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 2024 COST ALLOCATION PROCEEDING

(A.22-09-015)

(DATA REQUEST TURN-SEU-1)
DATA RECEIVED: FEBRUARY 23, 2023
DATE RESPONDED: MARCH 8, 2023

QUESTION 1:

Please provide the workpapers of all witnesses, both SoCalGas and SDG&E, in electronic format with all cells and formulas intact and functioning.

RESPONSE 1:

PROTECTED MATERIALS: PROVIDED PURSUANT TO NON-DISCLOSURE AGREEMENT IN A.22-09-015

The following two excel files contain confidential information and are being provided pursuant to the non-disclosure agreement executed on February 23, 2023, between SoCalGas and TURN in A.22-09-015:

- Protected Material Ch 3 Payan Gas Price Forecast 2024 to 2027
- Protected Material Ch 3 Payan Gas Price Forecast Feb 2023

In addition, please refer to the following is a list of executable versions of SoCalGas and SDG&E's supporting workpapers in native format:

- Ch 1 Rincon-Yen Storage Overview and Proposal
- Ch 2 Guo SCG Weather Design
- Ch 2 Guo SDGE Weather Design
- Ch 4 Huang Large EG Cogen
- Ch 5 Guo_Scg_MDM_Summary_wp
- Ch 5 Guo_Scg_noncore_Com_wp
- Ch 5 Guo_Scg_noncore_Ind_wp
- Ch 5 Guo_ScgRefinery_wp
- Ch 5 Guo_ScgSmCoGen_wp
- Ch 5 Guo_Sdge_MDM_Summary_wp
- Ch 8 Seres Embedded Costs
- Ch 9_SCG 2024TCAP LRMC Customer Costs
- Ch 9_SCG 2024TCAP LRMC Distribution Costs
- Ch 9_SCG 2024TCAP LRMC OM loader
- Ch 9_SCG Cost Allocation workpapers
- Ch 9_SCG First Page Flowchart Cost Allocation
- Ch 9_SCG Rate Base 2021 - SRM
- Ch 10_SDG&E Cost Allocation
- Ch 10_SDGE 2024TCAP LRMC Customer Costs
- Ch 10_SDGE 2024TCAP LRMC Customer Costs Min
- Ch 10_SDGE 2024TCAP LRMC Distribution Costs

- Ch 10_SDGE 2024TCAP LRMC OM Loader
- Ch 10_SDGE 2024TCAP Misc Data
- Ch 10_SDGE Rate Base – 2021 SRM
- Ch 12 Harte H2 Fueling Station Rate
- Ch13_Gas Rates SDGE – TCAP
- Ch13_Gas Rates SCG - TCAP
- Ch13_ Partial Electrification, Fixed Charge and CARE Bill – SoCalGas
- Ch13_SCG 2022 PPPS Rate Model – Final
- Ch13_SCG 2024 TCAP NGV Compression Rate Adder
- Ch13_SCG 2024 TCAP Submeter Credit
- Ch13_SCG TCAP Bill Impact Summary – CARE - 15
- Ch13_SCG TCAP Bill Impact Summary – CARE - 120
- Ch13_SCG TCAP Bill Impact Summary – CARE
- Ch13_SDG&E 2024 TCAP NGV Compression Rate Adder
- Ch13_SDG&E 2024 TCAP Submeter Credit

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QUESTION 2:

Please provide the 2021 FERC Form 2 for each utility in electronic format. Also, please provide the 2022 Form 2s as soon as they are available.

RESPONSE 2:

Please refer to the two electronic files of 2021 FERC Form 2 for SoCalGas and SDG&E:
- SoCalGas 2021 Annual FERC Form 2
- SDG&E 2021 Annual FERC Form 1 & 2 Rpt

2022 FERC forms will not be available until early April 2023.

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QUESTION 3a – 3g Re: Witness Seres Workpapers, page 3 of 20:

QUESTION 3a:

Please confirm or deny that the amounts shown in accounts 358, 372 and 388 represent Asset Retirement Obligations (AROs). If you cannot confirm, please explain why.

RESPONSE 3a:

Yes. The amounts shown in Accounts 358, 372, and 288 represent AROs.

QUESTION 3b:

Please identify any other amounts shown on this workpaper that represent AROs. For example, does Account 399 include or consist entirely of AROs for general plant?

RESPONSE 3b:

Yes, Account 399 is ARO for general plant. There are no other ARO accounts in this workpaper.

QUESTION 3c:

Please explain why the entry in the Accumulated Depreciation column for Account 358 exceeds the amount in the Investment column for that account.

RESPONSE 3c:

Please refer to response to Question 4 for ARO explanation. The reason the calculated ARO value is negative and greater than the asset retirement cost (investment) is because of the accumulated reserve balance of the underlying asset (Account 352 Wells). Note that the accumulated reserve balance for Account 352 is a debit (positive) balance when accumulated reserve should be negative. SoCalGas is incurring more cost of removal than is currently approved in revenue requirement.

QUESTION 3d:

Please explain why no entries are shown in the Depreciation Expense column for Accounts 358, 372, 388 and 399.

RESPONSE 3d:

Depreciation expenses for these FERC accounts are reversed in SAP to a regulatory asset, resulting in zero depreciation expense in our financials.

QUESTION 3e:

Please explain why Accumulated Depreciation for Accounts 372 and 388 is positive when most other entries in the column for Accumulated Depreciation are negative. Please explain what drives the changes in Accumulated Depreciation for these accounts from year to year?

RESPONSE 3e:

The ARO amounts in the schedule tie to the amounts shown in the accumulated reserves on Page 219 of the annual FERC Form 2 which includes the accumulated depreciation reserves for AROs as well as the ARO portion of the cost of removal (COR) that is recovered. The COR portion is a debit to the accumulated reserve resulting in a positive number on the Net Book Value schedule.

QUESTION 3f:

Please explain the factors that result in the figures in the 12/31/21 Weighted Average Rate Base column being much lower than those in the Net Book Value column.

RESPONSE 3f:

The main factor is the way Rate Base is calculated. Please refer to the following documents for a further explanation of how rate base is calculated: Microsoft Word - SCG-31-2R Second Revised Testimony Rate Base_2603.docx (socalgas.com). See PDM-2, Section III. Methodology.

QUESTION 3g:

Please explain the sources of the $8,056,524,000 figure shown as the total for the 12/31/21 Weighted Average Rate Base column and how that value was derived.

RESPONSE 3g:

The $8,056M rate base figure at 12/31/2021 represents the 13-month weighted average rate base (WARB) based on monthly general ledger balances. As it relates to SoCalGas and SDG&E's Cost Allocation Proceeding (CAP), the WARB excludes Customer Advances for Construction (CAC) per the 2020 TCAP decision (D.20-02-045) as well as items that receive regulatory treatment outside of the TY2019 GRC.

This specific WARB 2021 derivation can be found in Ch8. Workpapers, pg. 5. See link, Chapter-8.pdf (socalgas.com). For method how rate base is derived refer to Response 3(f).

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?

RESPONSE 4:

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.

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QUESTION 5:

Are the costs of Asset Retirement Obligations (AROs) funded by utility debt and equity? If yes, please explain how.

RESPONSE 5:

No.

QUESTION 6:

Re: Seres Testimony, page 19, footnotes 61 and 62. Please provide the comparable cost escalation percentages that were approved by the CPUC for SoCalGas and SDG&E for the years 2022 and 2023.

RESPONSE 6:

SoCalGas and SDG&E's comparable cost escalation factors for 2022 and 2023 are:

SoCalGas O&M %	SoCalGas Capital Escalation %
2022 – 1.935%	2022 – 1.18%
2023 – 2.29997%	2023 – 2.13%
SDG&E O&M %	SDG&E Gas Capital Escalation %
2022 – 1.988%	2022 – 1.179%
2023 – 2.2557%	2023 – 2.132%

These factors were used to develop the Petition for Modification (PFM) of D.19-09-051 for Post Test Year Mechanism 2022 and 2023 revenue requirement. These figures are a point in time forecast and will not get updated.

QUESTION 7:

Mr. Seres' testimony states, at page 19, lines 13-15 that: "To manage the increase in costs and equity between customer classes within CAP years, SoCalGas proposes an attrition rate increase for each attrition year 2025 through 2027 in the embedded cost of transmission and storage." However, at page 21 of the same testimony, lines 3-5, the witness states that: "SoCalGas recommends that the total storage cost be maintained at the level shown in Table 22 until another embedded cost study is performed for the next CAP, which is consistent with prior TCAP decisions D.20-02-045 and D.16-06-039." Please confirm that the cited language on page 21 is inconsistent with that on page 19, and that the language on page 19 represents the company's proposal in this case. If you cannot confirm, please explain why, and identify what the company's proposal is in this case.

RESPONSE 7:

The language on page 21, line 3 - 5 was meant to imply that SoCalGas and SDG&E do not intend to recreate a complete cost study of embedded storage costs until the next CAP.

<u>QUESTION 8a – 8d:</u>

Mr. Seres' Testimony states, at page 19, lines 11-15 that: "SoCalGas's embedded cost of transmission and storage is based on 2021 transmission costs. These costs are expected to be frozen from 2024 through 2027, one year longer than in previous 2020 TCAP. To manage the increase in costs and equity between customer classes within CAP years, SoCalGas proposes an attrition rate increase for each attrition year 2025 through 2027 in the embedded cost of transmission and storage."

<u>QUESTION 8a:</u>

Using the same logic, why shouldn't the embedded cost of transmission and storage be subject to similar increases for the years 2022 through 2024?

<u>RESPONSE 8a:</u>

SoCalGas and SDG&E's proposal of attrition rates adjustments is forward looking and does not apply to years before 2024. This proposal would be effective with the implementation of the CAP in 2024.

<u>QUESTION 8b:</u>

Absent such an adjustment, won't customers in 2024 be paying for transmission and storage based on 2021 costs, even though the revenue requirement for transmission and storage has increased each year since 2021?

<u>RESPONSE 8b:</u>

SoCalGas and SDG&E have not undertaken this study.

<u>QUESTION 8c:</u>

Has SoCalGas ever looked at how PG&E allocates its embedded transmission and storage costs? Isn't it true that PG&E applies its adopted cost allocation factors to the embedded cost revenue requirement adopted by the CPUC for each of the years the allocation will be in effect? If this is not SoCalGas' understanding of how PG&E's transmission and storage costs are allocated, please explain.

<u>RESPONSE 8c:</u>

Applicants object to this request on the ground that it seeks information not relevant to this proceeding, is not in scope for this proceeding, and is not likely to lead to the discovery of admissible evidence. In addition, Applicants also object on the ground the request assumes facts not in evidence and that the request potentially calls for a legal conclusion. Subject to and without waiving the foregoing, Applicants respond as follows: SoCalGas and SDG&E have not looked into how PG&E allocates its costs.

<u>QUESTION 8d:</u>

If the Sempra Utilities were directed by the Commission to apply their adopted cost allocation factors to the revenue requirements adopted for each company in the 2024 GRC, roughly how long after the GRC decision would it take for the Sempra Utilities to calculate rates based on those new adopted revenue requirements?

<u>RESPONSE 8d:</u>

If SoCalGas and SDG&E were directed by the Commission to apply their adopted cost allocation factors that are in current rates to the revenue requirements adopted for each company in the 2024 GRC, Applicants estimate it would take approximately 30 days after the GRC decision to calculate rates for only the gas rate design based on the GRC adopted revenue requirements. The gas rate design model does not calculate embedded backbone transportation service (BTS) nor individual storage component (i.e., injection, inventory, and withdrawal) rates.

QUESTION 9a – 9e:

Mr. Seres' Testimony states, at page 18, lines 4-6 that: "SoCalGas and SDG&E will be adding to the backbone transmission cost, incremental 2021 balancing costs related to PSEP, amortization of Backbone Transmission Balancing Account (BTBA), and GRC PSEP costs of total $99.3 million."

QUESTION 9a:

Please provide a breakdown of the $99.3 million into each of these components, and explain from where each of those figures was derived.

RESPONSE 9a:

Please refer to the table below. Under the Proposed column, are the BTS costs components, which include PSEP costs that are part of the BTS rate proposed in the CAP. The GRC PSEP costs total $150.7 million (include Franchise Fees and Uncollectibles (FF&U)), of which $99.4 million (including FF&U) is allocated to the Backbone Transmission costs. These costs are based on GRC 2019 Advice Letter 5892, Revenue Requirement Effective January 1, 2022, in Compliance with Decision (D.) 21-05-003 and Uncollectible Expense Rate Update for Post-Test Year 2022 in Compliance with D.19-09-051. The incremental 2021 balancing costs related to PSEP sources were approved in SoCalGas Advice Letter Nos. Advice Letter 5884, 5884-B, 5915 and SDG&E Advice Letter Nos. 3024-G and 3046-G.

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	Present	Proposed	increase (decrease)
Unbundled BTS Revenues w/FFU ($000's)	$240,798	$363,740	$122,942
PSRMA-BBT SCG w/o FFU $000	$0	$0	$0
PSRMA-BBT SDG&E w/o FFU $000	$0	$0	$0
SECCBA-BBT SCG w/o FFU $000	$23,674	$23,674	$0
SECCBA-BBT SDG&E w/o FFU $000	$7,600	$7,600	$0
SEEBA-BBT SCG w/o FFU $000	$4,204	$4,204	$0
SEEBA-BBT SDG&E w/o FFU $000	$10	$10	$0
SECCBA-BBT SCG - Phase 1b	$565	$565	$0
SECCBA-BBT SDG&E - Phase 1b	$0	$0	$0
SEEBA-BBT SCG - Phase 1b	$0	$0	$0
SEEBA-BBT SDG&E - Phase 1b	$0	$0	$0
SECCBA-BBT SCG - Phase 2	$1,049	$1,049	$0
SECCBA-BBT SDG&E - Phase 2	$0	$0	$0
SEEBA-BBT SCG - Phase 2	$0	$0	$0
SEEBA-BBT SDG&E - Phase 2	$0	$0	$0
TIMPBA-BBT SCG w/o FFU $000	$0	$0	$0
TIMPBA-BBT SCG w/o FFU $000	$0	$0	$0
BTBA w/o FFU ($000's)	($37,225)	($37,225)	$0
FFU Rate	1.0167	1.0167	
Balancing Accounts w/ FFU ($000's)	($126)	($126)	$0
SoCalGas PSEP GRC	$99,448	$99,448	$0
SoCalGas PSEP GRCM	$0	$0	$0
BTS Revenue w/FFU ($000's)	$340,120	$463,062	$122,942

QUESTION 9b:

In what year(s) were these PSEP costs incurred?

RESPONSE 9b:

The GRC PSEP costs were incurred in years 2017 to 2021.

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QUESTION 9c:

Have any additional PSEP costs been approved for recovery since this testimony was submitted? If so, where, and what were the associated revenue requirements?

RESPONSE 9c:

Please refer to the table below. Under the Proposed column, are the BTS costs, which include PSEP costs, as of January 2023 rates, that were approved in SoCalGas Advice Letter 6071 and SDG&E Advice Letter 3149-G. The GRC PSEP costs total $157.8 million (include Franchise fees and Uncollectibles (FF&U)), of which $104.2 million (including FF&U) is allocated to the Backbone Transmission costs.

	Present	Proposed	increase (decrease)
Unbundled BTS Revenues w/FFU ($000's)	$240,798	$397,002	$156,203
PSRMA-BBT SCG w/o FFU $000	$0	$0	$0
PSRMA-BBT SDG&E w/o FFU $000	$0	$0	$0
SECCBA-BBT SCG w/o FFU $000	$23,674	$25,766	$2,092
SECCBA-BBT SDG&E w/o FFU $000	$7,600	$18,233	$10,633
SEEBA-BBT SCG w/o FFU $000	$4,204	$2,649	($1,555)
SEEBA-BBT SDG&E w/o FFU $000	$10	$45	$35
SECCBA-BBT SCG - Phase 1b	$565	$1,322	$758
SECCBA-BBT SDG&E - Phase 1b	$0	$0	$0
SEEBA-BBT SCG - Phase 1b	$0	$0	$0
SEEBA-BBT SDG&E - Phase 1b	$0	$0	$0
SECCBA-BBT SCG - Phase 2	$1,049	$210	($838)
SECCBA-BBT SDG&E - Phase 2	$0	$0	$0
SEEBA-BBT SCG - Phase 2	$0	$0	$0
SEEBA-BBT SDG&E - Phase 2	$0	$0	$0
TIMPBA-BBT SCG w/o FFU $000	$0	$0	$0
TIMPBA-BBT SCG w/o FFU $000	$0	$0	$0
BTBA w/o FFU ($000's)	($37,225)	($42,289)	($5,064)
FFU Rate	1.0167	1.0166	
Balancing Accounts w/ FFU ($000's)	($126)	$6,035	$6,161
SoCalGas PSEP GRC	$99,448	$104,151	$4,703
SoCalGas PSEP GRCM	$0	$0	$0
BTS Revenue w/FFU ($000's)	$340,120	$507,187	$167,067
BTS Demand Dth/Day	2,532,308	2,530,689	(1,619)
BTS rate w/FFU $/dth day	**$0.36798**	**$0.54908**	**$0.18110**

QUESTION 9d:

Have any additional PSEP costs been requested for recovery in the 2024 GRC? If so, please quantify the associated revenue requirements.

RESPONSE 9d:

The 2024 PSEP costs requested for recovery in the 2024 GRC are for SoCalGas, $253 million (with FF&U) and for SDG&E, $41 million (with FF&U). $142 million is allocated to Backbone Transmission PSEP.

QUESTION 9e:

When new PSEP revenue requirements are approved for recovery by the CPUC, when are those costs actually reflected in rates? Does the answer differ by function, as between backbone transmission, local transmission and high-pressure distribution?

RESPONSE 9e:

The new PSEP revenue requirement will be reflected in rates in compliance with the CPUC Decisions. If the Decision requires a Tier 1 Advice Letter, the costs are reflected the next month following the decision. The answer does not differ by function, as between backbone transmission, local transmission and high-pressure distribution.

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<u>QUESTION 10a – 10d:</u>

Re: Seres Workpapers, page 16 of 20:

a) Re: Account 351, Structures and Improvements. Please explain how “Withdrawal and injection facilities are separate” and where they are recorded if not in this account. Are personnel involved in injection and withdrawal not housed in Account 351 structures? Is no work related to injection or withdrawal conducted within these structures?
b) Re: Account 352, Wells. If “double of the number of wells [are] required for withdrawal than injection,” how many wells are required for inventory? If injection and withdrawal were not of concern, wouldn’t one well suffice to build inventory?
c) Re: Account 117.1, Cushion Gas. If the purpose of cushion gas is “primarily” to provide a base pressure in the field so that minimum field deliverability can be achieved, why not allocate 80% of these costs to withdrawal rather than 67%?
d) Please provide any further explanation of the rationale for the allocation of costs in each account across inventory, injection and withdrawal beyond the brief statements presented in the column “% Distributed Rationale”

<u>RESPONSE 10a – 10d:</u>

SoCalGas performed a storage functionalization cost study in 2018. Please see, 2020 TCAP <u>Microsoft Word - Ch 8 Fung Direct [2020 TCAP] 7-12-18 (socalgas.com)</u> Chapter 8, pp. G-3 through G-7, for the description and rationale for the functional allocation of each FERC Account.

Each FERC account allocation percentage was determined based on the judgment and experience of the storage operations group with respect to the function of specific storage assets.

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QUESTION 11:

Re: Schmidt-Pines testimony, page 4, lines 1-6. If marginal costs are "based on 2021 underlying activities" and then "escalated to 2024 dollars to reflect SoCalGas costs for the first year of the new CAP cycle," why are not 2021 embedded costs similarly escalated? Please explain fully.

RESPONSE 11:

Please refer to Response 8a.

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QUESTION 12:

Please confirm that Tables 11, 12 and 13 of witness Schmidt-Pines' testimony do not include the base margin increase that SoCalGas has requested in its 2024 General Rate Case (GRC). If you cannot confirm, please explain.

RESPONSE 12:

Confirmed. Tables 11, 12 and 13 of witness Schmidt-Pines' testimony do not include the base margin increase that SoCalGas has requested in its 2024 General Rate Case (GRC).

QUESTION 13:

Please provide illustrative Tables 11, 12 and 13 that assume that the base margin increase requested by SoCalGas in the 2024 GRC is granted in full. Please provide comparable tables for SDG&E.

RESPONSE 13:

See excel attachment, TURN #13.xls.

TURN #13.xlsx

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QUESTION 14:

Please confirm that under the Sempra Utilities' proposals, the entire base margin increase granted in the 2024 GRC would be allocated to classes in proportion to the values shown in Column F of Table 11 (Schmidt-Pines), resulting in a scalar factor higher than 70%. If you cannot confirm, please explain.

RESPONSE 14:

Confirmed. As shown in attachment TURN #13.xls, Table 11, the scalar increases to 101% because of the entire base margin increase proposed in the 2024 GRC.

<u>QUESTION 15:</u>

How does CPUC Decision No. 22-09-026, eliminating line extension allowances for new residential applicants after June 30, 2023, impact the calculation of residential marginal customer costs moving forward? Since the costs of a new line and service extension will now be funded by the new customer, rather than the general body of ratepayers, shouldn't the capital component of residential customer costs be reduced to near zero? Please explain why or why not. How, if at all, would your answer differ for other customer classes? Why?

<u>RESPONSE 15:</u>

Under the long-run marginal cost (LRMC) method, yes, the capital component of residential customer costs should be reduced to near zero. As stated by Witness Peress (Chapter 14, page 15),

> "Marginal costs are relevant when considering the costs of service for a normally growing business. The growth in new natural gas services in California is expected by many to decelerate into the future, challenging the merits of this ratemaking approach. Similarly, and perhaps more materially, the elimination of line extension allowances as directed in Decision (D.)22-09-026 of the Building Decarbonization OIR (R.19-01-11) will substantially reduce the capital cost component associated with long run marginal cost analysis, further dissociating this methodology from the actual cost of service."

The CPUC should reconsider the use of LRMC method for cost allocation and rate design for gas utilities.

It should also be noted that line extension allowances will continue to be available to builders that have already signed up for the program. We expect this to continue during the proposed cost allocation period.

QUESTION 16a – 16d: Re: Schmidt-Pines Workpapers, page 14 of 38:
QUESTION 16a:

Please confirm that the estimated cost of a service line in 2024 dollars for a new business single family residential customer is $1,156.49, while the cost for a new multi-family residential service line is $1,241.99. If you cannot confirm, please explain.

RESPONSE 16a:

Confirmed. The estimated cost of a service line in 2024 dollars for a new business single family residential customer is $1,156.49, while the cost for a new multi-family residential service line is $1,241.99.

QUESTION 16b:

Please provide the average number of customers served by a new business single family residential service line.

RESPONSE 16b:

There are 1.5 customers served by a new business single family residential service line.

QUESTION 16c:

Please provide the average number of customers served by a new business multi-family residential service line.

RESPONSE 16c:

On average, there are 1.6 customers served by a new business multi-family residential service line.

QUESTION 16d:

Why shouldn't the marginal cost of a new service line for a new business multi-family residential customer be $1,241.99 divided by your answer to c) above?

RESPONSE 16d:

The average service length already employs the number of outlets, which represent the number of hookups that is associated with a new service line, in the denominator.

QUESTION 17:

The Chapter 1 testimony, at pages 11-12, proposes a Low OFO trigger that: "limits cumulative negative imbalances to no more than 2,500 MMcf. The 2,500 MMcf caps the amount of gas that balancing customers can in aggregate borrow from other storage customers to approximately 110% of the average daily demand estimated in the 2022 CGR." Please explain why, if balancing customers can "borrow" up to 2.5 Bcf of the gas that was injected into storage by other storage customers, at least some portion of the cost of that 2.5 Bcf (or the associated inventory capacity) should not be allocated to balancing customers.

RESPONSE 17:

SoCalGas and SDG&E do not believe that there are clearly identifiable costs associated with the borrowing of gas by balancing customers to allocate.

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 2024 COST ALLOCATION PROCEEDING

(A.22-09-015)

(DATA REQUEST TURN-SEU-1)
DATA RECEIVED: FEBRUARY 23, 2023
DATE RESPONDED: MARCH 8, 2023

QUESTION 18:

On how many days over the last five years have cumulative customer imbalances been negative? On how many days have they been negative by 2,500 MMcf or more?

QUESTION 18:

Between 2018 and 2022 the Cumulative Customer Imbalance posted on Envoy's Daily Operations page was negative on 167 days, and equal or less than -2,500MMcf on 2 days.

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 2024 COST ALLOCATION PROCEEDING

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QUESTION 19:

Re: Peress Testimony, page 15, lines 17-19. Please explain what is meant by "the cyclical cost shifts associated with developing and updating rates differently between embedded and long run marginal costs between and during cost allocation proceeding periods."

RESPONSE 19:

The referenced quote is meant to highlight the CPUC-authorized current hybrid cost allocation approach whereby customer-related, medium-pressure and high-pressure distribution cost studies use long-run marginal cost (LRMC) method but transmission and storge cost studies use embedded cost method. Both LRMC and embedded costs studies are developed using the most recent historical data available prior to the filing of the cost allocation proceeding (CAP) application. However, while LRMC numbers are then escalated forward to reflect CAP Test Year costs, embedded costs are not escalated forward.

This phenomenon is being addressed by SoCalGas's proposal to escalate embedded transmission and storage costs starting in 2025 based on attrition year escalation rates, see page 19 of Mr. Seres' direct testimony.