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Prepared by the Staff of the California Public Utilities Commission, California Energy Commission, the California Independent System Operator and the Los Angeles Department of Water and Power

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Aliso Canyon Gas and Electric Reliability Winter Action Plan

Executive Summary

As the seasons move toward winter, with drought conditions and raging fires on the minds of many Southern Californians, the delivery of adequate amounts of electricity and natural gas remains a challenge. The operational limitations of the Aliso Canyon natural gas storage facility has intensified the challenge of assuring the supply of electricity that lights homes and powers appliances, as well as natural gas that provides heats and is used for cooking. This Winter Action Plan is part of the state's response, along with the Winter Assessment Technical Report. The state's assessment found that while risks to energy infrastructure still exist due to the uncertainly of weather and system conditions without Aliso Canyon, conservation and other mitigation measures are expected to help meet the energy needs of Southern California this winter. The Winter Action Plan and Technical Report are companions to an assessment examining summer reliability presented earlier this year.[1]

The Summer Action Plan was a forecast primarily based on natural gas used by power plants to produce electricity because air conditioners run more during hot weather and electricity demand is higher. This Winter Action Plan flips the equation because more natural gas is used in the colder months by residents of homes and small businesses – often referred to as core customers – and less natural gas is used to generate electricity by power plants. In each case the actions plans are forecasts based on various types of analyses. The forecasts are tools Californians can use to prepare for future weather conditions in light of supply constraints resulting from the operational limitations of Aliso Canyon after a significant natural gas leak.

The assessments were prepared by the California Energy Commission (Energy Commission), California Public Utilities Commission (CPUC), California Independent System Operator (California ISO), and the Los Angeles Department of Water and Power (LADWP). They stem from three distinct analyses: the Energy Commission's independent analysis estimating the balance, or reserve margin, between supply and demand under a variety of different weather conditions combined with alternate Aliso Canyon injection and withdrawal scenarios. Second, hydraulic modeling of winter peak day demand by Southern California Gas Company (SoCalGas), which was reviewed by two independent experts: Los Alamos National Laboratory and the consulting firm Walker & Associates. The SoCalGas modeling estimates how much gas load might need to be curtailed. Third, an analysis by the California ISO and LADWP using the

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[1] The Summer Action Plan can be found at http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliability_for_the_Los_Angeles_Basin.pdf. The associated Technical Assessment is at: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf. In May, an update to the Action Plan was posted. The Update can be found at: http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN211671_20160527T164305_Aliso_Canyon_Update.pdf

gas curtailment estimates to determine how much gas electric generators could absorb and whether electricity service interruptions could occur.[2]

The analyses found, under normal weather conditions, with no gas withdrawn from Aliso Canyon and reasonable assumptions about utilization rates on pipeline delivering into SoCalGas, the gas system will be able to meet each month's average daily demand for the winter season from November 1 through March 31. In certain months, it will be able to do so only by increasing withdrawals from other storage facilities. A cold winter makes that more difficult, but still appears feasible with thin inventory margins. However, on a winter peak day, defined as the coldest day forecasted in a 1-in-10-year period for noncore customer demand (plus 1-in-35 demand for core customers), the gas balance analysis shows a need to curtail about 0.3 billion cubic feet (Bcf) of natural gas. Reducing this curtailment does not appear possible by withdrawing more gas from other storage fields.

The analyses also found Southern California residents could still face challenges. Other issues could arise – gas lines can freeze, regional demand could increase from other western states connected to California's system, and equipment breakdowns could limit delivery capacity. On the coldest days if disruption of service is possible, that risk may be reduced by using the natural gas at Aliso Canyon.

The gas balance analysis considered additional scenarios that assume injections at Aliso Canyon beginning at September, October, or November. These scenarios increase the inventory of gas available at Aliso Canyon and allow higher withdrawals. While none of the scenarios consider a return to the withdrawals level of the past at Aliso Canyon, the withdrawal scenarios tested are sufficient to alleviate the projected gas curtailments shown when Aliso Canyon is not part of the system. Even with higher inventories at Aliso Canyon, the analysis identifies several months in which SoCalGas will likely have to deviate from normal storage withdrawal patterns at Aliso Canyon and its other fields to avoid curtailments or preserve an operating margin. For scenarios where injections are delayed until October, the reserve margin on a winter peak day is less than 10 percent, providing little assistance to accommodate equipment failures or other events.

In the hydraulic modeling, which examines a snapshot of a single day and examines details not discernable in the gas balance, SoCalGas found that it cannot meet the 5.2 Bcf demand on the coldest day without gas from Aliso Canyon. It can provide a maximum of 4.5 Bcf per day, assuming pipeline capacity of 95 percent. This confirms that SoCalGas cannot meet its 1-in-10 year design day planning criterion of 5.2 Bcf. Some 0.7 Bcf of gas load would need to be curtailed on a 1-in-10 year peak day. This is a larger amount than the 0.3 Bcf shown in the Energy Commission analysis for reasons uncovered in the hydraulic analysis. The higher level of curtailments found by SoCalGas is attributable to additional system constraints found in the hydraulic modeling that are unidentifiable in the gas balance analysis and assumptions about lower pipeline utilization on cold days. The hydraulic modeling was verified by independent reviewers at Los Alamos National Laboratory and the consulting firm Walker & Associates.

[2] The latter two analyses are summarized here but can be found in a separate Technical Report that accompanies this Winter Action Plan.

Even with the estimated gas curtailment the analysis by the electric balancing authorities, California ISO and LADWP, shows that, under most conditions, they can replace the lost gas-fired electricity generation from resources not served by SoCalGas. Other noncore customers that comprise critical energy infrastructure, such as petroleum refineries, may not have to be curtailed, although the exact nature of curtailments depends on further settlement discussions among the parties relating to SoCalGas' curtailment rule and its application.

Customers at homes and small businesses do not appear to be at risk unless their demand exceeds the 4.5 Bcf per day. This will not occur under the winter peak day planning criterion which includes a 1-in-35-year core demand. That demand is in the range of 3.0 to 3.1 Bcf per day.[3]

The California ISO and LADWP assessed their ability to absorb the potential 0.7 Bcf of gas curtailment. Based on three assumptions, the balancing authorities concluded that they can absorb most of the 0.7 Bcf per day curtailment SoCalGas is showing for a winter peak day's 1-in-10-year demand. Those assumptions include that: a) electric transmission import capability remains unimpaired, b) no gas-fired generation that is needed outside of the SoCalGas service area is out of service, and c) every unit the balancing authorities seek to use has natural gas to operate.

The balancing authorities would need a small amount of additional natural gas to support minimum generation requirements (22 million cubic feet per day (mmcfd)), such as those needed to maintain transmission system reliability or respond to local contingencies (96 mmcfd). Also, there remains some risk of electricity service interruption owing to reliability rules that require the balancing authorities to maintain an operating reserve margin. Gas-fired resources are normally used to maintain those operating reserves because of the ability of these resources to respond rapidly. Even if the balancing authorities can serve all electricity demand without using gas-fired resources they need some gas to provide the reserves. If the balancing authorities have no natural gas owing to a gas curtailment, they could "shed load," which would result in curtailing electricity service to meet the reserve requirement.

This Winter Action Plan identifies 10 new measures to reduce, but not eliminate, the possibility of gas curtailments large enough to cause electricity service interruptions this winter. The measures are in addition to measures implemented for summer. Some of the new measures are aimed at reducing the impacts to customers, including electric generators, who have experienced additional cost to absorb the operational impact caused by the loss of Aliso Canyon. These new measures include extending the tighter gas balancing rules for noncore customers into the winter, in conjunction with creating new balancing rules for SoCalGas when it schedules gas for core customers; setting advance limits on gas consumption by generators on winter peak days, essentially "precurtailing" some electric generation; initiating focused messaging asking consumers to reduce gas use; creating demand response programs to reward lower natural gas use; and revising the withdrawal protocol at Aliso Canyon based on withdrawal and injection capacity, and winter demands. The new measures identified for winter are listed in Table ES-1.

[3] See Table 1.

Table ES-1: List of New Winter Mitigation Measures

Category	Mitigation Measure
Gas-targeted Programs to Further Reduce Usage	Develop and Deploy Gas Demand Response Program
	Develop and Deploy Gas Cold Weather Messaging
Winter Operations Changes	Extend Noncore Balancing rules into winter
	Add Core Balancing Rules
	Create Gas Burn Operating Ceiling for Electric Generation
Reduce Gas Maintenance Downtime	Submit Reports Describing Rapid Progress on Restoring Pipeline Service
Increase Supply	Identify and solicit additional gas supply sources including more California Natural Gas Production
	Prepare to buy Liquefied Natural Gas (LNG)
Use of Gas from Aliso Canyon	Update the Aliso Canyon Withdrawal Protocol and Gas Allocation Process
Refineries	Monitor Natural Gas Use at Refineries and Gasoline Prices

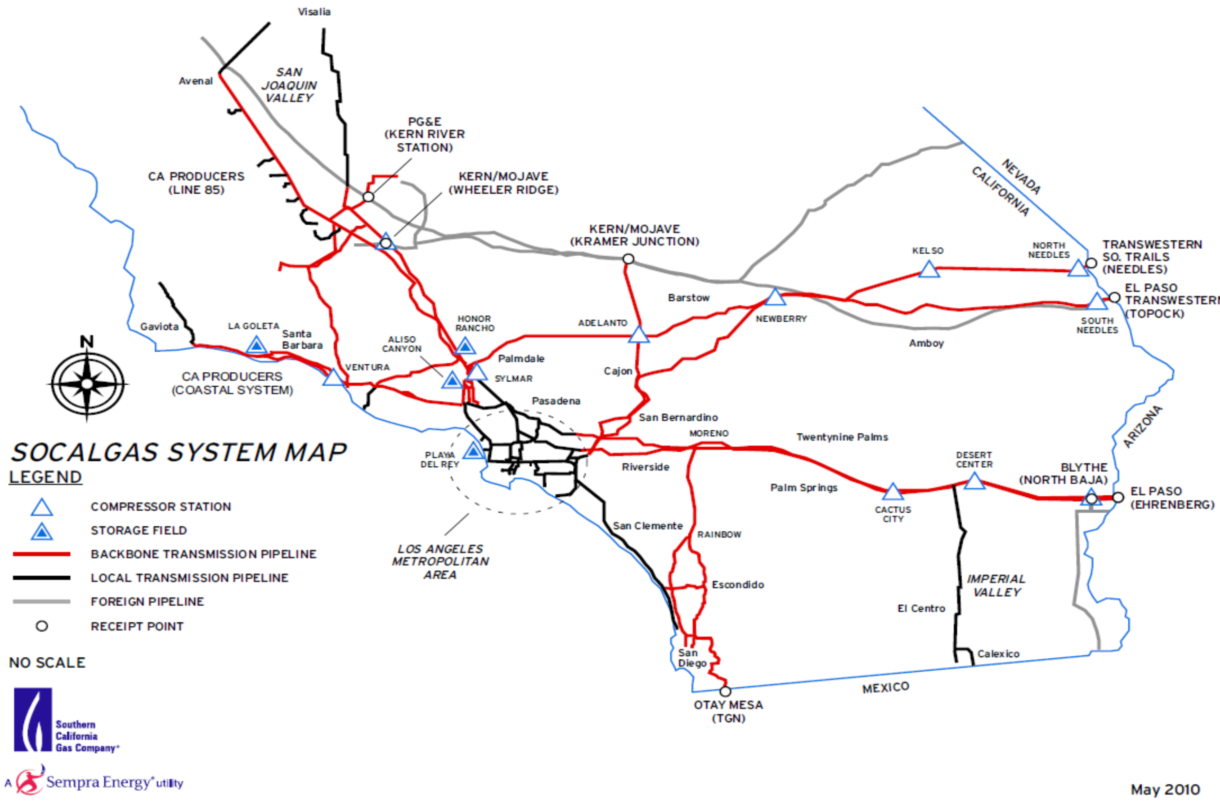
Background and Purpose of Analysis

Governor Edmund G. Brown Jr. issued an Emergency Proclamation January 6, 2016, calling on the Energy Commission, CPUC, and the California ISO to work together and "take all actions necessary to ensure the continued reliability of natural gas and electric supplies during the moratorium on gas injections into Aliso Canyon."

This report assesses natural gas supply and reliability issues for the upcoming 2016-2017 winter given the uncertain status of the Aliso Canyon underground gas storage facility. It presents an action plan to address these issues prepared by the Energy Commission, the CPUC, the California ISO, and the LADWP. It follows the Aliso Canyon Action Plan to Preserve Natural Gas and Electricity Reliability for the Los Angeles Basin released April 5, 2016 (Summer Action Plan), and provides updated measures to reduce risks to reliability this winter.[4] As with the Summer Action Plan, a separate accompanying document, the Technical Assessment, provides additional analysis from a more technical perspective. With few exceptions, background details about operations of the natural gas system in Southern California covered in the Summer Action Plan will not be repeated here. For more background, please see pp. 7-16 of the Summer Action Plan.

[4] For natural gas industry planning and operations, winter is traditionally defined as the months of November through March.

Figure 1: Southern California Gas Company Natural Gas Transmission System



Review of Summer Reliability Assessment

The Summer Assessment used a combination of hydraulic and statistical analysis of the gas system without the availability of gas from Aliso Canyon, overlaid with engineering analysis of the ability of the electric system to absorb gas curtailments. It found the key driver of gas curtailments, minus gas from Aliso Canyon, to be mismatches between supply nominated to come onto SoCalGas' system versus actual customer demand. Mismatches as small as 150 mmcfd could push operating pressures low enough inside the Los Angeles Basin such that SoCalGas operations' staff (also known as Gas Control) would need to order curtailments. Combining mismatches with potential facility outages such as at SoCalGas' other storage facilities or pipelines would further strain the gas system and result in increasingly large gas curtailments, ranging as high as 1,100 mmcfd in the most extreme case. The electricity balancing authorities estimated they could re-dispatch their systems to absorb a gas curtailment of only about 150 mmcfd. This resulted in estimating 14 days of potential outages of electricity service this summer that could occur under certain contingencies without use of Aliso Canyon.[5]

[5] Though not emphasized in describing the summer risks, that same analysis estimated 16 days of gas curtailment that could occur during "non-summer" months, assuming some number of days of system stress combined with days of planned and unplanned outages. The winter analysis turns out to depend much more on weather versus

The energy entities developed a Summer Action Plan that reduces these risks, although the risks cannot be eliminated. That plan included 21 measures counting several added in an update responding to stakeholder comments. The measures included steps to assure that the 15 Bcf at Aliso Canyon would be available if needed to avoid summer curtailment, efforts to make gas and electricity consumers aware of the risk and how they could help, and tightening the gas balancing rules. LADWP undertook several measures under the Summer Action Plan, dispatching its system and operating it differently than under normal conditions to lock in its gas burn, halt forward sales, and complying with the tighter balancing rules. These steps imposed significant cost on LADWP and its customers. Other measures likewise added costs for other customers. A list of the 21 summer measures and their status – each is characterized as either "done," "underway," or "continuing" – with the status of the winter measures characterized as "new" – is in Appendix A to this Winter Action Plan. Some of those measures required action or approval by either the CPUC or the Federal Energy Regulatory Commission (FERC). This will also apply to several winter measures.

It is not clear at this time whether an action plan will be needed for next summer or beyond. Staff at the various agencies and electricity balancing authorities will watch carefully what transpires over the winter with respect to the potential to return to injections at Aliso Canyon and what withdrawal levels SoCalGas might be able to achieve with wells that have been fully inspected for safety. They will determine in late winter whether a reliability action plan for summer 2017 is needed.

Current Situation

As ordered by the CPUC in January, 15 Bcf remains in the Aliso Canyon field. There also remains in place a moratorium prohibiting SoCalGas from injecting natural gas into Aliso Canyon until a comprehensive safety review of the facility is completed. Two heat waves have occurred this summer, triggering Flex Alerts that asked consumers to conserve energy, and associated other activities aimed at avoiding gas curtailments and electricity outages. More about the heat wave response and the successful efforts to avoid gas curtailments and electricity outages can be found in Appendix B.

SoCalGas is following prescribed procedures and continuing to inspect wells in anticipation of a request to return at least part of the field to injection and a more normal operating pattern, consistent with one of the measures contained in the Summer Action Plan and following Division of Oil, Gas and Geothermal Resources (DOGGR) rules, under Senate Bill 380 (Pavley, Chapter 14, Statues of 2016). All wells must either pass a battery of six safety tests or be plugged to isolate them from the field before any injection can begin. SB 380 requires DOGGR to hold a noticed public meeting on the matter and the CPUC Executive Director must concur with any DOGGR finding that the field is safe to return to injection.

Given the time required to test or isolate all the wells in the facility, SoCalGas has been working on parallel paths, testing some wells while plugging others, in hopes of being able to return no fewer than

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available capacity, assuming the current balancing rules continue. The winter assessment does not convert curtailment risk into a probability estimate or an estimate of the number of days at risk.

20 wells to injection. At an average expected withdrawal rate of 15 mmcfd, 20 wells in full operation (with all others safely plugged and isolated) would allow the withdrawal of a maximum of 300 mmcfd. This withdrawal level, however, is insufficient to cover the potential risks of gas curtailment under scenario 3 from the Summer Action Plan (assumes pipeline outage of 500 mmcfd) of the Action Plan Entities' April analysis.[6] In consultation with the other agencies, the CPUC on June 15, 2016 directed SoCalGas to assure that enough wells remained unplugged to support a daily withdrawal of 420 mmcfd, recognizing this would push potential reinjection further into the future.[7] Also on June 15, as authorized by SB 380, DOGGR authorized SoCalGas to withdraw using wells having passed all six tests plus those having completed the first two of the six safety tests, should withdrawing gas during the summer become necessary to prevent electricity curtailments during the summer, and in accordance with the 2016 Summer Withdrawal Protocol.[8]

Natural gas consumers are getting experience with the new operational flow order (OFO) rules implemented pursuant to CPUC approval in early June. These rules reflect the recommendation of the Summer Action Plan to tighten the balancing rules. The results of this are positive. SoCalGas is seeing shippers respond when called upon to remedy imbalances. Another development has been a settlement revising SoCalGas' curtailment order in Application 15-06-020 filed with the CPUC. The settlement allows curtailment by zone. It also calls for SoCalGas to cut only 60 percent of electricity generation (EG) load before going to other non-EG noncore customers (including refineries), then cut refineries to minimum levels (still to be defined) and then back to EG.[9] The settlement will be in place by November 1. As discussed later, it remains unclear how this will actually affect electric generators.

SoCalGas also has tested Line 3000 between the Topock, Arizona, receipt point and the compressor station at Newberry in compliance with CPUC safety requirements. Test results are not expected until late fall. SoCalGas anticipates, based on experience with testing of pipelines of this vintage, that remediation work will be required. Such remediation will remove from service the 540 mmcfd of

[6] *Aliso Canyon Risk Assessment Technical Report*, p. 33. Under Scenario 3, 600 mmcfd of gas would be curtailed; electric generators could cover 180 mmcfd of that but would need 420 mmcfd of gas to prevent electricity service outages. The Scenario 4 gas requirement of nearly 1,000 mmcfd could not be achieved in any case because only 15 Bcf in the field results in field pressure too low to support this level of withdrawal.

[7] Assuming an average withdrawal of 15 mmcfd per well, achieving the 420 mmcfd withdrawal requires 28 wells. Having said that and recognizing the additional requirement to withdraw using the smaller well tubing only (and not the annular space between the tubing and the well casing), SoCalGas is performing 6-hour flow tests to confirm the withdrawal rates.

[8] On August 1 the CPUC responded to a request by SoCalGas by granting authority to conduct flow tests on specified wells at Aliso Canyon. The withdrawal capacity of wells is not known with certainty and the test will provide information needed for SoCalGas to comply with the instructions to maintain a minimum withdrawal capacity of 420 mmcfd for summer reliability. The withdrawals will be made using wells that conform to the requirements of SB 380.

[9] The settlement goes into effect on the first day of the month 90 days after it is approved. Dispatchable electricity generation not forecasted to be operating during the curtailment period is the first to be curtailed followed by, during the winter months, up to 60 percent of electric generation load forecasted to be dispatched. During the summer months the amount is 40 percent.

capacity that line segment provides, likely through winter.[10] All but 200 mmcfd of this can be replaced using capacity at other receipt points into SoCalGas' "northern zone."

Basic Gas Demand, Capacity and Reserve Margin

The basics of the winter analysis were described in the summer assessment, as well as in the CPUC Energy Division's February 16 *Preliminary Staff Analysis: Analysis of Los Angeles Basin's 2016 Energy Demand and the Role of Aliso Canyon Storage.*[11] This section will describe some of that material again.

The key factor to winter demand is temperature. How cold it gets, both as an average over the season and the magnitude of a single day, correlates directly to natural gas consumption. The threat of extreme cold days is highest in December and January, though risks exist in earlier and later months. For example, the cold spells that occurred in late November 2000, February 2011, and February 2014 are times in which gas demand peaks occurred in Southern California outside the typical months. It also matters where it is cold. If temperatures drop to the east, wells or gathering lines can freeze in production areas, which reduce supply available to California. The effect is worse when combined with higher demand from customers located between California and the supply areas. Planners worry about the combination of three events: higher demand in California, well freeze-offs reducing supply and higher demand to the east.

As described in the CPUC's *Preliminary Staff Analysis*, SoCalGas adheres to a standard of meeting gas demand under the 1-in-10 year (for all customers core and noncore) and 1-in-35 (for core customers) year temperature conditions.[12] Policies give core customers --residents and small businesses -- the highest level of protection due to the criticality of home heating and of the building-to-building effort required to restore service after an outage.[13] SoCalGas projects that total customer demand on a 1-in-35 extreme winter peak day will be 5.2 Bcf. [14] If, hypothetically, 3.2 Bcf of supply flows into SoCalGas' backbone transmission system from the interstate pipelines, then 2 Bcf must come for storage or load must be curtailed.

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[10] SoCalGas has had Line 300 operating at a 20 percent pressure reduction since April 2016. Certain remediation work is also already occurring based on leak surveys completed before receipt of the ILI results.

[11] Available at
http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Analysis%20of%20Los%20Angeles%20Basin's%202016%20Energy%20Demand%20and%20the%20Role%20of%20Aliso%20Canyon%20Storage.pdf

[12] CPUC Energy Division *Preliminary Staff Analysis, p. 7.* The 1-in-35 year standard requires for the winter season, November to March, SoCalGas must determine, based on historical data, the pipeline and storage infrastructure needed to meet core customer demand on the coldest day expected in a 35-year period. The temperature and associated core load differ with each month based on the historical data. The 1-in-10 standard parallels the 1-in-35 but is based on meeting total customer demand (core and noncore) on the coldest day expected in a 10-year period. It is calculated in the same manner as the 1-in-35 standard.

[13] Without electricity, however, blower fans on home furnaces will not work and thermostats may not work.

[14] The exact figure tends to vary depending on year and assumptions about population growth, home size and so on. The 2014 California Gas Report showed peak demand of 5.08 Bcf for winter 2016 and 5.12 for winter 2017. The 2016 California Gas Report shows peak demand of 5.013 Bcf for winter 2016 and 5.014 for winter 2017. SoCalGas has told the technical review team that its forecast for the upcoming winter is 5.2 Bcf.

Similarly, CPUC Decision 07-12-019 determined that SoCalGas would need a total storage withdrawal of 2.292 Bcf to meet the 1-in-35 demand for core customers served by SoCalGas, SDG&E, plus Southwest Gas and the City of Long Beach. Of that, 1.65 Bcf could come from the combination of SoCalGas' other three storage facilities (that is, Honor Rancho, La Goleta and Playa de Rey). This leaves 0.642 Bcf as the remaining supply needed to reach the total required from Aliso Canyon under these system design conditions.[15]

Recall that winter peak day demand is 5.1 Bcf - 5.2 Bcf per day. That demand splits into 60 percent from core customers, 20 percent from electric generation plants, and another 20 percent from other noncore customers. The values of each for 2016 are shown in Table 1.

Table 1: Forecasted 2016 Winter Peak Day Demand[16]

Customer	2016 Forecasted Peak Demand	Percent of Peak Demand
Core	3.050 Bcf	60
Electric Generation	1.031 Bcf[17]	20
Noncore, not electric generation[18]	0.996 Bcf	20
Winter Total	5.077 Bcf	100

Source: CPUC Energy Division *Preliminary Staff Analysis*, February 16, 2016; initially taken from 2014 *California Gas Report, p. 90*

Table 2 presents the gas reserve margin under design conditions versus recent experience. At 15 Bcf in storage, pressure within Aliso Canyon allows a withdrawal capacity of Aliso Canyon of about 0.88 Bcf per day.[19] The combined withdrawal capacity from the other SoCalGas storage fields (Honor Rancho, La Goleta, and Playa del Ray) is 1.7 Bcf per day. Adding the storage withdrawal ability to SoCalGas' pipeline design capacity of 3.875 Bcf, SoCalGas would appear able to meet its winter peak demand of 5.1 Bcf per day, with a reserve margin of 0.5 Bcf. But that view of the situation does not describe the reality Southern California faces.

As indicated in the Summer Action Plan, for example, SoCalGas' daily operating data show that 3.4 Bcf per day has been the highest flowing supply coming into its system at any time in the last five years.[20] This would equate to a pipeline utilization rate of approximately 88 percent. Most often, supply receipts

[15] In 2007 when this withdrawal capability was adopted, peak winter demand was forecast to total 5.58 Bcf, higher than the current forecast. This forecast is due to a general decline in peak natural gas demand.

[16] Winter peak demand is calculated by SoCalGas as demand at 1-in -35 year conditions for core customers plus 1-in-10 year conditions for heating degree day-sensitive noncore customers. See 2014 *California Gas Report,* p. 90.

[17] This 1.031 Bcf forecast by SoCalGas is higher, by about 0.2 Bcf, from the recent historical gas burns reviewed by the CAISO and LADWP. Their analysis of how much gas curtailment electricity generators can absorb used the lower, more recent figure.

[18] This includes approximately 0.5 Bcf of use by oil refineries.

[19] This 0.888 Bcf may not be achievable if fewer wells are available or with changed withdrawal characteristics using tubing only instead of operations using both tubing and well casing, consistent with DOGGR's March 4 emergency rules.

[20] As calculated from data posted on SoCalGas' Envoy™ system. The 3.4 Bcf occurred on October 16, 2014. Envoy™ also shows maximum gas sendout to customers of 5.2 Bcf on January 14, 2013.

flowing to the SoCalGas system have totaled 3.0 Bcf per day or less, equating to a 77 percent utilization rate. Receipts should perhaps have increased this year, given that customers cannot withdraw from Aliso Canyon, but it would be imprudent to plan on 3.875 Bcf showing up at the receipt points every day. Table 2 illustrates gas reserve margin calculations demonstrating that SoCalGas would be 1.2 Bcf per day short without Aliso Canyon withdrawals and with only 1.0 Bcf coming from other fields as might happen due to outages or a pipeline constraint.[21] A somewhat more optimistic assessment would show SoCalGas still unable to meet winter peak day demand if pipeline capacity and storage withdrawals are constrained, with a shortfall of 0.8 Bcf. The winter risk assessment results refine these estimates further by considering multiple scenarios with and without Aliso Canyon and with somewhat different storage withdrawal and flowing receipt assumptions to help assess the range of risk customers in Southern California face this winter.

Table 2: Illustrative (Refined) Gas Reserve Margin Under Design Versus Experience if Winter Demand Exceeds Historical Supply/Capacity without Aliso Canyon

Supply/Demand	Design (Bcf/day)	Experience (Bcf/day)	More Optimistic (Bcf/day)
Pipeline Capacity (Flowing Supply Receipts)	3.8	3.0	3.4
Other Storage Supply (*excluding* Aliso)	1.7	1.0	1.0
Peak Winter Gas Demand	(5.2)	(5.2)	(5.2)
Reserve Margin	0.3	**(1.2)**	**(0.8)**

Note 1: Typical outages can reduce capacity 0.5-1.0 Bcf/day
Note 2: Electric generation typically requires 1.0-2.0 Bcf/day, winter/summer, respectively

Risk Assessment Results

The Winter Action Plan entities and technical team prepared three analyses to formulate the winter risk assessment. The first is a gas balance. The gas balance looks at the entire winter, considering different weather outcomes combined with Aliso Canyon injection and withdrawal scenarios. The Energy Commission prepared the gas balance, which reflects the Energy Commission's independent assessment and is provided as an appendix to this plan. The other two analyses are contained in the separate Technical Assessment. The Winter Action Plan entities and SoCalGas authored the Technical Assessment. It contains the hydraulic modeling of a 1-in-10 cold winter day with no Aliso Canyon available. The third analysis, also contained in the Technical Assessment, takes the potential gas curtailments found in the hydraulic analysis and assesses the impact to electricity service. This section summarizes the findings of the Independent Review conducted by Los Alamos National Laboratory and Walker & Associates. A copy of that analysis can be found on the Energy Commission website.

[21] The Summer Assessment had shown pipeline capacity of only 3.0 Bcf, resulting in a negative reserve margin of -0.5 Bcf.

Monthly Gas Balance with Storage Inventory Simulation

A "gas balance" compares supply (or capacity) to demand to see how much excess may or may not exist. In doing so it shows whether all demand can be served and provides a first look at potential curtailments and their magnitude. The summer technical assessment provided an illustrative balance for a peak day, as discussed above. The balances provided for the winter assessment explore periods longer than a single day, looking across the entire winter. This is important to calculate storage inventories. In addition, the storage withdrawals shown in Table 3 for the peak day are not sustainable for every day over the entire winter – SoCalGas' maximum inventory if all fields were full and Aliso Canyon were available without restriction would be only 120 Bcf. Clearly, 120 Bcf would not be enough inventory to withdraw 1 Bcf for all 150 days of the winter withdrawal season, even with Aliso Canyon fully in service.

There are two other reasons to produce the gas balance. It can show what inventory levels are achievable under different injection scenarios at Aliso Canyon, if reinjection is approved. The second reason is to provide an analysis prepared independently of SoCalGas, addressing a criticism of the summer analysis. SoCalGas has had the opportunity to review the analysis and provide comment. In certain instances, SoCalGas might have used slightly different assumptions in its hydraulic analysis, but the differences (highlighted below) do not change the general result and are instructive.

In summary, the gas balance analysis indicates that, using reasonable assumptions, with the use of Aliso Canyon and adjusting the use of withdrawals and injections into and out of Aliso, in aggregate most if not all demand conditions can be met. However the balance analysis does not provide the ability to examine conditions on a granular basis to determine if extremes experienced on a given day can be met. The hydraulic analysis is relied on to provide this granular examination gas system reliability under specific stress conditions that may occur on a given day.

A gas balance cannot address all scenarios. Critically, it cannot assess the impact of intraday events or calculate operating line pressures. Even on days the balance may show all demand being served, it remains only a snapshot of the day, or the month, or the year, on average. In looking at the monthly gas balance it is important to keep in mind that in showing December average demand of 3.3 Bcf, demand actually varies around that average. There will be many days in December where demand is higher than 3.3 Bcf. Weekend days and holidays will usually have demand lower than that average. The gas balance result tables in Appendix C calculate not only a deliverability balance in mmcfd per day, but translate that result into a "reserve margin." This helps compare demand over months but also helps a user recognize that what looks like flexibility of maybe 300 mmcfd equates to a reserve of only 10 percent. Natural gas planners do not have an explicit planning reserve margin requirement. Instead, they have to meet a peak day design criterion and curtail noncore load when needed to bring the system back to balance. The reserve margin in the gas balance can also be interpreted as indicating how much supply can be lost, due to outages for example, and still serve all demand.

Twelve cases were created, testing three weather conditions for each of four Aliso Canyon availability scenarios. The Aliso Canyon availability scenarios include (1) No Aliso injections or withdrawals; (2) Aliso injections using 20 wells starting September 1 and allowing withdrawals of up to 1.0 Bcf by December; (3) Aliso injections starting October 1, allowing withdrawals of up to 0.580 Bcf by December and lower than average withdrawals in January and February to maintain minimum inventory levels; and (4) Aliso injections starting October 1 with more pessimistic injection assumptions, allowing maximum daily withdrawals of up to 0.40 Bcf by December with and reduced withdrawals in January and February to maintain minimum inventory levels.

The gas balance analysis shows a need to adjust operations somewhat just to serve all demand in a normal winter if Aliso Canyon is not in service (Scenario 1). In a cold winter case, operations must be adjusted more, but as long as flowing supply in the quantities assumed is delivered to SoCalGas, SoCalGas should be able to meet all demand. On a 1-in-10 peak day, however, the simple gas balance shows SoCalGas to be short by 260 mmcfd.[22] Being short means, all else equal, that some demand cannot be served and must be curtailed. If a higher or lower demand forecast is used the 260 mmcfd would increase or decrease.

If injections can begin by September 1 (Scenario 2, which achieves a December 1 inventory at Aliso of 48.4 Bcf), these conditions can be alleviated. SoCalGas would need some adjustments with withdrawals at its other fields while supporting injections at Aliso Canyon. Doing so makes sense given the summer analysis showed that Aliso Canyon is the field where the gas is needed to support the Los Angeles Basin demand. Both the cold year and 1 in 10 peak day demands are satisfied.

Delaying injections to October 1 (Scenario 3, which achieves a December 1 inventory of 30 Bcf) makes September easier but requires care in November in a normal weather year and for both November and December in a cold year. Because delaying injection makes less gas available at Aliso Canyon, lower average withdrawals from the field are supportable in January, February and March because of the need to maintain the inventory needed on a peak day. The winter peak day demand is satisfied but the reserve margin is tight, at 6 percent.

Delaying injections to October 1 (Scenario 4, which achieves a December 1 inventory of 25.6 Bcf) combined with more pessimistic injection assumptions makes September easier but requires care in November in a normal weather year and for both November and December in a cold year. Because delaying injection makes less gas available at Aliso Canyon and even less than in Scenario 3 with lower injection assumptions, lower average withdrawals from the field are supportable in January, February, and March because of the need to maintain the inventory needed on a peak day. The winter peak day demand is satisfied but the reserve margin is tighter, at 3 percent.

[22] The reference to a 1-in-10 peak day can be confusing. The demand used to analyze a "winter peak day" consists of 1-in-10 demand for noncore customers *plus* 1-in-35 demand for core customers as explained in Table 1 and its footnote. The analysis in the Technical Report, however, is said by SoCalGas to be a true "1-in-10" demand for both core and noncore customers that totals to around 5.2 Bcf. The demand used by SoCalGas in the hydraulic analysis is slightly higher, at 5.2 Bcf, and is spread among the customer classes a little differently. This difference has no significant effect on the findings described here other than to say that a higher demand forecast would make the gas balance results look worse than they do now.

The detailed gas balance results are presented an Appendix B to this Winter Action Plan. They are summarized in Table 3.

Table 3: Gas Balance Results Summary

	WEATHER CASES		
ALISO INVENTORY SCENARIOS	**A. Normal Weather**	**B. Cold, Dry Winter**	**C. Winter Peak Day Weather**
1. No Aliso Canyon	Ok with withdrawal changes at other fields for December	Bigger change to withdrawals in December plus changes for November through February	Curtailment of300 mmcfd
2. Reinjection Starting 9/1 (48.4 Bcf)	Change required for Nov at other fields because injecting at Aliso; margin < 10% in Sep and Oct	Bigger change to remedy November curtailment; change for very low margin in December	Ok because now have 1000 mmcfd to withdraw from Aliso; reserve margin 14%
3 Reinjection Starting 10/1 (30 Bcf)	Change required for Nov at other fields because injecting at Aliso; Sep margin ok because Aliso injection delayed to Oct	Change to remedy November curtailment and tight margins in Oct and Dec	All demand served because now have 580 mmcfd to withdraw from Aliso but reserve margin tight, at 6%
4. Reinjection Starting 10/1 with Pessimistic Reinjection Assumptions (25.6 Bcf)	Change required for Nov at other fields because injecting at Aliso	Change to remedy November curtailment and tight margins in Oct and Dec	All demand served because now Have 400 mmcfd to withdraw from Aliso but reserve margin tight, at 3%

Hydraulic Analysis of Winter Peak Day

SoCalGas performed a hydraulic analysis looking at winter demand, similar to the analyses conducted for the summer analysis presented in April that used the DNV-GL *Synergi* hydraulic modeling platform[23] More than one stakeholder expressed concern that the Summer Action Plan relied too heavily on hydraulic analysis that was performed by SoCalGas and that it was therefore not sufficiently independent. Besides the Energy Commission performing an independent gas balance analysis to help inform the winter assessment, the California ISO engaged Los Alamos National Laboratory and Walker & Associates to perform an independent review of the hydraulic analysis. Their report is provided under separate cover.[24] The independent reviewers concluded that the method SoCalGas used "appears to be adequate for estimating the availability of gas and assessing the potential for curtailments." They also concluded that the method "appropriately accounts for operational factors" and that "no modifications to the hydraulic analysis methodology are needed." The reviewers believe that SoCalGas may have some overlap between the identified number of days of system stress and the number of days with unplanned outages, but that is somewhat offset by having understated the combined impact of high stress days with unplanned and planned outages occurring on the same day. In other words, this concern does not materially affect the outcome of the analysis.

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[23] As noted in the Summer Action Plan and the accompanying Technical Assessment, *Synergi* is widely used by gas utilities and is known as the industry standard. The FERC is also familiar with the use of *Synergi* in demonstrating that new pipelines are designed to meet forecast demand.
[24] See Backhaus, Zlotnik and Walker, *Independent Review of Hydraulic Modeling,* August 12, 2016.

The hydraulic analysis models intra-day operations of the gas system. A successful simulation result must operate the system to: 1) stay between the minimum and maximum operating pressures, 2) stay within the capacities of the gas transmission facilities, and 3) fully recover system linepack overnight. [25] Violating those parameters in the simulation identifies conditions that would, in real time, require the system operators to curtail load to preserve the physical integrity of the system.

The winter hydraulic simulation looks at a 5.2 Bcf demand, which corresponds to SoCalGas' latest forecast of 1-in-10 demand. The analysis initially assumes 60 mmcfd is received from California gas producers, consistent with experience and current economics. It also assumes a full 1,210 mmcfd is received into the Southern Zone; 1,590 mmcfd is received at Topock and a full 765 mmcfd is received at Wheeler Ridge. These yield a total of 3.625 Bcf per day of flowing supply received from upstream sources delivered by pipeline into SoCalGas' high-pressure gas transmission system. The receipts assumed for the northern and southern zones are higher than used in the Summer Assessment. This is justified, according to SoCalGas, by the new (yet costly) balancing rules in place, that lead SoCalGas to believe that daily mismatches between scheduled supply and actual demand are eliminated.[26] The analysis further assumes a combined 1490 mmcfd of gas withdrawals from SoCalGas' Honor Rancho, Playa del Rey and La Goleta gas storage fields and no gas withdrawals from Aliso Canyon.

SoCalGas' initial finding from this winter peak day hydraulic modeling was that the above pipeline capacity -- plus withdrawals from its other gas storage fields -- makes it capable of supporting a maximum demand of only 4.7 Bcf per day, assuming no other outages and that the assumed pipeline capacity if fully utilized. Any higher level of demand pushes operating pressures too low, inducing curtailments of gas service to recover the system.

This maximum servable demand of 4.7 Bcf per day is some 0.5 Bcf lower than the system design day planning criterion demand of 5.2 Bcf per day. This effectively means that SoCalGas cannot serve core loads plus meet the 1-in-10 year noncore demand condition without gas from Aliso Canyon or some other way of getting additional supply into its system beyond the combination of flowing supply receipts and storage withdrawal maximums analyzed.

In arriving at this initial finding of 4.7 Bcf per day maximum servable demand, SoCalGas also discovered that receipts coming into both its Wheeler Ridge Zone plus full withdrawals at Honor Rancho are infeasible. Wheeler Ridge delivers into the Los Angeles Basin using Line 225 which is also the pipeline gas from Honor Rancho would use. This congestion means SoCalGas must either back down flowing supply receipts at Wheeler Ridge or back down withdrawals from storage at Honor Rancho.[27] Thus, the final model solution limits Honor Rancho withdrawals to 850 mmcfd. This represents a reduction of 150 mmcfd compared to its maximum of 1,000 mmcfd.

[25] The volume of gas that can be stored in a pipeline is often referred to as linepack.
[26] Under CPUC Decision No. 16-07-008 approving the balancing rule settlement, these new rules expire in November unless they are replaced or extended.
[27] Recall that the summer analysis assumed much lower levels of supply flowing in at the receipt points, thus the conflict on Line 225 was never encountered.

This initial 4.7 Bcf would be further lowered should the gas supply levels assumed in the hydraulic analysis, in fact, not show up at the receipt points, as has occurred during recent cold spells in which demand and prices to California's east has drawn supply away. SoCalGas assumed a 5 percent supply reduction on these days.[28] In addition, work that may need to occur on Line 3000 once the in-line inspection results are completed would reasonably create a net loss of 200 mmcfd of supply. These events would reduce the maximum demand servable to 4.5 Bcf. A small additional decrease in maximum servable demand may occur once withdrawals are limited to use of only the tubing inside the withdrawal wells. All demand above 4.5 Bcf would be curtailed to preserve operating pressures to serve other customers.

SoCalGas' hydraulic analysis demonstrates ways in which the Energy Commission's gas balance analysis may be too optimistic. For instance, SoCalGas determined that it can withdraw 850 mmcfd (and maybe only 800 mmcfd) from Honor Rancho when Line 225 is full. Another reason why the gas balance analysis may be too optimistic is the inability to observe intraday effects at specific pressure valves, such as Moreno Station and tradeoffs between flowing gas into the Los Angeles Basin versus flowing it south to San Diego Gas & Electric or to properly simulate the impact of less than average withdrawals from Aliso Canyon on operating pressures in the Los Angeles Basin.

Electricity Analysis

As a further analysis, the California ISO and LADWP took the maximum servable demand of 4.5 Bcf as determined by SoCalGas and assessed the impact of a shortfall in the ability to meet that level on electricity generation. Assuming that electric transmission import capability remains unimpaired, the two electricity balancing authorities should be able to move generation around enough to absorb the 0.7 Bcf gas curtailment. Winter electricity demands are far lower in summer than in winter, giving the balancing authorities more freedom to move generation around within their systems.[29] This result further assumes that all gas-fired generation that is needed outside the SoCalGas service area is in service and that every unit that the balancing authorities seek to use in lieu of resources served by SoCalGas has natural gas service unimpaired by the SoCalGas curtailments.

During the winter, the electricity balancing authorities need a small amount of natural gas during every hour. Some 22 mmcfd is needed every day to support minimum generation requirements, such to support transmission line imports or to respond to local contingencies or to maintain minimum voltage levels. In addition, if an N-1 event occurs (that is one in which the Most Severe Single Contingency occurs, such as where a key generator or transmission circuit is lost), the balancing authorities have one hour to restore the reserves they used to satisfy the N-1 event. Restoring or holding those reserves could, if no other option is available, require the balancing authorities to shed load. Whether their demand response programs would be big enough or able to respond quickly enough to cover that load

[28] This would amount to a loss of 177 mmcfd and may be low relative to recent cold weather events.
[29] The Winter Assessment Technical Report cites a California ISO winter peak of 21,828 MW on January14, 2013. *Winter Assessment Technical Report,* p. 34.

shed requirement determines whether electricity service would need to be interrupted to other customers. To cover a non-simultaneous N-1 contingency event (meaning both CAISO and LADWP do not suffer an N-1 event at the same time) the electricity balancing authorities need a minimum of 96 mmcfd.

The electricity balancing authorities also reviewed gas throughput data, looking for instances where receipts of gas supplies flowing in from outside SoCalGas' system were low during winter months. The data reveal instances of cold days in which supply coming in at the receipt points is lower than assumed in the natural gas hydraulic analysis and in fact only 78 percent of the capacity was used at times. Should this occur, the gas curtailment to electric generators would be larger than that shown by SoCalGas in the hydraulic analysis. If receipts were even lower than the 78 percent, the curtailment to generators would be larger than the available generating resources outside the SoCalGas service area can replace, resulting in electricity service interruptions in Southern California.

In all, even with SoCalGas able to meet only a 4.5 Bcf per day demand instead of its 5.2 Bcf 1-in-10 year design day planning criteria, the California ISO and LADWP, under most conditions, can replace the lost generation from resources not served by SoCalGas.

Curtailment Implications: Impact by Customer Category

The New Curtailment Rules

As explained above, SoCalGas serves two basic categories of customers: core (residential and small commercial/industrial) and noncore (electric generators, large industrial, including refineries and large commercial). The 1-in-10 standard used in this report defines the total capacity required to meet the gas demand of both sets of customers. If the total capacity cannot be met, SoCalGas follows a curtailment procedure defined in its Tariff Rule 23 as revised on July 14, 2016 in CPUC Decision 16-07-008. The revised rules will become effective November 1, the beginning of the winter season for gas customers. These rules define a hierarchy of risk/priority of service, establishing the order in which customers will be curtailed, for the customer categories (and subcategories) in the event that all demand cannot be served.[30] Core customers have the highest priority of service and conversely are the last to be curtailed.

The new curtailment order defined in D. 16-07-008 is, from first to be curtailed to last, summarized as:

1. All <u>dispatchable electric generation</u> not forecast to be operating at the time the curtailment order is effective.
2. Up to <u>60 percent of dispatched electric generation</u> load during winter (November through March) and 40 percent during summer.

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[30] In addition to defining the risk hierarchy/priority of service the revised rules define 10 curtailment zones. The decision incorporating all of the changes can be accessed at:
http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=165051361
N.B. Ordering paragraph 3 of the decision erroneously states that the proceeding is closed. This has been corrected and the proceeding remains open concerning changes to balancing procedures.

3. Up to 100 percent of non-EG noncore and noncore cogeneration on a *pro rata* basis. *Refineries, however, may establish minimum usage requirements and these minimum requirements are not curtailed in this step.*[31]
4. Up to 100 percent of the remaining refinery load not curtailed in step 3 and up to 100 percent of EG load not curtailed in step 2.
5. Large core customers.
6. Other non-residential core customers (small commercial/industrial).
7. Residential core customers.

Impact to Non-Core Customers Other Than Electric Generators

Noncore customers other than electric generators, including oil refineries and associated facilities that move petroleum products, represent key infrastructure that is essential to California's economy and security. These customers have undoubtedly experienced additional costs, like the electric generators, complying with the tighter balancing rules and are worried about whether their gas service would be curtailed. In preparing the Summer Action Plan, the analysis assumed electric generators would be curtailed first. In addition, the magnitude of gas curtailment projected by the hydraulic modeling was never larger than the electrical generation (EG) load, meaning that no other natural gas customers were assumed to be curtailed. The CAISO and LADWP analysis did not attempt to change any gas use or operations at the refinery cogeneration facilities when they redispatched power plants to determine what gas curtailment electric generators could absorb. The curtailment burden in the summer analysis was completely born by electricity generation controlled by the two electricity balancing authorities: California ISO and LADWP.

The Energy Commission held a workshop June 17 to explore impacts to refineries, seeking to understand the impacts of losing natural gas service or electricity service. Some exposure to gas curtailment for the winter for the refineries and associated facilities remains. That exposure depends on the size of gas curtailment relative to: a) the size of EG load; b) the withdrawal available from Aliso Canyon (if any); c) the refineries' minimum load protected via the change to curtailment rules adopted in CPUC Decision No. 16-07-008; and d) the exact location (i.e., "zone") showing the curtailment-causing pressure deviation. Parties to the settlement updating SoCalGas' curtailment rule are supposed to meet and define a minimum level of gas curtailment that refineries could absorb consistent with block 3 of the revised curtailment rule described above. Preliminary indications are that the threshold those customers feel they can absorb may be zero. If the settlement agreed to means that the rest of the noncore fails to curtail, for whatever reason, the gas curtailment burden will fall back onto electric generators.

On the electric side, refineries and related facilities can receive some protection from electricity outages by applying for an outage exemption. CPUC Decision No. 01-04-006 agrees, in response to a request from the Energy Commission, to consider refineries an "essential use." The relevant utilities review such requests consistent with their tariffs, feasibility as affected by their system infrastructure configuration,

[31] The minimum usage requirements are based on a level of operation required to maintain safety, avoid damage to equipment and avoid the possibility prolonged outages/delayed restarts. The shutdown of refinery operations can result in refined fuel shortages and price increases with significant negative economic impacts.

and fairness concerns. The Energy Commission has facilitated updates to the exemption list for Southern California Edison (SCE) and conferred with LADWP in order to mitigate the impact of potential electricity outages to refineries. It appears that most of this critical petroleum-related infrastructure may be insulated from the impact of gas curtailments or electricity outages related to Aliso Canyon. While this critical energy infrastructure may be protected, it also means that the gas curtailment burden appears to fall, virtually fully, back to electric generators, especially since regardless of what the curtailment order is on paper, the fact remains that electric generation remains the highest load on the system and is easiest for gas system operators to curtail when operating decision need to be made in minutes. Prudent planning requires we recognize this is likely, that we plan for it to occur and appropriately model the curtailment burden on electric utilities and analyze the associated risks.

Mitigation Measures

This Winter Action Plan identifies implementation of ten additional measures to mitigate the risk and magnitude of natural gas curtailments and electricity service interruptions for the upcoming winter. Nearly all require working out additional details in order to implement. The additional measures include:

Gas Demand Response. Preliminary research by Energy Commission and CPUC staff suggests that demand response (DR) programs for noncore natural gas customers have not yet been developed anywhere in the United States. Some discussion appears in the literature about DR for core customers using programmable thermostats but no programs yet appear to exist. With SoCalGas unable to meet its 1 in 10 design criterion the time is now to design and implement a program that would create positive financial incentives for core and noncore customers to reduce natural gas demand in advance of and in order to reduce the magnitude of gas curtailments. The CPUC should order SoCalGas to implement a DR program that rewards large natural gas customers for reducing their demand, when so requested, by December 1, 2016. In past years gas utilities offered programs to awarded customers a rebate if their gas usage was 20 percent below usage in prior years. While these programs should be explored, the deployment of smart meters should allow the utilities to better target demand reduction to specific days and to better measure actual reductions. Agency staff will explore the best options with stakeholders.

Cold Weather Messaging. While alluded to in the Summer Action Plan and available to some degree at *conserveenergysocal.com,* more specific messaging pertaining to natural gas customers needs to be developed and deployed soon. SoCalGas should work with the Marketing and Outreach Advisory group created as a result of the Summer Action Plan and CPUC order to develop a plan to begin launching those messages no later than October 15, 2016.

Keep the Tight Noncore Balancing Rules. The settlement adopting tighter balancing rules for noncore customers in June 2016 expires unless extended by its terms. It expires November 30, 2016, or once Aliso Canyon achieves operations of 450 mmcfd withdrawal capability and 45 Bcf inventory. The Energy Commission's gas balance analysis suggests these levels are not likely to be achieved by November 30. The revised rules are costly to noncore customers but appear to have helped reduce the risk of gas curtailment. The CPUC should consider extending them for winter.

Add Core Balancing Rules. SoCalGas is responsible, with certain exceptions, for buying and scheduling the natural gas it uses to serve core customers. Unlike noncore customers who must balance their scheduled gas quantities to their actual demand (something that is often difficult for electric generators whose load is driven both by weather and the electricity market), SoCalGas balances its core loads to a forecast. In other words, noncore customers are responsible for forecast error. SoCalGas is not responsible for any forecast error.

A look at the gas balance tables in Appendix C shows monthly demand for core customers, even in a winter with normal weather, often to be in excess of 1500 mmcfd. The monthly balancing tolerance allowing a 10 percent difference between demand and supply could, in theory, easily be more than the 150 mmcfd identified as the maximum supply and demand differential tolerable while Aliso Canyon is not in full service. Noncore customers (including electric generators) can be completely in balance while SoCalGas is responsible for doing nothing to reduce a core customer imbalance that could be large enough to put the system in stress.

SoCalGas should assure that meter read information for the first portion of the gas day is analyzed and transmitted to the system operators. The operators should then update the gas quantities scheduled for core customers to achieve a better match of core customer gas purchases and actual core gas demand. CPUC action will be required to put this measure in place.

Submit Meaningful Reports Describing Rapid Progress on Restoring Pipeline Service During Maintenance Outages. Once SoCalGas gets its in-line inspection reports back it will likely have to take out of service and repair a 540 mmcfd pipeline in order to comply with safety requirements. The outage is likely to run into the winter months and its 200 mmcfd net impact is reflected in all of the analyses prepared for the Winter Action Plan. SoCalGas should do everything possible to get that line back into full service as quickly as possible. It should file with the CPUC, for release to the public, an update of actions taken and progress made to get that line – or any other that goes out of service while Aliso Canyon is constrained – back into service promptly. Utility managers and regulators recognize that both electricity line workers and gas pipeline crews are dedicated, hard-working individuals. SoCalGas should give them the tools and the resources to get Line 3000 back in service, to provide the measures needed to complete the job regardless of cost, and to share with customers the depth of the measures taken.

Gas Burn Operating Ceiling for Electric Generation. The California ISO should impose a ceiling (i.e., operations limit) on the electric generator gas burn for very cold days. Fixing the gas burn in advance of cold days is a form of uneconomic dispatch.[32] The practical effect, is to reduce the amount of gas burn that needs to shifted in real time should a gas curtailment occur. Effectively, it curtails some of the electric generation load in advance and increases the probability that SoCalGas will not have to curtail further.[33]

[32] LADWP implemented uneconomic dispatch for the summer and will likely continue to use

[33] This measure, as well as extension of some of the summer mitigation measures noted in Appendix B, may require FERC approval.

Prepare to Buy LNG. At the Summer Action Plan workshop and in subsequent comments several stakeholders raised the potential to obtain some Liquefied Natural Gas (LNG) and deliver it into the SDGE system from Sempra's LNG facility at Costa Azul in Mexico, using the Otay Mesa receipt point. Sempra has indicated interest but expressed concern that "affiliate rules" create an impediment to doing this. The Energy Commission and CPUC should investigate what those impediments may or may not be and see if they can be mitigated. Additional gas supply of 200 mmcfd on a day when curtailments are forecast could be a substantial mitigant to the total load requiring curtailment.

California Natural Gas Production. Stakeholders criticized the Summer Action Plan for assuming only 60 mmcd of California natural gas production was available. Sixty mmcfd is in fact consistent with the deliveries by California gas producers observed recently in the Envoy operating data. It also appears that more gas from California producers would help fill Line 85 and other capacity coming in from along the Coast, reducing the need for gas from Aliso Canyon. The question is whether economics and operations by the producers who, in the San Joaquin Valley are producing most of their natural gas as "associated gas" that is a byproduct from their crude oil wells favor their bringing more gas into the SoCalGas system. The Energy Commission has taken the lead in contacting producers to ask what, if anything, producers can do to increase deliveries into the SoCalGas system, and will report back its findings.

Withdrawal Protocol and Gas Allocation Process. One of the summer mitigation measures was to create a protocol to apply if and when some of the 15 Bcf of gas stored at Aliso Canyon needed to be withdrawn. That protocol was developed and is in place now. The experience with the summer heat waves and preparing for the potential to withdraw gas from Aliso Canyon demonstrated that certain revisions to the protocol and its gas allocation process would be helpful. In addition, the protocol needs to be updated to reflect changes in withdrawal and injection capacity and winter demands. The CPUC will take the lead in updating the protocol.

Monitor Gasoline Prices. It is not clear, despite the revised curtailment order, if refineries will share in a gas curtailment. The economic consequences of them not being able to operate could be large. The Energy Commission, through its PIRA database, should monitor refinery gas use and operations. The Attorney General should also monitor gasoline prices for potential price manipulation and be prepared to take action if needed.

Next Steps

Implementing the Winter Action Plan requires several follow-up steps. Those steps include the following:

- Provide needed details to execute mitigation measures.
- Develop and track the milestones to implement the Winter Action Plan.
- Update reliability risk assessments and adjusting the Winter Action Plan as the well testing plan unfolds and results potentially allow changes to injection and withdrawal capability.
- Provide responses updating the Winter Action Plan after obtaining stakeholder comments from the August 26 public workshop.

Conclusion

While risks to energy infrastructure still exist due to the uncertainly of weather and system conditions without Aliso Canyon, conservation and other mitigation measures are expected to meet the energy needs of Southern California this winter. The analyses show Southern California residents may still face challenges. Other issues could arise – gas lines can freeze, regional demand could increase from other western states connected to California's system, and equipment breakdowns could limit delivery capacity. On the coldest days if disruption of service is possible, that risk may be reduced by using the existing natural gas at Aliso Canyon.

The Winter Action Plan proposes 10 new measures to mitigate the risk of gas curtailments and electricity service interruptions. The measures are for immediate implementation. As with the summer analysis, the sooner the Aliso Canyon natural gas storage facility can be safely brought on line, the lower the risk to gas and electric reliability. The actions identified in this Winter Action Plan will reduce the risk, but will not eliminate it.

Appendix A: Mitigation Measures from Summer and Winter Action Plans

CATEGORY	MITIGATION MEASURE	Status
Prudent Aliso Canyon Use	Make available 15 bcf stored at Aliso Canyon to prevent summer electricity interruptions	Done
	Efficiently complete the required safety review at Aliso Canyon to allow safe use of the field	Underway
Tariff Changes	Implement tighter gas balancing rules. Implement the curtailment settlement agreement (as required by settlement approximately 90 days after Commission Decision, i.e. on or about November 1.	Done; see below for changes for Winter
	Modify operational flow order rule (OFO)	Done
	Call Operational Flow Orders Sooner in Gas Day	On Hold
	Provide market information to generators before cycle 1 gas scheduling	Done
	Consider ISO market changes that increase gas-electric coordination	Continuing
Operational Coordination	Increase electric and gas operational coordination	Done
	Establish more specific gas allocation among electric generators in advance of curtailment	Done
	Determine if any gas maintenance tasks can be safely deferred	Done
LADWP Operational Flexibility	Curtail physical gas hedging	Continuing
	Stop economic dispatch	Continuing
	Curtail block energy and capacity sales	Continuing
	Explore dual fuel capability	Done through September 13, 2016; continue through winter
Reduce Natural Gas and Electricity Use	Use New and Existing Programs Asking Customers to Reduce Natural Gas and Electricity Energy Consumption	Underway
	Expand gas and electric efficiency programs targeted at low income customers	Underway
	Expand Demand Response Programs	Underway for Electricity
	Reprioritize existing energy efficiency towards projects with potential to impact usage	Done
	Reprioritize solar thermal program spending to fund projects for summer and by end of 2017	Underway
	Accelerate Electricity Storage	Underway
Market Monitoring	Protect California Ratepayers	Underway
Gas-targeted Programs to Further Reduce Usage		
	Develop and Deploy Gas Demand Response Program	New for Winter
	Develop and Deploy Gas Cold Weather Messaging	New for Winter

CATEGORY	MITIGATION MEASURE	Status
Winter Operations Changes	Create Advance Gas Burn Operating Ceiling for Electric Generation	New for Winter
	Keep the Tighter Noncore Balancing rules	New for Winter
	Add Core Balancing Rules	New for Winter
Use of Gas from Aliso Canyon	Update the Aliso Canyon Withdrawal Protocol and Gas Allocation Process	New for Winter
Reduce Gas Maintenance Downtime	Submit Reports Describing Rapid Progress on Restoring Pipeline Service	New for Winter
Increase Supply	Identify and solicit additional gas supply sources including more California Natural Gas Production	New for Winter
	Prepare to Buy LNG	New for Winter
Refineries	Monitor Natural Gas Use at Refineries and Gasoline Prices	New for Winter

Appendix B: Avoiding Curtailments and Outages so far in 2016

It is fair to ask how with the two heat waves, one spanning June 18 to20 and another in July, that the gas system in fact avoided curtailment and the electricity system avoided customer outages without using any natural gas from Aliso Canyon. This heat wave resulted in a series of mitigation measures being deployed, including Flex Alerts, requests for conservation in state buildings, and intense monitoring by officials in various agencies. SoCalGas called an Operational Flow Order for low inventory at the 5 percent level and warned customers via its Envoy™ website and other mechanism near the end of the week prior that they should closely monitor Envoy™ for system condition updates throughout the weekend. SoCalGas also prepared Aliso Canyon for withdrawals in the event they became necessary, and operations personnel in the gas and electricity control facilities were on standby in the event that gas curtailments and electricity outages needed to be implemented. Both LADWP and the Southern California IOUs called on demand response programs to help reduce demand. Preliminary estimates indicate that as much as 630 MWs (June) and 400 MWs (July) were dispatched by the Southern California IOUs. LADWP was able to achieve 55 MWs of demand response during this period.

Had the heat wave continued as originally forecast, however, it quite likely would have been necessary to utilize gas in Aliso Canyon. The timing of the hot spell was particularly concerning because the high temperatures occurred over the weekend, through Monday, a day for which natural gas would have been scheduled the previous Friday. Had Monday been hotter temperatures than forecast on Friday, the system likely would have entered the kind of mismatch condition that the analytic team has identified as not remediable absent use of gas from Aliso Canyon. The combination of efforts employed was successful in avoiding a curtailment on June 20.

In summary, the risks identified in the summer analysis in fact occurred in late June. Those risks were mitigated by implementing and using the actions identified in the Action Plan. It should be noted that the heat wave was not that extreme, falling well short of a 1-in-10 electricity system peak demand for CAISO in both heat waves. While June 20 set a new record for LADWP's June demand, it was not an all-time record, and the July event, was less extreme than June's. Further, while the mitigation measures succeeded here, they may not be as fully effective under more severe weather conditions or if other gas storage, pipeline or generating facilities are out of service. The possibility of setting an annual peak load exists through the end of September. LADWP has seen more all-time peaks set in September than in any other month.

Appendix C: California Energy Commission Staff Gas Balance Results

The Energy Commission performed a gas balance analysis designed to calculate the margin, or extra space, between supply and demand each month. A "gas balance" is a standard utility planning tool that simply compares supply (or capacity) to demand to see if all demand can be served. The Summer Assessment provided an illustrative balance for a peak day, as discussed above. The balances provided for the Winter Assessment explore periods longer than a single day. This is important because the storage withdrawals shown in Table 4 for the peak day are not realistically sustainable for every day over the entire winter – there is not enough inventory to withdraw 1 Bcf for all 150 days of the winter withdrawal season even with Aliso Canyon fully in service. Looking across the entire year allows modeling of total monthly injections and withdrawals for their impact to monthly inventory levels.

Critically, the gas balance analysis was prepared by agency staff, not SoCalGas. SoCalGas received a draft of the analysis, with the opportunity to comment on it. The values for certain flowing supply assumptions differ slightly from what SoCalGas used in its hydraulic analysis, but the differences largely offset each other and do not change the general result.

The gas balance is built in a Microsoft Excel spreadsheet and other than limited calculations set up to convert historical data into monthly profiles for storage and such, relies only on basic arithmetic. It is set up on a calendar year basis, but allows a user to print results for a "gas storage year," running from April 1 to March 31. It also follows the injections and withdrawals each month to simulate changes to the storage inventory; this is useful for modifying use of storage as needed to remedy curtailments while assuring no violation of minimum inventory requirements. The Energy Commission's gas balance can calculate an annual, monthly, or peak day balance. Users can use built-in default values or choose their own values for most inputs.

A gas balance cannot address all questions, (as noted at the April 8 workshop presenting the Draft Summer Reliability Action Plan). Critically, it cannot assess the impact of intraday events or calculate operating line pressures. Even on days the balance may show all demand being served, it remains only a snapshot of the day, or the month, or the year, on average. In looking at the monthly gas balance it is important to keep in mind that in showing December average demand of, say, 3.3 Bcf, demand actually varies around that average. There will many days in December where demand is higher than 3.3 Bcf. Weekend days and holidays, on the other hand, will usually have demand lower than that average. The balance result tables therefore calculate not only a deliverability balance in mmcfd per day, but translate that result into a "reserve margin," in order to not only better compare across months but also to help a user recognize that what looks like flexibility of maybe 300 mmcfd may yield headroom above average demand of only 10 percent. Natural gas planners do not have an explicit reserve margin requirement because previously it has been acceptable to curtail noncore load to bring the system back to balance; electricity planners in California, in contrast, use a 15 percent reserve margin. The reserve margin or balance can also be interpreted as indicating how much supply can be lost – due to outages, for example – and still serve all demand.

General Assumptions

The gas balance is preset to use the natural gas demand published by the gas utilities in the 2014 California Gas Report (CGR). SoCalGas' monthly gas demand is found in its workpapers. The Balance could be updated to use the 2016 CGR but do not represent a material change from the 2014 values. The Balance allows use of demand under normal weather conditions, a "cold" year with dry hydro-electric conditions, and a peak day.[34] Users can also modify the demand assumptions as they like.

Table B-1: Gas Balance Flowing Supply Receipt Assumptions

	Flowing Supply (mmcfd)		
Receipt Point	**Gas Balance**	**Maximum**	**SoCalGas Winter Hydraulic Model**
California Line 85 Zone	60	160	60
California Coastal Zone	0	150	
Wheeler Ridge Zone	765	765	765
Southern Zone	1,010	1,210	1,210
Northern Zone	1,390	1,590	1,590
Total Flowing Supplies at Receipt Points	3,225	3,875	3,625

Table 5 shows the model assumptions for flowing gas supply received from pipelines delivering gas into the SoCalGas system. The analysis assumes 60 mmcfd is received from California gas producers; 765 mmcfd via the Wheeler Ridge Zone; 1,010 mmcfd via SoCalGas' Southern Zone; and 1,390 via the Northern Zone. The Southern Zone value reflects the pressure limitation on Line 2000 coming in at Ehrenberg that

[34] The "cold" year is identified in SoCalGas' most recent Triennial Cost Allocation proceeding (A. 15-07—014, Testimony of Bruce Wetzel, p. 10) as a 1 in 35 year condition. The peak day is a 1-in-10 year temperature condition for noncore plus 1 in 35 year for core customers.

reduces its maximum capability.[35,36] The Northern Zone value reflects that in-line inspection results have required necessary remediation work on Line 3000 that will shut down 540 mmcfd of capacity. 340 mmcfd of that can be offset if shippers deliver to an alternate receipt point into the Zone.[37] On a combined basis, these assumptions allow 3.225 Bcf per day of supply to flow into SoCalGas' system. This roughly 400 mmcfd combined reduction between the Northern Zone and the Southern Zone may be adequate to capture occasions on which cold weather to California's east reduces gas supply. The report prepared by the Federal Energy Regulatory Commission and the North American Electricity Reliability Corporation concerning the February 2011 cold weather event found that 20 percent of Permian and San Juan Basin supplies were lost due to the cold and cited similar cold spells occurring in 1989, 2003 and 2010.[38] Since that report we have also experienced freeze offs in December 2013 and the February 2014 so-called "polar vortex" event that have resulted in reduced flowing supplies to California. The 400 mmcfd, reduction, however, is less than a 20 percent cut and therefore may not be large enough to capture the impacts of cold weather to California's east under all circumstances.

Note that the gas balance assumes 200 mmcfd less into the Southern Zone than is assumed by SoCalGas in its hydraulic modeling.

For storage injections and withdrawals, the gas balance relies on 15 years' worth of daily inventory reported on SoCalGas' *Envoy* website to generate a "normal" working profile. The daily changes in inventory represent net injections or withdrawals. The gas balance uses as its initial assumption average injections or withdrawals established by the *Envoy* data for each month. The storage profile also allows a user to switch between using the average injection/withdrawal profile versus recorded maximums for each month. The average values may well be a decent proxy to reflect requirements allowing tubing-only injections and withdrawals in the future. In any case, a standard planning assessment should not use maximum recorded injections or withdrawals nor should it use maximum design day capabilities. For storage inventory, the analysis takes as its starting value the 58.6 Bcf reported via *Envoy™* as the April 1, 2016 inventory.

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[35] Ehrenberg is a major receipt point of the El Paso Natural Gas Pipeline into the Southern gas transmission zone

[36] In theory, the 200 mmcfd lost due to the pressure limitation could be made up with deliveries at Otay Mesa. Doing so requires either that a) LNG is available at Costa Azul or b) that gas delivered by El Paso Natural Gas to Ehrenberg is flowed south via North Baja and west via Mexico's Gasoducto Baja Norte to Otay Mesa. At current LNG prices the former is unlikely. The latter requires bearing the cost of the additional transportation from Ehrenberg across the two pipelines. The Energy Commission therefore chose to reflect the more conservative 1,010 for the Southern Zone.

[37] Both the April 8 workshop and the May 27 response to stakeholder comments explained that California enjoys having more upstream pipeline capacity than it has "take-away" capacity from the receipt points. This potential outage of Line 3000 and ability to replace some of that capacity using an alternate receipt point is an example of this benefit.

[38] *Outages and Curtailments during the Southwest Cold Weather Event of February 1 – 5, 2001*, p. 212 and p. 195, respectively.

Table B-2: Gas Balance Maximum Storage Withdrawal Assumptions for Winter Peak Day

Storage Field	Gas Balance	Maximum	SoCalGas Winter Hydraulic Model
	(mmcfd)		
Honor Rancho	1000	1000	850
Playa Del Ray	300	400	300
La Goleta	340	440	340
Total (without Aliso Canyon)	1,640	1,840	1,490

Table B-2 shows the storage withdrawal caps assumed in the gas balance, compared to the maximum feasible and to the values used in SoCalGas' hydraulic modeling for the winter assessment. Recall that the monthly withdrawals in the balance are based on a recorded profile set to the average value observed over a 15-year period. The values in Table B-2, in contrast, represent the maximum value those monthly withdrawals could swing up to on a given day. These values cannot be sustained every day all winter long without equipment breaking or inventory dropping below acceptable levels. These values are also only achievable if all equipment is working and it inventory is close to its maximum. The key difference between the gas balance and SoCalGas' hydraulic analysis is that SoCalGas dropped the value for Honor Rancho because of the Line 225 constraint explained previously in this Action Plan. Were the gas balance to have used the full 1,840 on a winter peak day, the results in all of those cases would improve by 200 mmcfd.

Scenarios Defined

Staff assessed twelve cases, testing three weather cases for each of four Aliso availability scenarios. Table B-2 presents a matrix defining the 12 cases. The Aliso availability scenarios include (1) No Aliso injections or withdrawals; (2) Aliso injections using 20 wells starting September 1 and allowing withdrawals of up to 1.0 Bcf by December; (3) Aliso injections starting October 1, allowing withdrawals of up to 0.580 Bcf by December and lower than average withdrawals in January and February to maintain minimum inventory levels; and (4) Aliso injections starting October 1 with pessimistic injection assumptions, allowing withdrawals of up to 0.40 Bcf by December and lower than average withdrawals in January and February to maintain minimum inventory levels.

Table B-2: Gas Balance Aliso Inventory Scenario and Weather Case Combinations

	WEATHER CASES		
ALISO INVENTORY SCENARIOS	**A. Normal Weather**	**B. Cold, Dry Winter**	**C. Winter Peak Day Weather**
1. No Aliso Canyon	1A. No Aliso Canyon + Normal Weather	1B. No Aliso Canyon + Cold, Dry Winter	1C. No Aliso Canyon + Winter Peak Day Weather
2. Reinjection starting Sept. (48.4 Bcf)	2A. Reinjection starting Sept. + Normal Weather	2B. Reinjection starting Sept. + Cold, Dry Winter	2C. Reinjection starting Sept. + Winter Peak Day Weather
3 Reinjection starting Oct. (30 Bcf)	3A. Reinjection starting Oct. + Normal Weather	3B. Reinjection starting Oct. + Cold, Dry Winter	3C. Reinjection starting Oct. + Winter Peak Day Weather
4. Reinjection starting Oct. with Pessimistic Reinjection Assumptions (26.5 Bcf)	4A. Reinjection starting Oct. with Pessimistic Reinjection Assumptions + Normal Weather	4B. Reinjection starting Oct. with Pessimistic Reinjection Assumptions + Cold, Dry Winter	4C., Reinjection starting Oct. with Pessimistic Reinjection Assumptions + Winter Peak Day Weather

Table B-3 summarizes the Aliso Canyon reinjection assumptions. Scenario 3 starts reinjection later than scenario 2, which means there are fewer wells available by December. Scenario 4 assumes more pessimistic assumptions either for the number of wells available or the estimated injection rate per well, which also means there are even fewer wells available by December.

Table B-3: Summary of Aliso Canyon Injection Assumptions. Resulting Inventory and Withdrawal Capability

Aliso Inventory Scenario	Sept. Total Injections MMcfd	Oct. Total Injections MMcfd	Nov. Total Injections MMcfd	Aliso Canyon Dec. Storage Inventory Level BCF	Maximum Withdrawal Capability Beginning in Dec. (Bcfd)
1. No Aliso Canyon	**0**	**0**	**0**	**15**	**n/a**
2. Aliso Canyon, Reinjection starting Sept.	300	400	400	48	1.0
3. Aliso Canyon, Reinjection starting Oct.	N/A	300	400	36	0.58
4. Aliso Canyon, Reinjection starting Oct. with More Pessimistic Reinjection Assumptions	N/A	150	200	25.6	0.4

Results staff prepared and ran a total of 12 cases encompassing the weather and Aliso condition parameters described above. Each begins with a “base” version. If the “base” version shows a negative balance (implying load would need to be curtailed) or a reserve margin less than 10 percent, staff looked to see if storage use could be adjusted, yet still remain with acceptable parameters, and thus improve the balance. The results tables for the normal weather and cold winter, dry hydro-electric condition scenarios is run for each month on a storage year basis, ending in March 2017. On a monthly basis through winter 2017, and the gas balance for the winter peak-day cases in scenario C is run for a single day, representing the 1-in-10 winter peak day. By analyzing supply and demand over the course of the season as in the A and B scenarios, the results inform whether total winter demand over the course of the season can be met. By analyzing the C scenarios, the results inform whether the CPUC mandated 1-in-10 year cold day design standard can be met.

The annual gas balance cases were initially run assuming average total storage injection (including Honor Rancho, La Goleta, and Playa Del Rey) and withdrawal supplies based on 15 years of data from SoCalGas’ Envoy website. , the initial base results showed low reserve margins in some months, primarily in the November to December timeframe, so adjustments were made to increase the total storage withdrawal rate to improve the reserve margins to a 10 percent range.

The overall results are summarized in Table B-3. Details for each Aliso Canyon Inventory Scenario and weather case follow.

Table B-3: Results Summary

	WEATHER CASES		
ALISO INVENTORY SCENARIOS	**A. Normal Weather**	**B. Cold, Dry Winter**	**C. Winter Peak Day Weather**
1. No Aliso Canyon	Ok with changes for December	Bigger change for December plus changes for November through February	Curtailment of 258 mmcfd
2. Reinjection Starting 9/1 (48.4 Bcf)	Change required for Nov at other fields because injecting at Aliso; margin < 10% in Sep and Oct	Bigger change to remedy November curtailment; change for very low margin in December	Ok because now have 1000 mmcfd to withdraw from Aliso; reserve margin 14%
3 Reinjection Starting 10/1 (30 Bcf)	Change required for Nov at other fields because injecting at Aliso; Sep margin ok because Aliso injection delayed to Oct	Change to remedy November curtailment and tight margins in Oct and Dec	All demand served because now have 580 mmcfd to withdraw from Aliso but reserve margin 6%
4. Reinjection Starting 10/1 with Pessimistic Reinjection Assumptions (26.5 Bcf)	Change required for Nov at other fields because injecting at Aliso	Change to remedy November curtailment and tight margins in Oct and Dec	All demand served because now Have 400 mmcfd to withdraw from Aliso but reserve margin 3%

<u>Scenario 1: Results With No Aliso</u>

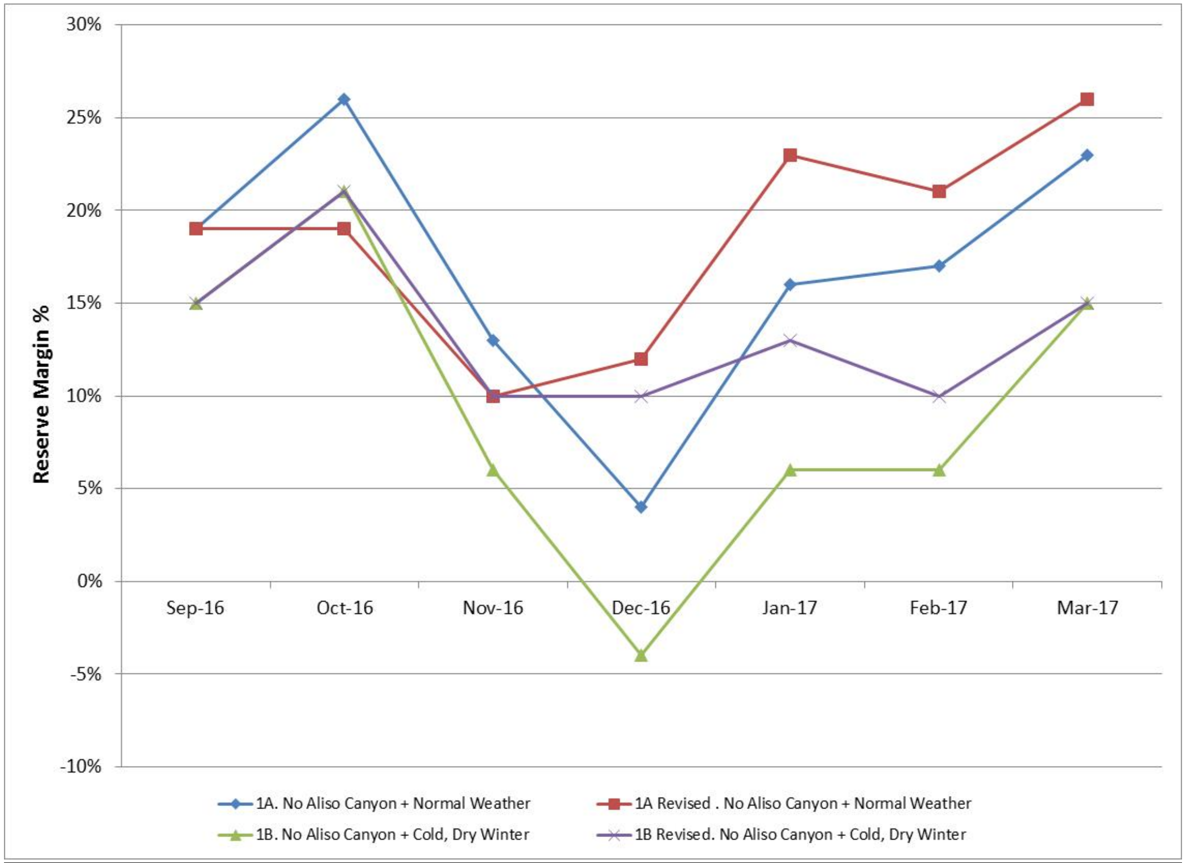
Figure 2 shows the reserve margin results of Scenario 1. With normal weather (Scenario 1A Base), December would show a reserve margin of only 4 percent absent withdrawing more gas from storage. Looking at the inventory available in the other fields and being mindful of the maximum withdrawal capability at those other fields, there appears to be room to increase the average withdrawal rate from the other three fields. Increasing that the average withdrawal from 190 mmcfd for December to 449 mmcfd, the reserve margin moves to 12 percent (Scenario 1A Revised).[39] Total storage inventory in March would still be a healthy 50 Bcf.

[39] As one walks through the cases, the Base version for each case assumes typical, average withdrawals from the other three storage fields. The Revised version shows changes to those withdrawals to better balance supply with demand while staying within the maximum withdrawal capability and recognizing the impact on inventory.

With the cold winter and dry hydro-electric conditions (which affect demand in late summer), November through February show very low reserve margins and December shows a negative balance of 139 mmcfd (Scenario 1B Base). The fall months, September and October, show sufficient reserve margins because demand is lower in these shoulder months. By increasing total storage withdrawals from Honor Rancho, La Goleta, and Playa Del Rey, within tolerances, the December issue as well as the tight margins in other months can be remedied and still end the winter season with 27 Bcf in storage (Scenario 1B Revised).

The winter peak day condition shows a gas curtailment of around 260 mmcfd. The assumption of 3.2 Bcf available via receipt points and 1.6 Bcf from storage yields a theoretical maximum peak day demand servable of 4.9 Bcf per day.

Figure 2: Reserve Margins for Scenario 1, Results with No Aliso



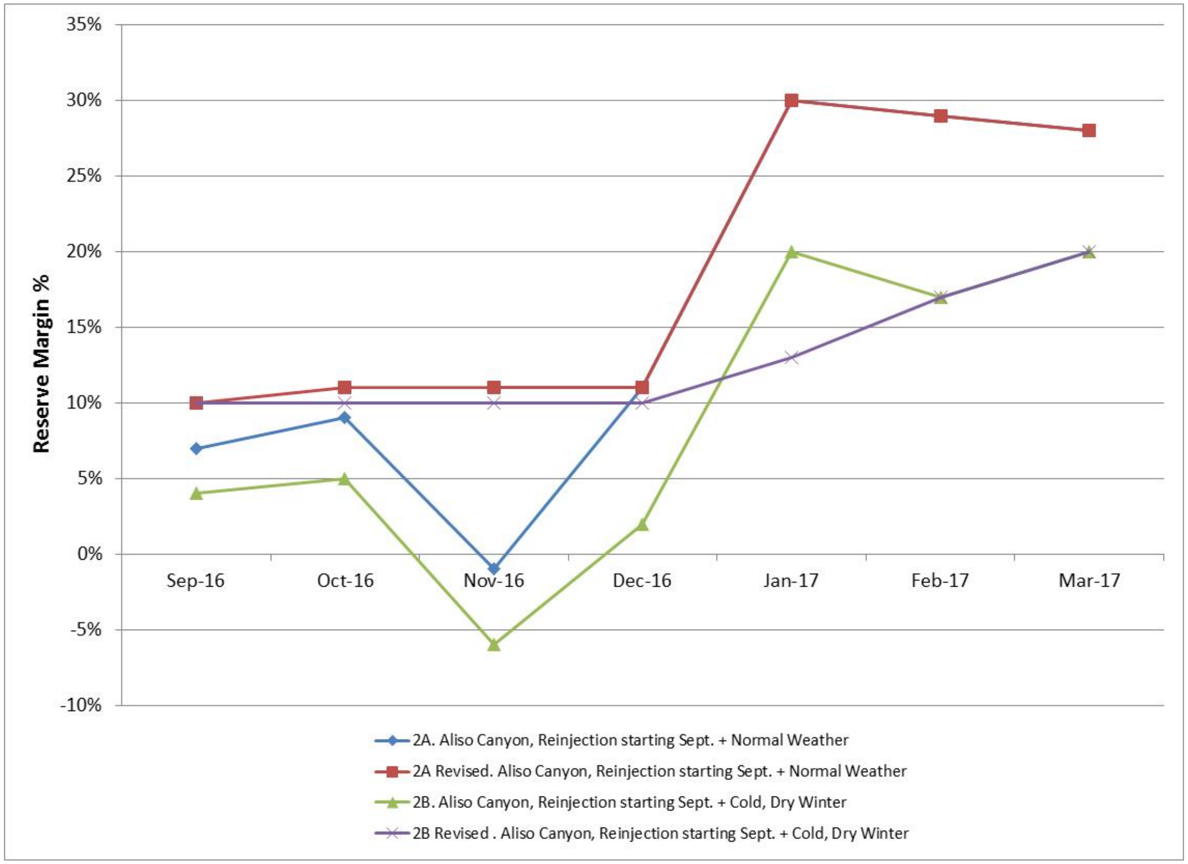
Scenario 2: Aliso Injections Beginning September 1

Figure 3 shows the reserve margins for scenario 2. With normal weather, the reserve margin is acceptable in all but September, October and November (Scenario 2A), owing to the additional demand created for injection. The normal injection season runs April through the end of October, so SoCalGas normally has seven months to refill its storage reservoirs by the beginning of the winter season. By compressing Aliso Canyon injections into this late summer three month period, additional demand is created in these few months beyond what SoCalGas would normally see. Injections at the assumed rates and with no withdrawals would achieve an inventory of 48.4 Bcf by December 1. By withdrawing some gas from the other three storage fields in November as well as small amounts in September and October, those low reserve margins in September, October, and November can be remedied (Scenario 2A Revised). The rest of the winter stays within acceptable limits and the ending inventory is still 41 Bcf.

For a cold winter and dry hydro-electric conditions, the reserve margins again are low as injections at Aliso Canyon begin, negative in November and very low in December (Scenario 2B). It appears there is room to increase withdrawals at other fields and still stay within reasonable inventory parameters. Making this change achieves a 10 percent reserve margin in virtually all months (Scenario 2B Revised).

On the winter peak day, all demand can be served, because the injections created inventory able to support a withdrawal of 000 mmcfd from Aliso Canyon if necessary. The theoretical maximum peak day demand that is servable increases to nearly 5.9 Bcf per day because the 1000 mmcfd now available from Aliso Canyon increases the total take from all storage fields combined to 2.6 Bcf for the peak day.

<u>Figure 3: Reserve Margins for Scenario 2, Aliso Injections Beginning September 1</u>



<u>Scenario 3: Aliso Injections Beginning October 1</u>

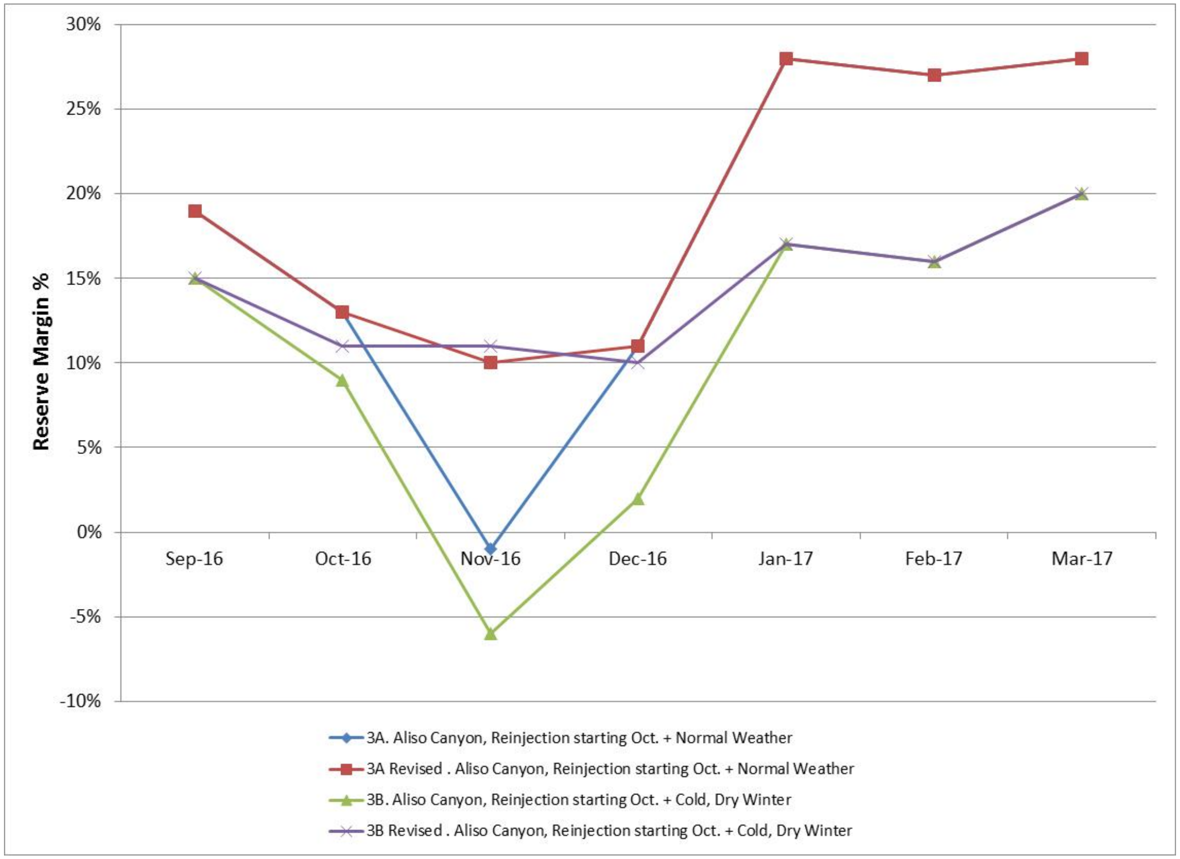
Figure 4 shows the reserve margins for Scenario 3. The normal weather case under Scenario 3 (Scenario 3A) is very similar to Scenario 2 except that September looks better as nothing is being injected at Aliso Canyon that month. November has a slight negative balance implying a small November curtailment. Delaying injections to October means that the inventory at Aliso Canyon will be lower than in Scenario 2 and only 30 Bcf by December 1. The January through March withdrawals from Aliso Canyon must therefore be reduced (by 75 mmcfd and 46 mmcfd in January and February, respectively) in order to maintain inventory at minimum levels needed at Aliso Canyon through the rest of the winter season.[40]

The cold winter and dry hydro-electric conditions case shows a low reserve margin in October and December with a negative balance in November of over 200 mmcfd (Scenario 3B). These were remedied by modifying withdrawals in those months (Scenario 3B Revised). SoCalGas' season-ending storage inventory is 18 Bcf.

The assumption of 3.2 Bcf available via receipt points plus now only 2.2 Bcf from storage with the lower Aliso Canyon inventory yields a theoretical maximum peak day demand servable of 4.9 Bcf per day. Under the assumptions used in Scenario 3, SoCalGas cannot meet its winter peak design day.

Figure 4: Reserve Margins Scenario 3, Aliso Injections Beginning October 1

[40] *Preliminary Staff Analysis, Analysis of Los Angeles Basin's 2016 Energy Demand and the Role of Aliso Canyon Storage Energy Division, February 16, 2016,* p. 12

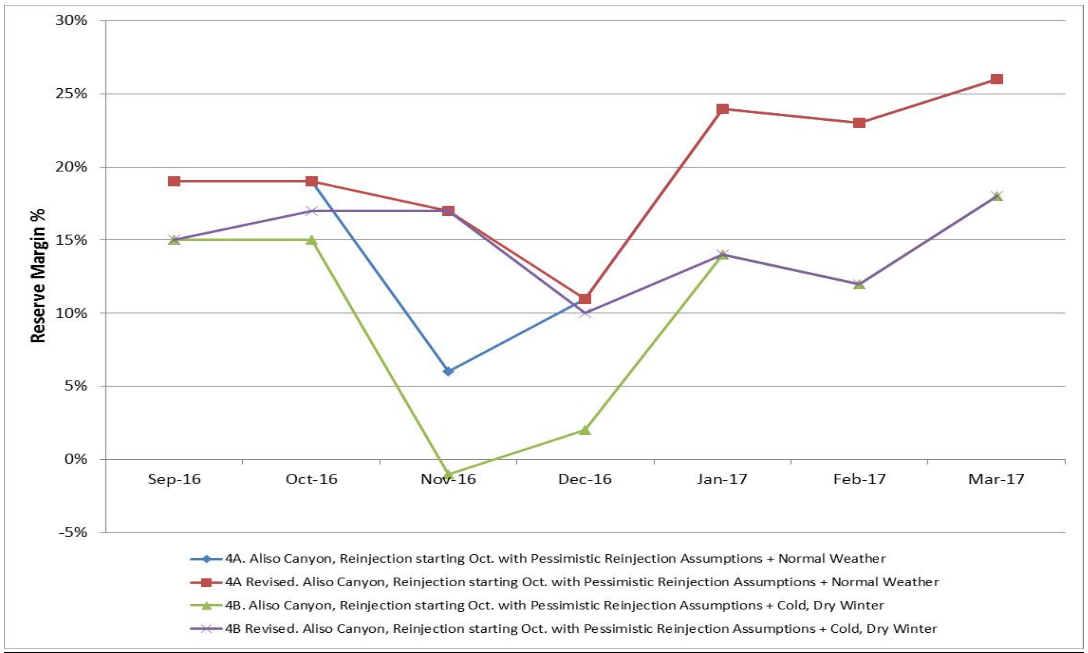


Scenario 4: Aliso Injections Beginning October 1 with More Pessimistic Injection Assumptions

Figure 5 shows the reserve margin results for Scenario 4. Scenario 4 reflects still lower injections at Aliso Canyon, illustrating the possibility that even fewer wells might be approved for reinjection or the injection/withdrawal capability of those wells might be lower. This time 150 mmcfd is assumed injected in October and 200 mmcfd in November. This achieves an inventory at Aliso Canyon of 25.6 Bcf by December 1. The normal weather cases under Scenario 4 are similar to Scenario 3 with a few exceptions. The reserve margins for October and November are higher under Scenario 4 because Aliso Canyon injections are reduced -- lower injections translate to lower demand in those months -- than in Scenario 3. No months have negative balances, but the reserve margin in November dips to 6 percent in the Scenario 4 base case. Increasing withdrawals from SoCalGas' other storage fields can improve that reserve margin given that total inventory appears robust. Compared to Scenario 3, reducing Aliso Canyon withdrawals from 375 mmcfd to 250 mmcfd in January and from 325 mmcfd to 200 mmcfd in February will maintain the Aliso Canyon inventory at about minimum levels needed there through the rest of the winter season. The Aliso Canyon inventory ends the season at just under 3 Bcf and overall storage inventory ends the season at 35 Bcf.

The higher demands in the cold winter dry hydro-electric condition base case for Scenario 4 results in a low reserve margin in December with a slight negative balance in November of 22 mmcfd. These were remedied by modifying withdrawals at SoCalGas' other storage fields in those months; the Aliso Canyon withdrawal pattern over the winter is the same as in the Scenario 4 normal weather case. The Aliso Canyon inventory ends the season at just under 3 Bcf and the resulting overall season-ending storage inventory is 16 Bcf.

Figure 5: Reserve Margins Scenario 4, Aliso Injections Beginning October 1 with Pessimistic Injection Assumptions



Scenario 1A Base: No Aliso + Normal Weather

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,016	784	676	618	616	646	732	1,115	1,539	1,500	1,436	1,185
Noncore excluding EG	481	472	470	466	487	486	470	457	454	490	489	479
Electric Generation	629	674	769	1,077	1,120	990	818	715	695	650	623	621
Wholesale & International	392	342	361	462	463	472	379	420	547	477	485	413
Co. Use and LUAF	33	30	30	34	35	34	32	36	43	41	40	35
Total	2,551	2,302	2,306	2,657	2,721	2,628	2,431	2,743	3,278	3,158	3,073	2,733
Storage Injection	125	232	260	176	99	104	130	117	0	0	0	0
System Total Throughput	2,676	2,534	2,566	2,833	2,820	2,732	2,561	2,860	3,278	3,158	3,073	2,733
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	14	199	438	359	132
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,239	3,424	3,663	3,584	3,357
DELIVERABILITY BALANCE (MMcfd)	603	691	659	399	460	527	664	379	146	505	511	624
Storage Inventory (Bcf)	59	66	74	79	80	82	86	89	83	70	60	56
Reserve Margin				14%	16%	19%	26%	13%	4%	16%	17%	23%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	0	0	0	0
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000

Scenario 1A Revised: No Aliso + Normal Weather

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,016	784	676	618	616	646	732	1,115	1,539	1,500	1,436	1,185
Noncore excluding EG	481	472	470	466	487	486	470	457	454	490	489	479
Electric Generation	629	674	769	1,077	1,120	990	818	715	695	650	623	621
Wholesale & International	392	342	361	462	463	472	379	420	547	477	485	413
Co. Use and LUAF	33	30	30	34	35	34	32	36	43	41	40	35
Total	2,551	2,302	2,306	2,657	2,721	2,628	2,431	2,743	3,278	3,158	3,073	2,733
Storage Injection	125	232	260	176	99	104	280	317	0	0	0	0
System Total Throughput	2,676	2,534	2,566	2,833	2,820	2,732	2,711	3,060	3,278	3,158	3,073	2,733
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	20	55	33	0	150	449	650	500	232
Total Supply	3,279	3,225	3,225	3,245	3,280	3,258	3,225	3,375	3,674	3,875	3,725	3,457
DELIVERABILITY BALANCE (MMcfd)	603	691	659	412	460	527	514	315	396	717	652	724
Storage Inventory (Bcf)	59	66	74	78	80	82	91	96	82	61	47	40
Reserve Margin				15%	16%	19%	19%	10%	12%	23%	21%	26%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	150	200	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	250	200	100
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	19,650	25,650	19,295	11,545	5,945	2,845

Scenario 1b Base: No Aliso + Cold Dry Winter

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,110	820	687	619	617	651	761	1,226	1,728	1,666	1,644	1,291
Noncore excluding EG	482	472	469	466	486	487	470	458	457	493	491	481
Electric Generation	669	732	849	1,199	1,244	1,076	872	770	749	708	664	657
Wholesale & International	424	365	375	464	468	470	394	452	583	528	529	451
Co. Use and LUAF	35	31	31	36	37	35	33	38	46	45	44	38
Total	2,720	2,420	2,411	2,784	2,852	2,719	2,530	2,944	3,563	3,440	3,372	2,918
Storage Injection	125	232	260	176	99	104	130	117	0	0	0	0
System Total Throughput	2,845	2,652	2,671	2,960	2,951	2,823	2,660	3,061	3,563	3,440	3,372	2,918
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	14	199	438	359	132
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,239	3,424	3,663	3,584	3,357
DELIVERABILITY BALANCE (MMcfd)	434	573	554	272	329	436	565	178	-139	223	212	439
Storage Inventory (Bcf)	59	66	74	79	80	82	86	89	83	70	60	56
Reserve Margin				9%	11%	15%	21%	6%	-4%	6%	6%	15%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	0	0	0	0
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000

Scenario 1b Revised: No Aliso + Cold Dry Winter

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,110	820	687	619	617	651	761	1,226	1,728	1,666	1,644	1,291
Noncore excluding EG	482	472	469	466	486	487	470	458	457	493	491	481
Electric Generation	669	732	849	1,199	1,244	1,076	872	770	749	708	664	657
Wholesale & International	424	365	375	464	468	470	394	452	583	528	529	451
Co. Use and LUAF	35	31	31	36	37	35	33	38	46	45	44	38
Total	2,720	2,420	2,411	2,784	2,852	2,719	2,530	2,944	3,563	3,440	3,372	2,918
Storage Injection	125	232	260	176	99	104	130	117	0	0	0	0
System Total Throughput	2,845	2,652	2,671	2,960	2,951	2,823	2,660	3,061	3,563	3,440	3,372	2,918
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	20	55	33	0	150	700	650	500	132
Total Supply	3,279	3,225	3,225	3,245	3,280	3,258	3,225	3,375	3,925	3,875	3,725	3,357
DELIVERABILITY BALANCE (MMcfd)	434	573	554	285	329	436	565	314	362	435	353	439
Storage Inventory (Bcf)	59	66	74	78	80	82	86	85	63	43	29	25
Reserve Margin				10%	11%	15%	21%	10%	10%	13%	10%	15%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	0	0	0	0
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000

Scenario 1c: No Aliso + Winter Peak Day Weather

	2016	2017
Demand (MMcfd)		
Core	3,050	3,035
Noncore Non-EG	996	996
EG	1,031	1,092
System Total Throughput	**5,077**	**5,123**
Supply (MMcfd)		
California Line 85 Zone	60	60
California Coastal Zone	0	0
Wheeler Ridge Zone	765	765
Southern Zone	1,010	1,010
Northern Zone	1,390	1,390
Total Flowing from Receipt Points	3,225	3,225
Storage Withdrawal		
Three Others	1,640	1,640
Aliso Canyon	0	0
Total Gas from Storage	1,640	1,640
Total Supply	**4,865**	**4,865**
DELIVERABILITY BALANCE (MMcfd)	**-212**	**-258**
Reserve Margin %	**-4%**	**-5%**

Scenario 2a Base: Aliso Reinjections Beginning September 1 + Normal Weather
(Reinjections @ 300 mmcfd in September increasing to 400 mmcfd Oct & Nov)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,016	784	676	618	616	646	732	1,115	1,539	1,500	1,436	1,185
Noncore excluding EG	481	472	470	466	487	486	470	457	454	490	489	479
Electric Generation	629	674	769	1,077	1,120	990	818	715	695	650	623	621
Wholesale & International	392	342	361	462	463	472	379	420	547	477	485	413
Co. Use and LUAF	33	30	30	34	35	34	32	36	43	41	40	35
Total	2,551	2,302	2,306	2,657	2,721	2,628	2,431	2,743	3,278	3,158	3,073	2,733
Storage Injection	125	232	260	176	99	404	530	517	0	0	0	0
System Total Throughput	2,676	2,534	2,566	2,833	2,820	3,032	2,961	3,260	3,278	3,158	3,073	2,733
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	14	404	891	730	268
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,239	3,629	4,116	3,955	3,493
DELIVERABILITY BALANCE (MMcfd)	603	691	659	399	460	227	264	-21	351	958	882	760
Storage Inventory (Bcf)	59	66	74	79	80	91	108	123	110	83	62	54
Reserve Margin				14%	16%	7%	9%	-1%	11%	30%	29%	28%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	300	400	400	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	453	371	136
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	24,000	36,400	48,400	42,045	28,002	17,614	13,398

Scenario 2a Revised: Aliso Reinjections Beginning September 1 + Normal Weather
(Reinjections @ 300 mmcfd in September increasing to 400 mmcfd Oct & Nov

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,016	784	676	618	616	646	732	1,115	1,539	1,500	1,436	1,185
Noncore excluding EG	481	472	470	466	487	486	470	457	454	490	489	479
Electric Generation	629	674	769	1,077	1,120	990	818	715	695	650	623	621
Wholesale & International	392	342	361	462	463	472	379	420	547	477	485	413
Co. Use and LUAF	33	30	30	34	35	34	32	36	43	41	40	35
Total	2,551	2,302	2,306	2,657	2,721	2,628	2,431	2,743	3,278	3,158	3,073	2,733
Storage Injection	125	232	260	176	99	404	530	517	0	0	0	0
System Total Throughput	2,676	2,534	2,566	2,833	2,820	3,032	2,961	3,260	3,278	3,158	3,073	2,733
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	100	50	400	404	891	730	268
Total Supply	3,279	3,225	3,225	3,232	3,280	3,325	3,275	3,625	3,629	4,116	3,955	3,493
DELIVERABILITY BALANCE (MMcfd)	603	691	659	399	460	293	314	365	351	958	882	760
Storage Inventory (Bcf)	59	66	74	79	80	89	104	108	95	68	47	39
Reserve Margin				14%	16%	10%	11%	11%	11%	30%	29%	28%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	300	400	400	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	453	371	136
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	24,000	36,400	48,400	42,045	28,002	17,614	13,398

Scenario 2b Base: Aliso Reinjections Beginning September 1 + Cold, Dry Winter
(Injections @ 300 mmcfd in September, increasing to 400 mmcfd October & November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,110	820	687	619	617	651	761	1,226	1,728	1,666	1,644	1,291
Noncore excluding EG	482	472	469	466	486	487	470	458	457	493	491	481
Electric Generation	669	732	849	1,199	1,244	1,076	872	770	749	708	664	657
Wholesale & International	424	365	375	464	468	470	394	452	583	528	529	451
Co. Use and LUAF	35	31	31	36	37	35	33	38	46	45	44	38
Total	2,720	2,420	2,411	2,784	2,852	2,719	2,530	2,944	3,563	3,440	3,372	2,918
Storage Injection	125	232	260	176	99	404	530	517	0	0	0	0
System Total Throughput	2,845	2,652	2,671	2,960	2,951	3,123	3,060	3,461	3,563	3,440	3,372	2,918
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	14	404	891	730	268
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,239	3,629	4,116	3,955	3,493
DELIVERABILITY BALANCE (MMcfd)	434	573	554	272	329	136	165	-222	66	676	583	575
Storage Inventory (Bcf)	59	66	74	79	80	91	108	123	110	83	62	54
Reserve Margin				9%	11%	4%	5%	-6%	2%	20%	17%	20%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	300	400	400	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	453	371	136
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	24,000	36,400	48,400	42,045	28,002	17,614	13,398

Scenario 2b Revised: Aliso Reinjections Beginning September 1 + Cold, Dry Winter
(Injections @ 300 mmcfd in September, increasing to 400 mmcfd October & November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,110	820	687	619	617	651	761	1,226	1,728	1,666	1,644	1,291
Noncore excluding EG	482	472	469	466	486	487	470	458	457	493	491	481
Electric Generation	669	732	849	1,199	1,244	1,076	872	770	749	708	664	657
Wholesale & International	424	365	375	464	468	470	394	452	583	528	529	451
Co. Use and LUAF	35	31	31	36	37	35	33	38	46	45	44	38
Total	2,720	2,420	2,411	2,784	2,852	2,719	2,530	2,944	3,563	3,440	3,372	2,918
Storage Injection	125	232	260	176	99	404	530	517	0	0	0	0
System Total Throughput	2,845	2,652	2,671	2,960	2,951	3,123	3,060	3,461	3,563	3,440	3,372	2,918
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	25	55	200	150	575	700	650	730	268
Total Supply	3,279	3,225	3,225	3,250	3,280	3,425	3,375	3,800	3,925	3,875	3,955	3,493
DELIVERABILITY BALANCE (MMcfd)	434	573	554	290	329	302	315	339	362	435	583	575
Storage Inventory (Bcf)	59	66	74	78	80	86	98	96	74	54	33	25
Reserve Margin				10%	11%	10%	10%	10%	10%	13%	17%	20%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	300	400	400	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	453	371	136
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	24,000	36,400	48,400	42,045	28,002	17,614	13,398

Scenario 2c: Aliso Reinjection September 1 +Winter Peak
(Aliso maximum withdrawals set to 1000 mmcf consistent with December 1 inventory of 48 Bcf)

	2016	2017
Demand (MMcfd)		
Core	3,050	3,035
Noncore Non-EG	996	996
EG	1,031	1,092
System Total Throughput	**5,077**	**5,123**
Supply (MMcfd)		
California Line 85 Zone	60	60
California Coastal Zone	0	0
Wheeler Ridge Zone	765	765
Southern Zone	1,010	1,010
Northern Zone	1,390	1,390
Total Flowing from Receipt Points	3,225	3,225
Storage Withdrawal		
Three Others	1,640	1,640
Aliso Canyon	1000	1000
Total Gas from Storage	2,640	2,640
Total Supply	**5,865**	**5,865**
DELIVERABILITY BALANCE (MMcfd)	**788**	**742**
Reserve Margin %	**16%**	**14%**

Scenario 3a Base: Aliso Reinjections Beginning October 1 + Normal Weather
(Injections begin October 1 @ 300 mmcfd increasing to 400 mmcfd November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,016	784	676	618	616	646	732	1,115	1,539	1,500	1,436	1,185
Noncore excluding EG	481	472	470	466	487	486	470	457	454	490	489	479
Electric Generation	629	674	769	1,077	1,120	990	818	715	695	650	623	621
Wholesale & International	392	342	361	462	463	472	379	420	547	477	485	413
Co. Use and LUAF	33	30	30	34	35	34	32	36	43	41	40	35
Total	2,551	2,302	2,306	2,657	2,721	2,628	2,431	2,743	3,278	3,158	3,073	2,733
Storage Injection	125	232	260	176	99	104	430	517	0	0	0	0
System Total Throughput	2,676	2,534	2,566	2,833	2,820	2,732	2,861	3,260	3,278	3,158	3,073	2,733
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	14	404	813	684	268
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,239	3,629	4,038	3,909	3,493
DELIVERABILITY BALANCE (MMcfd)	603	691	659	399	460	527	364	-21	351	880	836	760
Storage Inventory (Bcf)	59	66	74	79	80	82	96	111	98	73	54	46
Reserve Margin				14%	16%	19%	13%	-1%	11%	28%	27%	28%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	300	400	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	375	325	136
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	24,300	36,300	29,945	18,320	9,220	5,004

Scenario 3a Revised: Aliso Reinjections Beginning October 1 + Normal Weather
(Injections begin October 1 @ 300 mmcfd increasing to 400 mmcfd November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,016	784	676	618	616	646	732	1,115	1,539	1,500	1,436	1,185
Noncore excluding EG	481	472	470	466	487	486	470	457	454	490	489	479
Electric Generation	629	674	769	1,077	1,120	990	818	715	695	650	623	621
Wholesale & International	392	342	361	462	463	472	379	420	547	477	485	413
Co. Use and LUAF	33	30	30	34	35	34	32	36	43	41	40	35
Total	2,551	2,302	2,306	2,657	2,721	2,628	2,431	2,743	3,278	3,158	3,073	2,733
Storage Injection	125	232	260	176	99	104	430	517	0	0	0	0
System Total Throughput	2,676	2,534	2,566	2,833	2,820	2,732	2,861	3,260	3,278	3,158	3,073	2,733
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	350	404	813	684	268
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,575	3,629	4,038	3,909	3,493
DELIVERABILITY BALANCE (MMcfd)	603	691	659	399	460	527	364	315	351	880	836	760
Storage Inventory (Bcf)	59	66	74	79	80	82	96	101	88	63	44	35
Reserve Margin				14%	16%	19%	13%	10%	11%	28%	27%	28%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	300	400	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	375	325	136
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	24,300	36,300	29,945	18,320	9,220	5,004

Scenario 3b Base: Aliso Reinjections Beginning October 1 + Cold, Dry Weather

(Reinjections @ 300 mmcfd October increasing to 400 mmcfd November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,110	820	687	619	617	651	761	1,226	1,728	1,666	1,644	1,291
Noncore excluding EG	482	472	469	466	486	487	470	458	457	493	491	481
Electric Generation	669	732	849	1,199	1,244	1,076	872	770	749	708	664	657
Wholesale & International	424	365	375	464	468	470	394	452	583	528	529	451
Co. Use and LUAF	35	31	31	36	37	35	33	38	46	45	44	38
Total	2,720	2,420	2,411	2,784	2,852	2,719	2,530	2,944	3,563	3,440	3,372	2,918
Storage Injection	125	232	260	176	99	104	430	517	0	0	0	0
System Total Throughput	2,845	2,652	2,671	2,960	2,951	2,823	2,960	3,461	3,563	3,440	3,372	2,918
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	14	404	813	684	268
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,239	3,629	4,038	3,909	3,493
DELIVERABILITY BALANCE (MMcfd)	434	573	554	272	329	436	265	-222	66	598	537	575
Storage Inventory (Bcf)	59	66	74	79	80	82	96	111	98	73	54	46
Reserve Margin				9%	11%	15%	9%	-6%	2%	17%	16%	20%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	300	400	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	375	325	136
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	24,300	36,300	29,945	18,320	9,220	5,004

Scenario 3b Revised: Aliso Reinjections Beginning October 1 + Cold, Dry Weather
(Reinjections @ 300 mmcfd October increasing to 400 mmcfd November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,110	820	687	619	617	651	761	1,226	1,728	1,666	1,644	1,291
Noncore excluding EG	482	472	469	466	486	487	470	458	457	493	491	481
Electric Generation	669	732	849	1,199	1,244	1,076	872	770	749	708	664	657
Wholesale & International	424	365	375	464	468	470	394	452	583	528	529	451
Co. Use and LUAF	35	31	31	36	37	35	33	38	46	45	44	38
Total	2,720	2,420	2,411	2,784	2,852	2,719	2,530	2,944	3,563	3,440	3,372	2,918
Storage Injection	125	232	260	176	99	104	430	517	0	0	0	0
System Total Throughput	2,845	2,652	2,671	2,960	2,951	2,823	2,960	3,461	3,563	3,440	3,372	2,918
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	50	55	33	50	600	700	813	684	268
Total Supply	3,279	3,225	3,225	3,275	3,280	3,258	3,275	3,825	3,925	4,038	3,909	3,493
DELIVERABILITY BALANCE (MMcfd)	434	573	554	315	329	436	315	364	362	598	537	575
Storage Inventory (Bcf)	59	66	74	77	79	81	93	90	69	43	24	16
Reserve Margin				11%	11%	15%	11%	11%	10%	17%	16%	20%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	300	400	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	375	325	136
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	24,300	36,300	29,945	18,320	9,220	5,004

Scenario 3c: Aliso Reinjections Beginning October 1 + Winter Peak Day
(Aliso maximum withdrawals set to 580 mmcfd reflecting inventory of 36 Bcf by December 1)

	2016	**2017**
Demand (MMcfd)		
Core	3,050	3,035
Noncore Non-EG	996	996
EG	1,031	1,092
System Total Throughput	**5,077**	**5,123**
Supply (MMcfd)		
California Line 85 Zone	60	60
California Coastal Zone	0	0
Wheeler Ridge Zone	765	765
Southern Zone	1,010	1,010
Northern Zone	1,390	1,390
Total Flowing from Receipt Points	3,225	3,225
Storage Withdrawal		
Three Others	1,640	1,640
Aliso Canyon	580	580
Total Gas from Storage	2,220	2,220
Total Supply	**5,445**	**5,445**
DELIVERABILITY BALANCE (MMcfd)	**368**	**322**
Reserve Margin %	**7%**	**6%**

Scenario 4a Base: Aliso Reinjections Lower on October 1 + Normal Weather
(Injections begin October 1 @ 150 mmcfd increasing to 200 mmcfd in November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,016	784	676	618	616	646	732	1,115	1,539	1,500	1,436	1,185
Noncore excluding EG	481	472	470	466	487	486	470	457	454	490	489	479
Electric Generation	629	674	769	1,077	1,120	990	818	715	695	650	623	621
Wholesale & International	392	342	361	462	463	472	379	420	547	477	485	413
Co. Use and LUAF	33	30	30	34	35	34	32	36	43	41	40	35
Total	2,551	2,302	2,306	2,657	2,721	2,628	2,431	2,743	3,278	3,158	3,073	2,733
Storage Injection	125	232	260	176	99	104	280	317	0	0	0	0
System Total Throughput	2,676	2,534	2,566	2,833	2,820	2,732	2,711	3,060	3,278	3,158	3,073	2,733
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	14	404	688	559	232
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,239	3,629	3,913	3,784	3,457
DELIVERABILITY BALANCE (MMcfd)	603	691	659	399	460	527	514	179	351	755	711	724
Storage Inventory (Bcf)	59	66	74	79	80	82	91	100	88	66	51	43
Reserve Margin				14%	16%	19%	19%	6%	11%	24%	23%	26%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	150	200	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	250	200	100
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	19,650	25,650	19,295	11,545	5,945	2,845

Scenario 4a Revised: Aliso Reinjections Lower on October 1 + Normal Weather
(Injections begin October 1 @ 150 mmcfd increasing to 200 mmcfd in November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,016	784	676	618	616	646	732	1,115	1,539	1,500	1,436	1,185
Noncore excluding EG	481	472	470	466	487	486	470	457	454	490	489	479
Electric Generation	629	674	769	1,077	1,120	990	818	715	695	650	623	621
Wholesale & International	392	342	361	462	463	472	379	420	547	477	485	413
Co. Use and LUAF	33	30	30	34	35	34	32	36	43	41	40	35
Total	2,551	2,302	2,306	2,657	2,721	2,628	2,431	2,743	3,278	3,158	3,073	2,733
Storage Injection	125	232	260	176	99	104	280	317	0	0	0	0
System Total Throughput	2,676	2,534	2,566	2,833	2,820	2,732	2,711	3,060	3,278	3,158	3,073	2,733
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	350	404	688	559	232
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,575	3,629	3,913	3,784	3,457
DELIVERABILITY BALANCE (MMcfd)	603	691	659	399	460	527	514	515	351	755	711	724
Storage Inventory (Bcf)	59	66	74	79	80	82	91	90	77	56	40	33
Reserve Margin				14%	16%	19%	19%	17%	11%	24%	23%	26%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	150	200	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	250	200	100
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	19,650	25,650	19,295	11,545	5,945	2,845

Scenario 4b Base: Aliso Reinjections Lower on October 1 + Cold, Dry Winter

(Injections begin October 1 @ 150 mmcfd increasing to 200 mmcfd in November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,110	820	687	619	617	651	761	1,226	1,728	1,666	1,644	1,291
Noncore excluding EG	482	472	469	466	486	487	470	458	457	493	491	481
Electric Generation	669	732	849	1,199	1,244	1,076	872	770	749	708	664	657
Wholesale & International	424	365	375	464	468	470	394	452	583	528	529	451
Co. Use and LUAF	35	31	31	36	37	35	33	38	46	45	44	38
Total	2,720	2,420	2,411	2,784	2,852	2,719	2,530	2,944	3,563	3,440	3,372	2,918
Storage Injection	125	232	260	176	99	104	280	317	0	0	0	0
System Total Throughput	2,845	2,652	2,671	2,960	2,951	2,823	2,810	3,261	3,563	3,440	3,372	2,918
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	7	55	33	0	14	404	688	559	232
Total Supply	3,279	3,225	3,225	3,232	3,280	3,258	3,225	3,239	3,629	3,913	3,784	3,457
DELIVERABILITY BALANCE (MMcfd)	434	573	554	272	329	436	415	-22	66	473	412	539
Storage Inventory (Bcf)	59	66	74	79	80	82	91	100	88	66	51	43
Reserve Margin				9%	11%	15%	15%	-1%	2%	14%	12%	18%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	150	200	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	250	200	100
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	19,650	25,650	19,295	11,545	5,945	2,845

Scenario 4b Revised: Aliso Reinjections Lower on October 1 + Cold, Dry Winter
(Injections begin October 1 @ 150 mmcfd increasing to 200 mmcfd in November)

	2016									2017		
Demand (MMcfd)	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core	1,110	820	687	619	617	651	761	1,226	1,728	1,666	1,644	1,291
Noncore excluding EG	482	472	469	466	486	487	470	458	457	493	491	481
Electric Generation	669	732	849	1,199	1,244	1,076	872	770	749	708	664	657
Wholesale & International	424	365	375	464	468	470	394	452	583	528	529	451
Co. Use and LUAF	35	31	31	36	37	35	33	38	46	45	44	38
Total	2,720	2,420	2,411	2,784	2,852	2,719	2,530	2,944	3,563	3,440	3,372	2,918
Storage Injection	125	232	260	176	99	104	280	317	0	0	0	0
System Total Throughput	2,845	2,652	2,671	2,960	2,951	2,823	2,810	3,261	3,563	3,440	3,372	2,918
Supply (MMcfd)												
California Line 85 Zone	60	60	60	60	60	60	60	60	60	60	60	60
California Coastal Zone												
Wheeler Ridge Zone	765	765	765	765	765	765	765	765	765	765	765	765
Southern Zone	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Northern Zone	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Total	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225
Storage Withdrawal	54	0	0	50	55	33	50	600	700	688	559	232
Total Supply	3,279	3,225	3,225	3,275	3,280	3,258	3,275	3,825	3,925	3,913	3,784	3,457
DELIVERABILITY BALANCE (MMcfd)	434	573	554	315	329	436	465	564	362	473	412	539
Storage Inventory (Bcf)	59	66	74	77	79	81	88	80	58	37	21	14
Reserve Margin				11%	11%	15%	17%	17%	10%	14%	12%	18%
User-defined Aliso Storage Profile												
Injections	0	0	0	0	0	0	150	200	0	0	0	0
Withdrawals	0	0	0	0	0	0	0	0	205	250	200	100
Resulting End-of-Month Inventory	15,000	15,000	15,000	15,000	15,000	15,000	19,650	25,650	19,295	11,545	5,945	2,845

Scenario 4c: Aliso Reinjections Beginning October 1 + Winter Peak Day
(Aliso maximum withdrawals set to 400 mmcfd reflecting inventory of 25.6 Bcf by December 1)

	2016	2017
Demand (MMcfd)		
Core	3,050	3,035
Noncore Non-EG	996	996
EG	1,031	1,092
System Total Throughput	**5,077**	**5,123**
Supply (MMcfd)		
California Line 85 Zone	60	60
California Coastal Zone	0	0
Wheeler Ridge Zone	765	765
Southern Zone	1,010	1,010
Northern Zone	1,390	1,390
Total Flowing from Receipt Points	3,225	3,225
Storage Withdrawal		
Three Others	1,640	1,640
Aliso Canyon	400	400
Total Gas from Storage	2,040	2,040
Total Supply	**5,265**	**5,265**
DELIVERABILITY BALANCE (MMcfd)	**188**	**142**
Reserve Margin %	**4%**	**3%**