Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application 11-10-002
Exhibit No.: (SDG&E-106-R)

SECOND REVISED PREPARED DIRECT TESTIMONY OF

ROBERT M. EHLERS

CHAPTER 6

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

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

MARCH 30, 2012

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SECOND REVISED PREPARED DIRECT TESTIMONY OF

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(CHAPTER 6)

I. OVERVIEW AND PURPOSE

The purpose of my direct testimony is to present San Diego Gas & Electric Company's (SDG&E's) updated development of distribution marginal customer costs and marginal distribution demand costs. Together, marginal customer and marginal distribution demand costs comprise the marginal distribution costs which will be used as the foundation of the Electric Distribution Revenue Allocation found in the testimony of William G. Saxe (Chapter 3) and Electric Rate Design for Distribution found in the testimony of Cynthia Fang (Chapter 2).

The following testimony found in this chapter will outline SDG&E's use of the "Rental" (customer cost) and "NERA Regression" (distribution demand) marginal cost estimation methods in this filing.

II. SDG&E DISTRIBUTION MARGINAL COSTS BACKGROUND

For the past 20 years, the California Public Utilities Commission (Commission) has relied on marginal costs as the basis for revenue allocation and rate development for the different rate classes. The use of marginal costs for the development of utility rates sends an accurate price signal to the customer, which in turn promotes the efficient use of energy.

In this testimony, SDG&E will present updated studies for both marginal customer and marginal distribution costs. The marginal customer cost study will utilize the "Rental" method while the distribution demand costs will be based on the "NERA Regression" method. Recent rate proceedings (2004 and 2009 Rate Design Windows (RDW) and 2008 General Rate Case (GRC) Phase 2) were decided by an all-party settlement on revenue allocation and thus there was no formal adoption of marginal costs or marginal cost methodology.

In remaining consistent with Ordering Paragraph (OP) 3[1] of Decision (D.) 09-09-036, which adopted the settlement in SDG&E 2009 RDW, the marginal distribution demand and marginal distribution customer costs do not use the 2009 RDW Settlement as a precedential

[1] D.09-09-036 at OP3: In its next application to establish marginal costs, allocate revenues, and design rates for service provided to its customers San Diego Gas & Electric Company shall clearly disclose that any change included in today's settlement is not a precedential "starting point," and it must present a full and persuasive showing at that time for the entire cost allocation and rate design proposal.

"starting point" for the development of marginal costs in SDG&E's 2012 GRC Phase 2 application (Application).

III. OVERVIEW OF MARGINAL CUSTOMER AND DISTRIBUTION COSTS

The economic definition of marginal cost is the change in total costs caused by a change in the output quantity of a given product. This is measured as the cost of producing one more unit of output. Applying this definition to the utility context requires a number of qualifying assumptions in order to measure the distribution services that the utility provides to its retail electric customers. My direct testimony defines marginal cost as the change in the total cost of providing electric service to the utilities retail customers. In theory, marginal distribution demand costs measure the cost of serving an additional unit of customer kilowatt (kW) demand on a forecasted basis while marginal customer costs reflect the cost of adding an additional customer to the distribution system.

IV. OVERVIEW OF MARGINAL DISTRIBUTION DEMAND

Marginal distribution demand costs represent the cost of providing facilities from the high side of the substation transformer to the customer access point in order to meet the customer's individual demands. These marginal distribution demand costs are logically separated into feeder and local distribution components and substation components for the purposes of this Application. This disaggregation allows for flexibility in rate design and better reflects costs in revenue allocation. SDG&E's marginal distribution demand costs are developed for the system as a whole. SDG&E has a comparatively small service territory, which makes disaggregation of marginal distribution demand costs by specific geographic location unwarranted**.** Marginal demand costs do not include reliability investments, replacement costs, or customer access costs because these costs are not considered growth-related.

The distribution demand cost component includes distribution investment costs and other associated costs for Operations & Maintenance (O&M), Administrative & General (A&G), General Plant Loading (GPL), Working Capital (WC), and other. As in the past, SDG&E will continue its use the National Economic Research Associates (NERA) regression method to calculate unit marginal distribution demand costs for the various customer classes. NERA Regression has proven to provide greater year-to-year marginal cost stability, which in turn provides great price signals to the customer. A consideration taken from SDG&E's GRC Phase 2 Settlement Agreement (compliance requirement #6, D.08-02-034) requires the evaluation of new business costs, currently included in distribution demand costs, as part of marginal customer costs. This means the New Business Costs investment category would be subtracted from growth-related distribution investments. For this Application, SDG&E will continue to include New Business Costs in the distribution demand calculation. The study that evaluates the removal of New Business Costs from the distribution demand calculation can be found in the response to the Compliance Requirement - Question #1 in Attachment I of Ms. Fang's testimony.

A. Overview of Indirect Cost Background and Calculations

The investment costs for marginal distribution and customer components have been derived in units of dollars-per-kW and dollars-per-customer. 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 fixed O&M, fixed A&G, GPL and working capital. SDG&E is recommending changes in the methodology for calculation of several of these factors, including fixed O&M, fixed A&G, and GPL. These changes are described in the following paragraphs.

The methodology for calculating the A&G factor was updated in compliance with the standard NERA methodology utilizing five years of data from Federal Energy Regulatory Commission (FERC) Form 1 Pages 322 and 323, for the period 2005-2009. This method separates A&G related to electric plant and electric non-plant and calculates an annual average electric plant factor. This factor is determined by dividing the total electric plant A&G by the total year-end gross electric plant. The electric non-plant factor is determined by dividing the total electric non-plant A&G by the total electric O&M less fuel purchased power and A&G. The annual electric plant and electric non-plant factors are then averaged to obtain a five-year average factor for plant and a five-year average factor for non-plant A&G.

The methodology for calculating the GPL factor was updated in compliance with the standard NERA methodology utilizing five years of data from FERC Form 1 Page 207, for the period 2005-2009. Under the NERA methodology, the GPL factor is calculated by subtracting total electric general plant from total electric plant-in-service, then dividing the result by total electric general plant. The GPL factor is calculated annually over a five-year period to obtain yearly averages, which are then averaged over a five-year period to obtain the GPL used in this case.

The methodology for calculating the O&M factor was updated to provide a five-year average factor. SDG&E uses this factor to prorate Distribution Demand, Customer Demand, and Street Lighting related O&M.

The marginal customer component investments must be converted to an annual value, dollars-per-kW-per-year, to be useful for revenue allocation and rate design purposes. This methodology calculates an annual economic rent as opposed to a levelized annual payment method (as in a mortgage payment).

B. Unit Marginal Feeder and Local Distribution Cost

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 kilowatt of demand. The cost of feeder and local distribution facilities is based on the projected investments needed to meet load growth on the SDG&E system during a specific planning horizon. These facilities include poles, fixtures, capacitors, and overhead and underground conductors and devices.

SDG&E will continue the use of the NERA Regression Method to calculate marginal feeder and local distribution costs. By definition, the NERA Regression Method uses ten years of historical and five years of forecasted feeder and local 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 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.

The feeder and local distribution investments used in the NERA Regression Method were obtained from distribution capital budget forecasts for the period 2010 through 2012. Only three years of forecasted data was available from the capital budget data. Since only three years of forecast data was available, twelve years of historical investment data from years 1998 through 2009 was used for the historical period. Because marginal costs reflect the cost to meet new demand on the system, only capital budget investments and historical investments related to capacity additions were used in the regression calculation. Historical distribution peak load data and forecasted distribution peak load data was used in the regression for the fifteen-year period of 1998 through 2012.

After obtaining the distribution investment using the NERA Regression Method, the result is then adjusted to reflect both GPL and WC loadings. After adding GP and WC loadings, the resulting amount (reflected in $/kW) is then annualized to $/kW-yr using a RECC factor derived for feeder and local distribution plant accounts.

The annualized investment then receives an A&G overhead loader and the resulting sum is then escalated. Lastly, a fixed O&M loader is added to the escalated figure to derive the marginal investment amount for feeders and local distribution.

The marginal distribution costs, by components, for feeders and local distribution are provided in Table RME – 01 below:

Table RME-01
Feeders and Local Distribution - Marginal Distribution Demand Summary

Line No	Feeders and Local Distribution Demand Costs ($/kW/Yr)	Including New Business Costs (A)
1	NERA Regression Method	$74.06

C. Unit Marginal Substation Costs

Marginal substation costs represent the forecasted cost for construction of substations to serve an additional kilowatt of demand. The 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.

SDG&E also will continue the use of the NERA Regression Method to calculate marginal substation costs. Again, this method uses ten years of historical and five years of forecast substation investments along with annual distribution system peak determinants. The NERA Regression Method identifies the utility's cumulative incremental changes in distribution peak data as the independent variable, the utility's cumulative incremental distribution growth-related substation investments as the dependent variable, and then regresses the data over a fifteen-year period of data points.

The substation investments used to calculate marginal substation costs were obtained from capital budget forecasts for the period 2010 through 2012. Only three years of forecasted substation data was available from the capital budget data. Because only three years of forecast data was available, twelve years of historical investment data from years 1998 through 2009 was used for the historical component. Because marginal costs reflect the cost to meet new demand on the system, only capital budget investments and historical investments related to capacity additions were used in the regression calculation. Historical distribution peak load data and forecasted distribution peak load data was used in the regression for the fifteen-year period of 1998 through 2012.

After determining marginal substation costs for this case, I then adjusted the result to reflect both GPL and WC loadings. The resulting amount (reflected in $/kW) is then annualized to $/kW-yr using a RECC factor derived for substation plant accounts. The annualized investment then receives an A&G overhead loader and the resulting sum is then escalated. Lastly, a fixed O&M loader is added to the escalated figure to derive the marginal investment amount for feeders and local distribution.

SDG&E's marginal distribution costs, by cost component, for substations are provided in Table RME-02 below:

Table RME-02
Substation - Marginal Distribution Demand Summary

Line No		Including New Business Costs (A)
	Substation Distribution Demand Costs ($/kW/Yr)	
1	**NERA Regression Method**	**$27.85**

V. OVERVIEW OF MARGINAL CUSTOMER DEMAND

Marginal customer costs represent the cost of providing an individual customer access to electrical service. These marginal costs are composed of two types of costs. The first is the cost associated with the investment required to provide access (hook up) to a new customer. The second relates to the ongoing costs of maintaining the new customer. These two kinds of costs vary by customer type, size, service voltage and type of equipment used for access. Examples of the above costs include distribution-related investments for items such as transformers, service runs, meters, plus other customer related costs for O&M, Customer Accounts and Services, A&G, GPL and WC.

The marginal customer cost methodology presented by SDG&E in all prior electric marginal cost proceedings has been based on the "rental" method, as opposed to the "New Customer Only" (NCO) method, also called one-time hook-up costs (OTHC). For the purpose of the 2012 GRC, SDG&E will continue the use the "rental" method to calculate unit marginal customer costs for the various customer classes. SDG&E feels that the "rental" method sends the most accurate price signal to all customers with similar hookups, not just new customers (under NCO). In the practical application of customer electricity rates, all customers pay a "rental" cost for the distribution demand-related equipment and other services necessary to maintain an account. The rental method of marginal cost allocation follows the same process by applying the annualized investment cost and ongoing costs required to maintain the accounts of all customers. In this case, SDG&E continues consistency in its use of the rental approach, as it is a well-known and widely used methodology with a regulatory history spanning close to 30 years.

A. UNIT MARGINAL CUSTOMER COSTS

For this study, the marginal customer costs have been developed based on customer type, customer size and service voltage level, using primarily the same methodology adopted in SDG&E's 1996 RDW decision, (D.96-06-033). The only significant difference is that O&M expenses are allocated based on transformer, service, and meter capital costs (TSM). The revised allocation method is based on each customer group's weighted average capital investment for transformer, service and meter infrastructure. This method provides for a more accurate O&M allocation because it takes into account additional factors such as customer quantity and the size, cost and complexity of customer-service-related infrastructure. The methodology previously used for allocating the electric distribution O&M expense was based entirely on customer service expenses. The revised methodology change resulted from a study that was requested as part of the Commission Decision on the 2008 GRC Phase 2 Settlement Agreement, D.08-02-034. SDG&E performed this study in compliance with D.08-02-034 Compliance Request #5 and recommends its implementation moving forward.

This Application presents the marginal customer cost summarized by the major customer classes for revenue allocation and rate design purposes. The marginal customer costs are not time-differentiated by costing periods and are reflected in dollars-per-customer, per-year.

B. TRANSFORMER, SERVICE AND METER CALCULATION

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, meters, and services 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 demand and service levels were developed for: 1) transformers based on size (voltage and kVa rating), type (single- or three-phase) the cost of the pad, and the average number of customers per transformer; 2) service length based on the voltage level, wire size, number of runs, and average service length; and 3) meters based on size and type (single- or three-phase). The TSM investment cost for each customer range was based on engineering estimates for a typical customer by size/usage class.

To determine the average TSM costs for each customer class, customers are grouped by maximum annual demand level (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 or each TSM component. A weighted average is then calculated for each TSM component that produces the average TSM cost per customer class.

Once developed, the TSM costs are multiplied by GPL and WC loading factors. After receiving GPL and WC loading factors, the TSM costs are then converted to an annualized amount (dollars-per-customer-per-year) by using a Real Economic Carrying Charge (RECC). The Commission has adopted the RECC approach for SDG&E in all prior marginal cost decisions. This methodology calculates an annual economic rent as opposed to a levelized annual payment method (for example, a mortgage payment).

C. MARGINAL CUSTOMER ACCOUNT AND CUSTOMER SERVICE EXPENSE

Marginal Customer Account and Service expenses represent the cost of adding and maintaining a new customer account. These costs are estimated based on FERC account information for year-end 2009 (FERC Form 1 Data). For this filing, SDG&E conducted an internal study in accordance with its 2008 GRC Phase 2 Settlement Agreement Decision, D.08-02-034.

To allocate these costs to the individual customer classes, SDG&E analyzed each FERC account to determine the nature of the expense. Allocation factors developed for each customer class based on this analysis indicate no differentiation between rate schedules/classes, except in the case of unmetered schedules that should not be allocated meter-reading-related expenses. SDG&E used the developed allocation factors to allocate most of the FERC account cost estimates to customer classes. SDG&E allocated the remaining account cost estimates to the customer classes on a prorated basis. The net totals are adjusted by an A&G and GPL factor to calculate the total per customer costs for each class. The class total per customer costs are then escalated to 2012 dollars from 2009 estimates using escalation forecasts from SDG&E's 2012 GRC Phase 1 Application (A.10-12-005).

D. O&M EXPENSE

In order to develop a per-customer O&M expense allocation, SDG&E analyzed the FERC Distribution Overhead accounts (580 to 589) and Maintenance accounts (590 to 598), based on the most recent FERC Form 1 data, by each account, 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 expense. The O&M expense is then separated between overhead and underground lines by a factor based on overhead and underground plant balances (FERC accounts 364 to 369.2). Only the underground portion is allocated for the customer-related investment O&M, since ongoing marginal investment is assumed to be underground only.

SDG&E then allocates 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 factor before calculating the per-customer O&M cost.

The Customer Account and Customer Service and O&M costs are then added to the RECC to derive the total marginal cost per customer. The marginal customer costs, summarized by customer class, are provided in table RME-03. The study breaks down customer demand further by sub-class, customer size (demand) and voltage level.

Table RME - 03
Marginal Customer Cost Summary by Customer Class

Line Number		Customer $/Yr
1	Residential Class Average	259.05
2	Small Commercial Class Average	600.15
3	Commercial & Industrial Class Average	2,187.08
4	Agricultural Class Average	728.19
5	Lighting Class Average	19.64

VI. DISTRIBUTION MARGINAL COST DETERMINANTS

Distribution Marginal Cost Determinants are customer class characteristics that reflect how customers use the electricity a utility provides. These characteristics include parameters such as number of customers, various load characteristics such as customer peaks, and consumption of energy in various time of use periods. These characteristics are used for marginal cost studies, revenue allocation and rate design calculations. The distribution peak load determinants used for unit marginal distribution capacity costs are based on historic calendar years 1998 through 2009 and forecast calendar years 2010 through 2012. The distribution customer marginal cost determinants are based on historical peak loads, by customer, by class from 2009.

VII. 2008 GRC PHASE 2 COMPLIANCE REQUIREMENTS - D.08-02-034

This section will address 2008 GRC Phase 2 compliance requirement item numbers 1, 2, 3 & 5. The full response to the compliance requirements can be found in Attachment I of Ms. Fang's testimony (Chapter 3).

Compliance Requirement #1 - *"Determine SDG&E's new business distribution costs by customer class, and by customer payment versus utility investment. Use this to investigate the inclusion of the utility investment in new business as a customer marginal cost rather than as a distribution cost, as proposed by PG&E in its recent rate case."*

Response – SDG&E's response in accordance of compliance requirement #1 can be found in Attachment I of Ms. Fang's testimony. SDG&E has evaluated the inclusion of new business distribution costs as a customer marginal cost. For this Application, SDG&E will continue to include new business distribution costs under the distribution marginal cost. For complete detail of the study response, please refer to Ms. Fang's testimony.

Compliance Requirement #2 - *"Determine O&M of Existing underground distribution by customer class, and compare this with O&M for overhead."*

Response –SDG&E's response in accordance of compliance requirement #2 can be found in Attachment I of Ms. Fang's testimony.

Compliance Requirement #3 - *"Determine Expected Investment in replacement costs of existing underground distribution, and the customer classes served by this distribution."*

Response - SDG&E's response in accordance of compliance requirement #3 can be found in Attachment I of Ms. Fang's testimony.

Compliance Requirement #5 - *"A study with supporting testimony and work papers regarding appropriate levels of customer accounts and services O&M and TSM O&M, both in total and by customer class, since previous studies have not been conducted since 1996."*

Response - SDG&E's response in accordance of compliance requirement #5 can be found in Attachment I of Ms. Fang's testimony. As noted above in **Section A – Unit Marginal Customer Costs**, the allocation for the operation and maintenance accounts has historically followed the allocation of the customer service accounts. For this study, the allocation has been changed to follow the capital costs for transformers, services and meters (TSM). SDG&E proposes the adoption of this updated method of O&M allocation for this filing.

VIII. CONCLUSIONS AND RECOMMENDATIONS

SDG&E is requesting that the Commission adopt the use of the NERA Regression method for the distribution marginal cost and the use of the Rental method for the customer marginal cost studies. SDG&E has found that the NERA Regression method provides a more stable year-to-year marginal cost, which provides a better price signal to the customer. Remaining consistent with the NERA Regression Method, the Rental Method maintains consistency in also using RECC to calculate the annual marginal cost to the customer. This concludes my direct testimony.

IX. QUALIFICATIONS OF ROBERT M. EHLERS

My name is Robert M. Ehlers. My business address is 8330 Century Park Court, San Diego, California, 92123. I am a Principal Regulatory Economics Advisor in the Electric Rate

Design Section of the Regulatory Policy and Analysis Group at SDG&E. My primary responsibilities include the development of electric cost-of-service studies, revenue allocation studies, and rate design development.

I received my Bachelor of Science degree in Business Administration with an emphasis in Accounting from San Diego State University. I have been employed by SDG&E since 1999. Since joining SDG&E I have acted as the Lead Planner for the Information Technology Division in SDG&E's 2004 Cost of Service application and the 2008 GRC Phase 1 and provided support for witnesses in those cases. I have recently provided rate testimony in multiple FERC filings.

SDG&E 2012 GRC Phase 2 Testimony Errata Log

Exhibit	Witness	Page	Line	Errata Item
Exhibit No. SDG&E-106	Robert M. Ehlers	RME-3, RME-10, RME-11		References to Attachment A of Ms. Fang's testimony have been corrected to reference Attachment I of Ms. Fang's testimony.
Exhibit No. SDG&E-106	Robert M. Ehlers	RME-8	1	The words "by rate schedule," have been deleted from this sentence.
Exhibit No. SDG&E-106	Robert M. Ehlers	RME-9	29	The words "rate schedule" has been changed to "customer class".
Exhibit No. SDG&E-106	Robert M. Ehlers	RME-10, Table RME-03		Average Marginal Customer Costs by Customer Class have been updated to reflect changes in the marginal customer costs, as identified in my Chapter 6 Marginal Customer Cost Workpapers.
Exhibit No. SDG&E-106	Robert M. Ehlers	RME-10, RME-11		Roman numerals for testimony sections VII, VIII, IX and X have been changed to VI, VII, VIII, and IX.