APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-1.

Please provide your best explanation for the drastic reduction in summer injection capacity (from 800 MMcf/d in the last CAP to 458 MMcf/d proposed here) and winter withdrawal capacity (from 2400 MMcf/d to 1826 MMcf/d). Does SoCalGas expect this reduction to continue throughout the forecast period? Please explain why or why not.

Response

The capacities reflect median Envoy postings from 2024-2025 operations, not a reduction in physical capability. Summer injection median of 458 MMcfd and winter withdrawal median of 1,826 MMcfd represent the 50th percentile of daily capacity availability, with approximately half of operating days experiencing higher capacity enabling upward proration (Chapter 1, page MMD-4, lines 3-6 and page MMD-5, lines 1-4). The injection and withdrawal capacities established in D.24-07-009 reflect one day high capacities from a prior period, not the expected capacities as proposed in Table MMD-1.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-2.

In Table MMD-2 on page MMD-6 of Chapter 1, please confirm that the formula in the heading of Column E should read "(B*100% - 120%)" and the formula in the heading of Column F should read: "(D-E)". If you cannot confirm, please explain why.

Response

Yes. Please see corrected Table MMD-2 below. Note that there are corrections to Table MMD-2 headings in columns E and F. Also, column D is corrected to 2822 MMcfd to represent SoCalGas and SDG&E core demand, which results in a change to column F.

Table MMD-2: Proposed Core Storage Allocations Per Reasoning

A	B	C	D	E	F
Total Inventory Bcf	Average Year Demand MMcfd	Cold Year Winter 1- in - 35 Demand MMcfd	Peak Day 1-in-35 Demand MMcfd	Winter Flowing Supply MMcfd (B*100% - 120%)	Storage and Additional Flowing Supply Needed for Peak Day MMcfd (D-E)
76	949	1381	2822	949 to 1139	1683 to 1873

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-3.

On page MMD-8, the testimony states that: "The 12 Bcf of storage inventory allocation will be used to provide 10% monthly balancing when customers create positive imbalances by delivering more gas into the system than what they use, up to 12 Bcf on a combined basis. When positive imbalances are created by customers, there needs to be inventory space available within storage to accommodate supply over deliveries by customers."

a. When *negative* imbalances are created by customers, doesn't there also need to be gas in inventory to accommodate under-deliveries by customers?

b. If *cumulative* customer imbalances are negative, where will the gas in inventory come from to accommodate under-deliveries?

Response

a. Yes.
b. As is the case today, the gas stored in inventory by all customers will be temporarily used to accommodate under-deliveries by all customers, until such point as the gas is replaced through positive imbalances.

   SoCalGas provides Monthly Imbalance Service for its transportation customers under Rate Schedule G-IMB. Monthly Imbalance Service has four components: 1) Imbalance Trading; 2) no-charge Balancing Service; 3) Standby Procurement; and 4) Buy-Back. Balancing Service is provided at no charge if the customer's cumulative imbalance at the end of the monthly imbalance trading period is within 10% of the customers defined usage.

   SoCalGas also has the option to declare a Low Operational Flow Order (OFO) when daily aggregated under-deliveries are forecast to exceed the capacity reserved for this purpose in order to incentivize individual customers to reduce their respective under-deliveries.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-4.

For the last five years, please provide the daily *cumulative* system imbalance created by customers, indicating whether that total daily imbalance figure is positive or negative.

Response

See Excel file TURN-002_Q.2-4.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-5. Re: Chapter 2, pages EM-5 and EM-7:

a. Please explain why the Sempra Energy Utilities define a cold year as 1-in-35 years for core customers but only 1-in-10 years for noncore customers?
b. Doesn't this difference result in somewhat more costs being allocated to core versus noncore? Please explain why or why not.

Response

a. Past CPUC decisions mandated a 1-in-35 peak day for core customers and 1-in-10 peak date for noncore customers for gas system planning design. See footnote 12 on page EM-5.

b. The difference results in different allocation shares depending on the cost. For distribution costs allocation, more costs are allocated to the core. Local transmission costs are allocated using Cold Year Peak Month, in which the Core and Noncore costs are allocated close to equal. Storage balancing costs are allocated using average year throughput, which has more costs allocated to the Noncore compared to the Core customers.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-6. Re: Tables EM-5 and EM-6 on pages EM-9 and EM-10 of Chapter 5.

a. The forecasts of Electric Generation gas demand appear to be the same in both average and cold years. Is it the Sempra Energy Utilities' belief that Electric Generation gas demand is completely insensitive to temperature? If so, please provide the basis for this belief. If not, please explain why these forecasts are the same.
b. Does the cold year forecast for Electric Generation gas demand also consider dry hydro conditions? If not, why not?
c. Why is the demand forecast for Southwest Gas in a cold year (8324) lower than in an average year (8920)?

Response

a. The California Energy Commission did not provide electricity demand load forecast data for a cold year. As a result, SoCalGas and SDG&E used the same electricity demand load forecast for average and cold years.

b. See Response 2-6.a.

c. Note Table EM-6 with Southwest Gas 2024 CGR Cold-Year forecast is corrected.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Table EM-6
Composition of SoCalGas Throughput (MDth) 1-in-35 Cold Temperature Year

	2027	2028	2029	3-Year Avg. 2027-2029
Core				
Residential	218,086	214,611	212,362	215,020
Core C&I	93,533	92,243	91,048	92,274
Gas AC	14	14	14	14
Gas Engine	1,697	1,697	1,697	1,697
NGV	24,384	25,248	25,886	25,172
Total Core	337,714	333,813	331,007	334,178
Non-Core				
Non-core C&I	155,725	154,421	153,596	154,581
Electric Generation	221,794	229,728	234,377	228,633
EOR	10,723	10,582	10,446	10,584
Total Retail Non-core	388,242	394,731	398,419	393,797
Wholesale and International				
Long Beach	9,136	9,088	9,042	9,089
SDG&E	85,931	87,449	87,863	87,081
Southwest Gas	9,543	9,622	9,700	9,621
Vernon	8,125	8,525	8,790	8,480
ECOGAS	13,393	13,862	14,139	13,798
Total Wholesale & Intl.	126,129	128,546	129,535	128,070
Cold Year Throughput (CYTP)				
	852,085	**857,090**	**858,961**	**856,045**

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-7. Re: Chapter 5, Tables EM-6, -7, and -8:

a. Are the forecasts shown for the SoCalGas noncore customers classes based on 1-in-35-year cold temperatures or 1-in-10?
b. Is the same true for the corresponding SDG&E forecasts?

Response

a. See Response 2.5 a.

b. See Response 2.5 a.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-8. Re: Chapter 5, Tables EM-15 and EM-16.

Please provide a step-by-step explanation of how the total core storage capacity was allocated among the SoCalGas and SDG&E core customer classes.

Response

Response will come at a later time.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-9. Re: Chapter 6, pages PG-4 to PG-5.

Please provide the year-end balance in the FASRMA for each year that it has been in existence. Also, please provide the revenues and the capital and expense revenue requirements recorded to the FASRMA for each year beginning in 2011.

Response

The following file responsive to question 2-9. contains confidential information and is being provided pursuant to the Non-Disclosure Agreement executed on October 13, 2025, between SoCalGas and The Utility Reform Network (TURN) in A.25-09-014:

Please see PDF file, **CONFIDENTIAL**_TURN-002_Q.2-9.pdf. The confidential information is highlighted in yellow.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-10.

Please provide a copy of each of the Sempra Utilities' 2024 FERC Form 2 in both PDF and electronic formats.

Response

Please see files TURN-002_Q.2-10. FERC 2024 SDGE Annual FERC Form 1 and 2, and TURN-002 Q.2-10. FERC 2024 SOCALGAS Annual FERC Form 1.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-11.

Under the Sempra Utilities proposal in this case, would the adopted embedded costs, based on 2024 data, be scaled to equal the base revenue requirement for each year of the CAP cycle? If yes, would such scaling be on a uniform percentage basis across all functions? If not, please explain how the difference between adopted embedded costs and the current base revenue requirement would be recovered.

Response

Yes, the adopted embedded costs, based on 2024 data, be scaled to equal the base revenue requirement for each year of the CAP cycle. The scaling be on a uniform percentage basis across all functions.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-12.

In Chapter 8, at page FS-MSP-25, the Utilities state that: "on a summer peak day, about 69% of total power-plant gas usage is served from LT pipelines on the SoCalGas transmission system." What percentage of total power plant gas usage was served from LT pipelines on an *annual* basis in each of the years 2022, 2023 and 2024?

Response

Applicants object on the grounds the request seeks an analysis not prepared by the Applicants. This request is seeking a new annualized analysis that was not prepared, relied upon, or required for the Chapter 8 backbone-to-local reallocation methodology.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-13.

If the electric generation customers that are directly served off the backbone transmission system were to be served by local transmission facilities instead, would the actual cost of the backbone system change at all? If so, please explain how.

Response

The question incorrectly mixes actual system cost with cost functionalization. The testimony does not state that backbone costs physically change because certain EG customers are directly served from BBT assets; rather, it explains that some BBT assets are providing an additional LT service, so a portion of embedded backbone costs is reassigned to LT to better reflect cost causation and the actual services provided.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-14.

The Chapter 8 testimony, at page FS-MSP-21, states that: "The function of transporting supplies from interstate pipelines to the local transmission system or underground storage assets is what defines a pipeline as a backbone transmission pipeline. Similarly, the function of transporting supplies from the backbone transmission system to distribution and end-use customers is what defines a pipeline as a local transmission pipeline."
Are these functional definitions internal to the Sempra Utilities, or is there some external source upon which they are based?
If the latter, please provide such source(s). Why couldn't the definition of the backbone transmission system include transportation to certain large end use customers?

Response

Applicants object to the request to the extent the request misstates testimony/evidence as the question suggests these functional definitions were newly created for this proceeding or are merely unsupported internal labels. They are not. Subject to and without waiving the foregoing, Applicants provide the following response: Chapter 8 explains that backbone and local transmission classifications are determined solely by the function performed by the assets, and further states that these same functional definitions have been used by SoCalGas and SDG&E since the Supplemental Direct Testimony of David Bisi in A.11-11-002 and were approved by the Commission in D.14-06-007, Attachment III at 4.See footnote 42, page FS-MSP-22. The principal sources are: (1) Supplemental Direct Testimony of David Bisi, A.11-11-002, Section IV, which states that SoCalGas and SDG&E rely on functional definitions to classify transmission pipelines; (2) D.14-06-007, Attachment III at 4, as cited in Chapter 8 footnote 42, page FS-MSP-22; and (3) the analogous PG&E backbone/local framework also referenced in Mr. Bisi's testimony and Chapter 8.(4) PUC has accepted these definitions for 15 yrs.

Applicants do not agree that backbone should be redefined to include transportation to certain large end-use customers. That would improperly replace a function-based classification with a customer-based one, even though both Mr. Bisi's testimony and Chapter 8 make clear that factors such as the number or type of customers served are not classification criteria. Chapter 8 already addresses the fact that some end-use customers are served directly from BBT assets by recognizing that the system operates as a hybrid in those circumstances and by reallocating the portion of BBT costs that performs a local transmission function. Thus, the issue is not the definition of backbone; it is proper functional cost assignment.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-15.

In Chapter 8, for SDG&E, why are the labor factors used to allocate A&G expenses shown in Table FS-MSP-14 different from the labor factors used to allocate general and common plant in Appendix C when those labor factors are the same for SoCalGas in Table FS-MSP-6 and Appendix C? Please explain fully.

Response

SoCalGas tables are correct. The correct SDG&E table matches and is below. This is shown in the workpaper, SDG&E Embedded Cost Model_Public_DRAFT.xlsx, tab: Testimony Tables, row 113.

Appendix C Tables

SDG&E General & Common Plant Allocation Summary $MM

Category	Depreciation	Return	Taxes	Labor	Allocated Depreciation	Allocated Return	Allocated Taxes
Transmission	$ 56.58	$ 21.87	$ (0.26)	7%	$ 4.13	$1.60	($0.02)
Customer Cost	$ 56.58	$ 21.87	$ (0.26)	48%	$ 27.22	$10.52	($0.12)
Distribution - HP	$ 56.58	$ 21.87	$ (0.26)	2%	$ 1.20	$0.47	($0.01)
Distribution - MP	$ 56.58	$ 21.87	$ (0.26)	42%	$ 24.03	$9.29	($0.11)

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-16. Re: Chapter 8, Appendix A.

a. In the last CAP proceeding TURN asked in DR #1, Question 3(d): "Please explain why no entries are shown in the Depreciation Expense column for Accounts 358, 372, 388 and 399," and the Utilities responded that: "Depreciation expenses for these FERC accounts are reversed in SAP to a regulatory asset, resulting in zero depreciation expense in our financials." Would your answer remain the same today? If not, please explain.

b. Do the amounts shown in Appendix A as "Investment" for these same accounts represent the accrued depreciation amounts that have been reversed to a regulatory asset? If not, please explain what the "Investment" column represents.

c. In the last CAP proceeding TURN asked in DR #1, Question 4: "Are the costs of Asset Retirement Obligations (AROs) recovered from customers through the negative net salvage component of depreciation rates? If not, please explain how these costs are recovered, including identifying each specific component of the authorized revenue requirement that includes AROs. If so, does this mean that customers pay the costs of the underlying retirements prior to their being incurred?" and the Utilities responded that: "The Asset Retirement Obligations (AROs) reflect the liability associated with the eventual retirement of the company's tangible long-lived assets. Calculation of AROs is based on the estimated future cost of removal (retirement). As such, AROs are not collected from customers, however, cost of removal is collected from customers as part of the collection of depreciation expense in the Company's approved revenue requirement. The collection of depreciation expense, which includes the cost of the asset plus cost of removal less the salvage value of the asset, allows the current customers who are receiving benefits of the asset to pay their portion of the use of the asset over its useful life." Would your answer remain the same today? If not, please explain.

d. In the last CAP proceeding TURN asked in DR #2, Question 16: "Re: Your response to Data Request TURN-SEU-1, Question 4: Based on your answer, would it be correct to say that the cost of removal is collected from customers over the life of an asset as part of the depreciation rate, and that these amounts are intended to cover the cost of any ARO for that asset? If not, please identify and explain what is incorrect about the statement" and the Sempra Utilities responded: "Yes." Would your answer remain the same today? If not, please explain.

e. In the last CAP proceeding TURN asked in DR #1, Question 5: "Are the costs of Asset Retirement Obligations (AROs) funded by utility debt and equity? If yes, please explain how" and the Utilities answered: "No." Would your answer remain the same today? If not, please explain.

f. Do the Utilities incur property taxes on amounts recorded as Asset Retirement Obligations? If yes, please explain.

g. Do the accounting entries for Asset Retirement Obligations have any impact on the company's authorized revenue requirement? If the response is anything other than an unqualified negative, please identify and briefly describe the circumstances or conditions under which the entries would have an impact on the company's authorized revenue requirement.

Response a. – g.

a. Yes, the response remains the same.
b. No. The Appendix A "Investment" amounts are the gross original cost (book cost) of utility gas plant in service by FERC account, consistent with FERC Form 2 plant reporting, not accrued depreciation amounts reversed to a regulatory asset. The depreciation is shown in the column Accum Dep (Accumulated Depreciation).
c. The response remains the same.
d. The response remains the same.
e. The response remains the same.
f. No.
g. Accounting entries for AROs do not have a direct impact on authorized revenue requirement.

Question 2-17.

In the Chapter 8 Workpapers, under the Tab for "FERC Accounts and Exclusions," a few of the entries have explanations for the exclusions, such as "GRC Excluded," "Ex Haz Waste," or "GRC Ex CARE," but many do not. Please provide an explanation for each of the exclusions that do not currently include one.

Response

Applicants object on the ground the request is unduly burdensome because it seeks the creation of new narrative explanations for every excluded line item that does not already include a shorthand notation in the Chapter 8 workpapers. The Chapter 8 workpapers already identify the exclusions by FERC account in the tab titled "FERC Accounts and Exclusions," which is expressly described as the tab that "subtracts all base margin exclusions from FERC Accounts." That tab provides, by account, the 2024 recorded FERC balance, the exclusion amount, and the resulting net total, and in certain instances includes shorthand descriptors such as "GRC Excluded," "PBR excl Haz Waste," "GRC Ex CARE," and "PBR Ex DAP, DSM & Self-Gen." Preparing individualized written explanations for each unlabeled exclusion would require a manual review of numerous underlying accounting, GRC, balancing-account, and program records outside the Chapter 8 model and would be unduly burdensome labor, and beyond the reasonable scope of this request.

Subject to and without waiving these objections, Applicants respond as follows: exclusion entries without parenthetical shorthand reflect the same general type of adjustment shown throughout the tab removal of amounts not included in base margin so that the embedded cost study is based solely on base-margin costs. Exclusions include balancing and memorandum accounts that are not included in Base Margin, the amounts of Balancing Accounts that are above the GRC authorized amounts and other GRC exclusions. The absence of a shorthand note does not mean the exclusion lacks support or basis; it simply reflects the format and purpose of the workpaper as a quantitative model input, not a narrative document.

Question 2-18.

In the Chapter 8 Workpapers, under the Tab for "FERC Accounts and Exclusions," for Account 920, why is the number in the column for "FERC 2024 Balances less Exclusions" not equal to the difference between the prior two columns, but actually much larger than either of them?

Response

The difference is that Payroll Taxes are added. This is shown in the workpapers, under the Tab, FERC Accounts and Exclusion, cell I4. Payroll Taxes are added to Row 68. FERC Account 920 AdmGen Op-Salaries Plus Payroll taxes.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-19.

In the Chapter 8 Workpapers, under the Tab for "Cost Allocations Dist O&M," please explain the derivation of the allocation percentages in the box entitled "Model Input."

Response

The percentages were derived by direct 2024 expenditures and allocated between the pertinent functions, Customer Costs, Gas Distribution: High Pressure and Medium Pressure based on the O&M work performed. The direct costs do not include overheads and taxes,

Question 2-20.

In the Chapter 8 Workpapers, under the Tab for "Cost Allocation Dist A&G," please explain the derivation of the allocation percentages in the upper box. Do the dollars shown on this tab represent the total of Distribution and Customer A&G? If not, please explain where other A&G dollars for these functions appear in the workpapers.

Response

As stated in Response 2-19, the percentages were derived by actual direct 2024 expenditures and allocated between the pertinent functions, Customer Costs, Gas Distribution: High Pressure and Medium Pressure based on the A&G work performed. Direct costs do not include overheads and taxes. The total of Distribution and Customer A&G less exclusions used in the Embedded Cost study be found in workpaper, SCG Embedded Cost Model_Public_2027 CAP_NL.xls, tab, Embedded Cost Summary, cells H82 to J99.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-21.

In the Chapter 8 Workpapers, under the Tab for "Customer Cost Allocators," please explain the meaning of the term "Dart Hours" and the derivation of the figures shown.

Response

As stated in Chapter 8, page FS-MSP-31, "Data Analysis Reporting Tools (DART) system track orders hours (DART tracks time to complete each activity by customer class)." Some of the activities are Credit/Collections, Gas Leak, Turn on Meter/Turnoff Meter, Fumigation, Advanced Meter, meter work, etc. The allocations were computed by adding the 2024 hours for each activity by customer class and then divide by total hours.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-22.

Re: Chapter 9, page MSP-6, lines 14-21 and Table MSP-1. Were line extension allowances eliminated only for residential customers, or for all customers? Please provide a CPUC decision reference for your answer. Why are the figures in Table MSP-1, in the column headed "CAPEX $/customer" set to zero only for the residential class and not for other classes?

Response

For new service lines and meters, Chapter 9, page MSP-7, footnote 11, refers to Line Extension Allowance, per SoCalGas's Rule 20 and SDG&E's Rule No. 15. Yes, the line extension allowances were eliminated only for the residential customers in this Cost Allocation Proceeding's LRMC Customer Costs studies. According to SoCalGas's Rule 15, for Residential Allowances, "No allowance will be provided." This is for both applicable mainline and service. According to SoCalGas's Rule 15, "NON-RESIDENTIAL ALLOWANCES. For Eligible Projects approved by the Commission, the total allowance for both gas Main and Service extensions for Permanent Non-Residential service is determined by the Utility using the formula in Section C.2."

CPUC Decision 22-09-026, dated September 15, 2022, and effective July 1, 2023, is the basis for SoCalGas's Rule 20 and SDG&E's Rule No. 15.

In California, gas line extensions were primarily for residential customers. In previous Cost Allocation Proceedings, the Long Run Marginal Cost studies only took the line extension allowance into consideration for residential customers. The residential customers' allowances were computed by appliances. The nonresidential customers' allowances were computed by usage, which varies.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-23

Re: Chapter 10, page PDB-11. Table PDB-4 presents a "Minimum Standard" that is "based on the average day quantity in a 1-in-10 cold and dry year." What is the source of those figures? How much of that "minimum standard" reflects Electric Generation gas demand on the SoCalGas and SDG&E systems respectively for each year shown?

Response

The source is Table 41 (ANNUAL GAS REQUIREMENTS, MMcf/d 1-IN-10 COLD TEMPERATURE YEAR & DRY HYDRO YEAR) of the 2024 California Gas Report (CGR). Electric Generation represents 119.0 MMcf/day.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-24.

Re: Chapter 11, Figure BD-1. Please provide the annual throughput under Schedule GO-CEG for each year since that optional rate was introduced. Where do these volumes appear in the throughput forecast tables included in Chapter 5?

Response

As it relates to the volumes shown in the Chapter 5 forecast tables, the GO-CEG throughput is consolidated into the core C&I segment.

See Excel file, Turn-002_Q.2-24.

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-25.

Please provide a step-by-step explanation of how Gas Engine rates are determined, starting with the proposed allocation of base margin of $7.611 million shown in Table FS-MSP-30 and walking through each additional step to reach the proposed rate of $0.30401 per therm shown in Table MF-1. In particular, please explain why the proposed revenues from the Gas Engine class of $5.16 million are less than the base margin allocated to that class.

Response

The Gas Engine rates and revenue have a cap. In Chapter 12, Revised Rates Foster Direct Testimony the amount for Gas Engine in Table MF-1 the Gas Engine's Proposed revenues are $4.9 million, and the proposed rate is $0.29140/therm. The workpaper, Errata-SCG Rate Design Model_Public_DRAFT.xlsm, tab: Rates, Cell T310 shows the calculation: Average Year Throughput of 16,975 Mth *1000 * Rate Cap $0.29140 = $4.9 million. Below is listed the Gas Engine revenues (Cells T303:T312):

Total Allocated Base Margin post-SI, post-BTS Unbundle,	7,611,492
Plus Other Operating Costs	457,118
Plus Regulatory Accounts	2,009,922
Plus CSITPMA Allocated to Gas Engine	11,178
Plus GHG Allocated to Gas Engine	3,205,870
Plus CARB Allocated to Gas Engine	55,537
Total Transportation Revenue	13,351,117
Transportation Revenue Subject to Rate Cap	4,946,406
Gas Engine Rev Allocated to Other Classes	8,404,710
Gas Engine Rev Allocated to Gas Engine	4,946,406

APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2027 COST ALLOCATION PROCEEDING (A.25-09-014)
DATA REQUEST SET 2 FROM –TURN DATED MARCH 9, 2026
SOCALGAS RESPONSE DATED: MARCH 23, 2026-Partial

Question 2-26.

When was the Gas Engine rate class established? Please provide a reference to the Commission decision approving that rate class.

Response

Applicants object on the ground the request calls for a legal conclusion and to the extent it seeks information equally available to the propounding party. Subject to and without waiving the foregoing, Applicants provide the following response: the earliest decision Applicants could identify with the Gas Engine rate was CPUC Decision 94-12-052, in December 1994, which approved the Gas Engine rate.