Summer 2023 Southern California Gas Reliability Assessment

BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION
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Executive Summary

The summer 2023[1] reliability outlook for the Southern California Gas (SoCalGas) system is favorable, with expected pipeline capacity stable, and natural gas storage field inventory on target to fill by October 31[2], or earlier if favorable conditions persist. Following the record low temperatures, multiple cold days, multiple high sendout days, interstate supply interruptions, and record high gas prices of winter 2022-2023, SoCalGas is filling storage at the usual rate.

With the current natural gas assets, maximum inventory limits imposed, and sufficient interstate gas supplies, the model predicts no curtailments or emergency flow orders in summer 2023. The SoCalGas pipeline network should be able to meet average summer demand as well as the summer high sendout day, which is forecasted to be 2,513 MMcfd by the 2022 California Gas Report and 3,217 MMcfd by the 2020 California Gas Report.[3] Furthermore, unplanned storage outages, quantified by 20 percent reduction in withdrawal and injection rates, did not cause any degradation in reliability to the SoCalGas pipeline network.

To estimate summer risk, California Public Utilities Commission (CPUC) staff (Staff) modeled supply and demand using a new method that was developed during the Alison Canyon Investigation (I.) 17-02-002. The new method combines aspects of 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, 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 in storage inventory over the course of the summer and the system's ability to meet peak day demand.

Staff modeled three main scenarios based on variations in planned outages for maintenance reported to the CPUC by SoCalGas. The average daily pipeline capacity varies from 2,830 million cubic feet per day (MMcfd) for the worst-case scenario to 3,096 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.[5] Two additional sensitivities have been simulated, which decrease the withdrawal and injection capacity of all underground storage fields by 20 percent and La Goleta by 50 percent in order to address unplanned storage outages and the remoteness of La Goleta from the Los Angeles basin.

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[1] The gas summer is from April through October. This report covers May through October, since April actuals were available when the assessment began, i.e., the entire analysis was shifted one month.
[2] SoCalGas Envoy.
[3] https://www.socalgas.com/sites/default/files/Joint_Biennial_California_Gas_Report_2023_Supplement.pdf
[4] Less than half the days of the month will be higher than average due to the right skewness of the Gamma Distribution.
[5] 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.

There are at least three factors that are not captured by the model which could cause the summer's trajectory to differ from the modeled outcomes. First, 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. Second, any additional out-of-state disruptions to supply, such as an outage on an interstate pipeline, would not be captured. Finally, local transmission limitations could result in lower flow rates and hence lower injection rates into nearby storage.

Introduction

This report aims to assess the summer 2023 reliability of the SoCalGas natural gas network using a stochastic daily mass balance model. This model was developed by Energy Division Staff (Staff) and presented in Workshop #4 of Phase 2 of Order Instituting Investigation I.017-02-002 on October 15, 2020.[6] The model is based on the mass conservation law[7] and provides valuable insight into the natural gas system without being overly computationally expensive. The model has been slightly modified to perform further studies on short-term winter and summer reliability. The model has been previously used to assess winter 2022-2023 reliability and its results were published on the Aliso Canyon Well Failure webpage on December 7, 2022.[8]

In prior Reliability Assessments, Staff used a monthly mass balance combined with a summer high sendout day. The monthly mass balance was conducted to see how storage inventory filled up over the course of the summer. In that analysis, average demand and supply were assumed for every day of each month. This was coupled with a summer high sendout day analysis, which evaluated whether a peak summer 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 combines elements of 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, the model includes some days with higher or lower demand than the monthly average.[9] If needed, the model injects excess supply into storage or withdraws from storage to resolve a deficit. All days throughout the summer are modeled in this manner. The model is then repeated 100 times to create a probabilistic analysis that includes a spectrum of variations in demand. Thus, the model both evaluates the potential increase in storage inventory over the course of the summer, like the monthly mass balance, and the system's ability to meet peak day demand, like the summer high sendout day analysis.

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[6] https://www.youtube.com/watch?v=XcCK2q8quCQ

[7] 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.

[8] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/winter_reliability_2022_2023_daily_stochastic_mass_balance_model_final.pdf

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

Input Data and Assumptions

Withdrawal curves, injection curves, and initial inventory level

Previous analyses have used the same withdrawal and injection curves regardless of the calendar month. 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 March to August 2023 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.[10] For the months following August, staff assumed the same withdrawal and injection rates corresponding to August 2023. The initial inventory level of all four storage fields on May 1, 2023, was obtained from SoCalGas ENVOY.

Supply outlook and assumptions

As with previous assessments, staff requested that SoCalGas submit a list of planned infrastructure outages on its system as well as the expected reduction in system receipt capacity due to these outages for the upcoming six months. SoCalGas submitted a list of planned outages, which are mostly due to in-line inspections (ILI) of pipelines, pipeline remediation, and pipeline hydrotests. However, SoCalGas indicated that while some of these planned outages are posted on ENVOY,[11] other planned outages are still too preliminary to be scheduled and posted due to issues such as a lack of necessary construction permits or labor resource conflicts. Staff is incorporating all the outages in this assessment whether or not they are posted on ENVOY. The duration of the planned pipeline outages varies from four to 183 days, and the capacity impact varies from 130 MMcfd to 630 MMcfd. The planned outages total volumetric impact is approximately 66 billion cubic feet (Bcf) during the study period.[12] Based on the supplied data, Staff devised the following three scenarios to assess 2023 summer reliability:

1. Scenario 1: 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. The duration of the outages is rounded to full calendar months due to current modeling limitations, but this practice could also account for some of the uncertainty associated with the duration of planned outages. This scenario represents an upper bound or a best-case scenario for the summer season.
2. Scenario 2: all planned outages occur as scheduled, and their duration is rounded to full months.
3. Scenario 3: all planned outages occur as scheduled and described in Scenario 2. In addition, out-of-state disruptions limit the Northern Zone receipt capacity to only 1 billion cubic feet

[10] Closed-form integration was performed on the linearly regressed storage curves to obtain accurate inventory volumes
[11] March supply outlook can be found in the Pipeline/Station Maintenance Schedule on ENVOY: https://www.socalgas-envoy.com/ebb/attachments/1686238400783_SYSIMPT.pdf
[12] This number is obtained by multiplying the duration of each outage by its impact, then summing the volumes.

per day (Bcfd) during the entire study period. Scenario 3 represents a lower bound or a worst-case scenario.

Scenarios 1 to 3 offer very similar average daily supplies over the study period (3,096 MMcfd, 2,979 MMcfd, and 2,830 MMcfd[13]) with a 266 MMcfd average difference between the highest and lowest monthly average (Scenario 1 vs Scenario 3). All three scenarios assume no supplies from Otay Mesa, which is in the Southern Zone. In other words, the capacity reduction resulting from the planned outages occurring in the Southern Zone is subtracted from the El Paso-Ehrenberg/North Baja-Blythe subzone. Depending on outages, the Southern Zone supplies vary from 900 to 1210 MMcfd, while the Northern Zone supplies vary from 870 to 1,250 MMcfd. Supplies from Wheeler Ridge are assumed to be 765 MMcfd, and California Production is 60 MMcfd.

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.[14] 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 two columns of the table list the average daily demand by month forecasted by the 2022 California Gas Report (CGR) for two weather scenarios: average temperature with base hydro and cold temperature with dry hydro. For all three scenarios, the total available supplies (576 Bcf, 557 Bcf, and 525 Bcf) are higher than the forecasted demand for a cold and dry hydro year (398 Bcf) over the study period.

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

	System Receipt Capacity[15] (MMcfd) for Scenario			**2023 Average Daily Demand [16] (MMcfd) for**	
	1	**2**	**3**	**Cold Temp Dry Hydro**	**Average Temp Base Hydro**
Month					
May	3,065	3,065	2,815	2,182	2,146
June	3,065	2,855	2,815	2,119	2,105
July	3,095	2,840	2,840	2,133	2,125
August	3,285	3,155	2,905	2,204	2,179
September	3,285	3,285	3,035	2,203	2,189
October	2,975	2,975	2,725	2,147	2,122
Average Daily	**3,128**	**3,029**	**2,856**	**2,165**	**2,144**
	Total Available Supplies			**Total Forecasted Demand**	
May-October (Bcf)	**576**	**557**	**525**	**398**	**394**

[13] The average is weighted by the number of days in the calendar months.

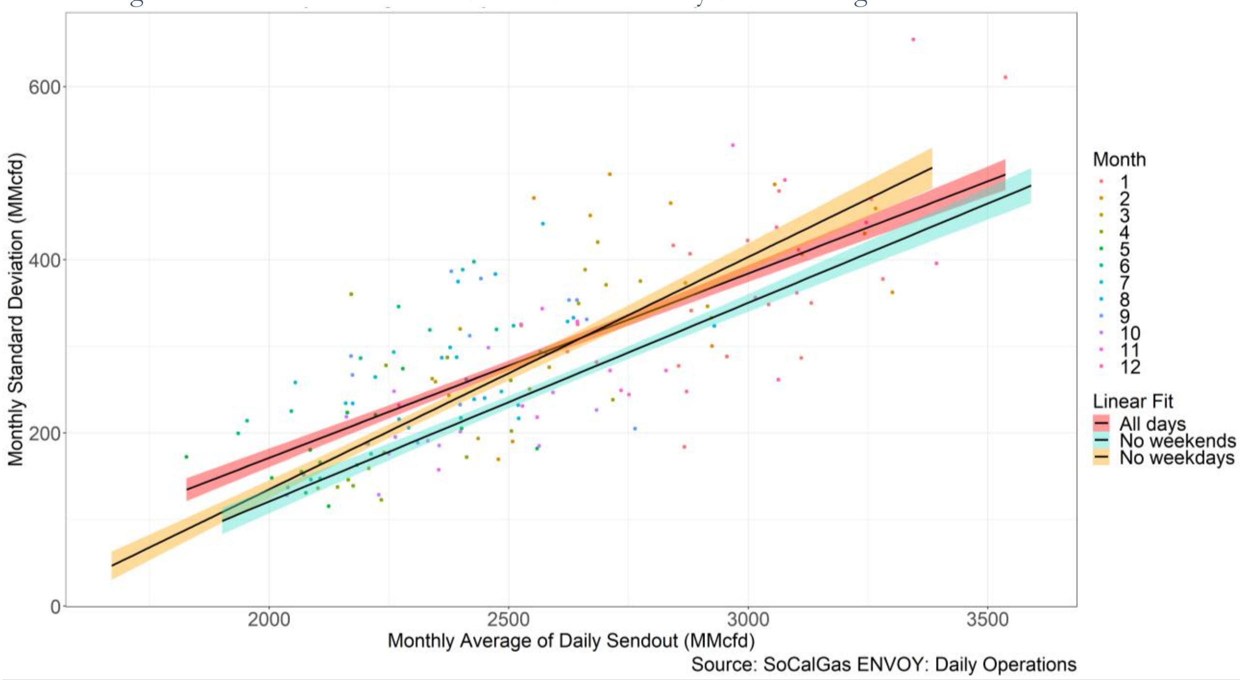
[14] Daily supply multiplied by the number of days in a month, summed over the seven-month period divided by one thousand.

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 indicating no seasonal or average need for withdrawals from underground storage in order to preserve reliability, but rather an injection season as usual.

Demand variability

To obtain the Gamma distributions used for the daily random draws,[15] three distributions per calendar month corresponding to three standard deviations (SD) were derived from historical data. 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 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. Higher standard deviation is typically associated with higher mean daily volume as shown in Figure 1.

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



To derive the linear regression model between the monthly average of the daily sendout and the monthly standard deviation of the daily sendout, historical data of daily sendout was used. In previous assessments, the historical data ranged from January 2010 to October 2018. For this assessment, the historical data range was extended to April 2023. The inclusion of additional data in the regression model did not result in a better correlation between the two variables but resulted in a

[15] 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.

negligible decrease in the standard deviation.[16] 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.

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.[17] Hence, it was used to perform multiple feasibility assessments. For the 2023 summer 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[18] of the daily demand for the period from May 1, 2023, to October 31, 2023 for a cold and dry hydro year, and an average year with base hydro. For example, for a cold and dry year, there are 11 and 28.1 days of demand higher than 2.5 billion cubic feet per day (Bcfd) but lower than 3.0 Bcfd using the normal and high standard deviation respectively. Similarly, there are no days with demand higher than 3.0 Bcfd but lower than 3.5 Bcfd using the low and normal standard deviation, but 2.61 days using the high standard deviation for a cold and dry hydro year.

In comparison, the 2022 CGR predicts a summer high sendout of 2,513 MMcfd in September 2023 under 1-in-10-year dry hydro conditions. In contrast, the 2020 CGR predicted a summer high sendout of 3,217 MMcfd for September 2023 under 1-in-10-year dry hydro conditions, which is about 28 percent higher than that forecasted by the newer forecasts in the 2022 CGR. Noteworthy is that in summer of 2022, SoCalGas experienced 21 days where the demand was higher than the summer high demand predicted by the 2022 CGR.[19] 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.

Given the uncertainty in the CGR 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,

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[16] 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.

[17] 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).

[18] 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.

[19] 2 days in July, 9 days in August, and 10 days in September

which would generate, on average, 27 days of demand higher than 2,513 MMcfd during the study period. The results of the model are discussed in the next section.

Table 2: Demand distribution for May-October for low, normal, and high standard deviation (variability) of a summer 2023 cold and dry hydro forecast

	Expected Number of Days		
	Low SD	**Normal SD**	**High SD**
Demand Range (Bcfd)			
Higher than 3.5	0	0	0.11
3.0 to 3.5	0	0.03	2.61
2.5 to 3.0	Negligible	11.0	28.1
2.0 to 2.5	183	133	91.7
Lower than 2.0	1.03	183	61.5
Total	**184**	**184**	**184**
September days above 2,513 MMcfd	**0**	**2.33**	**5.66**
Total days above 2,513 MMcfd	**Negligible**	**9.58**	**28.61**

Table 3: Demand distribution for May-October for low, normal, and high standard deviation (variability) of an average summer 2023 with base hydro

	Expected Number of Days		
	Low SD	**Normal SD**	**High SD**
Demand Range (Bcfd)			
Higher than 3.5	0	Negligible	0.08
3.0 to 3.5	0	0.02	2.11
2.5 to 3.0	Negligible	8.59	25.7
2.0 to 2.5	182	130	90.7
Lower than 2.0	1.57	45.1	65.5
Total	**184**	**184**	**184**
September days above 2,513 MMcfd	**0**	**2.0256**	**5.3802**
Total days above 2,513 MMcfd	**0**	**7.54**	**25.9**

Stochastic Daily Mass Balance Results

The main advantage of the stochastic daily mass balance model compared to a monthly mass balance is that it creates daily data such as the daily imbalance volume. Other metrics have been derived such as the number of imbalance days, which may lead to Emergency Flow Orders, 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. Aside from the daily inventory tracking, further analysis of the daily data (e.g., distributions or outliers) is usually not needed unless peculiar results warrant doing so. In other words, aside from daily inventory tracking, reporting averaged results of the different metrics is sufficient. In the following subsections, the results of the different metrics and inventory tracking are presented for all four scenarios.

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 repetitions[20] 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 scenarios, the model predicts no imbalance days, 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 summer season, with up to 44 days of demand above 2,513 MMcfd.

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 repetitions of the study period. EUV can be reported as a total or disaggregated by month. EUV is effectively zero for all three scenarios since the number of EFOs is zero. In other words, no curtailments are expected this summer as long as the model's assumptions hold.

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 repetitions of study period. Similar to the previous metrics, EUS can be reported as a total or can be disaggregated by month. Table 4 shows EUS for Scenarios 1-3. The high EUS during the study period indicates that additional supplies at California borders will not result in faster filling of underground storage due to injection limitations and near full underground storages by mid-summer. These supplies are not needed to meet the forecasted daily demand either. Therefore, a high EUS could also be interpreted as a margin available at the borders to meet a demand that is higher than forecasted.

Comparing EUS across different scenarios for the same month is also beneficial. For example, in August, Scenario 1 has 31.5 Bcf of additional supplies compared to 19.3 Bcf for Scenario 3, while the daily supplies in August for Scenario 1 are 3,285 MMcfd compared to 2,905 MMcfd for Scenario 3. This shows that the additional supplies in Scenario 1 did not result in any additional injections (it will be shown later that the four storage fields are forecast to be full by August) compared to

[20] 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.

Scenario 3.[21] A high EUS could also indicate that some additional planned outages could be scheduled without diminishing the system's ability to fill the underground storage or meet the forecasted daily demand. For example, September in Scenario 2 could sustain another planned outage with an impact of about 1,073 MMcfd (32.2*1,000/30).[22]

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

		Scenario		
		1	**2**	**3**
Month	**May**	5.03	5.06	1.69
	June	10.3	4.65	2.59
	July	25.8	17.7	14.7
	August	31.5	27.3	19.3
	September	31.7	32.2	24.4
	October	25.2	25.7	17.7
	November	10.6	4.69	4.94
	May-October Total	**129.53**	**112.61**	**80.38**

Table 5: Actual Receipts and Receipt Point Utilization for Scenarios 1-3

		Actual Receipts for Scenario (MMcfd)			RPU for Scenario (Percent)		
		1	**2**	**3**	**1**	**2**	**3**
Month	**May**	2,903	2,902	2,760	95	95	98
	June	2,722	2,700	2,729	89	95	97
	July	2,263	2,269	2,366	73	80	83
	August	2,269	2,274	2,282	69	72	79
	September	2,228	2,212	2,222	68	67	73
	October	2,162	2,146	2,154	73	72	79
	November	2,552	2,519	2,510	88	94	94
	May-October Average	**2424**	**2,417**	**2,419**	**78**	**80**	**85**

The EUS can also be used to obtain a calculated actual monthly receipts as opposed to the assumed monthly receipt capacity that was shown in Table 1. The actual receipts are calculated by subtracting the EUS spread over a full month[23] from the assumed receipt capacity for each month. Furthermore, the Receipt Point Utilization (RPU) can be calculated as shown in Table 5. The RPU is calculated by

[21] The additional supplies (3,285-2,905=380 MMcfd) multiplied by the number of days in August (31) is 11.8 Bcf, which is approximately the EUS difference between scenario 1 and scenarios 3 in August.
[22] The more conservative approach would be to run the model with this outage included. However, this estimate is obtained without tapping into withdrawals from underground storage, so it is already conservative.
[23] By simply dividing the EUS by the number of days in the month

dividing the calculated actual receipts by the assumed receipt capacity shown in Table 1. Based on Table 5, One may also conclude that the inventory levels would reach their maximum allowed capacity by the end of October as long as the RPU is within 78-85 percent on average during the May-October period.

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.[24] 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, and Figure 4 show the inventory tracking plots for Scenarios 1 to 3, while Table 6, Table 7, and Table 8 show the month-end inventories of Scenarios 1 to 3. As summarized in Table 1, Scenarios 1, 2, and 3 have total available supplies of 576 Bcf, 557 Bcf, and 525 Bcf compared to a forecasted demand of 475 Bcf over the study period for a cold and dry year. Scenario 1 represents the best-case scenario, Scenario 2 the likely scenario, and Scenario 3 the worst-case scenario. For all three scenarios, the total available supplies are higher than the total demand. 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.

Figure 2, Figure 3, and Figure 4 show that all storage fields are filled to their maximum allowed inventory no later than by the end of August for all three scenarios. Based on the model results, withdrawals occur rarely in the June-October period with an average of 1.59, 2.47, and 5.12 days of withdrawals for Scenarios 1, 2, and 3. Withdrawals are not high enough to be noticeable on the inventory plots. The total expected withdrawal volume during the June-October period does not exceed one Bcf.[25] However, one must note that modeled withdrawals are based on *daily* demand. Actual withdrawals are often caused by hourly demand and ramping needs, which varies significantly throughout the day. Therefore, actual withdrawals are likely to happen more frequently than indicated by the model.

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[24] 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.

[25] 167 MMcf, 421 MMcf, and 887 MMcf for Scenarios 1, 2, and 3

Figure 2: Inventory tracking for Scenario 1

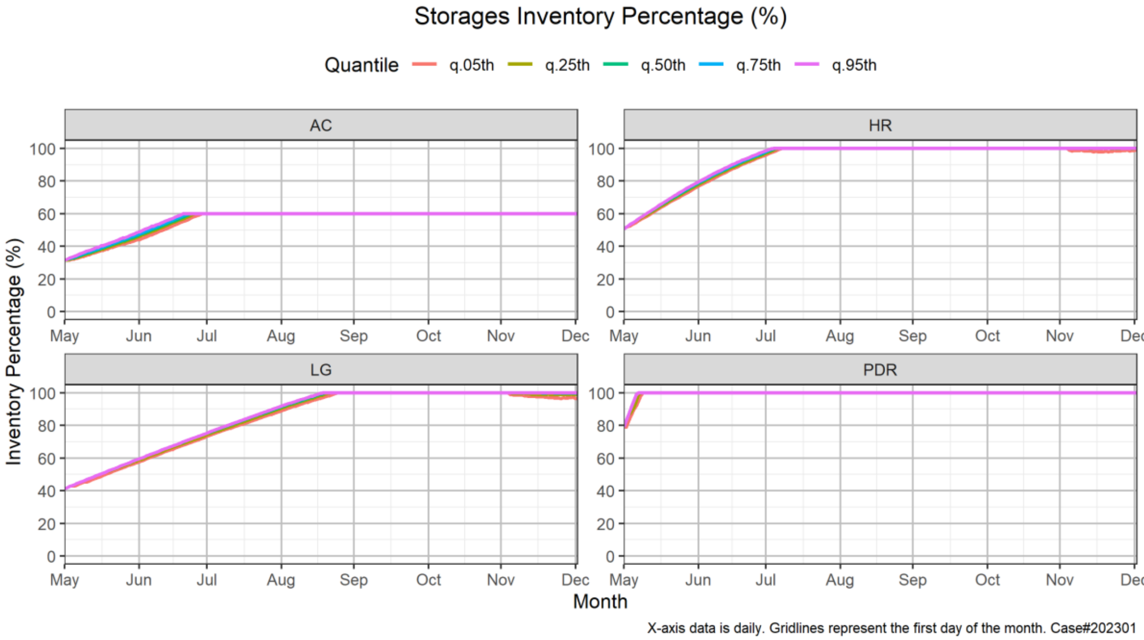
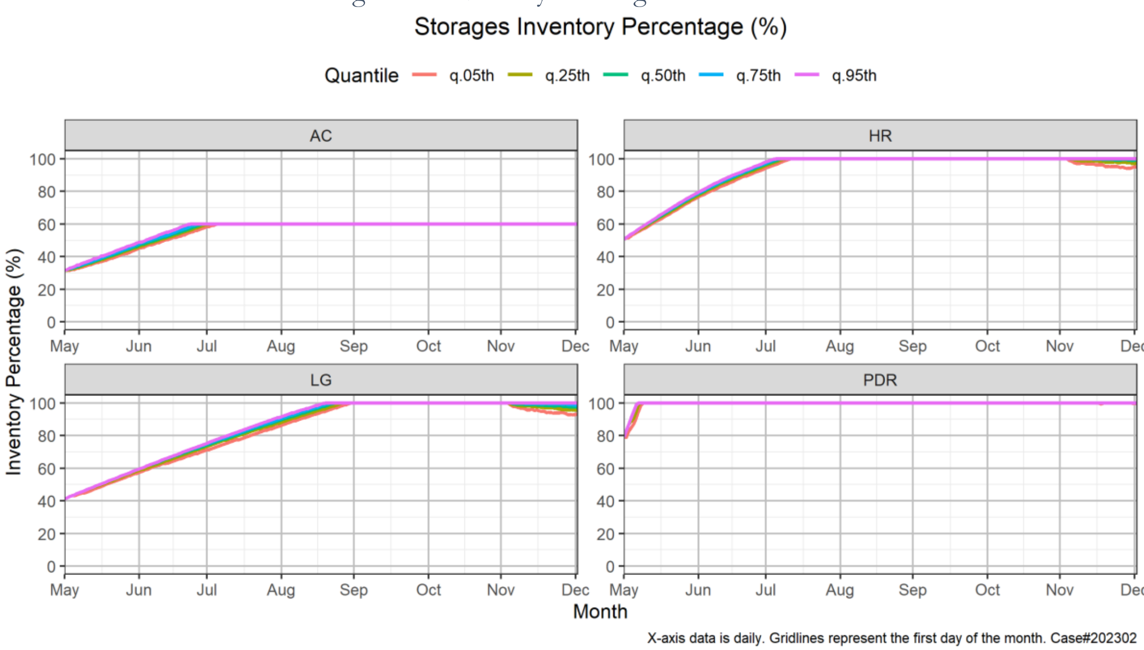
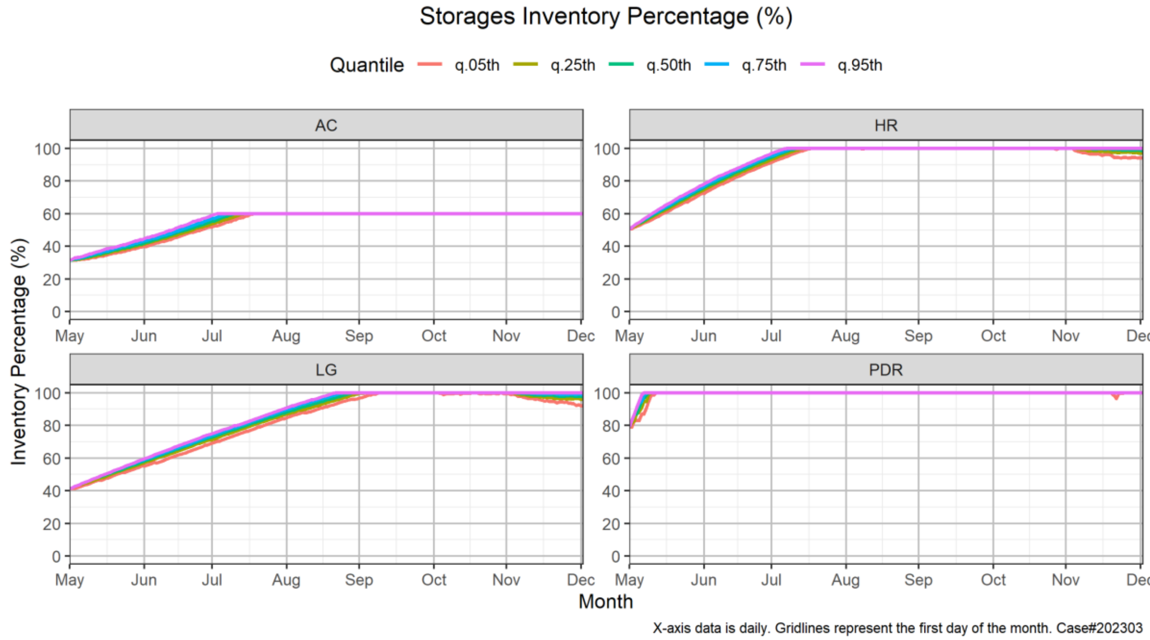


Figure 3: Inventory tracking for Scenario 2



Noteworthy is that the total withdrawn volume increases as total supplies decrease despite the total supplies being higher than the total demand, even though the total withdrawn volume is smaller than one bcf. In other words, the withdrawals in Scenario 3 are higher than the withdrawals in Scenario 2, which are higher than the withdrawals in Scenario 1. This, again, highlights the model's strength in predicting withdrawals despite average supplies being higher than average demand during each month in the study period even during the summer months.

Figure 4: Inventory tracking for Scenario 3



One of the advantages of the daily mass balance model is not only predicting withdrawals during months when the average supplies are lower than the average demand, but also predicting them during some months when the average supplies are higher than the average demand. This was very evident in the previous assessment of winter 2022-2023 and continues to be true in this assessment of summer 2023 as described above. Withdrawals are occurring in summer 2023 but only rarely and only to preserve reliability. Of note, is that no withdrawals were needed from Aliso Canyon, and no more than two storage fields were needed to meet a supply deficit on any day. While the model shows that those two storage fields are La Goleta and Honor Rancho, because of the withdrawal sequence that is already prescribed in the model, historical data would likely show that those two storage fields are Honor Rancho and Playa del Rey owing to their proximity to the basin, electric generators, and load centers.

The results obtained by the daily stochastic mass balance model do not contradict previous results obtained from 24-hour transient modeling in Synergi Gas. In particular, during the Aliso Canyon Investigation OII 17-02-002, a summer 2030 simulation with a demand of 2,675 MMcfd and pipeline supply of 2,222 MMcfd used only two storage fields (La Goleta and Play del Rey) to meet the supply deficit.

It is worth noting that neither the industry-standard 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 pipeline 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.

Table 6: Month-end inventory for Scenario 1 (median)

	Month						
	5	6	7	8	9	10	11
Aliso Canyon	31.9	41.16	41.16	41.16	41.16	41.16	41.16
Honor Rancho	21.04	26.23	27.00	27.00	27.00	27.00	27.00
La Goleta	12.71	16.08	19.56	21.5	21.5	21.5	21.45
Playa del Rey	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Total	67.5	85.4	89.6	91.6	91.6	91.6	91.5

Table 7: Month-end inventory for Scenario 2 (median)

	Month						
	5	6	7	8	9	10	11
Aliso Canyon	31.92	41.16	41.16	41.16	41.16	41.16	41.16
Honor Rancho	21.03	25.99	27.00	27.00	27.00	27.00	26.73
La Goleta	12.71	15.84	19.21	21.50	21.50	21.50	20.95
Playa del Rey	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Total	67.5	84.9	89.3	91.6	91.6	91.6	90.7

Table 8: Month-end inventory for Scenario 3 (median)

	Month						
	5	6	7	8	9	10	11
Aliso Canyon	28.86	37.63	41.16	41.16	41.16	41.16	41.16
Honor Rancho	20.32	25.41	27.00	27.00	27.00	27.00	26.75
La Goleta	12.41	15.59	18.89	21.50	21.50	21.50	21.01
Playa del Rey	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Total	63.3	80.5	89.0	91.6	91.6	91.6	90.8

In summary, inventory tracking shows relatively high inventory levels by the end of August and throughout September and October, with few withdrawals and no imbalance days or curtailments. The inventory levels heading into winter 2023-2024 are forecast to be high and supportive of a reliable winter 2023-2024. Noteworthy is that as of mid-August, Aliso Canyon is near full, while La Goleta and Honor Rancho are still at 53.7 percent and 78.5 percent respectively. This is likely caused by other inputs not captured by the model such as low and high inventory shut-ins, local transmission restrictions, and customers decisions.

Additional Sensitivities

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 truly 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 assessment, and to further investigate the effect of this assumption on the model, Staff ran two additional sensitivities on Scenario 3. In the first sensitivity, the utilization factor of La Goleta was set to 50 percent. In other words, only half the forecasted in-service wells are made available during the study period.[26] In the second 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.

In the first sensitivity, only three fields are full by the end of October, while La Goleta is only at 86 percent. Obviously, decreasing the injection capacity of La Goleta resulted in "slower" filling of the field despite being first in the injection priority. This sensitivity, however, did not result in an increased number of imbalance days or degradation of reliability.

In the second sensitivity, Aliso Canyon is full by mid-July similar to the baseline scenario, Scenario 3. Playa del Rey is not greatly affected because it is already at 79 percent at the beginning of study period (May 1). In addition, Honor Rancho reaches its full capacity approximately two weeks later compared to Scenario 3, while La Goleta is delayed by four weeks and reaches 100 percent by the end of September. Furthermore, the number of EFOs remain unchanged at zero. Table 9 summarizes the inventory levels by the end of October for Scenario 3 and both sensitivities.

Table 9: End-of-October inventory level for Scenario 3 and sensitivities

	AC	**HR**	**LG**	**PDR**	**Total**	**EFO**
	Bcf	Bcf	Bcf	Bcf	Bcf	#/day
Scenario 3	41.16	27.00	21.5	1.9	91.6	0
Sensitivity 1	41.16	27.00	18.5	1.9	88.5	0
Sensitivity 2	41.16	27.00	21.5	1.9	91.6	0

[26] This is done in the model by multiplying the injection and withdrawal rates by 50 percent at a given inventory level. This is a simple approximation as opposed to actually having half the wells out-of-service, since not all wells have the same rates.

Comparison with ENVOY actuals

To further validate the model and understand SoCalGas daily and storage operations, Staff compared the model's results with actual data obtained from ENVOY for the month of May 2023, which is one month into the simulation. The comparison is summarized in Table 10.

Table 10: Comparison between ENVOY and Model Scenario 3

		ENVOY	**Model**
1	Total Inventory Level on May 1 (Bcf)	45.7	45.7
2	Total Inventory Level on May 31 (Bcf)	52.3	63.3
3	**Total Volume Injected (Bcf)**	**6.6**	**17.6**
4	Average Sendout in May (MMcfd)	1,965.3	2,182.0
5	Average Receipts in May (MMcfd)	2,204.1	2,760.0[27]
6	**Difference between Sendout and Receipts in May (Bcf)**	**7.4**	**19.6**
7	Average Available Gross Capacity (MMcfd)[28]	2,797.7	2,755.0
8	**Difference between Sendout and Gross Capacity in May (Bcf)**	**18.4**	**19.6**
9	Average Receipt Point Utilization (Percent)[28] (Receipts/Capacity)	78.8	100.0

Table 10 shows that the net injections predicted by the daily model are much higher than the actual net injections during May as reported on ENVOY. Specifically, the model predicts 17.6 Bcf of net injections compared to 6.6 Bcf of actual net injections into SoCalGas storage. There are many factors that are contributing to this discrepancy, some of which are discussed below.

The most obvious reason for the discrepancy is the Aliso Canyon shut-in that occurred during May, which lasted from May 10 to May 31 and resulted in a capacity reduction of 425-445 MMcfd as per ENVOY maintenance schedules. Shut-ins are not incorporated explicitly into the model and were sometimes accounted for by reducing the utilization factor of the storage fields (the utilization factor would be 46/52 to account for six weeks of shut-ins, i.e., about 88 percent). The Aliso Canyon shut-in would explain about 9.35 Bcf of the difference between the model and the actual storage operations. In addition to the Aliso Canyon planned shut-in, ENVOY maintenance schedules show multiple unplanned outages in La Goleta that resulted in capacity reductions varying between 15-30 MMcfd due to compressor repair. In comparison, Scenarios 1 to 3 of the model incorporate only planned outages. Furthermore, the injection capacity of Honor Rancho reported by SoCalGas in its biweekly reliability reports is lower than what is used in the model.[29]

Another factor that could contribute to the discrepancy is the actual Receipt Point Utilization (RPU) in May. Table 10 shows that the total RPU is 78.8 percent excluding California Production. One may

[27] Note that these are the actual receipts (2,760 MMcfd), not the assumed receipts (2,815 MMcfd). The difference stems from injection limits computed by the model.
[28] Excluding California Production
[29] Staff will request clarification from SoCalGas, but this is likely due to ongoing compressor repair and mechanical limitations in Honor Rancho (Event ID. 6128 and 6255 on Maintenance Schedules page on ENVOY), which were not incorporated into the injection curves submitted.

attribute the low RPU to the restrictions imposed on the Southern Zone. However, the RPU of all zones is low. Specifically, the Wheeler Ridge Zone had an average RPU of 68 percent, the Northern Zone RPU was 76 percent, compared to 84 percent for the Southern Zone. The lower RPU may be attributable to the high number of High Operational Flow Orders (OFO) on the SoCalGas system this summer.[30] The System Operator calls High OFOs to avoid over-pressurization of the pipelines when more gas is scheduled onto the system than can be managed with pipeline deliveries and storage injections. High OFOs result in penalties to customers who schedule more gas than they use or inject outside a tolerance band. Frequent High OFOs require gas customers to be conservative in their gas purchases and scheduling to avoid penalties.

At this point it is not possible to ascertain whether the entire discrepancy is due to customers scheduling less than maximum possible gas on the receipt points or due to injection limitations that are not captured by the model, whether these limitations are due to unplanned outages, shut-ins, or local transmission bottlenecks. As noted above, High OFOs, which can be caused by injection limitations and result in customers scheduling less gas onto the system, are another likely factor. While one may expect faster filling for Honor Rancho while Aliso Canyon is undergoing its shut-in, the low injection rates at Honor Rancho combined with increased High OFOs while Aliso Canyon is offline might not allow this. It is likely that the discrepancy seen in May is due to a combination of both factors; low RPU and low injection availability on the system exacerbated by High OFOs driven by the need to avoid over pressurization events.

In future assessments, Staff will consider running the baseline scenarios using a lower utilization factor of the storage fields (wells availability) to account for unplanned wells outages. Including a model for OFO could also be beneficial though would require further assumptions regarding demand and penalties elasticity. In fact, this approach was previously adopted in the feasibility assessment of Aliso Canyon. Furthermore, Staff has previously considered incorporating the exact dates of the shut-ins. However, this could be disadvantageous when imbalance days occur during the shut-ins. In discussions with SoCalGas, it was indicated that a shut-in may be cancelled in case of critical emergencies. Therefore, incorporating the shut-ins may offer more accurate tracking of the inventory but may yield lower reliability metrics.

Summary

The stochastic daily mass balance model was used to assess the reliability of SoCalGas natural gas network in Southern California for the upcoming summer of 2023. Three scenarios have been devised with varying preliminary and non-preliminary planned outages, which were submitted by SoCalGas. 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.[31] With the current

[30] In May, High OFOs were called on 24 days as per ENVOY High OFO Event History. In June, High OFOs were called on every day. In July, High OFOs were called on the first 15 days.

[31] 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

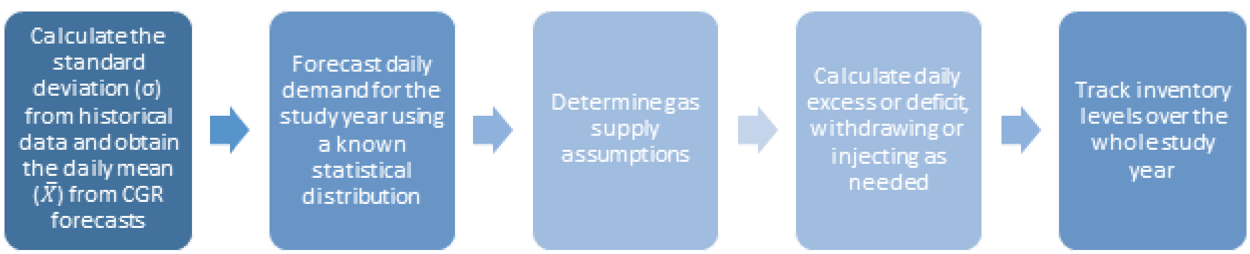
natural gas assets and withdrawal protocols in place and the maximum inventory limit of 41.16 Bcf set on Aliso Canyon, the model predicts no curtailments or emergency flow orders in the summer of 2023. Thus, the assessment predicts the system will be reliable during the upcoming summer.

Two additional sensitives have been simulated, which decrease the withdrawals and injection availability of all underground storage fields by 20 percent and La Goleta by 50 percent in order to address unplanned underground storage outages and the remoteness of La Goleta from the Los Angeles basin. Both sensitivities show no degradation in reliability since the number of imbalance days remain zero during the entire study period. Even with 20 percent of wells out-of-service, the SoCalGas natural gas network should be able to meet customers' demand every day during the 2023 summer, with up to 44 days with demand above 2,513 MMcfd. The SoCalGas natural gas network should be able to meet the forecasted summer high sendout days forecasted by both CGR 2020 and 2022.

Aliso Canyon. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf.

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 and industry-standard 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[32] 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[33] 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

[32] 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.
[33] 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,[34] 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,[35] 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 repetitions of a study period are enough to produce statistically convergent results. However, Staff continued to use 100 repetitions in this report.

[34] The injection sequence is currently set to La Goleta > Honor Rancho > Playa Del Rey > Aliso Canyon
[35] 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.[36]

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