Exhibit No.: ____________________
Application: A.18-07-024
Witness: Sharim Chaudhury
Chapter: 12R

REVISED PREPARED DIRECT TESTIMONY OF

SHARIM CHAUDHURY

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

AND SAN DIEGO GAS & ELECTRIC COMPANY

(RATE DESIGN)

March 2019 ~~July 2018~~

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CHAPTER 12

REVISED PREPARED DIRECT TESTIMONY OF SHARIM CHAUDHURY

(RATE DESIGN)

I. PURPOSE

The purpose of my testimony is to present the proposed natural gas transportation rates of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (collectively, Applicants). These proposed rates reflect revisions to current rates based on Applicants' proposed cost allocation proposals in this proceeding to allocate each utility's authorized base margin[1] across customer classes. Applicants' cost allocation proposals, based on updated cost studies, are described by witnesses Sim-Cheng Fung (Chapter 8), Marjorie Schmidt-Pines for SoCalGas (Chapter 9), and Michael Foster for SDG&E (Chapter 10).

A. Overview of Rate Design

Applicants' rate design models start with the proposed allocated base margin, and then incorporate the integration of the local transmission system costs for the two utilities,[2] along with the unbundling of the Backbone Transportation Service (BTS) costs.[3] Additionally, Applicants' rate design models recover in rates all Commission-authorized non-base margin costs, which reflect other costs incurred by the Utilities in providing transportation services to its customers during the cost allocation period. These non-base margin costs include, but are not limited to,

[1] Base margin is authorized by the California Public Utilities Commission (Commission) in the General Rate Case (GRC) or equivalent cost of service proceedings.
[2] This integration reflects the splitting of total local transmission costs between the utilities by the % share of cold-year peak month throughput.
[3] BTS costs represent the costs of SoCalGas' and SDG&E's transmission lines from the receipt points to SoCalGas' Citygate.

unaccounted-for gas (UAF),[4] company-use fuel, regulatory account balances (over-or-under collections), and any additional revenue requirements authorized by the Commission in proceedings outside the GRC.

B. Non-Margin Cost Allocation and Rate Design Proposals

Except as noted below, the methods employed to develop and allocate non-margin costs are consistent with those underlying the 2017 Triennial Cost Allocation Proceeding (TCAP) (Phase 2), a proceeding which resulted in a Commission-approved settlement. See Decision (D.) 16-10-004.

My testimony incorporates the following rate design and non-margin cost allocation proposals:

(1) For SoCalGas, increase the residential customer charge from $5 to $10 per customer per month;

(2) For SDG&E, replace the current residential minimum bill of $3 per customer per month with a residential customer charge of $10 per customer per month;

(3) Update SoCalGas' and SDG&E's submeter credits;

(4) Update SoCalGas' and SDG&E's Natural Gas Vehicle (NGV) compression costs;

(5) Provide a new method to allocate SoCalGas' and SDG&E's Self Generation Incentive Program (SGIP) costs across customer classes; and

[4] As described by witness Wei Bin Guo (Chapter 5), UAF gas is the difference between total receipts into SoCalGas' and SDG&E's respective service territories and total deliveries within SoCalGas' and SDG&E's respective service territories over a specified period.

(6) Propose methods to allocate SoCalGas' Storage Inventory for Balancing Function Memorandum Account (SIBFMA) costs and Reliability Function Cost Memorandum Account (RFCMA) costs across customer classes.

C. Illustrative Rates

The allocated non-margin costs are added to the allocated base margin costs to derive the transportation revenue requirement to be recovered in rates. The allocated transportation revenue requirements across customer classes become the starting point for the development of rates for each customer class.

Table 1 below shows SoCalGas' proposed 2020 class-average transportation rates and the resulting rate changes relative to the current rates.[5]

Table 1R: Class Average Rates ($/therm)

	7/1/2018	TCAP Proposed	$/th Change	% Change
SoCalGas:				
Res	$0.748	$0.743	($0.005)	-0.7%
CCI CA	$0.325	$0.380	$0.056	17.1%
Gas A/C	$0.154	$0.159	$0.004	2.7%
Gas Engine	$0.161	$0.163	$0.002	1.1%
NGV Uncompressed post-SW	$0.113	$0.129	$0.017	14.9%
Core Class Average	$0.599	$0.608	$0.009	~~1.4~~ 1.5%
NCCI-D CA	$0.077	$0.084	$0.008	10.1%
EG-D Tier 1 post-SW	$0.127	$0.128 ~~0.129~~	$0.002	~~1.9~~ 1.3%
EG-D Tier 2 post-SW	$0.056	$0.073 ~~0.074~~	$0.017 ~~0.018~~	~~31.5~~ 30.5%
TLS-CI CA Rate (w/ CSITMA & CARB adders)[1]	$0.024	$0.032	$0.008	~~33.0~~ 31.2%
TLS-EG CA Rate (w/CARB adder)	$0.021	$0.029	$0.008	~~37.6~~ 35.6%
UBS $1,000/yr	$23,290	$0	($23,290)	-100.0%
BTS w/Balancing Accounts $/dth/d	$0.264	$0.262	($0.001)	-0.4%
System Average Rate w/ BTS	$0.280	$0.288	$0.008	~~2.9~~ 2.8%

1 CSITMA is the California Solar Initiative Program Adder
CARB adder is for CARB administrative fees.

[5] As of July 1, 2018, which is the effective date of updated rates incorporating Aliso Canyon Turbine Replacement revenue requirement per approved Advice Letter 5294-A.

SoCalGas' proposed rates include the regulatory account balances as reflected by witness S. Nasim Ahmed (Chapter 6), who presents the regulatory account balances amortized in current rates.

Table 2 below shows SDG&E's proposed 2020 class-average transportation rates and the resulting rate changes relative to the current rates.

Table 2R: Class Average Rates ($/therm)

	7/1/2018	TCAP Proposed	$/th Change	% Change
SDG&E:				
Res	$0.916	$0.926	$0.010	1.1%
CCI CA	$0.278	$0.333 ~~0.323~~	$0.055 ~~0.046~~	~~16.4~~ 19.8%
NGV Uncompressed post-SW	$0.113	$0.130	$0.017 ~~0.016~~	14.6%
Core Class Average	$0.665	$0.674 ~~0.671~~	$0.009 ~~0.006~~	~~0.8~~ 1.3%
NCCI-D	$0.117	$0.099	($0.018)	-15.4%
EG-D Tier 1 post-SW	$0.127	$0.129 ~~0.130~~	$0.002 ~~0.003~~	~~2.0~~ 1.4%
EG-D Tier 2 post-SW	$0.056	$0.073 ~~0.074~~	$0.017 ~~0.018~~	~~31.7~~ 30.8%
TLS-CI CA Rate (w/ CSITMA & CARB adders)[1]	$0.025	$0.032 ~~0.033~~	$0.008	~~32.6~~ 30.9%
TLS-EG CA Rate (w/CARB adder)	$0.021	$0.029	$0.008	~~38.4~~ 36.3%
System Average Rate	$0.298	$0.344 ~~0.342~~	$0.046 ~~0.044~~	~~14.8~~ 15.3%

1 CSITMA is the California Solar Initiative Program Adder
CARB adder is for CARB administrative fees.

SDG&E's proposed rates include the regulatory account balances as reflected by witness John Roy (Chapter 7), who presents the regulatory balances amortized in current rates.

Appendix A contains a complete set of rate tables for SoCalGas and SDG&E incorporating all the proposed cost allocation methods in this TCAP corresponding to Tables 1 and 2.

II. CORE RATE DESIGN

In this section, Applicants describe their respective individual core rate updates. For residential customers, the rate updates include Applicants' proposed increase in customer charge and the corresponding compensating decrease in volumetric rates.

A. Residential Rates

Residential rates apply to three categories of residential customers: single-family, multi-family, and small master-metered dwellings.[6] SoCalGas' current residential transportation rates structure consists of a fixed customer charge of about $5 per customer per month for customers who are not in the California Alternative Rates for Energy (CARE) program;[7] and a two-tiered volumetric rate, baseline and non-baseline, with the baseline rate lower than the non-baseline rate. The baseline rate and the non-baseline rates are related to each other through the concept of Composite tier differential, where a Composite baseline rate is defined by adding gas price and the customer charge revenues per unit of baseline volume to the baseline rate. The current tier differential between SoCalGas' composite baseline and non-baseline rates is 1.15.

For SDG&E, the current residential rate structure consists of about $3 per customer per month[8] minimum bill[9] and a two-tiered volumetric rate, baseline and non-baseline. SDG&E

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[6] SoCalGas' master meters with annual usage less than 100,000 therms, on weather-normalized basis, for the last two calendar years. SDG&E's residential rates apply to all master-metered customers.

[7] The Commission adopted the current $5 per month fixed customer charge for non-CARE customers in the 1993 BCAP (see D.94-12-052). In SoCalGas' tariff, customer charge is implemented as per-meter per-day charge (currently at $0.16438). Hence, the monthly customer charge varies slightly around $5 from month to month depending on the number of days in a month.

[8] The Commission adopted a $3 per month minimum bill in the last TCAP Phase 2 (see D.16-10-004) for non-CARE customers. In SDG&E's tariff, minimum bill charge is implemented as per-meter per-day charge (currently at $0.09863). Hence, the monthly minimum bill varies slightly around $3 from month to month depending on the number of days in a month.

[9] For SDG&E, a non-CARE residential customer pays, at a minimum, $3 per-month bill. If the customer's calculated gas bill based on the volume of gas used, comprising cost of gas, gas transportation cost and public purpose program surcharge (PPPS), exceeds $3 per month, then the $3 minimum bill no

never had a fixed customer charge, and prior to the last TCAP decision, SDG&E simply had two-tiered volumetric rates with baseline rate lower than the non-baseline rate.

1. SoCalGas' and SDG&E's Proposed Residential Customer Charges

In this TCAP, Applicants propose to implement a $10 per month residential non-CARE customer charge for both SoCalGas and SDG&E.[10] CARE customers would receive a 20% discount on the residential fixed charge, as they do on their other gas charges today. In the prior TCAP Phase 2 proceeding (A.15-07-014), the Commission did not adopt Applicants' $10 fixed non-CARE customer charge proposals.[11] Since that decision was rendered, the Commission issued D.17-09-035, *Decision Identifying Fixed Cost Categories to be Included in a Fixed Charge*. Issued in Pacific Gas and Electric Company's application to revise its electrical marginal costs, allocation, and rate design (A.16-06-013), the Commission made several key determinations which provide prescriptive guidance on how electric utilities should calculate and present fixed charge proposals. To be clear, this decision does not approve any specific fixed charges for any of the utilities.[12] However, by establishing "a process designed to ensure that any fixed charge that may be adopted in the future: (1) reflects appropriate costs; (2) is calculated using a consistent methodology across utilities; and (3) would be implemented after each utility has shifted to default time-of-use (TOU) rates,"[13] Applicants believe the Commission has articulated a process by which it would give due consideration to a fixed customer charge.

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longer applies and the customer pays the calculated bill. Under minimum bill, a customer pays either the $3 or the calculated bill whichever is higher.

[10] As with SoCalGas' and SDG&E's current tariffs, this charge would be implemented as per-meter per-day charge of $0.32877 per-meter, per-day. Hence, the monthly customer charge would vary slightly around $10 from month to month depending on the number of days in a month. For convenience, I refer to the customer charge proposal as $10 per month.

[11] See D.16-10-004.

[12] See D.17-09-035 at 41.

[13] Id. at 3-4.

Guided by this newly adopted process, Applicants are proposing a fixed customer charge in this TCAP.

Decision.17-09-035 identified fixed cost categories to be included in a fixed residential customer charge if electric utilities were to propose implementing residential fixed customer charge in their respective cost allocation and rate design proceedings. Such fixed cost categories eligible to be recovered in residential fixed customer charge for electric utilities are directly comparable to fixed cost categories for gas utilities. I discuss the Commission's findings and rationale articulated in that decision regarding residential fixed customer charges, which have applicability here in determining whether Applicants' non-CARE gas customers can be assessed a $10 fixed charge. Applicants propose a $10 fixed non-CARE customer charge, which would be consistent with the $10 fixed charge cap articulated by the Commission in D.17-09-035 with respect to electric non-CARE customer fixed charge proposals.[14]

2. A Review of D.17-09-035 on Issues Pertaining to Residential Fixed Customer Charge

In D.17-09-035, the Commission addressed multiple issues pertaining to residential fixed customer charge. They included (a) fixed cost categories that are appropriate for recovery through a fixed charge; (b) review of alternative methods to calculate marginal customer connection cost; (c) proper timing for the potential introduction of new or increased fixed charge; and (d) marketing, education and outreach efforts necessary prior to implement fixed charge. In the sections below, the Applicants will discuss each of these issues and how their proposed residential fixed charges in this TCAP follow the directives identified in the decision.

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[14] See Id. at 3.

a. Categories of Fixed Costs Appropriate for Recovery Through a Residential Fixed Customer Charge

The Commission identified "categories of fixed costs that could be included in the calculation of a fixed charge, in the event a fixed charge proposal is brought before the Commission for approval in future applications."[15] More specifically, the decision determined that "a fixed charge should include only revenue cycle services costs (costs for account set-up, metering services, billing and payment) with certain exclusions, all meter capital costs, and minimum service drop and final line transformer (FLT) costs calculated by using the minimum observed cost for residential class."[16] The decision suggested that the minimum observed costs for FLT and service drop could be the 10th or 20th percentile of respective cost distributions, or the average cost for the bottom 10% or 20%.[17] The decision also allowed for other approaches "as long as they are reasonably consistent with the 'minimum observed cost' approach we adopt here."[18]

While the decision focused on categories of fixed costs eligible for inclusion in a residential fixed customer charge for electric utilities, it is directly applicable to gas utilities.[19] In this TCAP, Applicants have calculated fixed costs eligible to be recovered in residential fixed customer charge following the Commission's directive in D.17-09-035: comprising of revenue cycle services costs, and minimum service line, regulator and meter costs.[20]

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[15] D.17-09-035 at 2.
[16] Id. at 2. See also p. 33, Table 2: Cost Category Eligibility for Inclusion in a Fixed Charge.
[17] See Id. at 44.
[18] Id.
[19] Gas utilities, like electric utilities, incur revenue cycle services costs. Measurement of gas usage requires installation of meters. The counterparts of electric service drop and final line transformer are, respectively, gas service line and regulator for gas utilities.
[20] To estimate minimum service line cost, SoCalGas multiplied the 20th percentile line length in feet for half-inch plastic pipe (the cheapest service line pipes) by the average cost of half-inch plastic pipe per foot. SoCalGas also used size 1 meter and regulator commonly used for residential customers. SDG&E

b. Alternative Methods to Calculate New Customer Connection Cost

In discussing marginal customer costs, the Commission stated,

> Because the Commission's goal has been to design and set rate structures based on marginal cost and cost-causation principles, among others, a major focus in R.12-06-013 and in this proceeding has been on marginal customer costs.[21]

The Commission recognized that marginal customer cost is the sum of revenue cycle services costs and new connection costs (comprising meter, service drop, and FLT).[22] Additionally, the Commission noted that parties mostly agreed with including revenue cycle services costs in a fixed customer charge.[23] However, the Commission did not adopt a single method to calculate new customer connection cost (capital-related customer cost).[24] Parties proposed different methods to calculate new customer connection cost,[25] including the Rental method and New Customer Only (NCO) method, both of which have been addressed in Applicants' prior cost allocation proceedings. In addition, the Commission addressed the Energy Division's two proposed alternative modifications to the Rental method, referred to as the Adjusted Rental methods.[26] The Commission directed the electric utilities to show the range of

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used the average of the 20% of the lowest-cost projects out of the 1,520 one-inch plastic pipe projects completed during January 2017 through June 2018.

[21] D.17-09-035 at 18.

[22] See Id.

[23] See Id.

[24] See Id. at 38.

[25] In this testimony, I use the terms new customer connection cost, capital-related marginal customer cost, and marginal customer capital cost interchangeably.

[26] D.17-09-035 at 34-39, contains a discussion of these methods. Also, see the Energy Division Staff Proposal on Adjusted Rental Method for Marginal Customer Cost in PG&E GRC Phase 2 (A.16-06-013) Second Fixed Cost Workshop (November 2, 2016).

marginal customer-related cost estimates using the Rental, NCO, and Adjusted Rental methods when they propose fixed charges in the future.[27]

Applicants have applied that Commission direction to calculate and present marginal customer-related costs under these methods. Table 3 (for SoCalGas) and Table 4 (for SDG&E) show the estimated costs derived under the four methods.[28]

Table 3: SoCalGas' Residential Minimum Connection Cost Per Month[29]

	Rental Method	NCO Method	Adjusted Rental Method 1	Adjusted Rental Method 2
	$22.21	$15.74	$10.11	$20.32

Table 4: SDG&E's Residential Minimum Connection Cost Per Month[30]

	Rental Method	NCO Method	Adjusted Rental Method 1	Adjusted Rental Method 2
	$16.56	$21.97	$5.77	$14.08

As shown in Tables 3 and 4, even the minimum estimates of the range of estimated customer-related costs would support $10 per month customer charges for SoCalGas and $5.00 per month for SDG&E. However, the Rental method is the only method that accurately captures marginal capital-related customer cost for the reasons I describe below. Tables 3 and 4 show that the Rental method would support a fixed residential customer charge as high as approximately $22 and $16 per month per customer, respectively, for SoCalGas and SDG&E;

[27] D.17-09-035 at 39.
[28] The NCO method includes replacement costs of service lines, regulators and meters for 1.5% of existing service lines (both SoCalGas and SDG&E), 1.8% of SoCalGas' meters and regulators, and 2.5% of SDG&E's meters and regulators.
[29] Source: witness Schmidt-Pines (Chapter 9).
[30] Source: witness Foster (Chapter 10).

however, as stated earlier, Applicants are proposing $10 per month per customer charge for SoCalGas and SDG&E.[31]

In D.17-09-035, the Commission defines marginal customer cost as the cost of providing service to an additional customer.[32] The Commission also identifies that "[n]ew connections costs are composed of costs associated with the investment required to provide access to a new customer . . ."[33] Algebraically, this can be expressed in basic marginal cost definition as follows:

$$\mathit{Marginal\ customer\ capital\ cost} = \frac{\Delta\ \mathit{in\ total\ capital\ cost}}{\Delta\ \mathit{in\ one\ additional\ customer}}$$

Marginal cost is defined for small additional units, in this case gas service to an additional customer. This is precisely how the Rental method calculates marginal customer capital cost. Trying to express the NCO method algebraically shows that it is inconsistent with the basic definition of marginal cost:

$$\mathit{NCO\ method\ customer\ capital\ cost} = \frac{\Delta\ \mathit{in\ total\ capital\ cost\ for\ all\ new\ customers}}{\mathit{all\ customers\ (existing\ and\ new)}}$$

As the above equation shows, the denominator captures <u>all customers</u>, not <u>a change in the number of customers, let alone change in one additional customer</u>. NCO is an average cost method, not a marginal cost method. If the Commission is seeking to determine a true marginal customer cost, it must reject the NCO method, as it does not calculate the cost of providing service to an additional customer.

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[31] The electric utilities have a maximum allowable residential fixed charge of $10 per month for non-CARE customers that can be adjusted by no more than the annual percentage increase in the Consumer Price Index for the prior calendar year (see D.17-09-035 at 3).
[32] See D.17-09-035 at 18, fn 29. See also D.92-12-058 at 11 and 38.
[33] D.17-09-035 at 55 Finding of Fact 9.

c. Adjusted Rental Methods

In A.16-06-013, the Commission's Energy Division proposed two alternative methods by adjusting marginal capital-related customer cost derived by the Rental method: Adjusted Rental Method 1 (ARM1) and Adjusted Rental Method 2 (ARM2).[34]

As a conceptual matter, underlying the proposed Adjusted Rental methods, and the notion that they would produce legitimate marginal capital cost, renowned Economist Alfred Kahn was quoted as a supporting source. The quote states in part, " . . . marginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that will be saved by producing one less unit."[35] This quote was applied in the context of marginal customer related cost as " . . . marginal cost is the cost of connecting one more customer; it can equally be envisaged as the cost that would be saved by connecting one fewer customer."[36] This application of Dr. Kahn's quote leads to the belief that neither the Rental nor the NCO method satisfied the basic symmetry property of marginal cost in that "[t]he cost of a new hookup (embodied in both methods) is not the same as the cost saved due to a permanent loss of an existing customer hookup."[37]

The rationale appears to be that since the cost of a new hookup is not the same as the cost saved due to a permanent loss of an existing customer, and the fact that both Rental and NCO methods rely on new hookup costs only, these methods are not appropriately calculating capital-related marginal customer costs. Accordingly, in such situations one must somehow include

[34] The ARM1 and ARM2 methods are being addressed here because I am providing an illustrative analysis guided by the directives articulated by the Commission in D.17-09-035 for electric utilities should they propose a fixed customer charge. I am not suggesting that Energy Division is a party to this TCAP or that ARM1 and ARM2 methods are being proposed in this proceeding.
[35] See Energy Division Staff Proposal on Adjusted Rental Method for Marginal Customer Cost in PG&E GRC Phase 2 (A.16-06-013) Second Fixed Cost Workshop, p. 2 (November 2, 2016). See Appendix B.
[36] Id.
[37] Id. at 6.

both the cost of new hookup and the cost saved due to a permanent loss of an existing customer to derive appropriate capital-related customer cost.

In fact, Dr. Kahn does not discuss any such symmetry property of marginal cost. To provide the proper context of Dr. Kahn's discussion of marginal cost, I provide from Dr. Kahn's book the expanded quote:

> . . . marginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that would be saved by producing one less unit. Looked at the first way, it may termed incremental cost—the added cost of (a small amount of) incremental output. Observed the second way, it is synonymous with avoidable cost—the cost that would be saved by (slightly) reducing output. (Although these three terms are often used synonymously, marginal cost, strictly speaking, refers to the additional cost of supplying a single, infinitesimally small additional unit, while "incremental" and "avoidable" are sometimes used to refer to the average additional cost of a finite and possibly a large change in production or sales.) Why does the economist argue that, ideally, every buyer ought to pay a price equal to the cost of supplying one incremental unit?[38]

Clearly, Dr. Kahn does not state or imply that the cost of producing one more unit must equal the cost that would be saved by producing one less unit. The last sentence in the quote is consistent the with definition of capital-related customer cost as the capital cost of one additional hookup. The cost of providing access to an additional customer will be different than the cost saved due to removing access to an existing customer.

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[38] Kahn, Alfred E., *The Economics of Regulation, Principles and Institutions,* The MIT Press, Cambridge, Massachusetts and London, England, 1988, pp. 65-66.

Mathematically, I attempt to show why ARM1 and ARM2 would not produce a true marginal cost result.

i. ARM1

ARM1 is mathematically depicted as follows:

$$ARM1\ MCAC = r1 * Rental\ MCAC \qquad (1)$$

Where,[39]

$$r1 = \frac{TSM\ rate\ base\ value}{TSM\ replacement\ cost\ new\ value}$$

The ARM1 method adjusts the Rental capital-related marginal customer cost downward by an adjustment factor (r1) which the ratio of system-wide TSM rate base value to all TSM (existing and new) valued at the Rental method capital-related marginal customer cost. Energy Division proposed this adjustment factor to be at the system level; however, at least conceptually, it is more appropriate to develop this adjustment factor using residential TSMs only since our focus here is on residential TSM marginal cost. For the analysis below, I assume that the adjustment factor is based on residential TSMs only, not system-wide TSMs. The Rental MCAC in the equation (1) above can be rewritten as:

$$Rental\ MCAC = TSM\ replacement\ cost\ new\ value * \left(\frac{RECC}{All\ residential\ customers}\right) \qquad (2)$$

Plugging in this expression for Rental MCAC into ARM1 in equation (1) above result in:

[39] MCAC is the capital-related component of marginal customer access cost,
r1 is a system value and not customer-class specific,
TSM is final line transformer, service drop and meter,
replacement cost new value is the rental calculation (before RECC is applied) summed over all the Utilities' customers, and RECC is real economic carrying cost.
Note: O&M are added after MCAC is calculated for both ARM1 MCAC and ARM2 MCAC.

$$ARM1\ MCAC = \left(\frac{TSM\ rate\ base\ value}{TSM\ replacement\ cost\ new\ value}\right) * TSM\ replacement\ cost\ new\ value$$

$$* \left(\frac{RECC}{All\ residential\ customers}\right) \qquad (3)$$

Cancelling the TSM replacement cost new value in the numerator and the denominator in equation (3) leads to:

$$ARM1\ MCAC = TSM\ ratebase\ value * \frac{RECC}{All\ residential\ customers} \qquad (4)$$

ARM1 is supposed to reflect an adjustment to new connection cost under the Rental method with the adjustment being "correction" to the Rental method for violating the "basic symmetry property" of marginal cost. However, equation (4) shows that ARM1 new connection cost does not depend on new connection cost at all; rather, it depends on the rate base value of residential TSMs attributable to all past customer hookups. ARM1, therefore, is a backward-looking embedded cost method, not a forward-looking marginal cost method. In D.17-09-035, the Commission made it clear that new connection costs are forward-looking.[40]

ii. ARM2

ARM2 is mathematically depicted as follows:

$$ARM2\ MCAC = r2 * Rental\ MCAC \qquad (5)$$

where,

$$r2 = \frac{TSM\ replacement\ cost\ new\ value\ less\ depreciation}{TSM\ replacement\ cost\ new\ value},$$

The ARM2 method adjusts the Rental capital-related marginal customer cost downward by an adjustment factor (r2) which the ratio of TSM replacement cost new value less

[40] See D.17-09-035 at 17, Table 1.

depreciation to TSM replacement cost new value. Again, this adjustment factor is proposed to be at the system level. As with ARM1, it is more appropriate to develop this adjustment factor using residential TSMs only since our focus here is on residential TSM marginal cost. Using similar steps described for ARM1 above, the ARM2 can be rewritten, assuming the r2 adjustment factor should be based on residential TSMs, not system-wide TSMs, as follows:

$$ARM2\ MCAC = TSM\ replacement\ cost\ new\ less\ depreciation * \frac{RECC}{All\ residential\ customers} \quad (6)$$

While ARM2 still requires the calculation of Rental capital-related marginal customer cost, lowering this marginal cost by an adjustment representing depreciation costs attributable to all past customer hookups violates the concept that new connection cost should be forward-looking.

As discussed above, the proposed adjustment to Rental method-based new connection cost to retain the so-called basic symmetry property of marginal cost is unsupported. Additionally, as demonstrated above, ARM1 simply depends on backward-looking rate base value, and, hence, an embedded cost method. By adjusting Rental method-based new connection cost using backward-looking depreciation, ARM2 does not portray a forward-looking concept of marginal cost. Therefore, if the Commission is seeking a true marginal cost, the Adjusted Rental methods would not produce this result.

d. Proper Timing of Potential New or Increased Residential Fixed Customer Charge

D.17-09-035 refers to an earlier Commission decision (D.15-07-001),[41] which established four conditions to be met prior to further consideration of introducing fixed residential customer charge for electric utilities. These four conditions are:[42]

(1) for each IOU, A GRC Phase 2 decision issues that approves a calculation of fixed charges. To accomplish this, each IOU, in its next GRC Phase 2, must provide sufficient evidence to identify and calculate fixed customer costs that are specifically intended to represent marginal customer costs that would be the basis of a fixed charge;

(2) a GRC Phase 2 decision issues approving categories of fixed costs for consideration of a future fixed charge;

(3) a decision in the IOU's 2018 residential rate design window that approves a new fixed charge request from the utility;

(4) default TOU rate is implemented.

The gas utilities' cost allocation and rate design proceedings are comparable to electric utilities' GRC Phase 2 proceedings in that both allocate authorized base margins that are determined in GRC or similar cost of service proceedings. Applicants believe that they have met the first condition above by estimating fixed customer costs following the directives in D.17-09-035 that specifically intended to represent marginal customer costs that are the basis for the Applicants' proposed fixed customer charge. Applicants believe that the categories of fixed

[41] D.15-07-001, Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-Of-Use Rates.
[42] See D.17-09-035 at 48-49.

costs identified in D.17-09-035 for consideration of a future fixed charge satisfy the second condition above. Applicants hope that the Commission will address the third condition in this TCAP proceeding. The fourth condition is not applicable to the gas utilities. In D.17-09-035, the Commission noted that the Office of Ratepayer Advocates and The Utility Reform Network (i.e., parties in that proceeding) recommended postponing the implementation of fixed charges for electric utilities until 2020.[43] The Commission's consideration of a residential fixed customer charge for natural gas for Applicants beginning in 2020 does not conflict with that recommended timing.

e. Marketing, Education and Outreach Efforts Necessary to Implement Residential Fixed Customer Charge

D.17-09-035 states, "[t]he Commission expects a showing on the plans for marketing, education, and outreach efforts with respect to the proposed fixed charges and in relation to the TOU rates and in compliance with the directives of D.15-07-01, if and when, a utility files a proposal for a fixed charge."[44] The marketing, education and outreach efforts are particularly important for the electric utilities because of significant electric residential rate reforms comprising of tier consolidation, flattening of tier differentials and the introduction TOU rates. On the gas side, there has been no such rate reforms. In addition, SoCalGas already has a residential fixed customer charge. The Applicants are not proposing any marketing, education and outreach efforts pertaining to their proposed fixed customer charges in this TCAP application. However, the Applicants will undertake any such marketing, education and outreach efforts that the Commission deems necessary.

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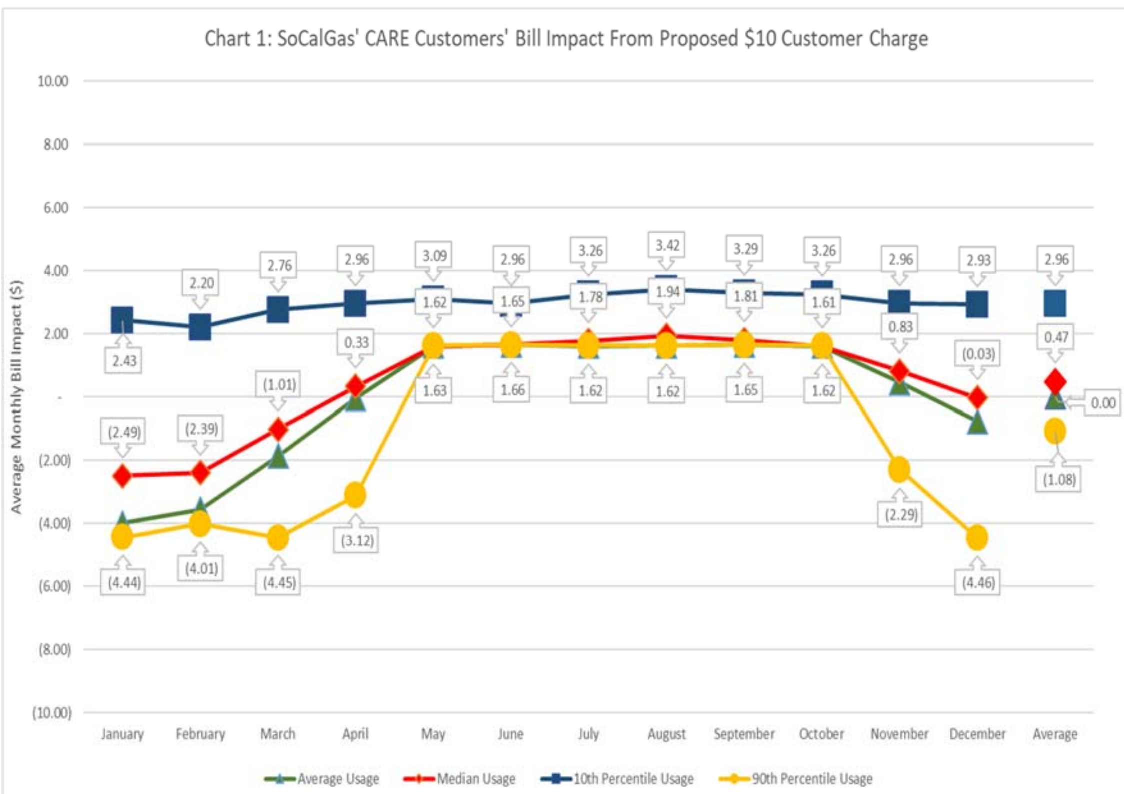
[43] See Id. at 48.
[44] Id. at 52.

3. Bill Impacts of Proposed Residential Customer Charge

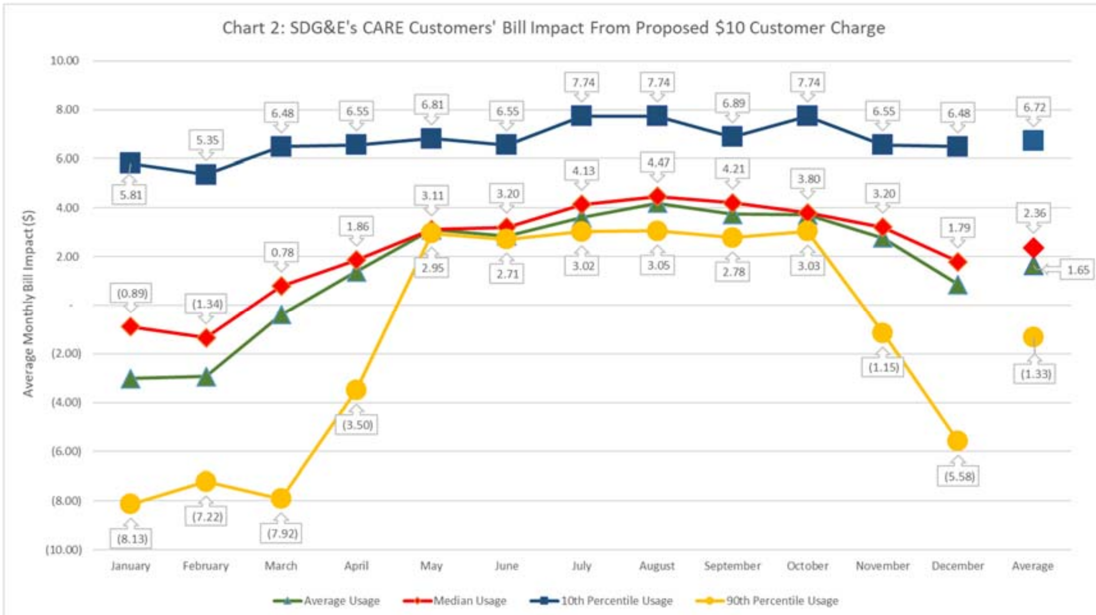
To evaluate the bill impacts of their proposed $10 per month customer charge and compensating lower volumetric rates on low income customers, the Applicants focused on their CARE customers' bills. Based on 2017 gas usage data for CARE customers, the Applicants estimated monthly bill impacts under four alternative gas usage scenarios: average, median, 10th percentile and 90th percentile usage.[45] The Applicants chose the 10th percentile usage scenario to represent low usage customers and the 90th percentile usage scenario to represent high usage customers. Charts 1 and 2 below show the monthly bill impacts for the four usage scenarios for CARE customers, respectively, for SoCalGas and SDG&E.



[45] 10th percentile usage means that 10% of the CARE customers' gas usage is at or below the 10th percentile usage level. 90th percentile usage means that 90% of the CARE customers' gas usage is at or below the 90th percentile usage level (10% of the CARE customers gas usage is above the 90th percentile usage level). As of December 2017, SoCalGas and SDG&E had 1,552,775 and 172,013 CARE customers, respectively.

Chart 1, shows bill impact for each month, as well as average monthly bill impact for SoCalGas' CARE customers for the four usage scenarios I described above. The bill impacts capture the difference in bills between SoCalGas' proposed $10 per month customer charge and status quo $5 per month customer charge. A positive monthly bill impact value reflects that the monthly bill will increase under the proposed $10 per month customer charge relative to the status quo $5 per month customer charge. Similarly, a negative monthly bill impact value reflects that the monthly bill will decrease under the proposed $10 per month customer charge relative to the status quo $5 per month customer charge.

For low gas usage (10th percentile) CARE customers, Chart 1 shows that the monthly bill is expected to increase every month, with an average monthly bill increase of $2.96 per month. For a CARE customer with median gas usage, average monthly bill will likely increase by $0.47 per month; however, such a customer's winter bills will be lower when the gas bills are generally higher due to heating load. For a CARE customer with average usage, average monthly bill will likely remain the same; however, such a customer's winter bills will be lower when the gas bills are generally higher due to heating load. For high usage (90th percentile) CARE customers, the average monthly bill is likely to be lower by $1.08 per month, with higher decreases in winter months.



The bill impacts in Chart 2 capture the difference in bills between SDG&E's proposed $10 per month customer charge and the status quo $3 per month minimum bill. For low gas usage (10th percentile) CARE customers, Chart 2 shows that the monthly bill is expected to increase every month, with an average monthly bill increase of $6.72 per month. For a CARE customer with median gas usage, average monthly bill will likely increase by $2.36 per month; however, such a customer's winter bills for some winter months will be lower when the gas bills are generally higher due to heating load. For a CARE customer with average usage, average monthly bill will likely increase by $1.65 per month; however, such a customer's winter bills will be lower for some winter months when the gas bills are generally higher due to heating load. For high usage (90th percentile) CARE customers, the average monthly bill is likely to be lower by $1.33 per month, with higher decreases in winter months.

In the past, some parties have opposed the introduction of customer charge for SDG&E and an increase in customer charge for SoCalGas on the grounds that such customer charges will lead to bill increases for low income customers with low gas usage. While this is true, it is also true that there are low income customers with relatively high gas usage who would benefit from the Applicants' proposed $10 per month customer charges. As demonstrated above, these CARE customers with relatively high gas usage will benefit from the Applicants' proposed customer charges through lower monthly bills, particularly during winter months when their bills are high. In evaluating the Applicants' proposed customer charges, the Commission should keep this low income higher usage customer segment in mind.

In the last TCAP decision, D.16-10-004, the Commission correctly noted that the proposed $10 customer charge leads to much higher bill impacts for SDG&E's residential customers compared to those for SoCalGas. Comparing the monthly bill impacts in Chart 1 and Chart 2 above, the Applicants also noticed that the bill impacts are higher (both positive and negative) for SDG&E's CARE customers relative to those for SoCalGas' CARE customers. This is because SDG&E never had a customer charge and the $10 customer charge (a movement from $0 to $10) leads to higher bill impacts for SDG&E's residential customers relative to SoCalGas' residential customers (a movement from $5 to $10). This is precisely the reason that the Commission should introduce a customer charge now for SDG&E. The longer the Commission waits to introduce a specific customer charge for SDG&E, the more difficult it will get because the bill impacts attributable to the introduction of a customer charge are likely get larger over time. A large bill impact should not dissuade the Commission from introducing a customer charge or increasing a customer charge. In D.17-09-035, the Commission noted that "Joint Utilities suggest that any bill impacts that are deemed excessive could be resolved through a reasonable phase-in process. We find merit in exploring this option in the relevant rate design proceedings."[46]

[46] D.17-09-035 at 49.

B. Submeter Credit

Submeter credits apply to utility customers with a master meter who provide gas service to residential sub-units (*e.g.*, multi-family dwelling units and mobile home parks). D.04-04-043 established a method for calculating submeter credits. In that decision, certain categories of costs were defined as "Utility Avoided Costs," the costs that utilities avoid for which a master meter customer is reimbursed through the submeter credit provided by the utility.[47] In this proceeding, the Applicants' proposed submeter credits are based on an updated study in compliance with the methodology set forth in D.04-04-043, and as was used most recently to update the submeter credits in the 2017 TCAP (Phase 2) approved by D.16-10-004. Currently, SoCalGas' submeter credit is set at $0.27386 /meter/day and SoCalGas proposes to set it at $0.13742/meter/day for this TCAP term.[48]

SDG&E's submeter credits are currently set at $0.38268/meter/day for multi-family (GS) customers and $0.40932/meter/day for mobile home (GT) customers. SDG&E proposes to set them at $0.26499/meter/day and $0.28570/meter/day, respectively, for this TCAP term.[49]

C. Core C&I Rates

SoCalGas and SDG&E each have a single tariff serving its core commercial and industrial (C&I) customers, Schedule G-10 for SoCalGas and Schedule GN-3 for SDG&E. Presently, SoCalGas' G-10 rate design consists of a $15 customer charge and three tiers of

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[47] To the extent these costs do not exceed the average costs that a utility would have incurred in providing direct service sub-unit customers.

[48] Per the method for calculating submeter credit, SoCalGas' proposed $10 per month customer has the effect of lowering submeter credit relative to that in current rates.

[49] Per the method for calculating submeter credit, SDG&E's proposed $10 per month customer has the effect of lowering submeter credit relative to that in current rates.

declining block volumetric rates. SDG&E's GN-3 rate design consists of a $10 customer charge and three tiers of declining block volumetric rates.

In D.16-10-004, the Commission-approved settlement retained the then-existing rate structure for the different tiers within SoCalGas' G-10 rate design and SDG&E's GN-3 rate design. Neither SoCalGas nor SDG&E proposes any changes to the current methodology.

D. Natural Gas Vehicle (NGV) Compression Rate Adder

A compression surcharge or compression rate adder is intended to cover the cost of providing compressed natural gas (CNG) to motor vehicles fueling at public access CNG vehicle refueling stations owned and operated by Applicants. The compression rate adder is charged to customers on a volumetric basis. This adder is incremental to the uncompressed commodity charge and transportation charge. The compression rate adder reflects the capital and operating costs of compressing the natural gas and providing public access to CNG fuel for NGV owners. Additional state fuel tax, federal excise tax, and utility user taxes, which can vary by location, are also charged to customers. Currently, there is a Sempra-wide[50] compression rate adder across both SoCalGas and SDG&E. Therefore, the compression rate adders for SoCalGas and SDG&E are nearly identical, with only a small difference due to differences in the Franchise Fees and Uncollectibles between the utilities.

In this TCAP, Applicants have updated the NGV compression rate adders to reflect current costs. These costs are composed of a capital-related revenue requirement related to public-access refueling equipment and a fully-loaded O&M-related revenue requirement. The Sempra-wide NGV compression rate adder is derived by dividing the combined SoCalGas and

[50] Sempra-wide rate refers to the calculation of a single rate between SoCalGas and SDG&E for a customer class, before applying utility-specific adders, such as Franchise Fees and Uncollectibles.

SDG&E compression cost revenue requirements by the combined demand forecast for compressed NGV volumes.[51] The resulting NGV compression rate adders proposed for this TCAP term are $1.04238 per therm and $1.04809 per therm for SoCalGas and SDG&E, respectively.

III. NONCORE RATE DESIGN

A. Noncore Distribution Rates

Applicants' current distribution-level service for noncore C&I and electric generation (EG) customers is provided under Schedule GT-NC for SoCalGas and Schedules GTNC and EG for SDG&E. The current noncore C&I rate design consists of a customer charge of $350 per month for both the utilities, four tiers of declining block volumetric rates for SoCalGas and a single tier volumetric rate for SDG&E. For EG customers, there are Sempra-wide rates; small EG customers pay a $50 customer charge and a volumetric rate, and large EG customers pay a lower volumetric rate. Neither SoCalGas nor SDG&E proposes any changes to the current methodology.

B. Transmission Level Service Rates

Applicants' current Sempra-wide rates for transmission-level service customers are provided under Schedule GT-TLS for SoCalGas and Schedule TLS for SDG&E. The current rate design consists of a class-average volumetric rate option and a reservation rate option for customers served off of the transmission system. Neither SoCalGas nor SDG&E proposes any changes to the current methodology.

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[51] The compressed NGV volumes are presented by witness Rose-Marie Payan (Chapter 3).

IV. OTHER PROPOSALS

A. Allocation of Self Generation Incentive Program (SGIP) Funds Based on Program Participation

Currently, SGIP Costs are allocated across all customer classes based on equal cents per therm, which means that all customers are allocated the same cost per therm of natural gas usage. On April 26, 2018, the Commission adopted Resolution E-4926, which requires the allocation of SGIP funds to be based on program participation over the previous three years. Per the Resolution, going forward, SGIP costs will be allocated across customer classes based on each class's past program participation. A re-allocation of SGIP costs based on program participation will align customer class participation with their respective program costs. As stated by the Commission, "SGIP cost allocation should be consistent with the Legislative intent to provide equitable allocation of costs and benefits."[52]

The resolution recommends that "[t]he allocation methodology should be based on actual incentives paid out and should take into account the impact of program changes as they occur."[53] The proposed allocation method conforms to the Commission's directive by totaling the incentives awarded in the most recent 3 years and allocating funds based on the percentage of incentives disbursed to each class.

Pursuant to Resolution E-4926, I used three years of data (in this case, May 30, 2015 through May 30, 2018) to calculate the proposed allocation percentages. Tables 5 and 6 below show proposed SGIP cost allocation percentages based on previous three years' program participation and the current allocation percentages across customer classes for SoCalGas and SDG&E, respectively. As directed in Resolution E-4926, these allocation percentages will be

[52] Resolution E-4926 at 18, Finding 4.
[53] Id. at 19, Finding 4.

updated each year based on the most recent three years of actual data. The updated allocations will be presented for approval in Applicants' Regulatory Account Update advice letter submissions in October each year.

Table 5: SoCalGas SGIP Cost Allocation

Class	3 Year Total Incentives Paid	Proposed % Allocation	Current % Allocation
Residential	$38,448	0.1%	25.9%
Core C&I	$356,733	1.3%	10.9%
Noncore EG	$28,023,417	98.6%	28.4%
Other Noncore	$0	0.0%	32.9%
Other Core	$0	0.0%	1.9%
Total	**$28,418,597**	**100.0%**	**100.0%**

Table 6R: SDG&E SGIP Cost Allocation

Class	3 Year Total Incentives Paid	Proposed % Allocation	Current % Allocation
Residential	$34,564	0.4%	85.7%
Core C&I	$7,259,875 ~~936,060~~	~~11.9~~ 91.3%	11.0%
Noncore EG	$660,000 ~~6,900,054~~	~~87.7~~ 8.3%	2.0%
Other Noncore	$0	0.0%	0.9%
Other Core	$0	0.0%	0.4%
Total	**$7,954,439 ~~7,870,677~~**	**100.0%**	**100.0%**

B. New Regulatory Accounts

1. Storage Inventory for Balancing Function Memorandum Account (SIBFMA)

As discussed in Chapter 6 (Ahmed), SoCalGas is proposing to establish the Storage Inventory for Balancing Function Memorandum Account (SIBFMA). As discussed in Chapter 1 (Dandridge), Applicants propose that SoCalGas procure up to eight billion cubic feet (Bcf) of gas for 8% monthly balancing due to customers' creating negative cumulative imbalances. Because the costs recorded in the SIBFMA relate to the balancing function, SoCalGas proposes to allocate the SIBFMA balance across customer classes based on each class's share of average year throughput (i.e., equal cents per therm), the same method currently used for allocating load balancing storage costs.

2. Reliability Function Cost Memorandum Account (RFCMA)

As discussed in Chapter 6 (Ahmed), SoCalGas is proposing to establish the Reliability Function Cost Memorandum Account (RFCMA). The purpose of the RFCMA is to record the revenue requirement on the gas purchase and transportation costs for procuring 21 Bcf of gas needed to provide withdrawal capability for daily operational needs throughput the year, as discussed in Chapter 1 (Dandridge). SoCalGas proposes a two-step approach to allocate the RFCMA balance across customer classes, which would be consistent with how the corresponding 21 Bcf of reliability function inventory capacity is allocated to customer classes. The first step is to split the RFCMA balance based on core storage inventory and load balancing inventory. In the second step, SoCalGas proposes to allocate the Core storage inventory component of the RFCMA using the method discussed in Chapter 5 (Guo), Table 14, and the load balancing inventory component of the RFCMA using average year throughput to all customer classes.

This concludes my revised prepared direct testimony.

V. QUALIFICATIONS

My name is Iftekharul (Sharim) Bar Chaudhury. I am employed by SoCalGas and SDG&E as the Rate Design and Demand Forecasting Manager within the CPUC/FERC Gas Regulatory Affairs Department, which supports gas regulatory activities of both SoCalGas and SDG&E. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011.

I hold a Bachelor of Arts degree in Economics from Illinois State University. I received my Masters and Ph.D. degrees in Economics from the University of California, San Diego.

I have held my current position managing the rates group since August 2014, and have been managing the demand forecasting group since April 2013. Prior to joining SoCalGas, I worked at Southern California Edison Company from June 1999 to March 2013, holding several positions of increasing responsibility, from Senior Analyst to Manager of Price Forecasting to Manager of Long-Term Demand Forecasting. From October 1998 to May 1999, I worked at the National Economic Research Associates (NERA) as a Senior Consultant. Prior to joining NERA, I worked at SoCalGas from 1991 to 1998, holding several positions of increasing responsibility, starting as Marketing Analyst to Senior Economist in the Rate Design group to Manager of Rate Design. I also worked for about a year at the California Energy Commission in the Demand Analysis Office.

I have previously testified before this Commission.

APPENDIX A

TABLE 1R
Natural Gas Transportation Rates
Southern California Gas Company
2020 TCAP Application

		Proposed Rates			Proposed Rates			Changes		
		Jul-1-18 Volumes Mth	Proposed Rate $/therm	Jul-1-18 Revenues $000's	Jan-1-20 Volumes Mth	Proposed Rate $/therm	Jan-1-20 Revenues $000's	Revenue Change $000's	Rate Change $/therm	% Rate change %
		A	B	C	D	E	F	G	H	I
1	CORE									
2	Residential	2,435,160	$0.74844	$1,822,559	2,346,353	$0.74327	$1,743,983	($78,576)	($0.00516)	-0.7%
3	Commercial & Industrial	1,023,186	$0.32464	$332,163	992,706	$0.38015	$377,375	$45,212	$0.05551	17.1%
4										
5	NGV - Pre Sempra-Wide	157,095	$0.12882	$20,237	178,769	$0.14815	$26,485	$6,248	$0.01933	15.0%
6	Sempra-Wide Adjustment	157,095	($0.00166)	($260)	178,769	($0.00163)	($292)	($32)	$0.00002	-1.3%
7	NGV - Post Sempra-Wide	157,095	$0.12716	$19,977	178,769	$0.14652	$26,193	$6,216	$0.01935	15.2%
8										
9	Gas A/C	772	$0.15436	$119	416	$0.15858	$66	($53)	$0.00422	2.7%
10	Gas Engine	20,699	$0.16141	$3,341	22,302	$0.16318	$3,639	$298	$0.00177	1.1%
11	Total Core	3,636,911	$0.59890	$2,178,159	3,540,545	$0.60761	$2,151,256	($26,903)	$0.00870	1.5%
12										
13	NONCORE COMMERCIAL & INDUSTRIAL									
14	Distribution Level Service	865,102	$0.07674	$66,392	919,735	$0.08450	$77,716	$11,323	$0.00775	10.1%
15	Transmission Level Service (2)	660,238	$0.02441	$16,114	626,080	$0.03205	$20,063	$3,949	$0.00764	31.3%
16	Total Noncore C&I	1,525,339	$0.05409	$82,506	1,545,814	$0.06325	$97,779	$15,272	$0.00916	16.9%
17										
18	NONCORE ELECTRIC GENERATION									
19	Distribution Level Service									
20	Pre Sempra-Wide	285,096	$0.08176	$23,310	331,442	$0.09191	$30,464	$7,155	$0.01015	12.4%
21	Sempra-Wide Adjustment	285,096	($0.00626)	($1,784)	331,442	($0.00357)	($1,184)	$600	$0.00268	-42.9%
22	Distribution Post Sempra Wide	285,096	$0.07550	$21,525	331,442	$0.08834	$29,280	$7,755	$0.01284	17.0%
23	Transmission Level Service (2)	2,392,699	$0.02064	$49,379	2,246,336	$0.02823	$63,409	$14,030	$0.00759	36.8%
24	Total Electric Generation	2,677,795	$0.02648	$70,904	2,577,778	$0.03596	$92,688	$21,784	$0.00948	35.8%
25										
26	TOTAL RETAIL NONCORE	4,203,134	$0.03650	$153,411	4,123,593	$0.04619	$190,467	$37,056	$0.00969	26.5%
27										
28	WHOLESALE									
29	Wholesale Long Beach (2)	73,520	$0.02035	$1,496	79,646	$0.02794	$2,225	$729	$0.00759	37.3%
30	Wholesale SWG (2)	65,367	$0.02035	$1,330	66,431	$0.02794	$1,856	$526	$0.00759	37.3%
31	Wholesale Vernon (2)	95,137	$0.02035	$1,936	96,890	$0.02794	$2,707	$771	$0.00759	37.3%
32	International (2)	91,378	$0.02035	$1,860	116,299	$0.02794	$3,250	$1,390	$0.00759	37.3%
33	Total Wholesale & International	325,403	$0.02035	$6,623	359,267	$0.02794	$10,038	$3,415	$0.00759	37.3%
34	SDG&E Wholesale	1,251,556	$0.01483	$18,558	1,118,614	$0.02195	$24,556	$5,998	$0.00712	48.0%
35	Total Wholesale Incl SDG&E	1,576,959	$0.01597	$25,181	1,477,881	$0.02341	$34,595	$9,414	$0.00744	46.6%
36										
37	TOTAL NONCORE	5,780,093	$0.03090	$178,592	5,601,473	$0.04018	$225,062	$46,470	$0.00928	30.0%
38										
39	Unbundled Storage (4)			$23,290			$0	($23,290)		
40	System Total (w/o BTS)	9,417,004	$0.25274	$2,380,041	9,142,019	$0.25993	$2,376,317	($3,724)	$0.00719	2.8%
41	Backbone Transportation Service BTS (3)	2,690	$0.26353	$258,736	2,690	$0.26245	$257,673	($1,063)	($0.00108)	-0.4%
42	**SYSTEM TOTAL w/BTS**	**9,417,004**	**$0.28021**	**$2,638,777**	**9,142,019**	**$0.28812**	**$2,633,991**	**($4,786)**	**$0.00791**	**2.8%**
43										
44	EOR Revenues	231,570	$0.05313	$12,303	208,941	$0.07108	$14,851	$2,548	$0.01795	33.8%
45	Total Throughput w/EOR Mth/yr	9,648,574			9,350,960					

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter." The Backbone Transportation Service (BTS) rate is for service from Receipt Point to Citygate.
2) These Transmission Level Service (TLS) amounts represent the average transmission rate, see Table 7 for detailed list of TLS rates.
3) BTS charge ($/dth/day) is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge. Charge is for both core and noncore customers
4) Unbundled Storage costs are not part of the Core Storage or Load Balancing functions (those are included in transport rates).
5) All rates include Franchise Fees & Uncollectible charges.

TABLE 2R
Residential Transportation Rates
Southern California Gas Company

		Present Rates			Proposed Rates			Changes		
		Jul-1-18 Volumes Mth A	Average Rate $/th B	Jul-1-18 Revenue $000's C	Jan-1-20 Volumes Mth D	Rate $/th E	Jan-1-20 Revenue $000's F	Revenue Change $000's G	Rate Change $/th H	% Rate change % I
1	RESIDENTIAL SERVICE									
2	Customer Charge									
3	Single Family	3,750,414	$5.00	$225,025	3,808,652	$10.00	$457,038	$232,013	$5.00000	100.0%
4	Multi-Family	1,743,024	$5.00	$104,581	1,784,011	$10.00	$214,081	$109,500	$5.00000	100.0%
5	Small Master Meter	124,314	$5.00	$7,459	121,819	$10.00	$14,618	$7,159	$5.00000	100.0%
6	Submeter Credit-$/unit/day	148,373	($0.27386)	($14,831)	141,547	($0.13742)	($7,100)	$7,731	$0.13644	-49.8%
7	**Volumetric Transportation Rate Exclude CSITMA and CAT:**									
8	Baseline Rate	1,839,570	$0.53602	$986,048	1,707,243	$0.30499	$520,696	($465,351)	($0.23103)	-43.1%
9	Non-Baseline Rate	584,298	$0.86474	$505,266	630,017	$0.84940	$535,138	$29,872	($0.01534)	-1.8%
10		2,423,869	$0.74820	$1,813,547	2,337,260	$0.74210	$1,734,472	($79,075)	($0.00611)	-0.8%
11	NBL/BL Ratio:									
12	Composite Rate $/th		$1.02367			$0.97937			($0.04430)	-4.3%
13	Gas Rate $/th		$0.31248			$0.27687			($0.03561)	-11.4%
14	NBL/Composite rate ratio (4) =		1.15			1.15				
15	NBL- BL rate difference $/th		0.32872			0.54441			$0.21569	65.6%
16										
17	Large Master Meter Rate (Excludes Rate Adders for CAT):									
18	Customer Charge	57	$411.17	$280	49	$411.17	$244	($36)	$0.00	0.0%
19	Baseline Rate	9,428	$0.24993	$2,356	7,787	$0.12454	$970	($1,387)	($0.12539)	-50.2%
20	Non-Baseline Rate	1,863	$0.40321	$751	1,306	$0.34684	$453	($298)	($0.05636)	-14.0%
21		11,291	$0.30004	$3,388	9,093	$0.18327	$1,666	($1,721)	($0.11677)	-38.9%
22										
23	**Residential Rates Include CSITMA, CARB and GHG Excludes CAT:**									
24	CSITMA Adder to Volumetric Rate	1,800,739	$0.00308	$5,550	1,745,667	$0.00311	$5,421	($129)	$0.00002	0.8%
25	CARB Adder to Volumetric Rate				2,346,353	$0.00101	$2,378			
26	GHG End User Adder to Volumetric Rate				2,346,353	$0.00000	$0			
25	Residential:									
26	Customer Charge		$5.00			$10.00			$5.00000	100.0%
27	Baseline $/therm		$0.53910			$0.30911			($0.22999)	-42.7%
28	Non-Baseline $/therm		$0.86782			$0.85352			($0.01430)	-1.6%
29	Average NonCARE Rate $/therm		$0.75129			$0.74622			($0.00507)	-0.7%
30	Large Master Meter:									
31	Customer Charge		$411.17			$411.17			$0.00	0.0%
32	BaseLine Rate		$0.25302			$0.12866			($0.12436)	-49.1%
33	Non-Baseline Rate		$0.40629			$0.35096			($0.05533)	-13.6%
34	Average NonCARE Rate $/therm		$0.30312			$0.18739			($0.11573)	-38.2%
35	**Residential Rates Include CSITMA & CAT:**									
36	CAT Adder to Volumetric Rate	49,671	$0.00150	$74	27,389	$0.00167	$46	($29)	$0.00017	11%
37	Residential:									
38	Customer Charge		$5.00			$5.00			$0.00000	0.0%
39	BaseLine Rate		$0.54060			$0.31078			($0.22982)	-42.5%
40	Non-Baseline Rate		$0.86932			$0.85519			($0.01413)	-1.6%
41	Large Master Meter:									
42	Customer Charge		$411.17			$411.17			$0.00000	0.0%
43	BaseLine Rate		$0.25452			$0.13033			($0.12419)	-48.8%
44	Non-Baseline Rate		$0.40779			$0.35263			($0.05516)	-13.5%
45	**Other Adjustments:**									
46	TCA for CSITMA exempt customers		($0.00308)			($0.00311)			($0.00002)	0.8%
47	California Climate Credit - April Bill		$0.00			$0.00				
48	**TOTAL RESIDENTIAL**	**2,435,160**	**$0.74844**	**$1,822,559**	**2,346,353**	**$0.74327**	**$1,743,983**	**($78,576)**	**($0.00516)**	**-0.7%**

See footnotes, Table 1.

TABLE 3R
Core Nonresidential Transportation Rates
Southern California Gas Company

		Present Rates			Proposed Rates			Changes		
		Jul-1-18 Volumes Mth	Average Rate $/th	Jul-1-18 Revenue $000's	Jan-1-20 Volumes Mth	Rate $/th	Jan-1-20 Revenue $000's	Revenue Change $000's	Rate Change $/th	% Rate change %
		A	B	C	D	E	F	G	H	I
1										
2	CORE COMMERCIAL & INDUSTRIAL									
3	Customer Charge 1	146,202	$15.00	$26,316	141,378	$15.00	$25,448	($868)	$0.00	0.0%
4	Customer Charge 2	61,115	$15.00	$11,001	62,136	$15.00	$11,185	$184	$0.00	0.0%
5	**Volumetric Transportation Rate Exclude CSITMA & CAT:**									
6	Tier 1 = 250th/mo	203,321	$0.54303	$110,409	202,399	$0.65197	$131,959	$21,549	$0.10894	20.1%
7	Tier 2 = next 4167 th/mo	453,170	$0.29523	$133,789	449,431	$0.34796	$156,385	$22,596	$0.05273	17.9%
8	Tier 3 = over 4167 th/mo	366,694	$0.12908	$47,333	340,876	$0.14413	$49,129	$1,796	$0.01504	11.7%
9		1,023,186	$0.32140	$328,849	992,706	$0.37685	$374,105	$45,256	$0.05546	17.3%
10										
11	**Volumetric Transportation Rate Include CSITMA & GHG, Exclude CAT:**									
12	CSITMA Adder to Volumetric Rate	1,008,238	$0.00308	$3,107	978,185	$0.00311	$3,038	($70)	$0.00002	0.8%
13	GHG Adder to Volumetric Rate	1,023,186	$0.00000	$0	992,706	$0.00000	$0			
14	Tier 1 = 250th/mo		$0.54611			$0.65508			$0.10897	20.0%
15	Tier 2 = next 4167 th/mo		$0.29831			$0.35107			$0.05276	17.7%
16	Tier 3 = over 4167 th/mo		$0.13216			$0.14723			$0.01507	11.4%
17			$0.32448			$0.37996			$0.05548	
18	**Volumetric Transportation Rate Include CSITMA & CAT:**									
19	CAT Adder to Volumetric Rate	137,753	$0.00150	$206	139,308	$0.00167	$232	$26	$0.00017	11%
20	Tier 1 = 250th/mo		$0.54761			$0.65675			$0.10914	19.9%
21	Tier 2 = next 4167 th/mo		$0.29981			$0.35274			$0.05293	17.7%
22	Tier 3 = over 4167 th/mo		$0.13366			$0.14890			$0.01524	11.4%
23			$0.32598			$0.38163			$0.05565	17.1%
24	Other Adjustments:									
25	TCA for CSITMA exempt customers		($0.00308)			($0.00311)			($0.00002)	0.8%
26	GHG Fee Credit $/th		$0.00000			$0.00000				
27	**TOTAL CORE C&I**	**1,023,186**	**$0.32464**	**$332,163**	**992,706**	**$0.38015**	**$377,375**	**$45,212**	**$0.05551**	**17.1%**
28										
29	NATURAL GAS VEHICLES (a sempra-wide rate)									
30	Customer Charge, P-1	229	$13.00	$36	263	$13.00	$41	$5	$0.00000	0.0%
31	Customer Charge, P-2A	130	$65.00	$101	115	$65.00	$90	($11)	$0.00000	0.0%
32	Uncompressed Rate Exclude CSITMA, GHG & CAT	157,095	$0.10943	$17,192	178,769	$0.12515	$22,373	$5,181	$0.01571	14.4%
33	Total Uncompressed NGV	157,095	$0.11031	$17,329	178,769	$0.12588	$22,504	$5,175	$0.01557	14.1%
34	Compressed Rate Adder	2,099	$1.03136	$2,164	2,833	$1.04238	$2,953	$789	$0.01102	1.1%
35										
36	**Uncompressed Rate Include CSITMA, CARB and GHG Exclude CAT**									
37	CSITMA Adder to Volumetric Rate	157,073	$0.00308	$484	178,769	$0.00311	$555	$71	$0.00002	0.8%
38	CARB Adder to Volumetric Rate				178,769	$0.00101	$181			
39	GHG End User Adder to Volumetric Rate				178,769	$0.00000	$0			
40	Uncompressed Rate $/therm		$0.11252			$0.12927			$0.01675	14.9%
41	**Other Adjustments:**									
42	TCA for CSITMA exempt customers		($0.00308)			($0.00311)			($0.00002)	0.8%
43	Low Carbon Fuel Standard (LCFS) Credit		$0.00000			$0.00000			$0.00000	
44	**TOTAL NGV SERVICE**	**157,095**	**$0.12716**	**$23,609**	**178,769**	**$0.14652**	**$26,193**	**$2,583**	**$0.01935**	**15.2%**
45										
46	RESIDENTIAL NATURAL GAS VEHICLES (optional rate)									
47	Customer Charge	5,618	$10.00	$674	216	$10.00	$26	($648)	$0.00000	0.0%
48	**Uncompressed Rate Exclude CSITMA & CAT**	5,501	$0.20696	$1,138	166	$0.28631	$48	($1,091)	$0.07936	38.3%
49		5,501	$0.32951	$1,813	166	$0.44207	$73	($1,739)	$0.11256	34.2%
50	**Uncompressed Rate Include CSITMA, Exclude CAT**									
51	CSITMA Adder to Volumetric Rate		$0.00308		5,501	$0.00311	$17		$0.00002	0.8%
52	CARB Adder to Volumetric Rate				5,501	$0.00101	$6			
53	GHG End User Adder to Volumetric Rate				5,501	$0.00000	$0			
54	Uncompressed Rate $/therm		$0.21004			$0.29043			$0.08039	38.3%
55										
56	**Uncompressed Rate Include CSITMA & CAT**									
57	CAT Adder to Volumetric Rate	0	$0.00150	$0	0	$0.00167	$0	$0	$0.00017	11.3%
58	Uncompressed Rate		$0.21154			$0.29210		$0	$0.08056	38.1%
59	Other Adjustments:									
60	TCA for CSITMA exempt customers		($0.00308)			($0.00311)			($0.00002)	0.8%
61										
62	**TOTAL RESIDENTIAL NATURAL GAS VEHICLES**	**5,501**	**$0.32951**	**$1,813**	**166**	**$0.57843**	**$96**	**($1,716)**	**$0.24892**	**75.5%**

TABLE 4R
Core Nonresidential Transportation Rates (continued)
Southern California Gas Company

		Present Rates			Proposed Rates			Changes		
		Jul-1-18 Volumes Mth A	Average Rate $/th B	Jul-1-18 Revenue $000's C	Jan-1-20 Volumes Mth D	Rate $/th E	Jan-1-20 Revenue $000's F	Revenue Change $000's G	Rate Change $/th H	% Rate change % I
1										
2										
3	NON-RESIDENTIAL GAS A/C									
4	Customer Charge	9	$150	$16	8	$150	$14	($2)	$0.00000	0.0%
5	Volumetric Rate	772	$0.13029	$101	416	$0.12088	$50	($50)	($0.00941)	-7.2%
6		772	$0.15128	$117	416	$0.15547	$65	($52)	$0.00420	2.8%
7	**Volumetric Rates Include CSITMA, Exclude CAT**									
8	CSITMA Adder to Volumetric Rate	772	$0.00308	$2	416	$0.00311	$1	($1)	$0.00002	0.8%
9	Volumetric		$0.13337			$0.12399			($0.00938)	-7.0%
10	**Volumetric Rates Include CSITMA & CAT**									
11	CAT Adder to Volumetric Rate	0	$0.00150	$0	0	$0.00167	$0	$0	$0.00017	11.3%
12	Gas A/C Rate		$0.13487			$0.12566			($0.00921)	-6.8%
13	Other Adjustments:									
14	TCA for CSITMA exempt customers		($0.00308)			($0.00311)			($0.00002)	0.8%
15										
16	**TOTAL A/C SERVICE**	**772**	**$0.15436**	**$119**	**416**	**$0.15858**	**$66**	**($53)**	**$0.00422**	**2.7%**
17										
18	GAS ENGINES									
19	Customer Charge	712	$50	$427	711	$50	$427	($1)	$0.00000	0.0%
20	Volumetric Exclude CSITMA & CAT	20,699	$0.13769	$2,850	22,302	$0.14094	$3,143	$293	$0.00326	2.4%
21		20,699	$0.15833	$3,277	22,302	$0.16008	$3,570	$293	$0.00175	1.1%
22	**Volumetric Rates Include CSITMA, Exclude CAT**									
23	CSITMA Adder to Volumetric Rate	20,699	$0.00308	$64	22,302	$0.00311	$69	$5	$0.00002	0.8%
24	Volumetric		$0.14080			$0.14400			$0.00320	
25	**Volumetric Rates Include CSITMA & CAT**									
26	CAT Adder to Volumetric Rate	0	$0.00150	$0	0	$0.00167	$0	$0	$0.00017	11.3%
27	Gas Engine Rate		$0.14230			$0.14567			$0.00337	2.4%
28	**Other Adjustments**									
29	TCA for CSITMA exempt customers		($0.00308)			($0.00311)			($0.00002)	0.8%
30										
31	**TOTAL GAS ENGINES**	**20,699**	**$0.16141**	**$3,341**	**22,302**	**$0.16318**	**$3,639**	**$298**	**$0.00177**	**1.1%**
32										
33	STREET & OUTDOOR LIGHTING (equals average Non-CAT CCI Rate)									
34	Street & Outdoor Lighting Base Rate		$0.32448			$0.37996			$0.05548	17.1%
35										

TABLE 5R
Noncore Commercial & Industrial Rates
Southern California Gas Company

		Present Rates			Proposed Rates			Changes		
		Jul-1-18 Volumes Mth	Average Rate $/th	Jul-1-18 Revenue $000's	Jan-1-20 Volumes Mth	Rate $/th	Jan-1-20 Revenue $000's	Revenue Change $000's	Rate Change $/th	% Rate change %
		A	B	C	D	E	F	G	H	I
1	NonCore Commercial & Industrial Distribution Level									
2	Customer Charge	584	$350.00	$2,452	563	$350.00	$2,367	($85)	$0.00000	0.0%
3										
4	**Volumetric Rates Include CARB Fee, Exclude GHG, and CSITMA**									
5	Tier 1 = 250kth/yr	121,573	$0.15737	$19,132	124,403	$0.18285	$22,747	$3,615	$0.02548	16.2%
6	Tier 2 = 250k to 1000k	205,061	$0.09908	$20,317	217,228	$0.11328	$24,608	$4,291	$0.01420	14.3%
7	Tier 3 = 1 to 2 million th/yr	109,960	$0.06179	$6,794	118,763	$0.06878	$8,168	$1,374	$0.00699	11.3%
8	Tier 4 = over 2 million th/yr	428,508	$0.03514	$15,057	459,341	$0.03697	$16,984	$1,926	$0.00183	5.2%
9	Volumetric totals (excl itcs)	865,102	$0.07086	$61,300	919,735	$0.07883	$72,506	$11,206	$0.00797	11.3%
10										
11	**Volumetric Rates Include CARB, GHG, CSITMA**									
12	CSITMA Adder to Volumetric Rate		$0.00308	$2,640		$0.00311	$2,843	$203	$0.00002	0.8%
13	GHG Adder to Volumetric Rate		$0.00000	$0		$0.00000	$0	$0	$0.00000	
14	Tier 1 = 250kth/yr		$0.16045			$0.18596			$0.02550	15.9%
15	Tier 2 = 250k to 1000k		$0.10216			$0.11639			$0.01423	13.9%
16	Tier 3 = 1 to 2 million th/yr		$0.06487			$0.07188			$0.00701	10.8%
17	Tier 4 = over 2 million th/yr		$0.03822			$0.04008			$0.00186	4.9%
18	**Other Adjustments:**									
19	TCA for CSITMA exempt customers		($0.00308)			($0.00311)			($0.00002)	0.8%
20	CARB Fee Credit $/th		($0.00100)			($0.00101)			($0.00001)	1.2%
21	GHG Fee Credit $/th		$0.00000			$0.00000			$0.00000	
22	NCCI - DISTRIBUTION LEVEL	865,102	$0.07674	$66,392	919,735	$0.08450	$77,716	$11,323	$0.00775	10.1%
23										
24	NCCI-TRANSMISSION LEVEL Incl CARB & GHG Fee Excl CSITMA (1)	6,438	$0.02136	$137	2,957	$0.02895	$86	($52)	$0.00760	35.6%
25	NCCI-TRANSMISSION LEVEL Incl CARB & GHG Fee and CSITMA (1)	653,799	$0.02444	$15,977	623,122	$0.03206	$19,978	$4,001	$0.00762	31.2%
26	NCCI-TRANSMISSION LEVEL (2)	660,238	$0.02441	$16,114	626,080	$0.03205	$20,063	$3,949	$0.00764	31.3%
27										
28	**TOTAL NONCORE C&I**	**1,525,339**	**$0.05409**	**$82,506**	**1,545,814**	**$0.06325**	**$97,779**	**$15,272**	**$0.00916**	**16.9%**

TABLE 6R
Noncore Electric Generation Rates and Enhanced Oil Recovery Rates
Southern California Gas Company

		Present Rates			Proposed Rates			Changes		
		Jul-1-18 Volumes Mth A	Average Rate $/th B	Jul-1-18 Revenue $000's C	Jan-1-20 Volumes Mth D	Rate $/th E	Jan-1-20 Revenue $000's F	Revenue Change $000's G	Rate Change $/th H	% Rate change % I
1										
2	**ELECTRIC GENERATION**									
3										
4										
5	**Small EG Distribution Level Service (a Sempra-Wide rate) Exclude CARB & GHG Fee & CSITMA:**									
6	Customer Charge	201	$50.00	$121	308	$50.00	$185	$64	$0.00000	0.0%
7	Volumetric Rate	77,207	$0.12566	$9,702	88,449	$0.12735	$11,264	$1,562	$0.00169	1.3%
8	Small EG Distribution Level Service	77,207	$0.12722	$9,822	88,449	$0.12944	$11,449	$1,627	$0.00222	1.7%
9										
10	**Large EG Distribution Level Service (a Sempra-Wide rate) Exclude CARB & GHG Fee & CSITMA**									
11	Customer Charge	28	$0.00	$0	30	$0.00	$0	$0	$0.00000	
12	Volumetric Rate	207,889	$0.05493	$11,419	242,993	$0.07200	$17,495	$6,076	$0.01707	31.1%
13	Large EG Distribution Level Service	207,889	$0.05493	$11,419	242,993	$0.07200	$17,495	$6,076	$0.01707	31.1%
14										
15	EG Distribution excl CARB Fee & CSITMA	285,096	$0.07451	$21,242	331,442	$0.08733	$28,944	$7,703	$0.01282	17.2%
16										
17	**Volumetric Rates Include CARB & GHG Fee, Exclude CSITMA**									
18	CARB Fee Cost Adder	283,261	$0.00100	$284	330,876	$0.00101	$335	$52	$0.00001	1.2%
19	GHG Cost Adder	90,289	$0.00000	$0	104,031	$0.00000	$0	$0	$0.00000	
20	EG-Distribution Tier 1 w/CARB Fee		$0.12666			$0.12836			$0.00170	1.3%
21	EG-Distribution Tier 2 w/CARB Fee		$0.05593			$0.07301			$0.01708	30.5%
22	Total - EG Distribution Level	285,096	$0.07550	$21,525	331,442	$0.08834	$29,280	$7,755	$0.01284	17.0%
23	CARB Fee Credit $/th		($0.00100)			($0.00101)			($0.00001)	1.2%
24	GHG Fee Credit $/th		$0.00000			$0.00000			$0.00000	
25										
26	EG Transmission Level Service Excl CARB & GHG Fee & CSITMA (1)	1,714,769	$0.02035	$34,902	2,246,336	$0.02794	$62,766	$27,864	$0.00759	37.3%
27	EG Transmission Level CARB Fee				634,285	$0.00101	$643			
28	EG Transmission Level Service - GHG End User Fee				30,343	$0.00000	$0			
29	EG Transmission Level Service Incl CARB & GHG Fee, Exclude CSITMA (1)	677,930	$0.02136	$14,477						
30	EG Transmission Level (2)	2,392,699	$0.02064	$49,379	2,246,336	$0.02823	$63,409	$14,030	$0.00759	36.8%
31										
32	**TOTAL ELECTRIC GENERATION**	**2,677,795**	**$0.02648**	**$70,904**	**2,577,778**	**$0.03596**	**$92,688**	**$21,784**	**$0.00948**	**35.8%**
33										
34	**EOR Rates & revenue Exclude CARB Fee & CSITMA:**									
35	Distribution Level EOR:									
36	Customer Charge	17	$500.00	$102	23	$500.00	$138	$36	$0.00000	0.0%
37	Volumetric Rate Excl CARB & GHG Fee & CSITMA	137,620	$0.07476	$10,289	151,758	$0.08642	$13,115	$2,826	$0.01166	15.6%
38										
39	**Volumetric Rates Include CARB & GHG Fee, Exclude CSITMA**									
40	CARB Fee		$0.00100			$0.00101				
41	GHG Fee		$0.00000			$0.00000				
42	Volumetric Rate Incl CARB Fee & Excl CSITMA		$0.07576			$0.08743			$0.01167	15.4%
43	Distribution Level EOR	137,620	$0.07550	$10,391	151,758	$0.08733	$13,253	$2,862	$0.01183	15.7%
44	CARB Fee Credit $/th		($0.00100)			($0.00101)			($0.00001)	1.2%
45	GHG Fee Credit $/th		$0.00000			$0.00000			$0.00000	
46	Transmission Level EOR Exclude CARB & GHG Fee & CSITMA	93,950	$0.02035	$1,912	57,184	$0.02794	$1,598	($314)	$0.00759	37.3%
47	**Total EOR**	**231,570**	**$0.05313**	**$12,303**	**208,941**	**$0.07108**	**$14,851**	**$2,548**	**$0.01795**	**33.8%**

1) CSITMA - Noncore C&I D Tariff rate Include CSITMA. Customers exempt, including Constitutionally Exempt, receive Transportation Charge Adjustment (TCA).
EG Tariff Rate Exclude CSITMA, since EG customers are exempt.
2) CARB & GHG Fees - EG-D and NCCI-D rates include CARB & GHG Fees.
3) EOR customers tariff Include CARB & GHG Fees and Excludes CSITMA; since EOR customers are exempt from CSITMA and get a credit for CARB & GHG Fees.
See footnotes, Table 1.

TABLE 7R
Transmission Level Service Transportation Rates
Southern California Gas Company

Line		Present Rates Jul-1-18 Volumes Mth	Present Rates Average Rate $/th	Present Rates Jul-1-18 Revenue $000's	Proposed Rates Jan-1-20 Volumes Mth	Proposed Rates Rate $/th	Proposed Rates Jan-1-20 Revenue $000's	Changes Revenue Change $000's	Changes Rate Change $/th	% Rate change %
		A	B	C	D	E	F	G	H	I
1	**Rate Excluding CSITMA & CARB Fee:**									
2	Reservation Service Option (RS):									
3	Daily Reservation rate $/th/day		$0.00671			$0.00963			$0.00292	43.6%
4	Usage Charge for RS $/th		$0.00994			$0.01363			$0.00369	37.1%
5	Class Average Volumetric Rate (CA)									
6	Volumetric Rate $/th		$0.01040			$0.01430			$0.00390	37.5%
7	Usage Charge for CA $/th		$0.00994			$0.01363			$0.00369	37.1%
8	Class Average Volumetric Rate (CA) $/th		$0.02034			$0.02793			$0.00759	37.3%
9										
10	115% CA (for NonBypass Volumetric NV) $/th		$0.02339			$0.03212			$0.00873	37.3%
11	135% CA (for Bypass Volumetric BV) $/th		$0.02746			$0.03771			$0.01025	37.3%
12	Total Transmission Level Service (NCCI, EOR, EG)	3,052,937	$0.02035	$62,138	2,872,415	$0.02794	$80,259	$18,121	$0.00759	37.3%
13										
14	**C&I Rate Including CSITMA & CARB & GHG Fee:**									
15	CSITMA Adder to Usage Charge	653,799	$0.00308	$2,015	623,122	$0.00311	$1,935	($80)	$0.00002	
16	CARB Fee Adder	1,338,168	$0.00100	$1,340	1,260,365	$0.00101	$1,277		$0.00001	
17	GHG Fee Adder	123,450	$0.00000	$0	109,151	$0.00000	$0		$0.00000	
18	Reservation Service Option (RS):									
19	Daily Reservation rate $/th/day		$0.00671			$0.00963		$0	$0.00292	43.6%
20	Usage Charge for RS $/th		$0.01403			$0.01775		$0	$0.00373	26.6%
21	Class Average Volumetric Rate (CA)									
22	Volumetric Rate $/th		$0.01040			$0.01430		$0	$0.00390	37.5%
23	Usage Charge for CA $/th		$0.01403			$0.01775		$0	$0.00373	26.6%
24	Class Average Volumetric Rate (CA) $/th		$0.02442			$0.03205		$0	$0.00763	31.2%
25										
26	115% CA (for NonBypass Volumetric NV) $/th		$0.02747			$0.03624		$0	$0.00876	31.9%
27	135% CA (for Bypass Volumetric BV) $/th		$0.03154			$0.04182		$0	$0.01028	32.6%
28	Other Adjustments:									
29	Transportation Charge Adj. (TCA) for CSITMA exempt customers		($0.00308)			($0.00311)			($0.00002)	
30	California Air Resources Board (CARB) Fee Credit $/th		($0.00100)			($0.00101)			($0.00001)	
31	GHG Fee Credit		$0.00000			$0.00000			$0.00000	
32	**Total Transmission Level Service Include CSITMA & CARB Fee**	**3,052,937**	**$0.02145**	**$65,493**	**2,872,415**	**$0.02906**	**$83,472**	**$17,978**	**$0.00761**	**35.5%**
33										
34	**EG & EOR Rate Including CARB Fee & GHG , excluding CSITMA:**									
35	CARB Fee Adder		$0.00100			$0.00101			$0.00001	
36	GHG Fee Adder		$0.00000			$0.00000			$0.00000	
37	Reservation Service Option (RS):									
38	Daily Reservation rate $/th/day		$0.00671			$0.00963		$0	$0.00292	43.6%
39	Usage Charge for RS $/th		$0.01095			$0.01465		$0	$0.00370	33.8%
40	Class Average Volumetric Rate (CA)									
41	Volumetric Rate $/th		$0.01040			$0.01430		$0	$0.00390	37.5%
42	Usage Charge for CA $/th		$0.01095			$0.01465		$0	$0.00370	33.8%
43	Class Average Volumetric Rate (CA) $/th		$0.02134			$0.02894		$0	$0.00760	35.6%
44										
45	115% CA (for NonBypass Volumetric NV) $/th		$0.02439			$0.03313		$0	$0.00874	35.8%
46	135% CA (for Bypass Volumetric BV) $/th		$0.02846			$0.03872		$0	$0.01026	36.0%
47										
48	**Other Adjustments:**									
49	California Air Resources Board (CARB) Fee Credit $/th		($0.00100)			($0.00101)			($0.00001)	1.2%
50	Greenhouse Gas (GHG) Fee Credit $/th		$0.00000			$0.00000			$0.00000	
51										
52	**Rate Excluding CSITMA, CARB, GHG Fee, & Uncollectibles (applicable to Wholesale & International):**									
53	Reservation Service Option (RS):									
54	Daily Reservation rate $/th/day		$0.00669			$0.00960			$0.00292	43.6%
55	Usage Charge for RS $/th		$0.00991			$0.01359			$0.00368	37.1%
56	Class Average Volumetric Rate (CA)									
57	Volumetric Rate $/th		$0.01036			$0.01425			$0.00389	37.5%
58	Usage Charge for CA $/th		$0.00991			$0.01359			$0.00368	37.1%
59	Class Average Volumetric Rate (CA) $/th		$0.02028			$0.02785			$0.00757	37.3%
60										
61	115% CA (for NonBypass Volumetric NV) $/th		$0.02332			$0.03202			$0.00870	37.3%
62	135% CA (for Bypass Volumetric BV) $/th		$0.02738			$0.03759			$0.01022	37.3%
63	**Total Transmission Level Service (WS & Int'l)**	**325,403**	**$0.02035**	**$6,623**	**359,267**	**$0.02794**	**$10,038**	**$3,415**	**$0.00759**	**37.3%**
64										
65	**Average Transmission Level Service**	**3,378,340**	**$0.02135**	**$72,116**	**3,231,682**	**$0.02894**	**$93,510**	**$21,394**	**$0.00759**	**35.6%**

TABLE 8
Backbone Transmission Service and Storage Rates
Southern California Gas Company

		Present Rates			Proposed Rates			Changes		
		Jul-1-18 Volumes Mth	Average Rate $/th	Jul-1-18 Revenue $000's	Jan-1-20 Volumes Mth, Mdth	Rate $/th	Jan-1-20 Revenue $000's	Revenue Change $000's	Rate Change $/th	% Rate change %
		A	B	C	D	E	F	G	H	I
1	**Backbone Transmission Service BTS**									
2	BTS SFV Reservation Charge $/dth/day	2,690	$0.26353	$258,736	2,690	$0.26245	$257,673	($1,063)	($0.00108)	-0.4%
3	BTS MFV Reservation Charge $/dth/day		$0.21083			$0.20996				
4	BTS MFV Volumetric Charge $/dth		$0.05271			$0.05249				
5	BTS Interruptible Volumetric Charge $/dth		$0.26353			$0.26245			($0.00108)	-0.4%
6										
7										
8	**Storage Costs: (incl. HRSMA)**									
9	Core $000			$59,943			$93,797	$33,854		
10	Load Balancing $000			$27,353			$70,614	$43,261		
11	Unbundled Storage $000			$23,290			$0	($23,290)		
12				$110,586			$164,411	$53,825		

See footnotes, Table 1.
1) CSITMA - NCCI and EG TLS Tariff rates include CSITMA. Customers exempt (Constitutional Exempt and EG) receive Transportation Charge Adjustment (TCA).
2) CARB Fee - TLS NCCI, EOR and EG Tariff rates include CSITMA. TLS NCCI, EOR and EG customers exempt as they pay CARB Fees directly receive credit.
3) Wholesale Customers excludes CSITMA and CARB Fee since these customers are exempt.

TABLE 1R
Natural Gas Transportation Rate Revenues
San Diego Gas & Electric Company
2020 TCAP Application

		At Present Rates			At Proposed Rates			Changes		
		Jul-1-18 Volumes mtherms	Average Rate $/therm	Jul-1-18 Revenues $000's	Jan-1-20 Volumes mtherms	Average Rate $/therm	Jan-1-20 Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**CORE**									
2	Residential	319,982	$0.91560	$292,977	313,234	$0.92591	$290,025	($2,952)	$0.01030	1.1%
3	Commercial & Industrial	182,660	$0.27781	$50,744	194,777	$0.33290	$64,841	$14,097	$0.05509	19.8%
4										
5	NGV - Pre Sempra-Wide	18,501	$0.14069	$2,603	24,129	$0.14570	$3,515	$913	$0.00501	3.6%
6	Sempra-Wide Adjustment	18,501	$0.01414	$262	24,129	$0.01217	$294	$32	($0.00197)	-13.9%
7	NGV Post Sempra-Wide	18,501	$0.15482	$2,864	24,129	$0.15787	$3,809	$945	$0.00304	2.0%
8										
9	Total CORE	521,144	$0.66505	$346,586	532,140	$0.67402	$358,676	$12,090	$0.00898	1.3%
10										
11	**NONCORE COMMERCIAL & INDUSTRIAL**									
12	Distribution Level Service	27,807	$0.11678	$3,247	29,376	$0.09876	$2,901	($346)	($0.01802)	-15.4%
13	Transmission Level Service (2)	17,168	$0.02443	$419	17,569	$0.03196	$561	$142	$0.00753	30.8%
14	Total Noncore C&I	44,975	$0.08152	$3,667	46,945	$0.07376	$3,463	($204)	($0.00776)	-9.5%
15										
16	**NONCORE ELECTRIC GENERATION**									
17	Distribution Level Service									
18	Pre Sempra-Wide	95,807	$0.05180	$4,963	68,867	$0.07646	$5,266	$303	$0.02466	47.6%
19	Sempra-Wide Adjustment	95,807	$0.01873	$1,794	68,867	$0.01729	$1,191	($603)	($0.00143)	-7.6%
20	Distribution Level post SW	95,807	$0.07053	$6,757	68,867	$0.09376	$6,457	($300)	$0.02323	32.9%
21	Transmission Level Service (2)	574,075	$0.02048	$11,756	461,363	$0.02801	$12,924	$1,168	$0.00753	36.8%
22	Total Electric Generation	669,882	$0.02764	$18,513	530,230	$0.03655	$19,381	$868	$0.00892	32.3%
23										
24	**TOTAL NONCORE**	714,857	$0.03103	$22,179	577,175	$0.03958	$22,843	$664	$0.00855	27.6%
25										
26	**SYSTEM TOTAL**	**1,236,000**	**$0.29835**	**$368,765**	**1,109,315**	**$0.34392**	**$381,519**	**$12,754**	**$0.04557**	**15.3%**

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter." The Backbone Transportation Service (BTS) rate is for service from Receipt Point to Citygate. The BTS rate is a SoCalGas tariff and service is purchased from SoCalGas.
2) The average Transmission Level Service (TLS) rate is shown here, see Rate Table 6 for detailed list of TLS rates.
3) All rates include Franchise Fees & Uncollectible charges.

TABLE 2R
Core Gas Transportation Rates
San Diego Gas & Electric Company

		At Present Rates			At Proposed Rates			Changes		
		Jul-1-18 Volumes mtherms	Average Rate $/therm	Jul-1-18 Revenues $000's	Jan-1-20 Volumes mtherms	Average Rate $/therm	Jan-1-20 Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**Residential RATES Schedule GR,GM**									
2	**Rates Exclude CSITMA & CAT**									
3	Minimum Bill/Customer Charge	884,624	$3.00	$221	874,067	$10.00	$104,888	$104,667		
4										
5	Baseline $/therm	215,947	$0.86668	$187,156	255,260	$0.48618	$124,101	($63,055)	($0.38050)	-43.9%
6	Non-Baseline $/therm	104,035	$1.04355	$108,566	57,974	$1.07318	$62,217	($46,349)	$0.02962	2.8%
7	Average Rate $/therm	319,982	$0.92487	$295,943	313,234	$0.92967	$291,206	($4,738)	$0.00480	0.5%
8	NBL/BL Ratio									
9	Composite Rate $/th		$ 1.18018			$1.17395			-$0.00623	
10	Gas Rate $/th		$ 0.31248			$0.27687			-$0.03561	-11.4%
11	NBL/Composite rate ratio		1.15			1.15				
12	NBL- BL rate difference $/th		0.17687			$0.58700			$0.41013	
13										
14	**Rates Include CSITMA, CARB and GHG Adders, Excludes CAT**									
15	CSITMA Adder to Volumetric Rate	258,048	$0.00331	$855	258,322	$0.00318	$822	($33)	($0.00013)	-3.9%
16	CARB Adder to Volumetric Rate				313,234	$0.00083	$261			
17	GHG End User Adder to Volumetric Rate				319,982	$0.00000	$0			
18	Baseline $/therm		$0.86999			$0.49019			($0.37980)	-43.7%
19	Non-Baseline $/therm		$1.04686			$1.07719			$0.03033	2.9%
20	Average NonCARE Rate $/therm		$0.92819			$0.93369			$0.00550	0.6%
21										
22	**Sub Meter Credit Schedule GS,GT**									
23	GS Unit Discount $/day	5,870	($0.38268)	($820)	5,879	($0.26499)	($569)	$251	$0.11770	-30.8%
24	GT Unit Discount $/day	27,189	($0.40932)	($4,062)	26,104	($0.28570)	($2,722)	$1,340	$0.12362	-30.2%
25										
26	**Schedule GL-1**									
27	LNG Facility Charge, domestic use $/month	321	$14.79	$57	293	$14.79	$52		$0.00000	0.0%
28	LNG Facility Charge, non-domestic $/mth/mbtu		$0.05480			$0.05480			$0.00000	0.0%
29	LNG Volumetric Surcharge $/th	74	$0.16571	$12	76	$0.16571	$13		$0.00000	0.0%
30				$69			$65			
31	**Volumetric Rates Include All Adders & CAT**									
32	CAT Adder to Volumetric Rate	2,764	$0.00000	$0	2,253	$0.00000	$0	$0	$0.00000	
33	Baseline $/therm		$0.86999			$0.49019			($0.37980)	-43.7%
34	Non-Baseline $/therm		$1.04686			$1.07719			$0.03033	2.9%
35	Average Rate $/therm		$0.92819			$0.93369			$0.00550	0.6%
36										
37	**Other Adjustments:**									
38	Employee Discount			($349)			($367)	($18)		
39	SDFFD			$1,340			$1,330	($11)		
40										
41	Credit for CSITMA Exempt Customers:		($0.00331)			($0.00318)			$0.00013	-3.9%
42										
43	California Climate Credit - April Bill		$0.00			$0.00				
44	**Total Residential**	**319,982**	**$0.91560**	**$292,977**	**313,234**	**$0.92591**	**$290,025**	**($2,952)**	**$0.01030**	**1.1%**

See footnotes, Table 1.

TABLE 3R
Natural Gas Transportation Rate Revenues
San Diego Gas & Electric

		At Present Rates			At Proposed Rates			Changes		
		Jul-1-18 Volumes mtherms A	Average Rate $/therm B	Jul-1-18 Revenues $000's C	Jan-1-20 Volumes mtherms D	Average Rate $/therm E	Jan-1-20 Revenues $000's F	Revenues $000's G	Rates $/therm H	Rate change % I
4	**CORE COMMERCIAL & INDUSTRIAL RATES Schedule GN-3**									
5	Customer Charge $/month	30,265	$10.00	$3,632	30,937	$10.00	$3,712	$81	$0.00000	0.0%
7	**Rates Exclude CSITMA & CAT**									
8	Tier 1 = 0 to 1,000 therms/month	82,658	$0.32811	$27,121	87,627	$0.40668	$35,637	$8,516	$0.07858	23.9%
9	Tier 2 = 1,001 to 21,000 therms/month	84,219	$0.19690	$16,583	88,939	$0.23702	$21,080	$4,497	$0.04012	20.4%
10	Tier 3 = over 21,000 therms/month	15,783	$0.15984	$2,523	18,211	$0.18909	$3,444	$921	$0.02925	18.3%
12	**Rates Includes CSITMA, Excludes CAT**									
13	CSITMA Adder to Volumetric Rate	182,649	$0.00331	$605	187,959	$0.00318	$598	($7)	($0.00013)	-3.9%
14	Tier 1 = 0 to 1,000 therms/month		$0.33142			$0.40987			$0.07845	23.7%
15	Tier 2 = 1,001 to 21,000 therms/month		$0.20022			$0.24020			$0.03999	20.0%
16	Tier 3 = over 21,000 therms/month		$0.16315			$0.19227			$0.02912	17.8%
18	**Rates Include CSITMA & CAT**									
19	CAT Adder to Volumetric Rate	35,463	$0.00000	$0	39,978	$0.00000	$0	$0	$0.00000	
20	Tier 1 = 0 to 1,000 therms/month		$0.33142			$0.40987			$0.07845	23.7%
21	Tier 2 = 1,001 to 21,000 therms/month		$0.20022			$0.24020			$0.03999	20.0%
22	Tier 3 = over 21,000 therms/month		$0.16315			$0.19227			$0.02912	17.8%
24	**Other Adjustments:**									
25	Adjustment for SDFFD			$281			$370	$89		
26	Credit for CSITMA Exempt Customers:		($0.00331)			($0.00318)			$0.00013	-3.9%
28	**Total Core C&I**	**182,660**	**$0.27781**	**$50,744**	**194,777**	**$0.33290**	**$64,841**	**$14,097**	**$0.05509**	**19.8%**

1) CSITMA - Tariff rate Include CSITMA, exempt customers (including CARE participants and Constitutionally Exempt) receive Credit for CSITMA.
CARE participants receive 20% CARE discount (Tariff rate less Credit for CSITMA Exempt Customers)*20%.
See footnotes, Table 1.

TABLE 4R
Other Core Gas Transportation Rates
San Diego Gas & Electric Company

		At Present Rates			At Proposed Rates			Changes		
		Jul-1-18 Volumes mtherms	Average Rate $/therm	Jul-1-18 Revenues $000's	Jan-1-20 Volumes mtherms	Average Rate $/therm	Jan-1-20 Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**NATURAL GAS VEHICLE RATES G-NGV & GT-NGV**		Sempra-Wide NGV Rates			*Sempra-Wide NGV Rates*				
2	Customer Charge									
3	P1 $/month	28	$13.00	$4	15	$13.00	$2	($2)	$0.00	0.0%
4	P2A $/month	10	$65.00	$8	13	$65.00	$10	$2	$0.00	0.0%
5										
6	**Uncompressed Rate Exclude CSITMA & CAT $/therm**	18,501	$0.11003	$2,036	24,129	$0.12584	$3,036	$1,000	$0.01580	14.4%
7	Compressor Adder $/therm exclude CSITMA & CAT	744	$1.03701	$772	628	$1.04809	$659	($113)	$0.01108	1.1%
8	Combined transport & compressor adder $/th		$1.14704			$1.17393			$0.02688	2.3%
9										
10	**Volumetric Rates Include CSITMA, CARB and GHG excludes CAT**									
11	CSITMA Adder to Volumetric Rate	11,409	$0.00331	$38	23,583	$0.00318	$75	$37	($0.00013)	-3.9%
12	CARB Adder to Volumetric Rate				24,129	$0.00083	$20			
13	GHG End User Adder to Volumetric Rate				24,129	$0.00000	$0			
14	Uncompressed Rate $/therm		$0.11335			$0.12985			$0.01650	14.6%
15	Combined transport & compressor adder $/th		$1.15036			$1.17794			$0.02759	2.4%
16										
17	**Volumetric Rates Include CSITMA & CAT**									
18	CAT Adder to Volumetric Rate		$0.00000			$0.00000				
19	Uncompressed Rate $/therm		$0.11335			$0.12985		$0	$0.01650	14.6%
20	Combined transport & compressor adder $/th		$1.15036			$1.17794			$0.02759	2.4%
21	**Other Adjustments:**									
22	Adjustment for SDFFD			$7			$7	$0		
23	Credit for CSITMA Exempt Customers $/th		($0.00331)			($0.00318)			$0.00013	-3.9%
24	Low Carbon Fuel Standard (LCFS) Credit		$0.00000			$0.00000				
25	**Total NGV**	**18,501**	**$0.15482**	**$2,864**	**24,129**	**$0.15787**	**$3,809**	**$945**	**$0.00304**	**2.0%**
26										
27	**RESIDENTIAL NATURAL GAS VEHICLES (optional rate)**									
28	Customer Charge	885	$5.00	$53	15	$5.00	$1	($52)	$0.00	0.0%
29	**Uncompressed Rate w/o CSITMA & CAT $/therm**	969	$0.25853	$251	9	$1.72275	$16	($235)	$1.46423	566.4%
30		969	$0.31329	$304	9	$1.81923	$17	($287)	$1.50594	480.7%
31										
32	**Volumetric Rates Including CSITMA , Excluding CAT**									
33	CSITMA Adder to Volumetric Rate		$0.00331		9	$0.00318	$0		($0.00013)	-3.9%
34	CARB Adder to Volumetric Rate				9	$0.00083	$0			
35	GHG End User Adder to Volumetric Rate				9	$0.00000	$0			
36	Uncompressed Rate $/therm		$0.26184			$1.72677			$1.46493	559.5%
37										
38	**Volumetric Rates Include CSITMA & CAT**									
39	CAT Adder to Volumetric Rate	0	$0.00000	$0	0	$0.00000	$0	$0	$0.00000	
40	Uncompressed Rate $/therm		$0.26184			$1.72677			($1.50594)	$5
41										
42	**Other Adjustments:**									
43	Adjustment for SDFFD			$0			$0	$0		
44	Credit for CSITMA Exempt Customers $/th		($0.00331)			($0.00318)			$0.00013	-3.9%
45										
46	**Total Residential NGV**	**969**	**$0.31329**	**$304**	**9**	**$1.82324**	**$17**	**($287)**	**$1.50996**	**482.0%**

1) CSITMA - Tariff rate Include CSITMA, exempt customers (including CARE participants and Constitutionally Exempt) receive Credit for CSITMA.

TABLE 5R
NonCore Gas Transportation Rates
San Diego Gas & Electric Company

		At Present Rates			At Proposed Rates			Changes		
		Jul-1-18 Volumes mtherms	Average Rate $/therm	Jul-1-18 Revenues $000's	Jan-1-20 Volumes mtherms	Average Rate $/therm	Jan-1-20 Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**NonCore Commercial & Industrial Distribution Level**									
2	Customer Charges $/month	42	$350.00	$177	44	$350.00	$185	$8	$0.00	0.0%
3										
4	**Volumetric Charges Exclude CARB, GHG, CSITMA**	27,807	$0.10741	$2,987	29,376	$0.08951	$2,629	($357)	($0.01789)	-16.7%
5	CSITMA Adder to Volumetric Rate	25,154	$0.00331	$83	27,293	$0.00318	$87	$4	($0.00013)	-3.9%
6	GHG Adder to Volumetric Rate		$0.00000	$0		$0.00000	$0	$0	$0.00000	
7										
8	**Volumetric Charges Include CARB, GHG, and CSITMA**									
9	Volumetric Rates $/therm		$0.11072			$0.09269			($0.01802)	-16.3%
10										
11	**Other Adjustments:**									
12	SDFFD 0.727%									
13	Credit for CSITMA Exempt Customers $/th		($0.00331)			($0.00318)			$0.00013	-3.9%
14	Credit for CARB Fee Exempt Customers $/th		($0.00076)			($0.00083)			($0.00007)	9.8%
15	Credit for GHG Fee Exempt Customers $/th		$0.00000			$0.00000			$0.00000	
16	**NCCI-Distribution Total**	**27,807**	**$0.11678**	**$3,247**	**29,376**	**$0.09876**	**$2,901**	**($346)**	**($0.01802)**	**-15.4%**
17										
18	**NCCI-Transmission Total (1)**	**17,168**	**$0.02443**	**$419**	**17,569**	**$0.03196**	**$561**	**$142**	**$0.00753**	**30.8%**
19	**NCCI-Transmission Class Average**	**17,168**	**$0.02443**	**$419**	**17,569**	**$0.03196**	**$561**			
20	**Total NonCore C&I**	**44,975**	**$0.08152**	**$3,667**	**46,945**	**$0.07376**	**$3,463**	**($204)**	**($0.00776)**	**-9.5%**
21										
22	**ELECTRIC GENERATION**									
23										
24	**Small EG Distribution Level Service (a Sempra-Wide rate) exclude CARB, GHG, and CSITMA**									
25	Customer Charge, $/month	46	$50.00	$28	69	$50.00	$41	$14	$0.00	0.0%
26	Volumetric Rate $/therm	19,210	$0.12635	$2,427	24,662	$0.12805	$3,158	$731	$0.00	1.3%
27										
28	**Large EG Distribution Level Service (a Sempra-Wide rate) exclude CARB, GHG, and CSITMA**									
29	Customer Charge, $/month		$0.00			$0.00			$0.00	
30	Volumetric Rate (Incl ITCS) $/th	76,596	$0.05523	$4,230	44,206	$0.07239	$3,200	($1,030)	$0.02	31.1%
31										
32	EG Distribution exclude CARB & GHG Fee, CSITMA	95,807	$0.06978	$6,685	68,867	$0.09292	$6,399	($286)	$0.02	33.2%
33										
34	**Volumetric Rates Includes CARB Fee, GHG Fee Excludes CSITMA:**									
35	CARB Fee Cost Adder - Small	17,675	$0.00076	$13	24,560	$0.00083	$20	$7	$0.00007	
36	CARB Fee Cost Adder - Large	76,596	$0.00076	$58	44,206	$0.00083	$37			
37	GHG Fee Cost Adder - Small	18,266	$0.00000	$0	23,450	$0.00000	$0	$0	$0.00000	
38	GHG Fee Cost Adder - Large	8,082	$0.00000	$0	4,665	$0.00000	$0			
37	EG-Distribution Tier 1 Incl CARB & GHG Fee, Excl CSITMA		$0.12711			$0.12888			$0.00177	1.4%
38	EG-Distribution Tier 2 Incl CARB & GHG Fee, Excl CSITMA		$0.05599			$0.07323			$0.01724	30.8%
39	Total - EG Distribution Level	95,807	$0.07053	$6,757	68,867	$0.09376	$6,457	($300)	$0.02323	32.9%
40	Credit for CARB Fee Exempt Customers $/th		($0.00076)			($0.00083)				
41	Credit for GHG Fee Exempt Customers $/th		$0.00000			$0.00000				
42										
43	EG Transmission Level Service Excl CARB & GHG fee & CSITMA	479,795	$0.02035	$9,765	461,363	$0.02794	$12,891	$3,126	$0.00759	37.3%
44	EG Transmission Level Service - CARB				39,584	$0.00083	$33			
45	EG Transmission Level Service - GHG				4,857	$0.00000	$0			
46	EG Transmission Level Service Incl CARB & GHG Fee & CSITMA	94,280	$0.02007	$1,893						
47	EG Transmission Level Service - Average (1)	574,075	$0.02048	$11,756	461,363	$0.02801	$12,924	$1,168	$0.00753	36.8%
48										
49	**TOTAL ELECTRIC GENERATION**	**669,882**	**$0.02764**	**$18,513**	**530,230**	**$0.03655**	**$19,381**	**$868**	**$0.00892**	**32.3%**

1) CSITMA - Tariff rate Include CSITMA, exempt customers (including CARE participants and Constitutionally Exempt) receive Credit for CSITMA.
Schedule EG Tariff Rate exclude CSITMA, since EG customers are exempt.
2) CARB - GTNC and EG Tariff rates Include CARB. Those EG and GTNC customers that are exempt will receive CARB credit.
3) GHG - GTNC and EG Tariff rates Include GHG. Those EG and GTNC customers that are exempt will receive GHG credit.
See footnotes, Table 1.

TABLE 6R
Transmission Level Service Gas Transportation Rates
San Diego Gas & Electric Company

Line		At Present Rates			At Proposed Rates			Changes		
		Jul-1-18 Volumes mtherms	Average Rate $/therm	Jul-1-18 Revenues $000's	Jan-1-20 Volumes mtherms	Average Rate $/therm	Jan-1-20 Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**Transmission Level Service Rate Excluding CSITMA, CARB, and GHG Fees**									
2	Reservation Service Option (RS):									
3	Daily Reservation rate $/th/day		$0.00674			$0.00968			$0.00294	43.6%
4	Usage Charge for RS $/th		$0.01000			$0.01371			$0.00371	37.1%
5										
6	Class Average Volumetric Rate (CA)									
7	Volumetric Rate $/th		$0.01045			$0.01437			$0.00392	37.5%
8	Usage Charge for CA $/th		$0.01000			$0.01371			$0.00371	37.1%
9	Class Average Volumetric Rate CA $/th		$0.02045			$0.02808			$0.00763	37.3%
10										
11	115% CA (for NonBypass Volumetric NV) $/th		$0.02352			$0.03230			$0.00878	37.3%
12	135% CA (for Bypass Volumetric BV) $/th		$0.02761			$0.03791			$0.01030	37.3%
13										
14	Average Transmission Level Service	591,243	$0.02035	$12,034	478,932	$0.02794	$13,382	$1,348	$0.00759	37.3%
15										
16	**C&I Rate Include CSITMA, CARB, and GHG Fees**									
17	CSITMA Adder to Usage Rate $/th	17,168	$0.00331	$57	17,569	$0.00318	$56	($1)	($0.00013)	-3.9%
18	CARB Cost Adder	111,448	$0.00076	$85	57,153	$0.00083	$48		$0.00007	
19	GHG Cost Adder	2,824	$0.00000	$0	5,718	$0.00000	$0		$0.00000	
20	Reservation Service Option (RS):									
21	Daily Reservation rate $/th/day		$0.00674			$0.00968			$0.00294	43.6%
22	Usage Charge for RS $/th		$0.01407			$0.01773			$0.00365	26.0%
23										
24	Class Average Volumetric Rate (CA)									
25	Volumetric Rate $/th		$0.01045			$0.01437			$0.00392	37.5%
26	Usage Charge for CA $/th		$0.01407			$0.01773			$0.00365	26.0%
27	Class Average Volumetric Rate CA $/th		$0.02452			$0.03210			$0.00758	30.9%
28										
29	115% CA (for NonBypass Volumetric NV) $/th		$0.02759			$0.03631			$0.00872	31.6%
30	135% CA (for Bypass Volumetric BV) $/th		$0.03168			$0.04193			$0.01025	32.3%
31										
32	**Other Adjustments:**									
33	Credit for CSITMA Exempt Customers $/th		($0.00331)			($0.00318)			$0.00013	-3.9%
34	CARB Fee Credit for Exempt Customers $/th		($0.00076)			($0.00083)			($0.00007)	9.8%
35	GHG Fee Credit for Exempt Customers $/th		$0.00000			$0.00000			$0.00000	
36										
37	**EG Rate Include CARB & GHG Fees, excludes CSITMA:**									
38	CARB Fee Cost Adder		$0.00076			$0.00083			$0.00007	
39	GHG Fee Cost Adder		$0.00000			$0.00000			$0.00000	
40	Reservation Service Option (RS):									
41	Daily Reservation rate $/th/day		$0.00674			$0.00968			$0.00294	43.6%
42	Usage Charge for RS $/th		$0.01076			$0.01454			$0.00378	35.2%
43										
44	Class Average Volumetric Rate (CA)									
45	Volumetric Rate $/th		$0.01045			$0.01437			$0.00392	37.5%
46	Usage Charge for CA $/th		$0.01076			$0.01454			$0.00378	35.2%
47	Class Average Volumetric Rate CA $/th		$0.02121			$0.02892			$0.00771	36.3%
48										
49	115% CA (for NonBypass Volumetric NV) $/th		$0.02428			$0.03313			$0.00885	36.5%
50	135% CA (for Bypass Volumetric BV) $/th		$0.02837			$0.03875			$0.01038	36.6%
51										
52	**Other Adjustments:**									
53	CARB Fee Credit for Exempt Customers $/th		($0.00076)			($0.00083)			($0.00007)	9.8%
54	GHG Fee Credit for Exempt Customers $/th		$0.00000			$0.00000			$0.00000	
55										
56	**Average Transmission Level Service**	**591,243**	**$0.02059**	**$12,175**	**478,932**	**$0.02816**	**$13,486**	**$1,310**	**$0.00756**	**36.7%**

See footnotes, Table 1.

APPENDIX B

Adjusted Rental Method for Marginal Customer Cost

An Energy Division Staff Proposal

For Presentation at the PG&E GRC Phase 2 (A.16-06-013)
Second Fixed Cost Workshop - November 2, 2016

Robert Levin – Energy Division

What is a Marginal Cost?

…"marginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that would be saved by producing one less unit." -- Alfred Kahn*

➔ Marginal costs are symmetric

In the context of Marginal Customer Access Cost (MCAC):

…"marginal cost is the cost of connecting one more customer; it can equally be envisaged as the cost that would be saved by connecting one fewer customer."

*The Economics of Regulation, Volume 1, pp.65-66

Marginal Cost and Opportunity Cost

When economists refer to the “opportunity cost” of a resource, they mean the value of the next-highest-valued alternative use of that resource.—Concise encyclopedia of Economics

“If consumers are to make the choices that will yield them the greatest possible satisfaction from society’s limited aggregate productive capacity, the prices they must pay for the various goods and services available to them must accurately reflect their respective ***opportunity costs***;”…Alfred Kahn

*The Economics of Regulation, Volume 1, p. 66, emphasis added

Two Methods for Capital-Related Marginal Customer Access Cost

Rental (RECC) Method

Assigns the real level annualized cost of a ***new*** final line transformer, service drop, and meter (TSM) to ***all*** customers.

New Customer Only (NCO) Method

Assigns the full cost* of a new TSM set to ***new customers only***; and spreads those costs over all customers in a customer class.

*Net present value of TSM revenue requirement over its service life.

Why Does the Choice of MC Methodology Matter?

- Both Columns B and C of PG&E’s Table F-1 Are Affected

TABLE F-1
PG&E RESIDENTIAL FIXED COSTS
AND FIXED CHARGES

(A)	(B)	(C)	(D)	(E)	(F)=(C)+(D)+(E)	(G)=(B)-(F)	(H)=(C)+(G)
		Marginal Costs					
Residential	Revenue Requirement ($ million)	Customer-Related ($ million)	Capacity-Related ($ million)	Energy-Related ($ million)	Total Marginal Cost ($ million)	Additional Fixed Costs ($ million)	Total Fixed Costs ($ million)
Distribution	$2,432	$742	$497	$0	$1,239	$1,193	$1,935
Generation	$2,661	$0	$205	$993	$1,198	$1,464	$1,464
PPP	$355	$0	$0	$0	$0	$355	$355
Total	$5,448	$742	$702	$993	$2,436	$3,011	$3,753
Customer-months	57,003,455	57,003,455	57,003,455	57,003,455	57,003,455	57,003,455	57,003,455
$/cust-mo	$95.57	$13.01	$12.31	$17.42	$42.74	$52.83	$65.84

Rental vs NCO

Neither method satisfies the basic symmetry property of a marginal cost:

- The cost of a ***new*** hookup (embodied in both methods) is not the same as the cost saved due to a permanent loss of an existing customer hookup.
  - Meters and transformers have salvage value- less than Replacement Cost New (RCN)
  - In case of annexation or condemnation, TSM facilities are valued less than RCN
  - If a site becomes uninhabitable, the utility’s write-down would be at book value, less than RCN

Rental vs NCO (2)

Rental (RECC) Method

"…we believe that the rental method does not produce a competitive price for customer hookups and, in fact, significantly overstates the price that would prevail a competitive market."

- "In effect, the rental method assumes that everyone has to pay rent at 10.21 percent (the RECC rate) of the replacement cost of new equipment. "

D.96-04-050*, p.67

New Customer Only (NCO) Method

- Depends on customer growth assumptions that are highly unstable from year to year, and that it produces anomalous results when customer growth rates are very high, very low, or negative.
- Further, NCO assigns no MC value (or opportunity value) to existing TSM equipment.

*This decision devoted 7 pages [pp.62-69] to a thorough discussion of Rental vs. NCO; This issue has not been examined in depth in more recent CPUC decisions.

Neither Method Values Existing Hookup Equipment Correctly

Rental (RECC) Method

Values used, depreciated TSM equipment at its Replacement Cost New (RCN) value--- well above its opportunity value or the book value that is embedded in the rates.

New Customer Only (NCO) Method

Values used, depreciated TSM equipment at ***zero****, in spite of the positive opportunity value associated with such equipment.

*NCO treats existing hookups as sunk costs.

So What is the Opportunity Cost of Hookups?

It is the value of the next best alternative use:

- In the event of a permanent departure of a customer, the Utility could:
  - Salvage and reuse (or sell) the meter and transformer, at a value less than replacement cost new (RCN)
  - In case of annexation or condemnation, obtain compensation (typically sought at replacement cost new less depreciation (RCNLD))
  - If a site becomes uninhabitable, the utility's write-down would be at book value, less than RCN

Adjusted Rental Method 1 (ARM1)

ARM1 MCAC = r1 * rental MCAC, where

r1 = (TSM rate base value) / (TSM replacement cost new value)

(r1 is a system value and not customer-class-specific, but does vary by asset class)

Notes: The rental calculation (before the RECC is applied), when summed over all the IOU's customers, represents the replacement cost new ("RCN") value of all the utility's hookup equipment (TSM sets).

- However, most of the TSM equipment service customers is <u>used</u>, of various vintages, and is substantially depreciated. The revenue requirement associated with TSM is based on the associated rate base, which is far less than the RCN value. Thus, normally r1 < 1 (and could be close to 0.5, except for meters, which are relatively new).
- The ARM1 MCAC represents the current value of a TSM set, and approximates the rate that the customer would pay for TSM if the utility only provided connectivity (TSM) service.
- This formula applies only to the capital (TSM)-related component of the MCAC. The expense components (which are identical in the rental and NCO methods) are unaltered.

Adjusted Rental Method 2 (ARM2)

ARM2 MCAC = r2 * rental MCAC, where

r2 = (TSM RCNLD* value) / (TSM replacement cost new value)

(r2 is a system value and not customer-class-specific, but does vary by asset class)

Notes: The rental calculation (before the RECC is applied), when summed over all the IOU’s customers, represents the replacement cost new (“RCN”) value of all the utility’s hookup equipment (TSM sets).

- However, most of the TSM equipment service customers is <u>used</u>, of various vintages, and is substantially depreciated. If annexed or condemned, typically the utility would seek compensation based on RCNLD (see, for example, D.03-04-032, pp.42-43)
- The ARM2 MCAC represents the theoretical market value of a TSM set if it were condemned by a governmental agency, or annexed by another utility.
- Again, this formula applies only to the capital (TSM)-related component of the MCAC. The expense components (which are identical in the rental and NCO methods) are unaltered.

*Replacement cost new less depreciation

ARM (either version) As Marginal Cost (1)

The ARM MCAC has a legitimate interpretation as an MC, for the following reasons:

- First, <u>it reasonably reflects the opportunity value of TSM equipment</u>, which is its market value if sold. Utilities when selling their distribution systems do not price them at the cost of new facilities (RCN). Much as they might like to price at RCN, no buyer would pay that amount. Instead, utilities typically ask a lower price based on replacement cost new less depreciation (RCNLD). The RCNLD price is the "gold standard" price to which utilities aspire if they wish to (or are required to) sell part of their distribution system. The actual sale price for utility distribution plant is often less than RCNLD (ARM2), and may approximate the lower Book Value (ARM1)

ARM (either version) As Marginal Cost (2)

- Unlike the Rental or NCO methods, the ARM calculation is reasonably symmetric.
  - If a customer were to leave the system permanently, his TSM equipment could be retired, shrinking the rate base accordingly, and the ARM1 calculation would reasonably represent the avoided cost to ratepayers. This is not the case for rental, because the disused TSM equipment cannot generally economically be reused at another site (while meters and transformers can sometimes be returned to stock and reused, there are significant associated unavoidable removal and installation costs).
  - If a customer is added, the utility could (theoretically) buy a used TSM set on the market, and would pay an amount for depreciated TSM equipment that would be similar to the rate base (ARM1) value of its existing TSM equipment.

ARM (either version) As Marginal Cost (3)

- The ARM method (like the rental method) avoids the NCO method's undesirable dependence on customer growth, and thus avoids the possibility of anomalous results described above.

- Unlike both the rental and NCO, the ARM method correctly captures the opportunity value of existing TSM equipment.
  - Rental method overvalues existing TSM equipment (treating it as if it were new)
  - NCO undervalues existing TSM equipment (assigning a value of zero).

Conclusion

Adoption of the ARM (1 or 2) could end a 24-year-old controversy in MC-based ratemaking; It could also end the practice of simply averaging the outcome of 2 competing MC calculations in “black-box” settlements.

- The ARM methodology has a legitimate interpretation as an MC
- The ARM method is easy to implement, requiring only a single step beyond the Rental calculation
- The ARM method fairly reflects the value of existing hookup equipment in utility rate base.
- The ARM method avoids dependence on customer growth rates

Appendix: More on Marginal Cost and Opportunity Cost

- The term "**marginal cost**" may refer to an opportunity cost at the margin, or to marginal *pecuniary* cost — that is to say marginal cost measured by forgone money. –Wikipedia
- In microeconomic theory, the **opportunity cost of a choice** is the value of the best alternative forgone where, given limited resources, a choice needs to be made between several mutually exclusive alternatives.
- Assuming the best choice is made, it is the "cost" incurred by not enjoying the *benefit* that would have been had by taking the second best available choice.
- -The *New Oxford American Dictionary* defines it as "the loss of potential gain from other alternatives when one alternative is chosen."
- Opportunity cost is a key concept in economics, and has been described as expressing "the basic relationship between scarcity and choice"
- The notion of opportunity cost plays a crucial part in attempts to ensure that scarce resources are used efficiently. Thus, opportunity costs are not restricted to monetary or financial costs: the real cost of output forgone, lost time, pleasure or any other benefit that provides utility should also be considered an opportunity cost.—Wikipedia

Appendix: RCNLD

See, for example, the following excerpt from D.03-04-032, authorizing a sale of certain PG&E distribution facilities to the Turlock Irrigation District (TID):

- "LID [Laguna Irrigation District] argues that PG&E and TID considered only one method of determining the value of the assets, replacement cost less depreciation new (RCNLD), and that other valuation methods might have yielded a lower and more reasonable sales price. LID therefore asks the Commission to include a condition that provides that the use of RCNLD to value the assets sold to TID shall not be precedent in other cases involving transfers of utility assets. Laguna has been recently involved in litigation with PG&E to condemn certain electric distribution facilities. (Laguna Irrigation District v. Pacific Gas and Electric Company, Kings County Superior Court No. 99 C 052.) Laguna is therefore concerned that the valuation method here may be precedent in its pending litigation. We agree with PG&E that the courts will assess whether evidence regarding the valuation of utility assets in Commission proceedings should be considered in the condemnation proceedings, as well as the weight to be given Commission decisions pursuant to California law. LID does not oppose the sales price and has presented no evidence to show that the use of the RCNLD method of valuation has created an unfair or unrealistic price for the assets being sold to TID, or that another method of valuation would have resulted in a different price. Previous Commission decisions have found that a sales price for utility assets based on RCNLD, when negotiated between the parties in arms-length transactions, is fair and reasonable. We therefore approve the sales price here based on RCNLD. However, we recognize that RCNLD is only one method of valuation, and we may consider different valuation methodologies in other cases". (D.03-04-032, pp. 42-43, emphasis added).