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SoCalGas Summer 2020 Technical Assessment

Additional submitted attachment is included below.

SoCalGas
A Sempra Energy utility®

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April 1, 2020

California Energy Commission Docket Office
Docket: 20-IEPR-03 – Electricity and Natural Gas
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Summer 2020 Technical Assessment

Southern California Gas Company (SoCalGas), as part of our ongoing commitment to providing safe and reliable service to Southern California and our customers, has prepared the attached "Summer 2020 Technical Assessment" (Assessment). The Assessment details the following issues relating to system reliability on the SoCalGas system for the upcoming summer season:

- While SoCalGas expects to return some of its pipelines to service this summer, there is still the potential for pipeline operating limitations to impact the sendout capacity of the SoCalGas system;
- SoCalGas may need to use gas stored at Aliso Canyon to meet noncore customer demand this summer; and
- The ability to fill storage to levels sufficient for the winter 2020-21 season may be jeopardized if pipelines remain out of service, or additional pipeline outages are experienced.

Should SoCalGas find that pipeline receipt capacity is trending towards the "worst case" scenario described in the Technical Assessment as the summer season progresses, SoCalGas may need to take action to further enhance storage injections, preserve inventory to meet winter inventory targets, and/or place greater restrictions on the use of storage in the 2020-21 winter season to support noncore demand.

SoCalGas remains committed to providing safe, reliable, and affordable natural gas service to our millions of customers across our service territory as part of the State's efforts to make sure there is a reliable supply of energy to California's residents, businesses, and economy.

Sincerely,

Rodger R. Schwecke
Senior Vice President
Gas Operations and Construction

Enclosure

SOUTHERN CALIFORNIA GAS COMPANY SUMMER 2020 TECHNICAL ASSESSMENT

April 1, 2020

Executive Summary

SoCalGas has prepared this technical assessment to provide a forecasted outlook of system reliability during the coming summer months, assess the preparedness of the system for this upcoming winter, and analyze the associated risks to energy reliability during these periods. For this assessment, SoCalGas analyzed the following: (1) pipeline capacity available to bring gas into the system, (2) the forecasted summer demand, (3) available system capacity to serve demand, and (4) the forecasted storage inventory for the following winter season. In performing this analysis, this assessment takes into consideration the various existing and potential outages and the operating restrictions on gas transmission and storage assets.

SoCalGas has sufficient capacity to serve the forecast summer peak demand of 3.32 billion cubic feet per day (BCFD) under the "best case" supply scenario, with or without the use of Aliso Canyon. Under the "worst case" supply scenario, SoCalGas has insufficient capacity to serve the forecasted summer peak demand, with a system capacity of 3.25 BCFD or 2.97 BCFD with and without the use of Aliso Canyon, respectively. Consistent with the Commission's July 23, 2019 Aliso Canyon Withdrawal Protocol,[1] SoCalGas may use Aliso Canyon to maintain service to core and critical noncore customers.

SoCalGas also performed a preliminary analysis of projected storage injection and resulting inventory through the summer to prepare for the 2020-21 winter season. Using demand forecast data prepared for the 2018 California Gas Report (CGR), the projected SoCalGas capacity to receive pipeline supplies, and an estimate of storage field inventory levels on April 1, SoCalGas finds that the current maximum allowable system storage inventory of 84.4 BCF[2] can be reached by November 1 under a "best case" supply scenario assumption.

However, under a "worst case" supply scenario assumption, available supplies are insufficient to meet forecasted demand through the summer season, resulting in approximately 11.59 BCF of noncore curtailment over the season even with all storage fields completely depleted by the end of the season. In order to achieve the November monthly minimum inventory levels specified in the Aliso Canyon Withdrawal Protocol, approximately 41.09 BCF of noncore curtailment over the summer season would be needed. If receipt capacity is trending toward this "worst case", SoCalGas may need to take action to further enhance storage injections, preserve inventory to meet winter inventory targets, and/or place greater restrictions on the use of storage in the 2020-21 winter season to support noncore demand.

[1] Aliso Canyon withdrawal is currently restricted to specific requirements specified in and pursuant to the CPUC's Aliso Canyon Withdrawal Protocol dated July 23, 2019.

[2] This assumes Playa del Rey's typical maximum inventory of 1.9 BCF.

System Reliability Assessment of Summer Months

SoCalGas does not have a summer design standard. This is partly because the SoCalGas system is a winter peaking system and service to the core customers is not at risk in the summer season. Although noncore customers are fully interruptible pursuant to the CPUC-approved SoCalGas Tariff Rule No. 23 and San Diego Gas & Electric Company (SDG&E) Gas Rule No. 14, the CPUC and SoCalGas/SDG&E have recognized that supply and operating constraints placed upon the electric grid balancing authorities[3] in the utilities' service territory can place electric reliability at risk, and understand the importance of working to maintain service to local electric generating (EG) plants in southern California.

In assessing reliability for the upcoming summer months, SoCalGas analyzed the supply outlook for the system and the peak demand forecast, which are addressed in turn, below.

Supply Outlook, Available Flowing Pipeline Supplies and Storage Withdrawal Capacities

The SoCalGas/SDG&E gas transmission system is nominally designed to receive up to 3.78 BCFD of flowing supply on a firm basis. This means that if customers deliver that much supply to the SoCalGas system, and there is sufficient customer demand, then SoCalGas can redeliver that gas supply to end-use customers.[4] Supplies delivered to the SoCalGas system, however, do not reach these maximum receipt levels for a variety of reasons, including that customers may choose to use SoCalGas' balancing service rather than deliver supplies, California production has declined over time, system demand frequently does not require maximum delivery of supply, or flowing supplies may not be available due to weather patterns or maintenance impacting the interstate pipelines upstream of the SoCalGas system. Additionally, planned and unplanned pipeline outages can reduce receipt capacity.

In order to calculate this season's capacity of the system to serve customer demand, assumptions must be made regarding the available supply. The peak summer demand period is expected to occur after July, so SoCalGas determined ranges of available flowing pipeline supplies by analyzing "best" and "worst" case scenarios for this period. The "best case" scenario assumes Line 235-2, Line 4000, and Line 2001 are returned to service in time for the peak summer demand period and limited gas supply is available at the Otay Mesa receipt point. The "worst case" scenario assumes that Line 235-2, Line 4000, and Line 2001 are out of service for remediation and no supply is available at Otay Mesa.

In addition to the outages and restrictions discussed above, SoCalGas took into consideration in its analysis that customers do not typically fully balance their supply with their demand given SoCalGas' balancing rules. Reviewing scheduled deliveries shows that customers have historically used on average 85% of available interstate receipt capacity. In situations with significant infrastructure outages and limited storage supply, however, SoCalGas would require tighter balancing and expect to see higher capacity utilization as a result.

Given these considerations, for the purpose of this peak day capacity calculation, SoCalGas has adopted a peak day utilization assumption of 90% for the "best case" supply scenario and 95% for the "worst

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[3] California Independent System Operator (CAISO), Los Angeles Department of Water and Power (LADWP), and Imperial Irrigation District (IID).

[4] Customer demand may also be required to be in a specific location, such as on the Southern System in order to receive the full receipt capacity of 1,210 MMcfd at Blythe and Otay Mesa.

case" supply scenario for all supplies except for local California production, which is assumed at the current production rate.[5]

Using the scenario information outlined above, the resulting "best" and "worst" case receipt capacities during the peak summer period are detailed below in Tables 1 and 2.

Table 1. "Best Case" Available Flowing Pipeline Supplies

Receipt Point	Capacity/Supply (MMcfd)	Details
North Needles	400	Reduced receipt capacity due to Line 3000 temporary pressure reduction and operating pressures of Line 235-2 and Line 4000.
Topock	300	
Kramer Junction	550	Limited to firm receipt capacity due to supply from North Needles and Topock.
Blythe	980	Reduced receipt capacity due to loss of pipeline on Southern System.
Otay Mesa	150	Expected level of supply available due to EG demand in Mexico.
Wheeler Ridge & Kern River Station	765	
California Production	70	Current level of local California production.
Total	**3,215**	
Assume 90% pipeline utilization	**2,901**	

[5] In Energy Division's final Scenarios Framework in I.17-02-002, adopted by the CPUC on January 4, 2019, Energy Division used an 85% utilization factor for certain aspects of its analysis. SoCalGas believes that 85% is more appropriate for that framework given the planning horizons used in the framework versus the single operating season used in this technical assessment.

Table 2. "Worst Case" Available Flowing Pipeline Supplies

Receipt Point	Capacity/Supply (MMcfd)	Details
North Needles	0	No receipt capacity due to Line 235 and Line 4000 outages.
Topock	0	
Kramer Junction	700	Increased receipt capacity due to lost receipt capacity at North Needles and Topock
Blythe	765	Reduced receipt capacity due to loss of pipeline on Southern System and Line 2001 outage due to remediation.
Otay Mesa	0	No receipt due to EG demand in Mexico.
Wheeler Ridge & Kern River Station	765	
California Production	70	Current level of local California production.
Total	**2,300**	
Assume 95% pipeline utilization	**2,189**	

The capacities shown in Table 2 as "worst case" are based on current known potential projects, which may impact receipt capacity. However, unexpected outages on the transmission system, such as those resulting from third-party damage and safety-related conditions, or impacts to maintaining these receipt capacities due to potential employee availability or governmental orders in response to COVID-19, could still occur throughout the summer season, further reducing receipt capacity beyond the level projected in Table 2.

For this assessment, based on current storage field withdrawal capacities and the supplies assumed in Tables 1 and 2, SoCalGas assumed that 2.12 BCFD (best case) and 1.24 BCFD (worst case) of inventory withdrawal capacity would be available during the peak summer season with the use of Aliso Canyon. Without Aliso Canyon, withdrawal capacity is reduced to 1.34 BCFD (best case) and 0.87 BCFD (worst case). These withdrawal capabilities are dependent on having sufficient inventory levels in storage to sustain these withdrawal capacities. The lower withdrawal rates available under the "worst case" supply assumption reflects the lower levels of storage inventory that could be attained by the peak summer demand period given the reduced pipeline supplies. Finally, these levels incorporate estimated impacts from the CalGEM well reassessment requirements that will be occurring throughout the year.

Peak Summer Demand Forecast and System Capacity Calculation

For the upcoming summer season, the forecasted level of total system demand is approximately 3.32 BCFD as shown in Table 3, itemized by customer type as:

Table 3. Summer 2020 Forecasted Customer Demand

Customer Type	Summer Demand (BCFD)
Core	0.788
Noncore, Non-EG	0.794
Noncore, EG*	1.738
Total	3.320

* 2018 CGR forecast for summer 2020.

Using the values reflected in Table 3, SoCalGas analyzed how much of this forecasted demand the system can sustain using hydraulic simulations of its gas transmission and storage system under both the "best" and "worst" case pipeline supply scenarios described in Tables 1 and 2, with and without utilizing Aliso Canyon.

Based on the forecasted summer 2020 demand and system capacity, SoCalGas will be able to meet forecast peak day demand under a "best case" supply scenario, with or without the use of Aliso Canyon. SoCalGas does not have a detailed demand forecast for the summer season greater than the peak day demand of 3.32 BCFD, and the location and level of EG demand impacts the system capacity. However, given the level of available pipeline and withdrawal supply under the "best case" scenario, SoCalGas estimates that it could support a sendout up to 4.20 BCFD and 3.80 BCFD with and without the use of Aliso Canyon, respectively.

SoCalGas is unable to meet the forecasted peak day demand of 3.32 BCFD under a "worst case" supply scenario with or without the use of Aliso Canyon, resulting in curtailment of 70 - 350 MMcfd of forecasted EG demand. "Worst case" scenario system capacities are summarized in Table 4 below.

Table 4. Summer 2020 "Worst Case" System Capacity (BCF)

Customer Type	**Summer Demand (BCFD)**	
	With Aliso Canyon Supply	**Without Aliso Canyon Supply**
Core	0.788	0.788
Noncore, Non-EG	0.794	0.794
Noncore EG	1.668	1.388
Total	**3.250**	**2.970**

Note that the system capacity is less than the sum of the available pipeline and storage supplies as a result of system hydraulics. Customer demand is not constant over the course of the day, and gas supplies from interstate pipelines travel slowly across the pipeline network at a constant rate. During those times of the day when demand exceeds the pipeline supply, SoCalGas will use supplies from its storage fields to make up the difference. When customer demand drops off, SoCalGas will reduce the amount of supply withdrawn from its storage fields or even inject excess supply into them if system conditions permit. Because storage supplies are not used at a constant rate for the entire day, the system capacity is always less than the sum of the available pipeline and storage supplies.

System Reliability Assessment for 2020-2021 Winter

While the summer season is a peak electric generation demand period, the summer season is also when SoCalGas prepares for the upcoming winter season by injecting gas supply into storage for the following winter season.[6]

Using public demand forecast data published in the 2018 CGR workpapers for the summer season (April through October 2020, average temperature with base hydro condition), a projection of the expected storage inventory levels on April 1 (49.12 BCF), and estimates for injection capacity at each field,

[6] SoCalGas Operations does not purchase and store any gas supply for the use of any customer. SoCalGas' Gas Acquisition department purchases supplies for storage only for the SoCalGas retail core and the SDG&E wholesale core market segment, excluding those core customers served by Core Transport Agents as part of a Core Aggregation Transportation program (CAT) and other wholesale providers.

SoCalGas performed a mass balance examining the ability to fill storage under both the "best" and "worst" case supply scenarios. This mass balance is presented below in Table 5.

Under both the "best case" and "worst case" scenarios, SoCalGas assumed lower levels of receipt point utilization than were used in assessing the peak day capacities because the mass balance is a seasonal assessment, spanning all 214 days of the summer season. It is not reasonable to assume that the high levels of receipt point utilization that were used in the peak day capacity assessments would occur for every day of the season, particularly when the available data is average daily demand.

For this mass balance assessment, SoCalGas assumed receipt point utilizations depending upon which assets are expected to be in service. Under the "best case" supply scenario, Line 235-2 and Line 4000 are assumed to be in service throughout the summer season, increasing the northern zone capacity to 1250 MMcfd. In April and June, Line 2001 is assumed to be out of service for the planned hydrotest and potential remediation. Due to the high level of pipeline supply assumed available, SoCalGas used a utilization factor of 85% corresponding to historical behavior. However, as system-wide injection capacity is diminished, it may become increasingly difficult to receive high levels of pipeline supply consistently through the summer season.

Under the "worst case" supply scenario, Line 235-2, Line 4000, and Line 2001 are assumed to be out of service for the entire summer season. Because of the reduced receipt capacity, SoCalGas assumed a utilization factor of 90% to reflect tighter balancing requirements.

Table 5. Monthly Storage Injection Assessment (CGR Average Temperature with Base Hydro) (MMCF)

		2020						
		APR	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**
Best Case	Supply Utilization	85%	85%	85%	85%	85%	85%	85%
	CGR Demand	72990	64170	62160	75485	81344	77400	75051
	Pipeline Supply	76815	79376	76815	85041	85041	82298	85041
	Storage Inj (+) / WD (-)	3825	13499	14655	2932	371	0	0
	Excess (+) / Short (-)	0	1707	0	6624	3326	4897	9990
	Month End Inv. (BCF)	52.94	66.44	81.10	84.03	84.40	84.40	84.40
Worst Case	Supply Utilization	90%	90%	90%	90%	90%	90%	90%
	CGR Demand	72990	64170	62160	75485	81344	77400	75051
	Pipeline Supply	66900	69130	51645	64387	64387	62310	69130
	Storage Inj (+) / WD (-)	-6090	4960	-10515	-11098	-16957	-9418	0
	Excess (+) / Short (-)	0	0	0	0	0	-5672	-5921
	Month End Inv. (BCF)	43.03	47.99	37.47	26.38	9.42	0.00	0.00

Under the "best case" supply scenario, SoCalGas expects to have sufficient capacity and supply to fill its storage fields by the end of the summer season. In fact, this calculation shows excess pipeline supply of 26.54 BCF over the summer season, most of which could potentially be stored at Aliso Canyon but for the Commission's inventory limitation of 34 BCF at that field.

Under the "worst case" supply scenario, available pipeline supply is insufficient to meet forecasted demand, and SoCalGas projects complete depletion of all storage fields with approximately 11.59 BCF of noncore curtailment over the summer season. However, this is an impractical and unreasonable scenario which jeopardizes core reliability going into the winter season.

In order to meet the November total month-end minimum storage inventory level of 29.50 BCF as specified in the July 23, 2019 Aliso Canyon Withdrawal Protocol, SoCalGas has calculated that approximately 41.09 BCF of noncore curtailment would be required over the summer season (See Table 6). Even so, if the storage fields enter the winter season at minimum inventory levels, there may be significant noncore curtailments required throughout the entire winter season to protect core reliability and maintain minimum inventory levels. [7]

Table 6. Monthly Storage Injection Assessment with Minimum Inventory (MMCF)

		2020						
		APR	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**
Worst Case	Supply Utilization	90%	90%	90%	90%	90%	90%	90%
	CGR Demand	72990	64170	62160	75485	81344	77400	75051
	Pipeline Supply	66900	69130	51645	64387	64387	62310	69130
	Storage Inj (+) / WD (-)	-5840	4960	-10515	-8723	0	0	0
	Excess (+) / Short (-)	-250	0	0	-2375	-16957	-15090	-6421
	Month End Inv. (BCF)	43.28	48.24	37.72	29.00	29.00	29.00	29.50

Even assuming that SoCalGas could maintain a 95% receipt point utilization factor every day through the entire summer season, which corresponds to a continuous 5% daily balancing requirement, the season-ending inventory for a "worst case" scenario will only reach 14.10 BCF with 1.64 BCF of noncore curtailment, still well below the November minimum inventory level.

Conclusion

This technical assessment provides forecasts of the upcoming summer and winter seasons and indicates that there may be a need to enact measures to support system reliability. For the upcoming summer season, SoCalGas estimates that it will be able to meet the forecasted peak day demand under a "best case" supply assumption even without supply from Aliso Canyon. Under a "worst case" supply assumption, the forecasted peak day demand cannot be met without curtailment even with the use of supply from Aliso Canyon.

SoCalGas also expects to be able to fill its storage inventory under the "best case" supply assumption in preparation for the winter 2020-21 season. However, under the "worst case" supply assumption, SoCalGas would be unable to fully fill storage. This may result in greater restrictions on the use of storage supply to support noncore demand, and corresponding noncore customer curtailment during the winter season to preserve inventory and associated withdrawal capacity for core customer reliability.

[7] For instance, if inventory levels only reach the November month end minimum inventory of 29.50 BCF by November 1, no withdrawal would be available for the month of November 2020.