Winter 2022-2023 Southern California Gas Reliability Assessment

BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION
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Executive Summary

The winter 2022-23[1] reliability outlook for the Southern California Gas (SoCalGas) system is favorable, with expected pipeline capacity stable, and natural gas storage field inventory 97 percent full.[2] While November is projected to be colder than normal, the winter overall is expected to be warm and dry.[3] This creates mixed signals for gas demand as warm winter temperatures typically lead to lower gas usage, while dry weather can decrease hydroelectric power generation and increase gas used for electric generation. Outside California, national and international natural gas prices are high and volatile, due in part to the war in Ukraine.[4] Also complicating the picture is the ongoing outage on an El Paso interstate pipeline serving SoCalGas' Southern Zone, which includes Riverside, Imperial, and San Diego counties. The pipeline, which ruptured on August 15, 2021, still has no return-to-service date.[5] While there is sufficient pipeline capacity to fully serve the Southern Zone, competition from upstream customers in Arizona and New Mexico for reduced gas flows may decrease supplies to Southern California on cold days.

To estimate winter risk, California Public Utilities Commission (CPUC) staff (Staff) modeled supply and demand under three main pipeline scenarios and two sensitivities using a new method that was developed during the Alison Canyon Investigation (I.) 17-02-002. In prior Reliability Assessments, Staff used a monthly mass balance combined with a 1-in-10 peak day analysis. 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 combines elements of both 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.[6] If needed, the model injects excess supply into storage or withdraws from storage to resolve a deficit. The model is then repeated 100 times to create a probabilistic analysis that includes a larger spectrum of variations in demand. Thus, the model both evaluates the potential for declines in storage inventory over the

[1] The gas winter is from November through March.
[2] SoCalGas Envoy, Nov. 7, 2022: https://www.socalgasenvoy.com/index.html.
[3] National Oceanic and Atmospheric Administration, "U.S. Winter Outlook: Warmer, drier South with ongoing La Niña": U.S. Winter Outlook: Warmer, drier South with ongoing La Nina | National Oceanic and Atmospheric Administration (noaa.gov).
[4] Forbes, "U.S. Natural Gas Production Sets a New Record, But Don't Expect Relief on Your Heating Bills, Sept. 25, 2022: https://www.forbes.com/sites/rrapier/2022/09/25/us-natural-gas-production-sets-a-new-record-but-dont-expect-relief-on-your-heating-bills/?sh=6b7c470515f4.
[5] Kinder Morgan, El Paso Natural Gas Pipeline Winter Preparedness, Oct. 26, 2022: https://pipeline2.kindermorgan.com/Documents/EPNG/EPNG_Winter_Prep_2022_Final-20221026113827.pdf.
[6] Less than half the days of the month will be higher than average due to the right skewness of the Gamma Distribution.

course of the winter, like the monthly mass balance, and the system's ability to meet peak day demand, like the 1-in 10 peak day analysis.

Two factors that the model does not capture could cause the winter'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 from the El Paso outage, would not be captured.

Staff modeled three main scenarios based on variations on preliminary and non-preliminary planned outages submitted to the CPUC by SoCalGas. The average daily pipeline capacity varies from 2,812 million cubic feet per day (MMcfd) for the worst-case scenario to 3,040 MMcfd for the best-case scenario. All three scenarios assume high demand variability; no supplies from Otay Mesa, a gas receipt point on the Mexican border; and no restrictions on underground gas storage fields.[7] With the current natural gas assets and withdrawal protocols in place, and sufficient interstate gas supplies, the model predicts no curtailments or emergency flow orders in the winter of 2022-2023. The SoCalGas pipeline network should be able to meet cold winter demand as well as the 1-in-10 peak demand, which is forecasted to be 4,672 MMcfd by the 2022 California Gas Report.

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. Both sensitivities show little degradation in reliability highlighted by a slight increase in the number of emergency flow orders during the study period.

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[7] 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.

Introduction

This report aims to assess the winter 2022-2023 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.[8] The model was originally developed to perform a feasibility assessment for the year 2020. The goal of the feasibility assessment for year 2020 was to validate the minimum, or feasible, inventory levels of the non-Aliso storage fields throughout a cold 2020 winter as well as the minimum required level at Aliso Canyon to maintain reliability during a 1-in-10 peak day within a cold and dry year. The model is based on the mass conservation law[9] and provides valuable insight into the natural gas system without being overly computationally expensive. The model, along with other information entered into the record, was relied on for decision D.21-11-008,[10] which established the interim allowed inventory of Aliso Canyon at 60 percent.[11] The model has been slightly modified to perform further studies on short-term winter and summer reliability.

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[12] 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

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

9 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 original 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.

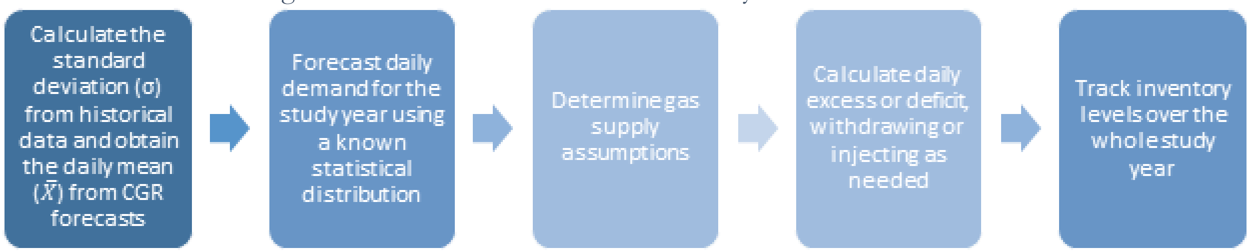
10 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF

11 The California Geologic Energy Management Division (CalGEM) determined that the maximum safe inventory at Aliso Canyon inventory is 68.6 Bcf. The CPUC currently allows a maximum inventory of 41.16, which is 60 percent of the CalGEM-approved maximum.

12 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.

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 1 below.

Figure 1: Illustration of the Stochastic Daily Mass Balance Model



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[13] 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 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,[14] 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

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[13] 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.

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

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,[15] 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.

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.[16]

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

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

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

for the period from September to March for the non-Aliso fields and from September to April for Aliso Canyon. 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] The initial inventory level of all four storage fields on October 3, 2022 was obtained from SoCalGas ENVOY

Supply outlook and assumptions

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 replacement, and pipeline hydrotests. However, SoCalGas indicated that while some of these planned outages are posted on ENVOY,[18] 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 planned pipeline outages varied from five to 213 days and reduced the system receipt capacity by 0-630 MMcfd. Based on the supplied data, Staff devised the following three scenarios to assess 2022-2023 winter reliability:

1. Scenario 1: all outages planned for the winter are cancelled, and the system receipt capacity remains as reported on October 3, 2022, for the remainder of the winter season. Hence the capacity from October to February is constant at 3,255 MMcfd inclusive of 60 MMcfd of California production. Planned outages resume in March and April resulting in a reduced capacity of 2,615 MMcfd and 2,395 MMcfd respectively. This scenario represents an upper bound or a best-case scenario for the winter season to account for rounding errors introduced in Scenario 2 that may over-estimate the duration of outages.
2. Scenario 2: planned outages occur as scheduled. However, their duration is rounded to full calendar months. For example, if a planned outage is expected to start at the end of October and end by the end of December, it is assumed that this outage will last for the entire months of November and December. The outage's duration is rounded to full calendar months due to current modeling limitations but could also account for some of the uncertainty associated with the duration of planned outages.
3. Scenario 3: planned outages occur as scheduled and described in Scenario 2. However, the Southern zone loses an additional 20 percent of its capacity during December-February due to adverse findings from the Line 2000 or Line 2001 hydrotest. Scenario 3 may be interpreted as the worst-case scenario.

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17 Closed-form integration was performed on the linearly regressed storage curves to obtain accurate inventory volumes

18 March supply outlook can be found here: https://www.socalgas-envoy.com/ebb/attachments/1648670020879_Maintenance_Outlook_March_2022.pdf

Scenarios 1 to 3 offer very similar average daily supplies over the study period (3,040 MMcfd, 2,913 MMcfd, and 2,812 MMcfd[19]) with a 228 MMcfd average difference between the highest and lowest average (Scenario 1 vs Scenario 3). All three scenarios assume no supplies from Otay Mesa so supplies are limited to 1,180 MMcfd in the Southern Zone (Ehrenberg) when no outages are planned. Depending on outages, the Northern Zone supplies vary from 870 to 1,250 MMcfd. With the exception of October, supplies from Wheeler Ridge are assumed to be 765 MMcfd and California Production is 60 MMcfd.

Since Scenario 2 does not exactly replicate the planned outage dates but rather rounds them to the end of the month, should the planned outages occur exactly as planned, the resulting capacity would be higher than Scenario 2. Therefore, if Scenario 2 succeeds, one can conclude that the natural gas system is reliable under Scenario 2 assumptions. Otherwise, further analysis may be needed depending on the results of the other scenarios.

Supply is also impacted by pipeline conditions outside California. For example, an August 15, 2021, explosion on an El Paso pipeline in Coolidge, Arizona led to an ongoing reduction in the amount of gas flowing west from Texas towards California. While there is still enough pipeline capacity to fully serve Southern California, California gas customers must compete for the reduced gas supply with consumers in upstream states such as Arizona and New Mexico.[20]

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.[21] 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 show the average daily demand by month forecasted by the 2022 California Gas Report for two weather scenarios: average temperature with base hydro and cold temperature with dry hydro. For all three scenarios, the total available supplies (644 Bcf, 617 Bcf, and 596 Bcf) are higher than the forecasted demand for a cold and dry hydro year (581 Bcf) over the study period. However, for several months, the average daily system receipt capacity is lower than the average daily demand of the cold temperature, dry-hydro demand scenario forecast (e.g., Dec-Jan of Scenario 2) indicating dependency on underground storage.

[19] The average is weighted by the number of days in the calendar months.
[20] CPUC Staff, Winter 2021-22 Southern California Reliability Assessment: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/winter2021-22-reliabilityassessment.pdf.
[21] Daily supply multiplied by the number of days in a month, summed over the seven-month period divided by one thousand.

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

	System Receipt Capacity[22] (MMcfd) for Scenario			2022-2023 Average Daily Demand[23] (MMcfd) for	
	1	**2**	**3**	**Cold Temp Dry Hydro**	**Average Temp Base Hydro**
Month					
October, 2022	3,255	2,860	2,860	2,172	2,151
November, 2022	3,255	2,945	2,945	2,580	2,491
December, 2022	3,255	3,195	2,959	3,208	3,014
January, 2023	3,255	3,195	2,959	3,081	2,905
February, 2023	3,255	3,195	2,959	3,022	2,856
March, 2023	2,615	2,615	2,615	2,656	2,540
April, 2023	2,395	2,395	2,395	2,462	2,386
Average Daily	3,040	2,913	2,812	2,738	2,619
	Total Available Supplies			**Total Forecasted Demand**	
October-April (Bcf)	644	617	596	581	555

Demand variability

To obtain the distributions used for the daily random draws,[24] 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 2.

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.[25] Hence, it was used to

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22 Includes 60 MMcfd of California Production

23 2022 California Gas Report REDACTED workpapers, Page 10, 11, 24, and 25 Line 28

24 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.

25 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 HDD and a 1-in-35 will have 1,476 (CGR 2022).

perform multiple feasibility assessments. For the 2022-2023 winter reliability assessment, the high standard deviation of a cold temperature and dry hydro year is also used as described below.

Figure 2: Historical standard deviation vs. mean daily volume using 2010-2017 sendout data

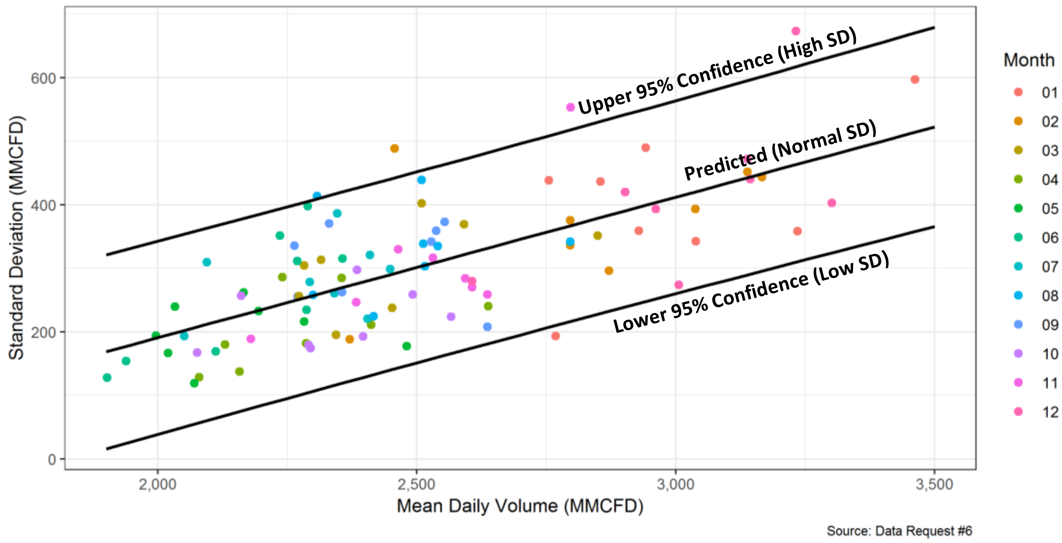

Table 2 and Table 3 summarize the Gamma distributions of the daily demand for the entire study period (from October 1, 2022, to April 30, 2023) for a cold and dry year, and an average year with base hydro. For example, for a cold and dry year, there are 0.27, 2.58, and 6.24 days of demand higher than 4 billion cubic feet per day (Bcfd) but lower than 4.67 Bcfd using the low, normal, and high standard deviation respectively. Similarly, there are 8.25 days with demand higher than 3.5 Bcfd but lower than 4 Bcfd using the low standard deviation, but 17.71 days using the high standard deviation for a cold and dry hydro year.

In comparison, the 2022 California Gas Report predicts a 1-in-10 peak demand of 4,672 MMcfd in December 2022 under 1-in-10-year dry hydro conditions, which corresponds to the 98.48th percentile of a *cold December's* Gamma distribution based on the high standard deviation and the 99.78th percentile based on the normal standard deviation, and 99.99897th percentile based on the low standard deviation. These percentiles reflect that a high standard deviation would forecast 0.47 December days with demand above 4,672 MMcfd, a normal standard deviation would forecast 0.07 days, and a low standard deviation would forecast a negligible number of days. Based on all these data, 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 seven days of demand higher than 4 Bcfd. It is important to note that the 1-in-10 peak day temperature relies on finding the probability that the minimum winter temperature is lower than 10 percent of the yearly minimum temperature that occurred since 1950. The 1-in-10 peak day demand temperature methodology used by the operator in the California Gas Report workpapers does not look into quantifying the distribution of daily demand within a certain year, be it average or cold or even within a certain month. It only looks into how cold a year was using Heating Degree Days (HDDs). On the other hand, Staff is simulating only a cold year not multiple years with varying degrees of cold. Therefore, it is not expected that the December percentile of 4.672 Bcfd be the 90th percentile among all demand days from October to April.

Table 2: Demand distribution for the study period for low, normal, and high standard deviation (variability) of a 2022-2023 cold and dry hydro

	Expected Number of Days		
	Low SD	**Normal SD**	**High SD**
Demand Range (Bcfd)			
Higher than 4.672	Negligible	0.09	0.85
4.0 to 4.67	0.27	2.58	6.24
3.5 to 4.0	8.25	14.31	17.71
2.5 to 3.5	136.93	119.89	105.72
Lower than 2.5	66.55	75.13	81.48
Total	**212**	**212**	**212**
December percentile of 4,672 MMcfd	**99.99897th**	**99.78485th**	**98.47995th**
December days above 4,672 MMcfd	**Negligible**	**0.07**	**0.47**

Table 3: Demand distribution for the study period for low, normal, and high standard deviation (variability) for a 2022-2023 average year with base hydro

	Expected Number of Days		
	Low SD	**Normal SD**	**High SD**
Demand Range (Bcfd)			
Higher than 4.672	0	0.01	0.27
4.0 to 4.67	0.01	0.67	3.13
3.5 to 4.0	1.5	6.81	11.82
2.5 to 3.5	122.83	112.37	100.95
Lower than 2.5	87.67	92.13	95.82
Total	**212**	**212**	**212**
December percentile of 4,672 MMcfd	**100th**	**99.97467th**	**99.49564th**
December days above 4,672 MMcfd	**0**	**0.008**	**0.14**

Stochastic Daily Mass Balance Results

The main advantage of the stochastic daily mass balance model compared to monthly mass balance sheets 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, looking at averaged results 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[26] to obtain the number of imbalance days per study period, or the expected number of imbalance days, which can be disaggregated by month. Table 4 shows the predicted number of imbalance days that occur by month for all three scenarios. Based on the results summarized in Table 4, the model predicts no or negligible imbalance days, even under high demand variability, for any of the scenarios, including the worst-case scenario. The highest number of imbalance days was 0.02 EFO in April of Scenario 3. 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 2022-2023 winter, with up to seven days with demand above 4 Bcfd. SoCalGas natural gas network should be able to meet the 1-in-10 peak day demand as well.

Table 4: Number of imbalance days per month for the three scenarios

		Scenario		
		1	**2**	**3**
Month	**October**	0	0	0
	November	0	0	0
	December	0	0	0
	January	0	0	0
	February	0	0	0
	March	0	0	0
	April	0	0	0.02
	October-April	**0**	**0**	**0.02**

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 negligible for all three scenarios since the number of EFOs is negligible.[27] In other words, no curtailments are expected this winter as long as the peak daily demand does not exceed the 1-in-10 peak day demand of 4.672 Bcfd, and the number of high-demand days (higher than 4 Bcfd) does not exceed seven.

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[26] 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.

[27] The EUV for scenarios 1, 2, and 3 is 0, 0, and 3.32 MMcf

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 study period. EUS can be reported as a total over the study period or can be disaggregated by month. Table 5 shows EUS for Scenarios 1-3. From Table 5, it becomes clear that, for example, additional supplies during October or November won't result in higher inventory levels or faster filling since there is already 10.6-30.1 Bcf of EUS during these months. The high EUS during the months of October and November indicate that additional supplies at California borders will not result in faster filling of underground storage due to the injection limitations and near full underground storages. 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 demand that is higher than forecasted.

Comparing EUS across different scenarios for the same month is also beneficial. For example, in October, scenario 1 has 30.1 Bcf of additional supplies compared to 18.3-18.4 Bcf for scenarios 2 and 3, while the supplies for scenario 1 are 3,255 MMcfd compared to 2,860 MMcfd for scenario 2 and 3. This shows that the additional supplies in scenario 1 did not result in any additional injections compared to scenarios 2 and 3[28].

A high EUS could also indicate that additional planned outages could be scheduled, and these outages will not diminish the system's ability to fill the underground storage or meet the forecasted daily demand. For example, October of scenario 2 could sustain another planned outage with impact of about 593 MMcfd (18.4*1,000/31). One may also conclude that minimum supplies in October simply must remain above 2,267 MMcfd, which is slightly higher than the average October demand of 2,172 MMcfd.

Table 5: Expected Unused Supplies (Bcf) for Scenarios 1-3

		Scenario		
		1	**2**	**3**
Month	**October**	30.1	18.4	18.3
	November	19.8	11.0	10.6
	December	4.48	3.66	0.98
	January	5.46	4.26	0.895
	February	6.16	4.56	0.93
	March	1.85	2.03	0.79
	April	1.06	0.99	0.41
	October-April	**68.95**	**44.77**	**32.92**

[28] The additional supplies (3,255-2,860=395 MMcfd) multiplied by the number of days in October (31) is 12.2 Bcf, which is the EUS difference between scenario 1 and scenarios 2 or 3 in October.

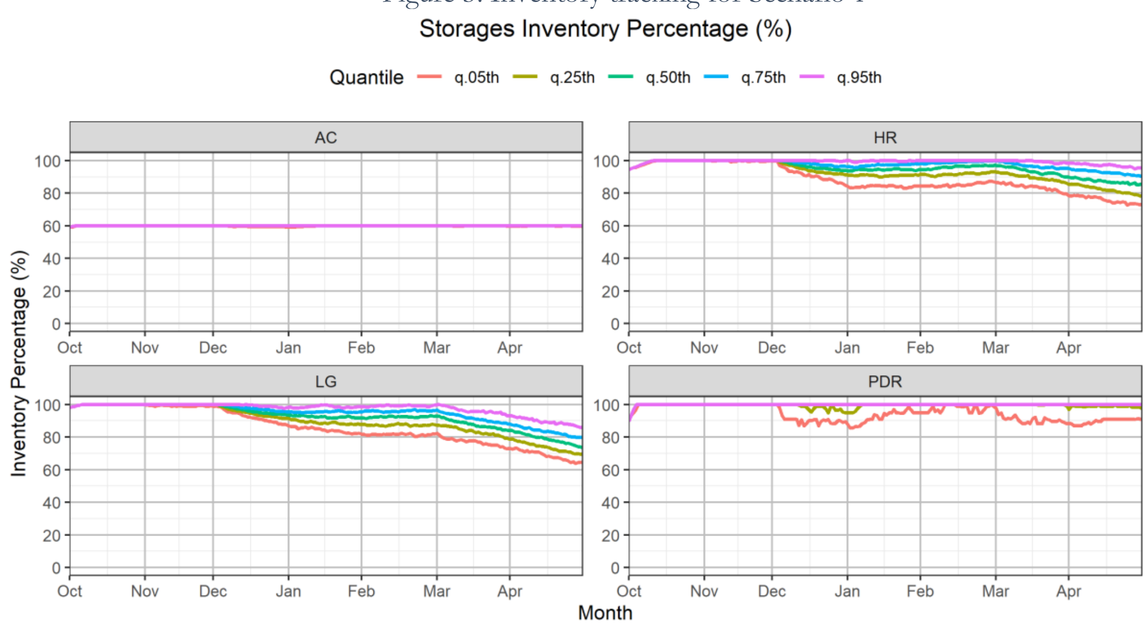
Inventory tracking

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 is not a deterministic value, but rather a probabilistic one, i.e., a distribution.[29] 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.

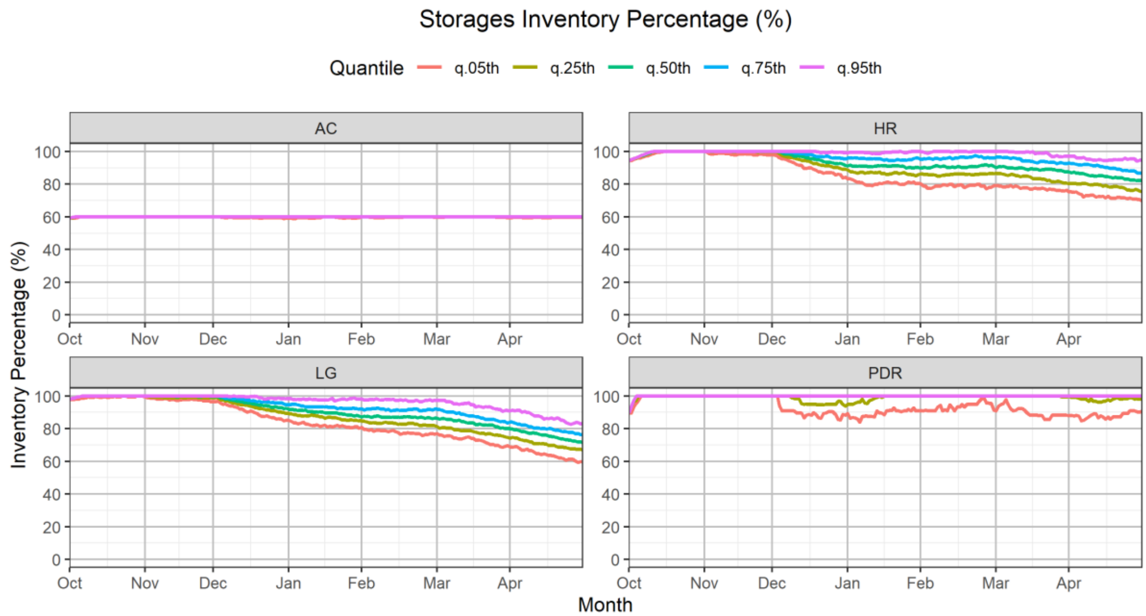
Figure 3, Figure 4, and Figure 5 show the inventory tracking plots for Scenarios 1, 2, and 3, which have total available supplies of 644 Bcf, 617 Bcf, and 596 Bcf compared to a forecasted demand of 581 Bcf over the study period for a cold and dry year. Scenario 1 represents the best-case scenario, Scenario 2 the likely scenario, and Scenario 3 the worst-case scenario. Note that for all three scenarios, the total available supplies are higher than the total demand, yet all scenarios will show reliance on storage to meet the daily demand throughout the winter. As described earlier, all three scenarios assume a high demand variability (high standard deviation) within a cold temperature and dry hydro year, no supplies scheduled at Otay Mesa, and all three scenarios withdraw and inject from all four storage fields using Aliso last in the sequence.[14,15]

Figure 3: Inventory tracking for Scenario 1



[29] 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 December 1st have 100 values for each scenario and statistics must be drawn to illustrate the results.

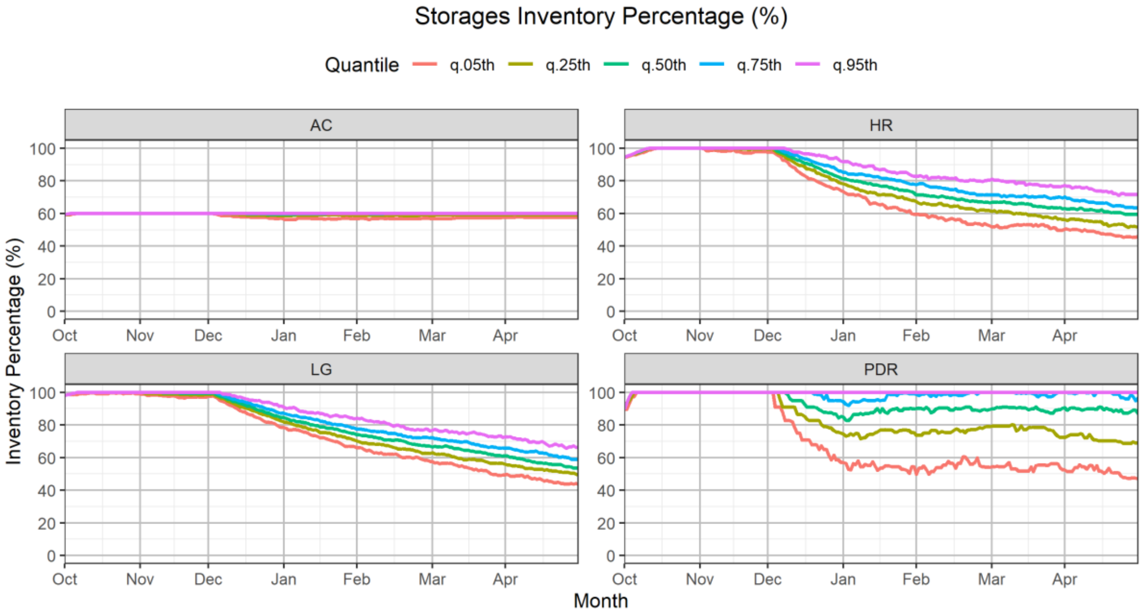
Figure 4: Inventory tracking for Scenario 2



Figures 3, Figure 4 , and Figure 5 show that by the end of October all three scenarios predict that all storage fields are filled to their maximum allowed inventory with a total of 91.56 Bcf. Withdrawals start to occur in November but are not high enough to decrease the inventory levels markedly. However, in December, withdrawals are more frequent and inventories in all non-Aliso fields start to drop. For Scenarios 1 and 3, the total inventory drops to 88.62 Bcf and 82.62 Bcf by the end of December. By the end of February, the total inventory is almost unchanged for Scenario 1, but drops to 75.14 Bcf for Scenario 3. By the end of April, the total inventory drops to 82 [76.2-87.5],[30] 80.69 [74.33-86.48], and 70.27 [62.27-76.71] for Scenarios 1,2, and 3 respectively. The lowest total inventory predicted by the model is 62.27 Bcf and corresponds to the 5th percentile of Scenario 3, which could be interpreted as a scenario with worst-case interstate supplies combined with daily demands that are higher than the forecasted monthly averages. The month-end inventories of Scenarios 1 to 3 are shown in Table 6, Table 7, and Table 7.

[30] Median [5th percentile, 95th percentile]

Figure 5: 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. For example, during December and January, the average demand is higher than the average supplies of Scenario 3, but lower than the average supplies of Scenario 1. Therefore, a monthly balance sheet would predict withdrawals for Scenario 3, but not for Scenario 1. In contrast, the daily mass balance sheet predicts withdrawal and inventory decrease (albeit small) for both scenarios as summarized in Table 6 and Table 7. This is because of the variability introduced around the average demand; a feature that can only be captured by the daily mass balance model compared to monthly balance sheets. It is worth noting that neither balance take into account market decisions made by gas users comparing the price of gas from storage to that of pipeline gas. In the high price gas market, the U.S. is likely to see this winter, those market decisions may lead to more storage being used than would be forecast based on reliability decisions alone.

In summary, inventory tracking shows relatively high inventory levels which enable the system to maintain a reliable winter[31] unless high gas prices lead to more reliance on storage and more frequent withdrawals that deplete storage faster and beyond what is predicted by this model. Although inventory levels decline, inventory does not go below minimum levels needed for withdrawal, and inventory remains to handle some contingencies.

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[31] In the worst-case scenario, the inventory level of Honor Rancho and La Goleta storage fields decreases by no more than 50 percent by the end of April. Aliso Canyon inventory level does not decrease much, and is still almost full by the end of April.

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

	Month						
	10	**11**	**12**	**1**	**2**	**3**	**4**
Aliso Canyon	41.16	41.16	41.16	41.16	41.16	41.16	41.16
Honor Rancho	27.00	27.00	25.39	25.50	26.18	24.24	23.13
La Goleta	21.50	21.50	20.18	19.72	19.94	18.13	15.80
Playa Del Rey	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Total	91.56	91.56	88.62	88.27	89.18	85.43	82.00

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

	Month						
	10	**11**	**12**	**1**	**2**	**3**	**4**
Aliso Canyon	41.16	41.16	41.16	41.16	41.16	41.16	41.16
Honor Rancho	27.00	27.00	24.67	24.35	24.53	23.59	22.29
La Goleta	21.50	21.41	19.91	18.85	18.59	17.20	15.34
Playa Del Rey	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Total	91.56	91.47	87.65	86.26	86.18	83.85	80.69

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

	Month						
	10	**11**	**12**	**1**	**2**	**3**	**4**
Aliso Canyon	41.16	41.16	40.75	41.12	41.04	41.16	41.1
Honor Rancho	27.00	27.00	22.07	19.59	18.00	16.94	16.02
La Goleta	21.5	21.38	18.18	16.06	14.39	13.13	11.49
Playa Del Rey	1.90	1.90	1.62	1.71	1.700	1.72	1.65
Total	91.56	91.44	82.62	78.47	75.14	72.95	70.27

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. 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 the 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.

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 is set to 50 percent. In other words, only half the forecasted in-service wells are made available during the study period. In the second sensitivity, the utilization factor of all four underground storages has been set to 80 percent, i.e., only eight out of each 10 forecasted in-service wells are made available.

In the first sensitivity, the fields inventory reaches 15.5 Bcf, 14.48 Bcf, 1.4 Bcf, 40.57 Bcf for La Goleta, Honor Rancho, Playa Del Rey, and Aliso Canyon, by the end of April compared to 11.49 Bcf, 16.02 Bcf, 1.65 Bcf, and 41.1 Bcf for the baseline Scenario 3. The inventory levels are summarized in Table 9. In other words, the decrease in supplies from La Goleta has been compensated for by more withdrawals from the other fields causing them to drop further than the baseline Scenario 3. However, the expected number of EFOs is still negligible at 0.05 EFO/study period, occurring only in April due to demands higher than 4 Bcfd.

In the second sensitivity, the number of EFOs increased to 0.13 EFO/study period occurring across the Jan-April period for demands higher than 3.5 Bcfd. Eighty-four percent of the EFOs are caused by an imbalance in the 0-250 MMcf range, while for the remaining 16 percent, imbalances range from 250 to 500 MMcf. In summary, unplanned wells outages degrades reliability but not to an alarming degree because the number of EFOs is still considerably smaller than one.

Table 9: End-of-April inventory level for scenario 3 and sensitivities

	AC	**HR**	**LG**	**PDR**	**Total**	**EFO**
	Bcf	Bcf	Bcf	Bcf	Bcf	#/day
Scenario 3	41.1	16.02	11.49	1.65	70.26	0.02
Sensitivity 1	40.5	14.48	15.50	1.40	71.88	0.05
Sensitivity 2	40.5	16.23	12.04	1.69	70.46	0.13

Summary

The stochastic daily mass balance model was used to assess the reliability of SoCalGas natural gas network in Southern California for the upcoming winter of 2022-2023. Three scenarios have been devised with varying preliminary and non-preliminary planned outages, which were submitted by SoCalGas. All three scenarios assume high demand variabilities, no supplies from Otay Mesa, and no restrictions imposed on underground gas storage fields.[32] With the current natural gas assets and withdrawal protocols in place, the model predicts no curtailments or emergency flow orders in the winter of 2022-2023. Thus, the assessment predicts the system will be reliable.

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 storage outages and the remoteness of La Goleta from the Los Angeles basin. Both sensitivities show very little degradation in reliability highlighted by a slight increase in the number of EFOs during the study period. Even with 20 percent of wells out-of-service, SoCalGas natural gas network should be able to meet customers' demand every day during the entire 2022-2023 winter, with up to seven days with demand above 4 Bcfd., SoCalGas natural gas network should be able to meet the 1-in-10 peak day demand as well.

[32] 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.