APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS EFFECTIVE JANUARY 1, 2020 IN THE TRIENNIAL COST ALLOCATION PROCEEDING

(A.18-07-024)

(DATA REQUEST TURN-SEU-04)

DATA RECEIVED: 2-19-19

DATE RESPONDED: 3-5-19

QUESTION 1:

For the SoCalGas system, from April 1, 2016 through the present:

a) Please provide total daily gas injections into underground storage, withdrawals from underground storage, losses from other sources (e.g., leakage), and inventory balances.

b) Please provide daily nominations by non-core customers from flowing gas and daily nominations to inject or withdraw gas from unbundled storage purchased by those customers. Divide into industrial and electric generation for each of SoCalGas and SDG&E, and wholesale (excluding SDG&E) to the extent available.

c) Please provide actual daily deliveries to non-core customers and actual injections and withdrawals from unbundled storage purchased by those customers. Divide into industrial and electric generation for each of SoCalGas and SDG&E, and wholesale (excluding SDG&E) to the extent available.

d) Please provide the daily load balancing net injection or withdrawal from storage and cumulative inventory for non-core customers.

e) Please provide daily nominations by core customers from flowing gas and daily nominations to inject or withdraw gas from storage allocated to by those customers. Divide into core customers of SoCalGas and core customers of SDG&E.

f) Please provide actual daily deliveries to core customers and actual injections and withdrawals from storage allocated to those customers. Divide into core customers of SoCalGas and core customers of SDG&E.

g) Provide daily heating degree-days for each of the SoCalGas system and the SDG&E system (using whatever mix of weather stations is used for load forecasting; if the mix is different for residential and commercial customers, please provide heating degree-days for both classes).

h) Identify any days when (i) each level of Low or High Operational Flow Order was in place; (ii) any non-core loads were curtailed (including the amount of aggregate curtailment).

RESPONSE 1:

a) Please see attached file: TURN-04 Q1(a) for daily injections, withdrawals, and inventory balances; Losses, or leakage is not available from underground storage.

b) Data being sought customer-specific and market-sensitive. A description of the data is as follows.

Flowing gas: the daily nominations and actual deliveries (i.e. scheduled quantities after cuts to nominations) by non-core and core customers of SoCalGas & SDG&E as of the final scheduling cycle, Intraday 4 (or, Cycle 6). SoCalGas/SDG&E do not have information if these customers/shippers are industrial or electric generation customers, as marketers pool gas for their individual customers, and could have pools comprising various combinations of non-core end uses.

Unbundled Storage: daily injection and withdrawal nominations (Q.1.b) and actual deliveries (i.e. scheduled quantities after cuts to nominations) (Q.1.c) by unbundled storage customers. These customers are not classified as industrial or electric generation, and they are not specific to SoCalGas or SDG&E service territory. They are comprised of gas marketers who held storage rights for arbitrage purposes and were able to buy gas from any point on the SoCalGas/SDG&E system and deliver to any pool or customer. The non-core and wholesale customers are identified and listed separately.

c) Please see response (b).

d) Please see attached excel file: TURN-04Q1(d) Total Daily Imbalance and Cumulative Imbalance totals. SoCalGas' Electronic Bulletin Board, ENVOY, provides this data in total, and it would be burdensome to divide it into only non-core customers.

e) Please see response (b). Additionally:

Core Storage: the daily injection and withdrawal nominations (Q.1.e) and actual deliveries (i.e. scheduled quantities after cuts to nominations) (Q.1.f) by core storage customers, including both the SoCalGas Gas Acquisition department as well as Core Transportation Agents (CTAs). These customers are not specific to SoCalGas or SDG&E service territory. They are comprised of gas agents who represent customers in either one or both territories and inject to a generic storage account or withdraw to a pool of customers in most cases.

f) Please see response (e).

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g) Please find the SoCalGas daily system average HDDs and the SDG&E daily system average HDDs for 04/01/2016 through 02/19/2019 in the below file.

TURN-04 Q1g.xlsx

h)

(i) Please refer to SoCalGas ENVOY Information Postings for this data:

Operations > High OFO Calculation > High OFO Event History; and
Operations > Low OFO Calculation > Low OFO/EFO Event History

(ii) Please see attached excel file: TURN-04Q1(h) and Q2 Curtailment events 2016- current.

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<u>QUESTION 2:</u>

Please provide usage by non-core G-30 customers using the medium pressure distribution system on a daily basis from November 2016 to March 2017 and November 2017 to March 2018. Identify any days when curtailment took place. If the information cannot be provided for these customers, please provide for the total of G-30 customers using both high-pressure and medium-pressure distribution and provide an explanation as to how loads are divided between the two groups for load forecasting and cost allocation.

<u>RESPONSE 2:</u>

Requested non-core G-30 medium pressure distribution daily data are provided in the attached Excel file below.

TURN-DR-02a.xlsx

Please see attached file for Curtailments: TURN-04Q1(h) and Q2 Curtailment events 2016-current.

QUESTION 3:

Please identify any changes in required storage inventories due to operational issues, including a description of the change, when the change was adopted, and a narrative as to how SoCal responded to the change by changing patterns of injecting or withdrawing gas.

RESPONSE 3:

Applicants object to the term "required storage inventories" as vague and ambiguous. Notwithstanding this objection, and subject thereto, Applicants respond as follows.

SoCalGas's Gas Acquisition department is responsible for meeting July 31 and October 31 storage targets during the injection season, and for meeting its share of peak day minimum storage levels during the withdrawal season. The July 31 and October 31 storage targets are prescribed in the Gas Cost Incentive Mechanism (GCIM) Preliminary Statement, and the peak day minimum storage levels are established by the System Operator.

Gas Acquisition's compliance with the July 31 and October 31 storage targets, and the peak day minimum storage levels, are addressed annually in its GCIM application and the California Advocates' GCIM Report.

Beginning in 2016, Gas Acquisition has been unable to meet its October 31 storage targets due to constraints on injecting into the Aliso Canyon storage field imposed by the CPUC. During the 2017 injection season, Gas Acquisition adjusted its activities to increase the level of gas held in the Aliso Canyon storage field from 14.7 Bcf to 23.6 Bcf in response to CPUC directive. During the past two injection seasons, Gas Acquisition has been directed by the CPUC to accelerate its summer injections to meet system minimum storage levels established in Injection Enhancement Plans.[1] Activities resulting from these directives have been reported in a Memorandum Account which has not yet been filed for recovery with the CPUC. In addition, during the 2018 injection season, Gas Acquisition adjusted its activities to increase the level of gas held in the Aliso Canyon storage field to 34 Bcf in response to CPUC directive.

[1] See Advice Letters 5139 and 5275-A.

QUESTION 4:

Please provide copies of any analyses performed by the Sempra Utilities within the last five years that assessed the economic tradeoff between reserving storage capacity or purchasing interstate pipeline capacity (annual or seasonal) to meet the cold-year and peak-day reliability needs of the bundled core customers, for example, more storage and less pipeline capacity or less storage and more pipeline capacity.

RESPONSE 4:

Gas Acquisition's interstate capacity requirements are prescribed by the CPUC per Decision (D.) 04-09-022. Gas Acquisition's storage allocation was prescribed most recently by the CPUC in TCAP decision D.16-06-039. Applicants have not performed any analysis within the last five years addressing the economic tradeoff between these assets.

QUESTION 5:

In D.16-06-039 the Commission adopted a settlement provision initially proposed by the Sempra Utilities which provided that: “Unlike today’s rules, the core would not be restricted to using a maximum of 83 Bcf of inventory including imbalances since, like other customers, it could use positive 5% monthly imbalances in addition to its storage inventory.” Please provide the following information for the period since the implementation of that provision:

a) How often has the core used storage inventory in excess of the 83 Bcf core reservation in order to accommodate positive core imbalances, or for any other reasons?

b) For each instance identified in a) above, please provide the date, the volume of core gas stored in excess of the 83 Bcf core reservation, and an explanation of the circumstances which resulted in the core storing more than 83 Bcf of inventory.

RESPONSE 5:

a) Due to restricted capacities at the Aliso Canyon storage facility, core inventory has not reached 83 Bcf since the implementation of D.16-06-039.

b) N/A

QUESTION 6:

Prior to the implementation of the settlement provision addressed in 2) above, what would have happened if positive core imbalances would otherwise have resulted in the core's storing a greater amount of gas than its allocation of inventory capacity? Please explain fully. Did such a situation ever occur? If so, please provides dates, volumes, and an explanation of what actions were taken to deal with each such situation.

RESPONSE 6:

Prior to the implementation of the TCAP settlement provision, Gas Acquisition did not have tariff authority to accrue positive imbalances which otherwise would have resulted in the core's storing a greater amount of gas than its allocation of inventory capacity. Therefore, this situation never occurred.

QUESTION 7:

Please provide information indicating the number of occasions over the last five years in which the core has used storage withdrawal capacity in excess of its reserved capacity in order to accommodate negative core imbalances, or for any other reasons. For each such instance, please provide the date, the volume of core gas withdrawn in excess of the core withdrawal reservation, and an explanation of the circumstances which resulted in the core withdrawing more than its allocated amount.

RESPONSE 7:

SoCalGas interprets the question as intending to request information regarding storage inventory capacity, rather than storage withdrawal capacity, because storage inventory is used to accommodate negative imbalances. Over the past 5 years, Gas Acquisition has not had a negative imbalance which could not be accommodated by its allocated inventory.

QUESTION 8:

How are the Sempra Utilities proposing to allocate the costs of the storage inventory capacity proposed to be reserved for the new Reliability function? Does this allocation apply only to the 21 Bcf specifically designated for Reliability, or does it include the 19 Bcf core inventory minimum for the end of March that "will support the Reliability Function" (Dandridge, p. 8).

RESPONSE 8:

The cost of 21 Bcf storage inventory capacity for the new Reliability function is $8.3 million as shown in Chapter 8 (Fung), p. 19, Table 23. The cost is allocated between the Core inventory ($3.9 million) and Load Balancing inventory ($4.4 million) functions. The Core inventory allocation of $3.9 million and Load Balancing inventory allocation of $4.4 million is a seasonal weighted average percent split based on withdrawal deliverability of 1,240 MMcfd on a year-round basis. The 21 Bcf of storage inventory allocated to the Reliability function provides a withdrawal capacity of 1,240 MMcfd on a year-round basis. This is split in the 151 days of winter by 840 MMcfd for Core Reliability and 400 MMcfd for Load Balancing, and the 214 days of summer by 400 MMcfd for Core Reliability and 840 MMcfd for Load Balancing. The attached spreadsheet shows that the seasonally-weighted average results in 47% for the Core and 53% for Load Balancing.

The allocation applies only to the 21 Bcf for the Reliability function.

QUESTION 9:

Under the Sempra Utilities' proposal, the core's reservations of storage inventory, winter and summer withdrawal, and winter injection are being reduced from current levels, but the core's reservation of summer injection capacity is proposed to increase from 388 MMcf/d to 433 MMcf/d. Please explain the rationale for this increase. Would the Sempra Utilities oppose assigning the additional 45 MMcf/d of summer injection capacity to the Load Balancing function instead? If so, please explain the reasons in detail.

RESPONSE 9:

Applicants propose to allocate 433 MMcf/d to the Core to provide it more flexibility to inject gas at the most beneficial times throughout the summer injection season. Regarding any proposed modifications to Applicants' proposals, Applicants presented a comprehensive storage allocation proposal in support of its application. Applicants will respond to recommended modifications from other parties after considering the entirety of proposals provided in intervenor testimony.

QUESTION 10:

In the last TCAP, the Sempra Utilities proposed a core reservation of summer injection capacity (388 MMcf/d) sufficient to fill the core's 83 Bcf of inventory ratably over 214 days (Watson, p. 9). Given the proposed core inventory reservation of 80 Bcf in this case, why would 374 MMcf/d not be the appropriate core summer injection reservation, following the same principle?

RESPONSE 10:

Please see response 9.

QUESTION 11:

Please provide the authorized gas base margin for both SoCalGas and SDG&E as of the date of implementation of the last General Rate Case decision and list all changes to authorized gas margin since then and the date of the change, including a reference to the CPUC decision or advice letter that authorized the change, up to the present. Also, please indicate whether each change was for a specific cost item or a generalized increase in base margin.

RESPONSE 11:

See Attachment Response 11.xls.

QUESTION 12:

Please review the units of demand shown for Tables 1 through 9 of Ms. Payan's testimony (Mth or MDth) and indicate if any of these require correction.

RESPONSE 12:

Tables 1 through 8 should all be in Mtherms. All of the tables, except Table 7, contain the correct unit reference. The header on Table 7 should read Mth/day.

Table 9 contains the exchange historical volumes. The data are in Mdth and the units are correctly specified in that table.

QUESTION 13:

Please provide recorded EG and Large Cogen gas demand in the same format as Mr. Huang's Table 1 for the years 2014-2018. Please provide a monthly breakdown of these annual totals as well, for the recorded period.

RESPONSE 13:

See attached file TURN-SEU-04-Q13.xlsx.

QUESTION 14:

Please provide a step-by-step explanation of how the EG and Large Cogen annual demand forecast of 253 MMDth and TCAP-period average coincident peak day forecast of 867 MDth per day shown in Tables 1 and 2 of Witness Huang's testimony are translated into the SoCalGas and SDG&E annual demand forecasts and peak day demand forecasts shown for the EG class in Tables 4, 6, 10 and 12 of Witness Guo's testimony.

RESPONSE 14:

The consolidated EG throughput in Tables 4, 6, 10 and 12 of Witness Guo's testimony are the summary of EG and Large Cogen in Chapter 4 (Huang), and other Cogens (Refinery Cogen and Small Cogen) in Chapter 5 (Guo). Breakdown of EG throughput of SoCalGas and SDG&E in Tables 4, 6, 10 and 12 of Chapter 5 (Guo) are listed below.

SCG EG Average Year Throughput (Unit: MDth)

	2020	2021	2022	3-Year Avg. 2020-2022
UEG/EWG/Large Cogen	212,275	207,575	206,875	208,908
Other Cogens	48,902	48,996	48,710	48,870
Total	**261,177**	**256,571**	**255,585**	**257,778**

SCG EG Peak Day Demand (Unit: MDth)

	2020	2021	2022	3-Year Avg. 2020-2022
UEG/EWG/Large Cogen	702	716	696	705
Other Cogens	133	132	131	132
Total	**834**	**848**	**827**	**837**

SDG&E EG Average Year Throughput (Unit: MDth)

Average Year Throughput	**2020**	**2021**	**2022**	**3-Year Avg. 2020-2022**
UEG/EWG/Lg Cogen	44,197	43,952	42,907	43,686
Small Cogen	9,328	9,343	9,341	9,337
Total	**53,525**	**53,295**	**52,249**	**53,023**

SDG&E EG Peak Day Demand (Unit: MDth)

Peak Day Demand	**2020**	**2021**	**2022**	**3-Year Avg. 2020-2022**
UEG/EWG/Lg Cogen	171	155	160	162
Small Cogen	25	25	25	25
Total	**197**	**181**	**186**	**188**

QUESTION 15:

The annual EG gas demand forecasts for both SoCalGas and SDG&E appear to be identical in both an average temperature year and a 1-in-35 cold year. Have the Sempra Utilities performed any analysis of the cold temperature sensitivity of electric customer end-use demand and/or the impact of colder-than-average temperature on EG natural gas demand? If so, please provide. If not, please explain why there is zero assumed increase in gas demand for electric generation during a 1-in-35 cold year, given the existence of some all-electric buildings within the companies' service territories.

RESPONSE 15:

No. SoCalGas does not forecast electricity demand. SoCalGas relies on California Energy Commission (CEC) for the California electricity demand forecast. For the average temperature year, the electricity demand forecast is from CEC's California Energy Demand Forecast, 2018–2030 Revised Forecast, dated January 2018. Because CEC does not have an electricity demand forecast for a 1-in-35 cold year, SoCalGas used the annual EG gas demand forecast from an average temperature year, as a proxy, for the 1-in-35 cold year annual EG gas demand forecast.

QUESTION 16:

Please provide the source documents from which the peak month demand forecasts for the EG class shown in Witness Guo's Tables 7 and 13 were derived.

RESPONSE 16:

The consolidated EG throughput in Tables 7 and 13 of Witness Guo's testimony are the summary of EG and Large Cogen in Chapter 4 (Huang), and other Cogens (Refinery Cogen and Small Cogen) in Chapter 5 (Guo). SoCalGas and SDG&E use gas demand for the month of December as the peak month. Breakdown of EG peak month demand of SoCalGas and SDG&E shown in Tables 7 and 13 of Chapter 5 (Guo) are listed below.

SCG EG Peak Month Demand (Unit: MDth)

	2020	2021	2022	3-Year Avg. 2020-2022
UEG/EWG/Lg Cogen	17,693	17,659	17,478	17,610
Other Cogens	4,077	4,099	4,069	4,082
Total	**21,770**	**21,758**	**21,547**	**21,692**

SDG&E EG Peak Month Demand (Unit: MDth)

Average Year Throughput	2020	2021	2022	3-Year Avg. 2020-2022
UEG/EWG/Large Cogen	3,318	3,225	3,542	3,361
Small Cogen	781	781	780	781
Total	**4,098**	**4,006**	**4,322**	**4,142**

QUESTION 17:

Why do the storage allocations shown in Tables 14 and 15 of Witness Guo's testimony include the storage assets reserved for the wholesale core customers of Southwest Gas and Long Beach, as shown on page 8 of Witness Dandridge's testimony?

RESPONSE 17:

Please see page 7 lines 4-6 in Chapter 1 (Dandridge), and page 5 lines 8-14 in Chapter 6 (Ahmed).

<u>QUESTION 18:</u>

Please provide a copy of SoCalGas' 2008 storage functionalization study.

<u>RESPONSE 18:</u>

To clarify the reference to the 2008 study, the three shaded columns were consulted when preparing Appendix G. Costs reflected in the attached file are from 2007 FERC Form 2. See attached file.

TURN-04 Q18 attach.pdf