Application of San Diego Gas & Electric Company (U-902-M) for Approval of Demand Response Programs and Budgets for the Years 2012 through 2014.	Application 11-03-002

CHAPTER V

AMENDED TESTIMONY OF

LESLIE WILLOUGHBY/KATHRYN SMITH

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

May 27, 2011

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CHAPTER V

PREPARED DIRECT TESTIMONY OF

LESLIE WILLOUGHBY\KATHRYN SMITTH

I. PURPOSE

The purpose of this testimony is to present the load impacts of SDG&E's demand response programs, present the budget for the measurement and evaluation of the demand response programs, and to recommend a new baseline for the SDG&E capacity bidding program.

II. BACKGROUND

In D-08-04-051 the commission adopted demand response load impact protocols. These protocols provided rules that specified required output data that must be included in all measurement and evaluation reports. For example these protocols require that every load impact measurement and evaluation report include hourly ex-post load impact results for each event day for the entire program as well as on average per customer. In addition each load impact report is required to contain a 10 year hourly forecast of expected future load impacts for 24 different temperature scenarios. The decision further required that every demand response activity be evaluated every year and that the load impact reports be filed with the CPUC on April 1st of each year. The decision specified that the load impact protocols be applied to all demand response activities, which includes both demand response programs and dynamic rates. Since the load impact protocols require a great number of tables to be produced and all reports formally filed with the docket office are required to be printed out in hardcopy the decision was later modified to require that only an executive summary that summarized the results of all the individual reports be filed with the commission. The individual measurement and evaluation reports are still required to be publically posted but not filed.

As required by the load impact protocols, SDG&E will file measurement and evaluation studies that will follow the load impact protocols on April 1st of this year. Originally this testimony was filed prior to the April 1st filing date, per the guidance document[1] for this proceeding which stated:

> *The utilities' load impact estimates in the 2012-2014 demand response Applications will likely be based on their April 2010 load impact reports (which were based on 2009 ex post data), and because many changes were made to existing programs for summer 2010, the available load impact data may not take into account these recent changes. On April 1, 2011, the utilities will produce their annual demand response load impact report, which will be based on the 2010 ex post data. In order for the Commission to evaluate the demand response load impact and cost effectiveness before approving funding for the next budget cycle, the Commission may (depending on the proceeding schedule) require the utilities to submit revised testimony on load impact and cost effectiveness to reflect the load impact estimates in their April 1, 2011, filings. I encourage the utilities to make their best efforts to use the 2010 ex post data as much possible to avoid the need to submit revised testimony after April 1, 2011.*

Subsequently on May 13th, the CPUC issued a ruling and scoping memo that gave further direction to the utilities:

> *The Joint Applicants shall revise their cost effectiveness analyses and load impact estimates for all demand response programs 1) using the data from the April 1, 2011 Load Impact Reports and 2) using the data from the April 1, 2011 Load Impact Reports and the inputs from Attachment 1. The Joint Applicants shall serve both sets of revisions not later than May 27, 2011.*

To comply with this ruling SDG&E has updated 1) the ex-post results and ex-ante forecast with the April 1st Load Impact filing information and 2) load impact forecast for the DemandSMART™ program as this contract was recently discontinued.

Demand Response activities for 2012-2014 include both dynamic rates and demand response programs. The Critical Peak Pricing Default ("CPP-D") rate and Peak Time Rebate ("PTR") were initially described in SDG&E's AMI business case A.05-03-015 and finally

[1] Administrative Law Judge's Ruling Providing Guidance for the 2012-2014 Demand Response Application 08-27-10

adopted in SDG&E's GRC phase II Settlement Agreement in D.08-02-034[2]. The Critical Peak Price Emergency Rate was also adopted in the GRC phase II settlement agreement. Although these rates have already been adopted by the CPUC, forecasts for these rates are included in this testimony in order to provide a complete demand response forecast.

In addition SDG&E has two other demand response programs that were previously approved by the CPUC as contracts. SDGE's Summer Saver program contract was approved in 2004 and later amended. The SDGE DemandSMART™ program was also approved as a contract in 2009. Although these contracts have already been approved, load impact forecasts are provided for these programs in order to provide a complete forecast for all of SDG&E's demand response activities. In May 2011, SDG&E mutually agreed with the third party to discontinue the DemandSMART™ contract in May of 2011. Therefore adjustments to the load impact forecasts have been made to reflect this change.

Demand Response programs for which SDG&E is requesting approval in this proceeding as described in the testimony of George Katsufrakis include the Capacity Bidding Program ("CBP"), Base Interruptible Program ("BIP"), Technical Incentives program ("TI"), Permanent Load Shifting ("PLS") and the Small Customer Technology Deployment Program ("SCTD"). Load impact forecasts for these programs are also included in this testimony.

III. EX-POST LOAD IMPACTS 2009 AND 2010:

This section contains the ex-post load impacts of the demand response activities for which events were called in 2009 and 2010. The 2009 results come from the 2009 measurement and evaluation reports filed in April of 2010. Table KS-1 below contains the 2009 ex-post results for the system peak day (09/03/2009) as well as the average result overall of demand

[2] Motion For Adoption Of All Party And All Issue Settlement,, 11/1/07, pp 7-8,

response events called in 2009. The Summer Saver program percentage reductions in the M&E report were expressed in terms of the percentage reduction of the air conditioning load. All other percentage load reductions in the table are expressed as the percentage of the entire load of the customers. The CPP-D 2009 ex-post results include results for the entire CPP-D program and do include results for CPP-D customers dually enrolled in BIP and in CBP. Therefore adding all the load impact results together from Table KS-1 will double count the load reduction from customers enrolled in both CPP-D and CBP. Ex-post CPP-D results broken down by multiple program participation group were not provided in the 2009 measurement and evaluation report. The ex-ante portfolio CPP-D forecast presented in the 2009 report only included CPP-D customers not enrolled in any other program

Table KS-1

2009 Ex-Post Measurement and Evaluation Load Impact Results (MW)

DR Program	Load Reduction System Peak Day (MW)	Load Reduction Average Event Day (MW)	Percentage Reduction System peak day	Percentage Reduction Average event day
Capacity Bidding Day-Ahead	12	10	28%	26%
Capacity Bidding Day-Of	15	13	20%	18%
CPP-D	29	23	6%	6%
Summer Saver Residential	19	17	53%	55%
Summer Saver Commercial	7	7	29%	25%

Table KS-2 contains the final measurement and evaluation ex-post load impacts for demand response activities for which events were called in 2010. As in Table KS-1 the percentage reductions for the Summer Saver program are presented as a percentage of air-conditioner usage rather than a percentage of whole house energy use. The BIP results are broken out into results for BIP customers enrolled on CPP-D and BIP customers not enrolled on CPP-D. Only one BIP event was called in 2010 and this event was called on the same day as a

CPP-D event. BIP customers enrolled in CPP-D were not eligible to participate in the BIP test event because a CPP-D event had also been called on the same day. However, the BIP customers enrolled on CPP-D did reduce their load in response to the CPP-D event and so their load reduction in response to the CPP-D event which occurred the same day as the BIP test event is included in the table below.

Table KS-2

2010 Ex-post Measurement and Evaluation Load Impacts

DR Program	Load Reduction System Peak Day (MW)	Load Reduction Average Event Day (MW)	Percentage Reduction System peak day	Percentage Reduction average event day
Capacity Bidding Day-Ahead	11	10	35%	29%
Capacity Bidding Day-Of	8	9	16%	16%
DemandSMART^{TM}	6	8	21%	33%
CPP-D	11.3	18.8	3%	5%
Summer Saver Residential	26	14	51%	55%
Summer Saver Commercial	8	5	21%	24%
BIP non-CPP	0.4	0.4	17%	17%
BIP CPPD	3.9.	3.9.	80%	80%

The average load impacts in Table KS-2 above contain the results for all customers enrolled on CPP-D including those also enrolled on other programs. Therefore adding these results together will double count the load reduction from customers participating on both CPP-D and CBP, DemandSMART^{TM} or BIP. Table KS-3 below contains the load impacts on the 2010 system peak day when CPP-D, CBP day-of, DemandSMART^{TM} and BIP were all called. Table KS-3 shows that the vast majority of the impacts of the BIP program (91%) come from customers also enrolled on CPP-D. For CBP day-of and DemandSMART^{TM} the percentages of load reduction coming from CPP-D customers is smaller, 27% and 11%

respectively. These load impacts for CPP-D, CBP and DSP were calculated within the final CPP load impact evaluation. The BIP calculations come from the final ex-post 2010 BIP results.

Table KS-3

Effects of Multiple Program Participation on Program Load Impacts System Peak Day 2010

Program	Load Reduction from CPP-D customers (MW)	Load Reduction from Non-CPPD (MW)	Load Reduction for the Entire Program (MW)	% of total program load reduction contributed by CPP-D customers
BIP	3.9	0.5	4.4	91%
CBP Day-Of	1.7	6.3	8	27%
DSP	0.6	5.6	6.2	11%
CPP-D not dual enrolled	5.0	0	11.2	100%

SDG&E TI program contains two subgroups of customers. The first group is comprised of the Auto-DR customers who have enabling technology that can be activated by either the utility or an aggregator. The second group is comprised of customers with enabling technology that can be controlled by the customer rather than by the utility. In this section the TI customers with Auto-DR technology customer are referred to as Auto-DR and TI customers with technology controlled by the customer are referred to as Semi-Auto. TI customers are currently participating on two programs the CPP-D program and the CBP program. TI customers were also eligible to participate on the DemandSMART™ program. The ex-post results for these technology enabled customers were included in the ex-post results presented in Table KS-1 through table KS-3 but for more complete information they are presented in Table KS-4 separately.

Table KS-4 2009 and 2010 Ex-Post M&E results for Auto-DR and TI customers			
Program	**Technology Type**	**2009 Load Impact (kW)**	**2010 Load Impact (kW)**
CBP Day-Ahead	Auto-DR	0	145
CBP Day-Ahead	Semi-Auto	157	559
CBP Day-Of	Auto-DR	605	943
CBP Day-Of	Semi-Auto	0	66
CPP-D	Auto-DR	1371	698
CPP-D	Semi-Auto	714	859

The Permanent Load Shifting Program

The Permanent Load Shift Program ("PLS") is designed as a permanent peak load reduction program. The phrase "permanent load shift" refers to the shifting of energy usage by one or more customers from one time-period to another on a recurring basis, and for this program, refers to shifting load during the "peak hours" (11am-6pm) within the "peak period" (May - October) of the year. The PLS program is not part of the energy efficiency initiative or part of demand response. The PLS program resulted from a 2008 CPUC decision (D.06-11-049) directing the California IOUs to seek permanent peak load reduction in their service territories. The SDG&E RFP process resulted in two contracts for the PLS program effective through 2011. For the first contract peak load was reduced by replacing the electric on-peak load of the air conditioning systems with gas cooling systems. The second contract used "fly-wheel" technology to allow freezers to operate without mechanical cooling during the on-peak period. Three customers had permanent load shifting technologies that were installed in 2009 and 2010. Ex-post verification methods included calculating on-peak load reduction using the on-peak demands of the customers before and after the technology was installed and end-use metering. The total ex-post measured load reduction for the program to date is 1,342 kW.

IV. SUMMARY OF LOAD IMPACT FORECAST FOR 2012-2014

Tables KS-5 contains a summary of the forecasted load impacts of SDG&E's demand response activities for 2011-2014 for August monthly peak day in a 1-in-2 weather year. The hours used in the calculation are 1pm-6pm to be consistent with the new summer Resource Adequacy ("RA") counting rules.

The general methodology for the ex-ante commercial demand response activities is as follows: The load forecasts presented in this testimony for all of SDG&E's demand response activities utilize the forecasts filed on April 1st 2011 as directed by CPUC May 13th Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo.

The forecast for the CBP day-of program is based on the enrollment projections that were originally made for DemandSMART™ and the 2010 final M&E results. The BIP ex-ante forecast is also based on the final 2010 results. The load impact forecast for Auto-DR customers enrolled on CPP-D and CBP are based on a combination of the previous year's forecast and the 2010 final load impact results. The Auto-DR results are not included in Table KS-5 separately in order to avoid double counting but are available later in this testimony in Table KS-8.

The general methodology for the ex-ante residential and small commercial forecast is as follows; The Small Customer Technology Deployment program ("SCTD") is a new program and the residential part of the forecast uses percentage load reductions from SDG&E Smart Thermostat measurement and evaluation study and the Connecticut Light and Power Company ("CLCP") "Plan it Wise" energy pilot. The residential reference load information is based on SDG&E's load research sample of central air conditioning customers. The small commercial part of the forecast uses SDG&E's dynamic load profile shape for the reference load combined with the ex-post Auto-DR measurement and the final evaluation results filed in April of 2011.

The Summer Saver forecast is the same forecast filed in April of 2011. The PTR forecast has been updated to reflect what was filed on April 1st 2011. The PTR forecast was modified from the 2010 filing to account for new study results from other utility pilots such as the Connecticut Plan it Wise pilot that compare the performance of voluntary critical peak pricing to voluntary PTR.

The forecast in Table KS-5 below is a portfolio forecast. The results for each program can be added together without double counting. The forecast assumes that SDG&E's proposal to end dual participation between CPP-D and CBP, and BIP is adopted. The forecast predicts that when customers are given a choice to either remain on their voluntary demand response program or remain on CPP-D the customers choose to remain on their voluntary demand response program. The SCTD estimates are incremental to PTR.

More detailed monthly forecast for each year for a 1-in-2 and 1-in-10 weather year are available in Appendix A of this testimony. In addition, as required by the guidance document the monthly 2011 demand response forecast adopted by the CPUC for RA as qualifying capacity is also included in Appendix A of this testimony.

Table KS-5 Portfolio Load Impact Forecast August 1 in 2 Peak Day 1pm-6pm (MW)				
DR Activities -	**2011**	**2012**	**2013**	**2014**
Day-Ahead Price Triggered				
PTR- Residential	0	69	70	71
CPPD - Large C&I (>200 kW)	13	12	12	12
CPPD - Medium C&I (20-200 kW)	0	0	26	26
CBP Day-Ahead	9	10	11	11
Small Customer Technology Deployment	0	6	10	12
Day-Of Price Triggered				
CBP Day-Of	20	22	24	26
Summer Saver	15	15	15	15
Day-Of Reliability Trigger				
BIP	7	10	13	16
Other DR Activities				
Permanent Load Shifting (PLS)	1	2	4	5
Total	65	146	185	194

V. EX-ANTE FORECAST DETAILS

1. Capacity Bidding Program (CBP)

The forecast for CBP and DemandSMART™ programs were very closely linked because both programs had similar structures and they target the same customers. The DemandSMART™ program was a bilateral contract whereas the CBP tariff is a standard offer available to any aggregator who chooses to participate. The DemandSMART™ program had a day-of trigger with a minimum notification of 30 minutes whereas the current CBP day-of program has a day-of trigger with a minimum of 3 hours notice. The CBP program allows the aggregator to nominate each month. The performance structure for CBP adjusts the capacity payments when the nominated value or committed load reduction is not reached. Customers with a maximum demand of > 20 kW are eligible for CBP. Given that the program structures between CBP and DemandSMART ™ were so similar, the discontinuation of the DSP program directly affects the CBP forecast. Therefore the CBP forecast presented in this testimony has been updated since the forecasts filed in April of 2011 to take into account 2010 ex-post information and the fact that the DSP has been discontinued.

Table KS-6 below shows the average load impacts for the CBP and DSP programs from 2007 through 2010. Although the weather on event days was not identical for each year, these ex-post average event day results are a good general indicator of the nature of program growth. The CBP program grew steadily through 2009. The DSP program began in 2010. The drop in the day-of CBP between 2009 and 2010 is due in large part to the fact that many customers left the CBP day-of program and moved over to the DSP program. SDG&E believes that the termination of the DSP program will result in customers moving back over to day-of CBP. Although a large number of customers did move between CBP and DSP in 2010, a smaller growth of 3.2 MW was still achieved for the total of the two programs together. This growth rate has been applied to the ex-ante load impacts for the CBP programs going forward.

Table KS-6

Ex-Post M&E Load Impact average event day (MW)

Year	CBP DA	CBP DO	DemandSMART™	Total	Growth
2007	6.6	1.2	0	7.8	7.8
2008	10.3	6.2	0	16.5	8.7
2009	10.3	12.5	0	22.8	6.3
2010	9.6	8.6	7.8	26.0	3.2

Table KS-7 CBP load impact forecast 2011-2014 (MW)				
Program	**2011**	**2012**	**2013**	**2014**
CBP Day-Ahead	9.3	10.2	11.1	11.3
CBP Day-Of	19.6	21.8	23.8	25.7
Total	28.8	32.0	34.9	37.0

Table KS-7 shows the 2011 – 2014 forecast for SDG&E's CBP. The CBP day-ahead program forecast assumes the load impact results for 2011 are very similar to the 2010 ex-post results. The 2012-2014 forecast assumes that very modest growth occurs due to the CBP program improvements proposed by SDG&E in this application for 2012-2014. The forecast also assumes that the elimination of CBP dual participation with CPP-D will result in a slight decrease in growth for the CBP program. The historical growth rate of approximately 6 MW per year is reduced to roughly 2 MW per year in the years of 2012-2014. The CBP day-ahead program assumes a very slight increase that is less than 1 MW per year.

2. BIP

The SDG&E BIP program currently has 20 accounts enrolled in BIP-A, the 30-minute notification option, and one customer enrolled in BIP-B, the 3-hour notification option. Customers enrolled on BIP receive a monthly capacity payment in exchange for pledging to reduce their load during events down to a firm service level on event days. Out-of-pocket penalties apply for failing to reduce to the firm service level. The trigger for this program is more restrictive than some of the other programs, therefore no BIP events were called in 2008 or 2009. However a test event was called in 2010 on September 27th. A CPP-D event was also called on the same day. According to the current tariff rules, CPP-D customers are not allowed to participate in a BIP event when CPP-D has been called. Therefore only the BIP customers not enrolled on CPP-D were notified of the BIP event. The BIP customers not enrolled on CPP-D provided a load reduction of 0.4 MW. Although the BIP customers enrolled on CPP-D were not notified of the BIP event and were not subject to BIP penalties, they reduced their load 4.0 MW in response to the CPP-D price signal. A full load reduction all the way down to their firm service level would have been a 5 MW reduction for the BIP customers enrolled on CPP-D.

The ex-ante analysis predicts that since the CPP-D BIP customers responded so well to CPP-D events they will reduce their load down to their firm service level for an actual BIP event. The forecast assumes that the currently enrolled non-CPP BIP customers would continue to reduce to the same level they reduced to in the test event. This results in an overall compliance rate of 70% which is the compliance rate use for all new customers joining the program. Previously this program has not been marketed by SDG&E, but the goal for 2014 is for the program to grow to 15 MW. Given that the BIP programs at PG&E and SCE are substantially larger than the SDG&E BIP program, this goal is reasonable.

3. Summer Saver

The Summer Saver ex-ante forecast presented in this testimony has been updated to include the April 1st 2011 load impact report results. This program was already approved by contract and therefore is not up for approval in this proceeding and is not being cost-effectiveness tested in this proceeding. Therefore the load impacts are being provided only for informational purposes. The aggregate program load reduction potential for residential customers is 10 MW for a typical event day under 1-in-2 year weather conditions and approximately 5 MW for the commercial customers for a total of 15 MWs program-wide.

4. TI forecast

Beginning in 2012, SDG&E proposes to eliminate the semi-automated option of the TI program and only to offer utility-controlled Auto-DR. Therefore all customers forecasted to be enrolled in the TI program from 2012-2014 are Auto-DR customers. The existing semi-automated TI customers are still included in the Auto-DR forecast but the load impacts are held constant and no new growth is included in the forecast. In 2010 on average 7 % of the CBP day-ahead load impacts and 12% of CBP day-of load impacts came from customers enrolled in TI. The load impact forecast for the CBP day-ahead TI program assumes that no new TI customers join. The percentage of CBP load impacts achieved through the future TI program remains at 12% the same as it was in 2010. For the CPP-D program the forecast filed previously in April of 2010 assumed that the CPP-D TI load impacts would grow at 0.6 MW per year from 2010 through 2014. Since SDG&E proposes in this proceeding to offer a payment to aggregators for enrolling CPP-D customers onto Auto-DR, the incremental Auto-DR growth rate is now forecasted to be 0.6 MW for 2010-2011, 1.0 MW for 2011-2012, 1.5 MW for 2012-2013, and 1.5 MW for 2013-2014. Although BIP customers are allowed to participate on TI, the TI forecast for BIP customers is zero given that all the customers enrolled on this program in summer of 2010 pledged reduce their loads to zero or near zero. The total TI forecast for 2011-2014 for is presented in Table KS-8 below.

Table KS-8

Ex-Ante Auto-DR Load Impacts August Peak Day

Year	CPP-D Auto-DR	CBP Day-Ahead Auto-DR	CBP Day-Of Auto-DR	Total
2011	1.5	0.7	2.3	4.5
2012	2.5	0.7	2.5	5.7
2013	4.0	0.7	2.8	7.5
2014	5.5	0.7	3.0	9.2

The SDG&E PLS program is also a technology program. For 2012-2014 the PLS program will not be restricted to two types of PLS technology like it was for the 2009-2011 cycle. Any technology that qualifies as PLS will be eligible. The program is predicted to grow to 2 MW in 2012, 4 MW in 2013, and 5 MW in 2014.

5. PTR

The MW estimates for PTR were calculated following the load impact protocols. Due to new information from PTR pilot results, some adjustments have been made to the assumptions used in the previous PTR forecast filed. A key assumption in the previous PTR forecast was that PTR will provide the same percentage load impacts as a CPP rate for customers who are aware of PTR. This assumption was justified by two PTR pilots. The first pilot was the Anaheim PTR pilot conducted in 2005[3]. This pilot only offered a PTR rate but SDG&E compared the results of the Anaheim pilot to the results of California Statewide Pricing Pilot which offered critical peak pricing rates. Comparing the two studies showed the load reduction from PTR and CPP rates were very similar. The second pilot was the Baltimore Gas and Electric 2008 pilot[4] which tested the effect of critical peak pricing rate and PTR programs on customer behavior and showed similar load reduction for critical peak pricing and PTR. The differences between the load reductions from CPP and PTR were statistically insignificant in this pilot. On account of these two pilots, all PTR forecasts filed previously have assumed that PTR would provide the same percentage reduction as CPP. However results from two other pilots became available in 2010 that show different load impacts between CPP rates and PTR rates. The Power Cents DC program final report[5] published in September of 2010 showed a percentage load reduction of

[3] Residential Customer Response to Real Time Pricing: The Anaheim Critical Peak Pricing Experiment Frank Wolak March 14th 2006
[4] BGE's Smart Energy Pricing Pilot Summer 2008 Impact Evaluation April 2009 Brattle Group
[5] PowerCents DC Program Final Report September 2010 E-Meter strategic consulting

34% for a CPP rate versus a 13% load reduction for a PTR rate. Also the Connecticut Plan it Wise pilot[6] results showed a 16.1% load reduction in response to a CPP rate versus a 10.9% response rate for PTR. The PTR forecast filed in this testimony assumes that PTR impacts for aware customer will be 67% of CPP impacts would be, based on the Connecticut pilot. The awareness rate for PTR used in the PTR forecast is 50% which is consistent with AMI Decision D.07-04-043. The reference load the PTR load impacts calculated uses the forecasted residential load for an August monthly peak 1-in-2 day as required by the load impact protocols. The meter deployment rate for residential electric AMI meters is on time with 1.3 million Smart Meters meter currently installed. Therefore the 2012 through 2014 PTR forecast assumes full Smart Meter deployment.

6. Small Customer Technology Deployment

The Small Customer Technology Deployment program ("SCTD") is a new program that will provide enabling technology to residential customers and small commercial customers. For residential customers the two major technologies that are accounted for in the load impact forecast for this program are pool pumps and programmable thermostats. No incentives other than the enabling technology itself are provided; all residential customers will be enrolled in PTR by 2012. Since PTR will be in place it is also important that the incremental impacts of enabling technology above the PTR impact alone be estimated.

Previous SDG&E Smart Thermostat studies and Summer Saver studies have shown that one factor that decreases the load impacts and cost-effectiveness of these programs is that customers who never or seldom use their air conditioners join the program and receive an incentive. The SCTD program improves this issue in two ways. One way this issue is improved is that no flat incentive is provided. Only a PTR incentive is provided and a PTR incentive is

[6] CL&P's Plan-it Wise Program Summer 2009 Impact Evaluation Brattle Group

only paid if a customer's usage is lower than their customer reference level. The other improvement this program makes is that Smart Meter data will be used to market the program to customers likely to have high on-peak air conditioner usage. Hourly Smart Meter whole house data can be used to identify customers who are likely to use their air conditioner on-peak. In order to estimate the effects that targeting customers using hourly whole house Smart Meter data will have on the load impacts, Freeman, Sullivan and Company ("FSC") conducted analysis on behalf of SDG&E using the load data from the load research air conditioning sample. This sample is a randomly selected sample of customers with central air conditioning. These customers have a meter both on their home and on their air conditioner. Using the whole house data only, FSC ran a regression model and identified the top 35% of customer most likely to have high on-peak air conditioning usage. The air conditioning usage of these top customers was then used to create the reference load for the residential Programmable Communicating Thermostat ("PCT") forecast.

The percentage load impacts for residential PCT program are incremental to the PTR percentage load impacts for the 50% of customers who are aware of PTR events. For the 50% of customers unaware of PTR events, the full percentage load reduction achieved by PCT was used. The full percentage load reduction used for the forecast comes from the SDG&E Smart Thermostat studies. The incremental load reduction above and beyond the PTR rate was informed by the Connecticut "Plan it Wise" pilot. This pilot offered both a PTR rate and a PTR rate with enabling technology to customers. Based on the results of this pilot a 16% incremental impact of enabling technology was assumed for the 50% of customers being aware of PTR events. The 16% is the percentage of air conditioning load reduced, not the percentage of whole house load reduced. The load impacts from pool pumps were calculated based on a pool pump demand response potential study[7] conducted by SCE. The forecasted number of residential customers enrolled in the pilot is 7,500 by 2012, 12,500 by 2013, and 15,000 by 2014. One-third of participants are forecasted to accept pool pump technology.

The small customer technology deployment program will also provide enabling technology to small commercial customers enrolled on the Peak Shift at Home rate. The reference load for the small commercial forecast is based on SDG&E dynamic load profile hourly small commercial customer load shape. Since the Statewide Pricing Pilot small commercial update results[8] showed no statically significant load reduction in response to the CPP rate alone an incremental load impact forecast is not necessary. The percentage load impact in response to enabling technology used in the forecast is 19.3% consistent with the 2009 SDG&E CPP-D Auto-DR M&E results. The forecast assumes that 1,000 customers enroll by 2012, 2,000 by 2013, and 3,000 by 2014.

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[7] Pool Pump Demand Response Potential June 2008 Design and Engineering Services SCE
[8] California Statewide Pricing Pilot Commercial and Industrial Analysis Update June 28 2006 CRA International

VI. MEASUREMENT AND EVALUATION BUDGET FOR 2012-2014

The CPUC adopted the load impact protocols in D.08-04-51. This decision requires that every demand response activity including voluntary demand response programs and dynamic rates be evaluated every year by April 1st. These evaluations must include all the output required by the load impact protocols. Examples of the output requirements are hourly ex-post results for each event; the hourly reference load for each event; confidence intervals for each ex-post event; and a monthly hourly 10-year forecast for each program for 24 different temperatures. The complete outputs provided by reports following these protocols have been useful in many ways. The availability of complete 24 hour ex-post program level estimates has been useful for answering data requests from the California Independent System Operator ("CAISO") as well as SDG&E resource planners who need to be able to add the hourly demand response load impacts back to the system load in order to determine what the system load would have been without demand response. Additionally, the monthly ex-ante forecasts are used each year in the Resource Adequacy ("RA") proceeding and the forecasts are also useful for other long term resource planning proceedings. The hourly ex-ante forecast has been used to double check internal hourly short term forecasts that are required to be sent to SDG&E's electric procurement group, the CAISO and the Energy Division when demand response events are called. The evaluation reports that followed the requirement of the load impact protocols are more complete than the previous load impact reports which reduces the frequency of analysts going back to an older evaluation report but not being able to find the desired information. Therefore, a major goal of the measurement and evaluation ("M&E") budget is to fund the load impact evaluations as required by the CPUC.

Since the load impact protocol requirements apply to both dynamic rates and voluntary demand response programs, both are included in the M&E budget presented in Table KS-9 below. This budget includes funding for the evaluation of dynamic rates like PTR and CPP-D that were approved in the SDG&E's GRC Phase 2 D.08-02-034. The 2009-2011 M&E budget for these two dynamic rates was adopted by the CPUC in D.09-08-027. This budget also includes funding for the evaluations of two dynamic rates that have been proposed by SDG&E in A.10-07-009.

These are the Peak Shift at Home rate ("PSH") which is a critical peak pricing program for residential customers and the Peak Shift at Work rate ("PSW") which is a default critical peak pricing program for small commercial customers. The testimony of Bill Saxe Chapter 3 page WGS-30 lines 6-11 and the testimony of Glen Breed page GCB-39 lines 19-23 in A.10-07-009 explain that measurement and evaluation funding for the PSH and PSW will be requested in this proceeding. Since the load impact protocols apply to both voluntary demand response programs and dynamic rates, keeping the evaluation budget for all load impact protocols required evaluation studies in one proceeding is preferred by SDG&E.

For budget planning there are four main categories that programs fall into. The first category is existing statewide demand response activities for which the load impact evaluation are conducted statewide. This category includes CBP, BIP, CPP-D, PTR and TA/TI. The budget for CBP, BIP and TA/TI includes SDG&E portion of the costs of a statewide load impact evaluation for each year. No funding for process/marketing evaluations is included in the budget for these three programs since these programs have been in place for several years. However, since roughly 20,000 new medium commercial customers will be defaulted to CPP-D in 2013 funding for one process evaluation along with the annual statewide load impact evaluations is included in the budget. Similarly, since PTR is also new, funding for one process/marketing evaluation is included along with funding for the annual load impact evaluations

The second category includes both new and existing demand response activities that SDG&E will need to conduct annual load impact studies for. For existing programs this includes the Summer Saver program evaluated by SDG&E. Future activities in this category include the PSW, PSH, SCTD and PLS. Since PSW, PSH, and SCTD are new, funding for one process/marketing evaluation is included in the budget. In addition, funding for annual load impact evaluations are also included in the budget. SCTD has a higher budget because it includes both the small commercial and residential programs.

The third category "Other Evaluation Activities" includes a line item called Customer Research Studies. Customer Research Studies include funding for studies that are not program specific evaluations. Examples of some of the historical customer research studies include potential studies, baseline studies, or high load high variance studies. The end-use metering category includes funding for data loggers that can be used to meter air conditioner usage and possibly other end uses. The demand response forecast application development category includes the ongoing costs of maintaining the demand response forecasting software that SDG&E has implemented and customized so that hourly forecasts of demand response load impacts can be provided to SDG&E's electric procurement group and to the CAISO as required by MTRU. The last category shows the labor required to support these demand response studies. SDG&E is requesting two full-time employees (FTEs) to support these studies.

Table KS-9 2012-2014 Measurement and Evaluation Budget			
SDG&E M&E Activities	**2012**	**2013**	**2014**
Statewide Program Evaluations			
Critical Peak Pricing Default	$100,000	$175,000	$75,000
Peak Time Rebate	$300,000	$175,000	$175,000
Base Interruptible Program	$30,000	$30,000	$30,000
TA and TI	$15,000	$65,000	$15,000
Capacity Bidding Program	$50,000	$50,000	$50,000
SDG&E Evaluations			
Summer Saver	$175,000	$250,000	$175,000
Small Customer Technology Deployment	$350,000	$150,000	$150,000
Peak Shift at Work	$0	$150,000	$75,000
Peak Shift at Home	$0	$200,000	$100,000
Permanent Load Shifting Evaluation	$25,000	$25,000	$25,000
Other Evaluation Activities			
Customer Research Studies	$100,000	$100,000	$100,000
Demand Response Forecasting App Development	$50,000	$50,000	$50,000
End Use Metering	$260,000	$260,000	$260,000
Labor to support studies			
M&E Analytical Support 2 FTE's	$220,458	$233,116	$246,525
Total M&E related costs	$2,295,422	$2,458,116	$1,946,525

VII. CAPACITY BIDDING BASELINE ANALYSIS

In the final decision on the 2009-2011 demand response program filing D.09-08-027 the CPUC adopted a new statewide baseline for the CBP program along with a few other programs. At SDG&E the only program affected was the CBP program. The baseline adopted consists of the average of the previous 10 non-event weekday days with a same-day adjustment. The adjustment is equal to the ratio of the usage the first three of the 4 hours prior to the event on the event day divided by the usage during the first three of the 4 hours prior to the event hour in the baseline calculation. The adjustment factor was capped at 20% and therefore could be no lower than 0.8 or higher than 1.2. The baseline is calculated individually for each customer, the cap is applied individually for each customer, and then the results for each customer are summed to get the result for the aggregator. For the remainder of this testimony this baseline will be referred to as the individual 10-in-10 adjusted baseline with a 20% cap.

SDG&E proposes to change the CBP baseline to an aggregate 10-in-10 baseline with a same-day adjustment with a 40% cap. The reason for the change is that both the Highly-Volatile Load Customer study conducted by Christensen Consulting and SDG&E 2010 CBP event results have demonstrated the 10-in-10 individual baseline with a 20% cap on the adjustment is inaccurate and is underestimating the program performance and aggregator payments. This change in baseline is necessary to ensure the continued success of the CBP program.

The 10-in-10 individual baseline with a same-day adjustment was shown to be highly accurate in two studies that were cited in the decision D.09-08-027. One was the KEMA 2003 baseline study[9] and the other was the Quantum 2006 baseline study[10]. However, the 20% cap was a new addition to the baseline which had not been studied. The KEMA 2003 study had used no cap on the baseline adjustment and the Quantum study adjustment factor could be no greater than 2 (100% cap) and could be no lower than 0.5. (50% cap) Thus the adoption of the 20% cap was a substantial deviation from the baseline that had been used in these previous measurement and evaluation studies that described the range in which the baseline was considered accurate.

[9] Protocol Development for Demand Response Calculation Findings and Recommendations KEMA-XENERGY Feb 2003

[10] Evaluation OF 2005 Statewide Large Non-residential day-ahead and reliability Demand response programs April 28th 2006 Quantum Consulting p 6-12

However, the decision also required that a high load high variance study be conducted that would provide a definition of high load high variance customers. The study would also report the number of customers who chose the same-day adjustment who also went over the cap. The Highly–Volatile Load Customer ("HVLC") study conducted by Christensen Associates shows in the executive summary in table ES-3 that 55% of SDG&E, 55% of SCE, and 56% of PG&E CBP customers exceeded the 20% cap for at least hour of one event. In addition the study shows that exceeding the cap was not just a one event or one hour occurrence for most customers. When CBP customers did exceed the cap they did so for an average of 52% of the event hours for SDG&E, 69% for SCE, and 63% for PG&E. This demonstrates that for the majority of the customers and for a very high percentage of hours, adjustment factors of greater than 1.2 are necessary in order to properly estimate load changes in response to weather or other factors.

One reason so many customers went over this cap is that the cap is applied at the individual customer level rather than at the aggregate portfolio level for the aggregators. For example, if an aggregator has three customers of equal size enrolled in their program and one customer requires a 1.10 adjustment factor, a second a 1.05 adjustment factor and a third a 1.35 adjustment factor, if the cap is applied individually, the baseline of the third customer will be capped. If the results for all three customers are added together first, the overall adjustment required for the portfolio is only 1.17 and nothing needs to be capped. Since the vast majority of adjustment factors go up rather than down due to the fact that demand response events typically have hotter weather than the previous days, a baseline cap applied at the individual level will usually produce a lower load impact result than when the cap is applied at the aggregate level. Therefore individual baselines with caps are more likely to underestimate demand response results than aggregate baseline with caps.

While the results from the HVLC study showing the large number of customers with adjustment factors over the cap provide very strong evidence that the cap is too low, the real test is whether or not the capped baseline provides accurate results. SDG&E analysis comparing the results from individual 10-in-10 baseline with the 20% cap to the 2010 M&E results show that the baselines are producing impacts that are significantly lower than measurement and evaluation results. The effects of the underestimation on aggregator's payments are compounded by the performance structure of the CBP program. According to the CBP performance structure, if the aggregator achieves less than 90% of their nomination, their payment is reduced by 50%; if they achieve less than 75% of their nomination they receive no payment. In terms of the baseline this means that if an aggregator's customers perform but the baseline underestimates the load reduction by 11%, the aggregator is underpaid by 50%; if the baseline underestimates the load reduction by 26% then the aggregator receives no payment at all. Therefore it is imperative that the CBP program use a baseline that is very accurate for the vast majority of customers.

Table KS-10 below shows the results of the individual 10-in-10 adjusted 20% cap baseline as a percentage of the M&E results for each month for the CBP day-ahead, CBP day-of and the DemandSMART™ program. Even though SDG&E has discontinued its DemandSMART™ program, the results are still relevant to the information about the accuracy of the baseline in general. SDG&E also forecasts that the current DSP customers will become CBP day of program participants. The results for the CBP day-ahead program were the most accurate, although the 85% of M&E result for July would have caused a 50% underpayment. CBP day-of baseline results for July and September are less than 75% of the M&E results, which if the entire program were one aggregator would result in a zero payment. The DemandSMART™ results performed the worst with the baseline as it was well under 75% of

M&E results for both July and August. The negative value in September indicates that the baseline predicted that customers increased load when in fact according to the M&E they reduced load.

Table KS-10 Baseline Load impacts as a percentage of draft 2010 M&E results				
Baseline	**Program**	**July**	**August**	**September**
10 in 10 individual 20% cap	CBP Day-Ahead	85%	95%	96%
10 in 10 individual 20% cap	CBP Day-Of	71%	89%	68%
10 in 10 individual 20% cap	DemandSMART™	51%	61%	-22%

Since the individual 10-in-10 baseline with a 20% cap is clearly underestimating load impacts and aggregate baselines with caps are less likely to underestimate than individual caps, a logical option to consider is switching to an aggregate baseline but keeping the 20% cap. Table KS-11 shows that the aggregate baseline with a 20% cap is in fact an improvement over the individual baseline but it still significantly below the load impact M&E results for day-of CBP in July and September and for DemandSMART™ in all months. Assuming the entire program is one portfolio and that the nomination was equal to the M&E results for day-of CBP, an underpayment of 50% would still occur in July and September, and for DemandSMART™ a zero payment would have been made for July and out-of-pocket penalties would have been charged for September even with the aggregated baseline.

Table KS-11 Baseline Load impact as a percentage of draft 2010 M&E results				
Baseline	**Program**	**July**	**August**	**September**
10 in 10 aggregate 20% cap	CBP Day-Ahead	94%	101%	104%
10 in 10 aggregate 20% cap	CBP Day-Of	83%	100%	75%
10 in 10 aggregate 20% cap	DemandSMART™	61%	78%	-9%

SDG&E carefully investigated how high the cap should be to improve the accuracy of the baseline. SDG&E suggests that an aggregate 10-in-10 baseline with a 40% cap is more accurate than the aggregate baseline with a 20% cap. With this baseline the results for both the CBP day-ahead and CBP day-of programs are at least 90% of the M&E results. There are some very minor overestimations of 104% for September day-ahead CBP and 104% for August day-of CBP. However, CBP payments are capped at the nominated load reduction so if the aggregator had nominated the M&E results no overpayment would have occurred. Due to the load shapes of the participating customers, this baseline is still under 90% of the measurement and evaluation results for DemandSMART™ for July and September.

Table KS-12
Baseline Load impacts as a percentage of draft 2010 M&E results

Baseline	Program	July	August	September
10 in 10 aggregate 40% cap	CBP Day-Ahead	102%	100%	104%
10 in 10 aggregate 40% cap	CBP Day-Of	95%	104%	91%
10 in 10 aggregate 40% cap	DemandSMART™	86%	108%	31%

Another reasonable question is whether or not there should be any cap on the baseline at all. Any cap is somewhat arbitrary and may work for some customers or weather scenarios but not for others. The baseline studies conducted by KEMA and Quantum Consulting of the 10-in-10 with no cap or a very high cap have shown that the 10-in-10 baseline is still accurate under these circumstances. One reason the cap was included for the baseline initially was to prevent participants from "gaming" the baseline results. Since the baseline uses the load data before the event occurs it is possible for a participant to increase their usage before the event begins in order to increase the baseline. However, the CBP program has other factors in place that discourage gaming besides the cap. The performance structure itself is a significant deterrent to gaming of the baseline. It is not possible with the CBP performance structure for a participant to game the baseline on an occasional basis. There is only one nomination for the entire month, no payments above the nominated value can be made, and payments are sharply reduced to zero or even to out-of-pocket penalties for results lower than the nominated results. In addition the same day adjustment omits the hour right before the event and uses three entire hours of pre-event usage. Therefore a customer would have to increase their morning load for a solid three hours in order to have a substantial affect on the baseline.

SDG&E proposes to implement a 40% cap on the aggregate baseline as its method to compensate CBP performance. Since it is difficult but not impossible to game the baseline, SDG&E is not proposing to remove the baseline cap completely. SDG&E does however believe that the current baseline which is at a 20% individual cap is inaccurate and is underestimating program performance and aggregator payments. Because the CBP program structure has other attributes that prevent overpayment besides the cap, SDG&E is comfortable increasing the cap to 40%. SDG&E's CBP program is a successful program according to measurement and evaluation load impact studies. SDG&E's proposal to change to a more accurate 10-in-10 aggregate baseline with a 40% cap will help ensure the continued success of this program.

VIII. QUALIFICATIONS – KATHRYN SMITH

My name is Kathryn E. Smith. My business address is 8306 Century Park Court, San Diego, California, 92123-1569. I am employed by San Diego Gas & Electric Company ("SDG&E") as a Senior Market Advisor in the Load Research Department. In my position I am responsible for providing statistical analysis related to electric load research.

I graduated from the University of California Berkeley with a Bachelor of Arts degree in Mathematics in 1999. I received a Master of Science in Statistics from San Diego State University in 2004. I have been employed by SDG&E and Sempra Energy in the Load Research department since 2005.

I have previously testified before the Commission.

IX. QUALIFICATIONS – LESLIE WILLOUGHBY

My name is Leslie Willoughby. My business address is 8306 Century Park Court, San Diego, California 92123. I am employed by San Diego Gas & Electric Company ("SDG&E") as Electric Load Analysis Manager in the Strategic Analysis and Pricing Department. In my current position, I am responsible for managing and conducting load and energy research analysis.

I attended San Diego State University in San Diego, CA, where I graduated with a Bachelor of Science in Business Administration in 1983. I continued to attend San Diego State University where I graduated with an MA in Economics in 1989. In 1990, I was employed by SDG&E to work in the Load Research Section of the Marketing Department as an Associate Economic Analyst. Over the past 20 years I have held positions of increasing responsibility within the company that have included Load and Energy Research. I have previously testified before the Commission.