

Application No. 25-09-014
Exhibit No. SCGC-02
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

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

June 15, 2026

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Attachment B: 86FERC ¶64,014, Dockets Nos. ER97-2355-000, et al., Presiding Administrative Law Judge (ALJ’s) Initial Decision (issued March 31, 1999), excerpts.

Attachment C: A.22-05-015, SCG-30/SDG&E-34, Revised Direct Testimony of Angel Le and Paul Malin at WNL/PDM-29, excerpt.

Attachment D: 18CFR201, Uniform System of Accounts Prescribed for Natural Gas Companies
Subject to the Provisions of the Natural Gas Act, excerpt.

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4 **On Behalf of**
5 **Southern California Generation Coalition**
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7 **1 Introduction**

8 This testimony responds to statements made in the following opening testimonies on
9 ratemaking issues that were served on May 15, 2026, in this proceeding:

- 10 □ Testimony of Michel Florio (“Florio Direct”) on behalf of The Utility Reform Network
11 (“TURN”), and
12 □ Testimony of Brian Collins (“Collins Direct”) on behalf of Indicated Shippers.

13 The opening testimonies address issues raised by the September 30, 2025, direct testimony by
14 Southern California Gas Company (“SoCalGas”) and San Diego Gas and Electric Company
15 (“SDG&E”) (jointly, “Applicants”). This testimony is presented by Catherine E. Yap on behalf
16 of the Southern California Generation Coalition (“SCGC”). Ms. Yap has more than four decades
17 of experience preparing and delivering testimony before this Commission as well as in other
18 jurisdictions. Ms. Yap’s statement of qualification is included as Attachment A to her direct
19 testimony dated May 15, 2026.

20 **2 The Commission Should Disregard TURN’s Claim that the Costs of Different Utility**
21 **Functions Are Allocated Differently.**

22 **2.1 The Applicants’ Embedded Cost Approach Is Consistent with the**
23 **Commission’s Long Standing Policies on Natural Gas Utility Cost Allocation.**

24 TURN witness Florio claims that the “various functional categories of the utilities’ costs
25 are allocated quite differently, based on how different customer groups use the system.”¹

26 Witness Florio is somehow suggesting that the Applicants have selected allocation factors that
27 disadvantage core customers relative to noncore customers. However, witness Florio’s

¹ Florio Direct at 5.

1 suggestion is not correct. Under the Applicants' proposed embedded cost allocation, the various
2 functional categories of the utilities' costs are allocated based on the marginal demand measures
3 that were adopted by the Commission in 1992 in Decision ("D.") 92-12-058² when the
4 Commission completed its deep analysis of the factors driving costs on the natural gas utility
5 systems.

6 Although the Commission's evaluation of the natural gas utility system was performed in
7 the context of a long run marginal cost allocation rather than an embedded cost allocation, the
8 fundamental approach is the same. The Commission's cost allocation framework did not create
9 a preference for any particular customer group but rather addressed those factors that drive costs
10 on the utility system and identified measures by which each customer group's usage and access
11 could be (and should be) measured for cost allocation purposes.

12 **2.2 Customer Access as Well as Customer Demand Drives Distribution System**
13 **Costs; Hence, the Sheer Number of Core Customers Served at Medium**
14 **Pressure Distribution Impose Significant Costs.**

15 Witness Florio complains that core customers are allocated 95 percent of the cost of the
16 medium pressure distribution because "since many noncore customers are served directly from
17 transmission lines and do not use the distribution system, those costs fall much more heavily on
18 the core."³ Witness Florio's statement misrepresents reality. There are plenty of noncore
19 customers served from the medium pressure distribution system. However, providing customer
20 access for millions of core customers imposes significant costs on the utility system. These
21 customers' access costs are reflected in the cost allocation of the medium pressure distribution
22 system.

23 As shown below in Table 1, the number of core customers overwhelms the number of
24 noncore customers on the medium pressure system by several orders of magnitude:
25
26

² D.92-12-058 (December 16, 1992.)

³ Florio Direct at 6.

Table 1: Breakdown of SoCalGas Customers by Service Level

	<u>Core</u>	<u>Retail Noncore</u>	<u>Wholesale/ International</u>	<u>Total System</u>
Transmission	109	86	5	200
High Pressure Distribution	7,712	248	0	7,960
Medium Pressure Distribution	<u>6,039,332</u>	<u>562</u>	<u>0</u>	<u>6,039,894</u>
Total	6,047,154	896	5	6,048,054

Interestingly enough, there are more core customers (108) served from the transmission system than there are noncore customers (86) served from the transmission system. However, the vast majority (99.86 percent) of customers on the SoCalGas system are core customers who are served from the medium pressure distribution system.

In its seminal decision, D.92-12-058, the Commission recognized that many of the cost drivers on the utility system were demands,⁴ which created a requirement for amounts of pipeline capacity that operate at various pressures, *i.e.*, transmission, high pressure distribution, and medium pressure distribution, on the utility system, as well as components of the storage system. Accordingly, the Commission established demand-related cost drivers related to the capacity requirements for each of those systems.⁵ However, the Commission also recognized that there was a “cost of a customer’s access to the gas utility’s supply system.”⁶ In other words, a significant amount of utility cost of service was related to the need to provide access to customers (meters, service lines, metering and billing services, *etc.*) and those costs were driven by the number of customers as well as the size of customers. Given that there are more than ten thousand times the number of core customers served at medium pressure as there are noncore customers served at medium pressure (6,039,332 divided by 562 is 10,746), it is not surprising that the great majority of the medium pressure distribution system cost of service is allocated to core customers.

⁴ D.92-12-058, slip op. at 20.

⁵ D.92-12-058, slip op. at Order Paragraph 2.

⁶ D.92-12-058, slip op. at 38.

1 **2.3 The Commission Should Reject TURN’s Proposal to Base the Cost Allocation**
2 **Process on the Applicants’ General Rate Case Filing Rather than**
3 **Functionalized Recorded Costs.**

4 Witness Florio recommends that future cost allocation proceedings “be filed every four
5 years, several months after the Phase 1 GRC applications, and utilize the revenue requirements
6 requested in those GRCs.”⁷ I disagree. Witness Florio is concerned that the cost allocations
7 based on recorded figures are out of date, but he ignores the fact that there is often a tremendous
8 deviation between the amount of revenue requirement requested by the Applicants and the
9 amount of revenue requirement that is authorized by the Commission in its decisions in general
10 rate case (“GRC”) proceedings. Witness Florio proposes that the Commission direct the
11 Applicants “to include in their upcoming GRC a fully functionalized breakdown of their
12 requested revenue requirements.”⁸ Witness Florio also proposes that the Applicants be required
13 to submit a filing mapping the adopted revenue requirements to FERC accounts and applying the
14 cost allocation policies adopted in this CAP to the new revenue requirements within 60 days of
15 the issuance of the GRC decision.⁹

16 The Commission should reject witness Florio’s recommendations. Ratepayers are better
17 off dealing with cost allocation studies that are based on recorded costs that can be verified by
18 parties rather than utility applications that reflect the Applicants’ self-interested projections but
19 often not the realities of the regulatory process.

20 Witness Florio’s conclusions are clearly colored by his view that the transmission
21 revenue requirement will continue to escalate rapidly during the period 2027-2030, a conclusion
22 that he has based on the change in transmission revenue requirement over the period 2020-2024.
23 He provided no evidence to support his belief. The 2020-2024 period was extraordinary given
24 the large number of Pipeline Safety Enhancement Program (“PSEP”) and Transmission Integrity
25 Management Program (“TIMP”) inspections and repairs on the transmission system that were
26 included in revenue requirement. Ratemaking authorized in this timeframe was very supportive

⁷ Florio Direct at 14.

⁸ Florio Direct at 13.

⁹ *Id.*

1 of the PSEP and TIMP activities with balancing accounts that passed through costs regularly or
2 general rate case treatment that authorized “separate capital adjustments for projects related to its
3 Pipeline Safety Enhancement Plan” beyond the base plant amounts projected in the post-test year
4 ratemaking model.¹⁰ In contrast, the ratemaking for test year 2024 significantly reduced
5 expenses and capital expenditures for TIMP and PSEP as well as general transmission and
6 distribution services, below the requested levels,¹¹ and changed the TIMP balancing account
7 from a two-way balancing account to a one-way balancing account.¹² Furthermore, the increases
8 in revenue requirement levels for the post-test years 2026-2027 are limited to below three
9 percent.¹³

10 Finally, witness Florio proposes to somehow substitute functionalized revenue
11 requirement from the Applicants’ imminent test year 2028 GRC filing for the cost allocation
12 study based on recorded embedded costs. Witness Florio believes that this can be accomplished
13 within 60 days of issuing the GRC decision by “mapping” revenue requirement to FERC
14 accounts. This is an unworkable proposal.

15 All four of the major utilities rely upon complex computer models to forecast their
16 Results of Operations (“RO”) for their GRCs; hence these models are referred to as RO models.
17 Regardless of what Pacific Gas and Electric Company has chosen to do in programming its RO
18 model, the Applicants do not functionalize their revenue requirements forecasted in the RO
19 model that the Applicants use to develop their GRC revenue requirement and rates. One cannot
20 merely “map” authorized GRC revenue requirement to the various FERC accounts and somehow
21 “determine” functionalized revenue requirements absent a major reprogramming of the
22 Applicants’ RO model, which would take a considerable amount of time to reprogram and
23 debug. Therefore, ordering the Applicants to revamp their RO model to functionalize the
24 revenue requirement would result in a substantial delay in the Applicants’ Test Year 2028 GRC

¹⁰ D.21-05-003, slip op. at Ordering Paragraph 5.

¹¹ D.24-12-074, slip op., Attachment A-5.

¹² D.24-12-074, slip op. at 248.

¹³ D.24-12-074, slip op., Attachment A-3. Post-test year 2025 was authorized a five percent increase.

1 proceeding to allow them sufficient time to complete the reworking and debugging of their RO
2 model.

3 **3 The Commission Should Reject TURN's and Indicated Shippers' Proposals to**
4 **Functionalize Capital-Related Revenue Requirement Based on Utility Plant Less Asset**
5 **Retirement Obligations.**

6 **3.1 Response to TURN's Proposal**

7 TURN's witness claims that Asset Retirement Obligations ("AROs"), which are
8 sometimes referred to as the "costs of removal," are not properly included in the net book value
9 of plant to be used in functionalizing return and taxes.¹⁴ Witness Florio claims that "using AROs
10 to allocate rate base, return, and associated taxes is incorrect, because AROs do not impact those
11 portions of the revenue requirement."¹⁵ Witness Florio errs in his thinking. The AROs are
12 properly part of the cost of plant that is used to functionalize capital costs in the Applicants'
13 embedded cost study in this cost allocation proceeding.

14 TURN raised this same argument in the two previous cost allocation proceedings, A.18-
15 07-024 and A.22-09-015. Although A.22-09-015 was settled, the prior proceeding, A.18-07-024,
16 was litigated. In its decision regarding A.18-07-024, the Commission rejected TURN's
17 argument stating:

18 We find that AROs are not merely a product of a financial
19 reporting requirement, as asserted by TURN, but rather AROs are
20 asset-related incremental costs and, hence, should be included in
21 the embedded cost study. We deny TURN's request to omit AROs
22 from the study.¹⁶

23 The Commission should reaffirm its previous decision on this issue.

24 AROs are an appropriate part of the book value of plant. The costs of the AROs are just
25 as much a part of the cost of plant as pipes or valves because once the plant is constructed, the
26 utility is obligated to retire the plant at the end of its useful life, often at significant cost. As
27 described by the Federal Energy Regulatory Commission ("FERC") in its Order 631:

¹⁴ Florio Revised Direct at 34.

¹⁵ Florio Direct at 17.

¹⁶ D.20-02-045, slip op. at 33 (footnote omitted).

1 An entity essentially recognizes a liability for the fair value of an
2 asset retirement obligation at the time the asset is constructed,
3 acquired, or when a change in the law creates a legal obligation to
4 perform the retirement activities. Upon initial recognition of that
5 liability, an entity also increases the cost of the related asset that
6 gives rise to the legal obligation by the same amount. The liability
7 is increased over time until the actual retirement activity
8 commences. Additionally, the asset retirement cost capitalized is
9 depreciated over the same life of the related asset giving rise to the
10 obligation.¹⁷

11 The FERC in Order 631 made it very clear that the ARO is an “integral part of the costs of the
12 particular asset that gives rise to the asset retirement obligations.”¹⁸

13 Consequently, the ARO is an essential part of plant cost that is used to calculate net book
14 value in the Applicants’ embedded cost study in order to functionalize return and taxes. The
15 Commission should reject witness Florio’s proposal to remove the ARO from net book value.

16 Witness Florio argues that his conclusion is substantiated because an “embedded cost
17 study already reflects the costs of AROs in the only portion of the revenue requirement that
18 includes them—depreciation expense.¹⁹ Using this reasoning, one might argue to exclude the
19 other portions of plant from the net book value of plant, because they are also included in
20 depreciation expense. Witness Florio’s reasoning does not make sense.

21 Witness Florio also claims, “ratepayers cover these costs through depreciation accruals
22 before the costs are actually incurred at the time of asset retirement, there is no rate of return
23 earned on those accruals, no income taxes, and no property taxes,” which he believes supports
24 his claim that AROs should be excluded from net plant.²⁰ This is not true. *The manner in which*
25 *a cost is financed does not determine whether it is a cost.*

26 As witness Florio acknowledges, customers pay for AROs over the entire life of capital
27 assets.²¹ The FERC clearly acknowledge this fact in its Order 631. The FERC’s use of AROs in

¹⁷ Attachment A: FERC Docket No. RM02-7-000, Order No. 631 (Issued April 9, 2003) at ¶11 (emphasis added).

¹⁸ Attachment A: FERC Docket No. RM02-7-000, Order No. 631 (Issued April 9, 2003) at ¶48.

¹⁹ Florio Direct at 17, emphasis omitted.

²⁰ Florio Direct at 18, emphasis omitted.

²¹ Florio Direct at 18.

1 its ratemaking certainly supports my opinion that AROs are a real part of the cost of utility
2 service and are appropriately included in net plant.

3 Witness Florio makes no secret of his motivation for excluding AROs from the
4 functionalization process. His objective is to shift the functionalization of capital-related
5 revenue requirement, return, taxes, and depreciation so that less is associated with distribution
6 and more is associated with transmission and storage, reducing rates for distribution service and
7 increasing rates for transmission service. Witness Florio claims, for example, that the share of
8 capital-related revenue requirement for storage would increase from the 11.2 percent proposed
9 by the Applicants to 14.5 percent if the Commission were to adopt his proposal to exclude AROs
10 from the cost of plant. Similarly, the share of capital-related revenue requirement for
11 transmission would increase from the 24.7 percent proposed by the Applicants to 28.4 percent
12 under witness Florio’s proposal. However, the share of capital-related revenue requirement for
13 distribution would decrease from the 57.5 percent proposed by the Applicants to 49.0 percent
14 under witness Florio’s proposal.²²

15 The Commission should reject, once again, witness Florio’s proposal as contrary to well-
16 established ratemaking accounting principles. Witness Florio’s proposal is nothing more than a
17 result-oriented attempt to shift costs from the distribution function to the transmission and
18 storage functions.

19 **3.2 Response to Indicated Shippers’ Proposal**

20 Indicated Shippers witness Collins recommends that the ARO amounts be removed from
21 the embedded cost used for class allocation. The Commission should reject witness Collins
22 claims about AROs as unfounded.

23 First, witness Collins claims that AROs are not part of the cost of plant currently
24 providing service to ratepayers.²³ This claim is directly contradicted by the finding of the FERC
25 that the ARO is an “integral part of the costs of the particular asset that gives rise to the asset

²² Florio Direct at 20.

²³ Collins Direct at 26.

1 retirement obligations.”²⁴ Thus, the ARO is part of the cost of the asset from the time it becomes
2 used and useful.

3 Second, witness Collins claims that the ARO amounts do not meet the known and
4 measurable standard because there is uncertainty regarding the final regulatory decisions for
5 decommissioning costs incurred for SoCalGas storage fields.²⁵ His concerns are overblown.
6 Accounting and ratemaking principles require that SoCalGas recognize its liability for the fair
7 value of AROs for its storage assets using its best estimates with current information.²⁶ If in the
8 future, storage regulatory changes impact the costs associated with storage field retirement, that
9 fair market value will be adjusted and future regulatory actions, including cost allocations, will
10 need to reflect the updated cost of the storage AROs. This is how regulation works.

11 Third, witness Collins claims that including the AROs somehow risks double recovery.²⁷
12 This concern is unfounded since the Applicants’ embedded cost study developed to allocate
13 functionalized margin is not developed to determine revenue requirement. As discussed above,
14 the Applicants’ revenue requirements are generated by the Applicants’ RO model without
15 functionalizing costs. The ARO is an appropriate part of the book cost of plant and should be
16 included in capital portion of the functionalized embedded cost analysis.

17 Last, witness Collins seems to attempt to blame inclusion of AROs in the embedded cost
18 analysis of storage for somehow amplifying what he believes are failures in the Applicants’
19 approach to allocating storage.²⁸ This is quite a stretch. Witness Collins should simply raise his
20 concerns about the storage allocation process directly instead of attempting to prop it up with his
21 unfounded concerns about AROs.

²⁴ Attachment A: FERC Docket No. RM02-7-000, Order No. 631 (Issued April 9, 2003) at ¶48.

²⁵ Collins Direct at 26-27.

²⁶ Attachment D: 18CFR201, Uniform System of Accounts Prescribed for Natural Gas Companies
Subject to the Provisions of the Natural Gas Act, General Instructions No. 24.

²⁷ Collins Direct at 27-28.

²⁸ Collins Direct at 29-30.

1 **4 TURN Is Correct in Rejecting the Applicants’ Proposal to Reallocate Backbone Costs**
2 **to Local Transmission.**

3 TURN witness Florio recommends that the Commission reject the Applicants’ proposal
4 to reallocate 20 percent of the cost of the backbone system to the local transmission function.²⁹

5 Witness Florio points out:

6 The costs of those lines initially identified as backbone *do not*
7 change depending upon whether they deliver solely to local
8 transmission and distribution lines or whether they serve a few
9 end-use customers directly. Nor does a line lose its character as a
10 backbone line by serving some large customers directly. There is
11 no physical location where the transition from backbone to local
12 occurs...where the split occurs at “the location where the pipeline
13 function transitions from transporting supply from interstate
14 pipelines and suppliers, to redelivering that supply to distribution
15 and end-use customers.” Rather, the lines continue to function as
16 backbone lines for their entire length, delivering gas from system
17 receipt points to storage fields and the local transmission system.³⁰

18 Witness Florio is correct. The Commission should reject the Applicants’ proposal to reallocate
19 backbone costs to local transmission. However, if the Commission is inclined to make such a
20 reallocation, the reallocation must be limited to the 8.0 percent established in my direct
21 testimony instead of the 20.4 percent proposed by the Applicants to eliminate the effect of the
22 Applicants’ mathematical error.³¹

23 **5 The Commission Should Reject Indicated Shippers’ Attempt to Rehabilitate the**
24 **Applicants’ Erroneous Proposal to Reallocate Backbone Costs to Local Transmission.**

25 Indicated Shippers witness Collins criticizes the Applicants proposal to “reallocate
26 approximately \$116.4 million per year in transmission costs from its BTS function to the Local
27 Transmission function,” stating that “SoCalGas’s computational methodology is flawed.”³²
28 However, witness Collins fails to recognize the fundamental flaw with the Applicants’ proposal,
29 which was pointed out by witness Florio: “the costs of those lines initially identified as backbone
30 do not change depending upon whether they deliver solely to local transmission and distribution

²⁹ Florio Direct at 20.

³⁰ Florio Direct at 31-32.

³¹ Yap Direct Testimony at 7.

³² Collins Direct at 31, citing to SCG-8 at FS-MSP-26.

1 lines or whether they serve a few end-use customers directly.”³³ The Commission should
2 disregard witness Collins’s attempt to rehabilitate the Applicants’ misguided recommendation to
3 reallocate backbone costs to local transmission.

4 **6 The Commission Should Reject TURN’s Proposal to Allocate Administrative and**
5 **General (“A&G”) Expenses and General Plant on the Basis of a Mixture of Labor and**
6 **Plant Ratios.**

7 TURN witness Florio proposes that the Commission adopt a new allocation procedure for
8 A&G expenses based in part on functionalized plant costs. It should be noted that witness Florio
9 is referring to the A&G expenses that are incorporated in the operating and maintenance
10 (“O&M”) expenses presented at pages 317 to 325 of SoCalGas Form 2. Witness Florio
11 complains:

12 [only] \$497 million of labor costs used in the SEUs’ calculation
13 (not including A&G labor itself) only includes the labor costs
14 booked as O&M expenses. Another \$257 million in labor costs
15 were capitalized as construction and booked to plant accounts, and
16 about \$7.5 million were attributed to removal of gas plant,
17 producing a total for Salaries and Wages of \$864.3 million.³⁴

18 Witness Florio then recommends that the Commission direct the Applicants to include
19 capitalized labor costs in the A&G allocation factor or provide a convincing explanation as to
20 why they are excluded.³⁵ Witness Florio’s recommendation should be rejected.

21 The Commission routinely uses functionalized labor ratios to allocate A&G costs in cases
22 where revenue requirements are separated between electric transmission and electric distribution
23 and generation activities.³⁶ The Commission’s approach conforms to the FERC’s traditional
24 labor ratio allocation method.³⁷ The FERC has utilized functionalized labor ratios for allocating

³³ Florio Direct at 31-32.

³⁴ Florio Direct at 42, describing the table at page 355 of SoCalGas FERC Form 2.

³⁵ Florio Direct at 42.

³⁶ D.04-07-022, slip op. at 282.

³⁷ D.03-08-062, slip op. at 11.

1 A&G costs since the 1970s.³⁸ The Commission should approve the Applicants' proposal to use
2 functionalized labor ratios to allocate A&G costs in their embedded cost studies.

3 Furthermore, the portion of A&G that is *not capitalized* has nothing to do with plant
4 costs. All of the plant-related A&G costs have already been removed because those A&G costs
5 related to plant construction have been capitalized. Table 2 below lists key elements of
6 SoCalGas A&G that are capitalized to plant:

7 **Table 2³⁹**

8	Account		Percent
9	<u>Number</u>	<u>Account Description</u>	<u>Capitalized</u>
10	920	A&G Salaries	13.3
11	921	Office Supplies	13.3
12	923	Outside Services	13.3
	925	Injuries & Damages	24.6
	926	Employee Pension & Benefits	26.3
	163	Stores (purchasing & warehousing)	57.5 - 80.2

13 The instructions to the FERC Uniform System of Accounts make very clear that the
14 utility's payroll is to be broken down between capitalized labor and non-capitalized labor
15 including A&G labor:

16 10. Payroll distribution. Underlying accounting data shall be
17 maintained so that the distribution of the cost of labor charged
18 direct to the various accounts will be readily available. Such
19 underlying data shall permit a reasonably accurate distribution to
20 be made of the cost of labor charged initially to clearing accounts
21 so that the total labor cost may be classified among construction,
22 cost of removal, gas operating functions (manufactured gas
23 production, natural gas production and gathering, products
24 extraction, underground storage, transmission, distribution, etc.),
25 and nonutility operations.⁴⁰

26 Thus, the utility is instructed to prepare the table reconciling its labor costs among the various
27 categories that is presented on page 355 of its Form 2, making explicit that the O&M expenses

³⁸ Attachment B: 86FERC ¶64,014, Dockets Nos. ER97-2355-000, et al., Presiding Administrative Law Judge (ALJ's) Initial Decision (issued March 31, 1999), slip op. at 23. ALJ order was affirmed in 92FERC61,268 (issued September 28, 2000).

³⁹ Attachment C: A.22-05-015, SCG-30/SDG&E-34, Revised Direct Testimony of Angel Le and Paul Malin at WNL/PDM-29.

⁴⁰ Attachment D: 18CFR201, Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, General Instructions No. 10.

1 presented at pages 317 to 325 of the Form 2 do not include those portions of labor, including
2 A&G costs that already have been capitalized as part of gas plant.

3 There is no particular correlation between the cost of capital plant, which is driven by
4 land and materials costs, capitalized labor and capitalized A&G costs, and the cost of non-
5 capitalized A&G costs. Non-capitalized A&G costs and non-capitalized labor costs, which are
6 recorded as O&M in the Form 2, are driven by the other activities of the utility organization, not
7 construction. The Commission should reject witness Florio's recommendation to utilize the total
8 amount of labor, including the capitalized labor, as an allocator of the non-capitalized A&G
9 amounts.

10 **7 The Commission Should Reject TURN's Proposal to Change the Allocation for "Safety**
11 **and Reliability" Distribution Costs.**

12 TURN witness Florio proposes that 80 percent of the distribution cost allocation for both
13 high- and medium-pressure distribution be allocated on the basis of annual distribution-level
14 throughput and 20 percent of the distribution cost allocation for both high- and medium-pressure
15 distribution be allocated on the basis of peak demand.⁴¹ This proposal is based entirely on the
16 notion that repairing and replacing components of the existing distribution capacity are not
17 driven by the need for peak capacity.⁴² This is not true. Regardless of whether the loads are
18 growing on the gas system, the need to maintain some level of capacity is driven by existing and
19 forecasted peak requirements. The Commission should reject witness Florio's proposal.

20 As the Commission recognized in its seminal decision, D.92-12-058, the requirement for
21 capacity on the high pressure and medium pressure distribution system is driven by peak month
22 and peak day requirements, respectively.⁴³ This fact is not a function of whether the loads are
23 growing or even shrinking. In either case, the capacity levels must meet the peak demand
24 requirements or the utility will be forced to curtail customer usage.

⁴¹ Florio Direct at 54-55.

⁴² Florio Direct at 54.

⁴³ D.92-12-058, slip op. at Ordering Paragraph 2.

1 The fact that a large portion of the cost of service for both the high- and medium-pressure
2 distribution systems is driven by safety requirements is, again, irrelevant to the recognition that
3 these costs are necessary to maintaining existing capacity. Unless the Commission determines
4 that an amount of capacity is no longer required to meet the loads on the high- and medium-
5 pressure distribution systems, the Applicants must continue to maintain the systems fully, which
6 includes completing the necessary safety-related evaluations and repairs. Cost responsibility
7 should be allocated among customer classes based on their share of the monthly peak loads for
8 the high-pressure distribution system and their share of peak day requirements for the medium-
9 pressure distribution system.

10 **8 TURN Is Correct in Its Assessment that Applicants Are Not Entitled to Recover the**
11 **Firm Access and Storage Rights Memorandum Account (“FARSMA”) Under-**
12 **Collected Balance from On-System Customers.**

13 TURN witness Florio correctly recognizes that storage customers are among the “on-
14 system customers” on the Applicants’ system who the Commission explicitly exempted from
15 paying for Off-System Delivery (“OSD”) services.⁴⁴ Thus, the Applicants’ proposal to “recover
16 the costs of offering OSD services by drawing revenues from the Noncore Storage Balancing
17 Account” results with “storage customers...effectively pay[ing] for the system modifications.”⁴⁵

18 Witness Florio also correctly points out that the language of the FASRMA does not
19 permit any revenues apart from OSD revenues to be credited to the FASRMA against the
20 incremental costs associated with providing OSD services.⁴⁶ Additionally, Witness Florio
21 correctly notes that the “recovery of OSD implementation costs was never guaranteed” since
22 FASRMA is a memorandum account and not a balancing account.⁴⁷

⁴⁴ Florio Direct at 75, citing to D.11-03-029, slip op., Conclusion of Law 4.

⁴⁵ Florio Direct at 75.

⁴⁶ Florio Direct at 76-77, citing to SoCalGas Preliminary Statement Part VI, FASRMA at Sheets 1-2.

⁴⁷ Florio Direct at 77.