Aliso Canyon Risk Assessment Technical Report

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

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EXECUTIVE SUMMARY

This technical report assesses the risks to energy reliability in the Greater Los Angeles area during the coming summer months without the use of the Aliso Canyon Natural Gas Storage Facility. This assessment was developed by the Aliso Canyon Technical Assessment Group, which is comprised of technical experts from several state and local energy entities.

This technical assessment finds that if no gas can be withdrawn from Aliso Canyon during the coming summer months, a significant risk exists of natural gas curtailments during up to 16 days this summer. These curtailments could interrupt service and affect millions of electric customers during as many as 14 summer days. Several factors contribute to this risk including mismatches between scheduled gas on the pipeline system and actual daily gas demand, planned and unplanned outages to non-Aliso storage that reduce supply, and planned and unplanned pipeline outages that reduce delivery capacity. Prolonged periods of high electrical demand also increase the risk of gas curtailments and electrical service interruption. This happens during extreme heat waves when air conditioning use spikes and all natural gas-fired electricity generation is required.

Aliso Canyon currently has a limited supply of 15 billion cubic feet (Bcf) of working gas in storage. Using this gas stored in Aliso Canyon as needed is very important to reduce the risk of gas curtailments and electrical service interruption this summer. Additionally, implementing other actions detailed in the *Draft Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin* further reduce—but do not eliminate—risks of gas curtailments and electrical service interruptions.

In summary, the report does the following:

- The study addresses summer 2016 only. A winter study may be needed in the future.
- Aliso Canyon gas injections will not resume until all wells have been inspected; the time frame for completion of that process is uncertain.
- The analysis assessed risk if Aliso Canyon was unavailable.
- The electric analysis assumes optimal conditions with minimum gas-fired generation in the Los Angeles Basin and fully available transmission capacity and energy supply.
- Analysis finds that gas curtailment events could interrupt electric supply from 22 to 32 days. Fourteen of these days are this summer.
- Transfer of gas supply to electric resources outside the Los Angeles Basin is minimal.
- Gas supply is necessary for electric generators to supply the public with electricity. Commercial and residential customers, hospitals, and refineries are at risk.
- A separate action plan discusses mitigation measures.

INTRODUCTION

This technical report is the work of the Aliso Canyon Technical Assessment Group, which used the report to develop the Aliso Canyon Action Plan. The Technical Assessment Group consists of members from the California Public Utilities Commission (CPUC), California Energy Commission (Energy Commission), California Independent System Operator (California ISO), Los Angeles Department of Water and Power (LADWP), and Southern California Gas Company (SoCalGas). The action plan addresses natural gas and associated electricity reliability impacts due to the SS-25 well leak and subsequent operating status of the Aliso Canyon underground natural gas storage field.

The Technical Assessment Group analyzed reliability for summer 2016. It looked at the SoCalGas system to understand the operational constraints that might exist on the system. Given the uncertainty about operations at the field and recognizing the January order of the CPUC to hold inventory at 15 Bcf to protect energy reliability, the analysis looked at operations assuming no injection and no withdrawal from Aliso Canyon. The analysis examines the criticality of Aliso Canyon to the integrated operations of gas and electric systems. It identifies what gas would be needed from the field to remedy strained operational conditions, assuming protocols and procedures are developed to provide clarity about how the gas currently stored at Aliso Canyon can be used to mitigate identified reliability risk this summer.

The report provides a background discussion describing SoCalGas' system operations, including existing tools to manage its system and the relationship with the San Diego Gas & Electric (SDG&E) gas system that SoCalGas supplies and operates. It discusses electric and gas coordination and reliability and provides background on the electric generation and transmission of the California ISO and LADWP Balancing Authority areas.

The report describes the detailed gas operations simulations conducted by SoCalGas, with oversight by the Technical Assessment Group members. The group assessed four different types of gas day demand profiles and found a number of conditions likely to result in gas curtailments. These operational findings lead directly to some of the mitigation measures recommended.

Having assessed the conditions that could cause natural gas curtailments, the Technical Assessment Group translated those into impacts to electricity generation, for the California ISO and LADWP Balancing Authority areas relative to their respective operational constraints and reliability criteria.

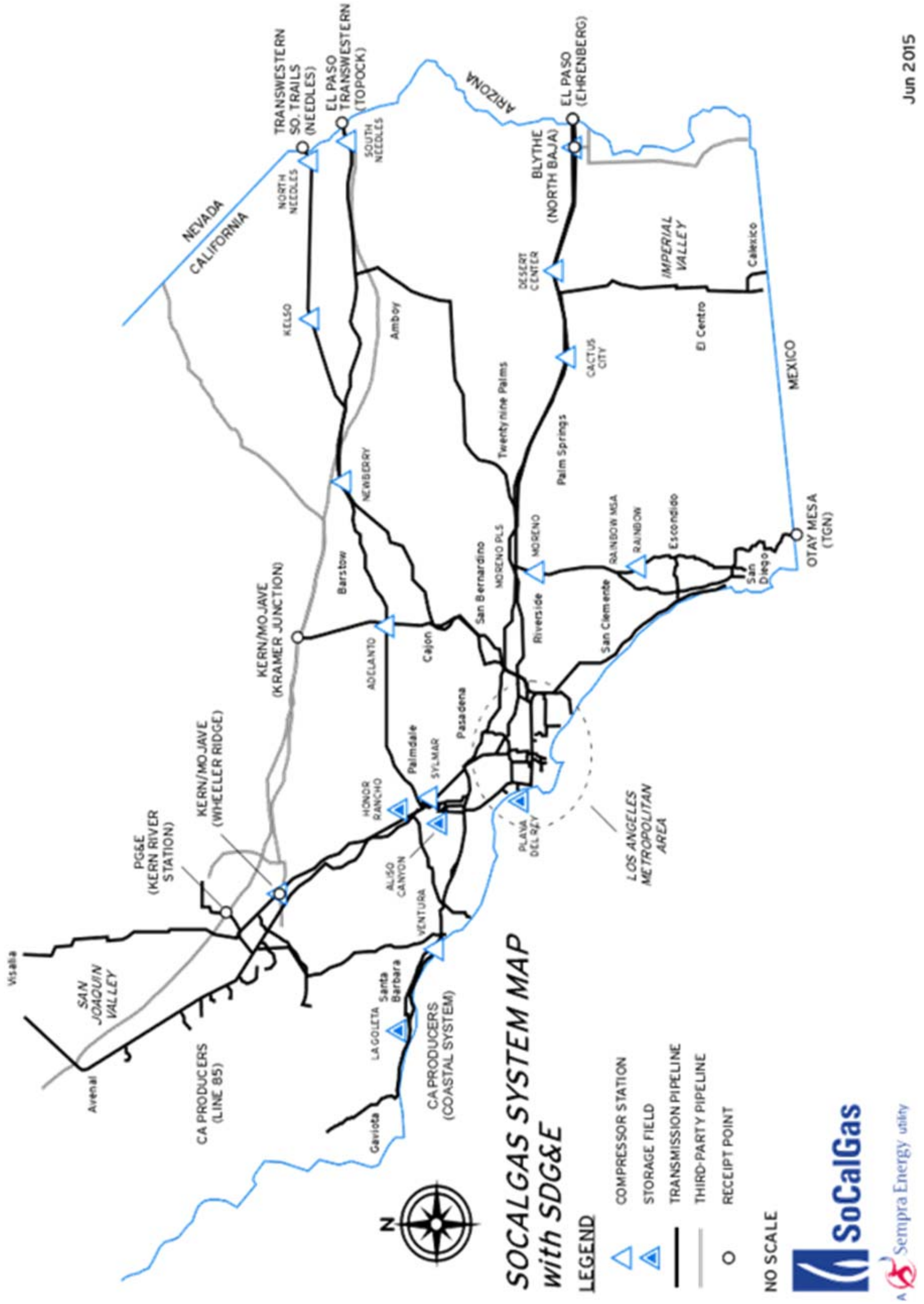
The report includes an appendix that includes more technical detail about the simulation model, supporting data, and assumptions. Inspecting all wells at Aliso Canyon must occur before any wells can be placed back into service. An additional appendix describes details surrounding the June 30 and July 1, 2015 natural gas curtailments, which occurred when Aliso Canyon was fully available, and the actions that the California ISO and LADWP took to avoid electricity service interruptions.

BACKGROUND

The following section discusses the background of gas operations and electric operations.

SoCalGas and SDG&E own and operate an integrated gas transmission system consisting of pipeline and storage facilities. With their network of transmission pipelines and four interconnected storage fields, SoCalGas and SDG&E deliver natural gas to more than five million residential and business customers. A map of the SoCalGas transmission system is included as Figure 1.

FIGURE 1 – SoCalGas' Gas Transmission system



The gas transmission system supports 21 million residents in Southern California. The system extends from the Colorado River to the east of SoCalGas' approximately 20,000 square mile service territory; to the Pacific Coast on the west; from Tulare County in the north; and to the United States/Mexico border in the south (excluding parts of Orange and San Diego counties).

The SoCalGas transmission system was initially designed to receive and redeliver gas from the east, to the load centers in the Los Angeles Basin, Imperial Valley, San Joaquin Valley, north coastal areas, and San Diego County. As SoCalGas and SDG&E accessed new supply sources in Canada and the Rocky Mountain region, the system was modified to concurrently accept deliveries from the north. The system today has the potential capacity to accept up to 3,875 million cubic feet per day (MMcfd) of interstate and local California supplies. However, flowing supplies generally do not exceed 3,000 MMcfd.

SoCalGas and SDG&E's primary supply sources are the southwestern United States, the Rocky Mountain region, Canada, and California's on- and off-shore production. The interstate pipelines that supply the SoCalGas transmission system are El Paso Natural Gas Company (El Paso), North Baja Pipeline (North Baja), Transwestern Pipeline Company (Transwestern), Kern River Gas Transmission Company (Kern River), Mojave Pipeline Company (Mojave), Questar Southern Trails Pipeline Company (Southern Trails), and Gas Transmission Northwest (GTN), via the intrastate system of Pacific Gas and Electric Company (PG&E). The SoCalGas transmission system interconnects with El Paso at the Colorado River near Needles and Blythe, California, with North Baja near Blythe, California, and with Transwestern and Southern Trails near Needles, California. SoCalGas also interconnects with the common Kern/Mojave pipeline at the Wheeler Ridge Compressor Station located in the San Joaquin Valley and at Kramer Junction in the high desert. At Kern River Station in the San Joaquin Valley, SoCalGas maintains a major interconnect with the PG&E intrastate pipeline system, and receives PG&E/GTN deliveries at that location.

SoCalGas operates four storage fields that interconnect with its transmission system. These storage fields – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey – are located near the primary load centers of the SoCalGas system. They have a combined inventory capacity of 135.6 Bcf, a combined firm injection capacity of 850 MMcfd, and a combined firm withdrawal capacity of 3,680 MMcfd. Some systems, such as the PG&E gas transmission system, have significant linear pipelines and rely heavily on linepack (storing gas in the pipeline as opposed to within a storage facility) for storage. SoCalGas' system does not have as much linepack as others. It operates using storage and pipeline supplies to meet customer demand. The SoCalGas system cannot function with only pipeline supply or with only storage supply. As a result, storage fields are a much more critical operating asset on the SoCalGas system.

In contrast, SDG&E has no storage fields in its service territory. Almost all of the gas into the SDG&E system comes from SoCalGas via its southern system through the Moreno Compressor Station. While discussed as a separate system, SDG&E's gas transmission system integrates with the SoCalGas system and falls under the responsibility of the SoCalGas System Operator.

Operational Role of Aliso Canyon

Aliso Canyon is the largest of SoCalGas' four storage fields in all regards: largest inventory capacity at 86.2 Bcf, largest withdrawal capacity at 1,860 million MMcfd, and largest firm injection capacity at 413 MMcfd (pre-Aliso Canyon Turbine Replacement Project). For summer operations (April through October), the SoCalGas Gas Control department strives to completely fill the storage field in order to provide firm injection services to customers and prepare for the upcoming winter. Aliso Canyon's withdrawal capabilities are also used during the summer to provide supply during the hourly peak electric generation demands that occur throughout the day, which cannot be met with flowing supplies because of the speed and magnitude that these peaks occur. On average, Aliso Canyon's withdrawal is used approximately 10 days per month during the summerin this way.

For winter operations (November through March), Aliso Canyon provides the needed winter supply and withdrawal services and prepares for the next summer. The large supply of gas that Aliso Canyon provides in the winter to the Los Angeles Basin also allows SoCalGas to maintain service to their customers located outside the basin. In the winter season, when interstate pipeline gas supplies become more expensive and even less available due to well freeze- offs, customers often elect to deliver as little as possible to the SoCalGas system. Absent Aliso Canyon providing supply to the Los Angeles Basin, SoCalGas will have to make a choice to send supplies to theLos Angeles Basin or to other communities.

Without Aliso Canyon, SoCalGas' storage capacities fall to 49.4 Bcf of inventory (a 64 percent loss), 437 MMcfd of firm injection (a 49 percent loss), and 1,820 MMcfd of firm withdrawal (a 51 percent loss). Only SoCalGas' Honor Rancho storage field can provide some of the lost capability to support demand in the Los Angeles Basin. The Playa del Rey storage field is too small to provide that level of support, while the La Goleta storage field is located too far away. The Honor Rancho storage field has significantly less inventory capacity than Aliso Canyon. It frequently supports demand centers in the San Joaquin Valley, the Northern System, and the Coastal System, which limits its effectiveness to support theLos Angeles Basin.

While more specific analysis is required for the upcoming winter, SoCalGas believes if Aliso Canyon were unavailable or not permitted to operate next winter, or if flowing supplies did not materialize because of conditions east of California, SoCalGas would be unable to meet their 1-in-10 year cold day reliability planning criteria and would require noncore (noncore includes electric generators) curtailment. Additionally, without the complete curtailment of all noncore customers, core reliability would be in jeopardy during a 1-in-35 year peak day event.

Role of Gas and Electric System Operator

(SoCalGas, California ISO, and LADWP)

The system operator maintains system reliability and integrity while working to provide reasonably priced service. This is accomplished using a Supervisory Control and Data Acquisition System (SCADA) that provides for real-time remote monitoring and operation of valves, compressor stations, pressure regulation equipment, and gas flow across the gas system for the gas system operator, and electric substations, tansmission ines, generators, circuit breakers, and voltage control equipment for the electric system operator. System operators perform these duties in a 24/7 control room environment.

Responsibilities of the system operator include: adhering to gas pipeline and electric transmission line safety and reliability parameters established by federal, regional, and/or state agencies; analyzing and responding to abnormal or emergency situations on the gas pipeline or electric transmission line systems; and coordinating necessary gas pipeline or electric transmission line outages for maintenance and/or emergency measures. The electric system operator maintains the instantaneous balance of electric supply with the real-time demand placed upon it. The system operator also serves as a communication coordinator between the various utilities conducting maintenance on their respective systems.

The system operator develops a daily operating plan that includes demand forecasts for their respective gas or electric systems and overall gas or electric facility utilization. These daily plans are based on weather, historical operations, amount of flowing gas or electric supply scheduled onto the system, and demand forecasts from the respective electric utilities, the California ISO, LADWP, and other large electric generators. In doing so, the system operator needs to have contingency plans immediately ready for changes in system conditions resulting from changes in weather patterns and loads, forecast error, and abnormal or emergency operating conditions. This is particularly important for the electric system operator because electricity cannot be stored in bulk, so electric supply and demand must be balanced in real-time. This need for a continually balanced electric transmission system means that a sudden unexpected increase in electric generation is necessary (for example when an electric transmission line relays and is removed from service). This electric generation increase creates a sudden unexpected increase in gas transmission system demand, since the majority of the electric generating stations in California use natural gas as their primary fuel source.

Some hydraulic system analysis and historical statistical studies show that the SoCalGas and SDG&E systems may be able to operate through times of system stress without Aliso Canyon. The SoCal Gas System Operator operates in a real-time environment without knowing how low actual system pressures will get or if the system will recover. Without Aliso Canyon, tit operates without a large tool to mitigate real-time changes. If conditions change during the gas day, the gas system operator must make adjustments in real-time. This is done by moving gas inventories to the load or withdrawing from storage.

These physical tools available to the gas system operator are supplemented by the ability to call high and low operational flow orders (OFOs) and emergency flow orders (EFOs). If physical tools, OFOs, and EFOs are not enough to deal with strained operating conditions, SoCalGas has the ability to curtail service to lower-priority customers, such as electric generators, in order to stabilize the system and protect service to higher-priority customers. These regulatory tools are explained more in detail. On the electric system, service to electric customers will be needed to be curtailed when the electric supply and demand balance cannot be maintained due to lack of generation capacity or transmission line capacity.

Existing Tools to Manage the SoCalGas & SDG&E System

Customers are responsible for scheduling and delivering gas supplies to the SoCalGas and SDG&E system to meet their usage. SoCalGas has few tools besides its storage fields to manage the mismatch between what customers bring onto the system in supplies and their usage. This mismatch can occur for a variety of reasons, including SoCalGas' and SDG&E's current monthly balancing rules, unexpected changes in weather, price arbitrage opportunities, and customer operational changes. With Aliso Canyon temporarily unavailable as a physical tool for the SoCalGas System Operator, SoCalGas must rely on regulatory tools in place to try to manage the system's reliability, integrity and safety. These tools include the low operational flow order ("low OFO"), the high operational flow order ("high OFO"), the emergency flow order ("EFO"), and SoCalGas Rule 23/SDG&E Gas Rule 14 curtailment procedures. The OFO procedures are orders initiated by SoCalGas under specified circumstances to encourage tighter balancing on the system: more gas onto the system (low OFO) or less gas on the system (high OFO). Tools for more extreme balancing needs are the EFO and finally, if required, actual curtailment of gas to customer facilities using the curtailment rules.

The low OFO and EFO procedures help to minimize supply-related curtailment threats by ensuring that transportation customers do not use any more storage withdrawal than has been physically allocated for the purpose of balancing. It also provides an incentive for customers to bring more pipeline supply into the system. The overuse of withdrawal for transportation balancing can jeopardize system reliability by exhausting SoCalGas' total withdrawal capability. The more closely customers align their supplies with their usage, the less likely that operational issues develop that will necessitate the utility curtailing end-use demand because of inadequate supply.

Electric and Gas Operations Coordination and Reliability

The Aliso Canyon Gas storage facility is integral to the reliable operation of the electric grid and infrastructure. Gas storage acts like a shock absorber for the real-time dynamic variations in electric demand. These facilities also provide additional gas delivery capacity when gas demand exceeds the amount of flowing supply and provides a place to inject unutilized gas when electric demand is less than expected. In both summer and winter, gas storage supports electric reliability when there are significant differences between flowing gas supply and actual gas demand. Such differences are due to either unexpected changes between the amount of gas scheduled the day before and the actual gas demand occurring in real time, or gas procurement commercial practices and incentives that can result in low flowing supply.

California ISO and LADWP Balancing Authorities are responsible for reliability electric service in their territories. Aliso Canyon has long been used by SoCalGas as a critical component of the transmission and distribution system. It provides natural gas service to 17 natural gas fired power plants, large hospitals, oil refineries, and other key parts of California's economy. Figure 2 shows the location of the 17 impacted resources in the Los Angeles Basin.

Figure 2 Electric Generation Plants Served by Aliso Canyon

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Table 1 – Power Plants Served by Aliso Canyon

Power Plants Served by Aliso Withdrawal		
#	Electric Generation Station	Capacity (Megawatts - MW)
1	LADWP Haynes Generation Station	1724
2	LADWP Scattergood Generation Station	803
3	LADWP Valley Generation Station	573
4	LADWP Harbor Generation Station	466
5	SCE Alamitos Toll	1970

6	SCE Huntington Beach Generating Station	452
7	SCE Redondo Beach	1343
8	SCE Barre Peaker	45
9	SCE Center Peaker	45
10	El Segundo Energy Center, LLC	526
11	Long Beach Generation, LLC	260
12	City of Glendale	288
13	City of Burbank	139
14	City of Pasadena	203
15	City of Anaheim - Canyon Power	200
16	City of Vernon - Malburg	138
17	Southern California Public Power Authority – Magnolia	328

Under the North American Electric Reliability Corporation (NERC) definition, a Balancing Authority and Transmission Operator has the responsibility of maintaining reliability by continuously balancing supply and demand and ensuring that the transmission is operated in a stable manner that prevents cascading outages from affecting the interconnection.[1] LADWP and California ISO are responsible for bulk electric system reliability and operational control of the electric generating resources served by Aliso Canyon.

All[2] of the generating resources in Table 1 above use gas as their only fuel source. Generating resources served by the Aliso Canyon gas storage facility represent almost 70 percent of the local capacity resources identified in California ISO's 2016 Local Capacity requirements for the Los Angeles Basin and nearly 75 percent of the local capacity available to the LADWP Balancing Authority. The other 25

[1] LADWP and California ISO are both a Balancing Authority and Transmission Operator and two of the 38 Balancing Authority Areas in the Western Electric Coordination Council (WECC) interconnection.
[2] (Distillate) capable For LADWP has limited alternate fuel capability at its Harbor and Valley Generation stations. The unit's capacity is limited and my only use alternate fuel for Blackstart emergencies largely to South Coast Air Quality Management District permit restrictions and operational constraints.

percent of available capacity being energy limited hydro pumped storage or small, run-of-the-river, aqueduct power plants. As a result, availability of these resources are critical to maintaining local reliability for both single and multiple contingency events as required by NERC transmission operations standards. If these resources are limited or curtailed due to gas limitations, it may be necessary to interrupt electric load in the local capacity area to avoid cascading blackouts and maintain system reliability as required by NERC Reliability Standards.

Under the NERC requirements the Balancing Authorities need to stand ready to respond to a sudden real-time loss of a transmission or generation element. Electric capacity reserved on gas fired generating resources is used to compensate for these sudden losses by instantaneously responding and recovering from the loss within minutes. The lost energy is replaced by the most efficient resources available to meet the current and future energy demand. An electric generator is also used to maintain stable voltages throughout the transmission grid by increasing or decreasing the power output, which will raise or lower voltage levels. During hot summer days when the electric demand is high, transmission lines are heavily loaded with flowing energy. As the load on transmission lines increases, voltage support provided by the generators is required in order to avoid a voltage collapse leading to transmission line relay tripping and ultimate loss of electric customer load.

Another critical role of maintaining electric generation is to manage the thermal loading on transmission lines. That happens when the output of the electric generators is increased and decreased at either end of a transmission line to transfer the energy source and keeps the flows of the line from exceeding the lines thermal capabilities. When an electric transmission line approaches its thermal limits, generation output near the receiving end is increased while the generation output near the sending end is decreased. This reduces the flowing energy on the line to keep it from a thermal overload and maintaining the balance of generation to electric demand.

Gas-fired generation resources served by Aliso Canyon provide contingency, operating reserves, and regulation reserve capacity to regulate system frequency around 60 Hertz. Based on 2015, these resources provided an average of 130 MW of reserves over the year and up to 244 MW of reserves during the summer months for California ISO. For the LADWP Balancing Authority, reserve capacity requirement can be in excess of 700MW. A large portion of this reserve capacity is located in the local area. To the extent there are gas limitations to these resources, they cannot be relied upon for reserves. These levels will have to be maintained by other resources in the California ISO and LADWP systems. These alternative resources may or may not be available, given prevailing operating conditions. Both LADWP and the California ISO maintain a portion of their system operating reserve by relying on resources in the SoCalGas region. Since gas curtailments issued by SoCalGas may impact resources beyond the immediate resources served by Aliso Canyon the gas curtailments could impact California ISO and LADWP's ability to maintain prudent system operating reserves.

The ability for LADWP and California ISO to shift electric supply from the resources affected by Aliso Canyon to other resources in Southern California or outside the SoCalGas system is limited based on timing and system conditions. The first limitation arises due to the need to maintain a minimum amount of local generation to ensure local reliability. The second limitation is due to limited ability to import energy into the area as a result of transmission constraints or supply availability. The ability to shift supply in the in the day-ahead market is greater and significantly decreases as real-time approaches.

California Independent System Operator (California ISO)

The California ISO is the bulk electric system operator for 30 million customers in northern and southern California and a small part of Nevada. As a system operator, the California ISO ensures bulk electric system stability and electric supply necessary to meet customer demand on a minute- by- minute basis 24 hours a day seven days a week. The California ISO's Southern California service area includes Southern California Edison's (SCE) 14 million electric customers, most of whom are in the Los Angeles Basin (excluding LADWP customers), (SDG&E) 1.4 million customers, and several municipal utilities in the region. The California ISO's portion of the Southern California load is served by a diverse mix of electric generation including wind, solar, combined heat and power, hydro, gas-fired resources, and energy provided over high voltage transmission lines. All these resources are optimized based on location, availability, and effectiveness to maintain transmission grid stability, voltage support, thermal loading on transmission lines, and provide the most efficient power solution to meet demand.

California's electric system has 26,000 miles of bulk electric transmission lines ranging from 60 kilovolts (kV) to 500KV and hundreds of electric generation sources that work in concert to continuously maintain system reliability and balance supply and demand. In 2012, the San Onofre Nuclear Generating Station representing 2,246 MW was retired. Solar resources have compensated for much of the energy loss during the daytime hours. However, the use of the gasfired generation has increased during the shoulder hours and to maintain local reliability.

Customer demand is dynamic and varies based on weather conditions and patterns. During hot summer periods, electric demand use is high during the daytime and evening hours, mainly due to air conditioning load. With the increased penetration of variable resources such as wind and solar, supply has also become variable. To balance supply and demand during the volatile periods, flexible gas-fired generation is used to fill the energy needs when variable resources are not fully used or unavailable. During the winter, electric demand is lower overall but increases sharply as evening when lighting load increases and solar production decreases.

Figure 3, which shows the California ISO system generation resources needed to meet the 24-hour customer demand for September 9, 2015, illustrates a typical daily late summer load pattern. The graph also illustrates the resource mix including renewable generation, predominately solar during this time of the year, gas-fired (thermal) generation, and imported generation from outside the California ISO Balancing Authority. The energy delivered from gas-fired resources has the flexibility to follow the load pattern by increasing and decreasing based on the availability of other resources types.

Figure 3: September 9, 2015 electric load profile.

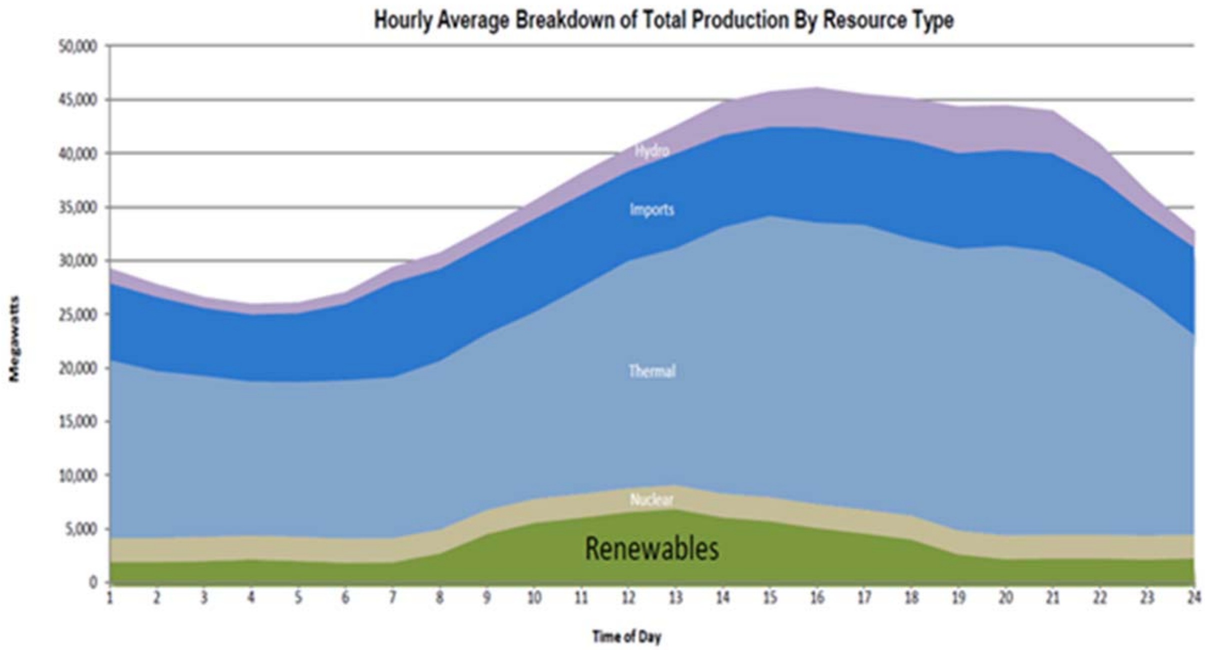


Figure 4, which shows the California ISO system generation needed for December 15, 2015, illustrates a typical winter load pattern. As in the summer graph, the same resource types make up the energy needed to serve the 24-hour customer demand. In the winter, the renewable energy is typically high due to the higher production of wind energy and the imports tend to be more plentiful based on temperature patterns throughout the west. Gas-fired (thermal) generation continues to be necessary to fulfill the remaining energy needs that are not available from the other resource types.

Figure 4: December 15, 2015 electric load profile

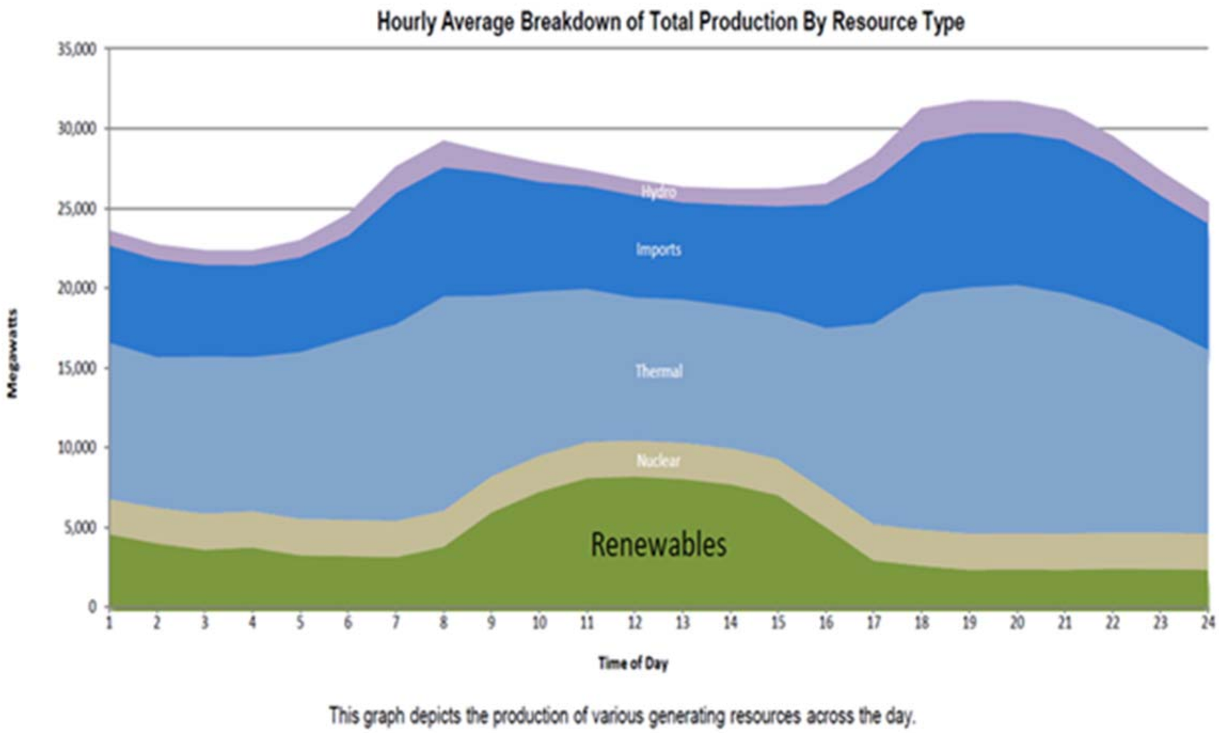
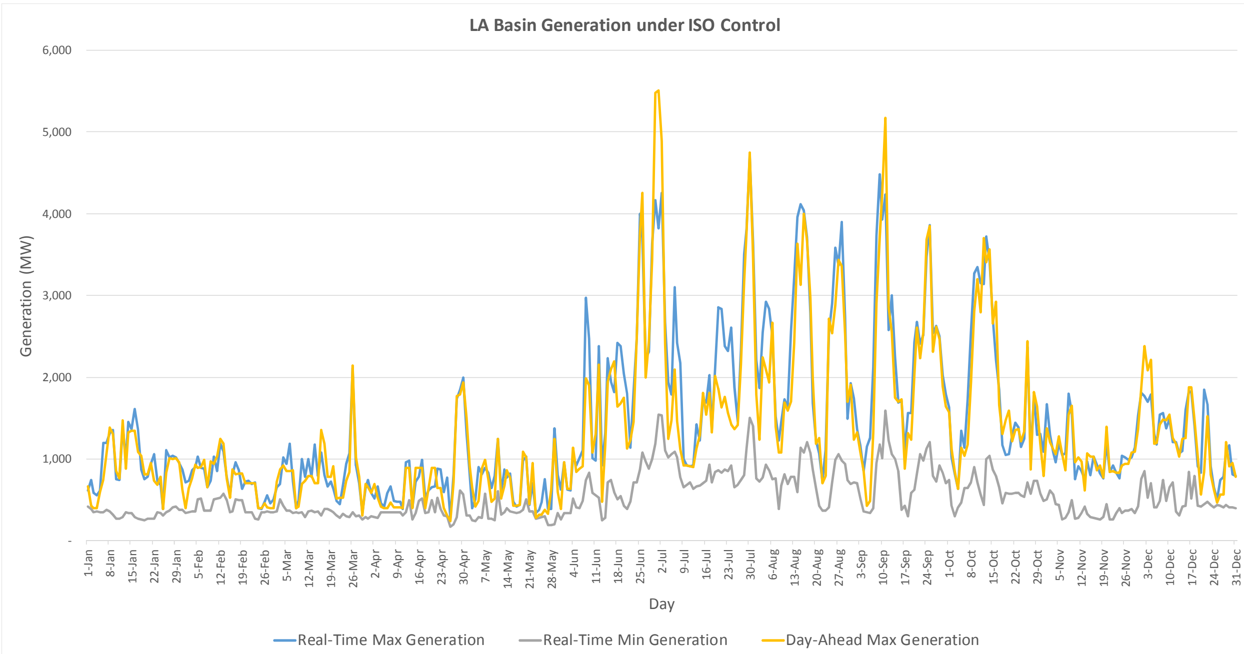


Figure 5 illustrates how the pattern of use of gas-fired generation in the Los Angeles Basin under California ISO control changes over the year. In May, the need for generation increases significantly and at times approaches the full capacity resources of 5,500 MW at times. This pattern continues as high loads could occur into October. One notable day was June 30, 2015. On June 30, the actual expected demand for gas exceeded SoCalGas' ability to deliver even with Aliso Canyon in operation due to high demand from generating resources and a major gas transmission pipeline outage. The California ISO had to reduce generation dispatch by about 1,500 MW from what was planned day-ahead across the peak hours. Appendix A has a more detailed explanation of this actual gas curtailment event.

Figure 5: Los Angeles Basin resource utilization under California ISO control



Los Angeles Department of Water and Power (LADWP)

LADWP, which provides electricity to 1.4 million customers, must meet specific supply reliability metrics. These metrics require LADWP to maintain transmission line loading within limits and provide voltage support for its system. Without this voltage support, LADWP is unable to accept into its system imported generation. Gas-fired generation plays a key role in meeting these metrics with specific generation minimums required which vary based on system load and conditions. LADWP owns some 40 percent of the ga-fired generation capacity in theLos Angeles Basin.i. This local, in-basin generation represents about 24 percent of LADWP's total electrical generation to meet its load; it imports the rest of the electricity it needs using electric transmission lines it owns.

LADWP forecasts its daily gas-fired generation requirement to meet its load and reliability requirements and schedules the necessary gas to meet this generation requirement. This forecast is based on expected system demand, weather, and system conditions. LADWP's gas consumption during the 2015 summer averaged 0.141 Bcf with a maximum usage of 0.336 Bcf. However, loss of a generation resource or transmission circuit, an unexpected reduction in variable generation (primarily wind and solar) and/or weather forecasting error may significantly increase the need for gas-fired generation. These events often happen without little advance warning.

At peak, approximately 72 percent of the available import capability is committed to importing LADWP, Burbank, and Glendale resources from external wind, solar, geothermal, coal, and nuclear resources owned by the Balancing Authority members. The remaining 28 percent of LADWP's electric transmission capacity is not used and is available to import more electricity from outside its system. This import capability can only be utilized if energy is available for purchase. Thus, LADWP has limited capability to shift load from gas-fired generation. It has some additional generation capacity it can utilize from its Castaic hydroelectric pumped storage facility. LADWP has some import capability from the California ISO that can replace a portion of its own gas-fired generation but the quantity would depend on whether the California ISO has excess energy available and the ability to transmit it to the tie with LADWP. The shorter the notice that LADWP has before it has to reduce its gas demand, the fewer the options that it has.

GAS OPERATIONAL ANALYSIS AND ASSESSMENT

Introduction

In order to quantify the potential system impact resulting from the limitations on the use of Aliso Canyon, hydraulic analyses must be performed. A review of the SoCalGas and SDG&E gas transmission system comparing supplies into the system and demand leaving it is insufficient. Such an analysis can provide an indication of a problem if the difference between supply and demand is large, but such a comparison does not take into account the way the system responds to intra-day changes in demand and the resulting impact on system operating pressures. Hydraulic analyses take these changing demand patterns into consideration and use industry-standard flow equations to calculate the resulting pressure changes throughout the pipeline network.

Under the direction and guidance of the Aliso Canyon Reliability Task Force, SoCalGas performed hydraulic analyses of its system for four historical days that the task force selected and assumed no supply was available from the Aliso Canyon storage field. Results and findings were presented to the task force.

Hydraulic Analyses Summary

The hydraulic analyses produced several findings:

- Differences between supply and demand turn out to be the key predictor of whether SoCalGas will have to curtail gas service.
- Without supply available from Aliso Canyon, a loss of capacity or difference between expected supply and actual demand greater than 5 percent of the total demand is likely to lead to gas system curtailments.
- While the electric generating plants ("EGs") located in the Los Angeles Basin receive supply directly from Aliso Canyon, the loss of Aliso Canyon as a supply source impacts customers system-wide, particularly those located on SoCalGas' Southern System and on the SDG&E system.
- Severe pressure drops in the Los Angeles Basin are also a possibility without supply from Aliso Canyon. It may result in a localized curtailment even with the system otherwise in balance.

- The loss of Aliso Canyon jeopardizes system reliability in both the summer (April to October) and winter (November to March) operating seasons, potentially even on days with only moderate overall customer demand.

Hydraulic Software & Modeling

DNV GL's Synergi Gas software application provides advanced hydraulic modeling solutions for pipeline network assets. DNV GL has over 44 years of industry-leading modeling software experience, and Synergi provides modeling of large, complex integrated multi-pressure level systems with full control over gas constraints (gravity, heating value and viscosity), equations of state, friction factor calculations, and heat transfer constants for both steady-state and transient analysis.

The model of the system is constructed from non-linear mathematical equations based on the provided network information. These equations represent network interconnection based on Kirchhoff's first law, which states that the flow into or out of a node in a network must sum to zero in order for mass to be conserved.

The equation solutions provide predictions of pressures, flows, valve positions, pipe diameters, compressor powers and speeds, and storage field utilization factors.

The application solves all equations in terms of nodal pressure, and then computes the resultant facility flows, given that facility flows are expressed as functions of unique constants and upstream and downstream pressures. The iterative process ideally results in a solution where all unknown facilities, unknown pressures, and unknown flows are solved to within the set tolerances.

SoCalGas has created a detailed proprietary model of its gas transmission network, and has used it with Synergi to perform hydraulic calculations for over 30 years. The model includes all transmission and storage assets (pipeline, compressor stations, valve stations, and storage fields) and all associated interconnections, locations for supply to be delivered to the system, and locations of demand on the system. Hourly demand profiles are applied to these points of customer demand, which can be an aggregation of customers (such as a point of supply from the transmission system to a distribution system) or a specific customer facility such as an electric generating plant.

In contrast to demand, supply delivered to the system occurs on a relatively steady basis. Supply and demand are rarely in balance. Any time when supply is less than the demand on the system, the system is said to be "drafting." When supply is greater than demand, the system is said to be "packing" so long as the ability to increase pack still exists. Because natural gas is a compressible medium, a pipeline can be used to store gas supply by operating between its minimum and maximum operating pressures, "packing" gas supply when the demand is low (and operating nearer to the maximum operating pressure) and "drafting" gas supply when the demand increases (and operating towards the minimum operating pressure). The volume of gas that can be stored in a pipeline is often referred to as "linepack."

The SoCalGas and SDG&E system has very little pack and draft capability relative to other pipeline networks, such as the PG&E's system. While SoCalGas and SDG&E can and do use the limited pack and draft capability when they have to quickly meet localized changes in hourly demand, they depend upon their storage fields to replenish lost linepack through withdrawal (taking gas out of the storage field) during the day or to absorb excess gas supplies through injection (putting gas into the field). Flowing supply coming into the system comes in too slowly to perform this function. It is the flexibility that their storage fields provide to the system that enables SoCalGas and SDG&E to maintain uninterrupted service to their customers.

When SoCalGas' engineers model the gas transmission system, they perform the same actions on the model that SoCalGas' Gas Control Department does on the actual system. Because supplies are fixed and delivered at a relatively constant rate, the engineer will simulate bringing on or cutting back storage supplies, opening or closing valve stations, and firing or turning off compressor station units to meet the changing customer demand throughout the operating day, just as the gas control operators would. In order for a simulation to be successful, the engineer must:

- Operate the system between its minimum and maximum operating pressures at all times;
- Operate within the capacities of the transmission facilities;
- Fully recover system linepack.

Exceeding maximum operating pressures presents safety risks, operating below minimum operating pressures jeopardizes continuous service to the distribution systems and customers, and fully recovering system linepack allows the simulated day to theoretically be repeated as often as necessary. Extreme demand conditions are rarely single-day events and recovering the system linepack is a requirement for the models to be successful. In reality, the system rarely recovers its pack completely in a single day, and system stress is incrementally increased the day after a high demand day.

Study Parameters & Assumptions

The task force identified four days of interest for hydraulic simulation. Each day represented an unusual occurrence in the Electric Generators (EG) market segment:

1. September 16, 2014: LADWP peak demand day
2. July 30, 2015: Largest change in EG hourly demand
3. September 9, 2015: Total peak EG demand day
4. December 15, 2015: Winter day with high EG demand

While these analyses only examined the impact to EG customers per the charter of the task force, SoCalGas' current curtailment rules would not necessarily limit any curtailment to only this customer class. All noncore customers are potentially interruptible, including businesses such as refineries, hospitals, hotels, and airports.

In order to capture the operational challenges on these days, SoCalGas assumed supplies for the simulation based upon a day-ahead forecast of demand, and then modeled the actual demand on that day. This represents actual customer behavior on the SoCalGas system. Without a requirement to do otherwise, customers and shippers are under no obligation to deliver supply matching their actual usage.

Table 2

Supply and Demand for the Sample Days

Description	9/16/2014 **Peak LADWP**	7/30/2015 **Large EG hourly change**	9/9/2015 **Peak EG**	12/15/2015 **Winter + high EG**
Day- Ahead Demand Forecast (MMcfd)				
Core	730	1026	689	1697
Noncore Non-EG	930	840	875	875
EG	1807	1354	1654	684
TOTAL	**3467**	**3220**	**3218**	**3256**
Assumed Supplies (MMcfd)				
CA Producers	60	60	60	60
Honor Rancho	1000	1000	1000	1000
La Goleta	340	340	340	340
Playa Del Rey	0	0	0	0
Pipeline	2067	1820	1818	1856
TOTAL	**3467**	**3220**	**3218**	**3256**
Actual Demand (MMcfd)	**3480**	**3189**	**3467**	**4023**
Imbalance (MMcfd)	**-13**	**31**	**-249**	**-767**

In all simulations, supply from SoCalGas' Playa del Rey storage field was withheld from the calculation of supply necessary to balance the demand forecast. It was held as an operational reserve to manage unexpected changes in demand because of its performance and proximity in the Los Angeles Basin to several large gas-fired power plants.

In Table 2, assumed supplies were sufficient to meet the day-ahead demand forecast, fully utilizing the withdrawal capacity at the Honor Rancho and La Goleta storage fields, and all transmission and storage facilities were assumed to be operational at full capacity (with the exception of Aliso Canyon). Pipeline supplies could have been somewhat larger than assumed, reducing the need for Honor Rancho and La Goleta supplies, but such an assumption would increase those pipeline supplies beyond that which has been historically delivered under similar conditions. Such a change would have had minimal effect on the simulation results.

In Table 2, the actual demand on two days – September 16, 2014 and July 30, 2015 – was nearly equal to the day-ahead demand forecast, while actual demand was significantly greater than the forecast on the other two days – September 9, 2015 and December 15, 2015.

None of the days that the Technical Assessment Group requested for examination are particularly high demand days in total for the entire system. Days where demand exceeds 3.2 billion cubic feet per day (Bcfd) are common in the winter. Peak summer days often show demand in this range. [3]

Results

Hydraulic analysis showed no operational issues for the September 16, 2014 and July 30, 2015 assessments. System pressures were maintained within maximum and minimum limits at all times. System linepack was fully recovered at the end of the simulated operating day. This was largely because supply and demand were essentially in balance – the day-ahead demand forecast (and associated supplies) closely matched the actual demand on those days. This was also because the simulation assumed no planned or unplanned outages that would reduce flowing supply.

Results for both September 9, 2015 and December 15, 2015 showed operational issues without Aliso Canyon, due partly to the large difference between the expected supply and actual demand on these days, and the concentration of demand in the Los Angeles Basin.

September 9, 2015 examination

The hydraulic analysis for September 9, 2015 showed that, technically, the simulation was successful. System pressures were maintained between the operational limits at all times, and system linepack was recovered. However, a closer examination of the results shows that SoCalGas and SDG&E would have likely issued curtailment orders.

Figure 6 shows the supply and demand profile for September 9, 2015. Demand on the system exceeds supply from 8 a.m. through 9 p.m., and all available supply is fully utilized beginning at 6 a.m., meaning that the system operator is utilizing all of its operational tools before the new gas day even starts at 7 a.m., leaving nothing else for contingencies and no operating flexibility during this time.

[3] This analysis focuses on summer 2016. Additional analysis may be necessary prior to winter 2016/2017.

Figure 6: September 9, 2015 – Demand & Supply

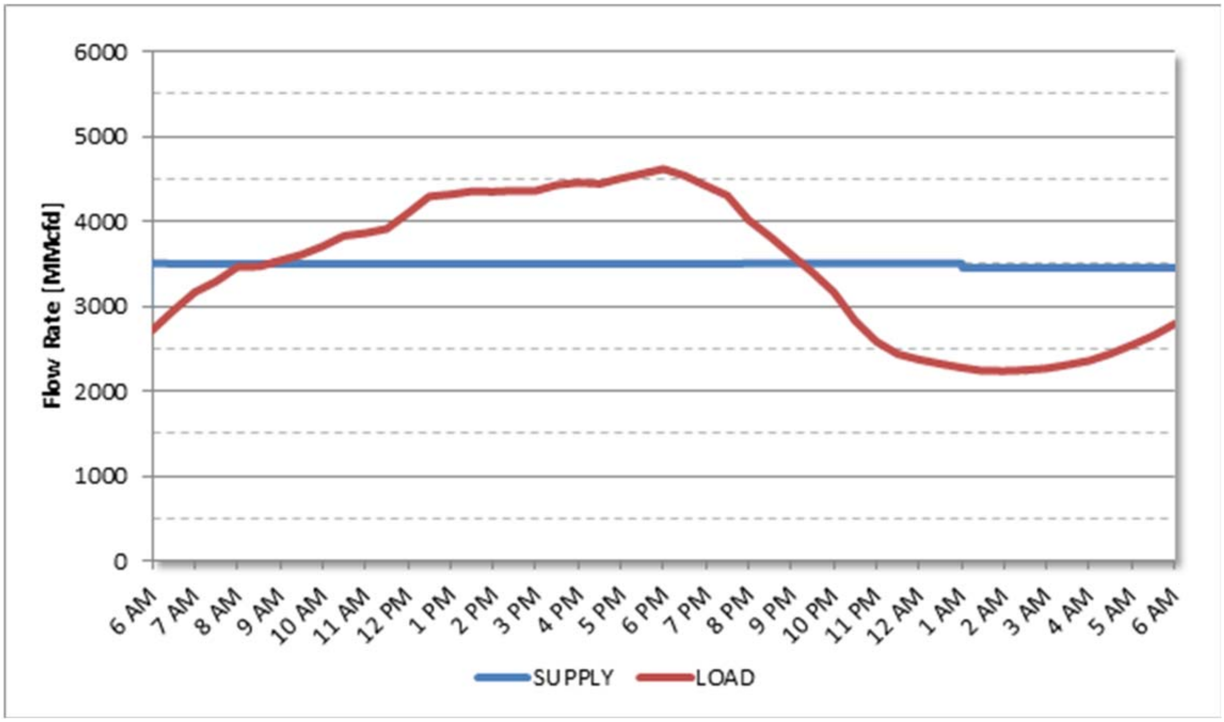


Figure 7 is a schematic showing the relationship between the SoCalGas Northern and Southern Systems. The Northern System is a primary supply source to the Los Angeles Basin, but also provides support to the Southern System serving San Bernardino, Riverside, Imperial, and San Diego counties. The Southern System currently lacks supply diversity. For the most part, it is dependent upon supply from a single interstate pipeline, with only a limited amount of support provided from Northern System. When supplies delivered on the Southern System are insufficient to support its level of demand, SoCalGas can divert some of the Northern System supplies from the Los Angeles Basin to the Southern System. Normally, SoCalGas would then supplement this loss of supply to the Los Angeles Basin with supply withdrawn from the Aliso Canyon storage field. However, in this scenario that is not an option, and any Northern System gas supply delivered to the Southern System comes at the expense of the Los Angeles Basin.

Figure 7: The Northern System Supports the Los Angeles Basin and Southern System

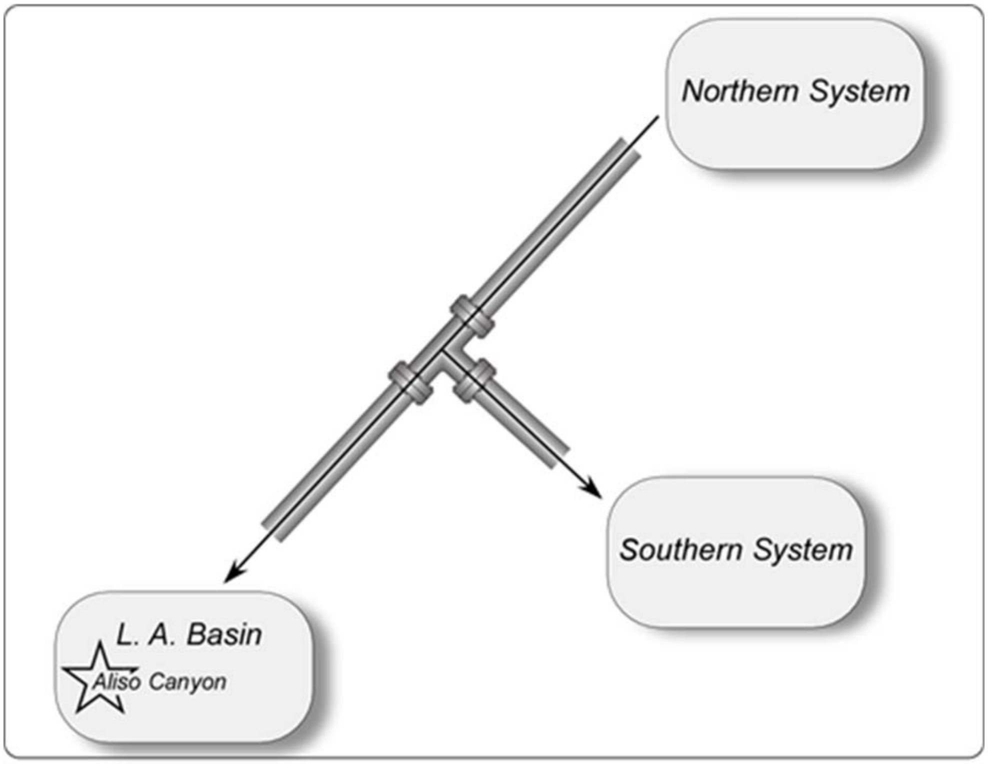
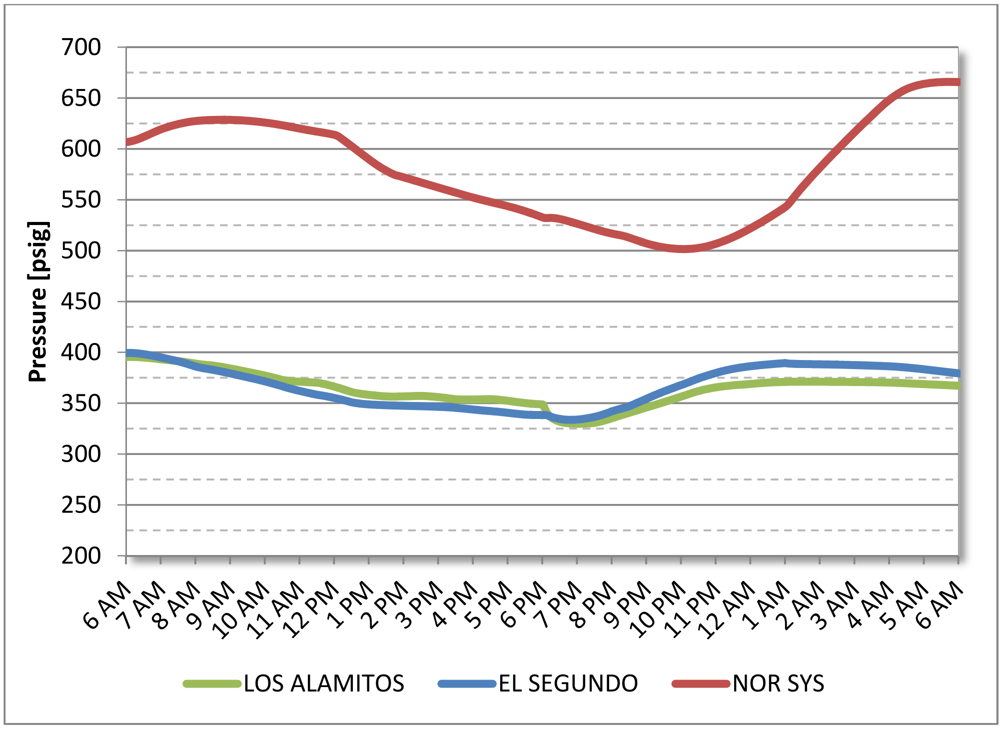


Figure 8 shows pressure on the Northern System and at points in the Los Angeles Basin near Los Alamitos on the east end and near El Segundo on the west.

Figure 8: September 9, 2015 – Northern System & Los Angeles Basin Pressures

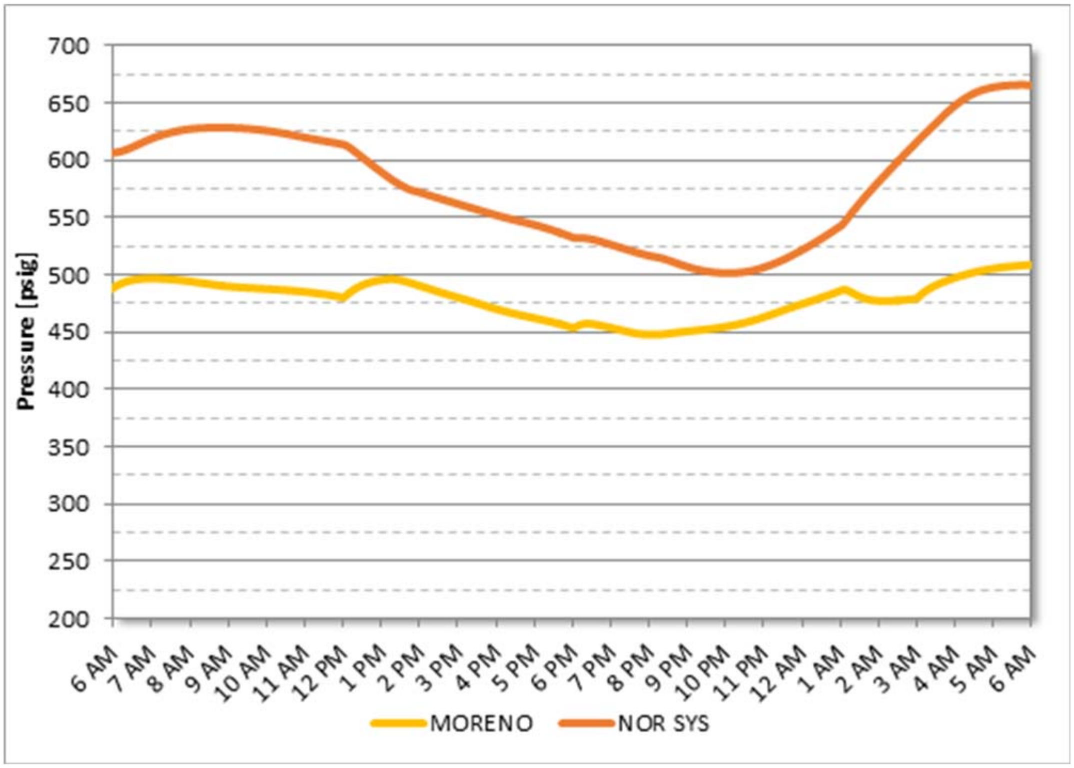


As shown in Figure 8, the Los Angeles Basin pressure is in a continuous decline from 6 a.m. through 5 p.m. While pressures eventually recovered and remained well above the minimum operating pressure, SoCalGas' Gas Control Department would have had no way to know that would happen during the early morning hours. When combined with the fact that all additional supply was fully utilized, as shown in Figure 1, that continuous drop in basin pressure would very likely have resulted in SoCalGas declaring a partial curtailment of noncore customer demand sometime in the morning of September 9, 2015 according to its standard operating procedures and assumptions.

Figure 9 also shows that pressure declined steadily on the Northern System as well. The Northern System supplies the Los Angeles Basin, and even though pressure on the Northern System dropped, it was not operating at minimum pressures. It is possible that sending additional supply to the Los Angeles Basin, and lowering the pressure on the Northern System, would slow the declining pressures in the Los Angeles Basin enough that the need for a curtailment could be eliminated. However, that is not an option in this scenario.

Figure 9 again shows the pressure on the Northern System and the pressure at Moreno Station. Moreno Station is the primary supply to the SDG&E system.

Figure 9: September 9, 2015 – Northern System & Moreno Pressures



Pressure at Moreno Station fell to near its minimum operating pressure despite receiving Northern System supplies. Had somewhat more supply been delivered from the Northern System to the Los Angeles basin as previously described to potentially prevent a curtailment in the Los Angeles Basin, a curtailment on the Southern System would have been required instead. Furthermore, pressures at Moreno Station, while just above minimum, are close enough to the minimum value that SoCalGas would have also declared a curtailment of noncore customer demand in late morning/early afternoon even with some additional supply from the Northern System.

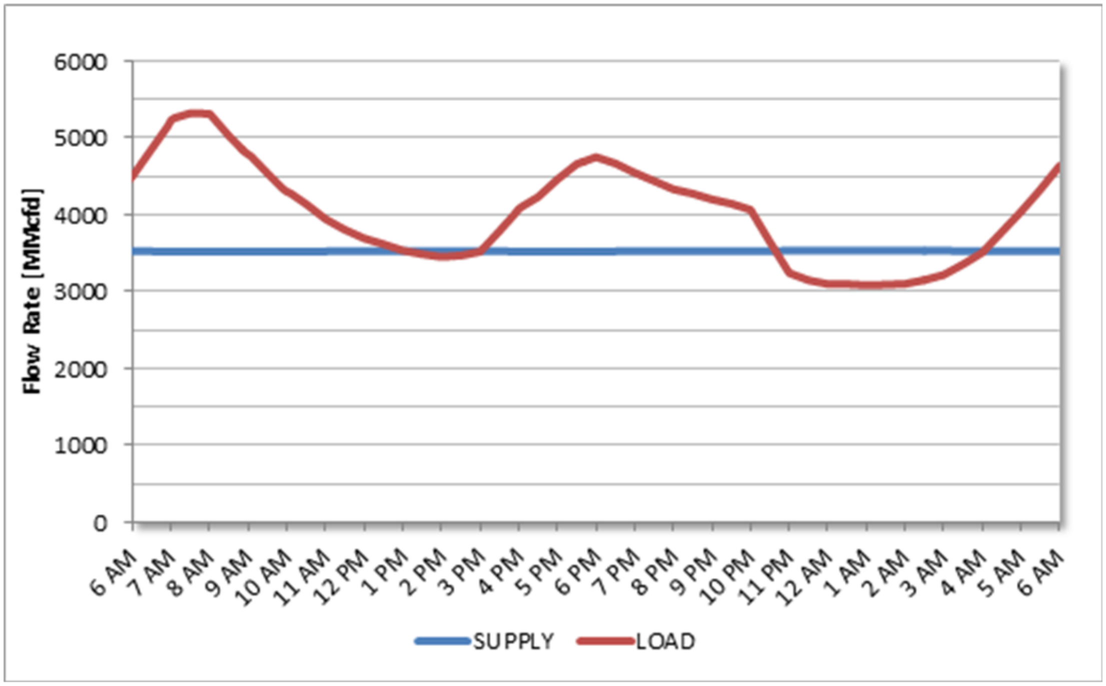
The 250 MMcfd difference between the demand forecast and the actual demand technically resulted in a successful simulation, but nevertheless would have resulted in some noncore customer curtailment. In order to raise pressures in the Los Angeles Basin and at Moreno Station enough to avoid a customer curtailment, SoCalGas determined that another 100 MMcfd of supply would be necessary. Therefore, the maximum difference between the expected supply and actual demand that can be tolerated without Aliso Canyon supply is estimated at 150 MMcfd (this can thus be viewed as the maximum supply shortfall that could be tolerated). This resulting figure of 150 MMcfd was used in further analyses to quantify the frequency of curtailment without Aliso Canyon and is presented later in this report.

December 15, 2015 Examination

For December 15, 2015, the hydraulic results showed that a nearly 800 MMcfd difference in the demand forecast (or, equivalently, an 800 MMcfd loss of supply) is too much for the system to overcome without the benefit of Aliso Canyon withdrawal supplies. Pressures dropped significantly and continuously across the entire system. System linepack was severely depleted at the end of the simulated operating day.

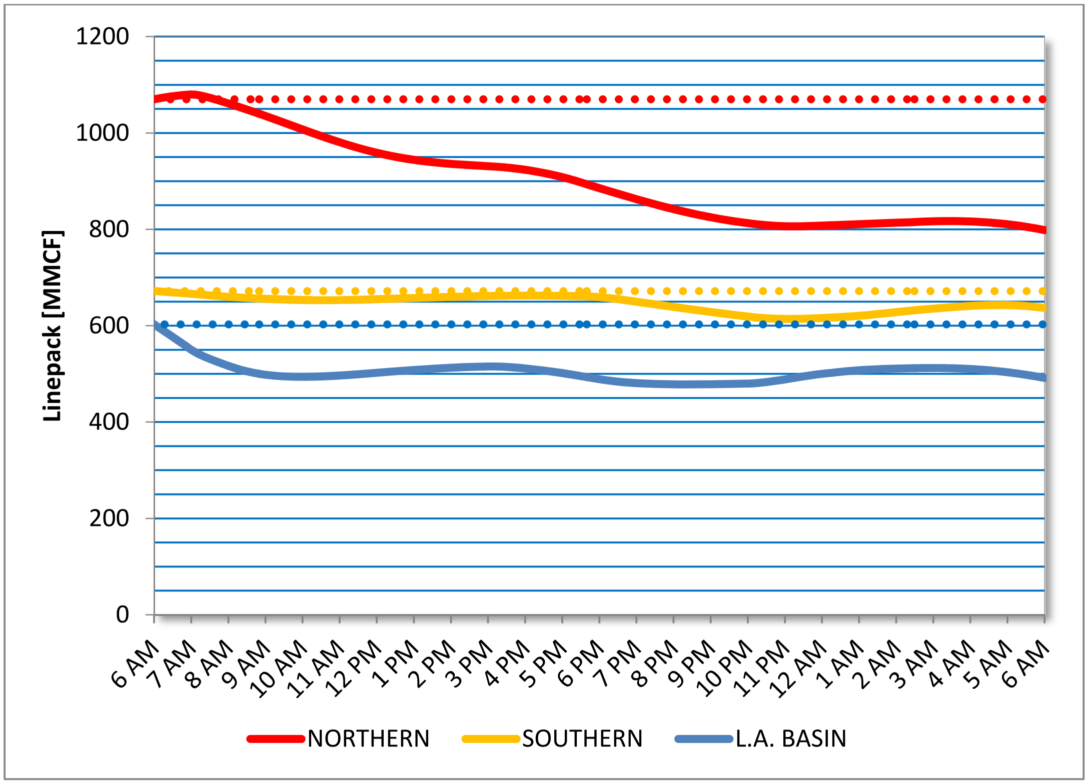
Figure 10 shows the demand and supply profile simulated for December 15, 2015. Demand exceeded supply at all times of the day until the late hours. As in the September 9, 2015 simulation, all available supply was fully utilized for the entire day beginning at 6 a.m. and provided no operational flexibility for the Gas Control Department.

Figure 10: December 15, 2015 – Demands & Supplies



As shown in the demand profile, a winter natural gas profile has two peaks: one in the morning as people wake up, turn the heater up, shower, and get ready for work; and a second in the evening when people return home. Typically, demand falls enough relative to supply after the morning peak such that the system can recover some linepack before the evening peak. In this simulation, however, there was no opportunity to recover linepack after the morning peak because supply never exceeded demand. This results in the continuous loss of linepack throughout the operating day, as shown in Figure 11, and any curtailment of customer demand on December 15, 2015 would have continued into at least December 16.

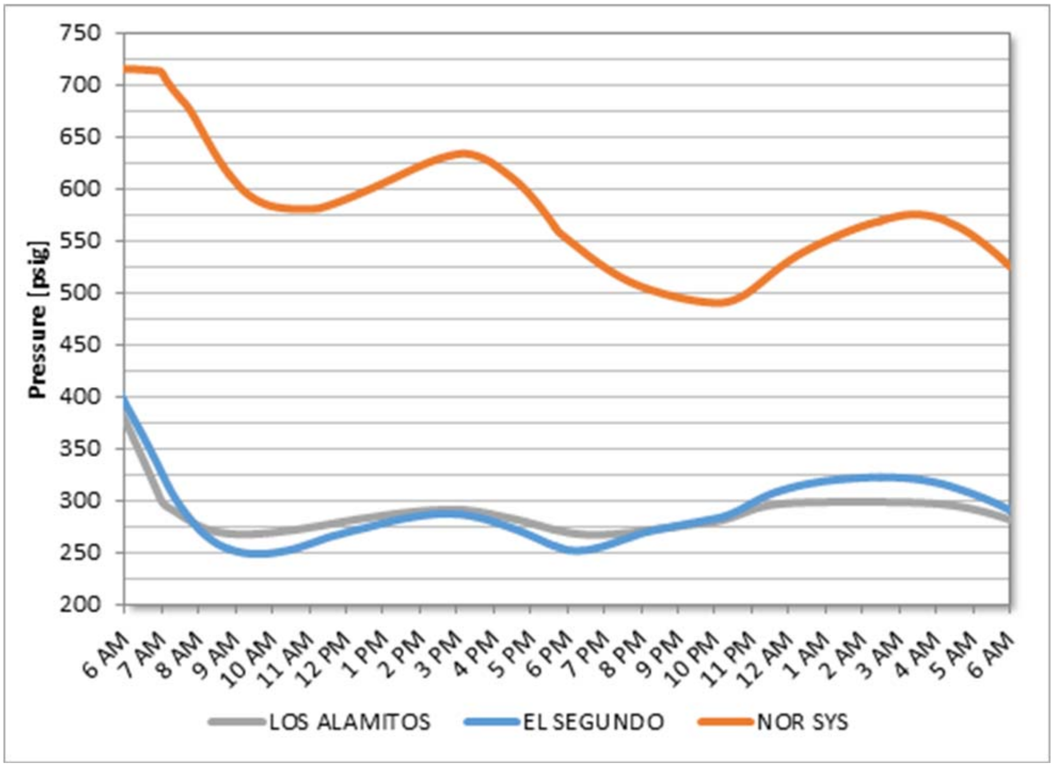
Figure 11: December 15, 2015 – System Linepack



As can be seen in Figure 11, the loss of linepack is most noticeable on the Northern System as SoCalGas once again uses gas from the Northern System to try and support both the Southern System and Los Angeles Basin.

Figure 12 shows the pressure on the Northern System and in the Los Angeles Basin near Los Alamitos and near El Segundo. Pressure on the Northern System never recovers at the end of the operating day and pressures in the Los Angeles basin approach minimum levels during both the morning and evening peaks.

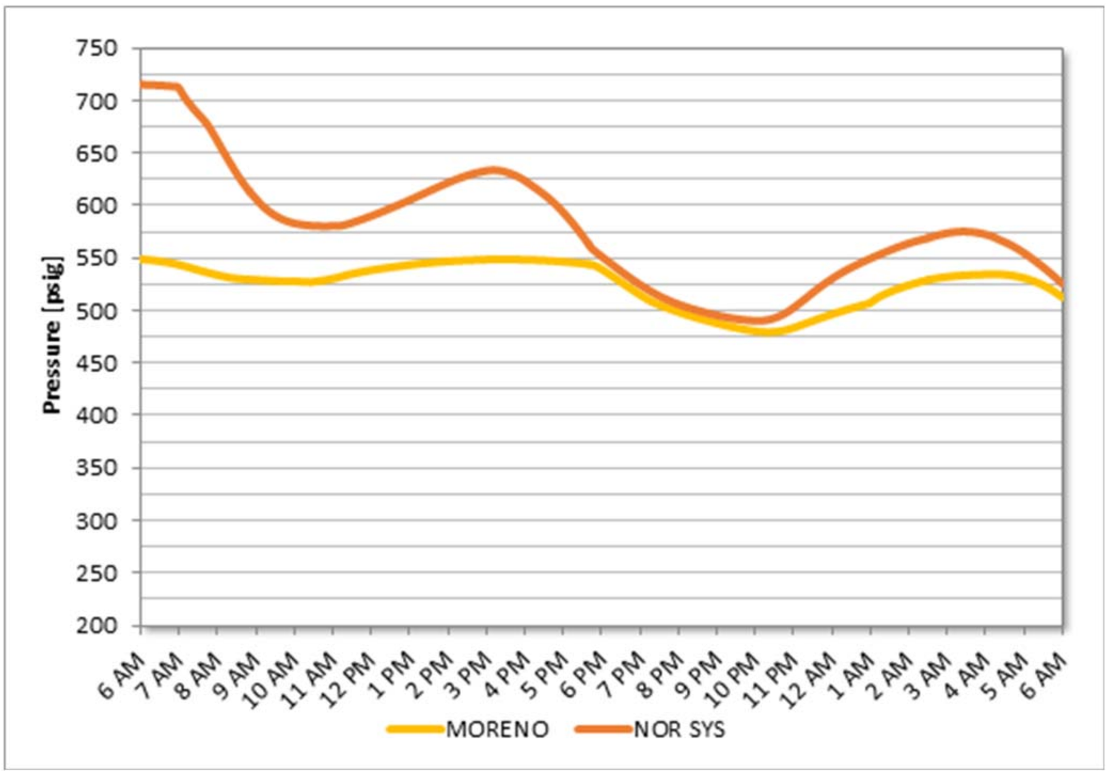
Figure 12: December 15, 2015 – Northern System & Los Angeles Basin Pressures



Furthermore, Los Angeles Basin pressures (Los Alamitos and El Segundo) fell rapidly, continuously, and significantly from 6 a.m. until 8 a.m. This rapid drop would have been enough to require SoCalGas to declare a curtailment of noncore service early in the day, likely lasting at least throughout the remainder of the day and into December 16.

Figure 13 shows pressure on the Northern System and at Moreno Station on the Southern System. The continuous loss of pressure on the Northern System leads to ineffective support to Moreno Station between the hours of 6 p.m. and 10 p.m. As shown in the figure, pressures equalize, at which point gas stops flowing from the Northern System towards Moreno Station, which results in the pressure drop at Moreno at this time. SoCalGas would have likely declared a curtailment of noncore service on the Southern System before 6 p.m.

Figure 13: December 15, 2015 – Northern System & Moreno Pressures



At the request of the Technical Assessment Group, SoCalGas re-examined this December 15, 2015 day to test the effects of possibly moving to 5 percent daily balancing.[4] Daily balancing, as proposed in the March 1, 2016 motion in Application 15-06-020, would require noncore customers to balance to within

[4] SoCalGas/SDG&E March 1, 2016 Motion for interim order establishing temporary daily balancing requirements.: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=159669501General link to filed documents in Application 15-06-020: http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:56:17248206001161::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1506020

95 percent of their actual usage, not forecast. Daily balancing at 95 percent would mean 95 percent of the supply needed to serve the December 15, 2015 demand would come in as flowing supply, increasing to 3.822 Bcfd from 3.256 Bcfd assumed in the original analysis that reflected no daily balancing.

Not surprisingly, this extra gas supply helps significantly and linepack is fully recovered across the entire system at the end of the operating day. Figure 14 shows that supply can now help recover linepack between the morning and evening peak demand periods because supply exceeds demand during these times. While this case assumed daily balancing in order to test its impact, the Technical Assessment Group recognizes that daily balancing is difficult and may not be fully effective based on the dynamic nature of the electric system. Even if daily balancing is implemented as the action plan mitigation measures suggest, it will never eliminate all mismatches between scheduled gas and actual use. When some mismatches still inevitably occur, electric outages as a result of insufficient gas supply remain a risk

Figure 14: December 15, 2015 (5% Balancing) – Loads & Supplies

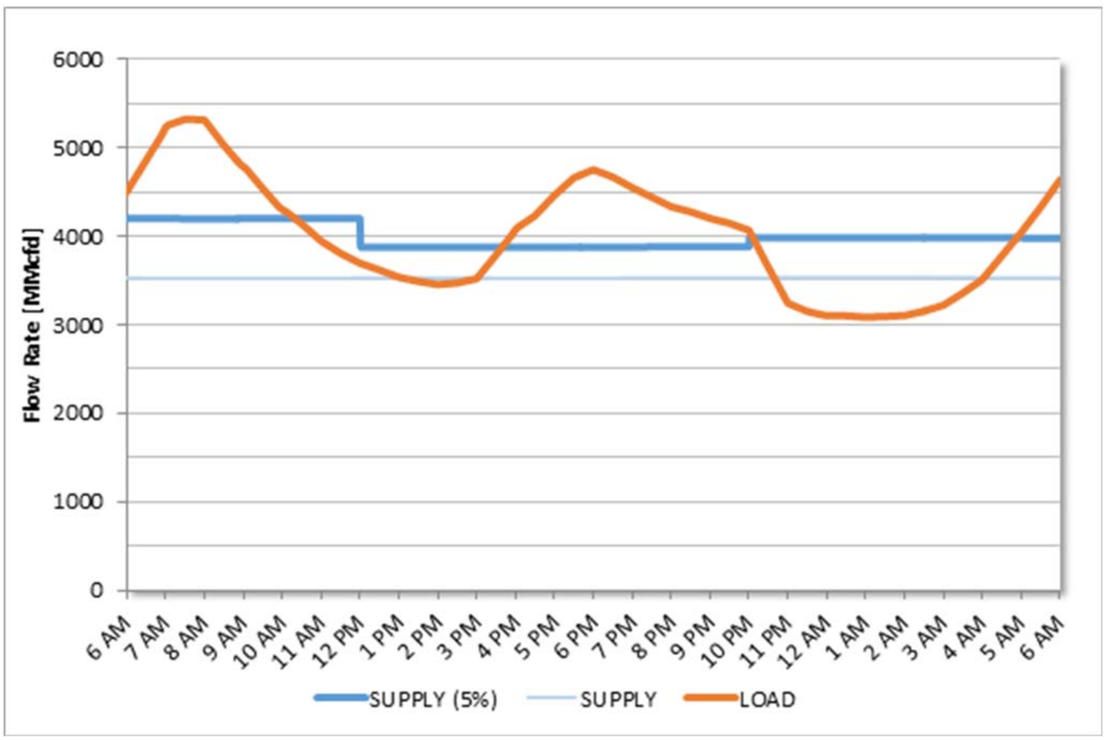
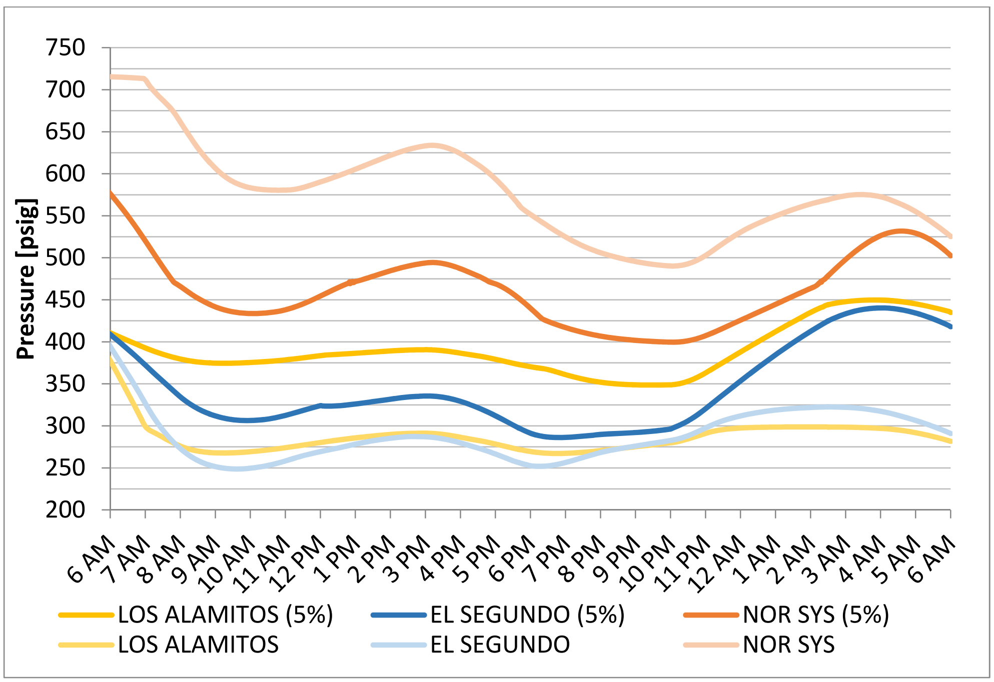


Figure 15 shows pressure improvement in the Los Angeles Basin.

Figure 15: December 15, 2015 (5 percent balancing) – Northern System & Los Angeles Basin Pressures



However, that the El Segundo area still experiences a sudden and continuous pressure drop from 6 a.m. through 9 a.m. While not as severe as previously examined, the extra supply from the interstate pipelines cannot travel quickly enough through the pipeline network to the pressure drop on the west side of the Los Angeles Basin. If SoCalGas Control department saw this pressure drop, it would almost certainly declare a noncore customer curtailment localized to the El Segundo area even with 5 percent daily balancing under this type of demand condition. Five percent daily balancing helps but even with it there may be days when demand changes quickly enough within the Los Angeles Basin that flowing supply cannot keep up and a gas curtailment for some number of hours will be needed.

CURTAILMENT RISK ASSESSMENT

The Reliability Task Force was asked to quantify the number of days throughout the year there would be a high risk of significant system stress on the SoCalGas and SDG&E pipeline systems absent supplies from Aliso Canyon. This risk assessment builds on the hydraulic analysis. In general, system stress and potential resulting curtailments cannot be predicted with certainty because there are so many variables that may occur on the SoCalGas pipeline and storage system. In addition, curtailments are possible during many combinations of sendout, receipts, temperature, and pipeline/storage facility outages. In order to develop an estimate of the number of days where the SoCalGas and SDG&E system could be in a state of stress thereby increasing the risk of curtailment, a statistical analysis was completed based on historical operating data, planned maintenance scenarios, and a historical average of forced outage events.

The scope of the analysis consisted of quantifying a range of days where curtailments resulting from significant system risk would be likely if Aliso Canyon were not available for withdrawal for the summer and winter seasons of 2016. The analysis was based on triggers from the hydraulic modeling performed, coupled with historical operating data from the years 2013 through 2015. In addition, four operating scenarios, each imposing an additional layer of stress on the system during a demand condition of 3.2 Bcfd or greater were reviewed to simulate possible plausible conditions.

- Scenario 1: 150 MMcfd supply shortfall between scheduled receipts and actual gas flows (Potential Gas Curtailment: 180 MMcfd – 84 MMcf/eight peak hours)
- Scenario 2: Scenario 1 in addition to a non-Aliso storage outage, reducing 400 MMcfd of system capacity (Potential Gas Curtailment: 480 MMcfd – 224 MMcf/eight peak hours)
- Scenario 3: Scenario 1 in addition to a pipeline outage reducing 500 MMcfd of system capacity (Potential Gas Curtailment: 600MMcfd - 280 MMcf/eight peak hours)
- Scenario 4: Combination of Scenarios 1, 2, and 3 resulting in an overall reduction of 900 MMcfd in system capacity (Potential Gas Curtailment 1100MMcfd -513MMcf/eight peak hours)

The supply shortfalls, loss of storage withdrawal (beyond Aliso), or loss of pipeline capacity could alternatively be real-time changes in demand (such as a fast/sustained ramp of gas-fired electric generation) or forecast variances. The criteria are applied over all the operating days. On some days, the system will be capable of tolerating variances from storage withdrawal or flowing supplies. This is due to the robust and redundant design of the pipeline system. That redundancy is removed as planned maintenance and outages occur. It should be noted that the 3.2 Bcf sendout threshold criteria for this analysis does not represent a "bright line," where curtailments would not occur below that sendout level. Curtailments are possible during many different combinations of sendout, natural gas receipts, temperature, and pipeline/storage facility outages. For these analyses, 3.2 Bcfd was chosen because it represents a high sendout condition for the gas system during the summer. And it was also the sendout for the September 9, 2015 gas day scenario that was analyzed hydraulically. Historically, sendouts higher than 3.2 Bcf yield higher peak hourly rates.

Curtailment Risk Summary

Based on the historical data from years 2013 to 2015 and the scenario criteria, there are an estimated 23 to 32 days where the SoCalGas and SDG&E systems will be under significant stress with Aliso Canyon capabilities unavailable. Ultimately, the actual magnitude and distribution of the system stress and potential curtailments will vary based on conditions at the time of the incident. The range is based on whether SoCalGas and SDG&E incur a planned or unplanned outage. An outage is defined as a pipeline or piece of equipment that is taken out of service.

An analysis of this complexity is difficult to evaluate while trying to ensure as many variables as possible are taken into consideration to effectively calculate the probability of curtailments. This analysis has two major steps:

1. Identify the data set and determine the total number of potential days where the SoCalGas system would be under significant stress
2. Utilize the days identified in Step 1, and overlay planned maintenance scenarios in addition to unplanned outages

The data from steps 1 and 2 is then evaluated to establish a range of days where the gas transmission system will be under stress, and curtailments will be likely.

Analysis Discussion

Step one

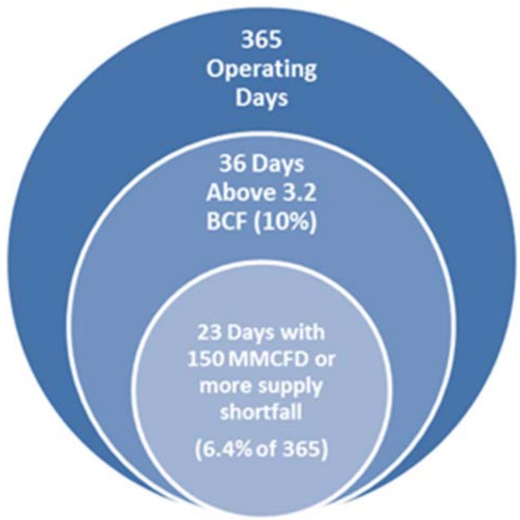
Since the analysis is based on historical data, it was important to ensure that an appropriate time span was utilized which encompasses representative operating conditions that could be expected in 2016. The task force determined that operating days from 2013 through 2015 were the most appropriate being that utilizing data from 2012 could skew the analysis because 2012 was the year the San Onofre Nuclear Generating Station (SONGS) was taken offline, resulting in abnormal operating conditions and electric generation compared to other years.

The data set consisted of operational data for each gas day for the chosen time span, where the results from the September 9 hydraulic analysis provided the governing criteria. The results from that hydraulic analysis indicated that if the difference between the expected flowing supplies and the actual demand exceeded 150 MMcfd, the pressures in the Los Angeles Basin and in the Southern System would not fully recover requiring the system operator to potentially call a curtailment in order to ensure system reliability is maintained.

The data for 2013—2015 resulted in a total data set of 1,095 operating days. Then, all days that had a daily sendout (total gas burn) of 3.2 Bcf or greater were identified, which resulted in a total of 108 days, or approximately 10 percent of the 1,095-day data set. Once the 3.2 Bcf or greater days were identified, the data set was further filtered to only those days where the difference in flowing supplies and sendout were 150 MMcfd or more, which gave a result of 70 days. This represented 6.4 percent of the 1,095-day data set.

Using the above percentages, about 10 percent of the year or 36 days will be 3.2 Bcf or above, and 6.4 percent of the year or 23 days will have a shortfall of 150 MMcfd or more. This is represented in Figure 16.

Figure 16: One Year Breakdown of Operating Data



Step two

Once the number of days where the gas transmission system is expected to be under stress and the risk of curtailments is high was identified (23 days per year), the estimated planned and unplanned outages on the gas system expected in 2016 were brought into the analysis (Scenarios 2 and 3). SoCalGas and SDG&E post outages that impact system capacity to its electronic bulletin board, Envoy, as soon as practical.

Next, SoCalGas created scenarios based on planned outages, like projects and maintenance on the gas transmission pipeline and storage systems that could occur in 2016. SoCalGas and SDG&E work regularly on their outage schedules—moving outages around to minimize reliability impacts to the extent possible. In order to continue to safely operate their systems, SoCalGas and SDG&E will continue to execute projects necessary for safety and regulatory compliance. The Step 1 analysis identified 23 days or 6.4 percent of the year where curtailments are likely, and the same percentage was applied to each of the planned outage conditions in order to determine how many days would occur under each condition. The following calculations in Table 3 describe the risk assessment for all the outages scenarios for 2016.

Table 3: Calculations to Determine Range of Estimated Days the SoCalGas and SDG&E Systems Will be Under Significant Stress:

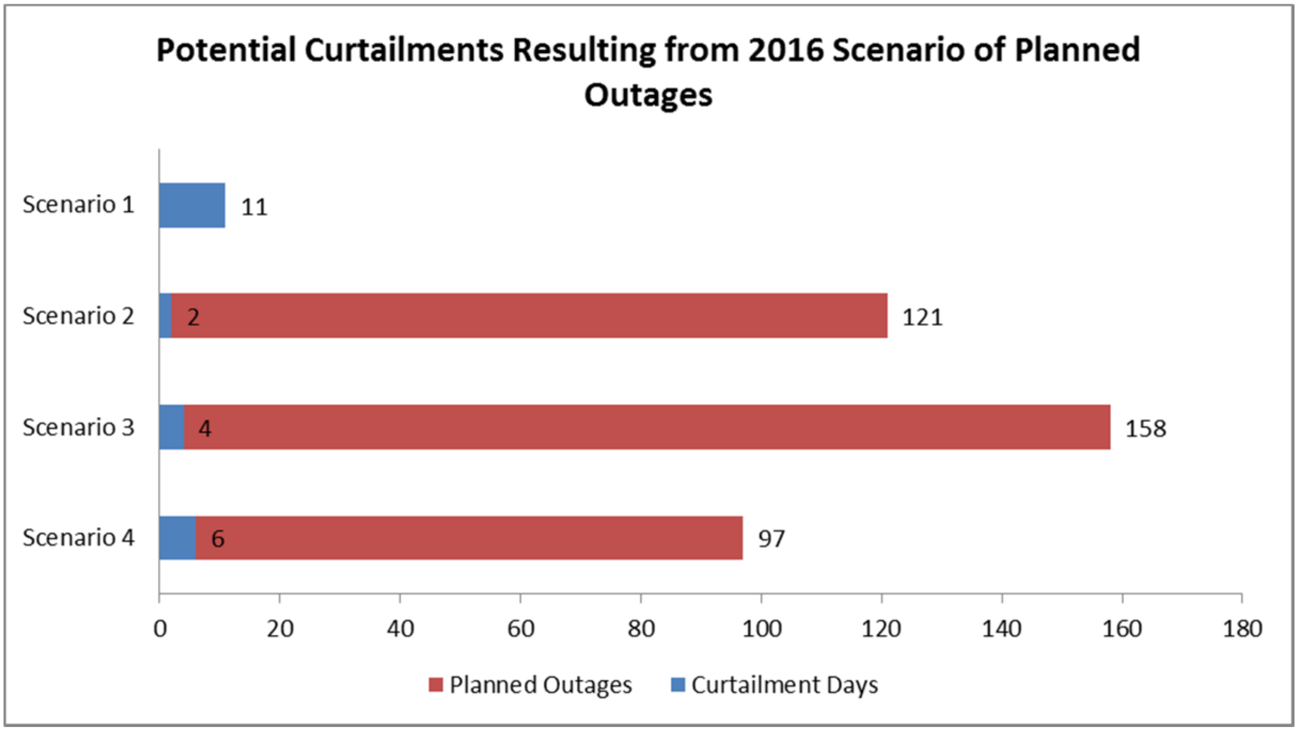
Total Data set (3 years 2013-2015):				
Total number of days in data set:	1095	days		
Number of days above 3.2 BCF:	108	days	10%	of total data set
Number of days > 150 MMCFD supply shortfall:	70	days	65%	of 3.2 BCF days
Annualized Data:				
Days per year above 3.2 BCF:	36	days		
Number of days > 150 MMCFD supply shortfall:	23	days	6.4%	of calendar year
Planned Outage Scenarios:				
Storage Outages > 400 MMCFD impacts:	121	days		
Pipeline Outages > 500 MMCFD impacts:	158	days		
Outage overlaps (both above occur concurrently):	97	days		
Isolate Days ONLY Storage Outages (no overlap):	24	days (121-97)		
Isolate Days ONLY Pipeline Outages (no overlap):	61	days (158-97)		
Apply 6.4% of calendar days from above to determine the estimated number of storage and pipeline outage days under stress:				
Storage Outages > 400 MMCFD impacts:	2	days (6.4% of 24)		
Pipeline Outages > 500 MMCFD impacts:	4	days (6.4% of 61)		
Outage overlaps (both above occur concurrently):	6	days (6.4% of 97)		
Estimated days of significant stress during a planned outage:	12	days (sum of above)		
Estimated days of significant stress throughout the calendar year:	11	days (23 - 12)		
Unplanned Outage Scenarios:				
Storage Outages > 400 MMCFD impacts:	21	days		
Pipeline Outages > 500 MMCFD impacts:	117	days		
Outage overlaps (both above occur concurrently):	5	days		
Isolate Days ONLY Storage Outages (no overlap):	16	days (21-5)		
Isolate Days ONLY Pipeline Outages (no overlap):	112	days (117-5)		
Apply 6.4% of calendar days from above to determine the estimated number of storage and pipeline outage days under stress:				
Storage Outages > 400 MMCFD impacts:	1	days (6.4% of 16)		
Pipeline Outages > 500 MMCFD impacts:	7	days (6.4% of 117)		
Outage overlaps (both above occur concurrently):	1	days (6.4% of 5)		
Estimated days of significant stress during unplanned outages:	9	days (sum of above)		

Total estimated range of days resulting in significant stress: 23 to 32 days
23 days based on planned outages
9 days based on unplanned outages (incremental to the planned outages)

Historical data for three years was utilized in order to forecast planned outages for 2016. Figure 17 shows the number of potential gas curtailment related to planned outages. The analysis utilized 6.4 percent of the days from Step 1 to estimate the condition under which a curtailment will occur. Based on this approach, the following is the breakdown of planned outages we might expect this year by scenario. The following bullets summarize the scenarios:

- Scenario 1: Forecasted 11 days where the SoCalGas system will be under significant stress throughout the year
- Scenario 2: Forecasted 121 days of planned storage outages with impacts greater than 400 MMcfd
    - Based on this methodology, it is estimated that there are two days where the system will be under significant stress in this condition
- Scenario 3: Forecasted 158 days of planned pipeline outages with impacts greater than 500 MMcfd
    - Based on this methodology, it is estimated that there are four days where the system will be under significant stress in this condition
- Scenario 4: There are 97 days where the two planned outage conditions above will overlap and occur concurrently
    - Based on this methodology, it is estimated that there are six days where the system will be under significant stress in this condition

Figure 17: Days of Potential Gas Curtailments Due to Planned Outages

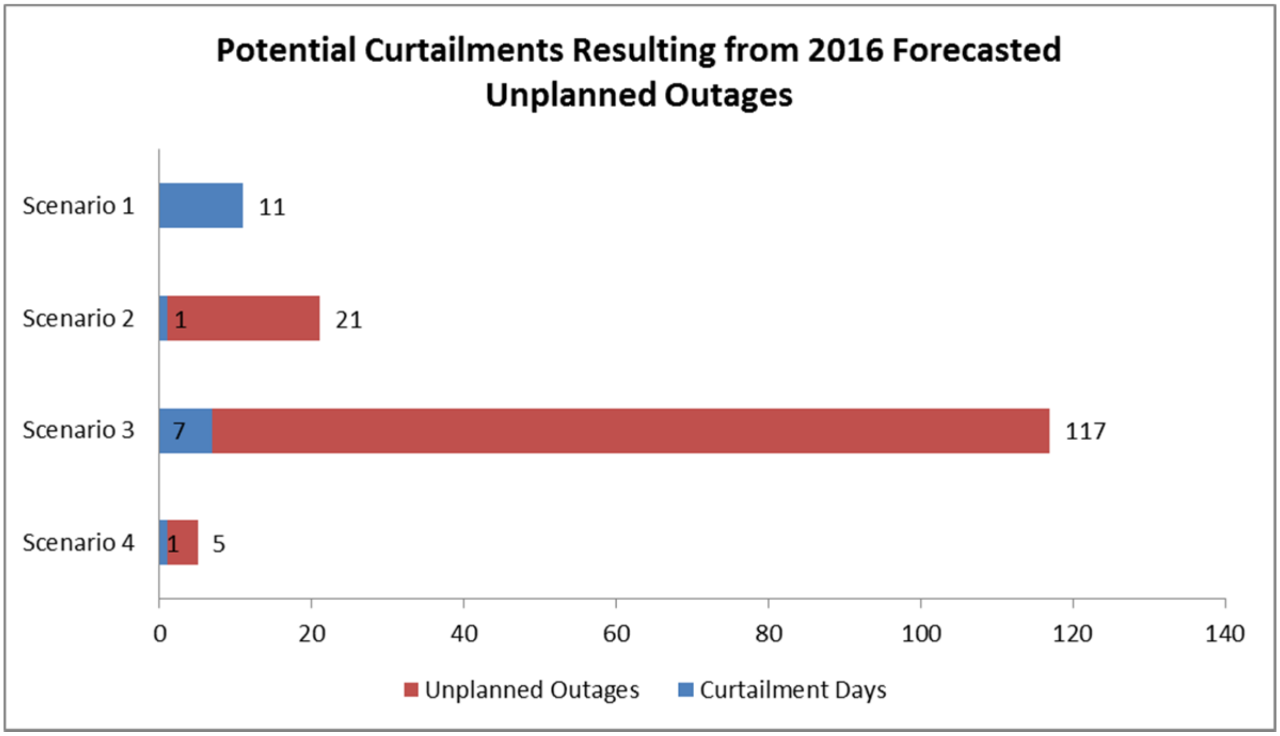


Historical data for the same three years was utilized in order to forecast unplanned outages for 2016. Figure 18 shows the number of potential gas curtailment related to unplanned outages. The analysis used 6.4 percent of the days from Step 1 to estimate the condition under which a curtailment will occur. Based on this approach, the following is the breakdown of unplanned forced outages that might be expected this year:

- Scenario 1: Forecasted 11 days where the SoCalGas system will be under significant stress throughout the year.
- Scenario 2: Forecasted 21 days of unplanned storage outages with impacts greater than 400 MMcfd.
    - Based on this methodology, it is estimated that there is one day where the system will be under significant stress in this condition.
- Scenario 3: Forecasted 117 days of unplanned pipeline outages with impacts greater than 500 MMcfd.
    - Based on this methodology, it is estimated that there are seven days where the system will be under significant stress in this condition.
- Scenario 4: There are five days where the two outage conditions above will overlap and occur concurrently.

- Based on this methodology, it is estimated that there is one day where the system will be under significant stress in this condition.

Figure 18 – Days of Potential Gas Curtailments Due to Planned Outages



Results

SoCalGas and SDG&E cannot forecast customer curtailment on their gas transmission system. Depending upon the level of demand, level and location of delivered supply, and availability of transmission assets, curtailment of customer demand can be avoided in one situation and be required in an otherwise similar situation. At the request of and under direction from the task force, SoCalGas and SDG&E have attempted to quantify the level of risk of uninterrupted service that may occur under a fixed set of assumptions.

Based on the historical data from years 2013 to 2015 and the analyses performed on specific historical days directed by the task force, SoCalGas and SDG&E have calculated a potential for 23 to 32 days where the SoCalGas and SDG&E systems will be under significant stress in 2016 without the Aliso Canyon storage field in operation, placing uninterrupted service to noncore customers at risk. The magnitude and distribution of this risk is grouped into the following "tranches" based on whether the SoCalGas and SDG&E systems incur planned or unplanned outages. These values are based on operating and outage data, and not on a hydraulic analysis based on specific operating conditions or days. The risk is expressed as a daily volume based on a 24-hour gas day (7 a.m. to 7 p.m.), and therefore hourly reductions are distributed across all 24 hours. For periods of risk that are less than 24 hours, the volume at risk may exceed these overall daily volumes.

- Scenario 1 quantified 11 days in which the gas demand exceeds the amount of gas that customers planned to bring in by more than 150 MMcfd but with no other pipeline or storage outages beyond Aliso Canyon. SoCalGas estimates under Scenario 1, there is a daily gas curtailment potential up to 180 MMcfd of which 84 MMcf occurs over the eight peak electric hours of the day. Of those 11 days, two days in scenario 1 are summer days and the balance of the nine are non-summer days
- Scenario 2 quantified two to three days based on planned and unplanned outages respectively in which there is a coincident planned or unplanned storage outage that reduces gas delivery capacity by 400 MMcfd in addition to the conditions of Scenario 1. SoCalGas estimates that gas curtailment up to 480MMcfd of which 224 MMcf for the eight peak electric hours would be necessary. Of those three days, two are summer days and one is non-summer.
- Scenario 3 quantified four to 11 days based on planned and unplanned outages respectively in which there is a gas coincident planned or unplanned pipeline outages reduce gas delivery capacity by 500MMcfd in addition to the conditions of Scenario 1. SoCalGas estimates that under Scenario 3, there is a potential for gas curtailment up to 600 MMcfd of which 280 MMcf for the eight peak electric hours would be necessary. Of those 11 days, nine are summer and two are non-summer.
- Scenario 4 quantified six to seven days based on planned and unplanned outages respectively in which there were combinations of storage and pipeline outages that reduces gas delivery capacity by 900MMcfd in addition to the conditions identified in Scenario 1. SoCalGas estimates that under this scenario 4, gas curtailment up to 1,100 MMcfd of which 513 MMcf for 8 peak electric hours would be necessary. Of those seven days, three are summer days in which high temperatures result in high demand.
- An additional nine days of curtailment may be anticipated to occur incremental to the 23 days under an unplanned outage condition, resulting in a range of potential curtailments using this methodology of 23 to 32 days. Table 4 provides a summary of scenario findings.

Table 4: Days of Curtailment Risk by Scenario

Curtailment Scenarios	Days of Curtailment Risk for Electric Generators
Scenario 1: 150 MMCF supply shortfall between scheduled receipts and actual gas flows (Potential Gas Curtailment: 180MMCF/Day - 84MMCF/8 peak hours)	11 Days (2 summer, 9 non-summer)
Scenario 2: Scenario 1 in addition to a non-Aliso storage outage, reducing 400 MMCFD of system capacity (Potential Gas Curtailment: 480MMCF/Day - 224MMCF/8 peak hours)	2-3 Days (2 summer, 1 non-summer)
Scenario 3: Scenario 1 in addition to a pipeline outage reducing 500 MMCFD of system capacity (Potential Gas Curtailment: 600MMCF/Day – 280MMCF/8 peak hours)	4-11 days (9 summer, 2 non-summer)
Scenario 4: Combination of Scenarios 1,2, and 3 resulting in an overall reduction of 900 MMCFD in system capacity (Potential Gas Curtailment 1100MMCF/Day -513MMCF/8 peak hours)	6-7 days (3 summer, 4 non-summer)

ELECTRIC ANALYSIS

SoCalGas performed hydraulic simulation analysis for selected sample days from 2015 and 2014. The selected sample represented days that had a total gas demand that exceeded 3.2Bcf. Based on the results of the hydraulic analysis, SoCalGas determined that under certain conditions and without the availability of Aliso Canyon, critical operations gas pressures will be difficult to maintain when actual gas demand exceeds gas scheduled into the SoCalGas system by more than 150MMcfd. Under such conditions, SoCalGas indicated gas curtailments would be necessary to manage operational pressures. SoCalGas' assessment further determined the frequency and magnitude of gas curtailments can increase due to planned and unplanned outage to gas pipelines and other storage facilities in the SoCalGas system on days the system is already stressed due to differences between scheduled gas and actual gas demand. Based on the gas assessment, California ISO and LADWP Balancing Authorities[5] performed a complementary joint assessment translating the gas assessment to electric impacts.

Electric generation taking noncore service on the SoCalGas system is the first gas customers having to respond to gas curtailments.[6] The less time the California ISO and LADWP have to respond to a gas

[5] California ISO and LADWP Balancing Authorities include the municipal utilities of Anaheim, Riverside, Pasadena, Azusa, Banning, Colton, Burbank, and Glendale. The Balancing Authorities will be referred to as California ISO and LADWP throughout the Electric Analysis section of this document.

[6] Currently, SoCalGas and SDG&E curtail end use load defined as "interruptible" off the system first. Next, "firm" noncore load is curtailed in a system of rotating blocks between electric generation and non-electric generation load, until the desired amount of gas is taken off the system. SoCalGas and SDG&E have proposed in Application 15-06-020 the authority to revise their curtailment procedures to take up to 60 percent of the electric generation load off the system as the first step in a curtailment event.

curtailments notice, the fewer options the California ISO and LADWP have to secure additional import energy to serve load in southern California area to displace the gas-fired generation affected by the gas curtailment. This means that the tolerance of short-notice gas curtailments can only be absorbed by imported energy to the extent there is room available in the electric transmission system and available supply. Historically, when the Southern California system experiences high electric loads, the southwest is also experiencing high loads. Available import energy has been scarce during these times, especially in real-time operating hours.

As Balancing Authority and Transmission Operator, LADWP and California ISO are required to meet NERC Reliability Standards requirements. These requirements include:

- The requirement for Balancing Authority to carry and maintain a minimum amount of contingency reserve
- The requirement for Balancing Authority and Transmission Operator to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements

The California ISO and LADWP performed a joint assessment to determine the minimum generation requirements needed based on the actual September 9, 2015 operating conditions. This assessment included:

- Power flow analysis to ensure acceptable electric system performance under pre- and post-contingency operations.
- Assumed normal transmission system configuration with all lines in service.
- The minimum generation levels to maintain local reliability, extrapolated to meet the load pattern.
- Maximize Imports based on transmission and supply limitations required to meet customer demand not met by minimum generation levels within the SoCalGas service territory.

The local reliability assessment focused on local transmission reliability that did not include the contingency reserve requirement necessary to immediately meet the greater of the loss of the Most Sever Single Contingency (MSSC) or approximately six percent of the hourly peak load. The assessment also does not include capacity needed to recover required contingency reserves within one hour after they are dispatched. Separate from the local reliability assessment, LADWP and California ISO determined that they would not be able to maintain sufficient contingency reserve[7] in Southern California area to meet reliability requirements.

[7] While the California ISO may be able to maintain system-wide contingency reserves requirements, it would not be able to maintain sufficient distribution of contingency reserves in Southern California.

While the quantity and location of the generation commitment may vary depending load level and system topology each day, historical experience and the summer 2016 seasonal assessment performed by the California ISO and LADWP show the need to have minimum generation commitment inside the Los Angeles, Orange County and San Diego areas. Maintaining the minimum generation requirement needed to reliably operate each local system limits the ability for both LADWP and California ISO to shift electric supply from inside the Los Angeles Basin to other areas of the SoCalGas system. This includes municipal utilities in the Southern California gas area that also require minimum generation to ensure reliability in their systems.

Figure 19 shows the minimum generation identified in the assessment needed in both LADWP and California ISO Balancing Authority areas translates into an LADWP and California ISO gas requirement of approximately 1901 MMcf for the day. Should transmission contingencies or forced outages occur, generation will be dispatched in the impacted areas to reposition the electric system to avoid further transmission overloads. This may require additional gas burn within the Los Angeles Basin and SoCalGas southern system. Additional gas may or may not be available, given real time operating conditions, which could result in electric service curtailments.

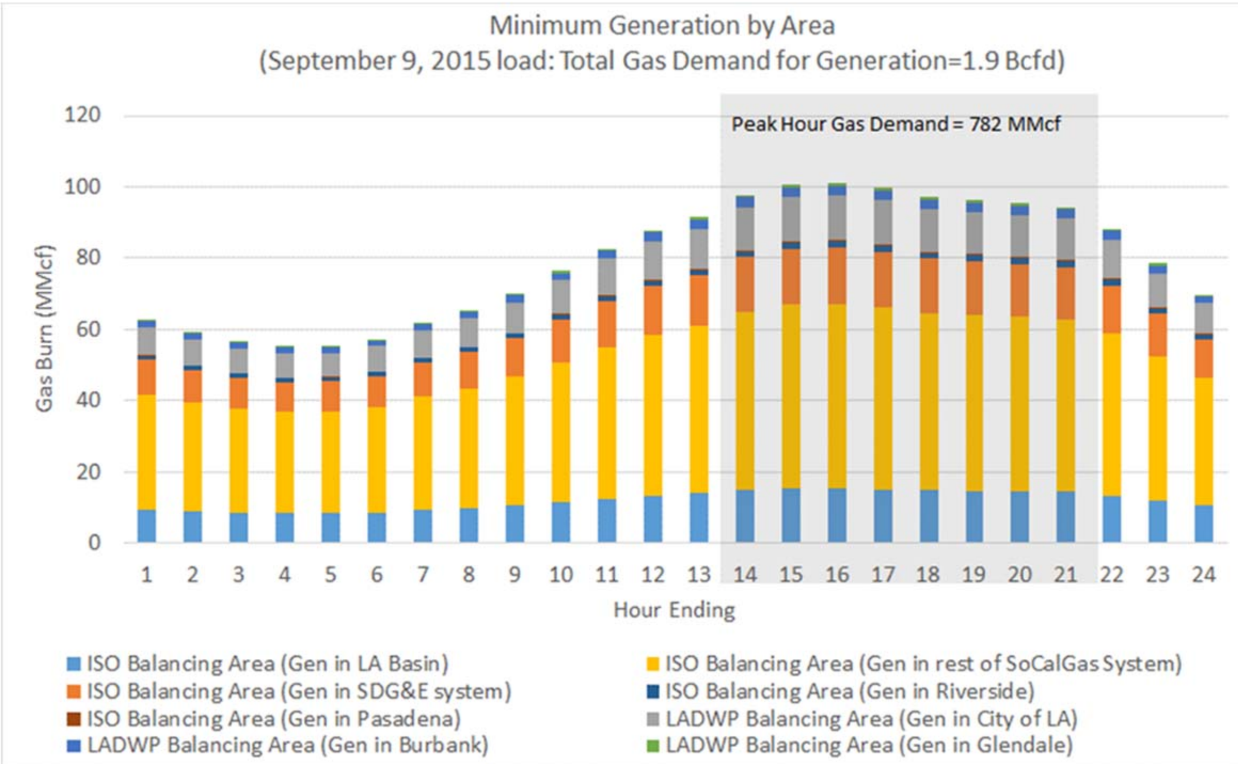
Case studies

Two power flow case studies were developed for this assessment utilizing the Western Electricity Coordinating Council - Operational Study Subcommittee's summer 2016 power flow case. The 2016 power flow cases modeled a 1-in-10 year load level. However, the load in the case was decreased to reflect a typical summer high load as represented by September 9, 2015. The case studies established the minimum generation in Orange County area and other areas to meet local reliability criteria while maximizing energy imports from the north and east into the Los Angeles Basin, Orange County and San Diego in order to minimize the use of gas fired generation needed throughout the remainder of the SoCalGas and SDG&E system.

A typical load pattern and maximum energy imports subject to transmission constraints[8] were assumed. Gas fired generation was scaled accordingly to meet the load pattern. The analysis calculated the hourly minimum generation in MW for the San Diego, Orange County, LADWP, and remaining areas within the SoCalGas and SDG&E system. The minimum generation requirement was then translated to the gas needed in MMcf per hour throughout the SoCalGas and SDG&E system to support the minimum generation requirement as illustrated in Figure 19.

[8] The most limiting transmission constraint in the California ISO system is the transmission running from northern California to southern California referred to as Path 26. The most limiting transmission constraint in the LADWP system is the Victorville to Los Angeles path.

Figure 19: Minimum Generation, Gas Requirements in MMcf



The minimum generation identified in the assessment needed in both LADWP and California ISO Balancing Authority areas translates into an LADWP and California ISO gas requirement of approximately 1901 MMcf for the day and more specifically 782 MMcf for the peak hours that would be most susceptible to gas curtailments as indicated by the shaded area in Figure 19 above.

Table 5 summarizes the inputs and results for the case studies. Rows 8 and 13 illustrates the amount of supply for California ISO and LADWP, respectively, that could be shifted assuming supply and transmission availability to support gas curtailment. Row 14 provides the total combined California ISO and LADWP supply that could shifted. Row 15 quantifies the approximate amount of gas curtailment relief that could be achieved by re-dispatching using the peak hour gas burn.

Table 5: Summary of Case Study Results

No	Case study with minimum ISO LA Basin and LADWP Generation	9/9/2015 Actual System Condition	9/9/2015 System Conditions with Minimum LA Basin and LADWP generation	2016 (1 in 10) Heavy Summer case with Minimum LA Basin and LADWP Generation
1	CAISO Southern California (SCE) Load + Losses (MW)	23,232	23,232	23,495
2	CAISO San Diego (SDGE) Load + Losses (MW)	4,938	4,938	5,292
3	CAISO Combinded Southern California Load (MW) (Rows 1 + 2)	28,170	28,170	28,787
4	CAISO LA Basin Gas Generation (MW)	3,816	1739	1739
5	CAISO Gas Generation taking service from SoCalGas (MW)	6,935	5,117	5,681
6	CAISO all other generation in Southern California not requiring service from SoCalGas (MW)	7,509	8,994	8,716
7	CAISO Imports into Southern California from North and East as measured by Southern California Import Transfer (SCIT) (MW)	14,932	16,399	16,204
8	CAISO Additional Import Requirement (Min Gen Case - Actual Case)		1,467	1,272
9	LADWP Load + Losses (MW)	6905	6905	7125
10	LADWP Gas Generation (MW)	2746	1646	1776
11	LADWP Other Generation (MW)	261	663	683
12	LADWP Import into Basin (MW)	3898	4596	4666
13	LADWP Additional Import Requirement (MW) (Min Gen Case - Actual Case)		698	768
14	Total CAISO and LADWP Import Requirement (MW) (Row 8 + 13)		2,165	2,040
15	Total additional gas required to replace additional Imports for 8 hour peak period (mmcf) (Row 14/103MWh*8 Hours)		168	158

California ISO Minimum Generation Requirements

For the California ISO balancing area, the amount of gas curtailment that can be managed depends on a number of factors. These factors include the electric load level in Southern California, local transmission constraints within California ISO's Southern California system and the amount of electric supply available that can use remaining transmission capacity between California ISO and neighboring balancing authority areas.

During the summer, the load in the California ISO southern system combines SCE and SDG&E transmission service areas.[9] On September 9, 2015, the southern system load was 27,526 MW.[10]

There are local transmission constraints that require specific generation to respond to transmission contingencies in Orange County and San Diego. Some local utilities that are embedded within the California ISO balancing area such as the city of Riverside and city of Pasadena also require minimum generation levels to maintain reliability on their local transmission or distribution systems depending on the load level. These transmission constraints require generation in specific areas to be prepared to respond to local transmission contingencies to avoid overloading other transmission lines or to maintain required voltage levels.

California ISO Ability to Shift Electric Supply from Basin/SoCalGas Area

Import capability in southern California from the northern California is limited by the north to south transmission path (Path 26) at a maximum of 4,000 MW total transfer capability when all lines are in service. If 3000 MW of energy is already flowing and 1000 MW available capacity on Path 26 remains, then the California ISO Balancing Authority could only absorb 1000 MW of generation curtailment in the Southern California area from the north. In addition, there is approximately 10,100 MW of east to west transmission capability between California ISO and Nevada[11] and Arizona. The real-time ability to increase energy delivery from the Southwest is limited by the small amount of supply available and remaining unused transfer capability. Lastly, there is approximately 3,000 MW of transfer capability between LADWP and California ISO. Typically during the summer 2500 MW is already flowing with energy from LADWP resources located outside the Los Angeles Basin leaving only 500 MW of capability for additional import energy assuming supply availability. In addition, the transmission throughout the system can become congested during times of high imports and may be limited in effectiveness to mitigate gas curtailments in times of high loading conditions.

There are some gas-fired resources located in southern California that take can take gas service from other pipelines other than those of SoCalGas for example the High Desert Generations facility. These resources can be used to help mitigate gas curtailments to gas fired resources on the SoCalGas system but may not serve to mitigate local transmission constrained areas such Orange County.

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[9] Load includes cities of Riverside, Anaheim, Pasadena, Vernon, Azusa Banning and Colton.

[10] California ISO 2015 peak load occurred on September 8, 2015.

[11] In December 2016, NV Energy started participation in the Energy Imbalance Market (EIM). NV Energy's participation in the EIM there increases the real-time transfer capability between Nevada and Southern California and therefore increases the flexibility for the California ISO to respond to real-time gas curtailments.

LADWP Minimum Generation Requirements

LADWP has constraints similar to those noted by the California ISO and as a result LADWP can experience similar situations. The amount of absorbable gas curtailment will be highly correlated with the amount of transmission capacity left available in its Victorville-Los Angeles path.

Any amount of gas curtailment beyond what can be absorbed will most likely result in the electric demand curtailment.

LADWP's minimum generation is determined by a minimization process in which the following three reliability criteria are the major constraints.

1. Before the loss of any transmission circuit or generator, all circuit loadings shall be less than the circuits' continuous ratings, and all voltages shall be normal.
2. Following the loss of the most critical single generator or transmission circuit, the loading on the most severely stressed transmission circuit shall be less than that circuit's two-hour rating (emergency rating)
3. Following the loss of the most critical single generation or transmission contingency, or any credible multiple contingency, LADWP steady state voltage shall meet LADWP's voltage limits.

The minimum generation requirement is the minimum generation that meets all three criteria. The minimum generation dispatch is determined daily for the next day, monthly and seasonally assuming worst-case conditions for the period. In real time, the system is continuously monitored to determine the minimum generation requirement is being satisfied.

In addition, a minimum generation commitment/availability is also determined by the same minimization process in which the following fourth reliability criterion is the major constraint.

4. Assuming the worst single contingency is not restored within two hours, sufficient LADWP generation shall be available within two hours to relieve loading on all circuits to the circuits' continuous ratings, and to restore voltage to 100 percent of normal.

Assuming all lines in service and generation available at each plant:

1. The minimum generation output (to meet 1, 2 and 3 above) typically ranges from 226 MW to 457 MW at 3,900 MW (nominal spring peak) to 1,523 MW to 2, 198 MW at 6905 MW (typical summer peak).
2. The minimum generation commitment (to meet 4 above) ranges from 549 MW at 3,900 MW (nominal spring peak) to 2,897 MW at 6,905 MW (typical summer peak).

The values will be higher if there are transmission limitations.

LADWP's Ability to Shift Electric Supply from Basin/SoCalGas Area

A daily resource plan is developed and used to ensure LADWP has adequate resources to meet its projected load including reserves for contingencies minimum generation requirements and regulation of variable generation resources such as wind and solar. This daily plan is used to forecast the amount of gas required to be used in the LADWP basin generators. This gas forecast is used to procure the necessary gas for each day.

During a gas curtailment a reduction in available gas will require the generators within the Los Angeles Basin or across SoCalGas system, depending on the operational gas conditions, to re-dispatch to reduce gas burn to some value as determined by SoCalGas. The options to make up for this reduction of in-basin generation are limited to imports of additional purchased power from outside the Los Angeles Basin, or use other uncommitted resources (not included in daily resource plan) outside the Los Angeles Basin. These options are limited by transmission import capability.

Some energy may be shifted from gas fired generation to the Castaic Power Plant in real time. But energy from Castaic is limited by reservoir elevation, and Castaic cannot sustain maximum output for more than a few hours, particularly on successive days. LADWP's ability to shift supply from the Los Angeles Basin to external sources is limited by the following three constraints:

1. The minimum generation requirements described above. A portion of the LADWP load must always be supplied by local gas-fired generation to meet Reliability Criteria 1, 2, and 3 above.
2. LADWP's ability to import external resources is limited by transmission capability. Based on the results of a joint power flow study with the California ISO that maximized imports, the total imports into the LADWP Balancing Authority at a peak load of 6,900 MW is 4,666 MW.
3. Market availability of capacity and energy from external resources.

Energy may be shifted from gas fired generation to imports within an hour or two, contingent on the availability of unloaded transmission capacity and sufficient resources from LADWP external resources or counterparties for purchase. Of the 4,666 MW of imports required to minimize the gas burn, 72 percent of the available import capability is already committed to importing LADWP, Burbank, and Glendale resources from external wind, solar, geothermal, coal, and nuclear resources owned by the Balancing Authority members. The remaining 28 percent of the import capability is useful in meeting load only if counterparties on the other end of the transmission paths have energy to sell. This is a critical point especially during high temperature and high demand events. During the July 1, 2015 gas curtailment, LADWP was unable to purchase energy in the real-time wholesale market at any price.

Electric Service Reliability Risk Assessment

The study considered the NERC Contingency Reserve requirements which dictate that available unloaded generation is available to be called on and loaded to cover the loss of generation or transmission elements within the LADWP system. This reserve is required to be dispatched to cover the loss of the LADWP Most Severe Single Contingency (MSSC) and usually is within the 700 to 800 MW range. The reliability requirement is to cover this loss within 15 minutes and a second requirement to restore the contingency reserves within 60 minutes of activation. For many scenarios, this reserve energy must come from in basin gas-fired generation. Since the analysis was completed with the intent to maximize the ability to curtail gas, this requirement is not included for LADWP. Ultimately, this will place an additional unscheduled burden on the gas supply or reduce the ability to absorb some of the gas curtailment.

The LADWP reliability assessments are conducted based on the expected electrical system conditions for the operating time period being analyzed. Currently the focus is for the upcoming summer operating season. These studies are performed using the appropriate WECC seasonal base case, modified as needed to simulate the conditions expected for this season. This includes all planned transmission and generation outages. These conditions are modeled in an off-line power flow program that runs a battery of transmission and generation contingencies to determine minimum generation commitment and post contingency generation increases to maintain NERC reliability requirements[12].

This is an assessment using best-case rather than worst-case assumptions. If any of the import transmission paths are not available or limited more than specified, or if market energy is not available, then LADWP will not have sufficient resources to meet the peak demand and electric demand curtailments are a likely result.

JOINT CALIFORNIA ISO AND LADWP IMPACT ANALYSIS AND RESULTS

The SoCalGas hydraulic analysis indicated that at times of high forecasted gas demand 3.2 Bcf or higher the gas system had the capability to maintain gas reliability within a 150MMcfd tolerance before pipeline pressures would be at unreliable levels. To the extent, the difference between the forecast gas and actual gas demand is more than 150MMcfd, the possibility of gas curtailment on the system increase. SoCalGas estimated four scenarios resulting in increasing depth of curtailment volume on the gas system with approximate number of days of curtailment. The assessment of the impact that a gas curtailment could have on the LADWP and California ISO electric system is limited to summer 2016. Curtailment on the gas system at the volumes estimated in the studies will significantly impact the reliability of the electric system. The chart below shows the impact on the electric system with increasing depths of curtailment volume estimated by SoCalGas.

The four scenarios of gas curtailment, indicated in Table 4 above, are:

- Scenario 1: If there is a difference of 150 MMcfd between scheduled gas and the actual gas demand, would translate into the 84 MMcf of curtailment on the gas system for the eight hour peak period (1 p.m. to 9 p.m.).
- Scenario 2: If there is a difference of 150MMcfd, plus non-Aliso Canyon storage outage reducing gas supply by an additional 400 MMcfd, would translate into 84 to 224 MMcf of curtailment on the gas system for the eight hour peak period.
- Scenario 3: If there is a difference of 150 MMcfd, plus pipeline outage reducing gas supply by an additional 500 MMcfd, would translate into about 224 to 280 MMcf of curtailment on the gas system for the eight hour peak period.
- Scenario 4: If there is a difference of 150MMcfd, plus impact of coincident outages of both pipeline and non-Aliso Canyon storage reducing gas supply by the combined 900 MMcfd, resulting into 280 to 513 MMcf of curtailment on the gas system for the eight hour peak period.

[12] Minimum generation commitment and post-contingency generation are key drivers for gas usage and are necessary to avoid post-contingency load shed.

Table 6 shows the impact analysis of curtailment during the summer peak period from Hour Ending 14 to Hour Ending 21 (1:00 p.m. to 9:00 p.m.) (eight hours) as represented by September 9, 2015 and estimated by SoCalGas.

Table 6: Summary of Assessment of Electric Impact of Gas Curtailments for a typical summer day (September 9. 2015)

Row	Description	Formula	Gas Curtailment Scenario			
			Scenario 1: No Outage	Scenario 2: Storage Outage	Scenario 3: Pipeline Outage	Scenario 4: Overlap Outage
1	Original Curtailment for day - Volume by SCG (MMcfd)		180	480	600	1100
2	Number of Hours of Curtailment	8	8	8	8	8
3	**Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)**	**(Row 1/24)*1.4*Row2**	**84**	**224**	**280**	**513**
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf)		659	659	659	659
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Rows 4 + Row 5	**782**	**782**	**782**	**782**
7	Actual ISO SCG system September 9 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns	Row 7 + Row 8	**923**	**923**	**923**	**923**
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	409
11	**ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)**	**Row 10 - Row 6**	**56**	**-84**	**-140**	**-373**
12	ISO LADWP Energy Conversion of Gas Burn Short for the day (MWh)	Row 11*103MWh/mmcf	5,802	-8,618	-14,386	-38,420
13	ISO LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row2	725	-1,077	-1,798	-4,802
14	Customer Impacted	Row 13*700	0	754,098	1,258,798	3,361,715
15	Estimated Days of Curtailment - Summer		2	2	9	3
16	**Total Aliso Withdrawal Needed for Summer for 8 hour peak period (MMcf) per scenario**		0	167	1257	1119

Analysis

California ISO and LADWP used September 9, 2015 as the summer peak load day on the electric generation system for the joint analysis. The minimum generation required for the California ISO to maintain electric transmission system reliability in the southern system would be about 659 MMcf for the eight hour peak period. Similarly, LADWP would need about 124 MMcf of gas to maintain reliability in LADWP's Balancing Authority for the eight hour peak period.

Assumptions for the Minimum Generation Peak Case: September 9, 2015 loading was used to study the impact of gas curtailment without Aliso Canyon Gas Storage. The summer case was built in way to study the minimum generation required in the Southern System to maintain electric system reliability. The fleet of resources dependent on gas operated by SoCalGas inside LA Basin and Southern System were kept at minimum to maintain reliability of the electric system. The assumptions include maximizing the transmission capability for imports into the Southern System while keeping the electric system reliable. The study assumes no contingency reserves (which are required to be maintained per NERC standard), and no planned or forced transmission or generation outages. The electric assessment study is not accounting for reserves. If the imported energy from outside the area or State is not available, additional gas would be need to dispatch generation to maintain contingency reserves to standard levels, manage approved planned or forced outages, relieve the transmission overloads, and provide contingency reserves or meet electric demand.

Results

The combined California ISO plus LADWP Balancing Authority would need about 782 MMcf of gas during the peak period to maintain reliability. These estimates are from power flow studies and might vary depending on the real – time conditions of the system. For the analysis, September 9 was selected because it was the peak load day in Southern California and Los Angeles Basin for 2015, with the highest gas burned for the electric generation system. Although September 9, 2015 was the peak day for 2015, it was not an all-time peak day but represents a typical high load summer day. The actual California ISO gas burned for September 9 for the entire SoCalGas fleet of resources was about 659 MMcf for the eight hour peak period. Similarly, LADWP had about 124 MMcf of gas burned for same 8 hour period. Based on the curtailment analysis, the allowable gas burn under each scenario for September 9, 2015 over the eight hour peak period would be the combined actual burns (California ISO plus LADWP Balancing Authorities) reduced by the curtailment volume (shown in the chart above). For the first scenario, the combined California ISO and LADWP Balancing Authorities gas burn was 923 MMcf for the eight hour peak period. With the curtailment volume of 84 MMcf, the allowable gas burn for the time period is about 839 MMcf (923 – 84). The difference between allowable gas burn of 930 MMcf and the gas burn needed to maintain the minimum generation would be the difference (either surplus or shortage) that California ISO plus LADWP can burn, in this scenario, it was 56 MMcf. If the difference is a positive, it would mean that California ISO and LADWP would have sufficient room to increase the energy produced by their gas resources up to the additional amount. If the difference is a negative, it would mean that California ISO and LADWP would be short of the gas needed to maintain electric reliability, if faced with the gas curtailment by the amount indicated in Table 5. In these scenarios, the minimum generation levels could not be maintained, the California ISO and LADWP would have to declare an emergency and prepare to interrupt load to maintain electric system reliability and not cause cascading outages into a greater electric footprint. The load curtailment may mean using interruptible load but could result in utilities to call for rotating blackouts per emergency procedures. Row 12 and Row 13 explain the amount of electric load (megawatt hours (MWh) and MW) impacted during peak hours by the gas curtailment due to the four scenarios.

One MW of electric curtailment roughly equals enough electricity for the instantaneous demand of 700 homes at once. All the scenarios, except for the first scenario, with only a difference of 150MMcf between the scheduled gas and actual gas, would have a load curtailment of varying impact with as many as 3.36 million customer homes impacted without the Aliso Canyon gas storage facility. To avoid load curtailment on the electric system on the summer days estimated for gas curtailment, withdrawal of 2.5 Bcf from Aliso Canyon storage is needed. That 2.5 Bcf is the total gas requirement for only the eight hour peak period for summer electric reliability. There could be additional gas needed for off-peak periods and winter outage days. The 15Bcf of working gas available in the Aliso Canyon appears to be sufficient to meet the summer reliability needs so long as the gas withdrawal capability necessary is available when needed and is effectively managed to meet reliability. Until SoCalGas is allowed to inject into Aliso Canyon and use the cycling capabilities of the field, SoCalGas will work with the CPUC to establish guidelines for how the remaining 15 Bcf of inventory will be used from Aliso Canyon for gas and electric reliability. When there is a stressful event on the system, SoCalGas will use all its tools to to limit using the gas that is remaining in Aliso Canyon. SoCalGas will also work with the grid operators and noncore customers to relieve the stress on the system using tools available to them. If this does not adequately alleviate the gas system problem, SoCalGas will follow the pre-established CPUC guidelines on how to use the gas in Aliso Canyon to best ensure reliability and safety of the gas and electric system.

MITIGATION MEASURES

Mitigation measures are being developed by the action plan entities reduce, but not eliminate, the risk and impact of electricity service interruptions. The action plan entities and the Technical Assessment Group believe there are risks to electric reliability that these measures cannot eliminate.

APPENDIX A: Analysis of Summer Gas Curtailment June 30, 2015 to July 1, 2015

The California ISO completed on June 29th, its Integrated Forward market run for trade date June 30, 2015 and reported to the gas utilities the expected gas burn resulting from market awards to electric generators. As a result of the combination of a high load forecast, low level of imports into the California ISO, and low levels of hydroelectric generation, the market committed a large amount of gas fired generation in the LA Basin, resulting in a high demand for natural gas.

SoCalGas reviewed the estimated gas burn and contacted the California ISO to report that there would be a supply line issue with that level of gas burn[13]. With its Envoy information system showing a projected total projected natural gas demand for the day of 3.8 Bcf, SoCalGas posted a curtailment watch at approximately 8:15 a.m. on June 30, 2015. The notice warned that *"SoCalGas and SDG&E are projecting a high gas send out for the next several days that may affect service to noncore customers in some localized areas. Customers are advised that they may be receiving a notice to curtail service sometime later today or tomorrow."*

SoCalGas expanded the watch area at approximately 12:15 p.m. At 3 p.m., SoCalGas initiated an emergency localized curtailment for the Los Angeles Basin beginning at 3 p.m. on Tuesday, June 30, 2015 and continuing to 8 p.m. on July 1, 2015: *"Due to the heat wave currently facing the western US, both the natural gas and electric systems are experiencing high utilization, which has resulted in SoCalGas calling an emergency localized curtailment for the Los Angeles Basin service area beginning at 3 PM PCT today. Currently SoCalGas does not need to curtail other areas, but we anticipate that demand will peak today in Southern California from 3 PM to 8 PM. We are closely monitoring the situation and will provide updates on Envoy as more information becomes available."*

Table 7: Receipt Point Capacity Maximum versus Available June 30 Curtailment Day

Supply (MMcfd)	Maximum	June 30
California Line 85 Zone	160	86
California Coastal Zone	150	16
Wheeler Ridge Zone	765	771
Southern Zone	1,210	913
Northern Zone	1,590	852
Total Flowing Supply at Receipt Points	3,875	2,638
From Storage June 30		812
Demand Served June 30		3,424
Demand Served July 1		3,429

[13] California ISO Market Update Call Meeting Minutes July 9, 2015.

Several conditions contributed to the adverse operating conditions. Extreme hot weather in the Western U.S., and especially the entire West Coast, along with drought impacts that decreased availability of hydro-electric generation, created a significant demand for natural gas to fuel electric power plants. In addition, an outage to conduct required compliance testing on Line 4000, a SoCalGas transmission pipeline that brings natural gas from the California border to the Los Angeles Basin, reduced the natural gas delivery capacity available to meet this increased demand. The testing and remediation work on Line 4000 reduced capacity into SoCalGas' Northern Zone by: 1) 540 MMcfd in the Needles/Topock Area starting on June 3, 2015; 2) 200 MMcfd in the Needles/Topock Area starting on June 12, 2015; and 3) 150 MMcfd at the Kern RIver/Mojave – Kramer Junction receipt point starting on June 14, 2015.[14] These capacity reductions were scheduled to continue through most of the summer and were all in effect during the June 30/July 1 curtailment event. The combination of high demand with reduced capacity to meet that demand required SoCalGas to call the emergency localized curtailment in order to preserve their ability to meet the demands of higher priority core customers.[15]

The curtailment affected electric generation customers in the Los Angeles Basin, who received limited gas service during the curtailment. Both California ISO and LADWP were required to use less gas. They modified operations to meet electricity demand while generating less electricity within the curtailment zone.

On June 30, California ISO System Operations worked with SoCalGas to determine what level of generation could be supported in the Los Angeles Basin. The gas curtailment amount was converted to MWs and the California ISO applied a pro-rata curtailment percentage to all gas fired generation in the LA Basin. The California ISO was requested to reduce generation output up to 1,700 MW to reduce gas usage on a select set of units in the north and south Los Angeles Basin. The California ISO curtailed approximately 1,600 MW using exceptional dispatch to the following generating facilities in the Los Angeles Basin in response to SoCalGas' request for gas curtailments at various hours on June 30, 2015[16]:

- Malberg Generating Station
- Glen Arm Unit 1-4
- Center peaker
- Carson Cogeneration
- Canyon Power Plant Unit 1-4
- Anaheim Combustion Turbine
- El Sungundo Energy Center Unit 5 - 8

[14] Real-time notice of the capacity reductions were posted on the Envoy™ system and later reported in response to the 24th Data Request from Southern California Generation Coalition in CPUC Application No. 13-12-013 by SDG&E and SoCalGas.

[15] SoCalGas submitted Advice No. 4827 on June 30, 2015 to notify the CPUC and affected parties of a curtailment event in its service territory.

[16] California ISO Draft 2015/2016 Transmission Plan.

- El Segundo Generating Station Unit 4
- Harbor Cogen Combined Cycle
- Hinson Long Beach Unit 1-2
- Alamitos Generating Station Unit 1-4
- Alamitos Generating Station Unit 5-6
- Barre Peaker
- Huntington Beach Unit 1-2
- Redondo Generating Station Unit 5-8
- Watson Cogeneration Company.

In addition to the generation curtailments mentioned above, the California ISO told market participants in its peak day conference call that morning that it had or would be taking the following additional steps:

1. Declare a Stage 1 Energy Emergency.
2. Deciding whether or not to issue a Flex Alert notice at about 10 a.m.
3. Expect to call baseload interruptible programs "very likely" throughout the Balancing Area
4. The California ISO and LADWP outage management teams will be meeting to coordinate outage issues for tomorrow to help avoid further problems.

The California ISO issued a Flex Alert urging voluntary conservation. SCE implemented approximately 400 MW of demand response. Most of this was obtained from its AC cycling program.

The following table provides a summary of the aggregated MW output and estimated total gas volume usage (in million standard cubic fed per hour - MMcfh) for California ISO generating facilities in the Los Angeles Basin and San Diego areas.

Table 8 Summary of Existing Generating Facilities Maximum Output and Estimated Total Gas Volume Usage in the LA Basin and San Diego Areas

	Gas Transmission Zone	**Aggregated Generation Output (MW)**	**Estimated Total Gas Volume Usage (MMcfh)[117]**
1	South of Moreno/SDG&E	2,997	27.35
2	South of Moreno / SCE	742	6.75
3	West of Moreno	748	6.8
4	East of Moreno	1,425	12.95
5	North of LA Basin	384	3.49

6	South of LA Basin	5,798	52.71
7	Northern Gas Transmission Zone	1,937	17.61

LADWP also bore a portion of the gas outage. In implementing the gas curtailment, SoCalGas asked LADWP what was the minimum quantity of natural gas that was needed. LADWP, at the time was experiencing an outage of its own at its coal-fired Intermountain generating station in Utah. It asked SoCalGas how much gas it could have. The result was a split of roughly 75 percent of the June 30 gas curtailment going to generators within the California ISO balancing authority and 25 percent going to LADWP.[17] LADWP curtailed about 500 MW of generation. On July 1, LADWP was asked to consume no more than what the hourly burn had been on June 30. LADWP's daily gas burn was approximately 190 MMcfd, on both days, which it was able to accommodate on the second day only because temperatures were lower on the second day, reducing electricity demand slightly.[18]

The sequence of phone calls and requests leads to LADWP stating that the curtailment rules are not clear as they do not specify what the curtailment would be based on or how it would be spread among gas fired generators. Also, the curtailment notice was given at 3 p.m., after the day-ahead wholesale market closed at 10 a.m. Once the day-ahead wholesale market is closed, the only option remaining is to purchase make up electricity in real-time markets. However, LADWP was unable to purchase energy in the real-time wholesale market at any price on July 1. By July 2 demand eased to levels within SoCalGas' system capability and the gas curtailment ended.

In ending the episode, SoCalGas modified the schedule to remediate Line 4000, moving a portion of the work to October. This pushed the work out of potentially high demand days during the summer but still allowed the pipeline work to be completed before start of the higher gas demand winter season. With Line 4000 restored and more moderate weather, Southern California avoided further gas curtailments and impacts to electric generation for the rest of the summer.

A review of this recent curtailment event highlights that stress conditions on the gas system can occur, resulting in gas curtailments, even with Aliso Canyon in operation.

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[17] SoCalGas reports that California ISO accounts for approximately 75 percent of the electric generation demand on the SoCalGas/SDG&E system. SoCalGas 2015 Customer Forum, Sixth Annual Report of System Reliability Issues, page 3.

[18] LADWP reported 198,451 British Thermal units (MMbtu) for June 30 and 197,907 MMbtu for July 1, which were converted to MMcfd at a heating value conversion of 1.035 MMBtu per thousand cubic feet (MCF).