Application of San Diego Gas & Electric Company (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 23-01-008
Exhibit No.: _________

CHAPTER 4

REVISED PREPARED DIRECT TESTIMONY OF

WILLIAM G. SAXE

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 29, 2023

SDGE™

TABLE OF CONTENTS

REVISED PREPARED DIRECT TESTIMONY OF
WILLIAM G. SAXE
(CHAPTER 4)

I. OVERVIEW AND PURPOSE

The purpose of my revised prepared direct testimony is to present San Diego Gas & Electric Company's (SDG&E) updated marginal distribution demand and marginal distribution customer costs, and the resulting electric allocation of distribution revenues to customer classes based on these marginal distribution costs.

My testimony is organized as follows:

- **Section II – Background**: Describes the development of the proposed updated marginal distribution demand and marginal distribution customer costs, and the use of these marginal distribution costs to develop the proposed electric cost-based distribution revenue allocation.
- **Section III – Marginal Distribution Demand Costs**: Presents the development of the proposed updated marginal distribution demand costs based on the National Economic Research Associates (NERA) Regression Method.
- **Section IV – Marginal Distribution Customer Costs**: Presents the development of the proposed updated marginal distribution customer costs based on the Rental Method.
- **Section V – Distribution Revenue Allocation**: Presents the proposal to use the proposed updated marginal distribution costs coupled with the Equal Percent of Marginal Costs (EPMC) methodology to allocate the authorized distribution revenue requirement.
- **Section VI – Marginal Distribution Costs of Solar Customers**: Presents the illustrative marginal and EPMC distribution customer and demand cost rates for Net Energy Metering (NEM) and Non-NEM customers.
- **Section VII – Summary and Conclusion**: Provides a summary of recommendations.
- **Section VIII – Witness Qualifications**: Presents my qualifications.

My testimony also contains the following attachments:

- **Attachment A –** Proposed Marginal Distribution Costs.

- **Attachment B –** Illustrative Cost-Based Distribution Revenue Allocation.
- **Attachment C –** Illustrative New Customer Only (NCO) Marginal Distribution Customer Costs.
- **Attachment D –** Comparison of Illustrative Marginal and EPMC Distribution Customer and Distribution Demand Cost Rates for NEM and Non-NEM Customers.

II. BACKGROUND

For more than 30 years, the California Public Utilities Commission (CPUC) has relied on marginal costs as the basis for revenue allocation and rate design development for the different customer classes. My testimony presents SDG&E's updated studies for both marginal distribution demand and marginal distribution customer costs. The proposed updated marginal distribution demand costs are based on the NERA Regression Method while the proposed updated marginal distribution customer costs utilize the Rental Method. Recent SDG&E rate design proceedings, specifically its Test Year (TY) 2008 General Rate Case (GRC) Phase 2 (Application (A.) 07-01-047), TY 2012 GRC Phase 2 (A.11-10-002), TY 2016 GRC Phase 2 (A.15-04-012), and TY 2019 GRC Phase 2 (A.19-03-002), were decided by settlement on revenue allocation without formal adoption of marginal distribution costs or marginal cost methodologies.

Marginal cost is the change in costs caused by providing one additional unit of a good or service. In the electric utility context, marginal cost is defined as the change in cost to provide electric service to an additional customer. Marginal distribution demand costs measure the cost of serving an additional unit of customer kilowatt (kW) demand on the electric distribution system. Marginal distribution customer costs reflect the cost of serving an additional customer on the electric distribution system. These marginal distribution costs are used as a frame of reference for the determination of cost-based rates when we design distribution rates to reflect the costs of providing utility electric service.

In addition to marginal distribution cost themselves, SDG&E is proposing that the authorized distribution revenue requirement be allocated to customer classes using the updated marginal costs proposed in my testimony and based on the System Average Percent Change (SAPC) approach, as addressed in the revised prepared direct testimony of SDG&E witness Ray Utama (Chapter 2). Allocating the authorized distribution revenue requirement based on marginal costs balances fairness and equity by providing customers clear and accurate price signals for the electric service they receive.

III. MARGINAL DISTRIBUTION DEMAND COSTS

A. Marginal Distribution Demand Cost Background

Marginal distribution demand costs represent the cost of providing facilities from the substation to the customer access point in order to meet the customer's individual demand. These marginal distribution demand costs are separated into (1) marginal feeder and local distribution costs and (2) marginal substation costs

Consistent with its previous GRC Phase 2 proceedings, SDG&E will continue the use the NERA Regression Method to calculate marginal feeder and local distribution and substation costs for the system as a whole. By definition, the NERA Regression Method uses ten years of historical and five years of forecasted distribution investments, along with annual distribution system peak determinants in a regression methodology. The NERA Regression Method identifies the utility's cumulative incremental changes in distribution peak load data as the independent variable, the utility's cumulative incremental distribution growth-related investments as the dependent variable, and then regresses the data over a fifteen-year period of data points.

SDG&E's marginal distribution demand cost component includes distribution investment costs related to load and customer growth for the period 2010-2024. These marginal distribution demand costs do not include reliability investments, replacement costs, or customer access costs, because these costs are not considered peak growth-related.

The distribution demand investment cost component is derived in units of dollars-per-kW. To more accurately reflect the true cost of investment, the investment costs are adjusted by various loading factors. These loading factors reflect additional costs that are related to the addition of capacity to the distribution systems. Loading factors have been derived for Operations & Maintenance (O&M), Administrative & General (A&G), General Plant (GP), and Working Capital (WC).

SDG&E's cumulative change in peak load data is based on distribution planning forecasted circuit and substation loads from 2010-2024.

B. Unit Marginal Feeder and Local Distribution Costs

Marginal feeder and local distribution costs represent the cost of expanding facilities from the distribution substation to the point of customer access to serve an additional kW of demand. The cost of feeder and local distribution facilities is based on the projected investments needed to meet load growth on SDG&E's system during a specific planning horizon. These investments include facilities such as poles, fixtures, capacitors, and overhead and underground conductors and devices.

The feeder and local distribution investments used in the NERA Regression Method were obtained from distribution capital budget forecasts for the period 2022 through 2024.[1] Only

[1] 2022-2024 Distribution Capital Budget Forecasts are found in the SDG&E TY 2024 GRC Phase 1 Revised Prepared Direct Testimony of Oliva Reyes. *See* A.22-05-016, SDG&E Revised Prepared Direct Testimony of Oliva Reyes (Electric Distribution Capital) (August 2022), (Exhibit (Ex.) SDG&E-11-R) at Appendix B.

three years of forecasted data was available from the distribution capital budget data. Since only three years of forecast data was available, and 15 years of total data is required for the NERA Regression Model, twelve years of historical investment data from years 2010 through 2021 was used for the historical period. Because marginal costs reflect the cost to meet new demand on the system, only distribution investments related to capacity additions were used in the regression calculation.

After obtaining the feeder and local distribution investment using the NERA Regression Method, the result is then adjusted to reflect both GP and WC loaders. The resulting amount (reflected in $/kW) is then annualized to $/kW-year using a Real Economic Carrying Charge (RECC) factor derived for feeder and local distribution plant accounts. The annualized investment amount then receives an A&G plant loader, fixed O&M loader, and A&G fixed O&M loader. Lastly, the resulting loaded annualized investment sum is escalated to 2024 dollars to derive the marginal distribution demand costs for feeder and local distribution.[2]

SDG&E's proposed marginal distribution demand costs for feeder and local distribution are provided in Attachment A to my testimony.

C. Unit Marginal Substation Costs

Marginal substation costs represent the forecasted cost for construction of substations to serve an additional kW of demand. The marginal cost of substations is based on the projected investments needed to meet the load growth on the SDG&E system during a given period of time.

[2] 2024 escalations are the cost escalation factors presented in SDG&E TY 2024 GRC Phase 1 Prepared Direct Testimony of Scott Wilder. *See* A.22-05-016, Workpapers to Prepared Direct Testimony of Scott Wilder - Cost Escalations, (Ex. SDG&E-41-WP).

The substation investments used to calculate marginal substation costs were obtained from capital budget forecasts for the period 2022 through 2024.[3] Only three years of forecasted substation data was available from the capital budget data. Because only three years of forecast data was available, and 15 years of total data is required for the NERA Regression Model, twelve years of historical investment data from years 2010 through 2021 was used for the historical component. Because marginal costs reflect the cost to meet new demand on the system, only distribution investments related to capacity additions were used in the regression calculation.

After obtaining the substation investment using the NERA Regression Method, the result is then adjusted to reflect both GP and WC loaders. The resulting amount (reflected in $/kW) is then annualized to $/kW-year using a RECC factor derived for substation plant accounts. The annualized investment then receives an A&G plant loader, fixed O&M loader, and A&G fixed O&M loader. Lastly, the resulting loaded annualized investment sum is escalated to 2024 dollars to derive the marginal distribution demand costs for substations.[4]

SDG&E's proposed marginal distribution demand costs for substations are provided in Attachment A to my testimony.

IV. MARGINAL DISTRIBUTION CUSTOMER COSTS

A. Marginal Distribution Customer Cost Background

Marginal distribution customer costs represent the cost of providing an individual customer access to electrical service. These marginal costs are composed of costs associated with the investment required to provide access (hook up) to a new customer and the ongoing costs related to maintaining the new customer. Customer costs related to initial access and those related to ongoing maintenance vary by customer type, size, service voltage, and type of

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[3] *See* Ex. SDG&E-11-R at Appendix B.
[4] Ex. SDG&E-41-WP.

equipment used for customer access, and include distribution-related investments for items such as final line transformers (transformers), service drops, meters, customer related O&M, Customer Service Distribution, A&G, GP, and WC.

Consistent with its previous GRC Phase 2 proceedings, SDG&E will continue the use of the Rental Method to calculate unit marginal customer costs for the various proposed customer classes, which for SDG&E consists of residential, small commercial, medium commercial, large commercial & industrial (large C&I), agricultural, and street lighting classes.[5] As explained below in Section F, SDG&E proposes the use of the Rental Method because it believes it sends a more accurate and more reasonable price signal of the cost of providing an individual customer access to the electrical system compared to other marginal distribution customer cost methodologies considered in previous GRC Phase 2 applications.

B. Transformer, Service Drop, and Meter (TSM) Costs

The customer investment costs for each customer type, customer size, and service voltage level were calculated using the TSM method. The TSM method includes transformers, service drops, and meters as the basis of the customer hookup costs. The installed costs for the TSM component are based on a detailed analysis of each individual component. Cost estimates for the various customer sizes and service levels were developed for: (1) transformers based on transformer size and the average number of forecasted customers per transformer; (2) service drops based on wire size, number of runs, average service length, and compression lug wires; and (3) meters based on size and type (single- or three-phase). The TSM investment cost for

[5] As explained in the revised prepared direct testimony of SDG&E witness Hannah Campi (Chapter 3), SDG&E is proposing to split the current medium/large commercial & industrial class into two classes: (a) medium commercial; and (b) large C&I.

each customer group was based on engineering estimates for a typical customer by size and class.

To determine the average TSM costs for each customer class, customers are grouped by maximum annual demand levels (in kW). Once grouped, the TSM costs for each customer demand level are calculated by multiplying the number of customers per demand level by the estimated demand-specific cost for each TSM component. A weighted average is then calculated for each TSM component that produces the average TSM cost per customer class. These TSM costs are then adjusted for Rule 15/Rule 16 allowances that residential and non-residential customers receive to cover TSM installation costs. For residential customers, the Rule 15/Rule 16 allowance to cover TSM costs is currently $3,981 per customer hook-up;[6] thus, the residential TSM costs used in the marginal distribution customer cost calculation reflects a maximum TSM cost per residential customer of $3,981. For non-residential customers, the Rule 15/16 allowance is calculated separately for each customer;[7] thus, the non-residential TSM costs are adjusted for the average percentage of TSM costs paid by non-residential customers based on historical data, which is 17%.

Once developed, the TSM costs are multiplied by GP, WC, and A&G Plant loading factors. After receiving GP, WC, and A&G Plant loading, the TSM costs are then converted to an annualized amount (dollars-per-customer-per-year) by using a RECC that calculates an annual economic rent.

C. O&M Costs

In order to develop a per-customer O&M cost allocation, SDG&E analyzed the Federal Energy Regulatory Commission (FERC) Form 1 Distribution O&M account costs (580 to 598)

[6] Rule 15 tariff, Sheet 5 (effective October 10, 2022) at Section C.3.
[7] *Id.* at Section C.4.

to determine which portion of each account relates to distribution demand and which relates to customer connection. The customer-connection-related account amounts are totaled for the O&M costs.

SDG&E then allocates the customer-related O&M costs to the various rate schedules by using a factor derived from each schedule's percentage of the grand total of the estimated TSM cost. These amounts are then adjusted by an A&G O&M loading factor before calculating the per-customer O&M cost for the marginal distribution customer costs.

D. Customer Service Distribution Costs

Customer service distribution costs represent customer support customer costs for activities such as customer service field, smart metering, billing, credit & collections, postage, branch office, customer contact center, marketing and communication, and customer programs. The customer service distribution costs allocated for marginal distribution customer cost purposes in this proceeding are based on a study of historical 2021 SDG&E Customer Service Costs to determine the appropriate allocation of each type of Customer Service Distribution Costs identified in SDG&E's TY 2024 GRC Application.[8]

E. Shared Service Drop Costs

Pursuant to the 2019 GRC Phase 2 Settlement, as adopted by D.21-07-010, SDG&E agreed to present marginal distribution customer costs for service drops shared by customers in this GRC Phase 2 application.[9]

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[8] Adjusted 2021 Customer Services Distribution Expenses presented in the SDG&E TY 2024 GRC Phase 1 Revised Prepared Direct Testimony of Ryan Hom. *See* A.22-05-016, SDG&E Revised Prepared Direct Testimony of Ryan Hom (Summary of Earnings) (August 2022), Ex. SDG&E-44-R at RH-B-39, Table RH-39.

[9] D.21-07-010, Appendix B, Section 2.2.16 Marginal Distribution Customer Costs – Shared Service Drops at 16.

Based on the 54 multi-family residential installations in 2020 and 2021, the average per residential customer service drop cost for shared service drops was $442, in 2024 dollars. This compares to an average per residential customer non-shared service drop cost in 2024 dollars of $331. This suggests that while customers are sharing these service drops, the cost per foot for these shared service drops is much higher, so the cost per customer for shared service drops is also higher.

Based on 94 multi-family non-residential installations in 2020 and 2021, the average per non-residential customer service drop cost for shared service drops was $2,613 in 2024 dollars. The non-residential customers sharing these service drops are typically either small commercial or medium commercial customers. The average per customer non-shared service drop cost is $644 in 2024 dollars for small commercial customers and $1,472 in 2024 dollars for medium commercial customers. Therefore, the cost per foot for shared service drops is much higher than non-shared service drops, so the cost per customer for shared service drops is also higher.

F. Support for Rental Method Adoption

SDG&E has consistently proposed the use of the Rental Method to calculate unit marginal distribution customer costs in GRC Phase 2 proceedings because the Rental Method sends a more accurate and more reasonable price signal of the cost of providing an individual customer access to the electrical system compared to the NCO Method that some parties have proposed in those proceedings. In the billing of utility electricity rates, all customers pay a "rental" price for the distribution customer-related equipment or TSM costs necessary to maintain a customer account. For instance, residential customers do not pay the upfront incremental cost of the TSM assets necessary to provide them electric service but rather customers pay to recover the cost of TSM assets as part of their electric rates in their monthly utility bills. Therefore, customers are essentially paying a monthly rental price for the TSM equipment installed through their monthly bills for electric service.

The Rental Method follows this "rental" process by annualizing the cost of the TSM investments required to maintain the accounts of all customers and then converting this annual cost into a monthly amount. Conversely, the NCO Method takes the cost per customer to hook up a new customer (not the annualized cost), multiplies that value only by the number of estimated new and replacement customers for the customer class, and then divides this amount by the total number of customers in that class to get the unit cost per customer. This method understates the marginal distribution customers costs and sends inefficient price signals to customers considering new hookups because new customers will never pay the full costs incurred to hook up to the utility's electric system. Additionally, because the NCO Method calculation relies on the forecasted number of new and replacement customers, the resulting unit cost for TSM under the NCO Method varies considerably depending on the assumed customer class growth rates and not necessarily in response to changes in the TSM costs.

Attachment A to my testimony presents SDG&E's proposed marginal distribution customer costs based on the Rental Method. In addition, for comparison purposes, Attachment C to my testimony presents illustrative SDG&E marginal distribution customer costs based on the NCO Method that has been used by other parties in SDG&E's previous GRC Phase 2 proceedings, including the NCO Method assumptions used in those proceedings.

V. DISTRIBUTION REVENUE ALLOCATION

SDG&E proposes to use the EPMC revenue allocation methodology to allocate the authorized distribution revenue requirement to customer classes. The EPMC methodology scales the customer class marginal distribution cost revenue responsibilities up or down by a single factor such that the sum equals the authorized distribution revenue requirement.

Under SDG&E's cost-based distribution revenue allocation proposal, the authorized distribution revenue requirement, minus any revenues that are directly assigned to a particular customer class,[10] is allocated among the customer classes based on the proposed marginal distribution cost revenue responsibilities by customer class. Each customer class's marginal distribution costs revenue allocation is the sum of marginal distribution customer costs, marginal feeder and local distribution costs, and marginal substation distribution costs. The unit marginal distribution costs are multiplied by the appropriate cost drivers to develop the marginal cost-based distribution revenue allocations by customer class. Marginal distribution customer cost revenues by customer class are developed by multiplying each class's unit marginal customer cost ($/customer/year) by the forecasted number of customers in that class. Total marginal feeder and local distribution cost revenues are developed by multiplying the unit marginal feeder and local distribution costs ($/kW/year) by the system non-coincident demand and the applicable loss factors. The customer class allocation of the marginal feeder and local distribution cost revenues is developed by multiplying the total marginal feeder and local distribution cost revenues by the product of the customer class's annual non-coincident demand and the estimated ratio of the average class contribution to the peak demand at the circuit level (Effective Demand Factor or EDF).[11] Total marginal substation distribution cost revenues are developed by multiplying the unit marginal substation costs ($/kW/year) by the system non-coincident demand and the applicable loss factors. The customer class allocation of the marginal substation distribution cost revenues is developed by multiplying the total marginal substation cost revenues

[10] SDG&E's directly assigned distribution revenues are labeled Non-Marginal Revenue Requirement Components and identified in Attachment B.2 to my testimony.

[11] EDFs reflect the ratio of the customer class's contribution to the circuit (substation) peak by dividing the class's average absolute demand (delivered and received load) at the time of the monthly circuit (substation) absolute peak demand over the class's average monthly absolute demand.

by the product of the customer class's annual non-coincident demand and EDF at the substation level.

The sum of the marginal distribution customer costs, marginal feeder and local distribution costs, and marginal substation distribution cost revenues is used to develop the distribution EPMC allocation factor. The EPMC allocation factor is then used to scale the marginal distribution class revenue allocations to equal the authorized distribution revenue requirement. The illustrative cost-based distribution revenue allocation by customer class, and the resulting EPMC distribution rates based on those revenue allocations, is provided in Attachment B.1, B.2 and B.3 to my testimony. Attachment B.1 to my testimony presents the marginal distribution cost allocation factors by customer class. Attachment B.2 to my testimony presents the allocation of distribution revenues to each customer class based on the marginal distribution cost allocations factors. Attachment B.3 to my testimony presents the resulting EPMC distribution rates and revenues by customer class.

VI. MARGINAL DISTRIBUTION COSTS OF SOLAR CUSTOMERS

Pursuant to the 2019 GRC Phase 2 Settlement Agreement, adopted by D.21-07-010, SDG&E agreed to perform an analysis on the marginal costs of solar customers in this GRC Phase 2 proceeding.[12] SDG&E performed an analysis examining the resulting marginal cost rate differences between solar customers on NEM and non-NEM customers. Attachment D to my testimony presents the comparison of the illustrative marginal and EPMC distribution customer costs and distribution demand cost rates for NEM and non-NEM customers.

[12] D.21-07-010, Appendix B, Section 2.2.6 Marginal Cost of Solar Customers at 13.

VII. SUMMARY AND CONCLUSION

SDG&E recommends that the CPUC adopt SDG&E's updated proposed marginal distribution demand and marginal distribution customer costs, presented in Attachment A, and SDG&E's proposal to use these marginal distribution costs coupled with the EPMC methodology to allocate authorized distribution revenue requirements, as presented in Attachment B to my testimony.

This concludes my revised prepared direct testimony.

VIII. WITNESS QUALIFICATIONS

My name is William G. Saxe. My business address is 8330 Century Park Court, San Diego, California 92123. I am employed at SDG&E as the Rates & Cost Studies Project Manager in the Customer Pricing Department. I have worked for SDG&E since February 2001. Prior to joining SDG&E, I was employed by Sempra Energy, the parent company of SDG&E, from April 1999 through January 2001. In addition, I was employed by the Illinois Commerce Commission (ICC) from September 1990 through April 1999.

I received a Bachelor of Science degree in Economics from the University of Wisconsin-Madison in 1985. I received a Master of Business Administration degree, with a concentration in Finance, from the University of Wisconsin-Madison in 1990.

I have previously testified before the CPUC on rate design, marginal cost and other issues. In addition, I have previously submitted testimony before the FERC and the ICC.

ATTACHMENT A

PROPOSED MARGINAL DISTRIBUTION COSTS

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY (SDG&E)
TEST YEAR (TY) 2024 GENERAL RATE CASE (GRC) PHASE 2, APPLICATION (A.) 23-01-008
MARGINAL DISTRIBUTION COSTS

Proposed Distribution Marginal Unit Costs

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on Rental Method:					1
2	Residential ($/Customer/Year)		$180.61			2
3						3
4	Small Commercial ($/Customer/Year)					4
5		0 - 5 kW	$273.93	$546.93		5
6		>5 - 20 kW	$549.43	$546.93		6
7		>20 - 50 kW	$841.75	$546.93		7
8		>50 kW	$1,392.74	$604.91		8
9						9
10	Medium Commercial ($/Customer/Year)					10
11		≤100 kW	$1,309.73	$749.33		11
12		> 100 - 200 kW	$1,940.58	$749.33		12
13						13
14	Large Commercial & Industrial ($/Customer/Year)					14
15		≤500 kW	$2,487.60	$752.02	$7,133.94	15
16		500 - 12 MW	$4,679.01	$851.37	$9,645.74	16
17		> 12 MW		$1,159.13	$13,047.80	17
18						18
19	Agricultural ($/Customer/Year)					19
20		≤20 kW	$515.26	$709.00		20
21		>20 kW	$957.48	$709.00		21
22						22
23	Lighting ($/Lamp/Year)		$8.04			23
24						24
25	Demand-Related Marginal Cost:					25
26	Feeders & Local Distribution Demand ($/kW/Year)		$61.48	$61.48		26
27						27
28	Substation Demand ($/kW/Year)		$30.76	$30.76		28
29						29
30	Total Demand-Related Marginal Cost ($/kW/Year)		$92.24	$92.24		30

Note: **Customer, Feeder & Local Distribution Demand and Substation Demand Unit Marginal Costs**: Customer, Feeder & Local Distribution Demand and Substation Demand Unit Marginal Costs are from the revised direct testimony workpapers of SDG&E witness William G. Saxe (Chapter 4).

ATTACHMENT B

ILLUSTRATIVE COST-BASED DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT B.1

SAN DIEGO GAS & ELECTRIC COMPANY (SDG&E)
TEST YEAR (TY) 2024 GENERAL RATE CASE (GRC) PHASE 2, APPLICATION (A.) 23-01-008
DISTRIBUTION REVENUE ALLOCATION

Distribution Marginal Cost Allocation Factor by Customer Class

Line No.	Customer Class (A)	Customer Marginal Cost Revenue ($000) (B)	Percentage Allocation (%) (C)	Demand-Related Marginal Cost Revenue ($000) (D)	Percentage Allocation (%) (E)	Total Distribution Marginal Cost Revenue ($000) (F)	Distribution Marginal Cost Allocation Factor (%) (G)	Line No.
1	Residential	$247,348	72.0%	$284,891	43.3%	$532,239	53.1%	1
2								2
3	Small Commercial	$57,345	16.7%	$66,315	10.1%	$123,660	12.3%	3
4								4
5	Medium Commercial	$23,415	6.8%	$107,135	16.3%	$130,550	13.0%	5
6								6
7	Large Commercial & Industrial	$12,032	3.5%	$186,355	28.3%	$198,388	19.8%	7
8								8
9	Agricultural	$3,385	1.0%	$12,205	1.9%	$15,589	1.6%	9
10								10
11	Lighting	$42	0.01%	$1,068	0.2%	$1,110	0.1%	11
12								12
13	System	$343,568	100.0%	$657,968	100.0%	$1,001,536	100.0%	13

Note:

(1) **Customer Marginal Cost Revenue**: reflects customer-related distribution marginal costs.
(2) **Demand-Related Marginal Cost Revenue**: reflects feeder & local distribution and substation demand-related distribution marginal costs.

ATTACHMENT B.2

SAN DIEGO GAS & ELECTRIC COMPANY (SDG&E)
TEST YEAR (TY) 2024 GENERAL RATE CASE (GRC) PHASE 2, APPLICATION (A.) 23-01-008
DISTRIBUTION REVENUE ALLOCATION

Illustrative Distribution Revenue Allocation by Customer Class

		Updated Distribution Revenue Allocation[1]					Comparison to Current Allocation[2]		
Line No.	Customer Class (A)	Distribution Allocation Factors (%) (B)	Non Marginal Distribution Revenue ($000) (C)	Marginal Distribution Revenue ($000) (D)	Proposed Cost-Based Total Distribution Revenue Allocation ($000) (E)	Proposed Cost-Based Total Distribution Revenue Allocation (%) (F)	Current Total Distribution Revenue Allocation ($000) (G)	Percentage Change (%) (H)	Line No.
1	**Residential**	53.1%		$1,022,920	$1,022,920	52.7%	$885,896	15.5%	1
2									2
3	**Small Commercial**	12.3%		$237,665	$237,665	12.3%	$283,912	-16.3%	3
4									4
5	**Medium Commercial**	13.0%	$138	$250,907	$251,045	12.9%			5
6							$730,150	-11.9%	6
7	**Large Commercial & Industrial**	19.8%	$11,199	$381,285	$392,484	20.2%			7
8									8
9	**Agricultural**	1.6%		$29,962	$29,962	1.5%	$26,986	11.0%	9
10									10
11	**Lighting**	0.1%	$3,895	$2,133	$6,029	0.3%	$13,160	-54.2%	11
12									12
13	**System**	100.00%	$15,232	$1,924,872	$1,940,104	100.0%	$1,940,104	0.0%	13
14									14
15	Distribution Revenue Requirement ($000):[3]	$1,940,104							15
16									16
17	Non Marginal Revenue Requirement Components ($000)								17
18	Lighting Facilities & Maintenance Charge Revenues:[4]	$3,895							18
19									19
20	Standby Revenues:[5]								20
21	Medium Commercial	$113							21
22	Large Commercial & Industrial	$8,041							22
23	Total	$8,154							23
24									24
25	Distance Adjustment Fee Revenues:[6]								25
26	Medium Commercial	$25							26
27	Large Commercial & Industrial	$3,157							27
28	Total	$3,182							28

Note:

(1) **Updated Distribution Revenue Allocation**: allocation of the current distribution revenue requirement based on the marginal Distribution Allocation Factors presented in this Application.
(2) **Current Total Distribution Revenue Allocation**: allocation of current distribution revenue requirement based on the current class distribution allocation percentages reflected in current rates; rates effective January 1, 2023, pursuant to SDG&E Advice Letter 4129-E.
(3) **Distribution Revenue Requirement**: the $1,940,104,131 Distribution Revenue Requirement reflects the current distribution revenues being collected in rates effective January 1, 2023, pursuant to SDG&E Advice Letter 4129-E, excluding revenues that have separate allocation treatment such as Demand Response (DR), Vehicle-Grid Integration (VGI), Medium Duty & Heavy Duty Electric Vehicle (MD/HD), and DG-R Under-Over-Collections.
(4) **Non-Marginal Lighting Facilities & Maintenance Charge Revenues**: Lighting Facilities Charges of $3,895,000 is the annual lighting facilities and maintenance revenues identified in the Lighting Model from SDG&E witness William Saxe (Chapter 6) revised direct testimony workpapers.
(5) **Non-Marginal Standby Revenues**: Standby Revenues of $8,154,000 is the standby revenues based on the forecasted 2024 standby determinants multiplied by the applicable current standby rates effective January 1, 2023, pursuant to SDG&E Advice Letter 4129-E.
(6) **Non-Marginal Distance Adjustment Fee Revenues**: Distance Adjustment Fees of $3,182,000 is the annual distance adjustment fees revenues based on the forecasted overhead and underground distance adjustment fee 2024 determinants in feet multiplied by the applicable current distance adjustment fees effective January 1, 2023, pursuant to SDG&E Advice Letter 4129-E.

ATTACHMENT B.3

SAN DIEGO GAS & ELECTRIC COMPANY (SDG&E)
TEST YEAR (TY) 2024 GENERAL RATE CASE (GRC) PHASE 2, APPLICATION (A.) 23-01-008
DISTRIBUTION REVENUE ALLOCATION

Distribution Equal Percentage of Marginal Cost (EPMC) Rates and Revenue by Customer Class

Line No.	Customer Class (A)	Determinants (B)	Marginal Distribution Rate (C)	EPMC Distribution Rate (D)	EPMC Distribution Revenue Allocation ($000) (E)	Line No.
1	Residential					1
2	Customer Marginal Cost ($/Customer-Month)	16,433,811	$15.05	$28.93	$475,383	2
3	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	20,428,840	$0.84	$1.61	$32,836	3
4	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	53,801,907	$4.98	$9.57	$514,701	4
5	Total - Residential				$1,022,920	5
6						6
7	Small Commercial					7
8	Customer Marginal Cost ($/Customer-Month)					8
9	Secondary					9
10	0 - 5 kW	744,245	$22.83	$43.87	$32,652	10
11	>5 - 20 kW	738,109	$45.79	$88.00	$64,951	11
12	>20 - 50 kW	82,774	$70.15	$134.81	$11,159	12
13	>50 kW	6,035	$116.06	$223.06	$1,346	13
14	Secondary Total	1,571,163	$36.46	$70.08	$110,109	14
15						15
16	Primary					16
17	0 - 5 kW	945	$45.58	$87.60	$83	17
18	>5 - 20 kW	171	$45.58	$87.60	$15	18
19	>20 - 50 kW	18	$45.58	$87.60	$2	19
20	>50 kW	50	$50.41	$96.88	$5	20
21	Primary Total	1,185	$45.78	$87.99	$104	21
22						22
23	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)					23
24	Secondary	3,075,510	$1.29	$2.49	$7,654	24
25	Primary	4,189	$1.29	$2.48	$10	25
26	Total	3,079,699	$1.29	$2.49	$7,664	26
27					$0	27
28	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				$0	28
29	Secondary	8,218,887	$7.57	$14.55	$119,573	29
30	Primary	14,758	$7.53	$14.47	$214	30
31	Total	8,233,645	$7.57	$14.55	$119,787	31
32						32
33	Total - Small Commercial				$237,665	33

34						34
35	**Medium Commercial**					35
36						36
37	Secondary					37
38	≤100 kW	177,365	$109.14	$209.77	$37,205	38
39	>100 - 200 kW	24,782	$161.72	$310.80	$7,702	39
40	Secondary Total	202,147	$115.59	$222.15	$44,908	40
41						41
42	Primary					42
43	≤100 kW	456	$62.44	$120.01	$55	43
44	>100 - 200 kW	336	$62.44	$120.01	$40	44
45	Primary Total	792	$62.44	$120.01	$95	45
46						46
47	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)					47
48	Secondary	3,795,092	$1.69	$3.24	$12,310	48
49	Primary	21,864	$1.68	$3.23	$71	49
50	Total	3,816,956	$1.69	$3.24	$12,381	50
51						51
52	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)					52
53	Secondary	9,994,436	$10.02	$19.25	$192,416	53
54	Primary	57,833	$9.97	$19.15	$1,108	54
55	Total	10,052,269	$10.02	$19.25	$193,524	55
56						56
57	Total - Medium Commercial				$250,907	57

58						58
59	**Large Commercial & Industrial**					59
60						60
61	Secondary					61
62	≤500 kW	44,514	$207.30	$398.41	$17,735	62
63	500 - 12 MW	5,945	$389.92	$749.39	$4,455	63
64	> 12 MW					64
65	Secondary Total	50,459	$228.81	$439.76	$22,190	65
66						66
67	Primary					67
68	≤500 kW	1,396	$62.67	$120.44	$168	68
69	500 - 12 MW	2,286	$70.95	$136.36	$312	69
70	> 12 MW	33	$96.59	$185.65	$6	70
71	Primary Total	3,716	$68.07	$130.82	$486	71
72						72
73	Transmission					73
74	≤500 kW	106	$594.49	$1,142.57	$121	74
75	500 - 12 MW	142	$803.81	$1,544.86	$219	75
76	> 12 MW	52	$1,087.32	$2,089.73	$109	76
77	Transmission Total	300	$779.43	$1,498.00	$449	77
78						78
79	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)					79
80	Secondary	3,574,181	$2.03	$3.91	$13,957	80
81	Primary	1,897,573	$2.02	$3.88	$7,372	81
82	Transmission					82
83	Total	5,471,754	$2.03	$3.90	$21,326	83
84						84
85	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)					85
86	Secondary	9,071,966	$12.02	$23.11	$209,620	86
87	Primary	5,534,139	$11.96	$22.99	$127,215	87
88	Transmission					88
89	Total	14,606,105	$12.00	$23.06	$336,834	89
90						90
91	Total - Large Commercial & Industrial				$381,285	91
92						92

93	Agricultural					93
94	Customer Marginal Cost ($/Customer-Month)					94
95	Secondary					95
96	≤20 kW	16,336	$42.94	$82.52	$1,348	96
97	>20 kW	33,506	$79.79	$153.35	$5,138	97
98	Secondary Total	49,842	$67.71	$130.14	$6,486	98
99						99
100	Primary					100
101	≤20 kW	23	$59.08	$113.55	$3	101
102	>20 kW	146	$59.08	$113.55	$17	102
103	Primary Total	169	$59.08	$113.55	$19	103
104						104
105	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)					105
106	Secondary	411,428	$1.49	$2.87	$1,179	106
107	Primary	62,162	$1.48	$2.85	$177	107
108	Total	473,590	$1.49	$2.86	$1,357	108
109						109
110	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)					110
111	Secondary	1,389,540	$7.32	$14.06	$19,537	111
112	Primary	183,159	$7.28	$13.99	$2,562	112
113	Total	1,572,699	$7.31	$14.05	$22,099	113
114						114
115	Total - Agricultural				$29,962	115

116						116
117	**Lighting**					117
118	**Customer Marginal Cost ($/Lamp-Month)**	**162,621**	**$0.26**	**$0.49**	**$80**	118
119	**Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)**	**99,089**	**$0.63**	**$1.21**	**$120**	119
120	**Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)**	**237,814**	**$4.23**	**$8.13**	**$1,933**	120
121	**Total - Lighting**				**$2,133**	121
122						122
123	**Total-System**					123
124	**Customer Marginal Cost ($/Customer-Month)**				**$660,310**	124
125	**Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)**				**$75,683**	125
126	**Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)**				**$1,188,879**	126
127	**Total - System**				**$1,924,872**	127
128						128
129	GRC Phase 1 Distribution Revenue Requirement:		1,940,104			129
130	Non-Marginal Revenue Requirement		15,232			130
131	Marginal Distribution Revenue Requirement Allocation		1,924,872			131
132						132
133	Marginal Customer Distribution Revenue Requirement		343,568			133
134	Marginal Demand-Related Distribution Revenue Requirement		657,968			134
135	Total Marginal Distribution Revenue Requirement		1,001,536			135
136						136
137	EPMC Allocation Factor		192.19%			137

Notes:

(1) **Distribution EPMC Rates and Revenues by Customer Class**: the distribution EPMC rates and revenues by customer class presented are from the revised direct testimony workpapers of SDG&E witness William G. Saxe (Chapter 4).
(2) **Marginal Distribution Rate**: equals the marginal cost by class and by voltage level for demand-related margin cost divided by the class determinants.
(3) **EPMC Distribution Rate**: equals the Marginal Distribution Rate multiplied by the EPMC Distribution Allocation Factor.
(4) **EPMC Distribution Revenue Allocation**: equals the EPMC Distribution Rate multiplying by the applicable determinants.

ATTACHMENT C

ILLUSTRATIVE NEW CUSTOMER ONLY (NCO) MARGINAL DISTRIBUTION CUSTOMER COSTS

ATTACHMENT C

SAN DIEGO GAS & ELECTRIC COMPANY (SDG&E)
TEST YEAR (TY) 2024 GENERAL RATE CASE (GRC) PHASE 2, APPLICATION (A.) 23-01-008
MARGINAL DISTRIBUTION CUSTOMER COSTS

Distribution Customer Marginal Unit Cost by Customer Class Based on New Customer Only (NCO) Method
Illustrative Marginal Customer Costs --- Not Proposed by SDG&E

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on NCO Method:					1
2	Residential ($/Customer/Year)		$98.56			2
3						3
4	Small Commercial ($/Customer/Year)					4
5		0 - 5 kW	$198.04	$280.58		5
6		>5 - 20 kW	$280.41	$280.58		6
7		>20 - 50 kW	$360.34	$280.58		7
8		>50 kW	$516.64	$294.79		8
9						9
10	Medium Commercial ($/Customer/Year)					10
11		≤100 kW	$656.78	$435.45		11
12		> 100 - 200 kW	$806.31	$431.54		12
13						13
14	Large Commercial & Industrial ($/Customer/Year)					14
15		> 200 - 500 kW	$1,114.54	$438.14	$2,871.77	15
16		> 500 - 12 MW	$1,684.69	$464.29	$3,569.61	16
17		> 12 MW		$520.80	$4,639.43	17
18						18
19	Agricultural ($/Customer/Year)					19
20		≤20 kW	$330.24	$318.26		20
21		>20 kW	$665.10	$318.26		21
22						22
23	Lighting ($/Lamp/Year)		$3.39			23

Note: **Distribution Customer Marginal Unit Cost by Customer Class Based on NCO Method**: the distribution customer marginal unit costs by customer class based on the NCO Method are being provided for comparison purposes only.

ATTACHMENT D

ILLUSTRATIVE MARGINAL AND EPMC DISTRIBUTION CUSTOMER AND MARGINAL DISTRIBUTION DEMAND COST RATES FOR NEM AND NON-NEM CUSTOMERS

ATTACHMENT D

SAN DIEGO GAS & ELECTRIC COMPANY (SDG&E)
TEST YEAR (TY) 2024 GENERAL RATE CASE (GRC) PHASE 2, APPLICATION (A.) 23-01-008
DISTRIBUTION REVENUE ALLOCATION

Comparison of Illustrative Net Energy Metering (NEM) and Non-NEM Distribution Equal Percentage of Marginal Cost (EPMC) Rates and Revenue by Customer Class

Line No.	Customer Class (A)	Non-NEM Rates: Marginal Distribution Rate[1] (B)	Non-NEM Rates: EPMC Distribution Rate[2] (C)	NEM Rates: Marginal Distribution Rate[1] (D)	NEM Rates: EPMC Distribution Rate[2] (E)	Line No.
1	Residential					1
2	Customer Marginal Cost ($/Customer-Month)	$14.59	$28.04	$17.98	$34.56	2
3	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	$0.75	$1.44	$1.15	$2.21	3
4	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	$4.48	$8.61	$6.80	$13.07	4
5						5
6	Small Commercial					6
7	Customer Marginal Cost ($/Customer-Month)					7
8	Secondary					8
9	0 - 5 kW	$22.80	$43.82	$25.47	$48.94	9
10	>5 - 20 kW	$45.80	$88.03	$45.37	$87.20	10
11	>20 - 50 kW	$70.08	$134.68	$72.29	$138.93	11
12	>50 kW	$116.05	$223.05	$117.05	$224.96	12
13	Secondary Total	$36.30	$69.76	$46.38	$89.15	13
14						14
15	Primary					15
16	0 - 5 kW	$45.58	$87.60	$45.53	$87.50	16
17	>5 - 20 kW	$45.58	$87.60	$0.00	$0.00	17
18	>20 - 50 kW	$45.58	$87.60	$0.00	$0.00	18
19	>50 kW	$50.41	$96.88	$0.00	$0.00	19
20	Primary Total	$45.79	$88.00	$45.53	$87.50	20
21						21
22	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)					22
23	Secondary	$1.29	$2.48	$1.29	$2.49	23
24	Primary	$1.28	$2.46	$1.29	$2.47	24
25	Total	$1.29	$2.48	$1.29	$2.49	25
26						26
27	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)					27
28	Secondary	$7.53	$14.48	$7.56	$14.52	28
29	Primary	$7.49	$14.40	$7.52	$14.45	29
30	Total	$7.53	$14.48	$7.56	$14.52	30

31						31
32	**Medium Commercial**					32
33						33
34	Secondary					34
35	≤100 kW	$108.53	$208.58	$120.98	$232.52	35
36	>100 - 200 kW	$161.64	$310.66	$162.83	$312.95	36
37	Secondary Total	$114.65	$220.36	$131.13	$252.02	37
38						38
39	Primary					39
40	≤100 kW	$62.44	$120.01	$62.44	$120.01	40
41	>100 - 200 kW	$62.44	$120.01	$62.44	$120.01	41
42	Primary Total	$62.44	$120.01	$62.44	$120.01	42
43						43
44	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)					44
45	Secondary	$1.72	$3.30	$1.29	$2.48	45
46	Primary	$1.71	$3.28	$1.28	$2.47	46
47	Total	$1.72	$3.30	$1.29	$2.48	47
48						48
49	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)					49
50	Secondary	$10.19	$19.58	$7.71	$14.82	50
51	Primary	$10.14	$19.48	$7.67	$14.74	51
52	Total	$10.19	$19.58	$7.71	$14.82	52
53						53
54	**Large Commercial & Industrial**					54
55						55
56	Secondary					56
57	≤500 kW	$205.77	$395.47	$218.05	$419.08	57
58	500 - 12 MW	$403.57	$775.63	$304.62	$585.45	58
59	> 12 MW	$0.00	$0.00	$0.00	$0.00	59
60	Secondary Total	$228.76	$439.65	$229.21	$440.52	60
61						61
62	Primary					62
63	≤500 kW	$62.68	$120.46	$62.45	$120.03	63
64	500 - 12 MW	$71.20	$136.85	$69.65	$133.87	64
65	> 12 MW	$96.59	$185.63	$96.66	$185.77	65
66	Primary Total	$68.10	$130.87	$67.89	$130.47	66
67						67
68	Transmission					68
69	≤500 kW	$591.73	$1,137.26	$0.00	$0.00	69
70	500 - 12 MW	$784.94	$1,508.58	$1,111.80	$2,136.79	70
71	> 12 MW	$1,086.63	$2,088.40	$0.00	$0.00	71
72	Transmission Total	$768.92	$1,477.80	$1,111.80	$2,136.79	72
73						73
74	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)					74
75	Secondary	$2.06	$3.96	$1.75	$3.37	75
76	Primary	$2.05	$3.94	$1.74	$3.35	76
77	Transmission					77
78	Total	$2.06	$3.95	$1.75	$3.36	78
79						79
80	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)					80
81	Secondary	$12.18	$23.41	$10.47	$20.13	81
82	Primary	$12.12	$23.29	$10.42	$20.02	82
83	Transmission					83
84	Total	$12.16	$23.37	$10.45	$20.09	84
85						85

86	**Agricultural**					86
87	Customer Marginal Cost ($/Customer-Month)					87
88	Secondary					88
89	≤20 kW	$42.05	$80.83	$57.03	$109.61	89
90	>20 kW	$78.37	$150.63	$94.53	$181.68	90
91	Secondary Total	$66.05	$126.95	$87.09	$167.39	91
92						92
93	Primary					93
94	≤20 kW	$55.49	$106.64	$0.00	$0.00	94
95	>20 kW	$55.49	$106.64	$62.35	$119.84	95
96	Primary Total	$55.49	$106.64	$62.35	$119.84	96
97						97
98	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)					98
99	Secondary	$1.34	$2.57	$1.97	$3.78	99
100	Primary	$1.33	$2.55	$1.96	$3.76	100
101	Total	$1.34	$2.57	$1.97	$3.78	101
102						102
103	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)					103
104	Secondary	$6.54	$12.58	$9.69	$18.62	104
105	Primary	$6.51	$12.51	$9.64	$18.52	105
106	Total	$6.54	$12.57	$9.68	$18.61	106
107						107
108	**Lighting**					108
109	Customer Marginal Cost ($/Lamp-Month)	$0.26	$0.49	NA	NA	109
110	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	$0.55	$1.06	NA	NA	110
111	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	$3.77	$7.25	NA	NA	111

Notes:

(1) **Marginal Distribution Rate**: equals the marginal cost by class and by voltage level for demand-related margin cost divided by the class determinants.
(2) **EPMC Distribution Rate**: equals the Marginal Distribution Rate multiplied by the EPMC Distribution Allocation Factor.