Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.

Application 05-03-015
Exhibit No.: ______________

ERRATA TO

CHAPTER 6
DEMAND RESPONSE BENEFITS

JULY 14, 2006 AMENDMENT

Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of

DR. STEPHEN S. GEORGE

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

July 14, 2006

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I. INTRODUCTION

The purpose of this *updated* testimony is to *amend* my March 28, 2006 testimony to include material information which will impact my (Chapter 6) testimony. The demand response benefits contained in this filing were developed for SDG&E by me during my tenure at CRA International (previously doing business as Charles River Associates, Inc.) as well as after my departure from CRA. I am currently employed at Freeman, Sullivan & Co. (FSC).

My testimony summarizes the basic methodology used to develop demand response impact estimates, documents the input values underlying the analysis and presents the impact estimates measured in terms of MW reductions and the dollar benefits of avoided generation capacity and energy. This testimony consolidates, supersedes, and replaces all previous direct and supplemental testimony filed by me or by any other SDG&E witness testifying in this docket, on the topics covered herein.

The primary changes between this supplement and the March 28th filing are as follows:

1. Benefit estimates for residential customers changed due to a change in the elasticity values underlying the analysis. As explained in Section IVb, elasticity values vary with weather. In the March 28th filing, we had erroneously used weather values representing a peak-period from 2 pm to 7 pm when calculating the values for the residential elasticity of

substitution for each climate zone, rather than the 11 am to 6 pm peak period proposed for the PTR program.

2. Benefit estimates for small C&I customers (those with peak demands less than 20 kW) changed for several reasons. The latest results from California's Statewide Pricing Pilot (SPP), which were released subsequent to the March 28th filing,[1] indicate that this customer segment is not price responsive in the absence of enabling technology. Thus, SDG&E has modified the proposed AMI implementation plan to include a program that offers programmable communicating thermostats (PCTs) to a targeted subset of the small customer segment (those with peak demands less than 20 kW but annual energy use above 20,000 kWh). The benefit estimates also reflect the penetration of PCT technology in new construction from likely modifications to CEC building standards. Consistent with the new SPP results, higher elasticity values than those used in the March 28th filing are employed here for customers with enabling technology and a value of 0 is used for those without enabling technology.

3. Benefit estimates for medium C&I customers (those with peak demands between 20 and 200 kW) have changed for two reasons. The latest SPP results also indicate a significant difference in elasticity values for this customer segment between customers with and without enabling technology, although, unlike for small customers, those without technology are still price responsive. Thus, PCTs are also being offered to these customers and the elasticity values have been changed to reflect the latest SPP research results. In addition, the alternative pricing option available to medium C&I customers who will be placed on a default CPP rate has been changed to incorporate a Capacity Reservation Charge (CRC) as discussed in Mr. Hansen's testimony (Chapter 14). This has the effect of generating additional demand-response benefits for this customer

[1] George, Stephen S., Ahmad Faruqui and John Winfield. *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update,* June 28, 2006.

segment as the CRC will induce customers to reduce peak demand in a manner similar to what a CPP rate will do.

4. Benefit estimates for large C&I customers (those with peak demands greater than 200 kW) have changed primarily as a result of the introduction of a CRC as the main alternative to the default CPP tariff for this customer segment. A slight change was also made in the elasticity of substitution underlying the demand response benefits for this customer segment and alternative sources were used to justify the elasticity value.

The net result of these changes is that the gross demand-response benefits rose from a net present value of $235 million to a value of $262 million. Because the new results depend, in part, on the installation of smart thermostats among small and medium C&I customers, the net benefits from demand response equal $244 million due to expenditures of $17.9 million (present value of revenue requirements) on PCTs.

II. SUMMARY OF METHODOLOGY FOR ESTIMATING DEMAND RESPONSE BENEFITS

Demand response benefits largely accrue from system peak load reductions resulting from customer response to dynamic pricing. These benefits include the avoided cost of procuring incremental electric resources during summer peak hours and the reduction in future costs of transmission and distribution upgrades. Additional benefits may include lower energy costs, if the reduction in energy during the peak period times the cost of peak-period energy exceeds the increase in energy use in the off-peak period times the cost of off-peak energy. In this section of the filing, we discuss the benefits associated with avoided generation capacity and changes in the total cost of energy needed to meet demand. Benefits associated with avoided transmission and distribution (T&D) upgrades are discussed in Mr. Lee's testimony (Chapter 4) although T&D benefits are based on the demand response impacts presented here.

In brief, the overall benefits discussed here are based on the change in capacity and energy use by rate period valued at the avoided cost of capacity and energy by period. Equations (1) and (2) are simplistic representations of the key equations used to derive demand response benefits.

(1) MW Impact = (Average use per customer during peak period on the current rate) x (% Drop in peak period use per customer given a change in price) x (Number of customers in the target population) x (Customer participation rate)[2]

(2) Total Benefits = [(MW Impact) x (Avoided Capacity Cost)] + [(MWh Impact by Rate Period) x (Avoided Energy Cost by Rate Period)]

Demand response benefits are estimated separately for the following customer segments:

A. General residential customers;
B. Small commercial and industrial (C&I) customers (energy demand less than 20 kW) with annual energy use below 20,000 kWh without enabling technology;
C. The same target group as in B but with enabling technology;
D. Small commercial and industrial (C&I) customers (energy demand less than 20 kW) with annual energy use greater than 20,000 kWh with without enabling technology;
E. The same target group as in D but with enabling technology;
F. Medium C&I customers (energy demand between 20 and 200 kW) without enabling technology;
G. The same target group as in F but with enabling technology; and
H. Large C&I customers (energy demand greater than 200 kW).

The major variables underlying estimates of demand response are:

A. The difference in prices by rate period under the new, time-varying tariffs and incentive programs compared with the previous tariff;
B. Customer acceptance of the new tariffs and programs (i.e., participation rates);
C. The magnitude of energy use by rate period prior to the new tariffs and programs going into effect; and,
D. Customer price responsiveness as reflected in summary measures such as the elasticity of substitution and daily price elasticity.[3]

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[2] A similar equation is used to predict the change in energy use in each rate period for each year of the forecast horizon.

The rate options and demand response incentive programs that will be offered by SDG&E will vary by customer segment. Table SSG 6-1 summarizes the rates and programs that will be offered to each customer segment.

Table SSG-6-1
Rate and Program Options

Customer Segment	2008	2009	2010	2011
Residential	Tiered rate	Tiered rate with PTR available to all with AMI meter	Tiered rate with PTR available to all with AMI meter	Tiered rate with PTR available to all
Small C&I (<20 kW)	Flat rate	Default TOU with PTR or Vol CPP available to all with AMI meter	Default TOU with PTR or Vol CPP available to all with AMI meter	Default TOU with PTR or Vol CPP available to all
Medium C&I (20-200 kW)	Default TOU or voluntary CPP	Default CPP with CRC or opt-out to TOU for all with AMI meter	Default CPP with CRC or opt-out to TOU for all with AMI meter	Default CPP with CRC option
Large C&I (>200 kW)	Default CPP with bill protection or voluntary TDR	Default CPP with CRC option	Default CPP with CRC option	Default CPP with CRC option

A. <u>Residential Customers</u>: Residential customers will remain on a tiered rate structure but will be eligible for a Peak Time Rebate program. This program will pay customers $0.65/kwh for energy reduced during the peak period on critical days. The peak period will be from 11 am to 6 pm. The load reduction for each customer will be calculated by comparing the customer's peak load on the event day with an estimate of what their load would have been in the absence of the

[3] The elasticity of substitution equals the ratio of the percentage change in the ratio of peak and off-peak energy use to the percentage change in the ratio of peak and off-peak prices. The daily price elasticity equals the percentage change in daily energy use over the percentage change in daily prices. These two measures in combination with the price ratios before and after the new rates go into effect are used to estimate the change in energy use and peak demand by rate period

incentive offer (referred to as their baseline usage). Prior to implementation, SDG&E will investigate methods for estimating baseline usage and will select an approach that strikes an appropriate balance between practicality, accuracy and achieving an incentive payment sufficient to maintain customer interest in providing demand reductions.[4] Events may be called on either the day before or the day of an event. Under a program such as this, there is no need for an upper or lower limit on the number of events but our analysis is based on the assumption that 13 events would be called each year.

B. Small C&I Customers (peak demands <20 kW): The current tariff for C&I customers with demands below 20 kW is a two-part tariff consisting of a fixed charge and a single price per kWh for all energy use. Starting in 2009, small commercial customers with AMI meters will be defaulted onto a three-period TOU rate but will also be given the opportunity to benefit from the PTR program or to volunteer for a CPP tariff.[5] The ratio of peak-to-off-peak prices for small C&I customers on the TOU rate will be roughly two to one. The summer peak period will be from 11 am to 6 pm on weekdays, the shoulder period from 6 am to 11 am and 6 pm to 10 pm on weekdays, and the off-peak period will cover all remaining hours. In the winter, the peak period will be from 5 pm to 8 pm on weekdays, the shoulder period from 6 am to 5 pm and 8 pm to 10 pm on weekdays and the off-peak period will cover all other times. The PTR incentive will apply only during the peak period on critical days. A subset of these customers (e.g., those with annual energy use greater than 20,000 kWh) will be targeted to receive PCTs for free.

C. Medium C&I Customers (peak demands between 20 and 200 kW): Starting in 2009, C&I customers with AMI meters and peak demands between 20 and 200 kW will be defaulted onto a CPP rate. The CPP tariff will have the same

[4] There is no way to achieve complete accuracy in estimating baseline values. Some approaches will estimate higher baselines than others which, in turn, would result in higher payments to customers, thus encouraging them to continue to respond to the implicit price signal of the PTR program. Baseline methods that estimate lower values will have the opposite effect.

[5] The CPP tariff would have roughly the same ratio of peak-to-off-peak prices as the implicit prices underlying the PTR. Based on the evidence presented below that these two rate/program options would produce essentially the same peak-period reductions given the same explicit/implicit price signals, we have not modeled separately the impacts for customers who would select the CPP option over the PTR option.

three rate periods as for small C&I customers. For up to 13 days during the summer period, the peak-period price will be significantly higher than on non-critical days. The ratio of peak-to-off-peak prices on critical days for C&I customers will be roughly eight to one. CPP notification will occur the day before a critical day. The impact estimates presented here assume all CPP days occur during the summer rate period. These medium C&I customers will have bill protection for their first 12 months on the CPP rate. Prior to 2011, these customers will have the option of selecting a TOU rate rather than staying on the CPP default option. Starting in 2011, SDG&E proposes that the primary alternative to a CPP tariff for these customers be the Capacity Reservation Charge (CRC).[6] The CRC will allow customers to reduce the uncertainty associated with the CPP rate by paying ahead of time for their desired capacity.[7] Since the main difference between the CPP rate and the CRC is the timing of payments for capacity, both options give customers an equal economic incentive to reduce demand. All medium C&I customers will be eligible to receive a PCT provided by SDG&E (as discussed in Mr. Gaines, Chapter 5 testimony).

D. <u>Large C&I Customers (peak demands >200 kW):</u> The tariff options for this customer segment will essentially be the same as for medium C&I customers except that the CRC option will go into effect in 2009 rather than 2011. All large C&I customers will receive bill protection for the 12 months of 2008 and will then transition to a default CPP rate beginning in 2009.

The number of customers on each rate option in a given year is a function of the eligible population in that year and customer acceptance of each rate. In the first few years of the forecast horizon, the size of the eligible population is significantly influenced by the meter deployment rate, as only customers with AMI meters can be on CPP tariffs or take advantage of the Peak Time Rebate. SDG&E's meter deployment plan calls for

[6] The CPP and CRC options are the only two options that we have modeled. SDG&E may offer other time differentiated rate options (e.g., real-time pricing) that will produce demand response impacts comparable to those resulting from the CPP and CRC options.
[7] See Mr. Hansen's testimony for further explanation of the CRC option.

installing nearly all meters over a 31-month period starting in mid-2008.[8] It is also assumed that direct access customers will not be eligible for new tariffs, so their load is excluded from the eligible population. This exclusion has the greatest impact on the large C&I population.

Estimates of the percentage of customers that will participate in each rate option or incentive program are documented in Mr. Gaines' testimony (Chapter 5) and summarized below in Section IVd. Estimates of average energy use by customer segment under existing rates were developed primarily from SDG&E's load research database. The base-case estimates for each customer segment are derived from data for calendar year 2003. The 2003 values are based on standard load research sampling methods and standard load research estimation methodologies.

Estimates of the elasticity of substitution and the daily price elasticity for each tariff and for the PTR program are primarily based on results from the SPP. The PTR program provides an implicit price signal in that the opportunity cost of consuming a kWh during the peak period on critical days equals the sum of the incentive payment and the average price of electricity.

Estimates of the elasticity of substitution for the small commercial PTR program and for the medium CPP tariff differ from those used in the March 28th filing because of results recently published showing that responsiveness varies significantly across customers with and without enabling technology.

The estimate for the elasticity of substitution for large C&I customers was based on work previously done for SDG&E by Christensen Associates. The estimate for the daily price elasticity for C&I customers was based on a review of the literature, as daily price did not prove to be statistically significant in the SPP analysis but there is sufficient justification to believe that a modest value should be used (as explained in Section IV).

In order to reflect the inherent uncertainty in selected input variables, a Monte Carlo simulation model was used to develop a probability distribution of demand response benefits. Four key drivers of demand response benefits were included in the simulation analysis:

A. The elasticity of substitution and daily price elasticity of energy demand;

[8] See Table SSG 6-18 for estimates of meter deployment rates.

B. Starting values for energy use by rate period on critical days;

C. Participation rates and awareness levels; and,

D. The marginal cost of generation capacity.

Each of these variables is represented in the Monte Carlo analysis by a probability distribution with specific characteristics described in more detail in Section V. A more detailed description of the Monte Carlo simulation analysis is also contained in Section V.

The resulting distribution of outputs reflects uncertainty in the key drivers of demand response. The mean value of the distribution (e.g., the 50th percentile) represents the expected value of demand response benefits[9]. The 90th percentile represents the point on the distribution where there is only a ten percent probability that benefits would exceed that value given the uncertainty reflected in the input values. The 10th percentile is the value where there is a 90 percent probability that the demand response benefits would exceed that amount.

III. SUMMARY OF DEMAND RESPONSE IMPACTS

The primary measures of demand response benefits reported in this section consist of avoided capacity (e.g., MWs) and the present value of monetary savings resulting from avoided capacity and energy use over the forecast horizon. Table SSG 6-2 contains estimates of the present value of the monetary benefits for the 10th, 50th and 90th percentiles of the probability distribution of benefits as determined by the Monte Carlo simulation analysis. The 50th percentile value is equivalent to the mean or expected value of the distribution. The avoided cost of capacity underlying these estimates equals a levelized cost of $85/kW-year. The avoided cost of energy varies by rate period and year, as detailed in Section IV.

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[9] The probability distribution that is assumed for each variable is described in Section V. Some of the distributions are symmetric, so that the mean (or expected value) and the mode (the most likely value) are the same. However, some distributions are asymmetric, in which case the mean and the mode differ. As a result, the 50th percentile values that are taken from the output of the Monte Carlo simulations will not be the same as those that would result from using the SDG&E PRISM simulation model with the most likely (or modal) values of the distributions as inputs.

Table SSG 6-2 Present Value of Demand Response Benefits (millions of 2006 $)			
Percentile	**Capacity**	**Energy**	**Total**
10th	198.3	10.9	209.2
50th	243.7	18.3	261.9
90th	290.7	25.07	315.7

As seen in Table SSG 6-2, the expected value equals roughly $262 million. The 10th percentile, that is, the value that is likely to be exceeded under 90 percent of the combinations of input values that were assumed to vary, equals $209 million. The 90th percentile value equals $316 million. Roughly 93 percent of the total, monetary value of benefits is attributable to avoided capacity costs and only about 7 percent is attributable to avoided energy costs.

Table SSG 6-3 contains estimates of the present value of avoided capacity and energy benefits attributable to each market segment. As seen, 47 percent of the total benefits are attributable to residential customers. Small C&I customers account for approximately 5 percent of the total benefits and C&I customers with demands greater than 20 kW account for the remaining 48 percent of the present value of benefits.

Table SSG 6-3 Present Value of Demand Response Benefits (Millions of 2006 $)				
Customer Segment	**Capacity**	**Energy**	**Total**	**Segment Percent**
Residential	110.4	12.8	123.2	47
Small C&I (<20 kW)	12.8	1.3	14.2	5
Medium C&I (20- 200 kW)	60.5	2.2	62.7	24
Large C&I (> 200 kW)	59.9	1.9	61.8	24
Total	243.7	18.3	261.9	100

Table SSG 6-4 contains impact estimates for 2011, the first forecast year after which all meters have been installed.[10] The first column in SSG 6-4 contains estimates of

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[10] Results are presented for a single year because MW reductions are only pertinent to a single year (e.g., you can't talk about the present value of MW reductions over many years without monetizing them). It should also be noted that the MW reductions reported here are at the end-use level, not at the point of generation. Avoided generation capacity will actually be greater than these values because it must be grossed up for reserves and line losses. These adjustments were made prior to determining the monetary

peak demand by customer segment, defined as the average kWh/hr used during the peak period on critical days prior to any reduction in usage resulting from the new rates and incentive programs.[11] The second column shows the contribution of each segment to overall peak demand. Columns 3 and 4 contain estimates of the avoided megawatts attributable to each segment. As seen, residential customers contribute more to the reduction in peak demand (e.g., 48 percent of the total reduction) than they do to overall peak demand (e.g., 43 percent). This is due to the fact that residential price responsiveness tends to be higher than that of C&I customers. In contrast, small C&I customers contribute more to peak demand (15 percent) than they do to peak demand reductions (4 percent), because they have relatively low price responsiveness.

Table SSG 6-4
Demand Response Impacts in 2011
(First Year After Full Meter Deployment)

	MW Forecast		MW Reductions		Benefits $ Millions (Nominal)			
Customer Segment	**MW**	%	**MW**	**%**	**Capacity**	**Energy**	**Total**	**%**
Residential	1258	43	105	48	10.8	0.9	11.7	49
Small C&I (<20 kW)	445	15	8	4	0.8	0.1	0.9	4
Medium C&I (20-200 kW)	674	23	53	24	5.5	0.1	5.6	24
Large C&I (>200 kW)	520	18	53	24	5.4	0.1	5.6	23
All Classes (50th Percentile)	2897	100	219	100	22.5	1.3	23.7	100

Table SSG 6-4 also shows the 50th percentile estimates for aggregate avoided megawatts in 2011. As seen, the 50th percentile value for avoided capacity is 219 MWs (at the end use level).

Finally, Table SSG 6-5 contains estimates of the capacity impacts for selected years over the forecast horizon, including each of the first three years over which meter deployment occurs, the year 2015 and the terminal year, 2038. Many underlying factors change year to year, including size of the eligible population (a function of both meter deployment and population growth), average use prior to application of the new rates, and avoided energy costs. Price responsiveness per customer and prices are held

value of avoided generation capacity and energy. In other words, the dollar benefit estimates in each table take into account reserve margin and line losses, but the reported MW savings do not.

[11] These numbers are for illustrative purposes only. They exclude direct access customers and were developed by multiplying the average use per hour for each segment based on SDG&E's load research data times the number of customers in each segment.

constant. As seen in the table, avoided capacity grows from a modest 107 MWs in 2009 to 377 MWs in 2038.

Table SSG 6-5
Avoided MW for Selected Years
(MW)

Customer Segment	2009	2010	2011	2015	2022	2038
Residential	43	80	105	114	132	168
Small C&I (<20 kW)	1	4	8	14	17	22
Medium C&I (20-200 kW)	13	26	53	63	76	100
Large C&I (>200 kW)	50	51	53	58	68	87
Total	107	161	219	249	292	377

IV. INPUT VALUES

This section documents the development of the input values underlying the benefit estimates presented in Section III. Sections IVa through IVe summarize the input values for the baseline scenarios for the following variables:

A. Energy use by rate period for customers in the target population prior to the introduction of alternative rate options and incentive programs;

B. Price elasticities, which are used to predict the change in energy use by rate period for the average customer on a new rate option or incentive program;

C. Explicit and implicit prices in each rate period under the existing and alternative rates and programs;

D. Customer participation rates and awareness levels for each option, including technology adoption rates for PCTs among small and medium C&I customers; and,

E. Miscellaneous input variables.

In order to address the uncertainty inherent in some of the input values, a Monte Carlo simulation model was used to develop a probability distribution of benefit estimates based on a range of values for the following input variables:

A. The elasticity of substitution and the daily price elasticity of energy demand

B. Starting energy use values by rate period on critical days due to variation in weather

C. Participation rates and awareness levels

D. The marginal cost of generation capacity.

The general approach to the Monte Carlo simulations and examples of the range in values for each variable are discussed in Section V.

IVa. Average Energy Use

Estimates of average energy use by customer segment under existing rates were developed primarily from SDG&E's load research database. Separate estimates were developed for each of two climate zones, one representing the mild climate in the coastal and mountain regions, and the other the hotter climate in the inland and desert regions. The base-case estimates for each customer segment were derived from data for calendar year 2003. The 2003 values are based on standard load research sampling methods and standard load research estimation methodologies. In SDG&E's judgment, 2003 was a relatively normal weather year—that is, it represents the 1 in 2 year guidelines contained in the Assigned Commissioner's Ruling (ACR) dated July 21, 2004.

Using the load research data, SDG&E developed estimates of average daily energy use by rate period, climate zone and season for bundled service customers (ie., excluding Direct Access Customers). The critical-day values are based on the top 13 system load days in 2003. These values were converted into the monthly average values required by the simulation model by multiplying the daily values by the number of average days in a month for each day type. On average, each summer month for residential customers has 2.2 critical days, 19.3 non-critical weekdays and 9.2 weekend days. Since the summer rate period for C&I customers is only five months long rather than the six-month season for residential customers, the average summer month has 2.6 critical days, 18.6 non-critical weekdays and 9.4 weekend days.

When predicting demand response benefits, both energy use and capacity savings are important input variables. For purposes of this analysis, estimated capacity savings correspond to the change in average kWh/hr during the entire peak period on critical days. Thus, the starting values for capacity can be computed by dividing the critical-day, peak-period values for the average month shown below in Tables SSG 6-6 through 6-9 by the corresponding average number of hours in the month. As discussed previously, for residential customers, there are 2.2 critical days on average each month, and 7 peak-period hours on each critical day, which leads to 15.4 critical-hours per month. Thus, the average capacity value in the Inland Climate Zone, for example, prior to the impact of the new rates, equals 1.2 kWh/hr (17.9 kWh from Table SSG 6-6 divided by 15.4 hours). For C&I customers, there are on average 18.2 critical hours per month (2.6 days times 7 hours). Thus, for example, the resulting starting capacity values for C&I customers with demands less than 20 kW in the Inland Climate Zone equals 3.9 kWh/hr (70.6 kWh/month from Table SSG 6-7 divided by 18.2 critical hours per month).

Table SSG 6-6
Average Monthly Summer Electricity Use for Residential Customers
(kWh/month)

Day Type	Period	Coastal & Mountain	Inland &Desert
Critical	Peak	11.4	17.9
	Off-Peak	24.1	31.0
Non-Critical Weekday	Peak	83.6	110.4
	Off-Peak	197.0	229.9
Weekend	All Day	144.7	176.6
Total		460.8	565.8

Table SSG 6-7
Average Monthly Summer Electricity Use For C&I Customers
Small Commercial (<20 kW)
(kWh/month)

Day Type	Period	Coastal & Mountain		Inland & Desert	
		Less than 20,000 kWh	Greater than 20,000 kWh	Less than 20,000 kWh	Greater than 20,000 kWh
Critical	Peak	24.2	160.0	28.1	185.8
	Semi-Peak	25.3	167.4	23.0	152.2
	Off-Peak	16.3	107.7	12.5	82.5
Non-Critical Weekday	Peak	143.2	947.7	167.0	1105.4
	Semi-Peak	152.2	1007.5	146.0	966.6
	Off-Peak	109.1	722.2	84.5	559.3
Weekend	All Day	177.4	1174.3	144.7	958.1
Total		647.6	4286.9	605.8	4010.0

Table SSG 6-8
Average Monthly Summer Electricity Use For C&I Customers
With Peak Demands Between 20 kW and 200 kW
(kWh/month)

Day Type	Period	Coastal & Mountain	Inland & Desert
Critical	Peak	738.7	736.8
	Semi-Peak	760.2	689.1
	Off-Peak	397.3	386.6
Non-Critical Weekday	Peak	4,356.3	4,173.9
	Semi-Peak	4356.3	4,103.3
	Off-Peak	2,526.1	2311.4
Weekend	All Day	4,643.1	4221.5
Total		17,785.5	16,622.7

SSG 6-9
Average Monthly Summer Electricity Use For C&I Customers
With Summer Demand > 200 kW
(kWh/month)

Day Type	Period	Coastal & Mountain Inland & Desert
Critical	Peak	6,135.2
	Semi-Peak	6,767.9
	Off-Peak	4,022.7
Non-Critical Weekday	Peak	37,990.6
	Semi-Peak	40,234.2
	Off-Peak	25,840.0
Weekend	All Day	41,371.5
Total		162,362.1

IVb. Price Elasticities

Estimates of the elasticity of substitution and the daily price elasticity are used to predict changes in energy use by rate period in response to the explicit prices associated with the new TOU and CPP rate options and the implicit price signals associated with the PTR program. In most instances, the elasticity estimates are based on the demand models estimated from the SPP after adjusting for the climate and air conditioning saturations found in the SDG&E service territory. Before using the SPP elasticities to estimate demand response for the PTR program, data from the Anaheim Public Utilities (APU) pilot program was analyzed. The APU pilot is conceptually similar to the PTR program, and impact estimates from that pilot were compared with estimates based on the SPP elasticities. The two estimates were quite similar, suggesting that customers respond to the implicit price signals associated with the PTR program in the same manner as they do to the explicit price signals associated with a TOU or CPP rate.

1. Residential Elasticities

For the residential sector analysis, impact estimates are based on price elasticities derived from the SPP, tailored to reflect the weather conditions and CAC saturations of SDG&E's customers. Equation (3) in Section 3.1 of the SPP Final Report (March 16, 2005), shown below for convenience, was estimated from data on SPP customers in the CPP-F treatment and control cells.

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sum_{i=1}^{N} \theta_i D_i + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \lambda(CDH_p - CDH_{op})\ln\left(\frac{P_p}{P_{op}}\right) + \phi(CAC)\ln\left(\frac{P_p}{P_{op}}\right) + \varepsilon$$

Where

Q_p = average daily energy use per hour in the peak period

Q_{op} = average daily energy use per hour in the off-peak period

σ = the elasticity of substitution between peak and off-peak energy use

P_p = average price during the peak pricing period

P_{op} = average price during the off-peak pricing period

δ = measure of weather sensitivity

λ = the change in elasticity of substitution due to weather sensitivity

CDH_p = average cooling degree hours per hour (base 72 degrees) during the peak pricing period

CDH_{op} = average cooling degree hours per hour (base 72 degrees) during the off-peak pricing period

ϕ = the change in elasticity of substitution due to the presence of central air conditioning

CAC = 1 if a household owns a central air conditioner, 0 otherwise

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

θ_i = fixed effect for customer

ε = regression error term.

The composite elasticity of substitution (ES) in this model is a function of three terms, as shown below:

$$\text{ES}=\sigma + \lambda(CDH_p - CDH_{op}) + \phi(CAC) \qquad (2)$$

In the SPP, estimates of the coefficients in equation (2) differed for the inner summer months of July, August and September and the transition summer months of May, June and October. Since critical days have a higher probability of occurring during the inner summer months, we used the elasticities representing the inner summer period to estimate demand impacts on critical days and we used values representing the entire six-month summer to estimate impacts on non-critical days and weekends. The estimated values for σ, λ and ϕ for the entire summer period (used for non-critical days) are, respectively, -0.02726, -0.002196 and -0.07096. The coefficient values for the inner summer period (representing critical days) are -0.03073, -0.00187 and -0.09107. The elasticities for the base case residential analysis, reported in Table SSG 6-10 below, were derived by multiplying the coefficients in equation 2 by the CAC saturations for each of

SDG&E's two climate zones and by the values for the weather term for each zone and day type. The saturation of central air conditioning for residential customers in SDG&E's service territory is 49 percent in the Inland climate zone and 26 percent in the Coastal climate zone. Table SSG 6-11 contains values for the weather variables that were used in developing the elasticity estimates. The weather data represents a population-weighted average of data from nine weather stations scattered throughout SDG&E's two primary climate zones. Using the coefficients and CAC saturations listed above along with the values in Table SSG 6-11 for critical days in the Coastal climate zone, the value of –0.064 in Table SSG 6-10 is determined as follows: [-0.064 = -0.03073 – 0.00187x5.26 – 0.09107x0.26].

Table SSG 6-10
Base Case Price Elasticities for Residential Customers

Response Measure	Coastal & Mountain			Inland & Desert		
	Critical	Non-Critical	Weekend	Critical	Non-Critical	Weekend
Elasticity of Substitution	-0.064	-0.048	n/a	-0.094	-0.069	n/a
Daily Price Elasticity	-0.040	-0.045	-0.019	-0.040	-0.048	-0.024

Table SSG-11
Weather Data Used To Determine Price Elasticity Estimates[12]

Weather Variable	Coastal & Mountain			Inland & Desert		
	CPP	Non-CPP	Weekend	CPP	Non-CPP	Weekend
CDH (peak – off-peak)	5.26	1.23	N/a	9.94	3.13	N/a
Daily CDH	2.89	0.55	1.00	5.76	1.50	2.20

The daily elasticities reported in the table are derived in a similar manner (i.e., by substituting the relevant weather and CAC saturation data into the daily model estimated from the SPP data). The model is similar to the one shown above except that the dependent variable is daily electricity use rather than the ratio of daily use in each period,

[12] These values have changed since the March 28th filing. Those in the March 28th filing erroneously were based on the 2 pm to 7 pm peak period rather than the 11 am to 6 pm rate period underlying this analysis.

and the price and weather terms are daily averages. Equations 3 and 4 represent the daily demand model and the effective daily price elasticity of daily energy use.

$$\ln(Q_D) = \alpha + \sum_{i=1}^{N} \theta_i D_i + \eta \ln(P_D) + \rho(CDH_D) + \chi(CDH_D)\ln(P_D) + \xi(CAC)\ln(P_D) + \varepsilon \qquad (3)$$

Where

Q_D = average daily energy use per hour

η = the daily price elasticity

P_D = average daily price

ρ = measure of weather sensitivity

χ = the change in daily price elasticity due to weather sensitivity

CDH_D = average daily cooling degree hours per hour (base 72 degrees)

ξ = the change in daily price elasticity due to the presence of central air conditioning

CAC = 1 if a household owns a central air conditioner, 0 otherwise

θ_i = fixed effect for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = regression error term.

The composite daily price elasticity of substitution in this model is a function of three terms, as shown below:

$$\text{Daily}=\eta + \chi(CDH_D) + \xi(CAC) \qquad (4)$$

The values for η, χ and ξ for the inner summer period, respectively, are -0.03966, 0.00121 and -0.01573. The all-summer values are -0.04194, 0.001606 and -0.01637.

Before applying the SPP elasticities to predict the impact of the PTR program for residential and small commercial customers, we examined how well the SPP demand models predicted impacts for a very similar rebate program implemented in the summer of 2005 by Anaheim Public Utilities (APU). The APU pilot program paid an incentive equal to $0.35/kWh for all energy reduced during the peak period on critical peak days during the summer of 2005. For the purpose of determining the incentive payment amount, reductions were calculated relative to a baseline value equal to energy use during the peak period on the three highest, non-critical days during the summer period for each customer. The incentive was paid as a bill credit at the end of the summer.

The peak period in the APU program was from noon to 6 pm and there were 12 events called during the summer period, which ran from June 1st through October 31st.[13] Data on 71 treatment customers and 52 control customers were used to estimate impacts.

Impacts for the APU pilot were estimated using a two-equation model conceptually similar to the two equations used in the SPP analysis. One equation had a dependent variable equal to the log of the ratio of peak to off-peak energy use and independent variables equal to the log of average maximum temperature, a weekend binary variable, a critical-day binary variable, an interaction term between the critical-day variable and a treatment binary variable and fixed effects variables for each customer. The second equation had daily energy use as the dependent variable and independent variables that are the same as in the first equation. The equations were estimated using the Stata statistical software package and the standard errors were estimated using the Newey-West correction.

The regression results are summarized in Table SSG 6-12. The "price" coefficient (CPP_Day*Treat) in the ratio equation equals -0.127 and the coefficient in the daily equation equals -0.040. The reduction in peak-period energy use on critical days predicted by the two equations combined equals 11.9 percent.

This impact estimate was compared with an estimate based on the SPP analysis, using the Price Impact Simulation Model (PRISM) that was developed as part of that project. The SPP elasticities[14] were adjusted based on the saturation of central air conditioning in

[13] Three of the twelve critical events were called in July, four in August and five in October.

[14] Elasticities representing the entire summer, not the inner summer, were used for this comparison because five or the twelve critical days in the Anaheim pilot occurred during October, which is not in the inner summer period. However, if the inner summer elasticity estimates are used, the peak-period reduction predicted by the PRISM model equals 12.1 percent, which is even closer to the impact estimated for the Anaheim pilot.

the APU service territory (equal to 46.6 percent) and the average APU weather. The implicit price during the peak-period on critical days equals the sum of the $0.35/kWh incentive offered by the program and the average base price of $0.097/kWh in the APU service territory.[15] That is, the implicit, peak-period price equals $0.447/kW. With these inputs, the reduction in peak-period energy use predicted by the SPP PRISM model equals 11.4 percent, which is extremely close to the 11.9 percent value estimated for the APU pilot. As a result, we believe it is appropriate to use the SPP demand models to predict the impact of SDG&E's proposed PTR program.

Table SSG 6-12
Regression Results For Anaheim Pilot
(Note: fixed effects coefficients are not reported)

Variable	Coefficient	Newey-West Standard Error	t-Stat
Dependent Variable = ln_Peak_Offpeak_Usage			
weekend	0.053	0.008	6.63
ln_temp	0.669	0.057	11.83
CPP_Day	0.006	0.023	0.26
CPP_Day*Treat	-0.127	0.032	-4.01
constant	-3.858	0.264	-14.62
Dependent Variable = ln_Daily_Usage			
weekend	0.037	0.006	6.17
ln_temp	1.338	0.065	20.58
CPP_Day	0.008	0.027	0.29
CPP_Day*Treat	-0.040	0.034	-1.16

[15] The demand impacts estimated for APU's pilot and for the PTR are based on the assumption that customers respond to the targeted incentive payment, not to the actual average incentive paid after the fact. The actual average incentive payment, which is paid in the form of a bill credit, may be greater or less than the planned payment, since it is a function of the planned incentive (e.g., $0.35/kWh) and the estimated reduction in peak demand. The estimated reduction in peak demand, in turn, is a function of the estimated baseline quantity. Thus, any difference between the baseline quantity and what a customer would have used in the absence of the program incentive will result in a difference between the actual average incentive per kWh and the planned incentive. If the baseline quantity is greater than what the customer would have used in the absence of the incentive (a value that can never be known), the actual incentive payment per kWh will be higher than the planned incentive payment, and vice versa. However, the actual average incentive per kWh can not be known until after the fact and, in the case of the APU pilot, it wasn't known until the end of the summer. Consequently, we believe it is most reasonable to assume that customers responded to the planned incentive payment. The actual incentive payment, or bill credit, may impact a customer's willingness to continue participating in the program, but it should not affect their price responsiveness.

constant	-2.520	0.293	-8.60

1. C&I Elasticities

Estimates for the elasticity of substitution for C&I customers with peak demands below 200 kW were also derived from the SPP. These estimates have been updated to reflect the latest findings from the SPP, which show an important role for enabling technologies in the C&I sector. Elasticity estimates for C&I customers with peak demands greater than 200 kW were based on analysis that was previously done for SDG&E by Christensen Associates.[16]

The elasticity of substitution estimates for customers with peak demands below 20 kW and between 20 and 200 kW are based on the recently-published analysis for the Track A, CPP-V treatment group in the SPP.[17] This analysis is based on data from two summers, 2004 and 2005. Key findings from this analysis are that customers with peak demands below 20 kW are not responsive to time-varying price signals on non-critical days and are only responsive on critical days when programmable-communicating thermostats (PCTs) are present. Customers with peak demands between 20 and 200 kW are price responsive on both normal and critical days, with and without enabling technology. However, demand response is highest on critical days for customers with enabling technology. Table SSG 6-13 shows the values of the elasticity of substitution that are contained in the latest SPP report and that underlie the analysis here.

In the SPP analysis, price was not statistically significant in the daily energy use equations for C&I customers. This lack of statistical significance does not necessarily mean that price doesn't influence daily energy use, only that this influence could not be estimated with sufficient precision based on the relatively small SPP sample sizes. There is much less variation in daily price across day types and treatment cells than there is in the price ratio, which would explain why it is possible to estimate the influence of price in the CES substitution equation and not in the daily equation. Furthermore, it is reasonable to expect that there would be some responsiveness to daily price variation, as a zero daily price elasticity combined with a negative and significant value for the

[16] Christensen Associates. *Documentation of Customer Demand Modeling in the Evaluation of RTEM and Hourly Pricing at SDG&E*. January 23, 2001.
[17] George, Stephen S., Ahmad Faruqui and John Winfield. *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update,* June 28, 2006.

elasticity of substitution would imply that the amount of energy reduced in the peak period would be exactly offset by an increase in energy use in the off-peak period. Since most load in the C&I sector is due to air conditioning and lighting, and these end uses are difficult to shift from one time period to another, we felt that it was appropriate to assume some small value for the daily price elasticity. A survey of the literature by Bohi[18] reported a range in estimates of the daily price elasticity from –0.05 to –0.20. To be conservative, we assumed a mean value of –0.025, which equals half of the low end of the range reported by Bohi.

The SPP did not include customers with peak demand greater than 200 kW. In support of a prior application in 2002 on real-time electricity metering and hourly pricing (A.00-07-055), SDG&E hired Christensen Associates to estimate demand-response based on hourly pricing schemes. This analysis relied on estimates of price elasticities by business type from the literature adjusted for the mix of business types present in SDG&E's service territory. The Christensen analysis produced an estimate for the elasticity of substitution for large C&I customers equal to -0.07. We compared this estimate with more recent analysis done for the California Energy Commission by Lawrence Berkeley National Laboratory using data from the Niagara Mohawk Company service territory.[19] In this study, estimates of the elasticity of substitution varied across business segments as follows: government/education (-0.10); public works (-0.02); commercial/retail (-0.06); healthcare (-0.04); and manufacturing (-0.16). The load-weighted average value for the elasticity of substitution in Niagara Mohawk's service territory was -0.11. Given that the large C&I segment in SDG&E's service territory is weighted toward government/education, commercial/retail and manufacturing, we believe that the estimate of -0.07 based on the Christensen work may be conservative in light of the Niagara Mohawk analysis.

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[18] Bohi, D.R. *Analyzing Demand Behavior.* Baltimore: Johns Hopkins University Prss, 1981.
[19] Goldman, C.,Bernie Neenan, et. al. *Customer Strategies for Responding to Day-Ahead Market Hourly Electricity Pricing.* August 2005.

Table SSG 6-13 C&I Price Elasticity Estimates				
Customer Segment	**Technology**	**Elasticity Measure**	**Day Type**	
			Critical	**Non-Critical**
< 20 kW	**No**	**Substitution**	0	0
		Daily	0	0
	Yes	**Substitution**	-0.089	0
		Daily	-0.025	0
20 to 200 kW	**No**	**Substitution**	-0.041	-0.049
		Daily	-0.025	-0.025
	Yes	**Substitution**	-0.082	-0.049
		Daily	-0.025	-0.025
>200 kW	**No**	**Substitution**	-0.070	-0.070
		Daily	-0.025	-0.025

IVc. Prices

Three existing rate options were used as starting points for prices: the DR rate for residential customers, Schedule A for small commercial, and AL-TOU for commercial customers with demand over 20 kW. The characteristics of these rates are described below.

1. **Domestic Service (Schedule DR):** An inverted tiered rate with five tiers. Prices vary seasonally and baseline quantities vary across climate zones.
2. **Small Commercial (Schedule A: C&I customers with demands <20 kW):** A two-part tariff consisting of a fixed monthly charge and a flat price per kWh for all energy used. There are no demand charges for this tariff.
3. **Medium and Large Commercial and Industrial (Schedule AL-TOU: C&I customers with demands >20kW):** A multi-part tariff with energy and demand charges that vary by time of day and season, as well as a basic service fee. There are three rate periods (e.g., peak, shoulder and off-peak) and two demand charges (non-coincident and maximum on-peak demand). The non-coincident demand charges apply to maximum demand whenever it occurs and the on-peak demand charges apply to maximum demand during the peak period. If the overall

maximum demand occurs during the peak period, the two demand charges are additive.

For residential customers, the PTR program was modeled by adding $0.65/kWh to the average price during the peak period on critical days. The current five-tiered rate structure was maintained, with the $0.65/kWh incentive layered on top of each tier. For small C&I customers, the demand response impacts were estimated as the sum of the impacts from moving from the existing, flat rate to the mandatory TOU rate plus the impact from layering the incentive price on top of the TOU price. The TOU rate is revenue neutral for the small commercial class and is cost based. Cost based revenue neutral CPP rates were developed for C&I customers with peak demands greater than 20 KW.

In order to accurately reflect existing and alternate average prices, it is necessary to model all components of customer's bills. For example, for customers on the DR rate, it is necessary to factor in the credits and surcharges associated with each tier and for customers on Schedule AL-TOU, it is necessary to capture demand charges in average energy prices. For AL-TOU customers, non-coincident peak demand charges were included in average price calculations for all rate periods whereas maximum on-peak demand charges were included only in the peak period average price calculations (on critical and non-critical weekdays).

Table SSG 6-14 contains estimates of the average maximum on-peak demand and non-coincident peak demand for C&I customers. For customers with monthly maximum demand between 20 and 200 kW, the estimate for average, non-coincident monthly peak demand was 57 kW for the summer. The corresponding average summer monthly maximum on-peak demand value is 56 kW. For customers with monthly maximum demand greater than 200 kW, the estimate for average summer non-coincident demand is 539 kW and the estimate for average summer maximum on-peak demand is 488 kW.

Table SSG 6-14 Average Monthly Billing Demand for C&I Customers (kW)		
Customer Segment	**On-Peak Demand**	**Non-Coincident Demand**
Medium (20-200 kW)	56	57
Large(> 200 kW)	448	539

The demand-response estimates are derived by comparing the average price paid by customers in each rate period under the current rate and the average explicit or implicit prices paid under alternative rate or incentive option. Given the complexities of the existing rates described above, average prices will vary across customers as a function of energy use and peak demand. Nominal price refers to the price prior to applying all the credits and surcharges for residential customers and the fixed charge and demand charges for C&I customers, and effective price is the average price paid after including all charges. The demand-response benefits are based on effective prices. For residential customers, the effective price is based on average energy use for a tier-2 customer. Table SSG 6-15 shows the nominal and effective prices for residential customers by day type and rate/incentive option. Tables SSG 6-16 and SSG 6-17 show the relevant prices for C&I customers.

Table SSG 6-15 Residential Nominal and Effective Prices							
Option	**Day Type**	**Nominal Tariffs**		**Effective Prices**			
				Coastal		**Inland**	
		Peak	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Current	**All**	14.9	14.9	14.2	14.2	14.6	14.6
Peak Time Rebate	**Critical**	79.9	14.9	79.2	14.2	79.6	14.6
	Non-Critical Weekday	14.9	14.9	14.2	14.2	14.6	14.6

Table SSG 6-16
Nominal and Effective Prices for C&I Customers with Peak Demands <20 kW

Option	Day Type	Price	Peak	Partial-Peak	Off-Peak
Current	All	Nominal	17.1	17.1	17.1
		Effective	17.7	17.7	17.7
TOU	Weekdays	Nominal	20.8	15.8	13.6
		Effective	21.3	16.4	14.2
PTR	Critical	Nominal	85.8	15.8	13.6
		Effective	86.4	16.4	14.2

Table SSG 6-17
Nominal and Effective Prices for C&I Customers with Peak Demands >20 kW

			20-200 kW			>200		
Rate	Day Type	Price	Peak	Partial-Peak	Off-Peak	Peak	Partial-Peak	Off-Peak
Current	All	Nominal	15.5	9.5	7.0	15.5	9.5	7.0
	Critical	Nominal	92.5	8.2	6.9	95.9	8.0	6.6
CPP	Non-Critical Weekday	Nominal	10.0	6.4	5.5	10.0	6.7	5.7
Current	All	Effective	21.1	15.2	12.6	21.0	15.0	12.5
	Critical	Effective	98.2	13.9	12.5	101.4	13.5	12.1
CPP	Non-Critical Weekday	Effective	15.6	13.9	12.5	15.5	13.5	12.1

IVd. Participation Rates and Awareness Estimates

Demand response estimates for the PTR program for residential customers are based on assumptions about the percent of customers who are made aware of each critical event through the various notification channels that SDG&E will employ. As detailed in Mr. Gaines' testimony, we assumed that the percent of residential customers that become aware of each critical event has a probability distribution where the most likely value is 70 percent, with minimum and maximum values of 50 percent and 85 percent.

For small C&I customers, only those with enabling technology are estimated to provide demand response benefits. Since the response is automated, we assume that 100 percent of customers with technology provide the average response.[20] As discussed in Mr. Gaines' testimony, SDG&E plans to offer PCTs free of charge to a subset of small C&I customers whose annual energy use exceeds 20,000 kWh. A similar offer to small commercial customers in the SPP produced an acceptance rate of roughly 33 percent. As such, we have assumed that 33 percent of the targeted group will accept the technology through this SDG&E-sponsored program. We further assumed that this level of acceptance will not be reached until 2013,[21] by which time PCTs will have been installed in roughly 11,000 premises among the small C&I customer population. In addition, we have assumed that the California Energy Commission will modify the Title 24 building standards to require that all new buildings will have PCTs installed. Given the growth-rate projected for the small C&I population as shown below in Table SSG 6-23, the new Title 24 standards would install PCT's in approximately 25,000 additional establishments by the year 2038.

For medium C&I customers, participation rates for the CPP tariff in 2009 and 2010 are based on estimates of the number of customers who could save money on the new rate and are equal to 69 percent of the customers with AMI meters in those years. Starting in 2011, demand-response estimates are based on a 100 percent participation rate for medium customers since the alternative option to the default CPP rate is the CRC rider, as discussed in Mr. Hansen's testimony. The CRC option will price capacity reserves at a rate equivalent to the CPP rate. As such, the average customer who would reduce demand by, say, 10 percent in response to the CPP price should be willing to reserve 90 percent of their desired capacity ahead of time while taking actions to reduce peak demand by 10 percent. In other words, the main difference between the CPP rate and the CRC is the timing of payments for capacity, so both options give customers an

[20] This is different than saying that 100 percent of these customers provide demand response. The elasticities underlying the estimates of peak-period reductions reflect the fact that roughly 23 percent of small C&I customers and about 17 percent of medium C&I customers in the SPP over road the automated PCT settings. Thus, implicit in the demand response estimates made here is that roughly the same percent of customers will over ride an event as did so in the SPP.

[21] Prior to 2013, the acceptance rate is the product of the meter deployment rate, the assumed steady-state acceptance rate of 33 percent, and the ramp rate equal to 20% in 2009, 40% in 2010, 60% in 2011, 80% in 2012 and 100% in 2013. Thus, the acceptance rate in 2009 equals 2.8%, which is the product of 42% (the meter deployment rate) times 20% (the ramp rate for 2009) times 33% (the steady state rate).

equal economic incentive to reduce demand. The technology acceptance rate for medium C&I customers is assumed to equal 33 percent, which is a conservative assumption in light of the fact that roughly 60 percent of medium commercial customers accepted a PCT in the SPP. This level of penetration will place PCTs among roughly 5,600 medium size commercial establishments by 2013. Additional technology penetration is achieved through the Title 24 building standards. Given the growth rate in this customer population, the revised Title 24 standards would place PCTs among an additional 16,800 medium commercial establishments by 2038.

For large C&I customers, demand-response benefits are based on a 100 percent participation rate starting in 2009, as all customers will be defaulted onto a CPP rate in 2009 and the alternative option will be the CRC. PCTs are not being offered to this customer segment, as air conditioning is not as large a percent of their total load as it is for other customer segments and the price elasticities are not dependent on enabling technology promoted by a utility.[22]

IVe. Additional Variables

In addition to the key input variables discussed above, the benefit simulation model requires input values for the following variables:

A. Meter deployment rates
B. The number of customers by rate class
C. Growth in the number of customers
D. Growth in average use per customer independent of any rate or incentive-induced impacts
E. Marginal capacity and energy costs by rate period
F. Generation reserve margins
G. Line loss factor
H. The discount rate used to calculate the net present value of benefits.

The values used for each of these variables are discussed below.

As described in Mr. Reguly's testimony (Chapter 8), nearly all AMI meters will be installed over a 31-month period. The planned meter implementation schedule was

[22] Many large C&I customers already have energy management systems that might be used to help automate demand response.

used to construct the annual deployment values presented in Table SSG 6-18 based on the following approach. We assumed a constant deployment rate per month across the entire service territory beginning with the initial meter deployments in May 2008 and continuing through December 2010. Next, we converted the monthly cumulative deployment rates into annual values by assuming that only meters installed prior to June 1st in each year would contribute to demand response benefits in that year. This assumption is based on the fact that the vast majority of demand response benefits are due to avoided capacity, and capacity constraints typically occur during the warmest summer months of July through September. Thus, although all meters are installed by the end of 2010, the demand response benefits from meters installed after May 2010 are not counted until 2011.

Table SSG 6-18
Annual Meter Deployment Rates Used for Simulation Modeling

Year	**Cumulative Deployment (%)**	
	Coastal	**Inland**
2009	42	42
2010	77	77
2011	100	100

The marginal costs of capacity and energy are discussed in Mr. Martin's testimony (Chapter 7). The marginal cost of capacity is assumed to be 85$/kw-yr and is held constant over the forecast horizon. The marginal energy costs vary by year and are presented in Mr. Martin's testimony.

The avoided capacity benefits are calculated in 2006 dollars using a discount rate of 8.23 percent[23]. The avoided capacity benefits also take into account the reserve margin and distribution line losses. The reserve margin is mandated by the CPUC and equals 15 percent. Distribution line losses by rate period are shown in Table SSG 6-19. The CPP-day, peak-period values are used in calculating demand-response benefits for generation

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[23] SDG&E's accounting practices include a convention in which capital is discounted starting at the beginning of a year and expenses are discounted at the end of the year. Since the energy benefits constitute avoided O&M expenses, they are discounted according to the end of year convention while generation capacity is discounted using the beginning of year convention.

capacity. Transmission line losses are already included in the $85/kW-yr avoided capacity value.

Table SSG 6-19 Line Losses		
Day Type/ Rate Period	**Summer**	
	Residential (%)	**C&I (%)**
CPP - Peak	5.81	5.90
CPP - Partial Peak	n/a	5.32
CPP – Off-peak	4.95	4.31
Non-CPP - Peak	5.13	5.18
Non-CPP - Partial Peak	n/a	4.90
Non-CPP – Off-peak	4.56	4.00
Holiday/Weekend	4.26	4.28

V. MONTE CARLO SIMULATION

In order to reflect the inherent uncertainty in selected input variables, a Monte Carlo simulation model was used to develop a probability distribution of demand response benefits. Four key drivers of demand response benefits were included in the simulation analysis:

A. The elasticity of substitution and the daily price elasticity of energy demand
B. Starting values for energy use by rate period on critical days due to variation in weather
C. Awareness levels for the PTR program for residential customers
D. Marginal generation capacity cost.

Each of these variables is represented in the Monte Carlo analysis by a probability distribution with specific characteristics described below. The Monte Carlo analysis takes 1000 draws from each probability distribution for each variable and calculates the demand response impacts and benefits associated with each combination of variable draws. For example, the Monte Carlo process will select a specific value from the probability distribution for the elasticity of substitution, the daily price elasticity, starting energy use values, awareness levels and marginal capacity costs, and enter each of these randomly chosen values into the simulation model. The model then calculates avoided capacity and energy benefits based on this particular set of values, records the output, and the process is repeated a thousand times. For example, one point on the output distribution might be associated with a high value for the elasticity of substitution, a value near the mean for the daily price elasticity, a low value for starting energy use (representing a below average weather year), a high value for awareness and a value near the mean for marginal capacity costs. A point on the low-end tail of the output distribution might reflect low values from the distributions for each of the variables whereas a value near the high-end tail of the output distribution would reflect relatively high-end values from the distributions for each of the input variables.

Uncertainty in the elasticity of substitution and the daily price elasticity is represented by the standard errors of the estimated elasticities. For residential customers, the standard errors of the estimated elasticities are based on the SPP analysis, adjusted for weather and CAC saturations specific to SDG&E. Plus or minus two standard deviations represents a 95 percent confidence interval around the mean value. For example, as seen in Table SSG 6-20, the elasticity of substitution for residential customers in the coastal climate zone on critical days is –0.064, with a standard deviation of 0.003. Thus, the 95 percent confidence interval is from –0.058 to –0.070. Each draw from the probability distribution of the elasticities is used for all forecast years in the simulation analysis. That is, elasticities are not allowed to vary from year to year.

Table SSG 6-20
Elasticities and Standard Errors used for Residential Customers in Monte Carlo Simulations

Rate Type	Elasticity Measure	Coastal & Mountain		Inland & Desert	
		Elasticity	Standard Error	Elasticity	Standard Error
PTR Program	Substitution	-0.064	0.003	-0.094	0.003
	Daily	-0.040	0.004	-0.040	0.004

Table SSG 6-21 shows the standard errors for the elasticity of substitution for C&I customers and the maximum and minimum values for the daily price elasticity. The standard errors for the elasticity of substitution for C&I customers are based on the SPP analysis. Recall from the previous discussion that the SPP could not precisely estimate daily price elasticities (e.g., daily price was not statistically significant) and a very conservative value of –0.025 was used based on the literature. Uncertainty in this estimate is assumed to follow a triangular distribution with a minimum value of zero and a maximum value of –0.05 (the low end of the values reported by Bohi, as discussed previously).

Table SSG 6-21
Standard Errors and Ranges of Price Elasticity Estimates Used for C&I Customers in Monte Carlo Simulations

Customer Segment	Technology	Elasticity Measure	Day Type: Critical	Day Type: Non-Critical
< 20 kW	No	Substitution	0	0
		Daily	0	0
	Yes	Substitution	0.0163	0
		Daily	±0.025	0
20 to 200 kW	No	Substitution	0.0086	0.0159
		Daily	±0.025	-0.025
	Yes	Substitution	0.0101	0.0159
		Daily	±0.025	±0.025
>200 kW	No	Substitution	0.0083	0.0083
		Daily	±0.025	±0.025

Uncertainty associated with weather is reflected in the starting values for energy use by rate period for residential customers on critical days.[24,25] C&I customer loads are less weather sensitive than residential loads and uncertainty in C&I starting values was not included in the Monte Carlo simulations. We assumed that the distribution of starting values by rate period followed a normal distribution and that energy use under a 1-in-10

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[24] Starting values on non-critical days have relatively little influence on the overall present value of benefits and, therefore, were not included in the Monte Carlo analysis.

[25] Although the elasticity of substitution and daily price elasticities for residential customers are a function of weather, we did not factor this variation into the simulation analysis because the variation is quite small and it is difficult to simultaneously reflect the influence of weather in the probability distributions of both the starting energy use values and the elasticities. By far, the largest influence of weather variation is the result of differences in the starting values, which has been captured.

year weather scenario represented the 90th percentile of that distribution. The mean value of the distribution is assumed to equal the 1-in-2 year values contained in Tables SSG 6-7 through 6-10. Given the assumption of normality, the 10th percentile estimates of starting values would equal the same percentage reduction compared to the mean of the distribution as the 90th percentile percentage increase from the mean value. Table SSG 6-23 contains the estimated standard errors for the starting values that reflect the above assumptions.

Table SSG 6-23
Standard Errors for Probability Distribution for Residential Energy Use by Rate Period on Critical Days

Customer Segment	Period	Coastal & Mountain	Inland & Desert
Residential	**Peak**	0.9	0.7
	Off-peak	0.6	0.8

Uncertainty due to variation in weather varies from year to year. That is, unlike with uncertainty in the elasticity values, where the same value drawn from the probability distribution is used across all forecast years, a different draw from the distribution for starting energy use values is made for each year of the forecast, since a high or low weather year would not occur 15 years in a row[26].

The probability distribution for levels of awareness of the PTR events for residential customers is represented by a triangular distribution with a minimum value of 50 percent, a mode of 70 percent and maximum value of 85 percent.

The final variable for which uncertainty is reflected in the Monte Carlo simulations is avoided capacity costs. The mean value used for avoided capacity is $85/kW-year. For the Monte Carlo simulations, a triangular probability distribution with maximum and minimum values equal to the mean value ±15 percent was used. Thus, the maximum value is assumed to equal $97.75/kW-year and the minimum value is assumed to equal $72.25/kW-year. Avoided capacity costs are held constant over the forecast horizon for each draw from the probability distribution.

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[26] While the Monte Carlo analysis could actually draw by chance a high or low weather year many years in a row, the probability of this occurring is very small and would only occur by chance, not by design.

VI. GROWTH FORECAST FOR CUSTOMERS AND USE PER CUSTOMER

Estimates of the number of customers for 2004 and forecasts of average annual growth rates for customers and energy use per customer by market segment and climate zone are presented in Table SSG 6-23. These estimates and forecasts were developed by SDG&E staff and are based on the following:

A. 2003 SDG&E electric customers and energy sales by market segment and climate zone
B. 2003 SDG&E electric customers in Orange county by market segment
C. Projected electric customers and energy sales by market segment from the SDG&E long-term resource plan forecast
D. An increasing share of SDG&E electric customers in Orange county, based on a historical trend that is assumed to continue, and
E. Projected shares of housing and employment growth in San Diego climate zones, based on sub-county area forecasts from the Final 2030 Forecast prepared by the San Diego regional planning agency, SANDAG.

Projections of electric customers and energy sales in the SDG&E long-term resource plan forecast are for the service territory. Sub-service territory forecasts for areas such as climate zones are not available. Therefore, the projected growth of SDG&E electric customers and energy sales in the long-term resource plan forecast must be distributed to climate zones for use in the AMI business case. The methodology for distributing service territory forecast to climate zones is summarized below.

The SDG&E AMI business case forecast starts with 2003 Orange county customers by market segment. SDG&E electric customers in Orange county are located in the coastal climate zone. From 1990 to 2003, the share of total SDG&E electric customers located in Orange county increased from about 7.8 percent to 8.8 percent. From 2004 onward, the business case forecast is based on the assumption that this share continues its upward historical trend. In 2021, the share of SDG&E electric customers in Orange county is projected to increase to approximately 10.2 percent of the total.

Electric customers in the San Diego county portion of the SDG&E service territory are located in one of two climate zones: coastal or inland. The San Diego

County portion of the SDG&E AMI business case forecast starts with 2003 customers by market segment and climate zone. The San Diego county climate zones are defined as a set of SANDAG master geographic reference areas (MGRAs)[27]. Projected customer growth in the San Diego county portion[28] of the resource plan forecast is distributed to each of the climate zones based on shares of housing or employment growth that SANDAG projects at the MGRA level.

For the residential segment, the share of occupied housing unit[29] growth forecast by SANDAG at the MGRA level is the basis for allocating shares of customer growth forecast by SDG&E to the climate zones. For example, if SANDAG forecasts a 55 percent of the growth in San Diego occupied housing units occurs in the set of MGRAs in the Inland Climate Zone, then 55 percent of the SDG&E residential electric customer growth forecast, net of Orange County, is allocated to the Inland Climate Zone. The remaining 45 percent of the forecast, net of Orange County, is allocated to the coastal climate zone in San Diego.

A similar distribution method is used to allocate the SDG&E commercial and industrial (C&I) customer growth forecast by market segment to San Diego climate zones. Shares of non-agricultural wage and salary employment growth projected by SANDAG at the MGRA level are the basis for allocating the SDG&E forecast of electric C&I customer growth, net of Orange county, to the climate zones in San Diego.

The number of large commercial customers excludes customers who are expected to be on a CPP rate prior to AMI deployment due to the anticipated approval of SDG&E's default CPP application. A total of 394 customers were excluded which resulted in an 11 MW decrease in the large commercial demand response estimates. This number is within the range of default CPP demand response estimates presented in SDG&E's default CPP application.

[27] A SANDAG MGRA in San Diego county is a census block or a split census block. There are 33,289 master geographic reference areas in the San Diego county portion of the SDG&E service territory.
[28] The San Diego county portion of the forecast equals the total SDG&E service territory forecast minus the Orange county portion of the forecast.

[29] In the SANDAG Final 2030 Forecast, households are occupied housing units.

In order to obtain the same annual service territory energy sales by market segment in both the AMI business case and the long term resource plan forecasts, energy use per customer by market segment and climate zone must change over time in the AMI business case. Therefore, the estimate of 2003 energy use per customer by market segment and climate zone is adjusted to eliminate annual differences in service territory energy sales by market segment.

The annual adjustments to the 2003 estimate of energy use per customer for each market segment are based on the percentage difference in annual energy use per customer from the resource plan forecast modified by an adjustment factor for each climate zone. For each market segment, the annual climate zone adjustment factors are simultaneously estimated each year with the Excel solver tool. The end result is a forecasted growth in service territory energy sales by market segment in the AMI business case that is consistent with the long term resource plan forecast.

Table SSG 6-23 Forecast of Customer Growth Rates and Use Per Customer by Climate Zone				
	Growth Rate in Number of Customers (%)		**Growth Rate in Energy Use per Customer (%)**	
	Coastal & Mountain	**Inland & Desert**	**Coastal & Mountain**	**Inland & Desert**
2004 Residential Customers	664,778	481,590		
Annual Growth Rates				
2004	1.45	1.43	3.35	3.35
2005	1.78	1.77	-1.06	-1.07
2005-2022	1.36	1.65	0.61	0.60
2023-2038	0.88	1.09	0.61	0.60
2004 Small C&I Customers	71,201	46,350		
Annual Growth Rates				
2004	1.86	1.28	1.15	1.13
2005	1.13	0.74	-0.18	-0.20
2005-2022	0.79	0.74	0.12	0.10
2023-2038	0.57	0.53	0.12	0.10
2004 (20-200KW) C&I Customers	9,219	4,960		
Annual Growth Rates				
2004	4.85	3.81	0.56	0.55
2005	4.71	3.91	-3.07	-3.11
2005-2022	2.43	2.89	-0.57	-0.61
2023-2038	1.97	2.33	-0.57	-0.61
2004 C&I Customers (>200 kW)	1,323			
Annual Growth Rates				
2004	5.08		1.58	
2005	5.09		-3.37	
2005-2022	2.98		-0.57	
2023-2038	2.35		-0.57	

VII. QUALIFICATIONS OF STEPHEN GEORGE

Dr. Stephen George has more than 27 years of experience consulting to electric and gas utilities and regulatory agencies, and 30 years of experience in the energy field. His areas of expertise include pricing strategy, demand-side management program design and evaluation, electric industry restructuring, strategic and market planning, market research, and energy demand modeling. He has worked for electric utilities in four states on issues associated with electricity pricing and advanced metering, including the recent design and evaluation of California's Statewide Pricing Pilot, the largest pricing experiment ever done in the US. He provided expert testimony on the demand-response benefits of dynamic pricing for one of California's largest utilities and advised the government of Victoria, Australia on the cost-effectiveness of implementing advanced metering and pricing reform. Steve is an expert on the design and implementation of competitive retail electricity markets. He has advised governments and utilities on retail market issues in numerous US states as well as Singapore, Ontario Canada, New Zealand and Australia. Dr. George has held previous positions as Vice President of CRA International and PHB Hagler Bailly, Inc. (formerly Putnam, Hayes & Bartlett, Inc.), Director of Putnam, Hayes and Bartlett, Inc., and Vice President of XENERGY Inc. He holds a Ph.D. in economics from the University of California, Davis, and a B.S. in economics from Santa Clara University.

EDUCATION

Ph.D. Economics, University of California, Davis
B.S. Economics, Santa Clara University

RELEVANT PROJECT EXPERIENCE

Electric Industry Restructuring

Dr. George's focus in electric industry restructuring is on the retail side of the business, examining issues associated with market rules and structures for retail competition, distribution system unbundling and strategy, default supply pricing and design, licensing and codes, information access, consumer protection, and affiliated interest rules. Among his most recent projects are:

- In a recent project for a European metering company, Dr. George conducted in-depth interviews with 12 utilities and metering service providers in England. The survey focused on a variety of topics, including the structure of the metering market, outsourcing, competitive positioning among meter service providers, contracting relationships, business operations, and related topics.
- Development of all aspects of the retail market design and implementation for the Singapore Electricity industry. Through this project, Dr. George developed recommendations concerning the overall structure of the retail market, the characteristics of standard offer service to both contestable and non-contestable consumers, business rules for consumer transfers among suppliers, user requirements for an electronic business transaction system to support customer switching, and meter standards for contestable consumers.

- Management of a consulting team assisting the Ontario Energy Board (OEB) to develop licenses and codes for all market participants in the restructured Ontario energy industry. The team developed licenses for generators, transmitters, distributors, the Independent Market Operator, gas and electricity retailers, and wholesale electricity suppliers. The various codes developed through this project included a distribution system code, retail settlement code, metering code, marketing code of conduct ,and affiliate relationships code. This project involved extensive public consultation with stakeholders.
- Expert testimony on behalf of ComEd concerning unbundling of delivery services under Section 16-108 of the Illinois Public Utilities Act.
- Expert testimony on behalf of Entergy concerning issues associated with distribution unbundling of metering and billing services.
- Recommendations to the Office of Regulator General, Victoria, Australia concerning provider of last resort rules and responsibilities, meter unbundling, and the net benefits of wide scale deployment of time-of-use metering for mass-market consumers.
- Management of a consulting team that developed recommendations to the Ontario Market Design Committee (MDC) on all aspects of retail competition, including retail settlement procedures, load profiling, procedures for transferring customers among electricity retailers, default supply obligations, separation of competitive and regulated activities, guidelines and codes for competitive metering and billing operations, consumer protection, and distribution and marketer licensing. Dr. George has directed a wide variety of stakeholder teams working on all aspects of retail restructuring and has been the primary consulting liaison on retail issues with the MDC.
- Evaluation of proposals for a metering and settlement framework to support the introduction of full retail competition in Victoria, Australia. The Victorian Government had asked the state's Distribution Businesses to produce proposals, which it then asked PHB Hagler Bailly to evaluate. Dr. George reported findings back to the Government, taking into account the Government's objectives, and made suggestions for an alternative approach.
- Development of a detailed report advising the Australian Metering and Reconciliation Committee on design of a retail settlement and metering strategy in support of expansion of the Australian competitive electricity market to all customers. Working under contract to the National Electricity Market Management Company (NEMMCO), Dr. George managed this work and was the primary author of a report entitled *Development of a Conceptual Metering and Settlement Design for Full Retail Competition in the National Electricity Market* (December 11, 1998). The report includes a worldwide review of settlement procedures and metering policies in jurisdictions where retail competition is already in place or planning is well advanced. The work involved more than half a dozen all-day workshops among a wide variety of stakeholders, including distribution company representatives, government agencies, meter suppliers, and competitive energy service providers.
- Development of regulatory and business strategies for metering under multiple scenarios concerning distribution unbundling and metering requirements for support of retail competition. The project involved detailed financial analysis of alternative metering technologies.

- Two reports to the Edison Electric Institute identifying major operating and business management issues associated with retail competition and distribution unbundling. Issues were examined under multiple scenarios regarding competitive supply of distribution services (e.g., metering, billing, and customer service) and public policies associated with meter requirements for direct access.
- Broad-based support to a Midwestern utility involved in both legislative and regulatory restructuring proceedings. The work included examination of distribution unbundling, identification of price and non-price impacts of restructuring on consumers, investigation of affiliate interest rules, and development of information strategies to support industry restructuring.
- Development of a report identifying organizational issues associated with distribution unbundling for another Midwestern utility.
- For the Government of Victoria, Australia, Dr. George developed a framework for examining cross-ownership policies and restrictions in the electricity and natural gas industries. The report examined the benefit and concerns associated with various cross-ownership combinations as well as appropriate analysis methods and policy options.
- For the New Zealand Commerce Commission, support in Commerce Act litigation involving alleged anticompetitive practices of one of New Zealand's leading electric utilities. Issues in the case involved structural boundaries between regulated and unregulated elements of a restructured electricity industry, preferential access to monopoly services and cross-subsidization of competitive businesses by monopoly services. .
- For one of the largest U.S. utilities, a detailed review of how California has implemented retail competition. The review has focused on distribution unbundling issues, including competitive provision of metering and billing.

Corporate and Market Strategy

Dr. George has conducted a wide variety of work assisting utilities in better understanding customers and markets in order to develop effective business strategies. Examples of relevant projects in this area include the following:

- Dr. George is currently supporting the three largest investor-owned utilities in California in a regulatory proceeding examining the role of advanced metering, dynamic pricing and demand response programs in support of the California electricity market. The work began with a detailed cost-effectiveness analysis of advanced metering and dynamic rates for one of the utilities. It expanded into development of a joint utility pilot program design effort for all three utilities and included estimation of demand models and impact estimates for various TOU and dynamic rate treatments.
- In response to a regulatory directive to Xcel Energy, Dr. George helped estimate the net benefits of a variety of time-of-use rate options. The evaluation examined the net benefits from a variety of perspectives, including participating and non-participating consumers, the utility, all ratepayers and society. A report summarizing this analysis was filed by Xcel with the Minnesota Commission.

- For a West Coast utility, Dr. George worked with other colleagues to evaluate the net benefits of innovative, time-of-use rate and real time pricing options for mass-market consumers in support of a general rate case.
- In order to help one of the largest electricity retailers in the world determine which U.S. states it should enter, Dr. George evaluated the retail market rules in most of the states where retail competition is currently allowed.
- Dr. George managed development of a comprehensive strategic marketing plan covering all major consuming sectors for a Midwestern utility. Through a series of senior management interviews, PHB assisted in the development of marketing objectives that were consistent with key corporate objectives. Using an analytical framework that systematically investigated the profitability of alternative strategic options and market segments, PHB worked closely with utility staff to identify targets of opportunity as well as potential risks. Dr. George also advised the marketing director on restructuring the planning and sales organization to be more responsive to the changing needs of the company and its customers.
- In a project for a medium-sized electric utility, Dr. George identified time-to-market bottlenecks in the sales, customer service and marketing planning departments, and made recommendations for restructuring the departments to improve sales and service effectiveness.
- In another project for the same company, Dr. George managed the development of a market strategy and detailed business plan for entry into the energy services business, with an emphasis on contract energy services (CES). From a customer's standpoint, CES provides an opportunity to completely outsource their entire energy operation, in essence purchasing end-use services (e.g., light, heat, motive force) from a full-service energy provider. From a supplier's perspective, CES affords the opportunity to bundle many value-added services into a single contract and to better control decisions regarding energy purchases, equipment investments and operational practices.
- In a project for a southeastern utility, Dr. George participated on a team that restructured the company into lines of business and strategic business units designed to compete more effectively in a restructured utility industry.
- In a project for the Electric Power Research Institute (EPRI), Dr. George investigated several topics, including issues concerning the importance of determining customer profitability across product lines and the development of strategic market management strategies in a competitive electricity industry. He also directed a project that developed case histories of product innovation in other industries in order to provide insights about market strategies for new products in the utility industry.
- As part of a senior consulting team, Dr. George developed a long-range strategic plan for a large electric utility holding company. The comprehensive effort examined how the company would fare in an increasingly competitive energy market under a variety of transition and equilibrium scenarios. Dr. George directed the analysis of the customer-side of the business and was also involved in benchmarking, performance improvement and organizational change analysis.

- On behalf of EPRI, Dr. George was the first to apply Quality Function Deployment (QFD) to the design of marketing and DSM programs. QFD is a design tool used widely in manufacturing to develop products and services that better meet customer's needs. It focuses on incorporating the "voice of the customer" in all elements of the planning process from conception through implementation. Dr. George managed the first application of the tool in designing a commercial sector efficient lighting program for PSI Energy. He also facilitated the development of a residential add-on heat pump program, a commercial/industrial communication and energy monitoring service, and automated payment machines. Dr. George has conducted QFD training workshops for well over 150 utility staff members representing more than two dozen utilities.
- Dr. George managed a large, multiyear project for the EPRI designed to develop methods and tools for assisting utilities to incorporate customer needs into the planning process. The comprehensive project focused not only on how to identify customer needs and wants, but also on how to organize and manage a utility's structure and resources to achieve a greater value orientation, as well as how to address the concerns that arise among regulators and other policy shapers when utilities shift from a cost to a value orientation.
- In a project for one of Spain's largest investor-owned utilities, Dr. George directed a major least-cost planning effort. Working closely with client staff, he developed a comprehensive understanding of the existing markets for demand-side alternatives using existing data as well as new survey data that he helped develop. He determined the relative costs and benefits of a wide variety of demand-side management options in all major consuming sectors, as well as the barriers and opportunities for achieving cost-effective options.
- Dr. George was the author of a strategic marketing planning report, "Demand-Side Management Strategy for 1990–1993," prepared for a major U.S. utility. The strategy included not only recommendations for specific demand-side programs, but also for the data collection and analysis, resource planning, program design, and monitoring and evaluation activities that accompany program implementation.
- In a study for another large utility, Dr. George directed a series of DSM program planning and evaluation activities that included a state-of-the-art econometric evaluation of the kWh impact of the company's Residential Conservation Services (RCS) program. Another analysis utilized a comprehensive benefit/cost assessment that involved the development of new conservation strategy selection software. Dr. George was the primary author of a major filing with the regulatory commission, which presented estimates of the conservation potential for the company's service territory and recommended specific program options.
- Dr. George managed a project for EPRI that reviewed much of the existing literature on commercial customer acceptance of demand-side options and programs and surveyed over 100 utilities about their specific experience in marketing demand-side programs. The project identified a variety of specific customer needs and characteristics that affect purchase and utilization decisions. The project also examined various market research methods used to investigate customer characteristics and interests, as well as the technical issues important to program evaluation.

- For Public Service of New Hampshire, Dr. George evaluated an interruptible rate program for commercial and industrial customers and helped design a new program that met with significantly greater success than the original. After implementing his recommendations, participation in the program increased from three to over 40 customers, and the amount of interruptible capacity under contract went from 1 MW to over 20 MW.
- Dr. George participated in a major project for the three largest investor-owned utilities in California that developed an evaluation methodology for acquiring supply-side resources through competitive auctions. The methodology allows one to compare alternative multi-attribute resource options using a self-scoring evaluation process.
- For many years, Dr. George organized and facilitated the Utility Customer Satisfaction Network, an ad hoc group of utility researchers who meet twice a year to discuss technical and practical issues associated with customer satisfaction measurement.
- Other relevant projects conducted by Dr. George in the area of planning and evaluation include:
  - An assessment of the load impact of a commercial audit program for the Bonneville Power Administration.
  - An investigation of the persistence of commercial conservation measure savings, also for BPA.
  - An analysis of the transferability of time-of-use rate impact estimates for EPRI.
  - An investigation into effective implementation factors for DSM programs, also for EPRI.
  - An analysis of residential DSM program evaluation studies for the California Energy Commission.

Market Research

Another one of Dr. George's primary areas of expertise is market research. He has directed numerous surveys and analyses designed to help utilities better understand their customers' needs and motivations. This work has primarily been used to improve marketing effectiveness in the increasingly competitive environment faced by utilities. Descriptions of relevant projects in this area follow:

- In a project for a Midwestern utility, Dr. George developed a comprehensive, three-year market research plan to support both strategic and tactical marketing planning.
- In a project for a major West Coast utility, Dr. George assisted the marketing department through a survey of large commercial customers. The telephone survey of 750 customers provided information on customer decision-making practices with respect to large capital investments, specifically focusing on cogeneration and thermal energy storage systems. The data was analyzed to determine customer segments and their buying factors and processes associated with investments in cogeneration and other large energy-using equipment.
- Dr. George directed individual market assessment studies of a number of large commercial customers of a major utility. Through a review of secondary sources and extensive interviews of firm personnel, each assessment described the customer's energy-related decision-making process, technological characteristics and position

within its market. The primary focus of the studies was to identify marketing threats and opportunities from the utility's perspective.

- In a project for a large New York utility, Dr. George managed a multiyear research effort that investigated a number of issues associated with the buying patterns of commercial customers. He designed a comprehensive research strategy including a detailed survey of the physical and behavioral characteristics of commercial customers, the development of end-use energy consumption and load profiles and the management of experimental studies to investigate the penetration of selected DSM technologies under various utility program alternatives.

Other relevant market research studies directed by Dr. George include:

- A survey of heating, ventilation, and air conditioning contractors to determine installation practices relevant to developing building standards.
- A focus group study among commercial sector energy managers to ascertain information relevant to the purchase of cogeneration equipment.
- The conduct of a large onsite residential appliance saturation survey designed, in part, to evaluate the validity of mail survey data.
- The conduct of a series of focus groups designed to assess the impact of various lease arrangements among commercial establishments on the purchase of energy using equipment.

Demand Modeling and Forecasting

Dr. George began his career in the Demand Assessment Office of the California Energy Commission where he played a key role in developing one of the first end-use forecasting models in the industry. Since that time, he has conducted numerous projects in the area of demand modeling and forecasting, some of which are described below:

- In a project for the Northwest Power Planning Council (NPPC), Dr. George managed the development of a large-scale electricity market model, including submodels for load forecasting, supply pricing and demand/supply integration. These models were used by the Council to examine the implications of alternative demand and supply scenarios for electric power policy in the Pacific Northwest. The load forecasting model combined updated versions of existing residential and commercial sector models with industrial and irrigation sector models developed specifically for the region.
- Dr. George was one of the earliest practitioners of Conditional Demand Analysis, a method of estimating end-use consumption from individual household survey data. He applied this technique in his doctoral dissertation to estimate residential end-use electricity consumption for several California utilities. His conditional demand analysis experience led to a contract with the California Energy Commission to estimate the variation in space conditioning electricity consumption over the days of the year as a function of changes in weather and other determining factors such as price.

Other relevant experience in the forecasting and modeling area include:

- An evaluation of alternative estimates of end-use consumption in the commercial sector.
- The development of a technology brief on price elasticity for EPRI.
- The estimation of econometric forecasting models for utilities in the Northwest and Midwest.
- The development of forecasting models for the Texas Energy and Natural Resources Advisory Council.

EMPLOYMENT HISTORY

2006 – Present	Principal Consultant, Freeman, Sullivan & Co., San Francisco, CA
2000 – 2006	Vice President, CRA International (formerly Charles River Associates), Oakland, CA
1988 – 2000	Vice President (and Director), Putnam, Hayes & Bartlett (merged with Hagler Bailly in 1998 to become PHB Hagler Bailly), San Francisco (and Palo Alto), CA
1984 – 1988	Vice President, Xenergy, Inc., Oakland, CA
1979 – 1984	Senior Research Associate and Vice President, Charles River Associates, Boston, MA
1976 – 1979	Analyst, California Energy Commission, Sacramento, CA

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