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PREPARED DIRECT TESTIMONY OF

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ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY)

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CHAPTER 10

PREPARED DIRECT TESTIMONY OF MICHAEL FOSTER

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY – SDG&E)

I. PURPOSE

The purpose of my prepared direct testimony is to present the Long Run Marginal Cost (LRMC) study for San Diego Gas & Electric Company's (SDG&E) Customer-related, Medium Pressure Distribution-related, and High Pressure Distribution-related service functions and to allocate gas base margin to SDG&E's six customer classes. My testimony is organized as follows:

- Section II describes principles of cost allocation;
- Section III provides an overview of SDG&E's cost allocation proposal;
- Section IV explains the derivation of Customer-related marginal costs;
- Section V explains the derivation of Medium and High Pressure Distribution-related marginal costs;
- Section VI presents SDG&E's Real Economic Carrying Charges and marginal loading factors;
- Section VII summarizes the method for allocating gas base margin to SDG&E's customer classes; and
- Section VIII shows the allocated costs.

II. COST ALLOCATION PRINCIPLES

Cost allocation refers to the process of determining the cost of each utility function and allocating these functional costs to the utility's customer classes. The cost allocation proposal described below allocates costs to customer classes based on cost causality and maintains consistency with the existing practices whenever possible. The fundamental principle applicable

to these LRMC cost studies, for purposes of allocating costs to customer groups, is the concept of cost causation. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs. The essential element in the selection and development of a reasonable cost allocation methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics, and the costs incurred by the utility in serving those requirements. A cost allocation based solely on cost causation therefore seeks to present cost-based rates.

III. COST ALLOCATION PROPOSAL

I propose to continue the cost allocation framework that was proposed by SDG&E in the 2017 Triennial Cost Allocation Proceeding (TCAP), Application (A.) 15-07-014. That TCAP resulted in a multi-party settlement of several issues and outcomes, including cost allocation outcomes, which were approved in Decision (D.) 16-10-004.

For SDG&E's LRMC study, I derived the cost allocations for the Customer-related and Medium and High Pressure Distribution-related functions using the LRMC method. LRMC of a service refers to incremental cost to serve one additional unit in the long run; such unit cost is called marginal unit cost. The cost causation unit is called a marginal demand measure. The consolidated marginal demand measures are presented by witness Wei Bin Guo (Chapter 5). The LRMC-based functional revenue (i.e., marginal cost revenue) is derived by multiplying the LRMC by the number of marginal demand measures. For Customer-related costs, the marginal demand measure is the number of customers. For Medium Pressure Distribution-related and High Pressure Distribution-related costs, the marginal demand measure is peak day for each system.[1]

[1] Peak Day Demand is the December Peak Day. See Chapter 2 (Teplow).

Customer-related costs reflect the capital-related and operations and maintenance (O&M) expenses incurred by SDG&E to provide customer access to the gas supply system. This includes provisions for service lines, regulators, meters, call centers, and service representatives. Medium Pressure and High Pressure Distribution costs are associated with building and maintaining systems that deliver gas to customer load centers from the gas transmission system. The LRMC study also incorporates inputs from witness Sim-Cheng Fung (Chapter 8) for Transmission-related costs and witness Sharim Chaudhury (Chapter 12) for the Natural Gas Vehicle (NGV) compression adder.

Marginal costs are based on the incremental costs incurred by SDG&E to provide an additional unit of output, or serve one additional customer, in the long run. This unit cost is referred to as the marginal unit cost. As described in Chapter 12 (Chaudhury), the Rental methodology is used to determine marginal customer costs per customer and results in a single effective marginal unit cost for all customers in each rate class. Medium Pressure and High Pressure Distribution marginal costs are forecasted using a linear regression analysis[2] that predicts cumulative marginal investment[3] as a function of cumulative marginal peak-day demand. This analysis is conducted for the Medium Pressure and High Pressure Distribution systems separately, producing a unique unit marginal capital cost forecast for both the High Pressure Distribution and the Medium Pressure Distribution systems.

SDG&E's authorized margin is allocated to its six customer classes using marginal demand measures applied to the marginal unit costs. These demand measures were established in D.92-12-058, and have been updated in the subsequent cost allocation proceedings since, most

[2] See D.92-12-058, p. 38. The Commission adopted the regression methodology, which SDG&E has utilized in every subsequent cost allocation proceeding to the best of my knowledge.
[3] Defined as the forecasted investment amount required to support one additional unit of peak-day demand.

recently in D.16-10-004. SDG&E allocates costs to three core customer classes and three noncore customer classes. The three core classes are residential, core commercial and industrial (C&I), and NGV. The noncore customer classes are C&I, small electric generation (EG) (less than 3 million therms per year), and large EG (greater than 3 million therms per year).

IV. CUSTOMER-RELATED MARGINAL COSTS

Customer-related marginal unit cost reflects the cost of a customer's access to the gas utility's supply system, and is comprised of: (1) the marginal capital cost of service lines and meter set assemblies; (2) the marginal direct O&M costs associated with the installation and service of those assets, as well as other customer support functions; and (3) O&M loaders.

A. Marginal Capital Costs

Service line, regulator, and meter (SRM) costs reflect the capital expense associated with providing customer access to the gas supply system. These costs include gas meters, regulators, pipes, and installation labor. The SDG&E Gas Distribution Engineering Department provides updated customer data, including:

- Meter size, type, regulator, fitting costs and installation costs;
- Service footages;
- Service costs for new hook-ups and replacements;
- Costs of service line installations; and
- Series of flow ranges,[4] and corresponding equipment profiles, at each range.

Twenty-six flow ranges are identified for which SRM costs are summarized. These total capital costs are annualized using corresponding Real Economic Carrying Charge factors, which

[4] The SDG&E Gas Distribution Engineering Department defines flow ranges to specify typical meter and regulator equipment design flow capacity used to support different levels of gas flow.

I discuss in Section VI. The annualized costs are multiplied by the number of meters for each customer class represented within each flow range to determine the total annual capital cost associated with serving each class. Finally, the total annualized capital cost is divided by the forecast number of customers in each class to determine each class' average marginal SRM cost. Table 1 shows the resulting 2020[5] annualized marginal capital-related costs per customer.

TABLE 1
CUSTOMER-RELATED LONG-RUN MARGINAL CAPITAL COSTS

Customer Class	Rental-Method Customer Cost (2020$/customer)
Residential	$174
Core Commercial/Industrial	$277
Natural Gas Vehicle	$919
Noncore Commercial/Industrial	$1,861
Small Electric Generation	$1,344
Large Electric Generation	$2,223

B. Marginal Direct O&M Costs

Customer Services direct O&M expenses are accounted for in FERC Accounts 901-905 and 907-910 and are allocated entirely as Customer-related function. These expenses are associated with responding to customer service field orders and generally operating and maintaining service lines, meters, and house regulators. FERC Accounts 870-894 record Distribution O&M. These expenses are associated with the maintenance of customers' meters, regulators, and service lines, as well as distribution mains.

Distribution O&M costs are assigned to market segments by classifying the costs as either Customer-related or Medium Pressure and High Pressure Distribution-related. Customer-

[5] Escalation factors updated to reflect Global Insight's forecast as of first quarter of 2017. See A.17-10-007 (2019 GRC), Exhibit SDG&E-39, SDG&E Direct Testimony of Scott R. Wilder, October 6, 2017.

related distribution O&M is allocated entirely to the Customer-related function. These activities include meter reading, customer services, credit collections, and billing services. The Medium and High Pressure Distribution-related expenses are allocated between the High Pressure Distribution, Medium Pressure Distribution, and Customer-related functions based on pipeline mileage as of December 31, 2016. The SDG&E Gas Distribution Engineering Department identifies the marginal portion of each of the FERC Accounts 870-894.

Customer-related distribution O&M is allocated to the customer classes using the effective percentage of total annualized SRM investment costs. The resulting allocation of Customer-related distribution O&M expenses to customer classes is combined with Customer Services O&M expenses, and then divided by the number of customers in each class to determine a per-customer direct O&M expense.

The direct O&M costs are allocated to customer classes in three steps. First, Customer Services marginal direct O&M expenses are classified into functions. Expenses by Customer Services function are then assigned to one of these operational activities. Finally, these expenses are allocated to customer classes based on either the operational activity performed or the market segment supported.

Once Customer Services costs are allocated to the customer classes, they are combined with the portion of Distribution O&M costs allocated to Customer-related function in order to develop total Customer-related direct O&M costs. Table 2 shows the total Customer-related direct O&M costs.

TABLE 2
CUSTOMER-RELATED DIRECT MARGINAL O&M EXPENSES
(2020$)

Customer Class	FERC 870-894 $000	FERC 901-910 $000	Customers per Class	Direct O&M $/Customer
Residential	$34,293	$2,327	865,245	$42
Core Commercial/Industrial	$3,514	$84	31,920	$113
Natural Gas Vehicle	$7	$0	58	$115
Noncore Commercial/Industrial	$25	$0	58	$428
Small Electric Generation	$26	$0	76	$345
Large Electric Generation	$11	$0	16	$668

C. O&M Loaders

Three distinct O&M loaders are applied to direct marginal O&M costs to develop the fully-loaded O&M. These loading factors reflect indirect costs for: (1) administrative and general (A&G) expenses, (2) general plant, and (3) materials and supplies (M&S). The A&G and general plant loading factors are percentages that are applied to the direct O&M costs for each functional category. M&S costs are assigned to each functional category based on plant investment. Application of O&M loaders to direct costs produces a fully-loaded marginal unit cost.

D. Fully Loaded Customer-Related LRMC

Table 3 provides the total marginal customer costs for the six SDG&E customer classes. These costs are the result of combining the fully-loaded O&M costs with the capital related costs from Table 1. The fully-loaded O&M costs include direct O&M and O&M loaders. The O&M loaders are A&G expenses, M&S, and general plant, as discussed in Section VI below. The noncore customer classes post significantly higher marginal costs per customer than the core customer classes because noncore customers have much higher gas service demands and require larger and more specialized metering and service facilities compared to core customers.

TABLE 3
CUSTOMER-RELATED LONG RUN MARGINAL COSTS
(2020$/customer)

Customer Class	Annualized Capital Cost	Expense-Related O&M Direct	M&S	A&G	General Plant	Total $/Customer
Residential	$174	$42	$0	$10	$7	$234
Core Commercial/Industrial	$277	$113	$0	$27	$20	$437
Natural Gas Vehicle	$919	$115	$0	$27	$20	$1,082
Noncore Commercial/Industrial	$1,861	$428	$2	$103	$75	$2,469
Small Electric Generation	$1,344	$345	$1	$83	$61	$1,833
Large Electric Generation	$2,223	$668	$2	$160	$118	$3,172

V. MEDIUM PRESSURE AND HIGH PRESSURE DISTRIBUTION-RELATED MARGINAL COSTS

Marginal costs are calculated for both the Medium Pressure and High Pressure Distribution systems. Separate marginal costs are calculated for the Medium Pressure and High Pressure Distribution systems because the two systems perform different functions.

A. Marginal Capital Costs

This LRMC study utilizes nine years of historical (2008 - 2016) and six years of forecast (2017 - 2022) distribution plant investments and marginal demand measures. The SDG&E Gas Distribution Engineering Department provides the historical period investments from an analysis of accounting data for Medium Pressure Distribution and High Pressure Distribution capital investments. The forecast investments are also provided by that department. The marginal demand measures are based on an analysis of peak-day throughput[6] on the Medium Pressure Distribution and High Pressure Distribution systems. I receive the marginal demand measures from the consolidated demand forecast, including peak-day load by market segment, which is presented in Chapter 5 (Guo).

[6] Throughput is defined as the volume of gas flowing through a meter over a specified period of time.

Linear regression is used to determine the marginal capital costs of the Medium Pressure Distribution and High Pressure Distribution systems. This method plots the cumulative incremental investment as the dependent variable against the cumulative incremental changes in peak-day demand, which is the independent variable. The slope of the best-fit line is taken to be the marginal capital cost. This capital cost is then annualized by using a weighted-average Real Economic Carrying Charges factor applicable to Distribution Demand-related distribution pipeline investments. The linear regression analysis is described in Section D below.

B. Marginal Direct O&M Costs

FERC Accounts 870-894 record Distribution-related O&M, and these expenses are assigned to market segments by classifying the costs as either Customer-related or Distribution-related. The Distribution-related expenses are allocated between the High Pressure Distribution, Medium Pressure Distribution, and Customer-related functions based on pipeline mileage as of December 31, 2016. The SDG&E Gas Distribution Engineering Department identifies the marginal portion of each of FERC Accounts 870-894.

Medium Pressure Distribution and High Pressure Distribution direct O&M expenses are divided by the peak-day demand of each system to determine their respective direct O&M expenses. Table 4 below presents a summary of direct distribution O&M expenses by market segment.

TABLE 4 DISTRIBUTION-RELATED DIRECT MARGINAL O&M EXPENSES (2020$)				
Distribution Function	**FERC 870-894** ($000)	**FERC 901-910** ($000)	**Peak-day Load** (mcfd)	**Direct O&M** ($/mcfd)
Medium Pressure	$13,665	$0	382,880	$35.69
High Pressure	$630	$0	412,211	$1.53

C. O&M Loaders

A&G, general plant, and M&S loaders are applied to direct costs to produce a fully-loaded marginal unit cost. The development of these loaders is described in Section VI.

D. Fully Loaded Distribution LRMC

Fully-loaded O&M costs are added to distribution marginal capital costs to determine the total marginal costs for the Medium Pressure Distribution and High Pressure Distribution systems. Table 5 presents the total marginal costs for the Medium Pressure Distribution systems.

TABLE 5 MEDIUM PRESSURE DISTRIBUTION LRMC (2020$/Mcf Medium Pressure Distribution peak day)		
	Marginal Investment Cost	$2,887.83
x	RECC Factor	7.73%
=	Annualized Investment Cost	$223.28
	Expense-Related	
+	O&M Cost	$35.69
+	A&G Cost	$8.55
+	General / Common Plant Cost	$6.28
+	M&S Cost	$0.54
=	**Total Marginal Cost**	$274.34

The following chart depicts the results of the regression analysis in graphical form.

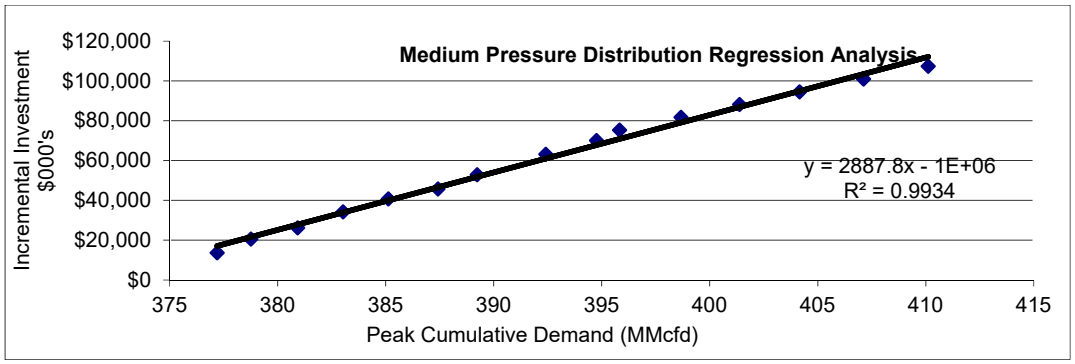
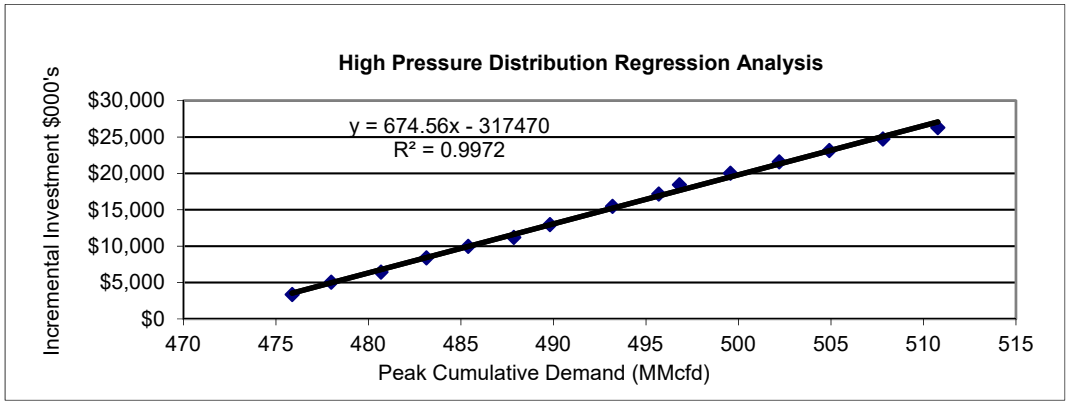


Table 6 presents the total marginal costs for the High Pressure Distribution systems.

TABLE 6
HIGH PRESSURE DISTRIBUTION LRMC
(2020$/Mcf High Pressure Distribution peak day)

	Marginal Investment Cost	$674.56
x	RECC Factor	7.73%
=	Annualized Investment Cost	$52.16
	Expense-Related	
+	O&M Cost	$1.53
+	A&G Cost	$0.37
+	General / Common Plant Cost	$0.27
+	M&S Cost	$0.12
=	**Total Marginal Cost**	$54.44

The following chart depicts the results of the regression analysis in graphical form.



VI. MARGINAL COST ESTIMATION FACTORS

A. Real Economic Carrying Charges (RECC)

In the previous sections, RECC factors appeared in the calculation of marginal unit costs for customer-related costs as well as Medium Pressure and High Pressure Distribution. RECC factors are used to convert capital investment into annualized capital costs. The LRMC Decision[7] established the use of RECC factors in LRMC studies:

> The Total Investment computes an arithmetic average by dividing the total investment during the planning horizon by the total load growth using the same period. The resulting unit marginal cost is than annualized using a Real Economic Carrying Cost (RECC) factor. The RECC capital amortization formula levelizes a stream of future payments in a manner similar to an annuity calculation but with an inflation adjustment. RECC models incorporate assumptions for service life, salvage value, cost of capital, inflation rates, and discount rates.[8]

The RECC factors used in Tables 3, 4 and 8 are the weighted averages for the respective Customer-related, Medium Pressure Distribution-related, and High Pressure Distribution-related functional categories, and, when applied to a capital investment, produce the first year charge of a series of annualized capital charges that remain constant in real terms over the life of the asset. The RECC factor is a function of authorized rate of return, inflation, salvage value, book life, and tax rates. Based on the differing book lives and salvage values of utility assets, separate RECC factors have been developed for service lines, pressure regulators, meters, and distribution capital investments.

[7] D.92-12-058.
[8] D.92-12-058, p. 32.

SDG&E has updated its RECC factors using inflation assumptions from Global Insight's forecast, updated tax rates, and SDG&E's authorized rate of return of 7.79% revised per Advice Letter No. 2160-G.[9] The authorized book lives and salvage values for the different investments have also been updated to reflect current factors.

TABLE 7
REAL ECONOMIC CARRYING CHARGE FACTORS

Cost Type	RECC %
Meters and Regulators	8.44%
Meter/Regulator Installation	8.82%
Service Line Pipe	7.74%
Weighted-Average Distribution	7.73%
Materials and Supplies	13.12%
Weighted-Average General/Common Plant	11.09%

B. Marginal O&M Loading Factors

Loading factors account for costs related to A&G expenses and payroll taxes, general plant, and M&S. SDG&E derives loading factors for marginal cost investments using the same methodology included in the 2017 TCAP Phase 2 application, A.15-07-014. The A&G and general plant loading factors are percentages that are applied to the direct O&M costs for each functional category. M&S costs are assigned to each functional category based on plant investment. Application of O&M loaders to direct costs produces a fully-loaded marginal unit cost.

1. A&G Loading Factor

A&G refers to operational expenses that are not directly associated with the production of any good or service, and include items such as rent and insurance. Marginal A&G expenses and

[9] SDG&E's January 1, 2013 Consolidated Rate Update which implemented SDG&E's updated costs of capital and capital structure, effective January 1, 2013.

payroll taxes are combined into a single loading factor. I relied on the recorded year 2016 A&G expenses from the Annual Report, which are then classified as either marginal or non-marginal by account. As shown below in Table 8, the A&G expenses and payroll tax loader is 23.95%. The A&G loading factor is calculated as a percentage of total O&M (less A&G) and then multiplied by the direct O&M unit cost for each function.

TABLE 8
A&G LOADING FACTOR
(2016$)

	Account Description	Marginal Costs (000s)
	A&G Expenses	$17,133
+	Payroll Taxes	$4,261
=	Total A&G with Payroll Taxes	$21,395
/	Total O&M Expenses excluding A&G	$89,314
=	A&G Loading Factor	23.95%

2. General Plant Loading Factor

General plant includes structures and improvements, office furniture and equipment, computer applications and equipment, shop and garage equipment, and communication equipment, as well as plant shared between SDG&E electric and gas operations allocated to the gas function. The recorded year 2016 general plant[10] total is multiplied by the weighted-average RECC factor of 11.09% to obtain an annualized general plant of $30.4 million. The general plant loading factor is then determined by dividing annualized general plant by total O&M expenses. Table 9 shows the derivation of the general plant loading factor.

[10] Total 2016 General Plant of $273,925K is the sum of Total General Plant of $13,701K (source: 2016 SDG&E FERC Form 2) and Common Utility Plant – Gas of $260,224K (source: 2016 SDG&E Gas FERC Form 1).

TABLE 9 GENERAL PLANT LOADING FACTOR (2016$)	
Account Description	2016 Recorded Costs (000s)
Total General Plant	$273,925
+ Average General Plant RECC	11.09%
= Annualized General Plant	$30,369
/ Total O&M Expenses	$172,649
= General Plant Loading Factor	17.59%

3. M&S Loading Factor

M&S includes those materials in stock for use in company operations. Examples of M&S items include pipe, valves, fittings, and safety equipment. Recorded year 2016 M&S costs of $3.3 million are allocated to the functions based on percentage of gross plant in each functional category and then multiplied by a RECC factor of 13.12% to obtain annualized M&S costs. M&S costs allocated to the customer cost function are further allocated to the customer classes at the same relative percentage as direct O&M. M&S loaders are then derived by dividing allocated M&S costs by the number of customers in each class. For the Distribution functions (i.e., Medium Pressure Distribution-related and High Pressure Distribution-related), allocated M&S costs are divided by peak-day load in order to determine the loader amounts. Table 10 presents the resulting M&S loading costs by customer class and function.

TABLE 10
M&S LOADING FACTORS
(2020$)

Customer Class	Allocated M&S	Customers per Class	M&S Loader ($/Customer)
Residential	$135,128	865,245	$0.16
Core Commercial/Industrial	$13,276	31,920	$0.42
Natural Gas Vehicle	$25	58	$0.42
Noncore Commercial/Industrial	$92	58	$1.58
Small Electric Generation	$97	76	$1.27
Large Electric Generation	$39	16	$2.47
Distribution Function	**Allocated M&S**	**Peak-day Load (mcfd)**	**M&S Loader ($/mcfd)**
Medium Pressure	$207,935	382,880	$0.54
High Pressure	$50,922	412,211	$0.12

VII. ALLOCATED BASE MARGIN

Upon completing the cost studies to allocate costs to functional categories, SDG&E allocates each functional cost to customer classes using the marginal demand measures: number of customers for the customer costs and peak day for both Medium Pressure Distribution costs and High Pressure Distribution costs. Each marginal demand measure reflects the forecast annual average marginal demand measures (listed above) for the years 2020 - 2022, reflecting the duration of the 2020 TCAP period.

For the Customer-related functional category, Table 11 shows marginal unit costs, the customer counts, and the marginal cost revenues by customer classes on an unscaled basis. The term "unscaled" refers to the sum of the marginal demand measures multiplied by the marginal unit costs for each customer class, not adjusted or "scaled" to equal SDG&E's authorized base margin. A scalar factor is applied to adjust total revenues to equal the authorized base margin.

TABLE 11
UNSCALED LONG RUN MARGINAL COST
CUSTOMER COST
(2020$)

Customer Class	Customer LRMC ($/customer)	Customer Count	Customer Cost ($000)
Residential	$234	874,067	$204,934
Core C/I	$437	30,937	$13,509
NGV	$1,082	28	$30
Total Core			$218,473
Noncore C/I	$2,469	53	$131
Small EG	$1,833	72	$132
Large EG	$3,172	18	$57
Total Noncore			$320
Total SDG&E			**$218,793**

Table 12 shows the allocation of Medium Pressure Distribution and High Pressure Distribution Marginal Cost Revenues by customer classes. Medium Pressure Distribution costs are allocated using 1-in-35 peak day core / 1-in-10 cold day noncore Medium Pressure Distribution service level peak day demand. High Pressure Distribution costs are allocated using 1-in-35 peak day core / 1-in-10 cold day noncore High Pressure Distribution service level peak day demand.

TABLE 12
UNSCALED LONG RUN MARGINAL COST
MEDIUM AND HIGH PRESSURE DISTRIBUTION COSTS

Customer Class	Medium Pressure Distribution LRMC ($/mcfd)	Medium Pressure Distribution Peak-Day (Mcfd)	Medium Pressure Distribution Costs ($000)	High Pressure Distribution LRMC ($/mcfd)	High Pressure Distribution Peak-Day (Mcfd)	High Pressure Distribution Costs ($000)
Residential	$274	283,108	$77,669	$54	283,169	$15,417
Core C/I	$274	105,566	$28,962	$54	107,283	$5,841
NGV	$274	3,845	$1,055	$54	6,081	$331
Total Core			$107,685			$21,589
Noncore C/I	$274	5,707	$1,566	$54	7,663	$417
Small EG	$274	5,481	$1,504	$54	6,371	$347
Large EG	$274	2,074	$569	$54	11,467	$624
Total Noncore			$3,639			$1,388
Total SDG&E			**$111,324**			**$22,977**

In D.92-12-058, the Commission stated that marginal cost revenues need to be scaled to the embedded-based authorized revenue requirement under SDG&E's ratemaking procedures. The current SDG&E gas base margin for transportation rates effective January 1, 2018, is $323 million and this is the revenue requirement used to determine the scalar. The scalar adjusts allocated marginal costs to the authorized base margin, excluding costs directly assigned to the Transmission ($40.5 million)[11] and NGV Public Access ($0.7 million) functions, which are not scaled.

In this TCAP, marginal costs are scaled at a rate of 80% in order to reconcile to the adjusted base margin[12] of $282 million. Table 13 shows the total cumulative SDG&E costs being allocated. Finally, scaled LRMC costs are added to the Transmission and NGV Public

[11] Including Franchise Fees and Allowance for Uncollectible (FF&U).
[12] Adjusted Base Margin refers to base margin excluding non-scaled items: Backbone Transmission Service (BTS) and NGV public access.

Access costs to determine the fully cost-based allocation of authorized gas base margin of $306 million.[13] The total costs for SDG&E being allocated is presented in Table 14.

TABLE 13
LONG RUN MARGINAL COST SCALED CUSTOMER AND DISTRIBUTION COSTS
($000 in 2020$)

Customer Class	Customer Cost	+	Medium Pressure Distribution	+	High Pressure Distribution	=	Unscaled LRMC	x	Scalar	=	Scaled LRMC
Residential	$204,934		$77,669		$15,417		$298,020		80%		$237,854
Core C/I	$13,509		$28,962		$5,841		$48,311		80%		$38,558
NGV	$30		$1,055		$331		$1,416		80%		$1,130
Total Core	$218,473		$107,685		$21,589		$347,747		80%		$277,541
Noncore C/I	$131		$1,566		$417		$2,114		80%		$1,687
Small EG	$132		$1,504		$347		$1,983		80%		$1,582
Large EG	$57		$569		$624		$1,250		80%		$998
Total Noncore	$320		$3,639		$1,388		$5,347		80%		$4,268
Total SDG&E	**$218,793**		**$111,324**		**$22,977**		**$353,094**		80%		**$281,809**

[13] Per Chapter 8 (Fung), the SDG&E transmission system is 100% backbone. For the purposes of this testimony, SDG&E's $40.5 million (including FF&U) in backbone transmission costs are allocated to the Backbone Transmission Service rate class. These costs will be incorporated in System Integration in Chapter 12 (Chaudhury), which unbundles part of the combined Southern California Gas Company (SoCalGas)/SDG&E transmission system into the BTS tariff, with the remaining transmission costs being allocated to the local transmission function and, ultimately, back to the customer classes.

TABLE 14
ALLOCATION OF BASE MARGIN
$ 000

Customer Class	Scaled LRMC	+	Backbone Transmission	+	NGV Public Access	=	Unadjusted Allocated Base Margin
Residential	$237,854		$0		$0		$237,854
Core C/I	$38,558		$0		$0		$38,558
NGV	$1,130		$0		$647		$1,777
Total Core	$277,541		$0		$647		$278,189
Noncore C/I	$1,687		$0		$0		$1,687
Small EG	$1,582		$0		$0		$1,582
Large EG	$998		$0		$0		$998
Total Noncore	$4,268		$0		$0		$4,268
Backbone Transmission	$0		$40,564		$0		$40,564
Total SDG&E	**$281,809**		**$40,564**		**$647**		**$323,020**

VIII. COMPARISON OF PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION

Table 15 shows a comparison of the proposed cost allocation to the current allocation. This comparison is pre-System Integration[14] and pre-BTS unbundling.[15]

[14] Shows rates pre-System Integration. Under System Integration, the costs of local transmission facilities are recovered on a common (or integrated) basis from customers of both SDG&E and SoCalGas. This integration reflects the splitting of total local transmission costs between the utilities by the % share of cold-year peak month throughput.

[15] Shows allocation pre-BTS unbundling. BTS represents the costs of SoCalGas' and SDG&E's transmission lines from the California Border receipt points to SoCalGas' Citygate.

TABLE 15
COST ALLOCATION COMPARISON
($000)

Customer Class	Adjusted Allocation of Base Margin	% Total	Current Allocation of Base Margin	% Total
Residential	$237,854	73.6%	$241,785	74.9%
Core C/I	$38,558	11.9%	$30,004	9.3%
NGV	$1,777	0.6%	$1,126	0.3%
Total Core	$278,189	86.1%	$272,916	84.5%
Noncore C/I - D	$1,687	0.5%	$2,112	0.7%
EG - D	$1,582	0.5%	$1,580	0.5%
TLS	$998	0.3%	$147	0.0%
Total Noncore	$4,268	1.3%	$3,838	1.2%
Backbone Transmission	$40,564	12.6%	$46,266	14.3%
Total SDG&E	**$323,020**		**$323,020**	

This concludes my prepared direct testimony.

IX. QUALIFICATIONS

My name is Michael W. Foster. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I received a Bachelor of Arts degree in Economics from the University of California, Santa Barbara in 1995. I received a Master of Business Administration degree from the Darden School of Business at the University of Virginia, Charlottesville in 2000.

As Principal Regulatory Economic Advisor, I support the gas transportation rates for both SoCalGas and SDG&E. This includes allocating authorized revenue requirements to customer rate classes, developing the design of the rate for each class, and computing the impact on customers' monthly bills.

I have previously testified before the Commission.