Winter 2019-20 Southern California Reliability Assessment

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Executive Summary

At the beginning of October, Southern California faced considerable uncertainty about the prospects for gas system reliability during the coming winter. As October 31—the traditional end of the natural gas injection season—grew nearer, gas storage supplies were lower than at the same time last year, and two critical transmission pipelines were out of service. Fortunately, Line 235-2, whose return-to-service had been repeatedly delayed by the discovery of new leaks, began operating at reduced capacity on October 15.[1] Line 4000, which is currently out of service for validation digs, is expected to return to service on October 24.[2]

The gas balance analyses in this report present seven possible scenarios ranging from a best-case to a worst-case assumption. At the time the gas balance analyses were completed, Lines 235-2 and 4000 were still out of service, and there was some uncertainty about whether they would return on schedule. Gas balances were created when the expected return-to-service date of Line 4000 was November 5, so they do not reflect the recently released October 24 date. Staff finds the risk this winter to be similar to or better than last winter as both Line 235-2 and Line 4000 could be in service whereas there was no chance of both lines being in service last year. Depending on how cold the winter is, curtailing service to some noncore customers may be necessary but should not threaten electric reliability. Therefore, the worst-case scenarios considered in this report now appear unlikely. However, we are presenting all the scenarios Energy Division staff prepared in this report to provide information about the risks that were considered and the actions that were undertaken to mitigate some of those risks.

The Southern California Gas Company (SoCalGas) system still approaches the winter with somewhat less gas in storage than this time last year. The total storage inventory as of October 1, 2019, was 73.6 billion cubic feet (Bcf), compared to 80.7 Bcf on October 1, 2018. It has been difficult for customers to build inventory at the non-Aliso storage fields for several reasons.[3] First, the pipeline outages continued to constrain the SoCalGas system, and when both Line 235-2 and Line 4000 were out of service during fall 2019, injections into storage became more challenging because less gas could be brought onto the system. Second, the SoCalGas system relied heavily on the non-Aliso fields to meet demand during winter of 2018-19, so those fields ended winter with lower than normal inventories. Moreover, Aliso Canyon reached its maximum allowable inventory capacity of 34 Bcf on June 19, 2019. Since injection capacity is largely concentrated at Aliso Canyon, once that field reached its 34 Bcf maximum, there was very little injection capacity left on the system.[4] Lastly, when injection capacity falls below 345 MMcfd—as it does when Aliso Canyon is

[1] In an October 14, 2019, post on Envoy, SoCalGas stated that it plans to run an inline inspection of Line 235-2 immediately upon its return to service. There is a chance that the results of the inline inspection could show urgent safety issues that would require the pipeline to be removed from service for immediate maintenance. https://scgenvoy.sempra.com/ebb/attachments/1571081835624_SoCalGas_Pipeline_Maintenance_Update_October_14_19.pdf

[2] Validation digs allow for inspection of actual pipe conditions to validate the accuracy of in-line inspection results.

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

[4] Aliso Canyon's greater injection capacity means that it can fill more rapidly than the other fields. Also, under the Aliso Canyon Withdrawal Protocol, gas can only be withdrawn from Aliso Canyon under specific conditions that

full—SoCalGas Rule 41[5] allocates all the injection capacity to the balancing function during the prime trading cycle, further increasing customers' difficulty injecting gas into storage.[6]

The best-case scenario in the gas balance analyses reflects Line 235-2 returning to service on October 15, Line 4000's return-to-service on November 5, and a winter season with relatively mild weather. Under this scenario, the non-Aliso fields reach their maximum capacity by the end of November, and Aliso Canyon would generally not be needed to meet gas demand. At the other end, the worst-case scenario assumes that both pipelines remain out of service, and Southern California has a 1-in-35-year cold winter. Under this scenario, the non-Aliso fields would not be full by November 30, and Aliso Canyon's current capacity would not be enough to meet demand. However, since Line 235-2 returned to service on October 15, this scenario is not likely to occur unless there is an immediate issue that requires Line 235-2 to be removed from service again.

In addition, if a 1-in-10 peak day occurs this winter, withdrawals from Aliso Canyon would be needed to meet demand under the best-case scenario. Under the worst-case scenario, withdrawals from Aliso Canyon would not be enough to meet the 1-in-10 peak day demand, which would likely lead to the curtailment of noncore customers. Therefore, SoCalGas remains unable to meet its 1-in-10 peak day design standard under this worst-case scenario. Prior technical assessments by the Joint Agencies have shown that even in cold weather, electricity service should not be impaired given that electric generators have lower demand in the winter, yielding more flexibility to absorb gas service curtailments.

The California Public Utilities Commission (CPUC) has undertaken several measures to boost reliability this winter, including revising the Aliso Canyon Withdrawal Protocol to allow more flexible use of the storage facility and directing SoCalGas to release up to 100 MMcfd of the injection capacity allocated to balancing to the market to increase storage injection. Energy Division staff have also submitted a Staff Proposal in the currently open SoCalGas Triennial Cost Allocation Proceeding that proposes to change SoCalGas' tariff so that in future, both customers and the balancing function will have access to injection capacity even when total injection capacity is low.[7]

This report is authored by CPUC staff and was shared with the Joint Agencies for review and comment. Should conditions significantly change, the CPUC will issue monthly supplemental reports this winter with input from the Joint Agencies to provide updates and revised gas balance analyses reflecting any new information.

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were only met three times this summer. Thus, demand peaks must be met by withdrawing gas from the non-Aliso fields.

[5] SoCalGas Rule 41: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/41.pdf

[6] This allocation of injection capacity was agreed to by Settling Parties during the last Triennial Cost Allocation Proceeding (TCAP). The Settlement Agreement was reached prior to the Aliso Canyon gas leak, although Decision (D.) 16-06-039, was not issued until June 28, 2016: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K355/164355965.pdf. A new TC AP is currently underway via Application (A.) 18-07-024: https://apps.cpuc.ca.gov/apex/f?p=401:57:0::NO.

[7] See October 3, 2019, Ruling in Application (A.) 18-07-024.

Supply Outlook

Transmission Pipelines

SoCalGas' Northern Zone continues to experience reduced pipeline receipt capacity as of this writing. Line 3000, which returned to service in September 2018, remains at reduced operating pressure. Line 235-2, which ruptured on October 1, 2017, returned to service at reduced pressure on October 15, 2019. Line 4000, which is adjacent to Line 235-2 near the rupture point, was taken out of service on September 19 for validation digs. SoCalGas originally predicted that Line 4000 would return to service on November 5 but recently stated that it would return on October 24 at reduced pressure,[8] which would increase the Northern Zone maximum to 950 MMcfd. SoCalGas has stated that it may further increase the operating pressure on Line 4000 by February 2020.[9]

In the worst-case scenario evaluated below, where both pipelines are out, the only operable receipt point in the Northern Zone is Kramer Junction, which can accept a maximum of 550 MMcfd on a firm basis, and up to 710 million cubic feet per day (MMcfd) when there is no competition from the other pipelines.[10] However, 710 MMcfd into Kramer Junction is not feasible once Line 235-2 is back in service.

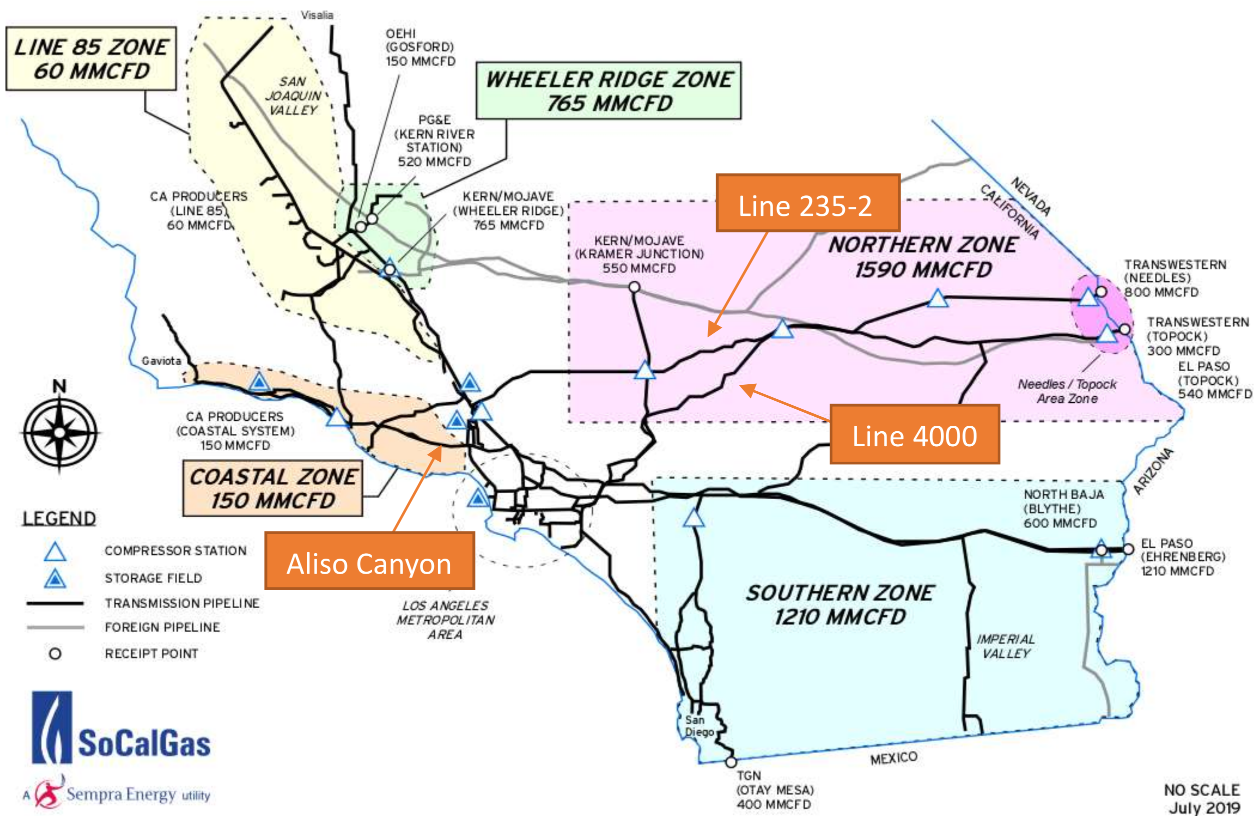
In the Southern Zone, SoCalGas has reduced the Ehrenberg receipt point from 1210 to 980 MMcfd due to a longstanding pressure reduction related to its Pipeline Safety Enhancement Plan and the loss of a right-of-way on Line 2000. The Southern Zone as a whole still has the ability to accept 1210 MMcfd if 230 MMcfd is delivered to Otay Mesa. While some gas is delivered to this receipt point, historically it has rarely seen deliveries of that size on a consistent basis. In this analysis, we assume that 50 MMcfd is delivered to Otay Mesa during the high-demand November-March period.

[8] See October 22, 2019, Pipeline Maintenance Update on SoCalGas' electronic bulletin board, Envoy: https://scgenvoy.sempra.com/ebb/attachments/1571768932131_SoCalGas_Pipeline_Maintenance_Update_October_22_Final.pdf.

[9] SoCalGas Winter 2019-20 Technical Assessment, p.3:https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SOCALGAS%20WINTER%202019-20%20TECHNICAL%20ASSESSMENT.pdf.

[10] Of that capacity, 550 MMcfd is firm and the remaining 160 MMcfd is interruptible.

Image 1: Receipt Points & Transmission Zone Firm Capacities



The Wheeler Ridge Zone can receive up to 810 MMcfd under certain conditions, but only 765 MMcfd on a firm basis. This increase to 810 is only possible when Line 235-2 is out of service, thus removing downstream competition on the pipelines. With Line 235-2 in service, less gas can be delivered at Wheeler Ridge. The best- and second-best case scenarios in the gas balance analyses assume 780 MMcfd to reflect approximately how much gas was delivered in the Wheeler Ridge Zone during high sendout days in winter 2018-19. The worst-case scenarios assume 800 MMcfd to compensate for both Lines 235-2 and 4000 remaining out of service.

Lastly, SoCalGas de-rated Line 85 as part of its Pipeline Safety Enhancement Plan.[11] Line 85 serves California natural gas producers, and the de-ration reduces the pipeline's capacity from 160 MMcfd to 60 MMcfd. However, the actual impact of this de-ration is substantially less than the nominal capacity loss due to the decline in California gas production. Due to that decline, we limit the total capacity provided by California production to the Line 85 Zone in our analysis.

Table 1 depicts the best- and worst-case pipeline scenarios this winter compared to the previous winter. These total supply figures show estimated receipt capacities and are not based on hydraulic modeling. Thus, they only consider daily gas usage and do not reflect hourly fluctuations in gas demand, which may put additional strain on the system. There is a risk that additional unplanned

[11] See SoCalGas Advice Letter 5493-G: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/5493.pdf.

outages to the pipeline system could further reduce SoCalGas' ability to meet demand for natural gas this winter.

Table 1: SoCalGas System Sendout for Winter 2019-20 Compared to Winter 2018-19

	MMcfd	Winter 2018-19 No Mitigations	Winter 2018-19 With Mitigations	Winter 2019-20 Best case	Winter 2019-20 Worst case
Pipeline Capacity					
Southern System	Blythe/Ehrenberg	980	980	980	980
	Otay Mesa	-	200	50	50
Northern System	North Needles	270	270	170	-
	Topock	-	-	230	-
	Kramer Junction	550	550	550	550
	Kramer Junction Int.	-	50	-	150
Wheeler Ridge	Wheeler Ridge	765	765	780	800
California Producers	California Production	60	60	60	60
Pipeline Capacity Subtotal		2,625	2,875	2,820	2,590
Non-Aliso Subtotal		1,370	1,370	1,405	1,405
All Storage Subtotal		2,610	2,610	2,745	2,745
Total Supply without Aliso Canyon		3,995	4,245	4,225	3,995
Total Supply with Aliso Canyon		5,235	5,485	5,565	5,335

Note: Mitigations for Winter 2018-19 included 200 MMcfd of interruptible capacity at Otay Mesa and 50 MMcfd of interruptible capacity at Kramer Junction. The 50 MMcfd reflected in the best- and worst-case scenarios reflect the average amount that has been delivered in the past year.

Gas Storage Facilities

Aliso Canyon's maximum allowable inventory of 34 Bcf remains unchanged. The table below compares the amount of gas in storage on October 1, 2019, compared to October 1, 2018.

Table 2: Total Storage Inventory

Bcf	October 1, 2018	October 1, 2019
Non-Aliso	47.1	40
Aliso Canyon	33.6	33.6
Total	80.7	73.6

Injection patterns in 2018 and 2019 have varied, which helps explain the noticeable difference in total storage inventories shown above in Table 2. In 2018, there was little injection capacity in the spring and early summer because Aliso Canyon exited winter with an inventory of roughly 22.2 Bcf—near its then-authorized maximum of 24.6 Bcf. Aliso Canyon's injection capacity was also significantly reduced due to maintenance between April 11 and June 4, 2018.[12] Once Aliso Canyon

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[12] Aliso Canyon's injection capacity was reduced by 400 MMcfd between April 11 and May 28, 2018, due to the finalization of the Aliso Canyon Turbine Replacement Project and compressor maintenance. Between May 29 and

became full on June 7, 2018, only the injection capacity from the non-Aliso fields was available, which averaged about 250 MMcfd.[13] On July 2, 2018, the CPUC increased the facility's maximum allowable inventory to 34 Bcf. This increase meant that Aliso Canyon's injection capacity was available again until the field filled up to 34 Bcf on September 30, 2018.

In comparison, in 2019 Aliso Canyon exited the winter with 20.1 Bcf in inventory, so its injection capacity was available in spring and early summer. During that period, SoCalGas was able to increase the inventories at all four fields. However, the non-Aliso fields had been severely depleted during the February cold snap, so they were still at relatively low inventories when Aliso Canyon reached its maximum on June 19, 2019. The combination of pipeline outages and the lack of injection capacity at Aliso Canyon has made it difficult for customers—notably SoCalGas' Gas Acquisition Department, which purchases gas for residential and small commercial customers—to physically bring gas onto the system and inject it for use in the winter.

The difficulties created by the reduction in injection capacity once Aliso Canyon is full are exacerbated by SoCalGas' Rule 41, which states, "The storage injection capacity allocated to the balancing function shall be the lesser of 345 MMcf/day or the full amount of available storage injection capacity of the Utility's system."[14] Since Aliso Canyon reached 34 Bcf, all available injection capacity, or approximately 260 MMcfd, has been allocated to the balancing function during the prime trading cycle.[15] As further discussed below in the "CPUC Actions and Updates on Proposed Mitigation Measures" section of this report, a CPUC Executive Director Letter was sent to SoCalGas on September 19, 2019, directing the SoCalGas System Operator to release up to 100 MMcfd of the injection capacity allocated to balancing to the market. This directive was due to the CPUC's growing concerns over winter reliability.

Gas Balance Analysis

Gas demand figures for the winter are derived from the forecasts in the *2018 California Gas Report*,[16] then used in several gas balance analysis scenarios. Staff prepared gas balances in order to provide an assessment independent of SoCalGas' own assessment and to test additional sensitivity cases with alternate assumptions. A gas balance is not a projection of future occurrences. Rather, it is a tool that demonstrates what may happen if the demand, supply, and storage assumptions shown come to fruition. A gas balance allows us to assess the average daily difference, or margin, between capacity (or supply) and demand to determine in general whether capacity is enough to meet demand. It also allows us to simulate the impact to month-end storage inventory from average daily storage

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June 4, 2018, the field's injection capacity was reduced by 295 MMcfd due to the compressor work and the initial operation of the Turbine Replacement Project.

[13] SoCalGas Envoy Capacity Utilization Page Archives.

[14] SoCalGas Rule 41 can be found here: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/41.pdf

[15] There are five cycles that provide customers an opportunity to nominate and schedule gas onto the system: Timely (Cycle 1), Evening (Cycle 2), Intraday 1 (Cycle 3), Intraday 2 (Cycle 4), and Intraday 3 (Cycle 5). Cycle 1, which is considered the prime trading cycle, is the first opportunity for customers to request and schedule gas delivery. Once Aliso reaches 34 Bcf, all available injection capacity during Cycle 1 is allocated to the balancing function.

[16] The *2018 California Gas Report* and its supporting workpapers can be found at: https://www.socalgas.com/regulatory/cgr.shtml.

injections and withdrawals. A gas balance exercise does not simulate operations hydraulically to determine constraints or assess hourly operations.

It is important to recognize that the demand forecasts are for average daily consumption for each month under average and 1-in-35 cold weather/dry hydro weather scenarios.[17] There will be days in the winter that will have higher or lower demand than the averages shown. Typically, a balance should demonstrate a positive deliverability margin of roughly 15%, meaning there is 15% more capacity than demand. This buffer is intended to ensure that the system retains reserve capacity to deal with unplanned outages or days with above-average demand. However, this Winter Reliability Assessment series does not maintain the 15% margin for three reasons. First, given the thin margins forecasted between gas supply and demand this winter, our initial analysis achieved very low reserve margins, and we were only able to maintain them during October and November. Second, even with both pipelines back in service at reduced pressure, there were thin or non-existent supply margins in the gas balance exercises through March 2020. Lastly, in order to apply the September 19, 2019, Letter from CPUC's Executive Director to SoCalGas[18] to the gas balance analyses, injection was maximized from October through December.

The gas balance analyses assume withdrawal of gas from the non-Aliso storage fields until they are within 110% of the month-end inventory requirements stated in SoCalGas' Aliso Canyon Risk Assessment Technical Report 2018-19 Supplement.[19]

The first gas balance, Scenario A in the appendix, is the best-case scenario with Line 235-2 back in service on October 15 and Line 4000 in service on November 5, with average weather throughout the winter. The non-Aliso fields reach their maximum capacity of 50.4 Bcf by the end of November and would be expected to contain a healthy amount of inventory throughout the winter. There would be approximately a 9% reserve margin on the system. Aliso Canyon would not be needed to meet gas demand on average days throughout the winter. Scenario A presents the lowest level of energy reliability concern.

Scenario B maintains Line 235-2 in service on October 15 and Line 4000 in service on November 5 but evaluates gas sendout under a 1-in-35 cold year/dry hydro demand forecast. The non-Aliso fields still reach 100% of their capacities by the end of November. Then, an average of 564 MMcfd would be withdrawn from the non-Aliso fields in December, after which an average of 300 MMcfd would be withdrawn from the non-Aliso fields in January before reaching the month-end minimums. Aliso Canyon would be needed in January and February at an average withdrawal rate of

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[17] A 1-in-35 cold weather/dry hydro year is different from a 1-in-35 extreme peak day. Under the 1-in-35 extreme peak day design standard set by the CPUC, all noncore can be curtailed. See D.02-11-073 and D.06-09-039 for the establishment of reliability standards.

[18] Executive Director Letter to SoCalGas: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Signed%20Letter%20to%20Bret%20Lane%20So%20Cal%20Gas%20Company%20re%20Injection%20Required%20for%20SCG%20Winter%20Reliability%20and%20Storage%20Inventory_v2.pdf

[19] SoCalGas' Aliso Canyon Risk Assessment Technical Report 2018-19 Supplement: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2018/2018%2011%2002%20SoCalGas%20(R.%20Schwecke)%20letter%20to%20CEC%20enclosing%20WINTER%202018-19%20TECHNICAL%20ASSESSMENT.PDF

257 MMcfd and 35 MMcfd, respectively. By the end of March, about 19 Bcf would remain in the non-Aliso fields and Aliso Canyon would hold 25 Bcf.

Scenario C considers an average winter and either Line 235-2 or Line 4000 back in service by November 5 at reduced pressure, resulting in an average Northern Zone capacity of 870 MMcfd. (Line 235-2 is assumed to have missed the October 14 return to service date.) In this scenario, the non-Aliso fields reach their maximum capacity of 50.4 Bcf by the end of November, then decrease to 39 Bcf by the end of December. Aliso Canyon withdrawals would be needed in December in order to maintain the month-end minimum at the non-Aliso fields. An average of 66 MMcfd would be withdrawn from the non-Aliso fields in February, then the winter season ends with gas injections in March.

Scenario D differs from Scenario C by using the 1-in-35 cold year/dry hydro demand forecast. Under this scenario, the non-Aliso fields are not predicted to be full before the winter. Furthermore, gas withdrawals from all four storage fields are expected from December through February. Aliso Canyon withdrawals would be needed in order to maintain the minimum month-end minimum at the non-Aliso fields. By the end of January, the non-Aliso fields would lose almost half of their November inventory. A minimum amount of injection would occur in March to end the winter with just 21 Bcf in the non-Aliso fields and 10 Bcf in Aliso Canyon.

Scenario E considers an average weather winter with both Lines 235 and 4000 out all season. By the end of November, the non-Aliso fields are near full but unable to reach 100% of their capacities. There is almost 500 MMcfd withdrawn from the non-Aliso fields each day of December, resulting in a combined inventory of 33 Bcf in the non-Aliso fields by the end of the month. Gas would be needed from Aliso Canyon in January and February in order to maintain the non-Aliso month-end minimum inventories. The non-Aliso fields reach a low of 17 Bcf total by the end of February and 20 Bcf by the end of March. Aliso Canyon ends the winter season with 29 Bcf.

In Scenario F, Lines 235-2 and 4000 are both out of service and the 1-in-35 cold year/dry hydro demand forecast is used. This results in 41 Bcf in the non-Aliso fields by the end of November. Inventory levels quickly decline in December to 25 Bcf in the non-Aliso fields and 26 Bcf in Aliso Canyon. January withdrawals would bring the non-Aliso fields to 23 Bcf and Aliso Canyon down to 3 Bcf. From here, if the month-end minimums were maintained in the non-Aliso fields, then the amount of gas in Aliso Canyon is not adequate. The negative figures in February and March for Aliso Canyon indicate how much more gas Aliso Canyon would need to have in order to maintain the month-end minimums in the non-Aliso fields. While Scenario F may have a low risk of occurring (there is a 3 percent chance of a 1-in-35 cold year occurring), the consequences and potential harm to society and the economy could be very high.

Based on the weather patterns of the last two winters, which began mild and ended with cold weather, Scenario G was created as a seventh analysis. This analysis utilizes the average weather demand forecasts for October through December (mimicking Scenario E), then the 1-in-35 cold year/dry hydro demand forecasts for January through March (mimicking Scenario F) with both pipelines out of service all winter. As seen in Scenario E, by the end of November, the non-Aliso fields are near full, but unable to reach 100 percent of their capacities. There is still a considerable amount of gas withdrawn from the non-Aliso fields in December and from the Aliso Canyon and non-Aliso fields in January. January would end with 23 Bcf in the non-Aliso fields to maintain the month-end minimums. In February, an average of 220 MMcfd can be withdrawn from the non-Aliso fields while maintaining the month-end minimums, with an additional 245 MMcfd needed from Aliso Canyon. Finally, March ends with approximately 14 Bcf in the non-Aliso fields and 12 Bcf in Aliso Canyon.

1-in-10 Peak Day Analysis

In addition to the 1-in-35 cold year/dry hydro analyses, staff performed a 1-in-10 peak day analysis for each month of the winter. Table 3 examines a peak day under the best-case scenario, Scenario A. The demand figures in Column (a) were provided to the CPUC through a data request and represent a peak day in each month. Column (b) in Table 3 shows the pipeline capacity assumed in Scenario A. In Column (c) a declining withdrawal capacity is used in the non-Aliso fields based on the month-end inventory each month. The shortfalls displayed in column (e) represent the amount of gas from Aliso and/or curtailments that would be required if a peak day occurs. Given the current pipeline return to service schedule, the SoCalGas system could not support 1-in-10 peak demand in any month, under any scenario without using Aliso Canyon and/or resorting to curtailments. All shortfalls in column (e) can be met with Aliso Canyon's withdrawal capacity.

The CPUC's *Winter 2018-19 SoCalGas Conditions and Operations Report*, which was a post hoc analysis of 2018-19 gas demand and sendout, emphasized the importance of gas sendout during hourly peaks rather than total daily sendout.[20] The volume of gas demand on the system tends to rapidly increase as users turn on their gas-fired furnaces for home heating in the morning and evening. Staff remains concerned about the risk of meeting demand in peak hours. The analyses in Tables 3 and 4 do not model or capture these hourly peaks.

Table 3: Ability to Meet 1-in-10 Analysis with Lines 235-2 and 4000 in Service

Scenario A, best pipeline scenario	(a) 1-in-10 Peak Day Demand	(b) Total Pipeline Capacity	(c) Estimated non-Aliso Withdrawal Capacity	(d) Total System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
November	4,353	2,810	1,436	4,246	(107)
December	4,949	2,820	1,259	4,079	(870)
January	4,949	2,820	1,079	3,899	(1,050)
February	4,652	2,820	1,079	3,899	(753)
March	4,428	2,820	1,079	3,899	(529)

Table 4 examines a peak day under the worst-case scenario, Scenario F. It shows that even with the use of Aliso Canyon, noncore curtailments would be needed to maintain stability on the gas system. SoCalGas remains unable to meet its 1-in-10 day peak demand design standard. January and

[20] See pages 18 and 22-29: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Winter2018-19LookbackReport_PublicDraft.pdf

February's shortfall amounts in column (e) exceed Aliso Canyon's withdrawal capacity. During winter 2018-19, electric generators on the CAISO and LADWP's system were subject to voluntary and mandatory curtailments to preserve gas system reliability. These analyses render the possibility that a similar situation could occur this winter; however, under current conditions electric reliability can be supported with the use of Aliso Canyon.

Table 4: Ability to Meet 1-in-10 Analysis with Lines 235-2 and 4000 Out of Service

Scenario E, worst pipeline scenario	(a) 1-in-10 Peak Day Demand	(b) Total Pipeline Capacity	(c) Estimated non-Aliso Withdrawal Capacity	(d) Total System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
November	4,353	2,590	1,360	3,950	(403)
December	4,949	2,590	1,093	3,683	(1,266)
January	4,949	2,590	913	3,503	(1,446)
February	4,652	2,590	758	3,348	(1,304)
March	4,428	2,590	856	3,446	(982)

CPUC Actions and Updates on Proposed Mitigation Measures

The *Summer 2019 Risk Assessment Technical Report* proposed several mitigation measures due to the continued pipeline outages and restricted use of Aliso Canyon.[21] The CPUC has undertaken several of these measures, in addition to other actions, which should help mitigate some of the risks Southern California faces this winter season.

The CPUC issued Decision (D.) 19-05-030 on May 30, 2019, to establish new SoCalGas operational flow order (OFO) penalty structures[22] aimed at providing customer cost relief.[23] The decision modified Rule 30 to cap the Stage 4 OFO penalty at the Stage 3 level of $5 per dekatherm and the Stage 5 OFO penalty at $5 per dekatherm plus the daily balancing standby rate (Schedule G-IMB) from June 1 to September 30. The decision also adopted an eight-stage penalty structure from October 1 to May 31, which aims to maintain greater uniformity between PG&E and SoCalGas rules during peak gas season.

[21] The Summer 2019 Risk Assessment Technical Report can be found here: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/TN228349_20190521T145912_Aliso%20Canyon%20Risk%20Assessment%20Technical%20Report%20Summer%202019.pdf

[22] The OFO balancing rules are meant to give customers an economic incentive to ensure their scheduled supply deliveries match their burn demands. SoCalGas calls an OFO on a day prior to the Gas Day if the system forecast of gas supply is not in balance with the system forecast of gas demand. When an OFO is called, customers are required to balance supply and demand within a specified tolerance band; otherwise, they face specified financial penalties for noncompliance.

[23] D.19-05-030 can be found here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M298/K555/298555621.PDF

On July 23, 2019, CPUC's Energy Division issued a revised Aliso Canyon Withdrawal Protocol to allow more flexible use of Aliso in response to energy reliability challenges and customer price impacts in Southern California.[24] Last winter, the Withdrawal Protocol required that Aliso Canyon be used only as an "asset of last resort," and several high demand cold weather events led to very low inventory levels at the non-Aliso fields. The revised Withdrawal Protocol is intended to help balance the system in times of stress and preserve the non-Aliso fields' inventory levels and withdrawal capacity so gas can be supplied when needed at critical hours of peak demand.

In addition, on August 1, 2019, the CPUC approved D.19-08-002, which established new balancing rules that require core customers to balance their deliveries to their burn rather than a forecast, beginning April 1, 2020.[25] The decision also required SoCalGas to begin incorporating Advanced Metering Initiative (AMI) data into its core forecasting process immediately, which has already helped reduce forecasting error significantly. Reduced core forecasting error should in turn help decrease the likelihood of OFOs.

As noted above, to enhance reliability this winter, the CPUC's Executive Director issued a letter to SoCalGas on September 19, 2019, directing the utility to take immediate action to increase injection at all available storage facilities. Specifically, SoCalGas' System Operator was directed to release up to 100 MMcfd of Cycle 1 firm injection capacity for customers prior to Bidweek. Moreover, the letter directed the System Operator to release any additional injection capacity on Cycle 1 on the day before the gas flow day. These temporary modifications are set to expire on December 31, 2019. The impacts of this directive are not yet known. SoCalGas is expected to file an advice letter and provide a status report of the impacts within 30 days of December 31, 2019. However, it is worth noting that if SoCalGas can inject an average of 50 MMcf more per day, then the system may see an average of 5 Bcf or more of injections by the time the modifications expire. Reaching 100 MMcfd of injections will largely depend upon system conditions.

In an effort to avoid the need for such emergency measures in the future, Energy Division staff have also submitted a Staff Proposal in the currently open SoCalGas Triennial Cost Allocation Proceeding that proposes changes to SoCalGas' tariffs so that both customers and the balancing function will have access to injection capacity even when total injection capacity is low. Lastly, the CAISO introduced their own mitigation measures by activating nomograms and scalars in response to gas constraints and increased gas prices.[26] The CAISO has obtained FERC approval for a nomogram extension in preparation for the winter season but will no longer use scalars as a mitigation tool.

With Line 235-2 back in service and Line 4000 scheduled to return to service on October 24, energy reliability risks in Southern California remain, but are considerably reduced compared to previous

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[24] The revised Withdrawal Protocol can be found here: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

[25] D.19-08-002 can be found here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K135/310135933.PDF

[26] Nomograms can be activated by the CAISO to enforce a gas constraint/limitation in a region, and scalars can be activated to increase the gas price index in a region. Both nomograms and scalars make gas-fired electric generation more expensive in Southern California.

years. However, it seems unlikely that storage will be completely full by November 1. As such, the CPUC will continue to communicate with the Joint Agencies during monthly meetings to monitor reliability throughout the winter and issue updates to the analyses presented here, if needed.

Appendix

Scenario A

SoCalGas Monthly Gas Balance							
Average winter, both pipelines in service							
	Line 235-2 Oct. 15			Line 4000 Nov. 5			
SoCalGas Monthly Gas Balance							
CGR Demand (MMcfd)	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	636	718	1,058	1,494	1,410	1,359	1,128
Noncore including EG	1,548	1,263	1,012	1,059	1,123	945	925
Wholesale & International	409	362	384	494	508	467	410
Co. Use and LUAF	33	30	31	39	39	35	31
Subtotal Demand	2,626	2,373	2,485	3,086	3,080	2,806	2,494
Storage Injection (Other Three Fields)	0	270	100	0	0	0	326
Storage Injection (Aliso)	0	0	0	0	0	0	0
Storage Injection Total	*0*	*270*	*100*	*0*	*0*	*0*	*0*
System Total Throughput	2,291	2,643	2,585	3,086	3,080	2,806	2,820
Supply (MMcfd)							
California Line 85 Zone	60	60	60	60	60	60	60
Wheeler Ridge Zone	780	780	780	780	780	780	780
Blythe (Ehrenberg) into Southern Zone	980	980	980	980	980	980	980
Otay Mesa into Southern Zone	30	30	50	50	50	50	50
Kramer Junction into Northern Zone	625	625	625	500	500	500	500
North Needles into Northern Zone	114	169	315	200	200	200	200
Topock into Northern Zone	0	0	0	250	250	250	250
Sub Total Pipeline Receipts	2,589	2,644	2,810	2,820	2,820	2,820	2,820
Storage Withdrawal (Other Three Fields)	0	0	0	266	260	0	0
Storage Withdrawal (Aliso)	0	0	0	0	0	0	0
Total Supply	2,589	2,644	2,810	3,086	3,080	2,820	2,820
DELIVERABILITY BALANCE (MMcfd)	298	1	225	0	0	14	0
Reserve Margin	13%	0%	9%	0%	0%	0%	0%
OTF Month-End Storage Inventory (Bcf)	39	47	50	42	34	34	44
Aliso Month-End Storage Inventory (Bcf)	34	34	34	34	34	34	34
Total Storage Inventory	73	81	84	76	68	68	78

Scenario B

SoCalGas Monthly Gas Balance							
Cold 1-in-35 year winter, both pipelines in service		Line 235-2 Oct. 15	Line 4000 Nov. 5				
SoCalGas Monthly Gas Balance							
CGR Demand (MMcfd)	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	641	742	1,151	1,680	1,583	1,518	1,241
Noncore including EG	1,633	1,294	1,059	1,114	1,189	990	978
Wholesale & International	427	367	408	547	562	508	453
Co. Use and LUAF	35	31	33	43	43	39	34
Subtotal Demand	2,736	2,434	2,651	3,384	3,377	3,055	2,706
Storage Injection (Other Three Fields)	0	209	158	0	0	0	34
Storage Injection (Aliso)	0	0	0	0	0	0	0
Storage Injection Total	*0*	*209*	*158*	*0*	*0*	*0*	*34*
System Total Throughput	2,291	2,643	2,809	3,384	3,377	3,055	2,740
Supply (MMcfd)							
California Line 85 Zone	60	60	60	60	60	60	60
Wheeler Ridge Zone	780	780	780	780	780	780	780
Blythe (Ehrenberg) into Southern Zone	980	980	980	980	980	980	980
Otay Mesa into Southern Zone	30	30	50	50	50	50	50
Kramer Junction into Northern Zone	625	625	625	500	500	500	500
North Needles into Northern Zone	114	169	315	200	200	200	200
Topock into Northern Zone	0	0	0	250	250	250	250
Sub Total Pipeline Receipts	2,589	2,644	2,810	2,820	2,820	2,820	2,820
Storage Withdrawal (Other Three Fields)	0	0	0	564	300	200	0
Storage Withdrawal (Aliso)	0	0	0	0	257	35	0
Total Supply	2,589	2,644	2,810	3,384	3,377	3,055	2,820
DELIVERABILITY BALANCE (MMcfd)	298	1	1	0	0	0	80
Reserve Margin	13%	0%	0%	0%	0%	0%	3%
OTF Month-End Storage Inventory (Bcf)	39	45	50	33	23	17.84	19
Aliso Month-End Storage Inventory (Bcf)	34	34	34	34	26	25	25
Total Storage Inventory	73	79	84	67	49	43	44

Scenario C

SoCalGas Monthly Gas Balance							
Average winter, one pipeline in service							
		Line 235 or 4000 return to service Nov. 5					
SoCalGas Monthly Gas Balance							
CGR Demand (MMcfd)	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	636	718	1,058	1,494	1,410	1,359	1,128
Noncore including EG	1,548	1,263	1,012	1,059	1,123	945	925
Wholesale & International	409	362	384	494	508	467	410
Co. Use and LUAF	33	30	31	39	39	35	31
Subtotal Demand	2,626	2,373	2,485	3,086	3,080	2,806	2,494
Storage Injection (Other Three Fields)	0	177	170	0	0	0	210
Storage Injection (Aliso)	0	0	0	0	0	0	0
Storage Injection Total	*0*	*177*	*170*	*0*	*0*	*0*	*210*
System Total Throughput	2,291	2,550	2,655	3,086	3,080	2,806	2,704
Supply (MMcfd)							
California Line 85 Zone	60	60	60	60	60	60	60
Wheeler Ridge Zone	780	780	780	780	780	780	780
Blythe (Ehrenberg) into Southern Zone	980	980	980	980	980	980	980
Otay Mesa into Southern Zone	30	30	50	50	50	50	50
Kramer Junction into Northern Zone	625	625	625	600	600	600	600
North Needles into Northern Zone	114	75	223	270	270	270	270
Topock into Northern Zone	0	0	0	0	0	0	0
Sub Total Pipeline Receipts	2,589	2,550	2,718	2,740	2,740	2,740	2,740
Storage Withdrawal (Other Three Fields)	0	0	0	346	180	66	0
Storage Withdrawal (Aliso)	0	0	0	0	160	0	0
Total Supply	2,589	2,550	2,718	3,086	3,080	2,806	2,740
DELIVERABILITY BALANCE (MMcfd)	298	0	63	0	0	0	36
Reserve Margin	13%	0%	2%	0%	0%	0%	1%
Non-Aliso Month-End Storage Inventory (Bcf)	39	44	50	39	33	31	38
Aliso Month-End Storage Inventory (Bcf)	34	34	34	34	29	29	29
Total Storage Inventory	73	78	84	73	62	60	67

Scenario D

SoCalGas Monthly Gas Balance							
Cold 1-in-35 year winter, one pipeline in service							
			Line 235 or 4000 return to service Nov. 5				
SoCalGas Monthly Gas Balance							
CGR Demand (MMcfd)	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	641	742	1,151	1,680	1,583	1,518	1,241
Noncore including EG	1,633	1,294	1,059	1,114	1,189	990	978
Wholesale & International	427	367	408	547	562	508	453
Co. Use and LUAF	35	31	33	43	43	39	34
Subtotal Demand	2,736	2,434	2,651	3,384	3,377	3,055	2,706
Storage Injection (Other Three Fields)	0	116	66	0	0	0	34
Storage Injection (Aliso)	0	0	0	0	0	0	0
Storage Injection Total	*0*	*116*	*66*	*0*	*0*	*0*	*34*
System Total Throughput	2,291	2,550	2,717	3,384	3,377	3,055	2,740
Supply (MMcfd)							
California Line 85 Zone	60	60	60	60	60	60	60
Wheeler Ridge Zone	780	780	780	780	780	780	780
Blythe (Ehrenberg) into Southern Zone	980	980	980	980	980	980	980
Otay Mesa into Southern Zone	30	30	50	50	50	50	50
Kramer Junction into Northern Zone	625	625	625	600	600	600	600
North Needles into Northern Zone	114	75	123	270	270	270	270
Topock into Northern Zone	0	0	0	0	0	0	0
Sub Total Pipeline Receipts	2,589	2,550	2,718	2,740	2,740	2,740	2,740
Storage Withdrawal (Other Three Fields)	0	0	0	450	250	100	0
Storage Withdrawal (Aliso)	0	0	0	194	387	215	0
Total Supply	2,589	2,550	2,718	3,384	3,377	3,055	2,740
DELIVERABILITY BALANCE (MMcfd)	298	0	1	0	0	0	0
Reserve Margin	13%	0%	0%	0%	0%	0%	0%
Non-Aliso Month-End Storage Inventory (Bcf)	39	43	45	31	23	20.08	21
Aliso Month-End Storage Inventory (Bcf)	34	34	34	28	16	10	10
Total Storage Inventory	73	77	79	59	39	30	31

Scenario E

SoCalGas Monthly Gas Balance							
Average winter, both pipelines out of service							
	4000 does not return. 235 out						
SoCalGas Monthly Gas Balance							
CGR Demand (MMcfd)	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	636	718	1,058	1,494	1,410	1,359	1,128
Noncore including EG	1,548	1,263	1,012	1,059	1,123	945	925
Wholesale & International	409	362	384	494	508	467	410
Co. Use and LUAF	33	30	31	39	39	35	31
Subtotal Demand	2,626	2,373	2,485	3,086	3,080	2,806	2,494
Storage Injection (Other Three Fields)	0	197	105	0	0	0	96
Storage Injection (Aliso)	0	0	0	0	0	0	0
Storage Injection Total	*0*	*197*	*105*	*0*	*0*	*0*	*96*
System Total Throughput	2,291	2,570	2,590	3,086	3,080	2,806	2,590
Supply (MMcfd)							
California Line 85 Zone	60	60	60	60	60	60	60
Wheeler Ridge Zone	800	800	800	800	800	800	800
Blythe (Ehrenberg) into Southern Zone	980	980	980	980	980	980	980
Otay Mesa into Southern Zone	30	30	50	50	50	50	50
Kramer Junction into Northern Zone	738.9	700	700	700	700	700	700
North Needles into Northern Zone	0	0	0	0	0	0	0
Topock into Northern Zone	0	0	0	0	0	0	0
Sub Total Pipeline Receipts	2,609	2,570	2,590	2,590	2,590	2,590	2,590
Storage Withdrawal (Other Three Fields)	0	0	0	496	350	180	0
Storage Withdrawal (Aliso)	0	0	0	0	140	36	0
Total Supply	2,609	2,570	2,590	3,086	3,080	2,806	2,590
DELIVERABILITY BALANCE (MMcfd)	318	0	0	0	0	0	0
Reserve Margin	14%	0%	0%	0%	0%	0%	0%
Non-Aliso Month-End Storage Inventory (Bcf)	39	45	48	33	22.0	17	20
Aliso Month-End Storage Inventory (Bcf)	34	34	34	34	30	29	29
Total Storage Inventory	73	79	82	67	52	46	49

Scenario F

SoCalGas Monthly Gas Balance							
Cold 1-in-35 year winter, both pipelines out of service							
	4000 does not return. 235 out						
SoCalGas Monthly Gas Balance							
CGR Demand (MMcfd)	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	641	742	1,151	1,680	1,583	1,518	1,241
Noncore including EG	1,633	1,294	1,059	1,114	1,189	990	978
Wholesale & International	427	367	408	547	562	508	453
Co. Use and LUAF	35	31	33	43	43	39	34
Subtotal Demand	2,736	2,434	2,651	3,384	3,377	3,055	2,706
Storage Injection (Other Three Fields)	0	136	0	0	0	0	0
Storage Injection (Aliso)	0	0	0	0	0	0	0
Storage Injection Total	*0*	*136*	*0*	*0*	*0*	*0*	*0*
System Total Throughput	2,291	2,570	2,651	3,384	3,377	3,055	2,706
Supply (MMcfd)							
California Line 85 Zone	60	60	60	60	60	60	60
Wheeler Ridge Zone	800	800	800	800	800	800	800
Blythe (Ehrenberg) into Southern Zone	980	980	980	980	980	980	980
Otay Mesa into Southern Zone	30	30	50	50	50	50	50
Kramer Junction into Northern Zone	738.9	700	700	700	700	700	700
North Needles into Northern Zone	0	0	0	0	0	0	0
Topock into Northern Zone	0	0	0	0	0	0	0
Sub Total Pipeline Receipts	2,609	2,570	2,590	2,590	2,590	2,590	2,590
Storage Withdrawal (Other Three Fields)	100	0	61	520	60	240	80
Storage Withdrawal (Aliso)	0	0	0	274	727	225	36
Total Supply	2,709	2,570	2,651	3,384	3,377	3,055	2,706
DELIVERABILITY BALANCE (MMcfd)	418	0	0	0	0	0	0
Reserve Margin	18%	0%	0%	0%	0%	0%	0%
Non-Aliso Month-End Storage Inventory (Bcf)	39	43	41	25	23	17	14
Aliso Month-End Storage Inventory (Bcf)	34	34	34	26	3	-3	-4
Total Storage Inventory	73	77	75	51	26	13	10

Scenario G

SoCalGas Monthly Gas Balance							
Hybrid scenario: average Nov.-Dec. and cold 1-in-35 Jan.-March. Both pipelines out.							
	4000 does not return. 235 out						
SoCalGas Monthly Gas Balance							
CGR Demand (MMcfd)	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	636	718	1,058	1,494	1,583	1,518	1,241
Noncore including EG	1,548	1,263	1,012	1,059	1,189	990	978
Wholesale & International	409	362	384	494	562	508	453
Co. Use and LUAF	33	30	31	39	43	39	34
Subtotal Demand	2,626	2,373	2,485	3,086	3,377	3,055	2,706
Storage Injection (Other Three Fields)	0	197	105	0	0	0	0
Storage Injection (Aliso)	0	0	0	0	0	0	0
Storage Injection Total	*0*	*197*	*105*	*0*	*0*	*0*	*0*
System Total Throughput	2,291	2,570	2,590	3,086	3,377	3,055	2,706
Supply (MMcfd)							
California Line 85 Zone	60	60	60	60	60	60	60
Wheeler Ridge Zone	800	800	800	800	800	800	800
Blythe (Ehrenberg) into Southern Zone	980	980	980	980	980	980	980
Otay Mesa into Southern Zone	30	30	50	50	50	50	50
Kramer Junction into Northern Zone	738.9	700	700	700	700	700	700
North Needles into Northern Zone	0	0	0	0	0	0	0
Topock into Northern Zone	0	0	0	0	0	0	0
Sub Total Pipeline Receipts	2,609	2,570	2,590	2,590	2,590	2,590	2,590
Storage Withdrawal (Other Three Fields)	100	0	0	496	320	220	100
Storage Withdrawal (Aliso)	0	0	0	0	477	245	16
Total Supply	2,709	2,570	2,590	3,086	3,387	3,055	2,706
DELIVERABILITY BALANCE (MMcfd)	418	0	0	0	10	0	0
Reserve Margin	18%	0%	0%	0%	0%	0%	0%
OTF Month-End Storage Inventory (Bcf)	39	45	48	33	23	17	14
Aliso Month-End Storage Inventory (Bcf)	34	34	34	34	19	12	12
Total Storage Inventory	73	79	82	67	42	29	26