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

Application No. 07-01-__
Exhibit No.: (SDGE-04) ________

PREPARED DIRECT TESTIMONY

OF JAMES S. PARSONS

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

JANUARY 31, 2007

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PREPARED DIRECT TESTIMONY

OF

JAMES S. PARSONS

CHAPTER 4

I. OVERVIEW AND PURPOSE

The purpose of my direct testimony is to present San Diego Gas & Electric Company's (SDG&E) proposals for distribution marginal customer costs, marginal distribution demand costs, marginal generating capacity costs, and marginal energy costs. The marginal customer and marginal distribution demand costs comprise marginal distribution costs. The marginal generation and energy costs comprise the marginal commodity costs.

I sponsor the unit marginal distribution costs, the unit marginal generating capacity costs, and the unit marginal energy costs, and explain their derivation in the following sections of this chapter. The marginal costs are provided in Attachments JSP-4-1 through JSP-4-3.

I am also sponsoring the determinants used in conjunction with the unit marginal generating costs to derive marginal customer cost revenue responsibilities, or marginal cost revenue by customer class. The marginal cost determinants for commodity costs are provided in Attachment JSP-4-3. The marginal cost determinants for distribution are provided in Chapter 5, Revenue Allocation, which I also sponsor. Those determinants are provided in Attachment JSP-5-3.

II. SDG&E MARGINAL COSTS REGULATORY HISTORY

The California Public Utilities Commission (Commission) has not adopted specific marginal capacity, energy, or distribution costs for SDG&E's revenue allocation and rate design since its 1996 Rate Design Window (RDW) decision (Decision (D.) 96-06-033). As such, in all of SDG&E's subsequent rate design proceedings, the proposed marginal costs served as a basis for eventual settlement on revenue allocation. SDG&E last submitted a complete marginal capacity and marginal energy cost study in its most recent RDW application (Application (A.) 05-02-019), where an all-party settlement on revenue allocation was reached with no adoption of specific marginal costs (*see* D.05-12-003). In that filing, the marginal distribution costs were updated using escalation factors from the prior RDW filing (A.03-03-029), which was also decided by a contested settlement that adopted a revenue allocation with no specific adoption of marginal costs (*see* D.04-04-042). SDG&E last provided a complete marginal distribution study in its 1999 RDW proceeding (A. 91-11-024, RDW segment filed November 1, 1999), which also was decided by an all-party settlement on revenue allocation without the adoption of specific marginal costs (*see* D.00-12-058).

III. OVERVIEW OF MARGINAL COSTS AND MARGINAL COST DETERMINANTS

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 Utility Distribution Company (UDC) electric service as the product. The definition used in this testimony is the change in the total cost of providing electric service which is caused by an increase in the amount of electricity supplied to customers by a UDC. These utility costs are assumed to be disaggregated into categories associated with providing changes in customer peak distribution demands or marginal distribution costs, access to customer service or marginal customer costs, changes in peak demand, and hourly energy or marginal commodity costs. The marginal distribution costs are further disaggregated into feeder and local distribution, and substation components, whereas the marginal commodity costs are further disaggregated between capacity and energy components.

Marginal demand costs theoretically measure the cost of serving an additional unit of customer kilowatt (kW) demand on a forecast basis. This demand cost component includes the investment costs and other associated costs for Operations & Maintenance (O&M), Administrative & General (A&G), General Plant Loading (GPL), and other accounting loaders. SDG&E has a sufficiently small service territory that disaggregation of marginal distribution demand costs by specific geographic location is not warranted. SDG&E's marginal distribution demand costs are developed for the system as a whole. Marginal distribution 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.

Marginal customer costs represent the cost of providing individual customer access to electrical service. The marginal customer cost methodology proposed 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. SDG&E proposes to continue the rental approach in this application. SDG&E believes this rental method provides more stable and consistent marginal customer costs than the NCO method. Marginal customer costs include the cost associated with investments required to hook up a new customer and the costs associated with maintaining the new customer account.

The investment costs for marginal demand and customer components have been derived in units of dollars-per-kW and dollars-per-customer. These investment dollars need to be adjusted for various loading factors for costs associated with these investments. These loading factors include factors for fixed O&M, fixed A&G, and GPL. SDG&E proposes no major changes in the methodology for calculation of these factors from the current Commission-adopted methodologies for SDG&E.

The marginal demand and customer component investments must be converted to an annual value, dollars-per-kW-per-year and dollars-per-customer-per-year, to be useful for revenue allocation and rate design purposes. The Commission has adopted the Real Economic Carrying Charge (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 (as in a mortgage payment), or a present worth method (as in differences in present worth of accelerated or deferred investments). SDG&E proposes to continue using the RECC approach for annualizing the marginal costs proposed in this report.

Marginal commodity costs are comprised of capacity and energy components. The marginal generating capacity component represents the marginal cost of providing an additional kW of demand during peak periods. The 2008 annualized capital cost of a Combustion Turbine (CT) is used as the proxy for the capacity marginal cost. The marginal energy cost represents the cost of providing an additional kW hour during any given hour. Average annual electric forward market prices for 2008 are applied to hourly system price profiles (the "E3"[1] price shapes adjusted for peaker CT operation) to derive hourly unit marginal energy costs.

The uses proposed for the marginal costs in this report are only for revenue allocation and rate design applicable to this General Rate Case (GRC) Phase II proceeding.

Determinants are customer class characteristics that reflect how the electricity provided by the UDC is used. 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 both revenue allocation and rate design calculations. The determinants included in this application for revenue allocation are forecast Test Year 2008 values that are based on load research data from calendar year 1995 through 2005. Commodity unit marginal costs use hourly load research data from calendar years 2003 through 2005. The distribution peak load determinants used for unit marginal distribution capacity costs are based on historic calendar years 1994 through 2005 and forecast calendar years 2006 through 2008.

IV. UNIT MARGINAL CUSTOMER COSTS

Marginal customer costs represent the cost of access to the electrical system for new customers. These marginal costs are composed of two types of costs. The first is

[1] abbreviation for Energy and Environmental Economics, Inc.

the cost associated with the investment required in order to provide access (i.e., hook-up costs of a new customer). The second relates to the cost incurred with the addition of and the maintenance of a new customer account: the customer accounting costs. These two kinds of costs vary by customer type, size, service voltage, type of equipment used for access, and the sophistication of the billing system.

SDG&E proposes using the rental method to calculate unit marginal customer costs for the various customer classes. This method applies the annualized investment cost and customer accounting costs to all customers.

The proposed 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 totally on customer service expenses.

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

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 multiple customer demand and service levels were developed for: (1) transformers based on size, type, and the average number of customers per transformer; (2) service length based on the wire size, the number of runs, and the average service length; and (3) meters based on customer type. The investment cost for each customer range was based on engineering estimates for a typical customer.

The total investment costs by customer range represent a weighted-average of all customer types (standard, demand metered, and time-of-use (TOU)) within the range. These totals are then multiplied by general plant and working capital loading factors resulting in the total TSM costs. The total TSM costs are then annualized using a RECC.

Marginal customer accounting expenses represent the cost of adding and maintaining a new customer account. These costs are estimated based on Federal Energy Regulatory Commission (FERC) account information for year-end 2005. To allocate these costs to the individual customer classes, each FERC account was analyzed to determine the nature of the expense. Allocation factors were developed for each customer class based on this analysis. These allocation factors were used to allocate most of the FERC account estimates to customer classes. The remaining accounts were allocated to the customer classes on a prorated basis. The net totals are multiplied by an A&G loading factor to calculate the total customer and accounting expenses for each class. The class totals are then escalated to 2008 dollars from 2005 estimates using escalation forecasts from the 2008 GRC Phase 1 showing.

The marginal customer costs, disaggregated by components, by rate schedule, and by service voltage level, are provided in JSP-4-1

V. 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 the SDG&E system during a specific planning horizon. These facilities include poles, fixtures, capacitors, overhead, and underground conductors and devices.

SDG&E proposes the use of the Regression method, also known as the "NERA" method,[2] to calculate marginal feeder and local distribution costs. This method uses ten years of historical and five years of growth-related feeder and local distribution investments along with annual distribution system peak determinants in a regression methodology. The regression has the cumulative incremental changes in distribution peak data as the independent variable, and the cumulative incremental distribution growth-related investments as the dependent variable, and regresses over the fifteen year period of data points.

The feeder and local distribution investments used in the Regression method were obtained from distribution capital budget forecasts for the period 2006 through 2008. 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 1994 through 2005 were 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 1994 through 2008.

The marginal investment amount derived in units of dollars-per-kW is then annualized to dollars-per-kW-per-year using a RECC factor derived for feeder and local

[2] National Economics Research Association (NERA) was first to propose this method.

distribution plant accounts. This annualized cost of investment is then adjusted for various loading factors for O&M, A&G, general plant, and working capital to derive the marginal feeder and local distribution unit cost.

The marginal distribution costs, by components, for feeders and local distribution are provided in JSP-4-2.

VI. UNIT MARGINAL SUBSTATION COSTS

Marginal substation costs represent the forecasted cost for construction of substations to serve an additional kW 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 proposes to use the Regression method to calculate marginal substation costs. Again, the method uses twelve years of historical and three years of growth-related substation growth-related investments along with annual distribution system peak determinants in a regression methodology. The regression has the cumulative incremental changes in distribution peak data as the independent variable, and the cumulative incremental distribution growth-related investments as the dependent variable, and regresses over the fifteen year period of data points.

The substation investments used in the Regression method were obtained from capital budget forecasts for the period 2006 through 2008. Only three years of forecasted substation data was available from the capital budget data. Again, since only three years of forecast data was available, twelve years of historical investment data from years 1994 through 2005 were 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 1994 through 2008.

The marginal investment amount derived in units of dollars-per-kW is then annualized to dollars-per-kW-per-year using a RECC factor derived for substation plant accounts. This annualized cost of investment is then adjusted for various loading factors for O&M, A&G, general plant, and working capital to derive the marginal substation unit cost.

The marginal distribution costs, by component costs, for substation costs, are provided in JSP-4-2.

VII. UNIT MARGINAL GENERATING CAPACITY COSTS

The calculation of marginal generation capacity costs has been debated in a number of proceedings without resolution including the last SDG&E Rate Design Window (RDW) application; the GRC Phase 2 proceedings of both PG&E and SCE; the 2006 Update of Avoided Costs in R.04-04-025; Phase 2 of R.04-04-025; the cost benefit analyses of demand response programs for PG&E, SCE, and SDG&E; and the AMI filings of both PG&E and SDG&E. And based on the Commission's statements in D.06-06-063, SDG&E expects that the issue will not be resolved in this proceeding either, but will be resolved in Phase 3 of R.04-04-025.

> As indicated in the comments in this proceeding, the utilities have proposed a CT-based valuation approach in pending applications for advanced metering infrastructure (AMI), rate design phases of general rate

cases, among others. … We have clearly stated that debate over avoided cost methodology should be conducted in this rulemaking, and not in multiple proceedings where the methods and inputs for specific applications of avoided costs are applied. (D.06-06-063, pages 79-80)

Therefore, SDG&E has not tried to break new ground in this application, but instead presents an analysis of marginal generation capacity costs consistent with its proposal in the last RDW application. SDG&E starts with a levelized nominal price of a combustion turbine of $85.00-per-kW-per-year in 2006.[3] This value has been used extensively by the Commission in R.02-06-001 and related proceedings. Most recently it was used and justified for the Avoided Generation Capacity cost in the SDG&E Advanced Metering Infrastructure (AMI) proceeding.[4] The marginal generation capacity cost proposed by SDG&E in its last RDW application, and the avoided cost of capacity proposed by SDG&E in R.04-04-025, phase 2, when adjusted for inflation, were also approximately $85/kW-year.[5]

Using similar data to that relied upon in the calculation of the $85 per kW-year nominal levelized value in 2006 dollars, a value of $76.40 is calculated in 2008 dollars based on a real economic carrying charge (RECC) approach. The RECC approach is used by SDG&E in other marginal cost calculations and has been used by all parties for

[3] SDG&E's analysis is based on a combustion turbine since it is the marginal capacity resource for SDG&E. SDG&E studied the alternative of duct firing in a combined cycle plant and rejected it as a marginal capacity resource. The analysis of duct firing and associated workpapers are contained in the workpapers to this chapter.
[4] See John C. Martin amended testimony, July 14, 2006 , filed in A.05-03-015.
[5] See testimony of David T. Barker in A. 05-02-019, filed February 19, 2005, and the testimony of David T. Barker filed in R.04-04-025, Phase 2, Exhibit 85, filed August 31, 2005.

calculation of marginal generation capacity costs in the most recent GRC Phase 2 cases of SCE and PG&E. The RECC value escalated for inflation over the life of the asset has the same present value as the levelized nominal cost (which has no escalation). While the levelized nominal value is closer to how contract prices are set, SDG&E has used the RECC approach in compliance with D.05-12-003,ordering paragraph 4.

SDG&E proposes to derive capacity costs based on the cost of a CT for each customer class using the "Top 300 hour" methodology, which is a variation of the "Top 100 hour" methodology used by the Commission in Competition Transition Charge (CTC) allocation proceedings.

The Top 300 hour methodology considers the magnitude of each customer classes' contribution to the top 300 hours of system load during a given annual period. It is a measure of when a marginal generation capacity unit might be required by a given customer class. This proposed Top 300 Hour methodology is used as a proxy to the earlier Commission-adopted approach of using Loss of Load Probabilities (LOLP) as an indicator of peaker generation capacity necessity.

The LOLP methodology was used in the last generation marginal capacity study submitted by SDG&E years ago in the 1995 RDW proceeding. The LOLP methodology was also used in SDG&E's 1989 and 1993 GRC Phase II proceedings. In the 1989 and 1993 proceedings, LOLP values were derived for 2,016 hours of the year, and these values were applied to corresponding 2,016 forecast hourly loads by customer, classes then summed across the 2,016 hours by customer classes to derive LOLP-weighted customer class values. These values were then used as LOLP-weighted coincident demands. The unit marginal generation cost was multiplied times the LOLP-weighted coincident demands to derive the marginal generating capacity cost revenue responsibilities by customer class.

In the settlement negotiations for the 1993 GRC proceeding, the parties agreed that 98% of the LOLP values were contained in the top 300 hours of the annual 2,016 hours. Consequently only the top 300 system hours were used for calculation of marginal generating capacity cost revenue responsibilities that were implicit in the settlement adopted by the Commission in the 1993 GRC proceeding. This use of the top 300 hours was also used in the subsequent 1995 RDW proceeding settlement.

The last RDW proceeding was the first time SDG&E has presented a marginal generating capacity cost since the 1995 RDW proceeding. SDG&E proposed to use the simpler top 300 hours method instead of the more complex LOLP values for marginal generating capacity allocation determinants. SDG&E proposes in this RDW proceeding to use the average customer class loads during the top 300 hours of system peak as a proxy for LOLP-weighted coincident demand values in the calculation of marginal generation capacity allocation determinants, just as was proposed in the last RDW application. SDG&E believes this methodology provides a reasonable estimate of each customer classes' contribution to the necessity for marginal generation capacity.

SDG&E proposes to use three years of load research data for the Top 300 hour methodology. The 100 hours of highest usage for years 2003, 2004, and 2005 were combined and sorted in descending order by system load to provide the 300 hours for each rate schedule. These 300 hours of class data were then analyzed by the rate schedule's applicable TOU periods to determine what percentage of the annualized combustion turbine cost should be assigned to that Schedule's TOU period. The marginal capacity cost is calculated as in dollars-per-kW hour in order that the marginal cost can be applied to the forecast year 2008 TOU periods.

The unit marginal capacity costs, the forecast year determinants and the marginal capacity cost revenue, by rate schedule TOU periods are provided in JSP-4-3.

VIII. UNIT MARGINAL ENERGY COSTS

SDG&E proposes calculating system unit marginal energy costs for each of 24 hours for a representative weekday day and a representative weekend day for each of the twelve months of the year. This results in 576 hourly system unit marginal energy costs. The hourly energy costs are based on an hourly price shape and a marginal price forecast.

The 576 hourly price shapes are based on the E3 consultants' recommendation in Section 2.3.3 of the final E3 report adopted in D.05-04-024. The E3 hourly price profile from that report was for 8769 hours based on the California Power Exchange (PX) day-ahead South Path 15 (SP 15) zonal prices during the 25 month time period between April 1998 and April 2000. These annual hourly price shapes were mapped into one representative annual hourly historic year for a market that includes both capacity and energy. While the price profile is now quite old, it has been the basis for SDG&E time-of-use profiles in the last several years. It provides an adequate hourly price profile until hourly data becomes available from the California Independent System Operator (Cal ISO) day-ahead hourly energy market in 2008. However, because the system hourly marginal price shape includes both a capacity and energy component, it was adjusted to avoid double counting capacity costs. Prices above the variable operating cost of a CT (the level that would cause a CT to be operating) are the capacity component of the prices and belong in the unit marginal generating capacity costs. Therefore, to capture only energy-related costs, the hourly prices are capped at the lowest price shape value in the period that the CT is assumed to be operating. An assumption was made that the CT would have a capacity factor of ten percent and would be running during the top 876 hours of the year.[6] This approach is used as a proxy for calculating the variable costs of operating a CT.[7] The adjusted 8760 annual hourly price shapes are then used as a basis to calculate the 576 representative weekday and weekend days' hourly "energy-only" price shapes for each month. This general approach to calculating energy-only prices is the same approach SDG&E has used in recent proceedings including Phase 2 of the Avoided Cost proceeding (R.04-04-025); the prior RDW application; and cost effectiveness analysis of demand response programs. It was also used by SCE in its last GRC, Phase 2, and by TURN in Phase 2 of the Avoided Cost Proceeding. An annual Electric Forward Market average price for the year 2008 is applied to these system hourly price shapes to derive the hourly unit marginal energy costs. The Electric Forward market prices are based on broker forward market data, the type relied on by SDG&E Electric and Gas Procurement functions. This data is in the form of daily forward SP-15

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[6] The same assumption used by the California Energy Commission in its study, "Comparative Cost of California Central Station Electricity Generation Technologies," August, 2003, 100-03-001, Appendix D. It is also similar to TURN's assumption in the SCE GRC Phase 2 of 900 hours. See Testimony of W.B. Marcus and M. Florio in A. 05-05-023, page 22.

[7] In previous studies, the assumed operating hours have fluctuated wildly causing the capacity value embedded in the market prices to dramatically vary across studies. See the rebuttal testimony of John C. Martin in the SDG&E AMI case, filed September 7, 2006, and revised September 19, 2006, pages JCM-9 – JCM-10. The 10 percent capacity factor is also reasonable based on recent experience. SDG&E's new CT at Miramar operated less than 10 percent in 2006. Testimony in R.04-04-025 also indicated that new CTs in central and northern California have been operating below a 10 percent capacity factor in the past several years. See rebuttal testimony of R. Thomas Beach in R.04-04-025, phase 2, Exhibit 103, page 59, filed October 28, 2005.

price quotes from August 1, 2006 through September 31, 2006 for both on-peak and off-peak prices. These values were then weight averaged to obtain one annual SP-15 Electric Forward price for the year 2008.

This approach was used to calculate the system unit marginal energy costs that are implicit in the current adopted commodity rates resulting from SDG&E's last RDW decision (D.05-12-003).

The next step is to translate these system hourly unit marginal energy costs into representative rate schedule TOU marginal energy costs. These unit marginal energy costs, in dollars-per-kW hour, as described above, are provided in the format of hourly values for typical weekday and weekend for each month of the year. Customer rate schedule typical load values are derived in the same hourly format of weekdays and weekends for each rate schedule based on load research data. The load research data used is consistent with the data for the Top 300 hour calculations in derivation of marginal generation capacity costs. This means three years of load research data from years 2003, 2004, and 2005 were used to derive typical rate schedule hourly loads.

The hourly unit marginal energy costs are then multiplied by the hourly rate schedule loads to derive typical hourly marginal cost hourly dollars for each rate schedule, by months for weekdays and weekends. These hourly marginal costs dollars are then aggregated by the applicable rate schedule seasonal and daily TOU periods sums to match the commodity rate categories necessary for the rate design models. Dividing by the corresponding rate schedule TOU loads then provides a unit marginal energy cost that can be applied to the forecast rate schedule TOU determinants to derive the marginal cost revenue.

The objective of this approach in calculating marginal energy cost revenue responsibilities is to coordinate the use of three different datasets in the calculation. The unit marginal energy costs are one dataset and are based on a forecast market price shape and forecast market price. The load research data is based on hourly annual historical data for years 2003, 2004, and 2005 and consists of 8760 hours by rate schedule for each year. The third dataset is the forecast year 2008 loads by rate schedule TOU periods.

The unit marginal energy costs, the forecast year determinants, and the marginal energy cost revenue by rate schedule TOU periods are provided in JSP-4-3.

IX. DISTRIBUTION MARGINAL COST DETERMINANTS

The distribution function marginal cost determinants are based on forecasts for year 2008 of the number of customers by customer classes, their coincident to system peak demands, their individual customer class non-coincident peak demands, and their sum of individual customer's non-coincident peak demands. The forecast of number of customers is marginal customer cost determinant. A weighted-average of the customer class coincident and non-coincident demands is used to calculate the feeder and local distribution marginal cost determinants, and the substation marginal cost determinants.

These marginal distribution cost determinants are applied to applicable customer unit costs, feeder and local distribution unit marginal costs, and substation unit marginal costs to calculate the distribution marginal cost revenue. The distribution marginal cost revenue is used in the distribution revenue allocation explained in Chapter 5. These marginal cost determinants are provided in JSP-5-3.

X. COMMODITY MARGINAL COST DETERMINANTS

The marginal energy cost determinants are based on forecasts of rate schedule TOU period sales for Test Year 2008. The test year sales are sponsored by SDG&E witness Greg Katsapis in Chapter 3. These sales were disaggregated to TOU periods by rate schedules using load factors based on analyzing the last ten years of rate schedule TOU data for bundled commodity customers. The load factors were then applied to the forecast sales to derive the marginal energy cost determinants. These determinants are provided in JSP-4-3.

The marginal capacity cost determinants are based on forecast rate schedule billing demands and sales. These demands and TOU sales disaggregations were based on load factors derived from ten years of data for distribution level customers. These marginal capacity cost determinants are also provided in JSP-4-3.

This concludes my prepared direct testimony.

XI. QUALIFICATIONS OF JAMES S. PARSONS

My name is James S. Parsons. My business address is 8315 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 San Diego Gas & Electric Company (SDG&E). My primary responsibilities include the development of electric cost-of-service studies, revenue allocation studies, and derivation of rate designs.

I received a Bachelor of Science degree in Engineering from The Pennsylvania State University 1966. I received a Master of Science degree in Business Administration from the San Diego State University 1972 I am a Registered Professional Engineer, Mechanical Branch, in the State of California. I have been employed by SDG&E since 1972 in various engineering, regulatory analysis, and rate design capacities.

I have testified before this Commission since 1980 in numerous costs of service, revenue allocation, and rate design proceedings.

ATTACHMENT

JSP-4-1

ATTACHMENT JSP-4-1
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
MARGINAL CUSTOMER COSTS

Residential Schedules

Line No	Cost Component	DR (A)	DR-LI (B)	DM (C)	DS (D)	DT (E)	Class (F)	Line No
	TSM Components ($/Customer)							
1	Transformers	254.53	251.56	323.96	971.22	4,581.61	255.98	1
2	Services	91.30	90.69	108.75	258.73	1,495.96	91.80	2
3	Meters	95.84	95.84	97.42	111.64	341.38	95.94	3
4	Subtotal ($/Customer)	441.67	438.09	530.13	1,341.59	6,418.94	443.71	4
5	General Plant Loading at	3.55	3.52	4.26	10.79	51.61	3.57	5
6	0.80%							6
7	Working Capital at	5.48	5.43	6.58	16.64	79.61	5.50	7
8	1.24%							8
9	Subtotal ($/Customer)	450.70	447.04	540.97	1,369.02	6,550.16	452.79	9
10	Annualized Cost at	45.16	44.80	54.21	137.18	656.35	45.37	10
11	10.02%							11
12	O&M Expenses	36.51	36.51	36.51	36.51	36.51	36.51	12
13	Customer Accounts/Services	40.92	40.92	40.92	40.92	40.92	40.92	13
14	Total ($/Customer/Year)	122.59	122.23	131.64	214.61	733.78	122.80	14

ATTACHMENT JSP-4-1
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
MARGINAL CUSTOMER COSTS

Small Commercial Schedules

Line No	Cost Component	Sch A (A)	Line No
	TSM Components ($/Customer)		
1	Transformers	1,942.22	1
2	Services	236.14	2
3	Meters	208.84	3
4	Subtotal ($/Customer)	2,387.19	4
5	General Plant Loading at	19.19	5
6	0.80%		6
7	Working Capital at	29.61	7
8	1.24%		8
9	Subtotal ($/Customer)	2,436.00	9
10	Annualized Cost at	244.09	10
11	10.02%		11
12	O&M Expenses	36.51	12
13	Customer Accounts/Services	40.92	13
14	Total ($/Customer/Year)	321.53	14

ATTACHMENT JSP-4-1
SAN DIEGO GAS ELECTRIC - ELECTRIC DEPARTMENT
2008 GRC PHASE II
MARGINAL CUSTOMER COSTS

Medium and Large Commercial/Industrial Schedules

		AL/AY/PAT-1 TOU					A6- TOU			
Line No	Cost Component	AD (A)	Secondary (B)	Primary (C)	Sec at Sub (D)	Pri at Sub (E)	Primary (F)	Pri at Sub (G)	Class (H)	Line No
	TSM Components ($/Customer)									
1	Transformers	7,948.66	7,974.69	0.00	8,118.55	0.00	0.00	0.00	15,727.41	1
2	Services	1,562.47	1,795.52	980.22	924.56	980.22	1,487.64	1,487.64	2,691.61	2
3	Meters	609.12	600.99	5,548.08	600.99	5,548.08	5,548.08	5,548.08	1,344.43	3
4	Subtotal ($/Customer)	10,120.26	10,371.20	6,528.30	9,644.10	6,528.30	7,035.71	7,035.71	19,763.45	4
5	General Plant Loading at	81.37	83.38	52.49	77.54	52.49	56.57	56.57	158.90	5
6	0.80%									6
7	Working Capital at	125.52	128.63	80.97	119.62	80.97	87.26	87.26	245.13	7
8	1.24%									8
9	Subtotal ($/Customer)	10,327.15	10,583.22	6,661.76	9,841.26	6,661.76	7,179.54	7,179.54	20,167.48	9
10	Annualized Cost at	1,034.81	1,060.47	667.53	986.12	667.53	719.41	719.41	2,020.84	10
11	10.02%									11
12	O&M Expenses	67.30	268.61	67.30	268.61	268.61	268.61	36.51	70.34	12
13	Customer Accounts/Services	67.47	75.44	301.12	75.44	301.12	301.12	301.12	78.86	13
14	Total ($/Customer/Year)	1,169.58	1,404.52	1,035.94	1,330.18	1,237.26	1,289.14	1,057.04	2,170.05	14

ATTACHMENT JSP-4-1
SAN DIEGO GAS ELECTRIC - ELECTRIC DEPARTMENT
2008 GRC PHASE II
MARGINAL CUSTOMER COSTS

Agricultural Schedules

Line No	Cost Component	Sch PA (A)	Line No
	TSM Components ($/Customer)		
1	Transformers	1,940.77	1
2	Services	403.02	2
3	Meters	203.27	3
4	Subtotal ($/Customer)	2,547.06	4
5	General Plant Loading at	20.48	5
6	0.80%		6
7	Working Capital at	31.59	7
8	1.24%		8
9	Subtotal ($/Customer)	2,599.13	9
10	Annualized Cost at	260.44	10
11	10.02%		11
12	O&M Expenses	36.51	12
13	Customer Accounts/Services	40.92	13
14	Total ($/Customer/Year)	337.87	14

Lighting Schedules

Cost Component	Unmetered Lighting (A)
TSM Components ($/Lamp)	
Transformers	20.73
Services	125.88
Meters	0.00
Subtotal	146.61
General Plant Loading at 0.80%	1.18
Working Capital at 1.24%	1.82
Subtotal ($/Lamp)	149.61
Annualized Cost at 10.02%	14.99
Number of Lamps	151,016.65
Number of Customers	6,176.80
Annualized Cost per Customer	366.52
O&M Expenses	102.90
Customer Accounts/Services	50.86
Total ($/Customer/Year)	520.28

ATTACHMENT

JSP-4-2

ATTACHMENT JSP-4-2
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
MARGINAL DISTRIBUTION CAPACITY COSTS

Line No	Feeders & Local Distribution		Line No
	Cost Component		
1	Investment ($/kW)	366.56	1
2	General Plant Loading	2.95	2
3	(at 0.804%)		3
4	Working Capital	0.04	4
5	(at 1.2403%)		5
6	Subtotal ($/kW)	369.54	6
7	Annualized Cost-Weighted Average F&LD	34.36	7
8	(at RECC of 9.298%)		8
9	A&G Loading Applicable to Plant	4.33	9
10	(at 1.172%)		10
11	Fixed O&M	3.77	11
12	A&G on Fixed O&M	1.59	12
13	(at 42.247%)		13
14	Total Annual Unit Cost ($/kW/Yr)	44.05	14

ATTACHMENT JSP-4-2
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
MARGINAL DISTRIBUTION CAPACITY COSTS

Line No	Substation Costs		Line No
	Cost Component		
1	Investment ($/kW)	130.45	1
2	General Plant Loading	1.05	2
3	(at 0.804%)		3
4	Working Capital	0.01	4
5	(at 1.2403%)		5
6	Subtotal ($/kW)	131.51	6
7	Annualized Cost Station Equipment (362)	11.58	7
8	(at RECC of 8.805%)		8
9	A&G Loading on Plant	1.54	9
10	(at 1.172%)		10
11	Fixed O&M	3.77	11
12	A&G on Fixed O&M	1.59	12
13	(at 42.247%)		13
14	Total Annual Unit Cost ($/kW/Yr)	18.48	14

ATTACHMENT

JSP-4-3

MARGINAL COMMODITY COST AND REVENUE

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Determinants (kWhrs) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Residential Class (Schedules DR/DM/DS/DT)				
1	Summer Season - ¢/kWhr	7.18741	3,831,845	275,410.53	1
2	Winter Season - ¢/kWhr	7.09444	3,816,159	270,734.97	2
3	Annual - ¢/kWhr	7.14102	7,648,004	546,145.50	3
	Schedule DR-TOU				
4	Summer On-Peak - ¢/kWhr	9.21458	1,799	165.77	4
5	Summer Off-Peak - ¢/kWhr	6.54857	8,464	554.27	5
6	Winter On-Peak - ¢/kWhr	7.88998	1,602	126.40	6
7	Winter Off-Peak - ¢/kWhr	6.84219	8,718	596.50	7
8	Annual - ¢/kWhr	7.01035	20,583	1,442.94	8
	Schedule DR-SES				
9	Summer On-Peak - ¢/kWhr	9.14980	0	0.00	9
10	Summer Semi-Peak - ¢/kWhr	7.66541	0	0.00	10
11	Summer Off-Peak - ¢/kWhr	5.97428	0	0.00	11
12	Winter Semi-Peak - ¢/kWhr	7.72040	0	0.00	12
13	Winter Off-Peak - ¢/kWhr	6.76320	0	0.00	13
14	Annual - ¢/kWhr	7.14114	0	0.00	14
	Schedule EV-TOU				
15	Summer On-Peak - ¢/kWhr	8.72135	14	1.22	15
16	Summer Off-Peak - ¢/kWhr	6.68795	33	2.21	16
17	Summer Super Off-Peak - ¢/kWhr	4.24894	11	0.47	17
18	Summer On-Peak - ¢/kWhr	7.87674	12	0.95	18
19	Summer Off-Peak - ¢/kWhr	7.15044	32	2.29	19
20	Winter Super Off-Peak - ¢/kWhr	4.47313	12	0.54	20
21	Annual - ¢/kWhr	6.72414	114	7.67	21

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Determinants (kWhrs) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Schedule A				
	Summer				
22	Secondary - ¢/kWhr	7.09757	855,969	60,753.02	22
23	Primary - ¢/kWhr	6.97525	343	23.93	23
	Winter				
24	Secondary - ¢/kWhr	7.31651	1,095,134	80,125.58	24
25	Primary - ¢/kWhr	7.18934	438	31.49	25
26	Annual - ¢/kWhr	7.22041	1,951,884	140,934.02	26
	Schedule ATC				
27	Summer Season - ¢/kWhr	6.94536	26,985	1,874.21	27
28	Winter Season - ¢/kWhr	7.26210	34,531	2,507.68	28
29	Annual - ¢/kWhr	7.12316	61,516	4,381.88	29
	Schedule A-TOU				
	Summer				
30	On-Peak - ¢/kWhr	8.98810	7,239	650.65	30
31	Semi-Peak - ¢/kWhr	7.33171	7,674	562.64	31
32	Off-Peak - ¢/kWhr	5.49246	12,781	701.99	32
	Winter				
33	On-Peak - ¢/kWhr	8.78953	3,854	338.75	33
34	Semi-Peak - ¢/kWhr	8.10149	14,782	1,197.56	34
35	Off-Peak - ¢/kWhr	6.03990	17,018	1,027.87	35
36	Annual - ¢/kWhr	7.07119	63,348	4,479.46	36
	Schedule AD				
	Summer Energy				
37	Secondary - ¢/kWhr	7.24171	26,506	1,919.49	37
38	Primary - ¢/kWhr	7.11691	0	0.00	38
	Winter Energy				
39	Secondary - ¢/kWhr	7.46179	34,514	2,575.36	39
40	Primary - ¢/kWhr	7.33210	0	0.00	40
41	Annual - ¢/kWhr	7.36619	61,020	4,494.85	41

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Determinants (kWhrs) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Commercial/Industrial TOU (Schedules AL-TOU, AY-TOU, A6-TOU, PA-T-1)				
	Summer On-Peak				
42	Secondary - ¢/kWhr	8.94390	740,093	66,193.18	42
43	Primary - ¢/kWhr	8.80663	86,147	7,586.65	43
44	Secondary Substation - ¢/kWhr	8.94390	13,296	1,189.18	44
45	Primary Substation - ¢/kWhr	8.80663	24,570	2,163.79	45
46	Transmission - ¢/kWhr	8.65528	2,526	218.63	46
	Summer Semi-Peak				
47	Secondary - ¢/kWhr	7.24708	786,177	56,974.84	47
48	Primary - ¢/kWhr	7.13237	94,803	6,761.70	48
49	Secondary Substation - ¢/kWhr	7.24708	14,848	1,076.05	49
50	Primary Substation - ¢/kWhr	7.13237	29,373	2,094.99	50
51	Transmission - ¢/kWhr	7.01697	2,888	202.65	51
	Summer Off-Peak				
52	Secondary - ¢/kWhr	5.45538	1,198,931	65,406.22	52
53	Primary - ¢/kWhr	5.35364	140,982	7,547.66	53
54	Secondary Substation - ¢/kWhr	5.45538	28,897	1,576.44	54
55	Primary Substation - ¢/kWhr	5.35364	52,257	2,797.65	55
56	Transmission - ¢/kWhr	5.28297	4,982	263.20	56
	Winter On-Peak				
57	Secondary - ¢/kWhr	8.78751	343,048	30,145.39	57
58	Primary - ¢/kWhr	8.65534	39,587	3,426.39	58
59	Secondary Substation - ¢/kWhr	8.78751	6,556	576.11	59
60	Primary Substation - ¢/kWhr	8.65534	12,558	1,086.94	60
61	Transmission - ¢/kWhr	8.50104	1,155	98.19	61
	Winter Semi-Peak				
62	Secondary - ¢/kWhr	8.07900	1,573,774	127,145.23	62
63	Primary - ¢/kWhr	7.95003	187,025	14,868.54	63
64	Secondary Substation - ¢/kWhr	8.07900	28,913	2,335.88	64
65	Primary Substation - ¢/kWhr	7.95003	54,414	4,325.93	65
66	Transmission - ¢/kWhr	7.82351	4,917	384.68	66
	Winter Off-Peak				
67	Secondary - ¢/kWhr	6.02015	1,556,634	93,711.72	67
68	Primary - ¢/kWhr	5.90724	185,450	10,954.97	68
69	Secondary Substation - ¢/kWhr	6.02015	37,784	2,274.65	69
70	Primary Substation - ¢/kWhr	5.90724	69,652	4,114.51	70
71	Transmission - ¢/kWhr	5.82966	7,787	453.96	71
72	Annual - ¢/kWhr	7.06622	7,330,024	517,955.90	72

ATTACHMENT JSP-4-3
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
2008 GRC PHASE II
MARGINAL COMMODITY COST AND REVENUE

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Energy (¢/kWhr) (A)	Marginal Cost Determinants (kWhrs) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Agriculture (Schedule PA)				
73	Summer Season - ¢/kWhr	6.77688	42,957	2,911.14	73
74	Winter Season - ¢/kWhr	7.16931	39,700	2,846.22	74
75	Annual - ¢/kWhr	6.96536	82,657	5,757.36	75
	Lighting				
76	Annual - ¢/kWhr	5.97274	109,342	6,530.71	76
77	System Annual Total - ¢/kWhr	7.11055	17,307,795	1,230,679.68	77

ATTACHMENT JSP-4-3
SAN DIEGO GAS ELECTRIC COMPANY - ELECTRIC DEPARTMENT
MARGINAL COMMODITY COST AND REVENUE

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Capacity (¢/kWhr or $/kW) (A)	Marginal Cost Determinants (kWhrs or kW) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Residential Class (Schedules DR/DM/DS/DT)				
1	Summer Season - ¢/kWhr	3.019	3,831,845.00	115,700.994	1
2	Winter Season - ¢/kWhr	0.000	3,828,647.00	0.000	2
3	Annual	1.513	7,660,492.00	115,700.994	3
	Schedule DR-TOU				
4	Summer On-Peak - ¢/kWhr	13.004	1,799.00	233.946	4
5	Summer Off-Peak - ¢/kWhr	0.911	8,464.00	77.117	5
6	Winter On-Peak - ¢/kWhr	0.000	1,602.00	0.000	6
7	Winter Off-Peak - ¢/kWhr	0.000	8,718.00	0.000	7
8	Annual	1.509	20,583.00	311.063	8
	Schedule DR-SES				
9	Summer On-Peak - ¢/kWhr	10.811	0.00	0.000	9
10	Summer Semi-Peak - ¢/kWhr	0.895	0.00	0.000	10
11	Summer Off-Peak - ¢/kWhr	0.755	0.00	0.000	11
12	Winter On-Peak - ¢/kWhr	0.000	0.00	0.000	12
13	Winter Off-Peak - ¢/kWhr	0.000	0.00	0.000	13
14	Annual	1.518	0.00	0.000	14
	Schedule EV-TOU				
15	Summer On-Peak - ¢/kWhr	11.260	14.00	1.576	15
16	Summer Off-Peak - ¢/kWhr	0.261	33.00	0.086	16
17	Summer Super Off-Peak - ¢/kWhr	0.000	11.00	0.000	17
18	Winter On-Peak - ¢/kWhr	0.000	12.00	0.000	18
19	Winter Off-Peak - ¢/kWhr	0.000	32.00	0.000	19
20	Winter Super Off-Peak - ¢/kWhr	0.000	12.00	0.000	20
21	Annual	1.458	114.00	1.662	21

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Capacity (¢/kWhr or $/kW) (A)	Marginal Cost Determinants (kWhrs or kW) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Schedule A				
	Summer				
22	Secondary - ¢/kWhr	4.176	855,969.00	35,747.629	22
23	Primary - ¢/kWhr	4.104	343.00	14.078	23
	Winter				
24	Secondary - ¢/kWhr	0.122	1,095,134.00	1,334.078	24
25	Primary - ¢/kWhr	0.120	438.00	0.524	25
26	Annual	1.901	1,951,884.00	37,096.309	26
	Schedule ATC				
27	Summer Season - ¢/kWhr	3.295	26,985.00	889.123	27
28	Winter Season - ¢/kWhr	0.067	34,531.00	22.981	28
29	Annual	1.549	61,516.00	912.104	29
	Schedule A-TOU				
	Summer				
30	On-Peak - ¢/kWhr	13.262	7,239.00	960.006	30
31	Semi-Peak - ¢/kWhr	0.914	7,674.00	70.105	31
32	Off-Peak - ¢/kWhr	0.584	12,781.00	74.585	32
	Winter				
33	On-Peak - ¢/kWhr	0.156	3,854.00	6.009	33
34	Semi-Peak - ¢/kWhr	0.238	14,782.00	35.110	34
35	Off-Peak - ¢/kWhr	0.000	17,018.00	0.000	35
36	Annual	1.795	63,348.00	1,145.816	36

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Capacity (¢/kWhr or $/kW) (A)	Marginal Cost Determinants (kWhrs or kW) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Schedule AD				
	Maximum Demand: Summer				
37	Secondary - $/kW/month	10.111	112.39	1,136.344	37
38	Primary - $/kW/month	9.972	0.00	0.000	38
	Maximum Demand: Summer				
39	Secondary - $/kW/month	0.303	146.34	44.292	39
40	Primary - $/kW/month	0.298	0.00	0.000	40
41	Annual			1,180.636	41
	Schedule A6-TOU				
	Maximum On-Peak Demand: Summer				
42	Primary - $/kW/month	17.081	5.72	97.721	42
43	Primary Substation - $/kW/month	17.081	3.31	56.487	43
44	Transmission - $/kW/month	16.662	13.06	217.681	44
	Maximum On-Peak Demand: Winter				
45	Primary - $/kW/month	0.114	7.83	0.891	45
46	Primary Substation - $/kW/month	0.114	3.54	0.403	46
47	Transmission - $/kW/month	0.111	8.63	0.958	47
48	Annual			374.140	48

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Capacity (¢/kWhr or $/kW) (A)	Marginal Cost Determinants (kWhrs or kW) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Schedule PA-T-1				
	Demand: Summer				
	Option C				
49	Secondary - $/kW/month	13.782	0.00	0.000	49
50	Primary - $/kW/month	13.591	0.00	0.000	50
51	Transmission - $/kW/month	13.259	0.00	0.000	51
	Option D				
52	Secondary - $/kW/month	14.374	448.98	6,453.849	52
53	Primary - $/kW/month	14.176	51.28	726.992	53
54	Transmission - $/kW/month	13.829	0.00	0.000	54
	Option E				
55	Secondary - $/kW/month	14.078	0.00	0.000	55
56	Primary - $/kW/month	13.884	0.00	0.000	56
57	Transmission - $/kW/month	13.544	0.00	0.000	57
	Option F				
58	Secondary - $/kW/month	13.472	0.00	0.000	58
59	Primary - $/kW/month	13.286	0.00	0.000	59
60	Transmission - $/kW/month	12.961	0.00	0.000	60
	Demand: Winter				
	Option C				
62	Secondary - $/kW/month	0.432	0.00	0.000	62
63	Primary - $/kW/month	0.426	0.00	0.000	63
64	Transmission - $/kW/month	0.415	0.00	0.000	64
	Option D				
65	Secondary - $/kW/month	0.461	525.03	241.785	65
66	Primary - $/kW/month	0.454	53.65	24.365	66
67	Transmission - $/kW/month	0.443	0.00	0.000	67
	Option E				
68	Secondary - $/kW/month	0.451	0.00	0.000	68
69	Primary - $/kW/month	0.445	0.00	0.000	69
70	Transmission - $/kW/month	0.434	0.00	0.000	70
	Option F				
71	Secondary - $/kW/month	0.461	0.00	0.000	71
72	Primary - $/kW/month	0.454	0.00	0.000	72
73	Transmission - $/kW/month	0.443	0.00	0.000	73
74	Annual			7,446.992	74

Line No	Rate Description (Rates Model Input Categories)	Marginal Cost Capacity (¢/kWhr or $/kW) (A)	Marginal Cost Determinants (kWhrs or kW) (B)	Marginal Cost Revenue ($ x 1000) (C)	Line No
	Schedules AL-TOU / AY-TOU				
	Demand: Summer				
75	Secondary - $/kW/month	13.472	6,960.74	93,774.138	75
76	Primary - $/kW/month	13.286	801.93	10,654.380	76
77	Secondary Substation - $/kW/month	13.472	111.23	1,498.462	77
78	Primary Substation - $/kW/month	13.286	226.95	3,015.263	78
79	Transmission - $/kW/month	12.961	36.84	477.419	79
	Demand: Winter				
80	Secondary - $/kW/month	0.432	7,923.47	3,419.783	80
81	Primary - $/kW/month	0.426	901.14	383.566	81
82	Secondary Substation - $/kW/month	0.432	135.52	58.491	82
83	Primary Substation - $/kW/month	0.426	264.72	112.678	83
84	Transmission - $/kW/month	0.415	27.91	11.590	84
85	Annual			113,405.769	85
	Agriculture				
86	Summer Season - ¢/kWhr	3.011	42,957.00	1,293.483	86
87	Winter Season - ¢/kWhr	0.120	39,700.00	47.497	87
88	Annual	1.622	82,657.00	1,340.990	88
	Lighting				
89	Annual	0.014	109,342.00	15.732	89
90	System Annual Total			278,932.206	90