Gas Report. The inventory levels before and during winter 2023-2024 are forecast to be high and supportive of a reliable winter 2023-2024.

Results of Additional Sensitivities

Lower Storage Utilization

One of the weakest assumptions associated with the daily mass balance model compared to models that conserve both mass and energy (e.g., Synergi Gas or NextGen) is assuming that withdrawals or injections from any of SoCalGas' four underground storage fields can be used to meet the difference between the interstate supplies and the demand regardless of the geographical locations causing this difference. In other words, a supply deficiency causing a pressure drop in the Los Angeles basin may not be remedied by withdrawals from La Goleta because of its remoteness. Similarly, over-pressurization in the Southern Zone may not be easily remedied by injections to, for example, Honor Rancho, which is located in the north. Therefore, the current withdrawal and injection sequence used by the model (La Goleta → Honor Rancho → Playa del Rey → Aliso Canyon) may not be always feasible during daily or hourly operations. On the other hand, modeling transient flows in SoCalGas pipeline network in Synergi Gas has shown that withdrawals from all the non-Aliso fields can be maximized before having to withdraw from Aliso Canyon on 1-in-10 peak days, which means having Aliso Canyon withdraw last in the model is not impossible either.

Similar to the Winter 2022-2023 and Summer 2023 Reliability Assessments, and to further investigate the effect of this assumption on the model, Staff ran one additional sensitivity on Scenario 3. In that sensitivity, the utilization factor of all four underground storages was set to 80 percent, i.e., only eight out of each 10 forecasted in-service wells are made available.[38] The basis for considering this sensitivity is the ongoing well testing required by the 2018 CalGEM rules, which causes wells to be removed from service, and to also address the model's inability to conserve energy. The lowered utilization factor did not result in a substantial change in the inventory levels or

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[37] As of September 25, 2023, 8.2 million dekatherms or roughly 7.9 Bcf of Unbundled Storage inventory had been sold: primaryStorageTransactions.pdf (socalgasenvoy.com).

[38] There is a simplification in that approach in that not all wells drilled in a storage field are identical. This simplification also does not account for the limits of the above-surface facilities such as the dehydrator units. A more rigorous model could be devised when needed, which would require individual wells and above surface data.

the number of imbalance days which remain less than one. The results of the first sensitivity are summarized in Table 8.

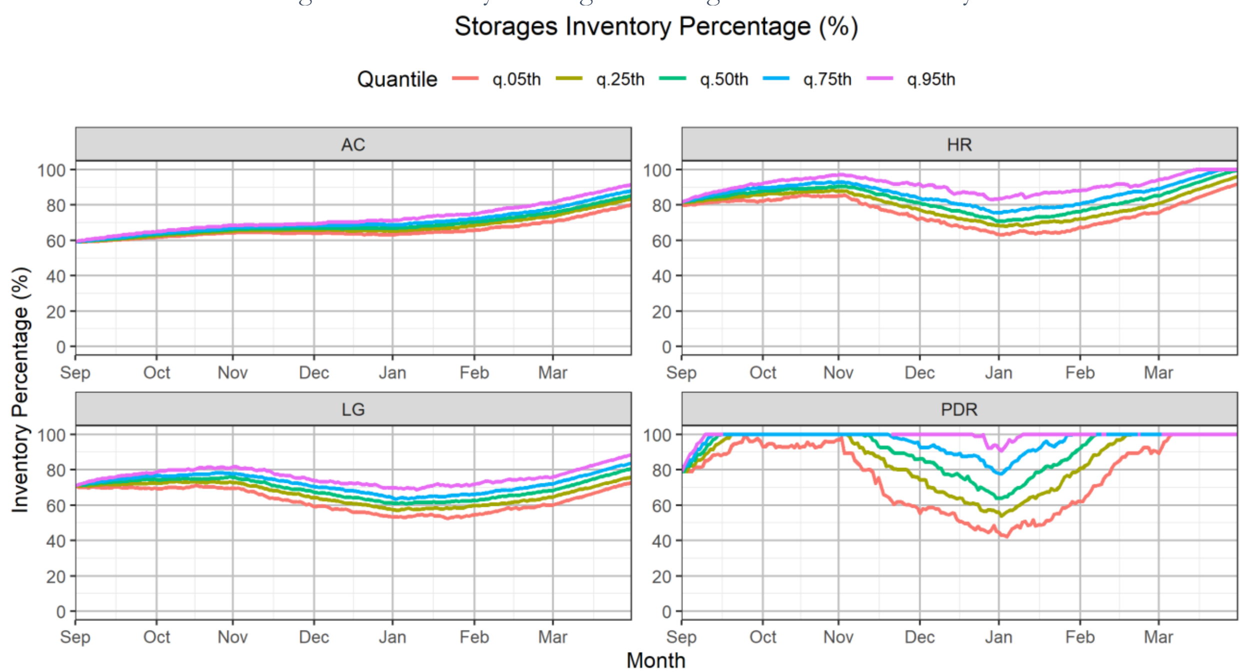
Table 8: End-of-March inventory level for Scenario 3 and sensitivities

	AC	HR	LG	PDR	Total	EFO
	Bcf	Bcf	Bcf	Bcf	Bcf	#/day
Scenario 3	68.60	27.00	21.50	1.90	119.00	<1
Sensitivity 1	68.60	27.00	21.42	1.90	118.92	<1
Sensitivity 2	58.65	26.94	17.38	1.90	104.87	<1

Higher Demand

To further address the uncertainty in the 2022 California Gas Report forecasts,[39] a second sensitivity was performed using the 2020 California Gas Report forecasts. Similar to the first sensitivity, the second sensitivity uses a utilization factor of 80 percent for all underground storages. It also uses the same supply and outages assumptions of the baseline Scenario 3. However, the second sensitivity uses the demand forecast of a cold and dry hydro year from the 2020 CGR forecasts.

Figure 5: Inventory tracking for the higher demand sensitivity



While the second sensitivity shows no imbalance days, the decrease in the inventory levels throughout the winter is remarkable compared to the baseline scenarios and the first sensitivity. Specifically, and from end of October to end of December (two months), La Goleta inventory level

[39] In summer of 2022, SoCalGas experienced 21 days where the demand was higher than the summer high demand predicted by the 2022 CGR. The highest recorded demand during that period was 3.2 Bcfd on September 6, much higher than the forecasted high sendout value of 2.579 Bcfd for summer 2022. During these 21 days, the average demand was 2.8 Bcfd.

drops from 75 percent to 60 percent, Honor Rancho drops from 90 percent to 70 percent, Playa Del Rey drops from 100 percent to 65 percent, while Aliso Canyon never reaches its full capacity and remains around 65 percent for most of the winter. In comparison, in the first sensitivity, which uses the 2022 forecasts, the inventory levels of La Goleta and Honor Rancho dropped to only 85 percent and 93 percent by the end of December, while Playa Del Rey remained full. The inventory tracking plot is show in Figure 5.

The second sensitivity illustrates how critical the gas demand forecasts are to the daily mass balance model and other models. The uncertainty in California seasonal demand and the 1-in-10 peak day demand forecasts must be quantified so that reasonable sensitivities can be performed around the baseline forecasts. This becomes increasingly important if regulatory limits are to be set on the maximum allowable inventory levels of the underground storage fields.

Summary

The stochastic daily mass balance model was used to assess the reliability of the SoCalGas natural gas network for the upcoming winter 2023-2024. Three scenarios have been devised with varying preliminary and non-preliminary planned outages, which were obtained from SoCalGas ENVOY. All three scenarios assume a cold and dry hydro year, high demand variability, no supplies from Otay Mesa, and no restrictions imposed on underground gas storage fields.[40] With the current natural gas assets and the newly authorized maximum inventory limit of 68.6 Bcf set on Aliso Canyon, the model predicts no curtailments or emergency flow orders in the winter of 2023-2024. Thus, the assessment predicts the system will be reliable during the upcoming winter.

Two additional sensitives have been simulated. The first sensitivity decreases the withdrawal and injection rates of all underground storage fields by 20 percent in order to simulate unplanned well outages and address the model's lack of energy conservation. The second sensitivity addresses the uncertainty in the 2022 CGR forecasts by using the 2020 CGR forecasts instead.

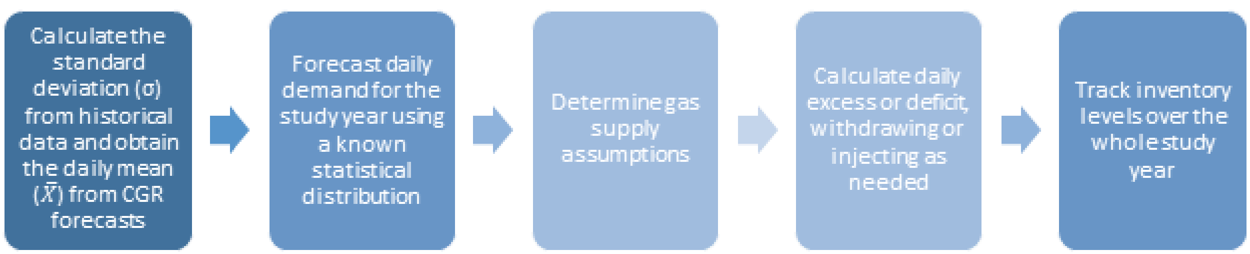
Both sensitivities show no degradation in reliability since the number of imbalance days remains less than one during the entire study period. With 20 percent of wells out-of-service, the SoCalGas system is able to meet customers' demand every day during the 2023-2024 winter, with up to four days with demand above 4 Bcfd. In addition, the SoCalGas natural gas network should be able to meet the 1-in-10 peak demand day of 4,612 MMcfd or 4,975 MMcfd forecasted by the 2022 and 2020 CGR respectively. The second sensitivity, however, show higher dependence on storage during the months of November and December.

[40] In practice, the Aliso Canyon Withdrawal Protocol limits the use of the Aliso Canyon storage field. However, it may be used on days where a Stage 2 or higher Low Operational Flow Order (OFO) would have been called without its use. The model assumes that such a stage would have been reached on days with demand high enough to require the use of Aliso Canyon. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf.

Based on the results of the three scenarios and both sensitivities, Energy Division Staff concludes that the winter 2023-24 reliability outlook is favorable for the Southern California Gas Company (SoCalGas) service territory.

Appendix: Review of the Stochastic Daily Mass Balance Model

The stochastic daily mass balance model attempts a mass balance on each day of the study year rather than the conventional monthly mass balance approach. This method provides an assessment of the system's ability to serve daily demand as a season progresses. The model inputs are the forecasted daily demand using random draws from a known distribution, the monthly assumed pipeline capacity, the storage withdrawal and injection curves, utilization factors[41] or well availability, the working gas capacity of the storage fields, and the maximum and minimum allowed inventory in the storage fields. The use of a distribution for daily demand makes it stochastic. The model outputs are mainly the expected average daily inventory levels and expected average frequency of Emergency Flow Orders (EFO) or imbalance days. Other metrics may be calculated such as the Expected Unused Supplies (EUS) and the Expected Unserved Volume (EUV). The model does not attempt to simulate customers' decisions on the natural gas network. In other words, if the pipeline operator issues an Operational Flow Order (OFO), which imposes a penalty for over- or under-delivering gas, customers may react to the OFO and make decisions that affect the amount of imbalance present in the system. Therefore, the model assumes a worst-case scenario, where customers' decisions are unaffected by OFOs, and hence the natural gas system is inelastic. It is noteworthy that most of these outputs would not be available if monthly mass balance sheets were used. The model steps are illustrated in the Figure below.



Sequentially on each day of the study year, the model determines whether there is an excess or deficit in the gas supply, then injects or withdraws accordingly, while adhering to the withdrawal and injection limits imposed by the withdrawal and injection curves. If there is insufficient supply (i.e., interstate supplies, California production, and storage) to meet the demand (mass imbalance) on a given day, the model flags that day as an imbalance day or an EFO day. EFOs are used as a proxy for insufficient supply or imbalance and as a proxy for reliability events.

The model withdraws or injects the full daily available volume[42] from one storage field before switching to withdrawal or injection from another storage field. This approach was chosen for its simplicity. In addition, the model is currently set to withdraw from and inject into Aliso Canyon last

[41] The utilization factor or use factor is the ratio of the time that a piece of equipment is in use to the total time that it could be in use. For wells, these could be used to account for planned and unplanned outages. For example, if a well is scheduled for maintenance for one month, then its utilization factor would be 1/12. It is one simple way to incorporate outages.

[42] The model integrates the withdrawal and injection curves to get the total change in volume. In other words, the model takes into account the intraday change in withdrawal and injection capacity.

because one of the feasibility assessment goals was to minimize its use. Other, more sophisticated algorithms could involve optimizing withdrawals and the withdrawal sequence to maximize the withdrawal capacity throughout the withdrawal season or to maximize the injection capacity available on a day following withdrawals.

Specifically, for each day in the simulation, if there is an excess of supply (i.e., supplies are higher than the demand), then the injection sequence is initiated,[43] while always respecting the injection limits. For example, if the supplies are 3 billion cubic feet (Bcf) and the demand is 2.5 Bcf, then 500 million cubic feet (MMcf) needs to be injected on that day. If La Goleta is not full (i.e., inventory <100 percent), and the average injection capacity on that day is, for example, 100 million cubic feet per day (MMcfd), then 100 MMcf is injected into La Goleta as long as its inventory is not above 100 percent. The remaining 400 MMcf is injected to the other fields following a specified injection sequence and using the same logic. If all the fields are either full or have used their maximum injection capacity but there is still excess gas, then that day is flagged as a high EFO day. In actual operations, the pipeline operator will issue a high OFO or turn gas away at the California border in an attempt to return balance to the system. The EFO in the feasibility assessment model does not necessarily translate to an actual EFO since the operator can issue a high OFO and customers may attempt to voluntarily increase or balance their gas usage in order to avoid penalties.

Similarly, if there is a deficit in interstate supplies (i.e., supplies are lower than the demand), then the withdrawal sequence is initiated,[44] while always respecting the withdrawal limits. For example, if the supplies are 3 Bcf and the demand is 4 Bcf, then 1 Bcf needs to be withdrawn on that day. If La Goleta is above its minimum allowed inventory level (e.g., 0 percent if no restrictions are imposed), and the average withdrawal capacity on that day is, for example, 200 MMcfd, then 200 MMcf is withdrawn from La Goleta as long as its inventory does not dip below 0 percent. Otherwise, a smaller amount is withdrawn that brings the final inventory volume to 0 percent. The remaining 800 MMcf (or more if La Goleta withdrawal was less than 200 MMcf) must be withdrawn from the other fields following the sequence and the same logic. If all fields have either reached their maximum daily withdrawal or are below their allowed minimum inventory level (or a combination thereof), but there is still a deficit in gas, then that day is flagged as a low EFO day. In actual operations, if there aren't sufficient supplies and linepack to meet the demand, the pipeline operator will issue a low OFO with increasingly stringent stages in an attempt to balance the system. Again, the EFO in the feasibility assessment model does not necessarily translate to an actual EFO or curtailments, since the operator can issue a low OFO and customers may attempt to voluntarily decrease or balance their gas usage in order to avoid penalties.

Because of the statistical nature of the model, a study period must be simulated multiple times. Staff found that 50 iterations of a study period are enough to produce statistically convergent results. However, Staff continued to use 100 iterations in this report.

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[43] The injection sequence is currently set to La Goleta > Honor Rancho > Playa Del Rey > Aliso Canyon

[44] The withdrawal sequence is currently set to La Goleta > Honor Rancho > Playa Del Rey > Aliso Canyon

In essence, the daily demand is the only random input, which is being generated from a known right-skewed distribution. Other inputs remain deterministic, though these inputs may be varied to simulate different scenarios or perform sensitivities. For example, the assumed interstate supplies are deterministic, but they vary by month to account for planned outages and other scenarios. Similarly, the number of wells is allowed to vary by month to account for planned outages, but sensitivities can be performed on the availability of wells using utilization factors. Staff has previously conducted parametric studies that included 972 scenarios per study period in order to vary these deterministic inputs.[45]

[45] Aliso Canyon Investigation 17-02-002 Phase 2: Additional Modeling Report https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M449/K511/449511926.PDF