

Application No. 25-09-014
Exhibit No. SCGC-01
Witness: Catherine E. Yap

**BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA**

Application of SOUTHERN CALIFORNIA GAS COMPANY (U904G) and SAN DIEGO GAS & ELECTRIC COMPANY (U902G) for authority to revise their natural gas rates and implement storage proposals effective January 1, 2027 in this Cost Allocation Proceeding.

Application 25-09-014

**Direct Testimony of Catherine E. Yap
On Behalf of the
Southern California Generation Coalition**

May 15, 2026

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- 2 Attachment C: Applicants Chapter 8 Workpapers, excerpt.
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- 4 Attachment E: SoCalGas Schedule No. G-BTS, Backbone Transportation Services, excerpt.
- 5 Attachment F: SoCalGas, BTS Opening Season 2026 Presentation, April 4, 2026, excerpts.
- 6 Attachment G: SoCalGas Preliminary Statement Part VI, Balancing Account, Noncore Storage
7 Balancing Account (“NSBA”).
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9 and Storage Rights Memorandum Account (“FASRMA”).
- 10 Attachment I: Errata-SCG Rate Design Model_Public.xlsx at tab “Rates”, excerpt.
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- 15 Attachment M: Applicants Response to SCGC-12.
- 16 Attachment N: U.S. Energy Information Administration, Natural Gas Statistics.

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4 **On Behalf of the**
5 **Southern California Generation Coalition**
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9 **1. Introduction**

10 This testimony is presented by Catherine E. Yap on behalf of the Southern California
11 Generation Coalition (“SCGC”). SCGC members include electricity generators and shippers that
12 transport gas on the Southern California Gas Company (“SoCalGas”) transmission system. Ms.
13 Yap has over four decades of experience preparing and delivering testimony before this
14 Commission as well as in other jurisdictions. Ms. Yap’s qualifications are set forth in Attachment
15 A.

16 In Application (“A.”) 25-09-014, SoCalGas and San Diego Gas and Electric Company
17 (“SDG&E”) (jointly “Applicants”) request authority to revise their natural gas transmission rates
18 and to implement storage proposals effective January 2027.¹ This testimony addresses a number
19 of the Applicants’ requests.

20 **2. The Allocation of Storage Costs Should Be Based on Storage Capacities, Not Median**
21 **Availability of Storage Equipment.**

22 The ratemaking for storage services is based on storage inventory, injection, and
23 withdrawal capacities. The Commission has traditionally relied upon an established capacity to
24 set the amounts of storage capacity provided to core reliability, load balancing, and unbundled
25 storage services.

26 **2.1. The Commission Should Reject Applicants’ Proposal to Rely on Median**
27 **Operating Values to Establish Injection and Withdrawal Capacities.**

28 In the current proceeding, the Applicants propose to reduce their total storage injection
29 and withdrawal capacities to reflect the median values utilized on the system during the 2024-

¹ Assigned Commission’s Scoping Memo and Ruling (“Scoping Memo”) at 1.

2025 storage year, which is April 1, 2024, through March 31, 2025. Table 1 below shows the current storage capacities:

Table 1² Current Capacities

	Inventory BCF	Withdrawal		Injection	
		Winter	Summer	Summer	Winter
Core	80.03	1890	606	392	150
Balancing	12	400	1225	345	345
UBS	25	50	50	50	50
Wholesale	2.47	60	19	13	5
Total:	119.5	2400	1900	800	550

Applicants’ proposal is shown below in Table 2:

Table 2³ Applicants’ Proposal

	Inventory Bcf	Injection Summer MMcfd	Injection Winter MMcfd	Withdrawal Summer MMcfd	Withdrawal Winter MMcfd
Core	76	250	135	540	1500
Balancing	12	184	374	1212	256
UBS	28	15	15	15	15
Wholesale	2.8	9	5	20	55
Total	118.8	458	529	1787	1826

Comparing Table 1, which shows current adopted levels, to Table 2, which shows the Applicants proposal, we see that while the Applicants propose to reduce inventory levels a small amount, Applicants propose dramatic decreases in other capacities. Applicants would drop summer injection capacity to 57 percent of the current level, drop winter injection capacity to 96 percent of the current level, reduce summer withdrawal capacity to 94 percent of the current level, and reduce winter withdrawal capacity to 76 percent of the current level.

2.2. Storage Inventory, Injection, and Withdrawal Costs Should Be Allocated on the Basis of Storage Capacities.

Storage inventory, injection, and withdrawal costs should be allocated on the basis of actual physical capacities based on the maximum availability during the previous operating

² D.24-07-009, slip op., Attachment A at 6.

³ Applicants Chapter 1 at MMD-3, excerpt from Table MMD-1.

1 period and not the median availability. The Commission’s decisions in other cost allocation
2 proceedings followed this approach. For example, in the Applicants’ Test Year 2020 Triennial
3 Cost Allocation Proceeding (“TCAP”), A.18-07-024, the Applicants proposed to reduce their
4 total storage inventory, injection, and withdrawal capacities to reflect the California Geologic
5 Energy Management Division (“CalGEM”), limitations on Aliso Canyon operations to a
6 maximum field pressure of 2,936 pounds per square inch absolute, which corresponds to a total
7 Aliso Canyon working inventory capacity of 68.6 Bcf.⁴ However, there was considerable
8 uncertainty as to what would be the allowed Aliso Canyon inventory level during the 2020-2023
9 TCAP period. As a result, the issues in the 2020 TCAP were not settled but instead were
10 litigated.

11 The Energy Division staff spent a considerable amount of time and effort amassing
12 information related to the operations of the Applicants’ storage fields under various conditions,
13 including different amounts of inventory capacity that the Applicants’ might be allowed to use at
14 Aliso Canyon. They issued a report in that proceeding presenting tables with storage capacity
15 figures associated with ranges of storage inventory allowed for use at Aliso Canyon.⁵ The
16 Commission adopted Tables 1-5 from the Energy Division report in the Commission’s decision in
17 the 2020 TCAP, Decision (“D.”) 20-02-045,⁶ and relied upon the tables as the basis for storage
18 cost allocation.⁷ In doing this, the Commission established injection and withdrawal capacities
19 based on the maximum levels of injection and withdrawal capacity rather than values based on
20 the average of the utilized capacities during some historic period.

21 In the Applicants’ following Cost Allocation Proceeding (“CAP”), A.22-09-015, which
22 produced the settlement table shown previously as Table 1, the Applicants proposed allocating
23 storage costs on the “average effective capacities,” which are not maximum inventory, injection,

⁴ A.18-07-024, Exhibit (“Ex.”) APP-1, Direct Testimony of Michelle Dandridge at 3; California Code of Regulations § 1726.

⁵ D.20-02-045, slip op., Appendix A at 4, 5, 8, 10, 11.

⁶ D.20-02-045, slip op. at 10-12.

⁷ D.20-02-045, slip op. at 37-39.

1 and withdrawal capacities but, rather, correspond to the average usage of the storage fields during
2 different periods.”⁸ The Applicants proposed injection and withdrawal levels were substantially
3 below the levels adopted in D.20-02-045 for a comparable level of storage inventory.⁹ However,
4 the Settlement Agreement adopted in D.24-07-009 provided for higher capacities rather than the
5 “average effective capacities,” based on maximum available capacities.

6 The Commission should reject the “expected capacity” figures proposed by the Applicants
7 in this proceeding, which are based on median values observed during the 2024-2025 storage
8 year. The Applicants’ proposal is inconsistent with precedent from past cost allocation
9 proceedings. The Applicants would improperly raise the unit cost of storage injection and
10 withdrawal capacity by spreading the cost of the injection and withdrawal capacity over fewer
11 units of capacity.

12 Instead, the Commission should establish storage injection and withdrawal capacities by
13 identifying the maximum available seasonal capacity rather than the median available seasonal
14 capacity during the 2024-2025 storage year. Table 3 below shows a comparison of the
15 Applicants’ proposed storage capacity values with SCGC’s recommended capacity values, which
16 are the maximum capacities observed during the summer and winter months of the 2024-2025
17 storage year:

18 **Table 3¹⁰**

	Applicants	SCGC
19 Injection Summer	458	543
20 Injection Winter	529	587
21 Withdrawal Summer	1787	2132
Withdrawal Winter	1826	2091

⁸ A.22-09-015, SoCalGas Chapter 1 at 3.

⁹ The Applicants proposed capacities ranged between 53 and 91 percent of levels adopted in D.20-02-045, Table 4, which corresponded to the then projected inventory level. However, the Commission authorized an increase in the Aliso Canyon storage inventory during the pendency of the proceeding, which supported higher injection and withdrawal capacities.

¹⁰ Attachment B: Yap Workpaper revising Applicants Workpaper for Chapter 1.

1 **3. The Applicants’ Proposed Reallocation of Backbone Transmission to Local**
2 **Transmission Is Flawed.**

3 **3.1. The Basic Premise of the Applicants’ Proposal Is Flawed.**

4 Applicants propose to reallocate a portion of the backbone system to the local
5 transmission function because they claim a portion of EGs are served directly from the backbone
6 system. The Applicants state:

7 Our analysis of summer peak day data found that on a summer peak
8 day, about 69% of total power-plant gas usage is served from LT
9 pipelines on the SoCalGas transmission system. An examination of
10 the California Gas Report 2022 through 2024 also found that EG
11 demand on the SoCalGas system made up about 30% of the entire
12 system demand on average.

13 Based on these findings, SoCalGas has applied a factor of 20% (i.e.
14 69% of 30%) to represent the functional percentage of LT service
15 provided by the BBT assets and to reallocate some costs from BBT
16 to LT to account for the local transmission function that those BBT
17 assets are providing.¹¹

18 The Applicants’ basic premise is flawed. Backbone transmission pipelines are designated
19 as such because they “receive gas supply from interstate pipelines and local California producers,
20 and redeliver that supply to the local transmission system and storage.”¹² The fact that a few
21 customers are directly served from the backbone system does not fundamentally change the
22 characteristics of those pipelines. Thus, it is incorrect to propose a “reallocation” of costs from
23 the backbone pipelines to the local transmission pipelines. SCGC recommends no reallocation of
24 embedded costs from the backbone subfunction to the local transmission subfunction.

25 Furthermore, when attempting to implement their flawed proposal, Applicants have made
26 two important errors in developing their recommendation to reallocate 20 percent of the backbone
27 cost of service to the local transmission subfunction.

¹¹ Applicants Chapter 8 at FS-MSP-25 (footnotes omitted).

¹² Applicants Chapter 8 at FS-MSP-3.

1 **3.2. Implementation Error 1: Applicants Propose to Use the 69 Percent Local**
2 **Transmission Portion Instead of the 31 Percent Backbone Portion of the EG**
3 **Usage to Determine Their Proposed Reallocation.**

4 The Applicants admit that 69 percent of the total EG usage is served from the local
5 transmission system, which means that 31 percent of EG usage is served from the backbone
6 system. Yet, they propose to use the percentage of the EG load served from the local
7 transmission system (69 percent) to allocate backbone assets to the local transmission function
8 rather than 31 percent (100-69 percent equals 31 percent) that is served from the backbone
9 system. If the Applicants are going to do any reallocating of backbone assets to local
10 transmission, the Applicants should use the *backbone portion of the total EG usage*, 31 percent,
11 times the EG demand on the system to represent the portion of backbone assets that they propose
12 to reallocate to the local transmission function.

13 **3.3. Implementation Error 2: Applicants Propose to Rely Upon Recent Recorded**
14 **Data to Determine the Portion of Total System Throughput Represented by**
15 **EG Usage Without Regard to Whether the Year Is a Cold Year.**

16 In their reallocation formula for applying backbone transmission assets to the local
17 transmission function, the Applicants propose to use the average of three years of recorded data to
18 determine the share of total system usage that is represented by EG usage.¹³ This is incorrect.
19 The Commission has directed that *cold year throughput* rather than average year throughput be
20 used to determine customer class shares in allocating backbone transmission.¹⁴ Applicants are
21 mistakenly relying upon recent recorded data to determine percentage shares without any regard
22 to the heating degree days associated with each of the recent years. Only one of those three years,
23 2023, had heating degree days at a level that would approximate a cold year.¹⁵ The Applicants
24 should use 2023 only to determine the EG share of usage. This correction reduces the EG share
25 of system throughput from 29.5 percent to 26.7 percent.¹⁶

¹³ Attachment C: Applicants Chapter 8 Workpapers at 13.

¹⁴ D.92-12-058, slip op. at 21-22.

¹⁵ Attachment D: Applicants Chapter 2 Workpapers at 3-4. Heating degree days for 2022 were 1209, heating degree days for 2023 were 1451, and heating degree days for 2024 were 1333. Cold year heating degree days is 1465.

¹⁶ Attachment B: Yap Workpapers revising workpaper to Applicants Chapter 8.

1 **3.4. The Combined Effect of the Two Corrections Clearly Demonstrates that the**
2 **Applicants' Proposed Reallocation Should Be 8.0 Percent Rather than 20.4**
3 **Percent.**

4 Recognizing the Commission has directed *cold year throughput* to be used in allocating
5 backbone transmission, produces a 26.7 percent share of usage for EG. As discussed previously,
6 if the Applicants are going to do any reallocating of backbone assets to local transmission, the
7 Applicants should use the *backbone portion of the total EG usage*, 30.8 percent, times the EG
8 demand on the system (26.7 percent) to represent the portion of backbone assets that they propose
9 to reallocate to the local transmission function. Combining these two corrections produces: 30.8
10 percent times 26.7 percent equals 8.0 percent be reallocated rather than the Applicants' erroneous
11 proposal that 69.2 percent times 29.5 percent equals 20.4 percent be reallocated.¹⁷

12 Table 4, below, presents a comparison of the allocation of costs to customer classes under
13 four alternatives, *i.e.*, (1) current rates, (2) Applicants' proposed cost allocation, which assumes
14 incorrectly that there should be a reallocation of backbone capacity costs to local transmission, (3)
15 SCGC's correction of the calculation of Applicants' proposed cost allocation, and (4) SCGC's
16 proposed cost allocation, which excludes any reallocation of backbone capacity costs to local
17 transmission:
18

¹⁷ Attachment C: Applicants Chapter 8 Workpapers at 13.

Table 4¹⁸

Customer Class	Current Allocation of Base Margin	% Total	Applicants Proposed Allocation of Base Margin	% Total	Applicants Proposed Allocation of Base Margin Corrected	% Total	SCGC Proposed Allocation of Base Margin	% Total
Residential	\$2,280,942	62.3%	\$2,371,762	61.4%	\$2,348,982	60.9%	\$2,333,677	60.5%
Core C/I	\$538,916	14.7%	\$625,612	16.2%	\$618,167	16.0%	\$613,166	15.9%
Gas A/C	\$61	0.0%	\$0	0.0%	\$0	0.0%	\$0	0.0%
Gas Engine	\$12,599	0.3%	\$7,611	0.2%	\$7,554	0.2%	\$7,515	0.2%
NGV	<u>\$40,058</u>	<u>1.1%</u>	<u>\$38,662</u>	<u>1.0%</u>	<u>\$37,188</u>	<u>1.0%</u>	<u>\$36,197</u>	<u>0.9%</u>
Total Core	\$2,872,577	78.5%	\$3,043,647	78.9%	\$3,011,891	78.0%	\$2,990,555	77.5%
Noncore C/I	\$143,801	3.9%	\$127,065	3.3%	\$117,742	3.1%	\$111,478	2.9%
Small EG	\$22,702	0.6%	\$15,661	0.4%	\$15,072	0.4%	\$14,676	0.4%
Large EG	\$20,771	0.6%	\$18,864	0.5%	\$17,752	0.5%	\$17,005	0.4%
EG Transmission	\$61,354	1.7%	\$94,304	2.4%	\$82,199	2.1%	\$74,066	1.9%
EOR	<u>\$10,281</u>	<u>0.3%</u>	<u>\$8,275</u>	<u>0.2%</u>	<u>\$7,642</u>	<u>0.2%</u>	<u>\$7,217</u>	<u>0.2%</u>
Total Retail Noncore	\$258,910	7.1%	\$264,170	6.8%	\$240,408	6.2%	\$224,443	5.8%
Long Beach	\$5,285	0.1%	\$5,154	0.1%	\$4,387	0.1%	\$3,873	0.1%
SDG&E	\$59,347	1.6%	\$68,583	1.8%	\$61,281	1.6%	\$56,375	1.5%
Southwest Gas	\$4,417	0.1%	\$5,966	0.2%	\$5,054	0.1%	\$4,440	0.1%
Vernon	\$3,576	0.1%	\$3,817	0.1%	\$3,312	0.1%	\$2,974	0.1%
Ecogas	<u>\$4,234</u>	<u>0.1%</u>	<u>\$6,099</u>	<u>0.2%</u>	<u>\$5,289</u>	<u>0.1%</u>	<u>\$4,745</u>	<u>0.1%</u>
Total Wholesale	\$76,859	2.1%	\$89,619	2.3%	\$79,324	2.1%	\$72,407	1.9%
UBS	\$30,850	0.8%	\$34,376	0.9%	\$34,376	0.9%	\$34,376	0.9%
BTS	<u>\$422,225</u>	<u>11.5%</u>	<u>\$427,920</u>	<u>11.1%</u>	<u>\$493,732</u>	<u>12.8%</u>	<u>\$537,950</u>	<u>13.9%</u>
Total Noncore	\$788,844	21.5%	\$816,084	21.1%	\$847,840	22.0%	\$869,176	22.5%
Total SoCalGas	\$3,661,421	100.0%	\$3,859,731	100.0%	\$3,859,731	100.0%	\$3,859,731	100.0%

4. The Backbone Transportation Service (“BTS”) Rate Should Continue to Be Based on Actual Backbone Capacity Not on Minimum Requirements Based on Customer Demand.

4.1. The BTS Tariff Already Allows for Reductions in Open Season Capacity Offerings.

Applicants’ G-BTS rate provides “for both firm and interruptible backbone transportation service rights” with a variety of receipt points available for service with a total amount of 3775 MMcf/d systemwide according to the tariff.¹⁹ The operationally available amount of backbone

¹⁸ Attachment B: Yap Workpapers revising workpapers to Applicants Chapter 12.

¹⁹ Attachment E: SoCalGas Schedule No. G-BTS at Sheet 3.

1 transportation service capacity at each point is stated on SoCalGas' Envoy system during each
 2 nomination cycle.²⁰ Therefore, the access rights provided by BTS contracts can be reduced if
 3 operating conditions require it.

4 Customers obtain BTS contracts through an Open Season process that is conducted every
 5 three years, as shown below in Table 5 for the last decade:

6 **Table 5: BTS Capacity Offered (MMcf/d)**

	<u>Year 2017¹</u>	<u>Year 2020²</u>	<u>Year 2023²</u>	<u>Year 2026³</u>
Northern Zone	1590	990	1425	1590
Wheeler Ridge Zone	765	765	765	765
Southern Zone	1210	750	650	650
CP Line 85 Zone	160	60	60	40
CP Coastal Zone	<u>150</u>	<u>150</u>	<u>150</u>	<u>150</u>
Total Offered	3875	2715	3050	3195
¹ A.22-09-015 Applicants Chapter 11 at 12.				
² A.25-09-014 Applicants Chapter 10 at PDB-8.				
³ SoCalGas, BTS Opening Season 2026 Presentation, April 4, 2026 at 12.				

14 As Table 5 demonstrates, the Applicants have adjusted the amount of backbone capacity rights to
 15 reflect constraints reasonably anticipated over the forecasted BTS period. The amount of
 16 capacity offered for each zone reflects not only the receipt point capacity for that zone but also
 17 other factors that may limit the pipeline capacity for that zone.²¹ Most notably, the Southern
 18 Zone is limited by the amount of demand present on the Southern System, which has declined
 19 significantly over the last ten years.^{22, 23} Similarly, there has been a decline in California gas
 20 production feeding into the CP Line 85 Zone.²⁴ The Northern Zone experienced capacity

²⁰ Attachment E: SoCalGas Schedule No. G-BTS at Sheet 5.

²¹ Attachment F: According to the SoCalGas, BTS Opening Season 2026 Presentation, April 4, 2026, at 8-10.

²² Applicants Chapter 10 at PDB-7.

²³ Attachment F: According to the SoCalGas, BTS Opening Season 2026 Presentation, April 4, 2026, at 10, the reduced capacity availability on the Southern System is driven by seasonal load conditions.

²⁴ Attachment N: U.S. Energy Information Administration, Natural Gas statistics by state, https://www.eia.gov/dnav/ng/hist/nal160_sca_2m.htm.

1 reductions during the Year 2020 and 2023 BTS cycles but has returned to the full receipt point
2 capacity reflected in the tariff for the 2026 Open Season.^{25,26}

3 While there has been variation in the amount of capacity offered over the last decade,
4 capacity has been offered based on the actual capability of the system. The variations in the total
5 amount of capacity that has been offered have reflected not only receipt point capacity but also
6 pipeline availabilities driven by operational factors including limits on upstream available supply
7 and downstream available demand.

8 **4.2. BTS Open Seasons Should Be Based on Pipeline Capacity, Not on the**
9 **Forecast Minimum Backbone Design Standard.**

10 In the previous CAP, A.22-09-015, the Applicants proposed that, should a reservation
11 charge credit mechanism be adopted, the quantity of BTS capacity be defined as 110 percent of
12 the forecast minimum backbone system design standard adopted in D.06-09-039.²⁷ Neither the
13 reservation charge nor the reduced basis for the BTS capacity was adopted in the Settlement
14 Agreement approved by the Commission in D.24-07-009.²⁸ Instead, a 100 percent volumetric
15 rate was adopted for backbone transmission service.²⁹

16 However, the Applicants once again propose to reduce the amount of BTS capacity
17 offered in the Open Season to 110 percent of the forecast minimum backbone system design
18 standard adopted in D.06-09-039 because “maintenance outages affecting customer’s firm BTS
19 capacity rights are expected to continue over the foreseeable future.”³⁰ Applicants’ proposal
20 would reduce the amount of BTS capacity offered in the 2029 Open Season to 2418 MMcf/d.³¹

²⁵ Attachment E: SoCalGas Schedule No. G-BTS at Sheet 1.

²⁶ Attachment F: According to the SoCalGas, BTS Opening Season 2026 Presentation, April 4, 2026, at 10, there is a 190 MMcf/d capacity limitation on the Topock Sub-Zone.

²⁷ A.22-09-015, Chapter 11 at 17.

²⁸ A.24-07-009, slip op., Attachment A at 7.

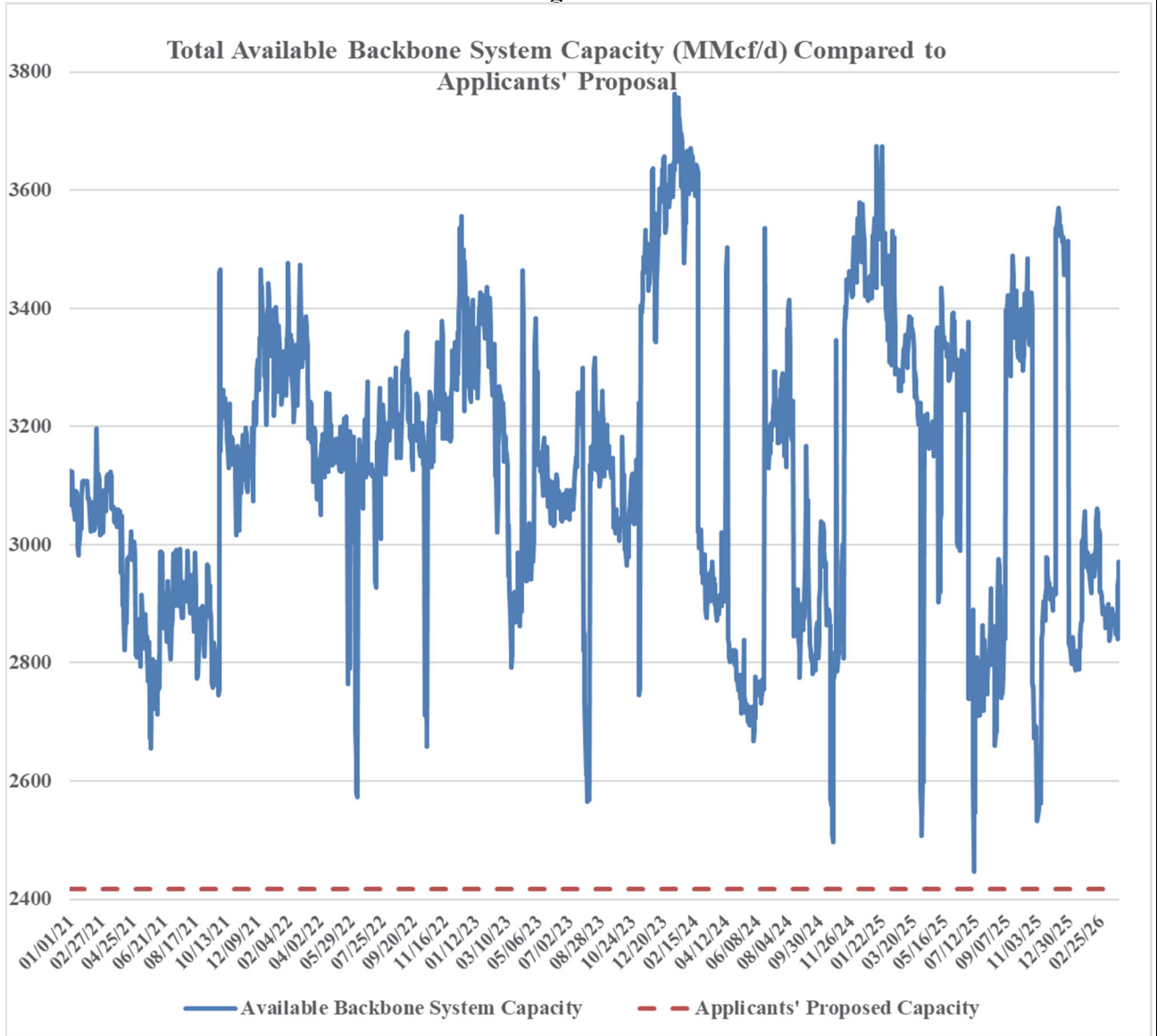
²⁹ A.24-07-009, slip op., Attachment A at 7.

³⁰ Applicants Chapter 10 at PDB-11 to PDB-12.

³¹ Applicants Chapter 10 at PDB-11.

1 As shown by the red dash line in Figure 1, the Applicants' proposal would reduce the
2 amount of BTS capacity offered during the 2029 Open Season to below even the lowest amount
3 of capacity that has been available operationally since the beginning of 2021:

4 **Figure 1³²**



23 The proposal does not make sense. The data presented in Figure 1 clearly shows that there has
24 been capacity available at levels in excess of the 2418 MMcf/d level proposed by the Applicants
25 every day for the past five years.

³² Attachment L: Envoy Reports of Daily Receipt Point Capacity Availability, data compiled for Cycle 1, January 1, 2021, through March 31, 2026.

1 There is no reason to change the current approach, which, while basing Open Season
2 capacity on actual pipeline capacities, has also permitted the Applicants to adjust the amount of
3 capacity offered in the Open Seasons to reflect the realities of pipeline maintenance and repair as
4 well as other operational factors. The tariff clearly states that capacity availability will be posted
5 on Envoy during each nomination cycle.

6 Furthermore, since the Applicants now offer a 100 percent volumetric BTS rate, there is
7 no risk that shippers will request refunds of demand charges if BTS capacity is cut because of
8 maintenance outages. There is no reason to artificially constrain the amount of BTS capacity
9 made available to shippers.

10 **5. Ratepayers Should Not Be Responsible for the Unamortized Costs of Off System**
11 **Delivery (“OSD”) Service.**

12 **5.1. Utilizing Any Overcollections in the Noncore Storage Balancing Account**
13 **(“NSBA”) to Cover the Unamortized Costs of OSD Service Is Tantamount to**
14 **Adding Costs to Transportation Rates.**

15 The Applicants propose to credit any overcollections of revenues arising from the NSBA
16 to the pending under-collected balance of \$4.0 million in the Firm Access and Storage Rights
17 Memorandum Account (“FASRMA”).³³ According to Applicants, the September 1, 2025,
18 balance in the FASRMA is \$4.0 million, which is made up of \$3.1 million of “unrecovered
19 capital revenue requirement of \$3.1 million” plus “\$0.8 million of on-going interest.”³⁴ Because
20 they are no longer offering OSD services, Applicants claim they see no opportunity for the
21 recovery of the under-collected FASRMA balance through OSD rates.³⁵

22 The Settlement Agreement for the previous CAP, A.22-09-015, eliminated any
23 shareholder responsibility for the costs of the unbundled storage program.³⁶ The majority of
24 embedded storage cost of service is allocated to transportation rates with the portion of the
25 embedded storage cost of service attributed to the unbundled storage program balanced against

³³ Applicants Chapter 10 at PDB-11.

³⁴ Applicants Chapter 6 at PG-5.

³⁵ Applicants Chapter 10 at PDB-10 to PDB-11.

³⁶ D.24-07-009, Attachment A at 6.

1 the revenues received from noncore storage contracts including contracts for hub services.³⁷ Any
2 revenues that are generated by noncore storage contracts or hub service contracts would flow
3 back to ratepayers as a credit against the cost of unbundled storage service through the actions of
4 the NSBA. Hence, Applicants are making a proposal that makes ratepayers entirely responsible
5 for the payment of the \$4.0 million balance in the FASRMA.

6 **5.2. The Commission Has Already Directed that On-System Customers Should**
7 **Not Subsidize OSD Services.**

8 The FASRMA tariff reads: “Pursuant to D. 11-03-029, the FASRMA will record system
9 modification costs in providing interruptible and firm [OSD] services and any related OSD
10 revenues to recover these costs.”³⁸ The tariff allows incremental operating and maintenance and
11 capital-related costs associated with OSD to be recovered from OSD revenues.³⁹ However, the
12 decision authorizing the OSD services very clearly stated that on-system customers were not to
13 subsidize the provision of OSD services. For example, D.11-03-029 states: “The offering of
14 interruptible OSD by the applicants shall not result in any increased costs being passed on to on-
15 system customers.”⁴⁰

16 It is also noteworthy that the Commission authorized the use of a memorandum account
17 instead of a balancing account for the Applicants to use when attempting to recover the cost of
18 providing OSD services from the OSD revenues. Memorandum accounts do not provide any
19 assurance to the Applicants that they will recover the costs booked into the memorandum account.
20 They are only given the opportunity to collect those costs through whatever mechanism the
21 Commission provides or through a request for rate recovery in an application.

³⁷ Attachment G: SoCalGas Preliminary Statement Part VI, Balancing Account, Noncore Storage Balancing Account (“NSBA”) at Sheet 1 to Sheet 2.

³⁸ Attachment H: SoCalGas Preliminary Statement Part VI, Memorandum Account, FASRMA at Sheet 1.

³⁹ Attachment H: SoCalGas Preliminary Statement Part VI, Memorandum Account, FASRMA at Sheet 1.

⁴⁰ D.11-03-029, slip op. at 46, Conclusions of Law No. 4.

1 In this case, Applicants are proposing to pass on unrecovered capital costs plus interest to
2 on-system customers despite the Commission’s statement that those customers are not to pay for
3 the provision of OSD services. The Applicants are not proposing to recover the unrecovered
4 costs from any arrangements associated with OSD services. The Commission should deny the
5 Applicants’ proposal to use any overcollection of revenues from the unbundled storage program,
6 or any other form of on-system rate recovery, to offset the FASRMA balance. Instead, the
7 Commission should order the Applicants to write off the unrecovered balance against earnings.

8 **6. The Commission Should Eliminate the Rate Subsidy that Is Built into the Core EG**
9 **Rate and Reject the Applicants’ Request to Extend the Applicability of the Core EG**
10 **Tariff.**

11 **6.1. The Commission Should Eliminate the Core EG Rate Subsidy.**

12 The Applicants develop the Core EG rate by prorating the allocation of costs to the Core
13 Commercial/Industrial (“C&I”) customers with the exception of the Core Fixed Cost Account
14 (“CFCA”).⁴¹ The customer-related, medium-pressure distribution, and high-pressure distribution
15 costs are properly prorated using the correct demand determinants.

16 The local transmission embedded cost of service, however, is allocated to Core C&I
17 customers using a 50/50 mixture of cold year peak month and peak day allocation⁴² while the
18 prorating of the local transmission costs to Core EG customers is erroneously performed based on
19 the share of average year volumes represented by the Core EG customers rather than the share of
20 cold year peak month/peak day volumes represented by the Core EG customers.⁴³ Similarly, the
21 storage cost of service is erroneously prorated to Core EG based on the share of average year

⁴¹ Attachment I: Errata-SCG Rate Design Model_Public.xlsx at tab “Rates”, excerpt of cells E989:J627 showing formulas. See the formula in row 609 for the exclusion of the CFCA.

⁴² Attachment I: Errata-SCG Rate Design Model_Public.xlsx at tab “Rates”, excerpt of cells E989:J627 showing formulas. See the formula in row 604.

⁴³ Attachment I: Errata-SCG Rate Design Model_Public.xlsx at tab “Rates”, excerpt of cells E989:J627 showing formulas. See the formula in row 614.

1 volumes represented by the Core EG customers rather than the share of medium pressure peak
2 day volumes represented by the Core EG customers that is relevant to storage allocations.^{44, 45}

3 Finally, the most concerning error is the complete exclusion of the CFCA costs from the
4 allocation to Core EG.⁴⁶ Applicants claim that the CFCA costs were excluded at the time the rate
5 was proposed because there were no CFCA costs associated with the rate.⁴⁷ While that may be
6 correct at the time the rate is proposed, going forward it is not correct. Every rate has variation in
7 usage associated with it on an ongoing basis. Excluding the CFCA costs creates a subsidy from
8 the remaining Core customers to the Core EG customers. This subsidy is wrong and should be
9 eliminated. The Applicants are using the core subsidy to promote their Core EG rates. The
10 elimination of the CFCA share leaves Core EG rates lower than they should be and, hence, closer
11 to the noncore rates otherwise applicable to EG customers.

12 **6.2. The Commission Should Deny Applicants' Request to Expand Core EG**
13 **Eligibility.**

14 Applicants propose to modify SoCalGas Rule 23 to increase core generation eligibility
15 from 1 MW to 10 MW and eliminate the monthly usage limitations of 20,800 therms per active
16 month for core electric generation eligibility.⁴⁸ Applicants claim there is a “growing demand for
17 flexible and reliable gas services among electric generation customers, particularly those
18 supporting grid stability, backup power, and renewable integration.”⁴⁹

19 The Commission should deny Applicants request for these changes to Rule 23. The
20 Commission should not encourage the expansion of EG gas usage by reducing the likelihood of

⁴⁴ Attachment I: Errata-SCG Rate Design Model_Public.xlsx at tab “Rates”, excerpt of cells E989:J627 showing formulas. See the formula in row 615.

⁴⁵ Attachment J: Errata-SCG Rate Design Model_Public.xlsx at tab “Base Margin” tab rows 678-687.

⁴⁶ Attachment I: Errata-SCG Rate Design Model_Public.xlsx at tab “Rates”, excerpt of cells E989:J627 showing formulas. See the formula in row 619, which refers to row 609 containing a formula that completely excludes the CFCA from the prorata of regulatory costs to Core EG.

⁴⁷ Attachment M: Applicants' Response to SCGC-12, Q.12.1.

⁴⁸ Applicants Chapter 11 at BD-1.

⁴⁹ Applicants Chapter 11 at BD-3.

1 curtailment. Promoting the expansion of EG gas usage runs counter to the spirit if not the letter
2 of SB 100, which states: “The Legislature finds and declares that the Public Utilities Commission,
3 State Energy Resources Conservation and Development Commission, and State Air Resources
4 Board should plan for 100 percent of total retail sales of electricity in California to come from
5 eligible renewable energy resources and zero-carbon resources by December 31, 2045.”⁵⁰

6 As discussed previously, the Applicants already propose to subsidize the Core EG rate. If
7 the Commission were to approve the Rule 23 changes, the Applicants would provide artificially
8 cheap core service to small EGs at an artificially high level of reliability. It is clear that the
9 Applicants would like as many tools as possible to promote their Microgrid Business venture for
10 which they have requested authority in A.25-04-006.

11 This completes my testimony.
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⁵⁰ Senate Bill 100 (De León, 2017) at Section 1.b.

Attachment A: Qualifications of Catherine E. Yap

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Attachment A: Qualifications of Catherine E. Yap

Q1. Please state your name and business address.

A1. My name is Catherine E. Yap and my address is Barkovich & Yap, Inc., P.O. Box 11031, Oakland, California 94611.

Q2. Please state your qualifications to offer this testimony.

A2. I am a principal in the firm of Barkovich & Yap, Inc., and have been consulting in the utility regulatory area for over three decades. During this time, I have directed and/or performed major examinations of cost-of-service requirements, allocation, rate design, and customer bill effects for electric, natural gas, water, and solid waste utilities. I have testified on numerous occasions before the California Public Utilities Commission (“Commission”) and in civil proceedings. I have consulted internationally on issues related to natural gas industry structure and marginal cost allocation and rate design.

Prior to this, I was employed for nine years by the Commission. Most recently, I was responsible for managing the Energy Rate Design and Economics Branch of the Public Staff Division (“PSD”). This branch was responsible for developing cost of service, rate design, and economic studies, such as sales forecasting and productivity assessment, for both electric and gas utilities. Members of the branch were responsible for presenting expert testimony, developing cost of service studies, and designing unbundled rates for the natural gas utilities during the Commission's extensive hearings on gas industry structure and rate design implementation. During this time, I participated extensively in the formulation of policy regarding the appropriate structure for the natural gas industry in California.

Previously, I was the Supervisor of the Gas Supply and Requirements Section of the Fuels Branch of the PSD. I was responsible for directing, and in some cases performing, advanced technical studies that evaluated California gas utility operations and associated contracts, investments, and expenses. I also acted as the highest level technical representative of the CPUC on natural gas matters and was involved in numerous

1 negotiated settlements involving natural gas pipelines, distribution utilities, producers, and
2 state and federal regulatory agencies.

3 Prior to that, I was a staff economist in the Policy Division acting as a consultant to the
4 Executive Director and to various Commissioners. I also testified on numerous occasions
5 as an expert witness regarding a variety of technical, economic, and financial matters
6 related to electric and natural gas utilities.

7 I have a B.A. in chemical physics from the University of California at Santa Cruz, and a
8 M.S. in Energy and Resources from the University of California at Berkeley. I have also
9 taken course work in finance, accounting, and organization theory from the University of
10 California, Extension, and Golden Gate University.

11 **Q3.** Have you testified previously regarding natural gas allocation matters?

12 **A3.** Yes. I testified numerous times regarding natural gas and electric cost allocation issues
13 over the past 45 years. Most recently, I testified in A.22-09-015, the Applicants previous
14 CAP as well as in A.24-03-019, Southern California Edison Company, Test Year 2025,
15 Phase 2 proceeding.

16 **Q4.** What testimony are you sponsoring in this proceeding?

17 **A4.** I am sponsoring Exhibit SCGC-01.

18 **Q5.** Was this material prepared by you or under your supervision?

19 **A5.** Yes, it was.

20 **Q6.** Insofar as this material is factual in nature, do you believe it to be correct?

21 **A6.** Yes, I do.

22 **Q7.** Insofar as this material is in the nature of opinion or judgment, does it represent your best
23 judgment?

24 **A7.** Yes, it does.

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