BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements	Rulemaking 13-09-011 (Filed September 19, 2013)

SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) 2015-2016 DEMAND RESPONSE PROGRAM PROPOSALS AND RESPONSE TO ADDITIONAL INFORMATION PURSUANT TO THE ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING PROVIDING GUIDANCE FOR SUBMITTING DEMAND RESPONSE PROGRAMS

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I. EXECUTIVE SUMMARY

San Diego Gas & Electric Company ("SDG&E") submits this request for approval of its 2015-2016 Demand Response Program ("DRP") proposals and response to request for additional information in accordance with the guidance provided in the January 31, 2014 *Assigned Commissioner and Administrative Law Judges' Ruling Providing Guidance for Submitting Demand Response Program Proposals* ("Ruling"). As discussed in further detail below, SDG&E seeks Commission authority to: (1) implement the revisions to selected DR programs; and (2) approve a two year portfolio budget of $42,210,940 to continue its DR programs in 2015-2016, with budgets of $20,629,469 for 2015 and $21,581,471 for 2016, respectively.

A brief discussion of the various program proposals are provided below with detailed discussions for the specific programs and budgets in the following Appendices: Appendix A—SDG&E DR 2015-2016 Proposed Budget; Appendix B—Program Implementation Plans with Changes; Appendix C—Program Implementation Plans without Changes; Appendix D—Proposed Tariffs, Schedules and Contract Changes, and Appendix E—December 2013 Monthly Expenditure Report.

In addition to its 2015-2016 DRP Portfolio proposals, SDG&E provides its response to questions 2 and 3 as outlined in Section 4 of the Ruling.

II. BACKGROUND

SDG&E's current 2012-2014 Demand Response Programs ("DRP") portfolio, and associated budgets, were approved by the Commission in Decision ("D.") 12-04-045, dated April 19, 2012 (as later corrected by D.12-08-023, dated August 20, 2012 to correct inadvertent errors and mathematical errors in D.12-04-045). SDG&E's current three-year DRP budget, as adopted by these decisions, is $65,806,526 (See, D.12-04-045, at pages 194 to195.)

Immediately following the issuance of D. 12-04-045, and in response to the outage of the San Onofre Nuclear Generating Station ("SONGS"), SDG&E received direction from the Energy Division, by letter dated April 25, 2012 to file a Tier 3 Advice Letter proposing DRP program augmentations and improvements to be effective no later than July 1, 2012. In response, SDG&E filed Advice Letter 2351-E on April 30, 2012, proposing modifications to its Schedule PTR—Peak Time Rebate Program, to slightly expand the scope of that program, and the establishment of a new SummerGen 2012 program, both proposed to be funded through budget fund-shifts from existing, approved DRP program budgets.

The Commission approved SDG&E's proposed revisions to Schedule PTR, and the establishment of a corresponding budget of $6.4 through a budget fund shift from the Capacity Bidding Program, through Resolution E-4502, dated May 24, 2012. SDG&E subsequently withdrew the proposal to establish the SummerGen 2012 program.

Subsequently, SDG&E filed Advice Letter 2370-E, dated June 1, 2012, to propose the establishment of a new Demand Bidding 2012 Program ("DBP"), to be funded by a proposed budget fund shift from an existing, approved DRP program budget. The Commission approved

SDG&E's establishment of DBP and its proposed budget by Resolution E-4511, dated July 12, 2012, as well as the budget shift of $1.8 million from the Base Interruptible Program ("BIP") to fund DBP for 2012.

Both the PTR revisions and the new DBP program were proposed and authorized for 2012 as near-term augmentations in what was then anticipated to be a temporary SONGS outage. When it later appeared that the outage might last longer than anticipated, SDG&E received further direction from the Energy Division on November 16, 2012 to file an Application proposing additional DRP augmentations for 2013 and 2014 in light of the continuing SONGS outage. In response, SDG&E filed Application ("A.") 12-12-016 on December 21, 2002.

Through A. 12-12-016, SDG&E proposed a series of DRP portfolio and budget augmentations for 2013 – 2014, to include the following:

(1) An increase of $1.6 million to SDG&E's previously authorized DRP budget for 2012 – 2014 to fund the DBP and expanded Customer Education, Awareness and Outreach ("CEAO") activities.

(2) A budget fund-shift of $4.9 million of unspent, previously authorized budget funds (pursuant to Resolution E-4511) for the PTR program back to the original source program, CBP, in an effort to restore CBP to its previously authorized full budget.

(3) Continuation of the previously authorized DBP program, with certain modifications, most notably the establishment of a new, day-of, 30-minute notice product, and continue the budget funding of DBP through the budget fund-shift from BIP as authorized by Resolution E-4511.

(4) Authorization to issue a new Request for Proposals ("RFP") solicitation to seek proposals from third-party vendors for new programs and technologies to implement load control programs.

(5) Authorization of a proposed new Community Partners initiative element of SDG&E's CEAO program to continue and expand to include south Orange County Community-Based Organizations.

The Commission approved the proposals SDG&E submitted through A. 12-12-016 in D. 13-04-017, dated April 18, 2013.

On September 19, 2013, the Commission issued its Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements (R. 13-09-011). As part of this rulemaking, the Commission indicated that it would be considering the impact on the IOU's next DRP cycle applications, and the possibility of adopting a one or two year Bridge Funding cycle to allow existing programs to continue, with some modification as the Commission and parties proceeded with the issues raised by R. 13-09-011.

As a result, on January 22, 2014, the Commission issued D.14-01-004, approving two years of bridge funding for the DRP programs in 2015 and 2016, and indicating that, "…it would be practical to revise the programs on a narrow basis to improve their success." On January 31, 2014, the Commission issued the Ruling, which, among other things, directed the IOU's to file their proposals for program improvements for 2015 – 2016.

III. SDG&E 2015-2016 DEMAND RESPONSE PROGRAM PROPOSALS

SDG&E's 2015-2016 DRP proposals, as described below, include enhancements or changes to some of programs designed to result in improvement to program performance, but without any change to the capped portfolio budget amount approved for 2013-2014 in D.12-04-045 and D.13-04-017. SDG&E expects that, should the Commission approve its program proposals, the program changes will be implementable within 90 days of the Commission's approval and completely updated no later than December 31, 2014.

A. PROGRAMS AND ACTIVITIES WITH MODIFICATIONS

In the following sections, SDG&E describes the various propose program enhancements and budget adjustments to specific programs and activities. These enhancements and budget adjustments are designed to improve customer participation and experience, and ensure that the overall portfolio is cost effective. Detailed PIPs are set forth in Appendix B.

1. Capacity Bidding Program ("CBP")

SDG&E is proposing several changes to the Capacity Bidding Program (CBP) all of which are designed to increase participation and improve program flexibility. SDG&E is proposing to add a 30-minute option to CBP with an incentive that is 15% higher than the current day-of incentive. We anticipate having residual Demand Response for this program because of this new product. The 30-minute notification product can be very valuable to SDG&E as it explores bidding this program into the CAISO wholesale markets in the near future. SDG&E is also proposing to allow non-residential customers with demand less than 20 kW to participate in the program. This adjustment is intended to open the program to small agricultural customers who have pumping load that can be shed quickly but may not meet the existing 20 KW threshold. A third party aggregator has concurred that eliminating the 20 KW minimum load drop would increase program participation and provide underserved nonresidential customers of 20 KW and below. Finally, SDG&E proposes to adjust the penalty structure to make it less complicated.

2. Demand Bidding Program ("DBP")

D.13-04-017 approved DBP revisions for SDG&E for 2013 and 2014. These revisions included incentives to non-residential customers capable of providing at least 5 megawatts (MW) of load reduction during a program event. This program was later refined to provide incentives for: (1) a DBP-Day Of ("DBP-DO") 30-minute product available to customers who would provide a 5 MW load drop; and (2) a Day Ahead product with specific triggers designed for the United States Navy ("DBP-N").

Planning for 2015-2016, SDG&E solicited feedback from DBP customers to identify what worked well and what can be improved. Based on the feedback received, SDG&E proposes to continue both products with the following changes:

(1) Increase the DBP-DO energy payment from $500/MWH to $600/MWH. DBP-DO would also require customers to reduce up to 60% of their bid in order to receive payment. This change would result in a revised Cost Effectiveness ratio of 2.02.

(2) For the DBP-N, the energy payment would increase from $400/MWH to $500/MWH and changing the minimum load reduction from 3MW to 2MW. This change would result in a revised Cost Effectiveness ratio of 2.45.

3. Local Marketing Education & Outreach ("LMEO")

The Local Marketing, Education and Outreach ("LMEO") program encompasses local program specific marketing, education and outreach efforts for the 2015-2016 implementation of SDG&E's Peak Time Rebate (also known as Reduce Your Use, or "RYU"), Small Customer Technology Deployment (also known as Reduce Your Use Thermostat, or "RYUT"), Permanent Load Shifting program, Technology Incentives, CPP-D and various Smart Pricing dynamic rates.

For the 2015-2016, LMEO consolidates the previous marketing programs; Customer Education Awareness and Outreach ("CEAO") and Other Local Marketing ("OLM") efforts. The total budget request for LMEO for the 2015-2016 program cycle is $3.7 million dollars, a reduction of 8% from the 2013-2014 combined approved CEAO and OLM budget of $4,030,000.

Pursuant to D.12-04-045, Ordering Paragraph 22, SDG&E has re-categorized the individual Demand Response program marketing requests into one consolidated LMEO program, which is a subcategory of the Marketing, Education and Outreach category. In addition, SDG&E is consolidating the various education and outreach costs related to dynamic pricing and its CPP-D rates (Critical Peak Pricing –Default for our commercial customers) in this filing. Due to the similarities between the dynamic rates adopted in D.12-12-004 and CPP-D (which is also a "dynamic rate"). This budget consolidation is consistent with the direction in D.12-12-004 (at page 56),

> "(W)e require SDG&E to recover post-2015 costs related to the dynamic rates adopted in this decision in its future Demand Response Program and Budget cycle applications. This treatment will allow a review of any ongoing costs, including education and outreach costs related to dynamic pricing, in the context of an examination of similar activities. We believe that this will best ensure that SDG&E coordinates its future education and outreach efforts for energy efficiency, demand response, and dynamic pricing tariffs, and should assist in avoiding duplicative activities and expenditures. [1]

CPP-D will become the default for mid-size (20-200 KW) customers in 2015 and an increased level of marketing, education and outreach is necessary for this transition. With this consolidation, SDG&E will no longer request the CPP-D marketing, education and outreach funding in SDG&E's upcoming General Rate Case, which previously funded CPP-D efforts for the large (200kW+) commercial and industrial accounts.

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[1] *Decision Adopting a Dynamic Pricing Structure for Residential and Small Commercial Customers and Denying the Motion for Approval of a Settlement Agreement*, December 27, 2012.

Despite ordering a single-program consolidated budget for "other local marketing" in D.12-04-045, the current Demand Response monthly report requests that SDG&E break out program marketing by individual program. For tracking and recording purposes, SDG&E therefore submits individual line items for each program to fall within the LMEO program as is set forth below.

Program Name	2015 Budget	2016 Budget	Total 2015-2016 Budget
Reduce Your Use	$ 250,000.00	$ 250,000.00	$ 500,000.00
Reduce Your Use Thermostat (SCTD)	$ 400,000.00	$ 400,000.00	$ 800,000.00
Permanent Load Shifting	$ 25,000.00	$ 25,000.00	$ 50,000.00
Technology Incentives	$ 50,000.00	$ 50,000.00	$ 100,000.00
CPP-D	$ 750,000.00	$ 500,000.00	$ 1,250,000.00
Smart Pricing	*N/A (Funded from D.12-12-004)*	$ 1,000,000.00	$ 1,000,000.00
TOTAL	**$1,475,000.00**	**$2,225,000.00**	**$3,700,000.00**

The LMEO program will focus on SDG&E's specific customer needs, working to educate and enroll customers in SDG&E-specific demand response programs and dynamic rates. Marketing, education and outreach will also continue to engage customers around the need for demand response and event participation. Due to the cyclical and often localized nature of demand response events, this ongoing engagement is crucial to overall demand response program performance. The LMEO efforts will seek to enhance and leverage the overarching education efforts that will be conducted as part of the newly launched statewide marketing, education and outreach ("SWMEO") campaign while conducting education for SDG&E customers on demand response and dynamic rate opportunities that are available within its service territory, and encouraging participation in demand response events, which predominantly occur only at the local level.

4. Small Customer Technology Deployment Program ("SCTD")

The Small Customer Technology Deployment program will begin rolling out to customers in the first quarter of 2014. The program will offer programmable communicating thermostats ("PCTs") to residential customers at no cost in exchange for a customer's agreement to participate in DR events. SDG&E will signal these devices on Reduce Your Use days to provide automatic load reduction for these customers.

The results of the 2014 deployment and DR season will be used to determine any adjustments/enhancements to the program in 2015 and 2016. SDG&E requests the full 2013-2014 budget amount for the 2015-2016 SCTD program to allow for continued implementation and provide services to new customers in the succeeding years based on 2014 results and lessons learned. At a minimum this effort would include maintaining engagement levels for customer who enrolled in 2014. At full capacity, this effort would include recruiting, enrolling, and deploying devices to additional residential customers, including targeting customers who are on the new dynamic pricing rates (e.g., Smart Pricing Program ("SPP")) rates. SDG&E will also continue to look into the use of additional technologies, for example pool pump controls, as outlined in the SCTD PIP.

SDG&E requests the opportunity to include Small Commercial customers in the SCTD offering in 2015 and 2016. Pursuant to D.12-04-045, SDG&E was directed to target the SCTD program to residential customers only to avoid duplication of efforts with HAN devices authorized in the AMI proceeding. The AMI offering will no longer be available after 2014, and

SDG&E requests the option to continue offering devices to Small Commercial customers should the 2014 efforts provide desirable results.

Finally, SDG&E will investigate in 2015 transitioning SCTD from a "no-cost" to a customer cost-sharing approach.

5. Technical Incentives Program ("TI")

Although, SDG&E is not planning any program operational changes at this time, it proposes to reduce the TI budget has been reduced in order to support maintaining CBP's cost effectiveness with the changes proposed above.[2] SDG&E will use the bridge years to evaluate possible program enhancements to improve the customer experience in an effort to increase adoption rates.

6. DR Information Technology ("IT") Infrastructure Budget Change

Consistent with the TI program changes to support CBP's cost effectiveness discussed above, SDG&E is also reducing its 2015-2016 IT budget by $800,000.[3] SDG&E will prioritize the various IT projects to ensure that program support is not compromised by this proposed reduction.

7. New Request for Proposals ("RFPs") For Load Control Products

Technologies that can be used to improve and expand incremental load reductions are constantly changing to improve load control capabilities and reduce costs of deployment of both the load control devices and supporting IT infrastructure. SDG&E requests Commission authorization to issue a new RFPs, as opportunities arise, with the objective of seeking new,

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[2] *2010 Demand Response Cost Effectiveness Protocols*, pages 29 to 30. TI incentives are considered capital costs of the Capacity Bidding Program.

[3] *2010 Demand Response Cost Effectiveness Protocols*, page 18. IT costs are considered part of program administrative costs of the Capacity Bidding Program.

innovative and aggressive technologies for load control programs, to modify, enhance or replace existing technologies (for example, pool pump controls) and assist customers who are on dynamic pricing or new time-of-use rates. This is consistent with the Commission's desire to continuously improve and expand DR load reductions. As noted in D.12-04-045 (at page 76),

> "…PG&E, SCE and SDG&E are all encouraged to procure additional third party cost-effective MWs of DR through competitive solicitations, above current minimum levels."

If there is a cost-effective and viable new project, SDG&E will file an application to request approval of the new project, request fund-shifts within its portfolio or additional program funds, as necessary.

B. PROGRAMS AND ACTIVITIES WITHOUT MODIFICATIONS

In the following sections, SDG&E briefly describes the programs and activities that do not have program changes. Appendix C provides more details on the various specific programs.

1. Base Interruptible Program ("BIP")

BIP, SDG&E's only Reliability program, is a continuation of the program that commenced in 2001 and offers a monthly capacity payment to non-residential customers who can commit to curtail at least 15% of Monthly Average Peak Demand, with a minimum load reduction of 100 kW.

If available, BIP will use the CAISO's Reliability Demand Response Product (RDRP) in the 2015-2016 program years to bid into the wholesale market in accordance with CPUC Decision (D.) 10-06-034, which adopted the "Reliability-Based Demand Response Settlement Agreement" (Settlement Agreement) in R.07-02-041. The Settlement Agreement caps emergency program enrollment and SDG&E will keep BIP below the level established in that proceeding.

While BIP is and will continue to be a retail demand response product that enables emergency responsive demand response resources to state and local situations, modifications will be necessary to meet the requirements of the CAISO RDRP during the 2015-2016 program years. SDG&E anticipates that the program will be fully compliant with the RDRP requirements during the 2015-2016 program years.

2. Emerging Technology—Demand Response Program ("DR-ET")

The DR-ET program will proceed in 2015-2016 with the same direction as the 2012-2014 PIP, with a change in the measures described for Electric Vehicle research efforts. The 2012-2014 PIP referred to a specific project around vehicle charging infrastructure, which is currently being completed. Future efforts involving similar topics will be pursued in 2015-2016, and the language for the Electric Vehicles has been updated to cover the goals for 2015-2016. There will be no program or operational changes in 2015-2016. The DR-ET Program consists of evaluating demand-reducing technologies and strategies that are applicable to the SDG&E region and market. The focus is on technologies and strategies that promise significant, cost-effective demand reduction in the short and/or mid-term time horizon, and that hold promise to be sufficiently reliable and scalable for market-wide implementation. Each evaluation project will address:

- The technology's or strategy's overall merits
- Applicability to demand reduction and related factors such as energy efficiency
- Applicability to our region, market and frameworks such as CAISO
- Applicability to existing SDG&E programs
- Possible adoption barriers
- Cost effectiveness
- Risks
- Recommendation about the utility's further support and involvement

The DR-ET program's evaluation projects have may include techniques and methods that may not be exclusively technology-driven. The emphasis of each project will vary on case by case basis, and may include:

- Technology Assessments
- Scaled Field Placements
- Demonstration Showcases
- Technology Development
- Business Incubation
- Market / Behavior Studies

Technologies or strategies found to be viable may subsequently be integrated into existing utility programs or become the basis for new programs in support of market introduction.

3. New Construction DR Pilot ("NCDRP")

The NCDRP was filed March 1, 2012, but the current decision for NCDRP was not approved until February of 2013. The current approval is through December 31, 2014. The New construction NCDRP was approved with the intended purpose of facilitating Integrated Demand Side Management ("IDSM") efforts by working closely with the Energy Efficiency Savings By Design and California Advanced Homes programs to encourage both residential and non-residential builders to incorporate Demand Response technology, infrastructure and/or programs into their new construction projects targeting both the eventual homeowners and building tenants. The pilot's purpose is to determine if providing design assistance during the early design phase of a new construction project, with DR project criteria, obviates the need for expensive retrofits at a later time. In addition, the pilot will enable newly constructed buildings to participate in existing DR Programs, which has several benefits including: increasing DR participation overall, the potential for ongoing load reduction, increased customer awareness and engagement, and incentives to the customer.

This program experienced delays in the 2012 to 2014 cycle that are also described in the section below related to why the program is underspent. The main drivers of those delays were the timing of the initial decision approving this pilot, the continued sluggish industry rebound in the new construction industry overall since the recession of the prior years, and the difficulty of retaining projects in the pilot given the remaining length of the cycle when construction projects generally take longer than 18 months.

While the pilot has experienced delays, SDG&E sees the new construction industry rebounding in the San Diego area and interest from builders is still high, if the timing can work. Therefore SDG&E is requesting that the NCDRP continue into the 2015-2016 cycle. The intent going forward, upon approval, will be to continue to work with design teams in the early phases of new construction design to pursue projects that were not only considering Energy Efficiency measures (namely thru Savings By Design or California Advanced Home Program participation), but also Demand Response enabling technologies. The program will continue to focus on identifying the level of benefits of new construction early design influence and its impact on lower costs (than the cost of a DR retrofit), and a comprehensive optimized building design for not only EE, but DR as well. With the availability of various dynamic pricing and Time-of-Use rates, DR-enabled new buildings and homes will be able to select the appropriate rates that work best for the owners/tenants. However, it is imperative to understand that most new construction projects can take anywhere from 18 months to 3 years for completion which may still pose challenges for the current pilot model. The long-term nature of most projects, along with the limited time frame for NCDRP, has made it very difficult to find projects that fit the current pilot model. If SDG&E is able to receive a timely Decision for this filing, it would help the pilot greatly, in that the pilot could then potentially recruit builders with projects now at early stages that would continue through 2016.

Although there has been a recent increased interest in DR from the new construction market, this market has recently experienced a gradual incline. The economic downturn over the recent years has reduced the quantity of development and new construction. In order to participate in the current program, those builders that may have current new construction projects would also have to have those projects completed prior to the close of the current approved program cycle (December 31, 2014). Not only would projects need to be completed, but part of the pilot requirements, including a load shed test that would have to be performed after the newly constructed building is occupied in order to verify estimated savings from implemented DR strategies. Completing the full pilot participation process in the given time frame is a nearly insurmountable challenge for those interested in pursuing DR for their new construction projects. The small number of potential projects that have been able to meet the early design influence and completion date requirements have either been delayed indefinitely (due to various reasons, such as budget limitations, permitting delays, etc.) or cancelled completely. If SDG&E's request to continue this program into 2015-2016 is granted, pilot continuity over the next three years will provide more time for builders to complete their projects.

4. Permanent Load Shifting Program ("PLS")

Permanent Load shifting Program (PLS) is a statewide program that was designed and implemented in collaboration with the other two IOUs and under the guidance of the energy Division. Permanent Load Shifting (PLS) can help reduce system peak load by shifting electricity use from on-peak to off-peak periods on a recurring basis. Shifting daily loads benefits the grid and distribution systems. PLS often involves storing energy produced during off-peak hours to support load during peak periods when energy use is typically high. SDG&E does not plan any changes to the PLS in the 2015-2016.

5. Measurement and Evaluation ("M&E") Activities

SDG&E recommends keeping the same M&E budget for 2015 and 2016 that was previously approved for 2013 and 2014. SDG&E has currently paid or committed to pay in a signed service agreement $2,505,703 in measurement evaluation costs. This is 70% of the combined 2012 and 2013 budget of $3,588,573. In 2012 and 2013 SDG&E had to absorb costs of unplanned evaluations due to new program that arose out of the closing of SONGS and the D.13-04-021[4] Ordering Paragraph 14 requirement to evaluate the 2013 Flex Alert campaign. Unplanned evaluations included the small commercial PTR load impact evaluation, DBP load impact evaluation, and Flex Alert load impact and process evaluations. These costs were largely offset by delays in the implementation of other DR programs. Because the implementation of the SCTD program and of SPP rates has been delayed until 2014, these activities did not require the budgeted, amounts resulting in 70% of the overall 2012-2013 adopted budget being spent. However, in 2015 and 2016 there will be no delayed programs to offset costs of any further unplanned evaluations. So it is important to keep the same M&E budget that was adopted in 2013 and 2014 for 2015 and 2016.

Historically, SDG&E has included the budget for the M&E of CPP and TOU rates in the demand response M&E budget. However, in accordance with decision D. 12-12-004, SDG&E is requesting measurement and evaluation funding for the evaluation of CPP and TOU rates for 2016-2020 in its GRC proceeding. The 2014 M&E budget does include $250,000 intended for the evaluation of critical peak pricing rates, so arguably this should be subtracted from the 2016

[4] *Decision on Phase 1 Issues: Utility Budgets for the Flex Alert Program for 2013 and 2014*, April 18, 2013.

M&E budget. However, since 250,000 is only 16% percent of the 2014 measurement and evaluation budget and unplanned evaluations do occur, SDG&E does not recommend lowering the 2016 measurement and evaluation budget at this time.

	2015	2016	Total
Utility Managed Evaluations	$1,913,116	$1,526,525	$3,439,641
Energy Division Managed Evaluations	$200,000	$200,000	$600,000

6. Demand Response Regulatory Policy and Support Activities

In order to provide continued program oversight and regulatory policy support activities to the programs, including general administration, reporting requirements, regulatory support for various data requests, participation in regulatory proceedings, etc., SDG&E requests funding at the same levels as 2013-2014 for 2015-2016. The budget for two years is $1,531,077 with no changes.

IV. LOAD IMPACTS, COST EFFECTIVENESS AND MEASUREMENT & EVALUATION

A. 2015-2016 DEMAND RESPONSE PROGRAM LOAD IMPACTS

The table below contains the draft ex-post load impacts for the average of all 2013 events along with the demand response forecast for 2014-2016. The forecast for programs with no proposed changes is the most recently forecast filed in April of 2013. The forecasting methodology for programs with proposed changes is described below.

Load Impact Forecast August 1 in 2 Peak Day 1pm-6pm (MW)				
DR Activities	**Actual 2013**	**2014**	**2015**	**2016**
Day-Ahead Price Triggered				
CPPD - Large C&I (>200 kW)	19.2	16.6	16.8	17.0
CPPD - Medium C&I (20-200 kW)	0.0	17.5	16.7	17.8
CBP Day-Ahead	10.4	9.4	9.4	9.4
DBP Day-Ahead	1.5	1.5	1.5	1.5
PTR	6.7	4.4	4.4	4.5
Incremental SCTD Residential	0.0	8.4	8.4	8.4
Incremental SCTD Small Commercial	0.0	0.0	1.4	1.4
Day-Of Price Triggered				
CBP Day-Of	10.8	10.2	15.9	16.8
DBP Day-Of	4.1	4.6	4.6	4.6
Summer Saver	19.4	15.0	15.0	15.0
Day-Of Reliability Trigger				
BIP	2.0	0.8	0.8	0.8
Other DR Activities				
Permanent Load Shifting (PLS)	0.0	0.6	1.2	1.2
Total	74.2	88.9	96.1	98.4

B. COST EFFECTIVENESS METHODOLOGY FOR 2015-2016

The Ruling states (at page 3), "(I)f the changes proposed for a program included changes to the inputs for the cost-effectiveness calculation of that program, the proposal shall include a revised cost effectiveness calculation and result." As discussed above, three programs have changes that impacted the inputs for cost effectiveness. Cost effectiveness was analyzed for the CBP, DBP, and PTR/SCTD programs to take into account the proposed program changes. The analysis was conducted using the Demand Response Reporting Template created by Energy and Environmental Economics (E3) and approved by the Commission for the 2012 through 2014 Demand Response Applications filed by the IOUs in 2011. For this analysis, the Template was updated with inputs for 2015 through 2016 using E3's Avoided Cost Calculator.[5] Load impact forecasts were updated based on more recent information as described above. The TI and information technology budgets were also adjusted as described in section A. The remaining inputs, methodology and protocols used for the tests are the same as those used in the 2012-2014 filing. The results of the analysis are presented in the following table and the DR Reporting Template can be found in Appendix F.

2014 Dollars	**Benefits**	**Costs**	**Net Benefits**	**Net $/kW-Yr.**	**TRC**
CBP	$5,264,864	$5,825,222	($560,358)	($13)	0.90
DBP Day Ahead	$378,575	$154,260	$224,315	$89	2.45
DBP Day of	$1,234,256	$609,650	$624,607	$114	2.02
PTR/SCTD	$4,436,945	$3,902,339	$534,605	$40	1.14

C. DISCUSSION OF IMPACTS OF PROGRAM CHANGES ON COST EFFECTIVENESS

1. Demand Bidding Program

SDG&E proposes changes to the DBP and is therefore submitting an updated cost-effectiveness analysis for this program. SDG&E is incorporating the April 1, 2013 actual result for the cost-effectiveness calculations for the 2015-2016 program demand reduction forecast.

2. Capacity Bidding Program

SDG&E is proposing several changes to the CBP program, all of which are designed to increase participation in the program. SDG&E is proposing to add a 30-minute option with an incentive that is 15% higher than the current day-of CBP incentive. SDG&E is also proposing to allow non-residential customers with demands less than 20 kW to participate in the program, and to remove the penalty for an aggregator who achieves a load reduction that is between 75% and

[5] Specifically, the file named DERAvoidedCostModel_v3_9_2011_v4d.xlsm was used; this file is the last Commission approved set of avoided costs to be used for demand response programs.

90% of its nomination. Therefore, SDG&E has prepared an updated CBP load impact forecast that incorporates the most recent 2013 event results and includes growth in the program due to the changes. This forecast is also used for the cost-effectiveness calculations.

The forecast for the day-ahead program is equal to the draft ex-ante CBP forecast planned to be filed April 1, 2014 that incorporates the 2013 event results. The forecast includes no growth for the day- ahead segment. For the CBP day-of forecast the 2014 forecast is equal to the draft ex-ante CBP day-of forecast planned to be filed April 1, 2014, which assumes no program changes are adopted. In 2015, SDG&E predicts that 50 percent of current load enrolled in the CBP day-of option will move to the 30-minute option. In addition, SDG&E expects new enrollment in both the 30-minute option and the 2-hour option due to the proposed program changes. The estimates of new enrollment were created taking into account information from conversations with aggregators about potential program changes and the historical pattern of growth in the program.

The following table details the forecasted demand reduction for the various CBP products.

CBP Forecast by Option			
Notification	Max Hours	Year	August Load Impact (MW)
CBP-DA	4	2014	9.4
CBP-DO 2 hour	4	2014	5.9
CBP-DO 2 hour	6	2014	4.4
CBP DO 30 minute	4	2014	0.0
CBP DO 30 minute	6	2014	0.0
Total			19.6
Notification	Max Hours	Year	August Load Impact (MW)
CBP-DA	4	2015	9.4
CBP-DO 2 hour	4	2015	3.8
CBP-DO 2 hour	6	2015	2.8
CBP DO 30 minute	4	2015	5.3
CBP DO 30 minute	6	2015	3.9
Total			25.2
Notification	Max Hours	Year	August Load Impact (MW)
CBP-DA	4	2016	9.4
CBP-DO 2 hour	4	2016	3.8
CBP-DO 2 hour	6	2016	2.8
CBP DO 30 minute	4	2016	5.8
CBP DO 30 minute	6	2016	4.3
Total			26.2

3. Small Customer Technology Deployment Program ("SCTD")

SDG&E is proposing to make small commercial customers eligible for SCTD technology. These customers are not eligible for PTR but may enroll in critical peak pricing rates. The forecast used for the expected load reduction from small commercial customers is equal to the small commercial forecast filed in May of 2011 as part of the 2012-2014 program. The reference load for the small commercial forecast is based on SDG&E's dynamic load profile hourly small commercial customer load shape. Since the Statewide Pricing Pilot small commercial update results 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 2,000 small commercial customers enroll in 2015.

The residential SCTD forecast is the forecast filed in April of 2012[6] with the portion of the load forecast due to pool pump technology removed. Pool pumps are eligible for SCTD funding and SDG&E is not proposing to change that, however, firm plans to market pool pump technology are not in place at this time.

V. PROGRAM BUDGET PROPOSAL AND COST RECOVERY MECHANISM

A. 2015-2016 DRP PORTFOLIO BUDGET PROPOSAL

Based on the discussion above, SDG&E's 2015-2016 DRP portfolio budget proposal is $40,770,940 with $19,909,469 for 2015 and $20,861,471 for 2016, respectively. The program specific budgets organized according to the approved budget categories can be found in Appendix A.

B. COST RECOVERY MECHANISM

As approved by D.12-04-045, SDG&E currently records all program costs associated with its existing DR programs and its current DRP bilateral contracts in its Advanced Metering and Demand Response Memorandum Account ("AMDRMA"). SDG&E plans to continue using

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[6] Since a vendor had not been selected for the program in by April of 2013 and marketing plans had not been finalized the SCTD forecast filed in 2013 did not represent a full scale rollout of the program. However, both a vendor and specific marketing plan are now in place therefore SDG&E is using the SCTD forecast filed in April of 2012 which did assume a full scale roll out of the program would occur in 2014.

the AMDRMA account along with SDG&E's Rewards and Penalties Balancing Account (RPBA). SDG&E will continue to the existing disposition of the AMDRMA balances being transferred to SDG&E's Rewards and Penalties Balancing Account (RPBA") on an annual basis for amortization in SDG&E's electric distribution rates over 12 months, effective on January 1st of the following year, consistent with SDG&E's adopted tariffs.

SDG&E is requesting that authorized demand response program costs related to DR Operation and Maintenance ("O&M") expenses, capital related costs (i.e., depreciation, return and taxes), customer capacity incentive payments, and all other costs, not recovered through SDG&E's General Rate Case ("GRC"), be recorded in AMDRMA.

The one exception to the way SDG&E records demand response programs costs in AMDRMA is the recording of the energy component of the DRP customer incentive payments in its Energy Resource Recovery Account ("ERRA").

VI. RESPONSES TO ADDITIONAL QUESTIONS POSED IN RULING

SDG&E provides the requested additional information and responses to additional questions posed in the Ruling. Please note that SDG&E has no comment to Question 1 regarding the budget categories and dollar amounts that would be impacted by PG&E's request to move its employee benefits from its General Rate Case to its demand response budgets for 2015 and 2016.

A. EXPLANATION FOR 2012-2013 DRP UNDERSPENDING

Question 2: PG&E, SDSG&E and SCE shall provide responses as to why they have each only spent less than 25 percent of a three-year budget over the course of 20 months and why this unspent funding should be made available to them in the 2015-2016 demand response program bridge funding.

Response: As of the end of 2013, SDG&E has spent a cumulative a cumulative amount of $18,735,059 from 2012 to December 31, 2013, representing approximately 29 percent of its

2012—2014 approved budget. Please see the December 2013 monthly report, submitted January 2014 to the Commission in Appendix E.[7] The majority of SDG&E's 2012-2014 portfolio budget is its incentive budget. SDG&E develops its portfolio incentive budget to ensure that it will be able to meet all incentive payments at its forecasted total portfolio demand reduction. However, SDG&E's actual incentive payments depend on the number of actual participants, the number of program events actually called, and amount of demand reduction provided during these events. SDG&E provides specific program explanations for its underspending, particularly for its lower incentive payments, in the following sections.

1. Base Interruptible Program

The Base Interruptible Program approved budget is $4,014,267 and the actual program budget spent is 17.8%. There are several reasons for the program being underspent. First, SDG&E's BIP incentive budget allows for a possible pay-out of the maximum incentive budget that would allow SDG&E to pay all incentives should the program meet its forecasted demand reduction of 20 MW. The BIP incentive budget was $2,828,839. However, program changes that went into effect 2012 have resulted in a lower incentive pay-out: (1) some large customers dropped out of the program due to pending changes to the back-up generator limitation; (2) some customers dropped out of the program due to non-performance; and, (3) Program redesign successfully discouraged free-riders from continuing to participate in the program. These changes resulted in lower incentive payments than originally anticipated.

2. Capacity Bidding Program

SDG&E spent approximately 29 percent of its authorized CBP 2012-2014 budget for the following three reasons:

[7] The complete SDG&E December 2013 DRP Monthly Report is available at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Monthly+Reports/2013_DR.htm.

(1) SDG&E's incentive budget anticipated accommodating the transfer of customers from the canceled DemandSmart contract to CBP. However, DemandSmart participants transferred to its DBP program instead of CBP;

(2) SDG&E lost one of the aggregators in its territory at the beginning of the program cycle; and

(3) SDG&E allowed for an incentive budget that would avoid placing enrollment caps due to lack of program funding.

3. Technology Incentives

The Technology Incentives program realized a reduction in spending due to the unavailability of the program from May 2012 to January 2013 to allow SDG&E to incorporate program infrastructure enhancements to address the new incentive payment structure ordered in D.12-04-045 (at pages 142 to 144). In addition, this new incentive payment structure has resulted in an overall reduction in program participation. While the number and rate of application submittals has not declined drastically, there has been a significant reduction in the volume of companies using the TI program. Based on customer and vendor feedback, the revised 60/40 incentive payment split has resulted in lower participation. The 60/40 split poses a cash flow problem for the demand response installers, who have to "float" 40% of the cost of a project until the end of a full year or the end of the demand response program season. The demand response installers, who are typically the project sponsors on a TI application, are then responsible for the dollar value of the 40% based on the actual performance of the demand response participant (e.g., the SDG&E customer). The cash flow problem becomes exacerbated by the fact that the demand response installers have no jurisdiction or influence on the actual performance of customer. Therefore, fewer vendors and installers are promoting, advertising, and ultimately participating in the program.

4. Permanent Load Shifting

Because of the lengthy processes of workshops for a statewide consistent program design, and due to the long regulatory approval framework, the PLS program did not launch until late 2013, resulting in lower program expenditures.

5. Small Customer Technology Deployment

D. 12-04-045 approved SDG&E's SCTD program, pending a re-filing of cost effectiveness in combination with its Reduce Your Use program and an updated PIP. SDG&E was directed to incorporate findings from its Residential Automated Controls Technology ("RACT") pilot, which was completed at the end of December 2011, in its updated PIP for SCTD. These updated requirements and PIP were submitted in SDG&E's Advice Letter 2363-E and approved effective June 20, 2012.[8]

SDG&E's Small Customer Technology Deployment began the process of securing both a device manufacturer and an installer through two RFPs in Spring 2013, following a period of research that took place in the second half of 2012. This RFP process was completed in the Fall 2013, and contract negotiations began with the two selected bidders. Prior to these efforts, there was little need for spending out of the SCTD budget. The program will be implemented by March 2014, with deployment expected to be completed by December 31, 2014. SDG&E anticipates that the majority of SCTD's approved budget will be utilized by the end of 2014.

[8] AL 2363-E is available at http://regarchive.sdge.com/tm2/pdf/2363-E.pdf.

Some program underspending is anticipated due to the change in available technologies between 2011 (when the program was filed) and 2013 (when the bidders were selected), and the final program design.

6. Locational Demand Response

The Locational Demand Response approved program budget is $433,234 and to-date has spent approximately three percent of its budget. LDR had a late start when the program approval did not come until February 2013.[9] The late start impacted the pilot in that target circuit needed to be reassessed. An alternative circuit was selected which allowed for the testing of local dispatch of Summer Saver customers on this circuit in Summer 2013. SDG&E anticipates, however, that it will spend the majority of the program funds this summer in accordance to with PIP. SDG&E believes that it will achieve the objectives of this pilot by 2014 and terminate this pilot at the end of 2014.

7. New Construction DR Pilot

The New Construction Demand Response Pilot was approved with a $1.1M budget.[10] To date, only eleven percent of the approved budget has been spent ($999,000 remaining to date). NCDRP didn't receive approval until February 2013, so the time frame in which new construction projects need to be completed, has been adversely impacted. In addition to the limited time frame, the overall downturn in the new construction market has impacted the number of potential projects. Previous potential projects that did meet the limited time frame have since either been suspended indefinitely or cancelled completely by the potential

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[9] SDG&E filed its LDR pilot plans through Advice Letter 2381-E and was approved on February 7, 2013. AL 2381-E is available at http://regarchive.sdge.com/tm2/pdf/2381-E.pdf.

[10] SDG&E filed its NCDRP pilot plans through Advice Letter 2381-E and was approved on February 7, 2013.

participants. The small number of potential projects that have been able to meet the early design influence and completion date requirements have either been delayed indefinitely (due to reasons mainly around project budget limitations) or cancelled completely.

Although there has been a recent increased interest in demand response from the new construction market recently, this market has been a gradual incline. The economic downturn over recent years has reduced the quantity of development and new construction projects overall. Builders that may have current new construction projects would also have to have those projects completed prior to the close of the current approved program cycle (December 31, 2014), and this is highly unlikely due to the long-term nature of new construction projects. If SDG&E's request to continue this program into 2015-2016, program continuity over the next three years would provide more time for builders to complete their projects.

8. Customer Education And Outreach

The Customer Education, Awareness and Outreach (CEAO) program is currently underspent due to the cyclical nature of demand response marketing campaigns, and due to how our communications partners (advertising agencies and others) bill for their services. However, SDG&E has committed close to 100% of the total three-year budget for CEAO at this time, with an anticipated demand response marketing, education and outreach campaign to be launched in the second quarter of 2014.

9. Other Local Marketing

The Other Local Marketing (OLM) budget, that covers marketing, education and outreach for four local programs is underspent primarily to the cost-savings achieved while implementing marketing plans for the Reduce Your Use program, and to the delayed launch of the SCTD program. However, SDG&E projects that it will spend close to 100 percent % of the local marketing budget for SCTD during the summer of 2014.

10. Emerging Technology—Demand Response Program

The ET-DR program is underspent through the end of 2013 for a several reasons. First, the ET-DR budget is planned in anticipation of viable (but unknown) technologies with the expectation that there will be compatible and willing customers to test these technologies. However, the actual participating technologies, which are typically new or untested, and finding appropriate test sites and customers who willing to take on the risks of testing new technologies, are challenging. The ET-DR vendors themselves may have difficulty meeting schedules and deadlines to make the technologies work. Currently, there are several projects in the ET-DR pipeline where the vendors have faced unexpected challenges to providing a final product suitable for testing, and our planned budget spend associated with those projects is delayed accordingly. These have caused delays in project payments. Second, ET-DR makes an effort to leverage program funds by co-funding projects with outside agencies whenever possible. One such project was planned for this budget cycle, but has recently been cancelled by the California Energy Commission, resulting in spending being below budget projections. Although, the program is currently underspent through the end of 2013, ET-DR anticipates fully spending the allocated budget for the 2012 – 2014 cycle.

11. Information Technology

The DR IT Infrastructure budget for 2012-2014 was approved at $5,409,750. We are projecting the current budget to be underspent due to changes in requirements, leveraging existing capability within our Customer Relationship Management and Customer Information

Systems (CRM/CISCO), reduced complexity in IT development, and implementation costs lower than what was originally forecasted.

B. COMMENTS REGARDING STAFF PILOT PROPOSALS

Question 3: In the case of funding for pilots in 2015 and 2016, D.12-04-045 requires that pilots approved for 2012-2014 be completed by December 31, 2014. As proposed in the Order Instituting Rulemaking, the pilot funds will be earmarked for the staff proposed pilots in 2015 and 2016. Utilities shall provide comments or concerns regarding this issue; other parties may comment as well.

Response: SDG&E addresses this question in two parts: (1) the reallocation of 2014-2015 pilot unspent funds to the staff proposed pilots in 2015 and 2016; and (2) the merits of funding the staff proposed pilots presented in in R.13-09-01 Attachment A[11].

First, SDG&E does not have any unspent 2013 funds nor anticipate any unspent 2014 funds available to reallocate to the 2015-2016 staff proposed pilots. SDG&E's cost recovery mechanism, as approved by D.12-04-045, is the use of its Advanced Metering and Demand Response Memorandum Account ("AMDRMA") through which SDG&E records all actual DRP program expenditures. SDG&E then recovers its program expenses on an annual basis through the amortization of SDG&E's electric distribution rates over twelve months, effective January 1st of the succeeding year. SDG&E does not collect its authorized program budget through a balancing account mechanism.

The Staff Pilot proposals include two pilots: (1) Participation of Demand Response in the Wholesale Energy Market which consists of two components, (a) IRM 2 Enhancement in Northern California; and (b) IRM 2 Implementation in Southern California; and (2) Pilot to Increase Customer Responsiveness to Dynamic Electricity Rates. With respect to the IRM 2 pilots to test participation of DR in the wholesale energy markets as described in the staff

[11] Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements

proposal, although SDG&E supports the objectives of the staff proposal SDG&E believes duplicating Pacific Gas and Electric Company's ("PG&E") IRM2 pilot would prove to be redundant and inefficient. SDG&E will already be bidding a portion on its CBP as a Proxy Demand Resource ("PDR") into the CAISO market beginning 2014, thus making a pilot in SDG&E's service territory redundant and an inefficient use of ratepayer funds. SDG&E proposes instead that Staff optimize the Evaluation, Measurement and Verification plan to include the evaluation of SDG&E's CBP PDR results, and create an effective mechanism for a "lessons learned" and best practices between PG&E and the Southern California electric utilities after the pilot period. In addition, the building of third party capabilities to bid into the CAISO PDR would best be addressed as part of the ongoing Rule 24 proceeding.

SDG&E supports the Staff's proposal to increase customer responsiveness to dynamic electricity rates through behavior-based programs. However, SDG&E's behavior–based programs are part of SDG&E's local Integrated Demand-Side Management ("IDSM") programs and are under the oversight Energy Efficiency proceeding. Therefore, consistent with the August 27, 2010 *Administrative Law Judge's Ruling Providing Guidance for the 2012-2014 Demand Response Applications* regarding the request for DR IDSM funding (at page 14), SDG&E intends to request the approval of the DRP component for its 2015 behavior-based programs that would include dynamic pricing rate customers in the upcoming 2015 Energy Efficiency Program filing.

VII. CONCLUSION

For the reasons set forth above and in the attachments submitted in support of this filing, SDG&E respectfully requests that the Commission:

(1) Approve the approve a two year portfolio budget of $42,210,940 to continue its DR programs in 2015-2016, with budgets of $20,629,469 for 2015 and $21,581,471 for 2016, respectively;

(2) Approve the proposed program and activities changes for CBP, DBP-DO, DBP-N, Local Marketing and Outreach, SCTD, TI, IT Infrastructure;
(3) Approve the continuation of the New Construction DRP in 2015 and 2016;
(4) Approve the proposed revisions to the tariffs, schedules and contracts in Appendix D:
(5) Authorize SDG&E to issue RFP solicitations to seek proposals from third-party vendors for now programs and technologies to implement load control programs, intended to augment and expend existing technologies and programs in SDG&E's service territory;
(6) Approve the program and activities that have no changes from the 2012-2014 program design;
(7) Approve the 2015 ME& budget of $2,113,116 and 2016 M&E budget of $1,726525;
(8) Approve SDG&E's cost recovery mechanism as described herein;
(9) Approve SDG&E's CBP PDR implementation in lieu of participating in Staff's proposal to implement IRM 2 Implementation in Southern California; and,
(10) Approve SDG&E's proposal to request the approval of the DRP component for its 2015 behavior-based programs that would include dynamic pricing rate customers in the upcoming 2015 Energy Efficiency Program filing instead of participating in the Staff proposal to increase customer responsiveness to dynamic electricity rates through behavior-based programs.

Respectfully submitted

By *\/s\/ Thomas R. Brill*

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APPENDIX A

Appendix A
SAN DIEGO GAS AND ELECTRIC
SUMMARY OF UTILITY DEMAND RESPONSE PROGRAMS
AND BUDGETS FOR 2015-2016 BY PROPOSED PROGRAM CATEGORY [1]
(Thousands of Dollars)

Line	Programs by Category		AUTHORIZED		Budget Requested for 2015-2016		
	PROGRAM	Footnote	2013	2014	2015	2016	TOTAL
1	Category 1 - Reliability Programs						
2	Base Interruptible Program (BIP)		1,228,025	1,728,052	1,228,025	1,728,052	2,956,077
3	Total		1,228,025	1,728,052	1,228,025	1,728,052	2,956,077
4	Category 2 - Price-Responsive Programs						
5	Capacity Bidding Program (CBP)		4,003,071	4,188,271	4,003,069	4,188,269	8,191,338
6	Demand Bidding Program (DBP)	2	877,905	877,905	877,905	877,905	1,755,810
7	Peak Time Rebate (PTR)		161,667	161,667	161,645	161,645	323,290
8	Total		5,042,643	5,227,843	5,042,619	5,227,819	10,270,438
9	Category 4 - Emerging & Enabling Technologies						
10	Emerging Technologies (ET)		703,625	707,345	703,625	707,345	1,410,970
11	Small Customer Technology Deployment (SCTD)		4,094,831	4,094,826	4,094,826	4,094,826	8,189,652
12	Technology Incentives (TI)		2,990,962	2,999,842	2,785,709	2,785,709	5,571,418
13	Total		7,789,418	7,802,013	7,584,160	7,587,880	15,172,040
14	Category 5 - Pilots						
15	Locational Demand Response (LDR)		144,384	147,559	-	-	-
16	New Construction Demand Response (NCDRP)		487,121	487,121	487,118	487,118	974,236
17	Total		631,505	634,680	487,118	487,118	974,236
18	Category 6 - Evaluation, Measurement & Verification						
19	Evaluation, Measurement & Verification (DRMEC)		1,913,116	1,526,525	1,913,032	1,526,430	3,439,462
20	Research		200,000	200,000	200,000	200,000	400,000
21	Total		2,113,116	1,726,525	2,113,032	1,726,430	3,839,462
22	Category 7 - Marketing, Education & Outreach						
23	Customer, Education and Outreach (CEAO)		377,500	357,500	-	-	-
24	Other Local Marketing (OLM)		1,550,000	1,550,000	-	-	-
25	Local Marketing, Education and Outreach (LMEO)		-	-	1,473,085	2,225,085	3,698,170
26	Total		1,927,500	1,907,500	1,473,085	2,225,085	3,698,170
27	Category 8 - DR System Support Activities						
28	Regulatory Policy & Program Support		745,050	786,297	745,005	786,072	1,531,077
29	IT Infrastructure & System Support		1,503,000	1,077,875	956,425	813,015	1,769,440
30	Total		2,248,050	1,864,172	1,701,430	1,599,087	3,300,517
31	Category 10 - Special Projects						
32	Permanent Load Shifting (PLS)		1,159,825	1,077,766	1,000,000	1,000,000	2,000,000
33	Total		1,159,825	1,077,766	1,000,000	1,000,000	2,000,000
34	GRAND TOTAL		22,140,082	21,968,551	20,629,469	21,581,471	42,210,940

Footnotes:
1 All budgets adopted by D.12-04-045 as corrected by D.12-08-023
2 Budget adopted by D.13-04-017

APPENDIX B

Appendix B

PIPs with program changes

Program Implementation Plan (PIP)
Capacity Bidding Program
~~2012~~2015-~~2014~~2016

PROGRAM NAME AND PROGRAM ID

(Note: Program ID represents the program code to be utilized in Program Builder)

Projected Program Budget

The budget dollars listed below reflect the administrative, capacity and energy incentive cost.

Program ID#	Program Name	2015~~2~~ Budget	2016~~3~~ Budget	Total 2015~~2~~-2016~~4~~ ~~Budget~~
CBP	Capacity Bidding Program	$56,09005,364785.9100 ~~3,929,664.00~~ 4,003,069.00	$65,71885,764385.9100 ~~3,929,664.00~~ 4,188,269.00	~~$2017,156302,294875.7300~~ $7,859,3288,191,338.00

Projected Load Impacts by Year

Program ID#	Program Name	2015~~2~~ Load Impact	201~~3~~6 Load Impact
CBP	Capacity Bidding Program	28.724.71.5	32.722.525.8

~~(Note: Cost-Effectiveness results to be obtained from Kevin McKinley)~~

Projected Cost Effectiveness by Year

Program ID#	Program Name	~~2012~~ 2015 Cost Effectiveness	~~2013~~ 2016 Cost Effectiveness
CBP	Capacity Bidding Program	.9	.9

PROGRAM DESCRIPTORS (Include the following items)

- **Market Sector**:
  - Non-Residential
- **Program Classification**:
  - ~~Statewide~~Core
- **Program Statement:**

The ~~2012-2014~~2015-2016 Capacity Bidding Program offers customers various product options by which participants can earn incentives to participants who reserve power reduction capacity with the availability and capability to meet requested load reductions during an emergency or abnormally high demands for power. This program is available to commercial/industrial customers~~, greater than 20 kW,~~ receiving bundled service, Direct Access service or Community Choice Aggregation service, and being billed on a commercial, industrial or agricultural rate schedule. Participation in this program must be taken in combination with the customer's otherwise applicable rate schedule. This program is also available to "Demand Response Providers," a third party entity that combines the loads or one or more customers for the purpose of participating in this program.

~~Customers participating in the CBP are not eligible to participate in any other utility demand response programs that offer capacity payments and energy payments.~~

For multiple program participation, see Rule 41.

The Technical Assistance/Technical Incentive (TA/TI) program is available to customers to help enable their participation in DR programs and events. ~~kWickview is available for customers to view their performance in events and understand their energy usage and make informed decisions on how they use their energy.~~

Participants may also utilize Technical Assistance Technical Incentive (TA/TI) program and kWickview to provide ~~automated enabling technologies and~~ online presentment solutions that will increase the ability for customers to participate in DR events~~, in an automated fashion and help them understand their energy usage and make informed decisions on how they use their energy.~~

Capacity Program participants will be surveyed about enabling technology installations, DR events, and technology and online presentment preferences to better determine best practices and lessons learned for future implementation. Best practices and lessons learned from the DRWMP pilot will be used to implement new technologies and presentment solutions strategies in an effort to increase customer use, load reduction and integration into the wholesale markets.

This program will focus on event communication and marketing to increase the ease of participation.

Help lines for more information will be available for customers during DR events.

Program Term

~~The program currently has 6 Demand Response Providers participating in the program, which results in an overall number of 109 customers, 588 meters and 20 MW's enrolled.~~ Enrolled participants are expected to remain in the program for a minimum of 12 calendar months and must have the required metering and operable communication equipment while participating in the program. Participants may opt out of the program anytime after their 12 month term.

1. *Eligibility*

The Capacity Bidding Program allows individual customers or third-party Demand Response Providers who sign up customers into a load reduction portfolio. This program will primarily be marketed to commercial/industrial customers~~, greater than 20 kW~~, receiving bundled service, Direct Access service or Community Choice Aggregation service, and being billed on a commercial, industrial or agricultural rate schedule. Program participation criteria will include the following:

Comment [A1]: I'm assuming this is the MPP discussion? We should probably have a simple statement that says something like " For mulitiple program participation, see Rule 41". That way we don't have to change each PIP.

Comment [A2]: I deleted this verbiage and added new verbiage underneath. Please review and see if that works.

Comment [A3]: We should probably discuss putting something like this in the general technology PIP that Fred is writing up? Just a thought

Comment [A4]: I deleted the last sentence. It probably would be better used in Fred's PIP.

Comment [A5]: Are "participants" aggregators or customers or both? Do we provide access to the aggregators?

Comment [A6]: As I understand it aggregators are both. We do provide aggregators access to kWickview to view the 15-minute data for each of their customers.

Program Implementation Plan (PIP)
Capacity Bidding Program
~~2012~~2015-~~2014~~2016

1. Non-Residential Customers
2. ~~Annual maximum demand of 20 kW on time-of-use rate~~
3. A fifteen-minute interval data recording meter with related telecommunications capability, compatible with the Utility's meter reading, time-of-use billing, and telecommunications systems.

2. Operating Months

The program will operate May through October (6 months). Weekends and holidays excluded.

3. Curtailment Window

The curtailment window for an event will be weekdays between the hours of 11 am to 7 pm. Limit 1 event per day and maximum of ~~24~~ 44 hours/month.

4. Event Triggers

Events may be called if the following event triggers are met at the utilities discretion:

Day-Ahead Event:
Market price > 15,000 btu/kWh heat rate
Local Emergency
- Transmission or Distribution Emergency
- Overloaded Equipment
- Emergency Grid Maintenance
- Fire or Fire Prevention Emergency
- Extreme Weather

Day-Of Event:
Market price > 15,000 btu/kWh heat rate
Local Emergency
- Transmission or Distribution Emergency
- Overloaded Equipment
- Emergency Grid Maintenance
- Fire or Fire Prevention Emergency
- Extreme Weather

5. Notification Time

Day-Ahead Event: Customers will be notified of an event ~~by~~ no later than 2 pm the day before.

Day-Of Event: Customers will be notified of an event by 9 am but not later than 2 hrs before event.

Day-Of Event 30 Min: Customers will be notified of an event no later than 30 minutes before event.

Program Implementation Plan (PIP)
Capacity Bidding Program
~~2012~~2015-~~2014~~2016

- **List measures:** There are various incentive levels provided in this program. For incentive credit rates available through CBP for both the "Day-Ahead" and "Day-Of" options refer to Schedule CBP tariff under the Rate section . Direct enrolled customers, will receive 80% of the capacity incentive rates below; Demand Response Providers will receive 100% of the incentive amount.

Comment [A7]: We need to come back to this but I forgot why? I think Beth recommended something or asked a question on this item.

- **List non-incentive customer services:**
  - Online Interface
  - Call center help lines
  - IDSM referrals

PROGRAM RATIONALE

The CBP allows participation by individual customers or through third-party Demand Response Providers who sign up customers into a load reduction portfolio. The program provides the participant with a summer capacity payment in order to reserve their load reduction capacity. This provides the participant with a revenue stream for having this capability. The program also has a non-performance penalty.

The Demand Response Providers recruit participants, help them develop demand reduction strategies, handle notifications of load shedding events, and distribute payments. Demand Response Providers have the flexibility to customize their offering to individual customers and to diversify the portfolio sufficiently to hedge the risk. Customer contracts with Demand Response Providers can include various elements such as a reservation payment, an energy payment, a penalty, response requirements, etc. that provides a different reward/risk proposition than SDG&E may be able to offer.

In addition the CB program purpose is to:

- Automate DR load reduction through the Technical Incentive (TA/TI) program.
- Reduce peak-time electric load.
- Educate customers on participation benefits:
  - Receive incentives for saving energy during temporary critical times.
  - ~~Reduced consumption equates to lower bills — even for temporary reductions.~~
  - ~~Get advance notice when energy supply could become an issue.~~
  - ~~Receive and utilize customer friendly technologies and energy presentment interfaces.~~
  - Serve as a model for other businesses and consumers.
  - Public relations benefits.
  - Participation incentives whether or not events are called.
  - Participation can be through a Demand Response Provider to mitigate risk of penalties.

Objectives

- Provide an option by which customers can contribute toward reducing peak energy consumption on the utility grid, while at the same time managing and controlling their individual energy consumption and costs.
- Reduce energy costs through customer participation which helps the state as well as the SDG&E community by the reduction of peak energy demands, as well as reducing the likelihood of rolling blackouts and rotating outages.

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- Provide customers with tools to better manage their consumption and demand, maximize potential energy savings and participation in demand response programs.
- Target customers with maximum load reduction potential.
- Encourage IDSM
  - Emphasis will be given to identify Demand Response opportunities during the Energy Efficiency TA audit.

- **Implementation Design**

~~The ISO PDR registration process requires 10~~5 ~~business days to update account information and in order to keep CBP payments and associated process on a monthly basis. The CBP nomination deadline needs to be advanced 15 days prior to each program operational month. The ISO has a 10 business day service level agreement to approve registration and update master file information.~~

~~San Diego hopes to gain experience through pilots participating as PDR to~~ inform us how to handle more dynamic nominations. ~~determine whether it's feasible to design processes to allow the nomination deadlines to remain closer to the current timeline.~~

~~Any DA or CCA customers are not allowed to directly bid CBP quantities into the wholesale market. To best assure control of DR MW quantities funded by SDG&E program funds, SDG&E will maintain control of Program DR resources at the CAISO and exclude bidding in the CAISO market by third party SCs.~~

~~The CBP will be administered by SDG&E and is open to any customer who provides a minimum of 20 kW load reduction. The program offers its participants the flexibility to identify their load reduction amounts and the time periods of reduction. Participants can receive significant payments per month for capacity during summer months (May 1 through October 31st), and additional incentives for load reduction. The incentives paid to customers will vary depending on their ability to reduce both in volume and selected product hours.~~

~~We have update the CBP capacity incentive prices based on analysis done on more recent energy market activities. The tables below display the revised prices.~~

~~1. Load Reduction Incentive Payment, Day-Ahead Program Option ($/kW-month):~~

~~Product~~	~~May~~	~~Jun~~	~~Jul~~	~~Aug~~	~~Sep~~	~~Oct~~
~~1 to 4 hours~~	~~2.67~~	~~7.21~~	~~15.64~~	~~19.32~~	~~12.76~~	~~3.85~~
~~2 to 6 hours~~	~~2.74~~	~~7.39~~	~~16.25~~	~~19.99~~	~~13.14~~	~~3.94~~
~~4 to 8 hours~~	~~2.81~~	~~7.61~~	~~16.99~~	~~20.76~~	~~13.71~~	~~4.05~~

~~2. Load Reduction Incentive Payment, Day-Of Program Option ($/kW-month):~~

~~Product~~	~~May~~	~~Jun~~	~~Jul~~	~~Aug~~	~~Sep~~	~~Oct~~
~~1 to 4 hours~~	~~3.21~~	~~8.65~~	~~18.77~~	~~23.19~~	~~15.31~~	~~4.62~~
~~2 to 6 hours~~	~~3.29~~	~~8.87~~	~~19.50~~	~~23.99~~	~~15.77~~	~~4.73~~
~~4 to 8 hours~~	~~3.38~~	~~9.13~~	~~20.39~~	~~24.91~~	~~16.45~~	~~4.86~~

The CBP is open to any commercial, industrial or agricultural customer with an interval meter. Working directly through SDG&E or through an Aggregator, customers choose the event

Comment [A8]: For nomination deadlines, don't we know this already? I'm not sure that the pilots will tell us that piece right? The pilots will help to inform us of how to handle more dynamic nominations, but the deadlilnes are the deadlines.

Comment [A9]: Please review my changes to see if this is sufficient.

Comment [A10]: Per Beth we don't need this verbiage in the PIP. The CAISO has not resolved how DA will be handled.

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duration that best fits with their operational needs. Curtailment durations are pre-selected by CBP participants and are available in increments of:

- 1-4 hours
- 2-6 hours
- 4-8 hours.

Customer participation is limited to no more than 1 event per day and ~~24~~ 44 hours during a calendar month. Curtailment hours are between 11:00 am and 7:00 pm Monday through Friday, and exclude weekends and holidays. Customers must remain on the program for a minimum of 12 calendar months.

The Capacity Bidding Program will hold at least one program event per year in order to maintain consistency with the requirements on other sources of Qualifying Capacity.

SDG&E may call an event whenever the electric system supply portfolio reaches a resource dispatch equivalence of 15,000 Btu/kWh heat rate, or as system conditions warrant. CBP events are due to such factors as weather conditions, power plant outages or transmission bottlenecks.

For customers participating directly with SDG&E, the CBP incentive will be calculated based on the customer's actual load reduction. Directly enrolled customers receive eighty percent (80%) of the hourly incentive rate whereas Demand Response Providers receive the full incentive. In no case will a customer receive a credit payment for a given hour if it does not meet the minimum energy reduction threshold, as nominated in the monthly load reduction nomination. The billing and payment of incentive payments , as well as all other amounts, charges, penalties and fees due to or from customers will be made in the course of customer's normal billing for services.

For customers participating through Demand Response Providers, the billing and payment of incentive payments, as well as all other amounts, charges, penalties and fees due will be made according to SDG&E's Rule No. 30, the Aggregator contract.

For aggregators we have reverted to the original program group aggregation baseline rather than individual meters. This provides more flexibly for the aggregators in selecting accounts for their portfolios. We are also expanding the Day-Of Adjustment cap plus or minus from 20% to 40%, this is to take into account for larger variations in the customers operations.

~~Participating Accounts will be split into two groups for the purposes of determining the BHEU ("Baseline Hourly Energy Usage"). The high use group will consistent of all Participating Accounts with an average monthly maximum demand greater than 1000 kW for at least 3 of the most current 12 months and the low use group will contain all other Participating Accounts. For the high use group the customer cap will be equal to 1.4 and the customer floor will be equal to 0.6 unless another cap or floor is mutually agreed to by aggregators and SDG&E in May of each program year or when the customer first enrolls in the program.~~

~~Participant must remain in the program for a minimum of 12 calendars or no longer than a maximum term of 36 month. At the conclusion of the 36-month term, unless notice is provided by the customer to the utility to the contrary, the agreement shall automatically extend for an additional 12 months. Such extension shall apply to each succeeding 12-month period unless notice to the contrary is provided by the customer to the utility. This provides flexibility to aggregators to enter into multi-year contracts with cutomers.~~

- **Incentives (program benefits)**

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- Participants will receive a monthly capacity payment and energy incentives during events in return for load reduction when requested.
- ~~Participants may also taking advantage of the opportunity to enroll in our Technical Assistance Technical Incentive (TA/TI) program which provides free technical audits and technology incentives to customers who install technologies for Auto and semi-auto DR and commit to participating in a Demand Response program for 12 consecutive months.~~
- ~~Customers can receive $300 per kW for Auto DR and $125 per kW for semi-auto DR.~~

- ~~The program may utilize direct response, cross program marketing, internet marketing/enrollment and third party Demand Response Providers program promotion.~~

- ~~Direct response and internet marketing messaging may be sent to customers with the benefits of DR participation.~~

- ~~Social media and community based organizations and partnerships will be used to market too hard to reach segments.~~

- **Program cycle**: ~~2012-2014~~2015-16

- **Program budget:**

  - Total Administrative Cost

    - (Managerial and Clerical Labor, Human Resource Support and Development, Travel and Conference Fees, and General and Administrative Overhead (labor and materials).

  - Total Direct Implementation Cost

    - (Includes all financial incentives used to promote participation in a program and the cost of all direct labor, installation and service labor, hardware and materials, and rebate processing and inspection used to promote participation in a program.)

  - Total Marketing & Outreach

    - (Includes all media buy costs and labor associated with marketing production.)

  - Integrated Budget Allocated to Other Programs

    - (Includes budget utilized to coordinate with other DR programs.)

PROGRAM STRATEGY

~~(Provide estimated quantitative information on number of projects, companies, non-incentive customer services and/or incentives that program aims to deliver and/or complete in 2012-14 timeframe. Provide references where available.)~~

- **Target audience**: Non-Residential

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- **Marketing, Education &Outreach**

~~SDG&E plans to market this program directly to large customers through the Demand Response Providers. This segment is already familiar with the objectives of demand reduction and many of the available programs. Customers usually choose to speak directly with the Demand Response Providers for information on program specifics.~~

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~~The following specific marketing activities are planned.~~

~~Date~~	~~Activity~~
~~2012-2014~~	~~Conduct 2 Annual Off site Customer Trainings~~
~~2012-2014~~	~~Present Information at Demand Response Providers Sponsored Forums~~
~~2012-2014~~	~~Print Fact Sheets~~
~~2012-2014~~	~~Conduct special training for Demand Response Providers~~
~~Each year~~	~~1 Customer Recognition Newspaper Ad~~

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- ~~The CBP Program will work closely with the Military to determine how we can get this group of customers to participate in demand response programs.~~

~~CBP Program Marketing Tools~~

~~Cost~~

- ~~Segment Targeted Email 444,000 @ $.01 + $500(set-up fee) $5,500 (12 times)~~
- ~~Segment Targeted Direct Mail 60,000 @ $3.00 +$30,000(cost/creative)~~
- ~~Micro Website Internal$10,000~~
- ~~Social Media $5,000/yr~~
- ~~Retailers/Manufacturers(POS) $5,000/yr(signage, flyers, etc.)~~
- ~~Newsletters 60,000@ $1.50+$30,000(design)~~
- ~~Demand Response Providers Free~~
- ~~Public Relations Free~~
- ~~Public Affairs Free~~
- ~~SDG&E Events Free~~

- ~~Cross Program Marketing (Third Party On-line Presentment)~~
  - ~~Internet Marketing~~
  - ~~Energy Efficiency Programs~~
  - ~~Renewables~~
  - ~~New Constructions~~
  - ~~Partnerships~~

~~Customers will receive educational and event specific marketing to assist with DR participation and load reduction goals. Listed below are the tools that will be utilized to educate and notify participants about DR.~~

Program Implementation Plan (PIP)
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- ~~Welcome Kits(Education)~~
- ~~Event Performance (Education)~~
- ~~Text (Event Notification)~~
- ~~Email(Event Notification)~~
- ~~Phone Calls(Event Notification)~~
  - ~~a. Content~~
    - ~~i. Environmental messaging~~
      - ~~1. Saving the environment~~
      - ~~2. Saving SDG&E physical resources~~
    - ~~ii. Saving money~~
    - ~~iii. Saving energy~~

- **Internal Training Efforts and Activities**
  Internal groups will be educated about the CBP program details and customers eligibility. The CBP Program will work internally to develop cross program marketing collateral to educate and recruit customers.

- **Program Delivery**
  We expect participation in this program to increase becasue of the added 30 Min. product. and the launch of the TI program. ~~significantly increase as 20,000 additional customers with Smart Meters will be eligible to participate on this CB program.~~

  ~~This program will utilize target marketing to recruit customers over the three year program cycle. Once customers have accepted the program offer they will receive a start up package with the necessary forms to start the enrollment process. The Program will push for Technical Assistance Technical Incentive (TA/TI) program which provides free technical audits and technology incentives to customers who install technologies for Auto and semi-auto DR. Participants will receive marketing information on IDSM opportunities concerning Energy Efficiency and self-generation.~~

- **Customer Research & Feedback**
  The CBP Program will utilize the following tools for research and feedback:
  - ~~Customer Surveys~~
    - ~~Segmentation~~
    - ~~Online~~
    - ~~Mail-in~~
  - Smart Meter Data
  - DR Participation Data
  - Impact evaluations
    - Measure event and non-event changes in energy use due to the program
    - Provide estimates of gross and net energy and demand saving
  - Process evaluations
    - Provide recommendations to improve program effectiveness
    - Document program procedures and activities
    - Measure customer satisfaction
    - Often include surveys and/or interviews of program personnel, trade allies and contractors who help implement the program, and customers.

- **Key stakeholders**

  - Retailers/Manufacturers(POS)
  - Technology Installers
  - CCSE

- Energy Innovation Center
- Energy Information Center
- Public Relations
- Public Affairs
- Smart Meter Group
- Smart Grid Group
- CAISO

- **Program issues and risks**
  - There are "unknowns" about the technology and protocols
  - Customers don't understand DR/Pricing, etc.
  - Retailers entering into the market
  - CPUC/CAISO Demands
  - Customer confusion on types of events
  - Customer satisfaction
  - Event fatigueness

- **CAISO relationship, if applicable**

- **Statewide coordination** (with other IOU's, Demand Response Providers, Stakeholder groups etc.)

PROGRAM THEORY AND OTHER ATTRIBUTES

The CBP allows participation by individual customers or through third-party Demand Response Providers who sign up customers into a load reduction portfolio. Installed technologies will empower customers to improve DR participation and manage their business electric energy usage. With the emergence of renewable and battery storage participants will be educated about IDSM integration opportunities with the installed communicating technologies.

Installed technologies may be expected to:

1. Automate load reduction during demand response events
2. Notify participants that a DR event is pending, terminated, underway, or completed
3. Provide off-peak load shifting capabilities
4. Allow remote connectivity and controllability of technologies
5. Indentify and notify the utility and participants of IDSM opportunities
6. Be reliable long-term solutions to DR and IDSM

The enabling technologies provided to participants will be essential to automate load reduction within the business, alleviating the need for the customer to take actions to initiate DR strategies during an event. These enabling technologies will also give participants the opportunity to receive one time incentive of $300 kW. All SDG&E customers will be educated on how TA works and how TI enabled technologies can increase their CBP participation incentive. Participants will be provided conservation tips to maximize their CBP incentive. The CBP Program may also promote community competitions with prizes for customers that reach high levels of DR participation.

<u>SDG&E long-term goals:</u>

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- Partner w/ Retailers to marketing and promote DR capable technologies
- Provide additional incentives that encourage program enrollment.
- Provide technology features and capabilities allowing for maximum utilization of DR components.
- Enhance current online tools for participants to manage their equipment and energy bills.

- **Program design to overcome barriers**

Multiple Participation
Multiple participation creates confusion for customers who are notified for multiple events.

~~**Technology Integration with AMI Network**~~
~~As the utility integrates DR enabling technologies onto the AMI Network the utility will have to ensure that this process is handled efficiently and securely. As these enabling technologies emerge the utility with have to work with manufacturers to ensure technologies can be added to the network efficiently and seamlessly. Negative technology integration impacts may include, lengthy installation times, communication failures between the enabling technology and the AMI network, security breaches to utility or participant site and usage information. To overcome these barriers the utility will work closely with manufacturers to test and ensure the enabling technology integration as required and expected by utility Management, IT, Security staff.~~

~~**Enabling Technology Installation**~~
~~This program anticipates installing enabling technologies at business sites over the three year program cycle. The coordination of this task will cut across many SDG&E groups and require an exceptional amount of proactive company synchronization including procurement, testing, installing, joining the network, and keeping the enabling technologies fully functional. Overcoming these barriers will require hours of diligent testing, regular meetings between required groups and the utilization of industry communication standards.~~

~~**Economic Downturn**~~
~~The economic downturn will be a big issue in getting customers enough information to implement any suggestions that might be needed from their operating budgets.~~

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Education and Awareness
The general lack of awareness about the program, in particular needs to be addressed. Greater outreach efforts, through workshops, association afflictions, larger assigned accounts and enhanced website presentations will be developed.

- ~~**Best Practices**~~

~~This program will utilize statewide and nationwide DR best practices and lessons learned for DRWMP, enabling technologies programs, and ISDM programs.~~

- **Addresses strategic drivers**

~~The strategic drivers:~~

~~**Alignment with Resource Adequacy**~~

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~~Resource adequacy program has two goals. First, it provides sufficient resources to the California Independent System Operator to ensure the safe and reliable operation of the grid in real time. Second, it is designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future. The intent of the Resource Adequacy (RA) program is to ensure that sufficient capacity is available to meet the needs of California Public Utilities Commission (CPUC) jurisdictional Load Serving Entities (LSEs)[1].~~

- ~~Proposed DR Programs to be Compatible with RA Rules (Measurement Hours)~~
  - ~~Program Hours: 4:00 pm – 9:00 pm Nov-Mar and 1:00 pm – 6:00 pm Apr-Oct~~
  - ~~Program Event Lengths/Consecutive Event Days: 4 consecutive hours on 3 consecutive days~~
  - ~~Program Test Events: Starting in 2012, every program to hold at least one event/year. If no actual event by late summer, call test event in Aug/Sep~~

- ~~**Targeted Dispatch**~~
- ~~"Demand response programs that can be dispatched locally to mitigate local capacity constraints could mitigate the need to spend some additional money on transmission and distribution upgrades…"~~
  - ~~ALJ Ruling at page 9~~
  - ~~Utilities SHALL design DR programs with locational dispatching capabilities~~
- ~~Estimate a value associated with locational dispatch capabilities, or qualitatively describe their potential impacts in constrained areas~~
- ~~Utilities encouraged to create programs targeted towards specific transmission facilities and contingencies~~

  ~~This program will utilize locational dispatch to alleviate the need to spend company dollars for transmission and distribution upgrades. Being able to reduce load in an automated fashion will allow for the utility to maximize current transmission and distribution resources.~~

- **DR Integration with CAISO Wholesale Markets**
- **SDG&E will utilizie a portion of the Capacity Bidding Program load to participate in the CAISO wholesale markets. As it stands, this program is most closaely aligned with the Proxy Demand Resource (PDR) CAISO product.**
- ~~Report required to CPUC by January 31, 2011~~
- ~~Lessons learned from 2009 PLP Pilot~~
- ~~Evaluation of costs and benefits of integrating all DR programs into PDR/PL systems developed by CAISO~~
- ~~Assessment of the effect of each DR program on scarcity pricing~~
- ~~Identification of barriers to integration with PDR/PL~~
- ~~Suggested next steps on how to address barriers~~

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- **Innovation**

Allowing automated DR lessens the need for customer action to respond to DR events.

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[1] ~~Commission Jurisdictional LSEs include all Investor Owned Utilities (IOUs) Electricity Service Providers (ESPs) and Community Choice Aggregators (CCAs)~~

Allowing customer choice and preferences ensures that customer's satisfaction remains high.

- **Integrated/coordinated DSM** (if applicable)

  1. Leverage customers participating in DR to EE programs

EM&V

(Describe any process evaluation or other evaluation efforts that will be undertaken by the utility to determine if the program is meeting its goals and objectives. Include the evaluation timeframe and brief description of scope, as well as a summary of specific methodologies, if already developed. If not developed, indicate the process for developing them. Please include, as well, whether there are program-tracking databases that will be needed for evaluation purposes.)

(Note: This section will require input and coordination with Kevin McKinley and Leslie Willoughby)

PILOTS

~~(Please describe any pilot projects that are part of this program)~~

Lessons Learned and Best Practices will be utilized from DRWMP pilot and implemented within this program.

PERFORMANCE METRICS

- Success indicators
- Key milestones

Customer Participation goal
Customer satisfaction goal
Load reduction goals

~~PROGRAM LOGIC MODEL~~

~~(Provide a program logic model)~~

~~Factors Considered in Review of Proposals~~
~~Decision 09-08-027 August 20, 2009~~

~~1. **Cost effectiveness:** The cost effectiveness analysis contained in these applications is based on a Consensus Framework proposed by most of the parties in R.07-01-041. This framework is not as broad as the subsequent protocols proposed by Commission staff, which required a sensitivity analysis of many inputs rather than a single benefit/cost ratio for each program and test.~~
~~However, it does provide a useful estimate for examining the cost effectiveness of programs. For a more detailed discussion of the usefulness and limitations of the~~

~~Consensus Framework cost effectiveness estimates used in these applications, see Section 7.1 below.~~

~~2. **Track record of performance for continuation of existing programs:** This includes, but may not be limited to, actual load drop (especially compared to enrolled load and estimated load drop), target groups and types of participants, actual cost, how often it was called, actual load drop rate, actual load pick-up rate, and other factors as appropriate.~~

~~3. **Projected future performance:** Expected performance in the future including, but is not necessarily limited to, estimated participation (customers and enrolled load) and estimated load drop at peak times.~~

~~4. **Cost.**~~

~~5. **Flexibility or versatility:** Whether a program can be called under a variety of circumstances, or only in very rare or specialized situations. For example, does the program have multiple triggers? Can it be called on a price responsive basis for simple day to day resource dispatch, as well as for contingency matters such as emergencies? Can it be called in non-summer months to respond to generator outages?~~

~~6. **Adaptability to changes in the structure of the electricity market:** Ability of a program to adapt to the Market Redesign and Technology Upgrade (MRTU) and the new CAISO markets. For example, is a program likely to be able to supply some of the operational characteristics of Proxy Demand Resource or participating load? What interaction or shared dispatch and control could CAISO have with the program?~~

~~7. **Locational value:** Whether the program can be called by location. For example, can the program be activated ("called") by specific location if necessary, particularly in transmission and distribution congestion areas? Does the program help to alleviate a particular geographic challenge? Does it count towards locational resource adequacy or more specific local needs?~~

~~8. **Integration with advanced metering infrastructure, Smart Grid, and emerging technology:** What enabling technologies are required for the program? Would this enabling technology become obsolete or redundant once AMI is installed at the participant customers site? Will the program increase the operational capability of AMI? How might the program contribute to a Smart Grid?~~

~~9. **Consistency of offerings throughout the state:** Are equivalent programs available in or appropriate for other parts of the state? Is the program consistent enough across utilities that commercial customers with multiple facilities can participate easily?~~

~~10. **Simplicity/Understandability:** Can customers understand how the program operates and what is expected of them?~~

~~11. **Customer acceptance and participation:** Are participating customers likely to recognize that the program had been called? Is participation likely to cause customer hardship? Can the customer override an event – if so what does the utility expect will be the rate of customer override?~~

~~12. **Environmentalbenefits:** Does the program have any particular environmental benefits that other programs do not have? Does the program help with firming intermittent renewable energy?~~

~~13. **Contribution to existing Commission or state policies and goals:** Is the program consistent with statewide goals or policies? For example, will the program simply shift usage from peak to another time or does the program also reduce overall usage? Is it integrated with other demand-side programs? Does it result in significant greenhouse gas (GHG) reductions?~~

Proposed Demand Response
Demand Bidding Program
Program Implementation Plan (PIP)
~~2013~~2015-~~2014~~2016

Program Name

Demand Bidding Program (DBP-DO) & Demand Bidding Program- Navy only (DBP-N)

Projected Program Budget

Program Name	~~2013~~ 2015Budget	~~2014~~2016 Budget	Total ~~2013~~2015-~~2014~~ 2016 Budget
Demand Biddin Program	$877,904	$877,904	$1,755,808

Projected Load Impacts by Year

Program Name	~~2013~~ 2015 Load Impact	~~2014~~ 2016 Load Impact
Demand Bidding Program	~~10~~ 7 MW	~~10~~ 7 MW

Projected Cost Effectiveness for 2012-2014

Program Name	~~2013~~2015-~~2014~~ 2016 Cost Effectiveness
Demand Bidding Program – Navy only	~~3.79~~ **2.02**
Demand Bidding Program	~~4.32~~ **2.45**

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Program Descriptors

- **Market Sector**
  - Non-Residential
- **Program Classification**
  - Core
- **Program Statement**
  - ~~The~~ Both Demand Bidding Program offers incentives to non-residential customers for reducing energy consumption and demand during a ~~specific day of~~ Demand Bidding Event. Both Demand Bidding Program ~~was~~ were designed to overcome barriers that have in the past ~~have~~ limited larger customers from participating in demand response programs to their full potential. The program characteristics are: no penalties for non-performance or under performance, the immediately

preceding similar day prior to the event baseline with day of adjustment, bidding demand reduction capabilities ~~the day prior~~ and aggregation ~~up to 5~~of billable meters. An event shall be initiated upon notice from the CAISO of a stage 1, 2, 3 emergency or imminent statewide transmission emergency, or as conditions warrant by SDG&E.

Demand Bidding Program- Day Of (DBP-DO) distinctions:

- A participating customer may aggregate up to 5 billable meters.
- A participating customer must be capable of providing at least 5 MW of load reduction within 30 minutes of being notified.
- An event shall be initiated upon notice from the CAISO of a stage 1, 2, 3 emergency or imminent statewide transmission emergency, or as conditions warrant by SDG&E.
- Customers are notified of an event 30 minutes prior to an event.
- The customer provides their estimated MW reduction with their -signed contract and that is utilized as their initial bid. The customer can submit a new value anytime throughout the year.
  - If an event is called the customer has the opportunity (30 minutes prior) to increase or decrease their bid.
  - The bid will reset after an event to their contract MW reduction value after an event.
- Customers who successfully shed load will receive $600/MWh if they achieve at least 60% of their load reduction bid or up to 150% of their load reduction bid.

Demand Bidding Program- Navy Only (DBP-N) program distinctions:

- A participating customer may select a pool of up to 20 billable meters, with only 8 billable meters to be bid in for a day ahead event.
- A participating customer must be capable of providing at least 2 MW of load reduction for the next day during event hours.
- The customer bids the day prior to the event when the receive notification.
- An event can be initiated upon notice from the CAISO of a stage 2, stage 3 emergency, a transmission or imminent system emergency, or as local emergency conditions warrant by ~~the Utility~~SDG&E.
- Customers who successfully shed load will receive $500/MWh if they achieve at least 50% of their load reduction bid or up to 150% of their load reduction bid.

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- **Program Fundamentals**
  - See Demand Bidding Program Tariff

Program Rationale and Expected Outcomes

- **Implementation Design**
  - **Delivery mechanisms**
    - **DBP-DO**
      - DBP customers ~~provide bids daily for the next day.~~ estimated MW reduction is use for their initial bid.
      - Customer may update their bid within that 30 minute window to either increase or decrease their bid.
      - SDG&E accepts all bids unless CAISO asks for a specific amount of curtailable load.
      - SDG&E will call events no later than 30 minutes prior to the event, notification is sent through an email and a confirmation of bid email is sent.

Proposed Demand Response
Demand Bidding Program
Program Implementation Plan (PIP)
~~2013~~2015-~~2014~~2016

- **DBP-N**
  - DBP-N customers will submit their selected 8 billable meters and provide their load reduction bid the day prior to the event.
  - SDG&E accepts all bids unless CAISO asks for a specific amount of curtailable load.
  - SDG&E will make all efforts to notify the customer of an event the day prior by 13:00. In the event of an event that occurs after 13:00 all parties will make their best effort to facilitate the bidding process.

- **Incentives**
  - The c~~C~~ustomers participating in DBP-DO will receive $6~~5~~00/MWh for DBP-DO events.
  - The customers participating in DBP-N will receive $500/MWh for DBP-N events.

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- **Delivery and Coordination**
  - This program will work internally with stakeholders to determine if conditions warrant the program being activated, as well in collaboration with the CAISO operating procedures. The program will continue to look for ways to enhance the measureablity of the customers load reduction.

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Comment [kk1]: I need some help on how to discuss the desire to look into sub metering to see if it will enhance the customers' ability to shed load. I don't think we want to directly call it out.

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- **Program Objectives**
  - Provide a highly dependable quantity of DR that can be called on to mitigate transmission system emergencies or contribute to system reliability needs during emergencies or price spikes.
- **Program cycle**

~~2013~~ 2015 ~~-~~ - ~~2014~~2016

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Program Strategy

- **Target Audience**
  - DBP-DO: Large Commercial and Industrial customers who can curtail 5MWof curtailable load.
  - DBP-N: Customers who are considered a Navy branch of the federal government.

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- **Marketing, Education & Outreach**
  - N/A
- **Aggregator Considerations**
  - ~~BIP will be designed to enable participation of an Aggregator with large or small aggregated resources that may be configured to offer energy economically in response to a reliability event for the delivery of energy in a real-time emergency.~~ N/A

Comment [kk2]: We cleaned this up in a separate filing, but couldn't find it. Requested from Mark, but he couldn't find it either. It would have been in January or February of 2013

- **CAISO Relationship**
  - ~~The proposed modifications to the program that will be made to comply with the Settlement Agreement will allow BIP to integrate into the California ISO market and operations and be dispatched by the CAISO real-time economic dispatch algorithm. The enrollment caps for the program which are also required by the Settlement Agreement are designed to limit the amount of DR that is not visible to the CAISO wholesale market process.~~ N/A

Comment [kk3]: See comment above

- **Statewide Coordination**
  - ~~The CPUC, CAISO, PG&E and SCE are parties to the Settlement Agreement and the modifications to BIP are consistent with the direction and efforts to modify other emergency DR programs throughout the State.~~ N/A
- **Integrated/coordinated DSM**
  - Participation in ~~BIP~~ DBP-DO or DBP-N does not interfere with a customer's ability to invoke Energy Efficiency measures. The program participants are encouraged to participate in Energy Efficiency, Distributed Generation and other DSM activities. ~~The use of a firm service level for event measurement and the Excess Energy charge create a need for an increased level of active~~

~~energy management, providing an incentive for participants to seek additional tools and opportunities to manage their energy use.~~

EM&V

- Annually a load impact evaluation of the program will be conducted in accordance with the load impact protocols including a ten year forecast based on ex-post event results. The impact evaluation will be completed by April 1st each year and will be filed with the CPUC. Additionally, other analysis related to program design (such as a baseline analysis) will be conducted as needed. One process/market evaluation for the program is planned during the three year cycle to be used to inform future program design and to evaluate and improve the operation of the program.

Pilots

- ~~As an emergency program that is ultimately limited by the enrollment caps imposed by D.10-06-034, any pilot activity associated with the program would be for enabling technologies from other programs and not exclusive to BIP.~~N/A

Local Marketing, Education and Outreach (LMEO) Program Implementation Plan (PIP)

Program Name and Program ID

~~Other Local Marketing~~

Local Marketing, Education and Outreach (LMEO)

Projected Program Budget

Program Name	2015 Budget	2016 Budget	Total 2015-2016 Budget
Reduce Your Use	$ 250,000.00	$ 250,000.00	$ 500,000.00
Reduce Your Use Thermostat	$ 400,000.00	$ 400,000.00	$ 800,000.00
Peak Load Shifting	$ 25,000.00	$ 25,000.00	$ 50,000.00
Technical Incentives	$ 50,000.00	$ 50,000.00	$ 100,000.00
CPP-D	$ 750,000.00	$ 500,000.00	$ 1,250,000.00
Smart Pricing	*N/A (Funded from D.12-12-004)*	$ 1,000,000.00	$ 1,000,000.00
TOTAL	**$1,475,000.00**	**$2,225,000.00**	**$3,700,000.00**

Projected Load Impacts by Year

N/A

Projected Cost Effectiveness for 2015-2016

N/A

Program Descriptors

- **Market sector**
  - Residential, Non-Residential
- **Program Classification**
  - Core
- **Program Statement**
  - The Local Marketing, Education and Outreach (LMEO) program encompasses local program specific marketing efforts for the 2015-2016 implementation of the Reduce Your Use (RYU), Reduce Your Use Thermostat (SCTD,)Peak Load Shifting (PLS) programs, Technical Incentives, CPP-D for mid-size customers and Smart Pricing programs. Per D-12-04-045, Ordering Paragraph 22. SDG&E has re-categorized the individual Demand Response program marketing requests into the Local Marketing, Education, and Outreach (ME&O) subcategory of the ME&O category. Per D-12-12-004, SDG&E is including costs related to the marketing, education and outreach efforts for the default of mid-size customers to CPP-D rates, and for the post 2015 costs of SPP rates for small business, agricultural and residential customers in this demand response application.

Program Rationale and Expected Outcomes

- **Program Implementation and Design**
  - **Delivery mechanisms**

- The Reduce Your Use program will continue to focus on an educational campaign for residential customers about the program and how to benefit from participation. Ongoing engagement with enrolled customers will be provided with event-day with conservation tips and education about the benefit of utilizing enabling technologies to maximize their bill credit.
- The Reduce Your Use Thermostat (SCTD) Program will facilitate implementation of Automated Demand Response (DR) enabling technologies at no cost to residential and small commercial customers. SDG&E will use interval data to identify specific segments for marketing and education regarding the thermostats and how they can enable participation in local demand response events.
- The Permanent Load Shifting (PLS) program provides eligible customers an incentive to purchase and install qualified PLS technology for the purpose of shifting peak load to off peak hours on a regular basis. Marketing and education will focus on keeping the limited number of enrolled customers engaged and updated about demand response events and load-shifting strategies in order to incentivize the highest response.
- The Technical Incentives (TI) program provides qualified financial incentives to participating customers that are ntended to encourage customer adoption and installation of DR strategies, measures and enabling technologies. Limited ongoing funding is requested to maintain existing program materials, conduct outreach and training for segmented and targeted business customers, and to continue to encourage conservation through the use of enabling technology.
- The CPP-D rate will be made the default rate for all mid-size (20 – 200kW) customers starting in 2015. A high-touch campaign focused on rate education, event management strategies via direct marketing and outreach to this specific segment of commercial and industrial customers will launch in 2015 with the default to the new rate.
- The SPP rate for small business and residential customers will launch in 2015. Funding received as part of the Demand Response application for 2016 will maintain the targeted communications that are delivered to residential and small business customers that inform them of their rate options and of the applicable event management strategies (for customers on the rate with the event component) so that customers are engaged in conservation strategies and participate in local demand response events.

- **Delivery & coordination**
  - **Program Objectives**
    - The main objective of local marketing is to
      - Encourage enrollment in local utility demand response programs;
      - Encourage understanding of available local technology to assist with demand response participation; and
      - Incentivize participation in actual local event days through continuous engagement with enrolled customers
  - **Program Cycle**
    - 2015-2016

Program Strategy

- **Target Audience**
  - Reduce Your Use is targeted at all SDG&E Residential customers. Targeting will work in conjunction with customers who are identified as opportunists under the rollout of the Smart Pricing tariff for residential customers.
  - The Reduce Your Use Thermostat program is targeted at all SDG&E Residential customers, and will utilize load profile data and analysis to identify the correct audience for targeted efforts
  - The Peak Load Shifting program marketing efforts will be targeted at business customers who are already enrolled in the program.
  - The Technical Incentives program is targeted at large commercial and industrial customers who are eligible for incentives
  - The CPP-D program is targeted at customers with demand above 20kW
  - The SPP program is targeted at residential customers, and commercial and agricultural customers with demand less than 20kW

Marketing Education & Outreach

- Reduce Your Use marketing will:
  - Convert current subscribed customers
  - Employ direct targeted efforts, including online, direct mail and e-mail
  - Proactively engage with customers through outreach in order to enroll them in event alerts and notifications
  - Increase the number of customers who are receiving and responding to event day alerts
- Reduce Your Use Thermostat marketing will:
  - Maintain the customer base that was recruited in 2014 through email or direct mail
  - Contact customers that were recruited during 2014 to remind them about the demand response season
  - Recruit additional customers into the program, based on an analysis of benefits and program applicability
  - Utilize SDG&E's network of local community based organizations in order to engage in marketing, education and outreach with hard-to-reach and underserved communities to encourage participation in demand response programs and conservation strategies in order to lower their bills
- Peak Load Shifting marketing will:
  - Update and maintain program specific marketing and education materials
  - Conduct outreach and education via specific thermal energy storage workshops at the Energy Innovation Center
- Technical Incentives marketing will:
  - Update and maintain program specific marketing and education materials
  - Conduct outreach and education via workshops at the Energy Innovation Center and from SDG&E Account Excutives
- CPP-D marketing will:
  - Educate and inform mid-size customers of their new default rate by building the foundation of knowledge needed for understanding CPP and how different

options/selections and actions can help customers be successful through event participation
    - Conduct targeted direct marketing campaigns to help customers understand time-of-use rates, how to prepare for CPP-D events, and to encourage event response and conservation when asked.
    - A dedicated web presence, including specific interactive content with rate information and event management strategies will be developed.
    - Conduct rates and solutions workshops at targeted industry segments
  - SPP marketing will:
    - Maintain targeted communications from the rate launch
    - Drive continued enrollment in the Energy Management tool and all of the relevant goals, alerts, subscriptions, rate analysis options and other tools behind SDG&E's My Account portal.
    - Delivere messages to residential and small business customers that inform them of their rate options and of the applicable event management strategies
    - Utilize SDG&E's network of local community based organizations in order to engage in marketing, education and outreach with hard-to-reach and underserved communities and to encourage participation in demand response events and conservation strategies in order to lower their bills
    - Increase engagement with customers in order to promote conservation strategies and participation in local demand response events.

- **Program Delivery**
  - Program objectives will be accomplished through the use of the following:
    - Targeted and localized communications, e.g. direct mail, and e-mail
    - Reminder and reengagement efforts to current subscribed customers
    - Integration into Business customer outreach seminars and events

- **Aggregator Considerations** N/A
- **CAISO** N/A

Statewide Coordination

  - Coordination with the Statewide Marketing Education and Outreach (SWMEO)~~team~~ effortis critical in order to ensure that messages are consistent and that customers understand the local offers available through SDG&E. Per D.13-12-038, the SWMEO effort will include information about demand response concepts and time of use rates at the statewide level. Local program marketing will leverage the education provided by SWMEO to the maximum extent in order to enable localized communications and increase customer engagement with dynamic rates and other demand response programs as well as encourage participation in local demand response events.

EM&V N/A
Pilots N/A

Small Customer Technology Deployment Program Implementation Plan (PIP)
2015-2016

Projected Program Budget

Program Name	2015 Budget	2016 Budget	Total 2015-2016 Budget
SCTD	$4,094,825	$4,094,825	$8,189,650

Projected Load Impacts by Year

Program Name	2015 Load Impact	2016 Load Impact
SCTD	9.8 MW	9.8 MW

Projected Cost Effectiveness by Year (TRC - Calculated in combination with PTR)

Program Name	2015 Cost Effectiveness	2016 Cost Effectiveness
SCTD	~~1.2~~ 0.97	~~1.2~~ 0.97

Program Statement

- SDG&E will use Smart Meter interval data along with other tactics to identify, market to, and install load control devices in the homes or businesses of residential and small commercial customers with peak usage attributed to air conditioning and other loads that could provide demand response, such as pool pump load
- SCTD enabling technologies will allow SDG&E to send a signal to reduce the electric use of specific equipment. The intent of these enabling technologies is to make it easier for customers to participate in Peak Time Rebate or dynamic rates, and to make the load reduction more reliable by automating load reduction associated with central air conditioning, pool pumps, and other potential peak usage equipment that could provide demand response.
- Tailored deployment strategies will help to maximize the level of customer education, participation, use, and acceptance of commercially available demand response technologies
- The SCTD program will give customers the ability to manage various end-use

electric loads year-round through the use of utility tested and validated, enabling technology. These technologies will empower customers who are currently less likely to engage in demand response and energy actions to improve these activities by using the automated solutions provided by this program.

Program Fundamentals

- Residential customers participating in SCTD must either be on residential rates compatible with Schedule PTR or must have elected to participate on an optional dynamic rate
- The curtailment window for Demand Response (DR) events for both residential and small commercial customers participating in SCTD will be based on their electric service rate
- Eligible residential customers with installed, paired, and verified enabling technologies will be eligible to receive a higher bill credit of $1.25 per kWh reduced on PTR event days
- Customers who participate on a dynamic rate will receive the benefits of managing their energy according to the time of use and shedding load during peak periods

Program Rationale and Expected Outcomes

- Delivery Mechanisms
    - SDG&E customers may be recruited through a variety of channels including contractors, cross-program marketing, internet marketing, and highly targeted direct mail or e-mail
        - Ongoing communication and/or engagement will be through the customers' preferred channel when applicable.
- Demand Response Incentives
    - Participating customers will receive devices at no cost or low cost through rebates
    - Contractors can offer no or reduced cost installations
    - Customers will be eligible for any incentives or reduced costs associated with the program/rate in which they are enrolled.
- Delivery and Coordination
    - Program is designed to leverage AMI infrastructure and facilitate participation in existing and future dynamic rates and DR programs for which the customer qualifies
    - Customers will have access to online information about how to participate in DR events, and how to best manage energy and make informed choices
    - SDG&E may roll out SCTD in a phased approach during the Bridge years, depending on 2014 results
- Program Objectives
    - SCTD will introduce the technology and empower customers to automate load reduction, to minimize the need for the customer to take action to initiate load reduction during a DR event, whether the customer is participating on the PTR tariff or a dynamic rate.
    - SCTD will provide an option for residential and small commercial customers

who have not had the opportunity to participate in DR programs with automation
- Key program goals are to
  - Optimize DR program awareness, participation through adoption of technology
  - Achieve a predictable load reduction
  - Deliver a positive customer experience during a demand response event
  - Leverage new and developing channels to bring cost effective enabling technologies to customer including the retail channel
  - Continue to take lessons learned and put in place best practices for continuous improvements

Program cycle:
- 2015-2016

Program Strategy

- Target Audience
  - SDG&E residential customers on a rate compatible with PTR or on an SDG&E residential dynamic pricing rate; timed with the roll out of DR messaging to Home Area Network devices when available.
  - SDG&E's small commercial customers on a dynamic rate
- Marketing, Education and Outreach
  - The SCTD program will coordinate with Customer Education and Outreach efforts to direct customers to programs in order to create an understanding and awareness of Demand Response.
  - The SCTD program marketing effort will focus on utilizing segmentation to identify the proper target audience
  - The SCTD program will leverage the Utilities local knowledge and locally targeted Customer Education and Outreach to enhance the applicability of the outreach effort
- Implementation
  - SCTD will take lessons learned from both previous HAN programs and pilots, and from the 2012-2014 SCTD implementation to inform the direction that the program will take in 2015 and 2016
  - The 2012-2014 model includes direct install to residential customers at no cost
  - Based on 2014 results, SDG&E will determine if it is best to continue with this model, or to move on towards a contractor-driven approach, a retail approach, or some combination of the two
  - Future program design may include a customer pay provision

Customer Research & Feedback

- The SCTD Program may utilize pertinent process and program impact research data collected from Measurement and Evaluation studies. Additional research may be employed to evaluate ongoing activities related to program implementation – these tools may include;
  - Participant surveys
  - Focus groups
  - Smart Meter Interval Data Analysis

  - DR Event participation data

EM&V

- An annual load impact evaluation will be conducted in accordance with the load impact protocols including a ten year forecast based on ex-post event results
- The impact evaluation will be completed by April 1st each year and will be filed with the CPUC
- Other analysis related to program design (such as baseline analysis) will be conducted as needed
- One process/market evaluation for the program is planned during the program cycle
- The 2012-2014 program evaluation will help inform changes/adjustments that can be made in 2015 and 2016 to improve the customer experience

Proposed Demand Response
Program Implementation Plan (PIP)
Technology Incentives
201~~2~~5 -201~~4~~6

Program Name
Technology Incentives (TI)

Projected Program Budget

Program Name	201~~2~~5 Budget	2016~~3~~ Budget	~~2014 Budget~~	Total 2015~~2~~-2016~~4~~ Budget
Technical Incentives	$2,785,708.74~~3,000,000~~	$2,785,708.74~~3,100,000~~	~~$3,200,000~~	$5,571,417.48~~9,300,000~~

Projected Load Impacts by Year

Program Name	2015~~2~~ Load Impact	201~~3~~6 Load Impact	~~2014 Load Impact~~
Technical Incentives	NA	NA	~~NA~~

Projected Cost Effectiveness by Year

Program Name	2015~~2~~ Cost Effectiveness	2016~~3~~ Cost Effectiveness	~~2014 Cost Effectiveness~~
Technical Incentives	NA	NA	~~NA~~

Program Descriptors

- **Market Sector**
  - Non-Residential
- **Program Classification**
  - Core
- **Program Statement**
  - The program provides qualified commercial customers with incentives to help with technologies that enable load reduction, through automated demand response, at the customer location. The program offers up to three hundred dollars ($300.00/kw) of approved, installed and verified kW reduction from a load shed test or 100% of the cost of installing enabling devices, whichever is less for Automated Demand Response (Auto-DR) measures. Only Auto-DR measures that meet open Auto DR Standards will be considered eligible for incentives under this program.
- **Measures:** Not Applicable
- **Non-incentive customer services**
  - The program offers free workshops to both end-use customers and vendors, who might be implementing the technologies that had been identified.

Program Rationale

- **Implementation Design**
  - The Technology Incentives Program is primarily driven through utility Account Executives, Program Advisors, Segment Advisors, third party aggregators, controls vendors, and engineering consultants. It is also promoted through utility held workshops and business associations.

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- SDG&E Account Executives will be involved in promoting the Technology Incentives program to their customers and moving them to an appropriate Demand Response Program, based on what was identified in the audit and the capability of the facility's Energy Management Systems (EMS).
- Customers receiving a Technical Incentive will be obligated to enroll and participate in at least one of SDG&E Auto-DR programs, for three consecutive years.
- Auto-DR technology provided through an aggregator will also enable SDG&E CPP Peak Day option which will provide customers on CPP-D with an incentive payment to curtail on short notice when SDG&E requires load reductions that were not evident in the Day Ahead timeframe.
- The incentive includes a performance based component based upon the customer's actual achieved load reduction using the installed auto-DR device(s).
    - Installation Payment - 60% of the total eligible incentive will be given after installation, load shed test, and upon enrollment in a qualified DR program or rate.
    - Performance Payment - The remaining 40% of the eligible incentive is paid at the end of the first DR season or calendar year as applicable to the program or rate, following the payment of the 60% payment referenced above and is based on the actual rate of participation as determined during the DR season. The full 40% incentive balance will be paid if the customer's participation is equal to or greater than the estimated load reduction. If the actual performance is less than the estimated load reduction, the Performance Payment will be reduced proportionally with the measured load reduction.
    - Example of the 60%/40% split
        - TI Load Shed tested and approved for 100 kW
        - Customer can receive up to $300/kW of approved reduction or cost of enabling, whichever is less. (eligible for up to $30,000 incentive)
        - Total project cost is $35,000 and since this cost is greater than the eligible incentive, the incentive payment is limited to $30,000.
        - The Installation Payment equal to 60% of the total incentive is paid upon installation, load shed test, and enrollment (in this case $30,000 is eligible for incentive) 60% = $18,000
        - After one year of DR event(s) the customer's participation rate averaged 60 kW. (60/100 = .60) The Performance Payment would thus equal 60% of the remaining $12,000 or in this case $7,200.
- ~~An additional TI incentive is available to aggregators who provide Auto DR technology to customers participating on the Critical Peak Pricing Day Ahead rate. Evidence from the Statewide Price Pilot shows that event participation doubles for medium sized customers with enabling technologies. Providing the additional incentive to aggregators is designed to further expand Auto DR capability into the customer space.~~
    - ~~TI incentive payment to Aggregator requires Auto-DR for CPP-D~~
    - ~~Based on Twelve months - $30.00/kW~~
    - ~~Effective January thru December~~
    - ~~$4.00/kW paid monthly May through October.~~
    - ~~$1.00/kW paid monthly November through April~~
    - ~~This provides an incentive, a revenue stream and performance measurement for the aggregator, which keeps the aggregator, engaged with the DR customer~~.
- **Program Cycle**
    - 2015~~2~~-2016~~4~~

Program Strategy

- **Target Audience**
    - The Technology Incentives Program is geared to any commercial, industrial or agricultural customer with a monthly on-peak demand of 20 kW or greater. Its purpose is to enable/incentivize measures that were identified by the Technical Assistance audit.
    - Potential customers are those that can or are participating in one of the following programs; Critical Peak Pricing Default, Capacity Bidding, ~~DemandSMART~~, or any authorized pilot.

- **Marketing, Education & Outreach**
  - The program is typically marketed through utility Account Executive, for the larger assigned customers. Aggregators, Segment Advisors, Program Advisors, controls vendors and auditors are utilized to reach smaller customers.
  - Utility sponsored workshops will be held to educate and direct customers toward automation.
  - The TI program marketing effort focuses on creating program specific material highlighting the benefits to relevant customers with expressed interest and a call to action and develops marketing materials and messages that make it easy for the customer to engage in the enrollment process.
- **Customer Research & Feedback**
  - Follow up during the entire process with the customer needs to have higher emphasis and surveys after measures have been processed need to be continually evaluated for efficiencies and making it user friendly for the customer/vendor.
  - A customer survey will be requested following the installation and enrollment in a DR program to evaluate the process and their experience with the program.
- ~~**Aggregator considerations**~~
  - ~~Aggregators provide a set of "feet on the street" for utility programs. Additional qualified aggregators will be pursued and encouraged to participate in the programs.~~
  - ~~Offering aggregators an incentive to be involved with CPP-D customers, as well as a CPP day of component, will add a new dimension to Auto-DR and at the same time emphasize energy efficiency to the customer.~~
- **CAISO Relationship:** NA
- **Innovation**
  - ~~Incentives for aggregators to drive participation from non-residential customers on CPP Rate~~
  - The TI program is going to be heavily integrated with newly redesigned TA program that has an IDSM focus. The goal will be to properly transition those findings into the TI program along with deeper retrofit opportunities. This specific attempt will result in a high conversation rate than previous years.
  - The TI program is going to adopt the Demand Response Automated Server (DRAS) under its budget while keeping the cap the same. This will ensure a tighter management of ADR customers and their enrollment and longevity in Demand Response retention.
- **Integrated DSM**
  - Emphasis will be given to identify Energy Efficiency opportunities during the entire TI process.
  - Integrated audits, through the TA program, will be stressed so that both demand response and energy efficiency concerns are met for the customer. Approaching each customer with a "whole system" solution will ~~should~~ attract more interest and promote overall efficiencies.

- **EM&V:**
  - Analysis related to program design (such as a baseline analysis) will be conducted as needed. One process/market evaluation for the program is planned during the three year cycle to be used to inform future program design and to evaluate and improve the operation of the program

- **Pilots:** Not Applicable

APPENDIX C

Appendix C

PIPs without program changes

Proposed Demand Response
Base Interruptible Program
Program Implementation Plan (PIP)
~~2012-2014~~2015-2016

Program Name

Base Interruptible Program (BIP)

Projected Program Budget

Program Name	201~~2~~5 Budget	201~~3~~6 Budget	Total 201~~2~~5-201~~4~~6 -Budget
Base Interruptible Program	~~N EED AMOUNTS Please~~$1,228,025 ~~$1,113,000~~	~~$1,283,000~~ $1,728,052	~~$ 4,179,000~~ $2,956,077

Projected Load Impacts by Year

Program Name	2012 Load Impact	2014 Load Impact
Base Interruptible Program	~~11~~ 4 MW	~~16~~ 5 MW

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Projected Cost Effectiveness for ~~2012-2014~~2015-2016

Program Name	~~2012-2014~~2015-2016 Cost Effectiveness
Base Interruptible Program	1.15

Program Descriptors

- **Market Sector**
  - Non-Residential
- **Program Classification**
  - Core
- **Program Statement**
  - BIP is a continuation of the program that commenced in 2001 and offers a monthly capacity payment to non-residential customers who can commit to curtail at least 15% of Monthly Average Peak Demand, with a minimum load drop of 100 kW.
  - If available, BIP will use the CAISO's Reliability Demand Response Product (RDRP) in the ~~2012-2014~~2015-2016 program ~~cycle~~ years to bid into the wholesale market, in accordance with CPUC Decision (D.) 10-06-034, adopting the "Reliability-Based Demand Response Settlement Agreement" (Settlement Agreement) in Rulemaking R.07-02-041 The Settlement Agreement also caps emergency program enrollment and SDG&E will keep BIP below the level established in that proceeding.

Proposed Demand Response
Base Interruptible Program
Program Implementation Plan (PIP)
~~2012-2014~~2015-2016

- While BIP is and will continue to be a retail demand response product that enables emergency responsive demand response resources to state and local situations, modifications will be necessary to meet the requirements of the CAISO RDRP during the ~~2012 – 2014~~2015-2016 program ~~cycle~~years.
- ~~Based on the preliminary design documents provided by the CAISO, SDG&E anticipates making the following modifications to the existing~~ BIP program design:
  - ~~Option B will be eliminated as it does not comply with notification timelines for the RDRP product and historically there is very limited participation in this option.~~
  - Incentive payments will be differentiated by season to better reflect the capacity value of the program on a monthly basis and in alignment with SDG&E's Resource Adequacy needs.
  - Require a least one test event annually if no event is triggered based on program criteria.
  - New Applicant pre-qualification consisting of a load reduction plan and a "pre-enrollment" test event that would be operated like an actual curtailment event to ensure notification equipment is operational and to verify the customer is able to reduce load to or below its proposed Firm Service Level. There would be no penalty for non-compliance with this "pre-enrollment" test, but the customer would not be allowed to enroll at that Firm Service Level. The customer would be allowed to participate in the program only after a successful "pre-enrollment" test of a proposed Firm Service Level and approval of their load reduction plan.
  - Participants who fail to comply with a curtailment or test event will have their Firm Service Level set to the level achieved during the event. ~~In order for this to be effective for the next program month the Firm Service Level will need to be submitted by the 15th of the month.~~
  - Existing customers who want to change their Firm Service Level will be required to perform a re-test before the new Firm Service Level can be established. Changes to Firm Service Levels will only be accepted in November. The re-test must confirm that the new Firm Service Level is achievable by the participate.
  - In order for the FSL change to be effective for the next program month the Firm Service Level will need to be submitted by the 15th of the month.

- **Program Fundamentals**
  - See Base Interruptible Program Tariff

Program Rationale and Expected Outcomes

- **Implementation Design**
  - **Delivery mechanisms**
    - BIP program can be called for multiple reliability-only events, including system emergencies (CAISO alerts and stages), Transmission emergencies (loss of resources), and Local transmission and distribution system (overload) emergencies.
    - Program participants are notified of a curtailment event via the ~~internet~~ SDG&E website, email and/or~~and alpha numeric page~~text if they provide a phone number or email and have 30 minutes from the time of receipt of notice ~~to curtail~~ to achieve ~~load~~ their load drop.
  - **Incentives**
    - Customers receive a monthly capacity payment and are subject to Excess Energy Charges if they do not achieve their Firm Service Level during an event in the manner detailed in the tariff.
  - **Delivery and Coordination**
    - As an emergency program, BIP is designed to be responsive to the CAISO objective to avoid involuntary load shedding when all market based options have been exhausted.
  - **Program objectives**
    - Provide a highly dependable quantity of DR that can be called on to mitigate transmission system emergencies or contribute to system reliability needs during extreme emergencies.

Proposed Demand Response
Base Interruptible Program
Program Implementation Plan (PIP)
~~2012-2014~~2015-2016

- **Program cycle**
  - ~~2012 - 2014~~2015-2016

Program Strategy

- **Target Audience**
  - Medium to large Commercial and Industrial customers who can curtail up to 15% of their firm service level and minimum 100kW and Aggregators who can provide a minimum of 1MW of curtailable load.
- **Marketing, Education &Outreach**
  - ~~The BIP outreach and marketing effort is limited and focuses on educating relevant customers with expressed interest to first explore DR program opportunities that are not restricted to emergency situations.~~This program does not have a marketing budget as directed by the CPUC. The program has experienced some attrition last cycle and will work through internal and external channels to try and identify customers who would be good candidates for BIP to boost available MWs.
- **Aggregator Considerations**
  - BIP will be designed to enable participation of an Aggregator with large or small aggregated resources that may be configured to offer energy economically in response to a reliability event for the delivery of energy in a real-time emergency.
- **CAISO Relationship**
  - The proposed modifications to the program that will be made to comply with the Settlement Agreement will allow BIP to integrate into the California ISO market and operations and be dispatched by the CAISO real-time economic dispatch algorithm. The enrollment caps for the program which are also required by the Settlement Agreement are designed to limit the amount of DR that is not visible to the CAISO wholesale market process.
- **Statewide Coordination**
  - The CPUC, CAISO, PG&E and SCE are parties to the Settlement Agreement and the modifications to BIP are consistent with the direction and efforts to modify other emergency DR programs throughout the State.
- **Integrated/coordinated DSM**
  - Participation in BIP does not interfere with a customer's ability to invoke Energy Efficiency measures. The use of a firm service level for event measurement and the Excess Energy ~~charge~~ Charge create a need for an increased level of active energy management, providing an incentive for participants to seek additional tools and opportunities to manage their energy use.

EM&V

- Annually a load impact evaluation of the program will be conducted in accordance with the load impact protocols including a ten year forecast based on ex-post event results. The impact evaluation will be completed by April 1st each year and will be filed with the CPUC. Additionally, other analysis related to program design (such as a baseline analysis) will be conducted as needed. One process/market evaluation for the program is planned during the three year cycle to be used to inform future program design and to evaluate and improve the operation of the program.

-Pilots

- As an emergency program that is ultimately limited by the enrollment caps imposed by D.10-06-034, any pilot activity associated with the program would be for enabling technologies from other programs and not exclusive to BIP.

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Proposed Demand Response
Emerging Technologies Demand Response
Program Implementation Plan (PIP)
2015-2016

Program Name

Emerging Technologies Demand Response (ET – DR)

Projected Program Budget

Program Name	2015 Budget	2016 Budget	Total 2015-2016 Budget
Emerging Technology Demand Response	$703,625~~04,000~~	$707,345~~707,000~~	$1,410~~1,~~97~~00~~0

Comment [MCS1]: Used the same budget values as 2013 and 2014

Projected Load Impacts by Year

Program Name	2015 Load Impact	2016 Load Impact
Emerging Technology Demand Response	N/A	N/A

Projected Cost Effectiveness for 2012-2014

Program Name	2015 -2016 Cost Effectiveness
Emerging Technology Demand Response	N/A

Program Descriptors

- **Market sectors**
  - Non-Residential
  - Residential
- **Program Classification**
  - Core
- **Program Statement**
  - The ET-DR Program consists of evaluating demand-reducing technologies and strategies that are applicable to the SDG&E region and market. The focus is on technologies and strategies that promise significant, cost-effective demand reduction in the short and/or mid-term time horizon, and that hold promise to be sufficiently reliable and scalable for market-wide implementation. Each evaluation project will address:
    - The technology's or strategy's overall merits
    - Applicability to demand reduction and related factors such as energy efficiency

    - Applicability to our region, market and frameworks such as CAISO
    - Applicability to existing SDG&E programs
    - Possible adoption barriers
    - Cost effectiveness
    - Risks
    - Recommendation about the utility's further support and involvement
  - The program's evaluation projects may include techniques and methods that may not be exclusively technology-driven. The emphasis of each project will vary on case by case basis, and may include:
    - Technology Assessments
    - Scaled Field Placements
    - Demonstration Showcases
    - Technology Development
    - Business Incubation
    - Market / Behavior Studies
  - Technologies or strategies found to be viable may subsequently be integrated into existing utility programs or become the basis for new programs in support of market introduction.
- **Program Fundamentals**
  - Eligibility- All Bundled and Direct Access customers
  - Months of Operation – Year round
  - ET-DR doesn't provide direct incentives. Instead, the program shares the pilot implementation cost at a rate between 0% and 100%. The actual rate and dollar contribution is determined on a case-by-case basis, and depends on the following factors:
    - Total project cost to pilot customer, consisting of
      - Parts
      - Installation
    - Customer Eagerness to Participate
    - Financial viability for the pilot customer (payback time)
    - Anticipated load drop.
- **Measures:**
  - HVAC - Significant demand reduction potential exists for HVAC technologies, in particular related to space cooling in the SDG&E service territory climate. Some projects will explore this potential by evaluating promising HVAC control technologies, including standalone controls as well as those that integrate with the smart grid. Special emphasis will be placed on technologies that are easy to retrofit into existing systems and buildings as these make up the majority of the untapped market.
  - Energy Storage - Decentralized energy storage can contribute to flattening the load curve by shifting demand from peak times to when inexpensive energy is abundant. Also, energy storage will support grid operations to balance local power supply and demand. Several innovative storage methods will be explored, with particular emphasis on practicality and cost effectiveness.
  - Advanced Controls - A large amount of energy is wasted in unoccupied rooms or buildings that are fully conditioned or have their lights on, or have other active consumers of electricity that do not need to be running when not actively in use. A subset of projects will focus on advanced controls that allow for intelligently curtailing, disabling or shifting this energy use such that impact to building occupants is minimal. Priority will be given to technology that integrates with existing,

enabling infrastructure such as internet connections, Wi-Fi networks, BMS, AMI, home automation, etc.

- Electric Vehicles – With an increase in EV vehicles in the marketplace, there is a need to identify technologies and rate structures that enable EV charging with consideration to both consumer desires and grid reliability. There will be continued studies on equipment that enables start/stop and rate-of-charge controls to enable demand response capabilities. There is also an interest in understanding the effects of dynamic pricing options on consumer charging behavior. ~~This demonstration will complement SDG&E's EV Rate and Technology Study with temporary experimental EV rates approved by the CPUC in June of 2010. A variety of electric vehicle supply equipment (EVSE), communication and transaction processing technologies will be tested. The EVSE equipment will enable control of electric vehicle (EV) charging equipment and facilitate service pricing plan options: start/stop load control and rate-of-charge commands (240V and 120V). Observe user behavior in terms of charging equipment choices as influenced by relative ease-of-use and pricing plans that reflect the cost of each type of EV charging option.~~

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Comment [MCS2]: This was referring to a specific project, and I rephrased it to be more generally applicable to the next funding cycle

- **Non-incentive customer services**
  - Some of our projects will have desirable secondary impacts that go beyond Demand Response. These impacts include, but are not limited to:
    - Energy Efficiency
    - Integration of Security with Controls
    - Individual Customer Education
    - Market-wide Customer Education

Program Rationale and Expected Outcomes

- **Implementation Design**
  - Emerging Technology starts by identifying technologies from a quarterly scan and screening process. Implementation, or technology transfer, occurs after a product has been evaluated and reported on.
- **Delivery and coordination**
  - The Emerging Technology Program is driven through the utility Account Executives, Program Advisors, Segment Advisors, aggregators, controls vendors, and engineering consultants.
  - Installation may be done in multiple instances if scalability needs to be evaluated, and/or if there is reason to believe that results may vary significantly from instance to instance.
  - Evaluation of the pilot by an independent 3rd party, with focus on relevant factors identified in the Program Statement. The 3rd party produces a report for publishing on the ETCC website.
  - Program management expresses a recommendation about the utility's further support and involvement, and if applicable, next steps.
- **Program Cycle**
  - 2015 - 2016

Program Strategy

- **Target Audience:**
  - Emerging Technologies will target Residential, Commercial, and Industrial customers
- **Education and Outreach**
  - New DR capable technologies will be displayed at highly visible locations around SDG&E's territory through demonstration showcases. Additionally, all emerging technology project reports will be published on the ETCC Website.

- **Customer Research and Feedback**
  - Emerging Technology will identify potential participants using customer surveys, Smart Meter interval data, and DR participation data. Emerging Technologies will use Process evaluations to get customer feedback and improve the engagement process.
- **Aggregator considerations** N/A
- **CAISO Relationship**
  - Some products/projects that Emerging Technology investigates may interface with the CAISO wholesale market. The necessary considerations will be developed in more detail when planning each project.
- **Statewide Coordination**
  - SDG&E is a member of the Emerging Technologies Coordinating Council. Reports on all projects will be published on the ETCC website.
- **Integrated/coordinated DSM**
  - DSM integration and coordination will take place on a project by project basis. In addition to Demand Response, ET projects can include: Energy Efficiency, Energy Storage and Renewable Energy Generation.
  - Projects incorporating Integrated Demand Side Management will be reported on the IDSM Quarterly reports.

- **EM&V** N/A
- **Pilots** N/A

Proposed Demand Response
New Construction Pilot
Program Implementation Plan (PIP)
2015-2016

Program Name

New Construction Pilot (NCDRP)

Projected Program Budget

Program Name	2015 Budget	2016 Budget	Total 2015-2016 Budget
New Construction Pilot	$487,117.95	$487,117.95	$974,235.90

Projected Load Impacts by Year

Program Name	2015 Load Impact	2016 Load Impact
New Construction Pilot	N/A	N/A

Projected Cost Effectiveness for 2012-2014

Program Name	2015-2016 Cost Effectiveness
New Construction Pilot	N/A

Program Descriptors:

- **Market sector**
  - Residential and Non-Residential New Construction (Cross-cutting)
- **Program Classification**
  - SDG&E Pilot
- **Program Statement:**
  - The New Construction Demand Response Pilot Program ("NCDRP") will be designed as an Enabling Technology Pilot Program. The pilot tests the New Construction market as a delivery channel for SDG&E Demand Response ("DR") Technologies. This will be accomplished by working with builders, architects, and others in integrating DR technologies into the design process. The technologies that are installed will help achieve load reduction during critical peak energy usage periods as well as provide customers with real time information on dynamic pricing.
  - NCDRP will provide financial incentives as well as design assistance to facilitate participation in the pilot. This pilot will be administered and implemented by the same program and implementation staff as existing SDG&E New Construction Energy Efficiency Programs, namely California Advanced Homes (CAH) and Savings by Design (SBD).

Proposed Demand Response
New Construction Pilot
Program Implementation Plan (PIP)
2015-2016

- **Program Fundamentals:**
  - Incentives
    - SDG&E will cover 75 - 100% of incremental cost for the pilot for the installation of the DR enabling equipment
  - The measures for the pilot may include, but are <u>not necessarily limited to</u>:
    - Energy management systems ("EMS");
    - Internet Gateways;
    - Room Air Conditioning Controllers;
    - Pool Pump Controllers;
    - Electrically heated Spa Controllers;
    - Automated Lighting Controls;
    - Programmable Communicating Thermostats ("PCT's");
    - Online curtailment management and monitoring tools;
    - Smart appliances;
    - In Home Displays ("IHD's");
    - Load control devices
      - Smart Strips
      - Smart Panels
      - Plug Load Controllers
    - Thermal Energy Storage
    - Electricity Storage (battery)
      - The utility load reduction signal and/or communication will allow the home to be responsive to dynamic pricing signals from SDG&E
- **Non-incentive customer services:**
  - Design Assistance
    - Working with design teams to integrate DR technologies early in the design process.
    - Ensure compatibility or handshake of devices interfacing with Smart Meters, HAN, IHD's, etc.
    - Ensure that communicating devices are within their maximum communicating range of each other and Smart Meters. If not, ensure hardwired "repeaters" are installed and linking otherwise out or range devices.
  - Workforce Education and Training ("WE&T"):
    - Ensure contractors are aware and knowledgeable of DR enabling technologies. SDG&E will train contractors on the proper installation of DR enabled technologies and that the devices are properly connected to and communicating with Smart Meters.
    - SDG&E will take lead in the training of sales staffs / leasing agents for residential projects and occupants / facility staff for nonresidential projects. The result of this training will enable staffs to educate customers on the benefits of DR and energy management.
  - Marketing Support
    - SDG&E will partner with homebuilders participating in the pilot in developing marketing collateral that explains technologies in the home and a pathway to participate in SDG&E DR programs.

Proposed Demand Response
New Construction Pilot
Program Implementation Plan (PIP)
2015-2016

Program Rationale and Expected Outcomes

- **Implementation Design**
  - Delivery mechanisms
    - SDG&E will work with current CAHP and SBD customers and leverage those relationships in identifying potential candidates for the pilot.
  - Delivery and coordination
    - NCDRP will complement the DR offerings in Customer Programs in two ways:
      - Installation of DR enabling technology.
      - Education and Outreach to prospective customers to increase number of customers that participate in DR programs. Also, both residential and nonresidential participants in the pilot will have Auto DR capability that will enable demand response in critical load demand times.
- **Program objectives**
  - Facilitate Integrated Demand Side Management
  - Determine the effectiveness of a New Construction DR technology enabling program.
  - Measure adoption rate of homes that have the DR enabling technology installed into DR programs.
  - Educate New Construction market factors in DR concepts and benefits.
  - Determine if the cost savings associated with early design influence are enough to offset New Construction participants who received the DR technologies but did not participate in a DR program.
  - Provide design assistance during the design phase of a project that obviates expensive retrofits at a later time.
  - Evaluate effectiveness of PLS enabling technologies, including bill analysis and operation of devices.
- **Program cycle**
  - 2015-2016

Program Strategy

- **Target audience**
  - Residential Homebuilders / Developers
  - Nonresidential Owners/Developers
- **Marketing, Education & Outreach**
  - The New Construction pilot marketing effort focuses on creating program specific material highlighting the benefits to relevant customers with expressed interest and a call to action and develops marketing materials and messages that make it easy for the customer to engage in the enrollment process.
  - As part of the new construction kickoff SDG&E will lead a training session for construction staff on the installation of DR technologies selected for the project.
  - New Construction will ensure that processing and associated support staffs are adequately trained to comply with pilot requirements.
- **Program Delivery**
  - The two delivery channels for this pilot are California Advanced Homes Program for the residential pilot participants and Savings by Design for the nonresidential pilot participants.

- SDG&E will, for the first time, work with the builders and design teams during the design and construction phase to ensure DR enabling technologies are incorporated into the project.

- **Aggregator considerations**
  - SDG&E will manage this pilot to the extent possible that aggregators and potentially their proprietary Energy Management Systems are considered when installing enabling technologies into the commercial building.
  - An expected outcome of this pilot is to answer the question of what level of preparedness can SDG&E make a commercial building ready for Auto DR and still have aggregators able to install potentially proprietary energy management systems.
- **CAISO relationship** N/A
- **Integrated/coordinated DSM**
  - This pilot program will select homes that have or are participating in the California Advanced Homes or Savings by Design programs. This will be a prerequisite to participation in the DR pilot, ensuring the homes and businesses will be energy efficient.
  - Integrate across other demand response initiatives.
    - As a DR enabling program the New Construction DR Pilot Program will feed projects into existing new residential and nonresidential DR programs.

EM&V

- Annually a load impact evaluation of the program will be conducted in accordance with the load impact protocols including a ten year forecast based on ex-post event results. The impact evaluation will be completed by April 1st each year and will be filed with the CPUC. Additionally, other analysis related to program design (such as a baseline analysis) will be conducted as needed. One process/market evaluation for the program is planned during the three year cycle to be used to inform future program design and to evaluate and improve the operation of the program.

Pilots The program is a DR pilot.

Program Implementation Plan
Permanent Load Shift
~~2012-2014~~2015-2016

Program Name and Program ID

(Note: Program ID represents the program code to be utilized in Program Builder)

Projected Program Budget

Program ID#	Program Name	~~2012~~ 2015 Budget	~~2013~~ 2016 Budget	Total ~~2012-2014~~2015-2016 Budget
	PLS	$1,000,000~~888,140.42~~	$1,000,000~~,298,140.42~~	~~$3,399,421.26~~2,000,000

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(Note: Load Impact results to be obtained from Kathryn Smith)

Projected Load Impacts by Year

Program ID#	Program Name	~~2012~~ 2015 Load Impact	~~2013~~ 2016 Load Impact
	PLS	~~1000 kW~~1 MW	1MW~~1820kW~~

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(Note: Cost-Effectiveness results to be obtained from Brenda Gettig)

Projected Cost Effectiveness by Year
PLS does not follow the established CE methodology. The incentive dollar amount was determined by the ED staff.

Program ID#	Program Name	~~2012~~ 2015 Cost Effectiveness	~~2013~~ 2016 Cost Effectiveness
	PLS		

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Program Descriptors

- **Market Sector**
  - Non-Residential
- **Program Classification**
  - Statewide
- **Program Statement**

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Permanent Load Shifting (PLS) can help reduce system peak load by shifting electricity use from on-peak to off-peak periods on a recurring basis. Shifting daily loads benefits the grid and distribution systems. PLS often involves storing energy produced during

off-peak hours to support load during peak periods when energy use is typically high. As part of the 2006-2008 Demand Response Application (A.) 05-06-006, et. al. the Commission, on November 30, 2007, issued Decision (D.) 06-11-049, Order Adopting Changes to 2007 Utility Demand Response Programs. This Decision, among other things, ordered the Utilities to pursue Request for Proposals and bilateral arrangements for PLS to promote system reliability during the summer peak demand periods. A four-year PLS pilot was approved for all the Utilities from 2008-2011. As the Utilities ran their pilots, the Commission issued D.09-08-027 in 2009 directing the Utilities to work with parties to examine ways of expanding the availability of PLS. The study was to consider other ways of encouraging PLS, as well as an evaluation of what incentive payment would be appropriate for a future standard offer. In November 2010, a Statewide PLS Study, authored by Energy + Environmental Economics and StrateGen, provided information to the Joint Utilities for use in preparing a proposed PLS program.
In compliance with D.12-04-045, the Utilities worked collaboratively to develop and propose a standardized, statewide PLS program. As part of the PLS program design process, the Utilities incorporated the findings from the Statewide PLS Study into the

- program design of the 2012-2014 PLS Program.
    - ~~Permanent Load Shifting (PLS) as originally adopted by the Commission Decision 06-11-049, refers to shifting energy usage from one time period to another on a recurring basis. Permanent load shifting often involves storing electricity produced during off-peak hours and then using the stored energy to support load during peak periods. Unlike other demand response programs, PLS operates on a regular basis, not just peak times, and it can reduce summer peak demand as much or more than typical demand response programs. Previous Commission decisions approved utility Requests for Proposals (RFP's) to solicit multi-year commitments with third parties for permanent load shifting projects to reduce peak demand resulting in various statewide PLS pilot programs. In 2010 the Commission ordered further study and an evaluation of the utility PLS pilot programs and related issues in Decision 09-08-027. Consulting firm E3 was selected to conduct the study and deliver results by December 1, 2010. Strategies to increase the availability, and to influence program design of PLS programs have been considered based upon the study results which provided information on the following:~~
        - ~~Definition of PLS~~
        - ~~Establish historical context of PLS pilots in CA and elsewhere~~
        - ~~Identify core functionality that PLS can provide CA~~
        - ~~Examine standard offer, TOU rates, RFP options~~
        - ~~Cost-effectiveness model~~
        - ~~Identify the best available information on PLS technologies and the state of the industry~~
        - ~~Program types~~

- **Non-incentive customer services**
    - **N/A**

Program Rationale

PLS is a statewide program designed to help customers shift electricity use by offering a one-time upfront incentive, based on designed kW shift to offset initial investments in a mature thermal energy storage (TES) system. Customers will be required to shift energy usage during the summer peak hours as defined by each utility. Providing an incentive to invest in a PLS technology helps the utilities reduce the need for peak generation investments, reduce the likelihood of shortages during peak periods, and lower system costs overall by reducing the need for peaking units.
Time-of-use (TOU) rates further encourage PLS because customers can reduce their energy bills by shifting cooling load from peak periods when rates are higher to off-peak periods when rates are lower. Transferring demand and energy consumptions out of the most costly periods of the day can help achieve large bill savings.

~~As stated in the Dec. 1, 2010 statewide E3 PLS study , PLS is defined with the overarching goal of "routine shifting from one time period to another during the course of a day to help meet peak loads during periods when energy use is typically high and improve grid operations in doing so (economics, efficiency and/or reliability). The definition was derived from four elements that encompass PLS: permanency; 2) load shifting; 3) location; and 4) additional value streams. The permanency of PLS technology can provide a sustained capacity of load shifting during normal operation, and can be sustained for years. Load shifting from peak hours to off peak hours provides operational and resource planning benefits from SDG&E with an anticipated energy cost savings to the customer. The location of the PLS technology should be behind the customer meter, expanding eligibility to all commercial customers.~~

~~It is difficult to create a simple, technology neutral PLS program design that addresses all of the different technologies and cost effective incentive levels. This challenge was recognized in the PLS study and recommendations were made to create two technology categories: 1) mature and 2) emerging. A mature technology category includes larger thermal storage systems and process shifting applications with the medium and large customer. An emerging technology category includes the small customer for thermal energy storage and electrical battery storage.~~

~~The 2012-2014 PLS program meets the PLS definition and has used the study recommendations as a guide in program design and implementation.~~

- **Implementation Design**
  - ~~Broad t~~Technology ~~categories~~:
    - Thermal energy storage
    - ~~Electric energy storage~~
    - ~~Process shifting~~
  - Incentive levels:
    - $~~500~~ 875 per kW

- Not to exceed 50% of project cost
- The key objective of the PLS program is to shift energy usage during the full duration of the on-peak time period to off-peak time period on a permanent basis during the months of May1 – October 31. Due to the year round nature of the technology additional benefits may be realized.
- ~~Technologies unable to shift for the full duration of on peak hours will be considered for a pro-rated incentive.~~
- The Permanent Load Shifting program is primarily driven through SDG&E Account Executives and sub-contractors to perform outreach and education. It is also promoted through SDG&E held workshops and business associations.

- **Program Cycle**
  - ~~2012-2014~~2015-16
- **Program Budget**
  $3,399,421.26

Program Strategy

The SDG&E Permanent Load Shifting program provides eligible commercial customers an incentive to purchase and install qualified ~~PLS~~ Thermal Energy Storage technology for the purpose of shifting peak load to off peak hours on a regular basis. ~~The type of load shape that would provide a customer potential program participation can be delivered by technologies in three broad categories; thermal energy storage, electrical energy storage and process shifting. Outreach and marketing efforts will be implemented to target these customers and educate them about the PLS technologies and available incentives. The customer has the option of choosing their own vendor or having SDG&E work with the customer to identify opportunities through a verification report produced by the customer or sub-contracted vendor.~~ Upon SDG&E measurement and verification of potential load shift and commissioning, a one- time incentive payment will be submitted to the customer. The customer may have the option of providing the incentive payment directly to the vendor on their behalf. Customers will also be provided the opportunity to use the SDG&E Technical Audit program to identify and create a PLS verification report, inclusive of additional energy efficiency and demand response opportunities, rebates and incentives.

~~To educate customers on the advantages of PLS, a bill analysis tool is available for all customers to determine the financial impact of shifting their energy load. This tool will also be used to identify and target customers who will benefit from PLS technologies. Marketing and outreach efforts will be implemented to these customers for potential participation.~~

~~Even though strategies to increase the availability and to influence program design was considered and implemented based upon the study results issued December 1, 2010, further direction will be provided through the pending CPUC PLS Guidance Document and other interested parties. Based on the pending direction and information, the 2012-2014 PLS program is subject to change.~~

- **Target Audience**
    - All commercial customers within the SDG&E service territory with the potential of shifting electric load for the full duration of on peak hours to off peak hours on a regular, reoccurring basis.
    - Customers engaged in new construction and retrofit projects.
    - Direct Access customers are eligible

Program Theory and Other Attributes

Permanent Load Shifting (PLS) is similar to most demand response programs in that it shifts load during summer peak hours, however the load shift occurs without triggers and on a regular basis. PLS is also available year round with varying technologies.

- ~~**Program Design to overcome barriers**~~
    - ~~Permanent Load Shifting is recognized by the Commission that it could reduce the likelihood of shortages during peak periods and lower system costs overall by reducing the need for peaking units.~~
    - ~~A standard offer was created for two categories to encourage technology neutrality and customer participation.~~
    - ~~Incentive levels were established to encourage participation, based on recommendations from the E3 PLS study . While all projects were taken into account, most available data analyzed was based on thermal energy storage.~~
    - ~~Lack of education/training about PLS technologies — their design, implementation and operation is a severe challenge and has been addressed through program design and targeted outreach efforts.~~

- **Advancing strategic objectives**
  Permanent Load Shifting can assist with system reliability and supports the modernization of the electric grid.

- **Integrated DSM**

    PLS customers may participate with other Demand Response programs as long as the kW load shift is in addition to the PLS load shift. The same load shift cannot be incentivized by more than one program.

    The identification of energy efficiency opportunities and the installation of recommended measures will be developed within the PLS program where applicable and cost effective. At minimum, a strategy will be defined for customers to act on energy efficiency opportunities prior to the installation and commissioning of PLS equipment.

EM & V
To be completed by Kevin Mckinley

Performance Metrics

- To reach projected kW goal within budget constraints.
- ~~Approximately 10-15 PLS projects per year~~

Program Logic Model

TBD

Proposed Demand Response
Program Implementation Plan (PIP)
Internal Peak-Time Rebate (PTR)
2015-2016

PROGRAM NAME AND PROGRAM ID

Internal Peak-Time Rebate (PTR)
Program ID: 624001

Projected Program Budget

Program ID#	Program Name	2015 Budget	2016 Budget	Total 2015-2016 Budget
624001	Peak Time Rebate	$161,645~~67~~	$161,645~~66~~	$~~485,000~~323,290

Projected Load Impacts by Year

Program ID#	Program Name	2015 Load Impact	2016 Load Impact
624001	Peak Time Rebate	4MW	4MW

*

Projected Cost Effectiveness by Year

Program ID#	Program Name	2015 Cost Effectiveness	2016 Cost Effectiveness
624001	Peak Time Rebate + Small Customer Technology Deployment	*1.~~15~~2	*1.~~15~~2

~~(Note: Cost effectiveness results to be obtained from Kevin McKinley)~~

- SCTD and PTR cost effectiveness

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Program Descriptors

- **Market Sector**
  - Residential
- **Program Classification**
  - Rate Program

Program Statement

- The Peak Time Rebate (PTR) schedule tariff was approved by the Commission on July 14, 2006, by Decision 05-03-015. This Schedule is applicable, in combination with the customers' otherwise applicable rate schedule. This tariff is applicable to electric bundled residential customers with an installed smart meter on an individually metered service point which has been tested and verified according to SDG&E procedures, who opt-in to the tariff be electing to receive event alerts.
- The tariff provides a bill credit of $0.75 kWh for each kWh of actual reduction during each PTR event. Customers with enabling technology will receive a higher bill credit of $1.25/kWh. There are no penalties for non-participation. That is, the customer is billed just as they otherwise would have been billed if the customer did not reduce usage below their PTR customer-specific reference level.

Proposed Demand Response
Program Implementation Plan (PIP)
Internal Peak-Time Rebate (PTR)
2015-2016

- SDG&E may call a PTR Event on any day of the year between the hours of 11 am and 6 pm.
- PTR will include both Day-Ahead and Day-Of events.
- **Measures**
  - A bill credit of $0.75 kWh for each kWh of actual reduction during each PTR event.
  - A bill credit of $1.25/kWh with enabling technology of actual reduction during each PTR event. As described in the rate schedule enabling technology is defined as technology which can be initiated through a signal from the Utility to reduce electric use for specific end use equipment or appliances and has been registered with the Utility by the customer.
- **Non-incentive customer services**
  - PTR will provide a means for SDG&E to demonstrate to residential customers some of the benefits of smart metering. These include:
    - Greater visibility into usage
    - Capability and demonstration of aggregating demand response for the benefit of the community
    - Detailed response feedback

PROGRAM RATIONALE AND EXPECTED OUTCOMES

- **Implementation Design**
  - With the completion of Smart Meter installations territory wide by 2012, SDG&E will have the opportunity to implement the approved Peak Time Rebate (PTR) Tariff Schedule. Smart Meters provide a platform for a variety of new energy products and services to help residential customers manage their energy consumption and associated costs. In addition, the implementation of the PTR tariff allows SDG&E's customers a unique opportunity to:
    - Receive increased Demand Response benefits though active participation;
    - Receive higher incentives through Enabling Technologies[1];
    - Become more educated about conservation and energy efficiency;
    - Take the first step in preparation for dynamic pricing.
  - A PTR event may be called on any day of the year. There is no limit to the number of PTR events that may be called. As such this program will support a year round educational campaign in order to maximize program participation. If no events are called in a year, a test event will be scheduled to test related systems, notifications, and customer performance.
  - PTR events may take place between the hours of 11 am and 6 pm. There is no minimum duration for a called event.
    - Every time a Critical Peak Pricing (CPP) event is triggered a PTR event may also be triggered.
    - A PTR event may also be triggered the day of an event if warranted by temperature and system load conditions.
    - A PTR event may also be triggered as warranted by extreme system conditions such as special alerts issued by the California Independent System Operator, SDG&E system emergencies related to grid operations or under conditions of high forecasted California spot market prices or for testing/evaluation purposes.

[1] SCHEDULE PTR Sheet 2

- Event Notifications
  - Day-Ahead Event: Customers will be notified of a curtailment event the day before the event will occur through their preferred channel (email or text [SMS]).
  - Day-Of Event: Customers will be notified of a day-of event through their preferred channel (email or SMS).

- **Delivery mechanisms**
- **Incentives**
  - Customer incentives are the primary driver for program participation. As noted, customers will receive a bill credit of $0.75 for each kWh of actual reduction in consumption during each Peak Time Rebate (PTR) event. Customers with enabling technology will receive a higher bill credit of $1.25/kWh.
- **Program cycle**
  - January 1, 201~~2~~5-December 31, ~~2014~~2016

PROGRAM STRATEGY

- **Target audience**
  - All the SDG&E Residential Customer Segments will be targeted.
- **Marketing, Education & Outreach**
  - The key objectives of this program are to provide an overall educational campaign for residential customers about the PTR tariff and how to benefit from participation. All eligible SDG&E customers will receive information about the rate and be provided with conservation tips and the benefit of utilizing enabling technologies to maximize their bill credit.
  - The objectives of the Marketing, Education, & Outreach (ME&O) Strategy are:
    - Educate customers on how demand response and PTR are mutually beneficial.
    - Educate customers on the PTR Rate and their eligibility.
    - Get customers to enroll for individual event notifications and event performance feedback, which will help to achieve demand reduction MW goals.
  - The educational campaign required to optimize program participation with PTR includes the following:
    - Rate Introduction
      - Rate education and eligibility – direct mail, web
    - Event notification education - channels offered and how to sign up
      - Pre-event notifications – email, text (SMS) and voice
      - Post-event performance – email, SMS, voice and bill
    - Conservation tips – via direct mail, web
- **Program Delivery**
- All residential customers will receive educational materials about the new PTR rate when they are eligible to participate. The educational materials will inform and motivate customers to sign up for PTR notifications.
- Customers will also be educated about demand response event days, their eligibility to participate on the event days, how and why they are receiving a bill credit, and conservation tips on how they can maximize their bill credit. This education will utilize direct mail, email, web, and other communication channels as they become available.

Proposed Demand Response
Program Implementation Plan (PIP)
Internal Peak-Time Rebate (PTR)
2015-2016

- Customers will be able to enroll for PTR event and performance feedback notifications via email ~~and/or~~, text (SMS) and voice.
    - Mass media, web, and social media may also be utilized for notifying customers who do not enroll for email or SMS notifications.
    - Event notifications will provide customers with an email and/or SMS the day-before the event.
    - Event Performance Feedback notifications will provide customers with an email and/or SMS after the event letting them know how they were able to perform

- SDG&E will also evaluate and consider all relevant triggers including temperature and system load conditions, as well as other system operating conditions, energy market conditions and other emergency conditions in determining whether to initiate a PTR event.
- PTR will include several elements to increase customer satisfaction with the program.
    - Provide in-home and online tools for participants to manage their energy.
    - Provide customers with choice, control, and convenience.
        - Choice – Customer can choose how they want to be communicated with.
        - Control – Customers can control how often they are communicated to; control their energy use with specific energy savings goals (i.e. customer-specific reference level); etc.
        - Convenience – Customers can take action when it is convenient for them when they receive a communication from SDG&E (i.e. day-ahead event notification). Customers can also evaluate their event performance when it is convenient for them.

- **Customer Research & Feedback**
    - The PTR program will utilize all pertinent process and program impact research data collected from Measurement Evaluation studies. Additional research may be employed to evaluate ongoing activities related to program implementation. These research tools may include:
    - Customer Satisfaction Surveys
        - Online
        - Mail in
    - Notification Messaging
        - Timing of receipt of messaging
    - Program Effectiveness
        - Analyzing the hourly event performance, notifications, customer-specific reference levels, etc. will allow the program effectiveness to be measured and identify ways to improve.
        - Measuring event and non-event changes in energy use and/or receipt of notifications will allow the program to measure if notifications are successfully contributing to load reduction.
    - Event Performance Feedback
        - Customers will be sent their event performance after the event has occurred via their preferred channel (email, ~~or~~text SMS and voice).

  - Event performance is calculated by using the customers' hourly interval energy usage during the event window (11am to 6pm) and comparing it to their customer-specific reference level.
  - Customers will be provided their event performance even if they were not able to reduce below their customer-specific reference level.

- **Program Issues and Risks**
  - Risks:
    - Introduction of interval data can confuse and overwhelm customers. PTR will need to educate customers on how their interval data is being used for PTR.
    - Energy is not top of mind for most consumers. PTR education will need to inform and remind customers of the need for demand response and how it is mutually beneficial.
    - Customer education is challenging.
      Even sophisticated customers find the terminology and concepts difficult to un derstand.
    - Customers need better guidance when setting parameters on their energy use.
    - Customers don't understand demand response, electricity pricing, etc.
- **Aggregator Considerations: NA**
- **CAISO Relationship: NA**
- **Statewide Coordination**
  - Regularly scheduled meetings/phone calls with the CA IOUs will take place for PTR. Best Practices and lessons learned will be shared with local and statewide groups.
- **Program Design to Overcome Barriers**
  - Event Participation and Load Reduction - Participants will be educated about the positive effects of DR participation, such as environmental, reliability, and mutual cost benefits.
  - When a PTR event is called, SDG&E will provide customers with tips on how they can conserve energy to earn a credit.
  - SDG&E will provide customers with their customer-specific reference level which provides an energy baseline which they should aim to conserve below during a PTR curtailment event. Customers will also receive event performance feedback the day after the event. Currently, customers have to wait until their bill to see how they performed on any events that are called. Providing customers with feedback sooner will help customers understand how their actions result in energy savings.
- **Best Practices**
  - A key best practice that PTR will utilize is providing customers with post-event feedback on their participation in an event. Customers will have the opportunity to sign up for post-event notifications via email,~~ and~~ text (SMS) and voice to see how they participated on events compared to their customer-specific reference level. A Pilot Program undertaken by Duke Energy in 2010 indicated that providing customers with their feedback via direct mail 3 days after an event still initiated a behavior change.
  - PTR will also use new communication channels to inform customers on event days. A lesson learned from the recent PTR Pilot in Anaheim indicated that 70% of the total event reduction was received from the customers who received an event notification prior to the event. Day-ahead notifications are going to be utilized for PTR to allow customers sufficient time to change their energy use prior to the event (ex. changing their thermostat settings before heading to work).
- **Advancing strategic objectives**
  - This program will advance strategic objectives by:

- Offering new communication channels and tools for customers will give them the choice, control, and convenience to effectively manage their energy use.

- **Addresses strategic drivers**
  - The PTR program will allow customers for the first time on a large scale to participate in a rate based program. The PTR program will evaluate the acceptance and participation on this rate based program. With the emergence of dynamic pricing, PTR serves as a stepping stone to familiarize residential customers with the benefits of a rate based program.
- **Integrated/coordinated DSM: NA**
- **Integrate across other demand response initiatives: NA**

- **EM&V**

- **PILOTS**
  - New Construction Pilot – SDG&E's New Construction Pilot is proposing to install enabling technologies on newly constructed homes (~350 homes). These homes will be eligible to receive the higher PTR incentive once the technology has been registered with the Utility.
  - Proposed Residential Technology Deployment (RTD) Program – Participating customers on this proposed program will be eligible to receive the higher PTR incentive as soon as they are enrolled on an RTD Program.

APPENDIX D

Appendix D

Tariffs and Contracts

SDGE
A Sempra Energy utility

BASE INTERRUPTIBLE PROGRAM CONTRACT

This Base Interruptible Program Contract (the "Contract") is made and entered into by and between San Diego Gas & Electric Company, a California corporation, hereinafter referred to as "SDG&E" and ________________________________,hereinafter referred to as "Customer" on this ________ day of ________, ~~2012~~2014. SDG&E and Customer shall each be referred to herein as a "Party" and collectively as the "Parties." This Contract shall become effective when signed by both parties. Capitalized terms not defined herein shall have the definitions assigned to them in "Schedule BIP," attached hereto as Attachment A and incorporated by this reference.

I. BIP ENROLLMENT

The Base Interruptible Program ("BIP") offers a monthly capacity payment to non-residential customers who can commit to curtail at least fifteen percent (15%) of their Monthly Average Peak Demand with a minimum load reduction of at least 100kW during energy curtailment events as called by the California Independent Systems Operator (CAISO) or SDG&E.

By entering into this Contract, Customer is enrolling in and hereby agrees to comply with the terms of this Contract, which by this reference also includes the terms of that certain BIP Tariff approved by the California Public Utilities Commission ("CPUC").

Customer's enrollment in BIP shall be conditional until (a) SDG&E approves Customer's BIP enrollment application in writing, and (b) SDG&E determines, in its sole discretion, that Customer is able to meet certain energy load reduction requirements, which may include, without limitation, review and testing of Customer's ability to meet its Firm Service Level (as defined below) during a real or simulated curtailment event, in all cases without financial penalty to Customer until enrollment is confirmed. Once Customer has met both of these requirements to SDG&E's satisfaction, Customer shall be fully enrolled in BIP.

II. PROGRAM REQUIREMENTS

Once Customer is fully enrolled, upon notification of a curtailment event, Customer shall have thirty (30) minutes to reduce its energy usage to the "Firm Service Level" set forth on Attachment B attached hereto and incorporated by reference. Each time Customer reduces its energy usage to its Firm Service Level (or below) during a curtailment event, Customer shall earn a Committed Load Incentive Payment as a credit on their bill, but in no event shall such credit be more than the total bill amount and credits shall not carry over to subsequent bills. Customer may adjust its Firm Service Level without penalty once a year during the month of November by submitting a written request to SDG&E, which shall be approved or denied by SDG&E in its sole but reasonable discretion. Customer shall provide written notification of such changes to: Attention: BIP Manager, SDG&E, 8335 Century Park Court, CP 12E, San Diego, CA 92123.

The first time Customer is unable to meet its Firm Service Level during a curtailment event (real or simulated), Customer's Firm Service Level will be re-tested and adjusted according to the actual Firm Service Level Customer was able to meet during the curtailment event, or Customer may discontinue its participation in BIP; provided, however, if Customer cannot (a) commit to a Firm Service Level of less than fifteen (15%) of its Monthly Average Peak Demand with a minimum load reduction of at least 100kW, (b) reduce its minimum load by at least 100kW during a re-test, or (c) meet its adjusted Firm Service Level in any subsequent curtailment event, Customer shall be immediately discontinued from participation in the Program. All testing by SDG&E to determine Customer's ability to participate in the program (excluding curtailment events, real or simulated) shall be performed without financial penalty to Customer.

Once Customer is fully enrolled in BIP, if a curtailment event is called (real or simulated, except for re-testing) and Customer is unable to meet its Firm Service Level, Customer shall be charged an Excess Energy Usage Charge based on the amount of excess energy above its Firm Service Level used during the Interruptible Period. Such Excess Energy Usage Charge shall be charged to Customer's account independent of whether Customer's Firm Service Level is eventually adjusted or Customer chooses to discontinue its participation in BIP.

III.
ASSIGNMENT
Customer shall not assign this Contract without prior written consent of SDG&E, and any assignment of this Contract without prior written consent shall be void ab initio.

IV. DISPUTE RESOLUTION
Any dispute that cannot be resolved between the Parties shall be settled by the means set forth in Schedule BIP. In any action in litigation to enforce or interpret any of the terms of this Contract, the prevailing party shall be entitled to recover from the unsuccessful party all costs, expenses (including expert testimony) and reasonable attorneys' fees (including fees and disbursements of in-house and outside counsel) incurred therein by the prevailing party, to the extent permissible by law or authorized by specific federal statutory authority, as applicable.

V DISCLAIMER OF WARRANTY
No promise, representation, warranty, or covenant not included in this Contract has been, or is relied on by either Party. Each Party has relied on its own examination of this Contract, the counsel of its own advisors, and the warranties, representations, and covenants in the Contract itself.

VI. TERM
This Contract shall be effective as of the date first written above. Unless otherwise cancelled or terminated in accordance with the terms herein, this Contract shall be terminable by SDG&E in its discretion at any time upon thirty (30) days' prior written notice and terminable by Customer in its discretion during the month of November only.

VII. INDEMNIFICATION AND LIMITATION OF LIABILITY
Customer shall indemnify, defend and hold SDG&E and its current and future parent company, subsidiaries, affiliates and their respective directors, officers, shareholders, employees, agents, representatives, successors and assigns ("SDG&E Parties") harmless for, from and against any and all claims, actions, suits, proceedings, losses, liabilities, penalties, fines, damages, costs or expenses including without limitation, reasonable attorneys' fees (including fees and disbursements of in-house and outside counsel) of any kind whatsoever (collectively, "Claims") directly or indirectly resulting from or arising out of this Contract or Customer's participation in BIP, whether based upon negligence, tort, strict liability or otherwise, including but not limited to third party Claims of any kind. This indemnification obligation shall not apply only to the extent that any such Claims are caused by either the willful misconduct of SDG&E or by SDG&E's sole negligence. This indemnification obligation shall survive the termination of this Contract.

In no event shall any SDG&E Party be liable to Customer for any indirect, consequential, special, incidental, exemplary or punitive damages, business interruption or loss of profits, anticipated savings, or the like under any theory, including, but not limited to, tort, contract, breach of warranty or strict liability for any Claims arising under this Contract, including but not limited to the design, manufacture, installation, operation, maintenance, performance or demonstration of the Utility System.

The "Utility System" includes any metering, meter communication equipment, internet communication software, energy demand management software or related goods and services used by Customer for participation in BIP. SDG&E shall not be responsible for any business loss, actual or implied, as a result of the partial or complete failure of the Utility System to operate.

Notwithstanding the foregoing, if Customer is a **federal governmental authority or agency**, each Party's liability to the other for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be determined in accordance with applicable law.

VIII. COMPLIANCE WITH LAWS
Customer shall comply with all of the terms and conditions of this Contract, Schedule BIP, and all applicable rules, regulations and laws in effect on the effective date or at any time during the term of this Contract, including, but not limited to, all orders and rulings of any governmental authority with jurisdiction over BIP, SDG&E or this Contract.

IX CPUC CONTINUING AUTHORITY

This Contract shall at all times be subject to the jurisdiction and authority of the CPUC and to any changes or modification that the CPUC may, from time to time, direct in the exercise of its jurisdiction.

Notwithstanding any other provision of this Contract, either Party shall have the right to unilaterally file with the CPUC, pursuant to the CPUC's rules and regulations, an application for a change in rates, charges, classification, or any rule, regulation, or agreement relating thereto.

X. NO ORAL MODIFICATIONS

No modification of any provisions of this Contract shall be valid unless in writing and signed by duly authorized representatives of both Parties. Representatives of both Parties internally authorized to execute such documents pursuant to its corporate policies shall sign any amendments to this Contract.

XI. ESSENTIAL CUSTOMER DECLARATION

I hereby warrant and represent that I am the ____________________________(title) of _________________________ (company), and am duly authorized to make this declaration on behalf of my company at the following location.

Address ____

City ____

State California ___________ Zip ________________

Form 142-05207
(08(0/12)

SB_GT&S_0394596

To the best of my knowledge, I understand that my company is considered an essential customer at the location stated above under the CPUC's rules and is exempt from rotating outages. I declare that I have voluntarily elected to participate in an SDG&E interruptible program for all or part of my electrical load based on adequate back-up generation or other means to interrupt load when requested by SDG&E, while continuing to meet my essential needs.

IN WITNESS WHEREOF, SDG&E and Customer have executed this Contract as of the date first written above:

Customer:		San Diego Gas & Electric Company:	
By	______________________	By	______________________
Title	______________________	Title	______________________
Date	______________________	Date	______________________

The following attachments are attached hereto and incorporated by reference:

Attachment A: Schedule BIP
Attachment B: Customer's Firm Service Level
Attachment C: Customer Contact Information
Attachment D: Customer Account Information

ATTACHMENTA
Schedule BIP

[Attached]

ATTACHMENT B
Firm Service Level

By executing this Contract, Customer hereby agrees, accepts and acknowledges that Customer shall maintain a Firm Service Level of ____________ during the term of Customer's enrollment in the BIP. Customer hereby acknowledges that the above Firm Service Level may only be adjusted once a year during the month of November, and in no event may such Firm Service Level (a) equal less than fifteen (15%) of Customer's Monthly Average Peak Demand or (b) represent a minimum load of reduction of less than 100kW.

Customer Signature:

____

Date: __________________

ATTACHMENT C
Customer Contact Information

Primary Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

Secondary Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

Additional Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

Additional Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

Additional Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

ATTACHMENT D
Customer Account Information

Site #1
Account Name ____________________
Account Number ____________________
Site Address ____________________
Existing Electric Meter Number ____________________

Site #2
Account Name ____________________
Account Number ____________________
Site Address ____________________
Existing Electric Meter Number ____________________

Site #3
Account Name ____________________
Account Number ____________________
Site Address ____________________
Existing Electric Meter Number ____________________

Site #4
Account Name ____________________
Account Number ____________________
Site Address ____________________
Existing Electric Meter Number ____________________

Site #5
Account Name ____________________
Account Number ____________________
Site Address ____________________
Existing Electric Meter Number ____________________

Attach additional Customer Account Information sheets to this contract if required. (Sheet ___ of ___)

SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

APPLICABILITY

The Base Interruptible Program (BIP) offers a monthly capacity payment to non-residential customers who can commit to curtail at least 15% of Monthly Average Peak Demand, with a minimum load drop of 100 kW and who request service on this schedule.

BIP enrollment will be capped in accordance with CPUC Decision (D.)10-06-034, adopting the "Reliability-Based Demand Response Settlement Agreement" in Rulemaking (R.) 07-02-041.

TERRITORY

Within the entire territory served by the Utility.

RATES

Committed Load Incentive and Excess Energy Usage Charges are set forth in Table 1.

Table 1 - Committed Load Incentives and Excess Usage Charges

Month/s	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Term	B	B	B	B	A	A	A	A	A	A	B	B
Monthly Incentive Per kW	$2.00	$2.00	$2.00	$2.00	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$2.00	$2.00
Excess Energy Usage Charge Per kWh	$1.20	$1.20	$1.20	$1.20	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$1.20	$1.20

Customers must enroll in both Terms A & B

SPECIAL CONDITIONS

1. Definitions: The Definitions of terms used in this schedule are found either herein or in Rule 1, Definitions.

2. Qualifying Customer: Applicable to all non-residential time-of-use metered customers who can commit to curtail at least 15% of Monthly Average Peak Demand, with a minimum load reduction of 100 kW and who request service on this schedule and comply with Special Condition 3. This tariff is available to bundled, Direct Access, and Community Choice Aggregation (CCA) customers. Qualifying customers are required to complete a Base Interruptible Program Contract with SDG&E in order to participate in this Schedule BIP.

   a. Third-Party Aggregators: Customers can participate in this Schedule BIP directly with SDG&E or via a Third-Party Aggregator. Customer participation in this Schedule BIP via a Third-Party Aggregators shall be subject to the terms and conditions of this Schedule BIP and Rule No. 29, Third-Party Aggregators for BIP.

(Continued)

SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

SPECIAL CONDITIONS (Continued)

2. Qualifying Customer (Continued)

   b. New Customers: New applicants to the BIP program will have to meet pre- enrollment qualifications in order to participate in the program. Applicants will be required to submit a load reduction plan with their enrollment applications. BIP application screening will also include testing the customer's ability to comply with curtailment event requirements, before enrollment is effective and without financial penalty.

3. Program Operation

   a. Interruptible Period: Shall be the period of time during which the Utility has informed the customer to interrupt load by use of a communications process utilizing equipment as described in Special Condition 14. The Utility will coordinate with the customer the manner of communications and provision of the interruption notice to the customer. Customer is responsible for assuring that any communications process is not interfered with in any manner. Customer is responsible to respond to the communications in a manner consistent with this tariff. If the Utility initiates communications indicating that an interruption period is occurring and other customers have received the communications then the customer shall be deemed to have received the communications if the Utility can verify that it initiated the communications to the customer.

   b. Interruptible Period Termination. An interruptible period will terminate upon notification that the Stage 2 or other emergency has ended.

   c. Committed Load: Is the difference between the customer's or aggregator's group recorded Monthly Average Peak Demand less the customer's selected Firm Service Level, as shown in the Customer's Base Interruptible Program Contract (Form 142-05207).

   d. Excess Energy Usage: Is the amount of energy used by the customer or aggregator's group during any 15 minute interval of an Interruptible Period that is in excess of the customer's or aggregator's group selected Firm Service Level.

   e. Resetting Non-Complying Participants' Firm Service Level: Customers who fail to comply with a curtailment or test event will have their Firm Service Level set to the level achieved during the event. In order for this to be effective for the next program month the Firm Service Level will need to be submitted by the 15th of the month.

   f. Changes to Firm Service Level: Existing customers that want to change their Firm Service Level will be required to perform a re-test before the new Firm Service Level can be established. Changes to Firm Service Levels will only be accepted in November.

(Continued)

SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

SPECIAL CONDITIONS (Continued)

3. Program Operation (Continued)

   g. Monthly Average Peak Demand: Solely for the purpose of this tariff, Monthly Average Peak Demand is the average hourly demand recorded between the hours of 11:00 a.m. and 6:00 p.m. Monday through Friday, excluding holidays, or when BIP events were called during a calendar month during the months of May through October. The Monthly Average Peak Demand is recalculated on a monthly basis, using historical demand.

   h. Firm Service Level: Customer's or aggregator's group maximum expected level of demand, as specified by the customer in the Base Interruptible Program Contract (Form 142-05207), during any 15 minute interval of an Interruptible Period.

   i. Additional Group Aggregation Requirements: To calculate the aggregate Monthly Average Peak Demand, the Utility will sum the Monthly Average Peak Demand for each participating meter. The Monthly Average Peak Demand is recalculated on a monthly basis, using historical demand.

4. Program Triggers: A BIP Event can occur by one or more of the following:

   a. After the California Independent System Operator (CAISO) has (i) forecasted a Stage 1 Emergency and publicly issued a Warning notice; (ii) has taken all necessary steps to prevent the further degradation of its operating reserves; and (iii) notified SDG&E that a Stage 1 Emergency is imminent; or

   b. After the CAISO has declared a Stage 2 Emergency.

   c. CAISO calls for Interruptible Load. The Utility may call for an Interruptible Period provided the Interruptible Period commences within 30 minutes after the Utility initiates communications to the customer.

   d. Extreme temperature conditions impacting system demand.

   e. SDG&E discretionary events for test purposes, program evaluation or system contingencies. SDG&E expects that actual events would normally, under most circumstances, eliminate the need for a test. In the absence of an actual event, there will be at least one program test event per year. Pre-qualification test for new customers and retest for existing customer do not count toward event limits.

   ~~Special One-Time Opt-Out Window: Beginning fifteen (15) days after the date of Commission approval of Advice Letter 2040-E, modifying the Program Trigger provisions above, and for a period of 30 days thereafter, customers receiving service under this Schedule may upon written notice to SDG&E exercise one of the following options:~~

(Continued)

SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

SPECIAL CONDITIONS (Continued)

4. Program Triggers: (Continued)

   (1) Terminate service under Schedule BIP and return to the otherwise applicable tariff (OAT). Requests to terminate service under this Schedule and to return to the OAT will be effective on the next regularly scheduled meter read date after a timely receipt of request, or;

   (2) Increase or decrease the Firm Service Level. Increases or decreases in the Firm Service Level will be effective at the beginning of the next calendar month after timely receipt of the signed Amendment to Base Interruptible Program Contract (Form 142-05207).

5. Program Availability. BIP is available to be called year round. BIP shall be limited as to its availability to customers based on any limitations the Utility has in getting communications systems in place. The Utility will staff up as quickly as practical to provide this service to as many customers as quickly as practical so long as communications are in place before service commences.

   a. Limitation of Interruptible Period:

      i. The Interruptible Periods shall not exceed four (4) hours for any calendar day, nor 10 Interruption Periods per calendar month, nor 120 hours during any calendar year.

6. Customer Specific Baseline: As written, Customer Specific Baseline does not apply to the Base Interruptible Program tariff.

7. Incentive/Energy Payment:

   a. Committed Load Incentive Payment: Is determined by multiplying Committed Load by Committed Load Incentive. This credit will be applied to the bill of the customer on their otherwise applicable rate within 90 days of the Interruptible Period. The customer's total bill for service, including the Committed Load Incentive Payment, shall always be a positive value, or zero. Committed Load Incentive shall be zero if the Committed Load is less than 100kW or less than 15% of the customer's recorded Monthly Average Peak Demand.

   b. Excess Energy Usage Charge: Customer shall pay a charge multiplied by Excess Energy Usage Rate. This charge will be applied to the bill of the customer on their otherwise applicable rate within 90 days of the Interruptible Period.

8. Actual Demand Reduction: Actual Demand Reduction equals the difference between the customers Monthly Average Peak Demand and the Firm Service Level.

(Continued)

SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

SPECIAL CONDITIONS (Continued)

9. Event Notification/Communication: Customers, at their expense, must have access to the Internet and an e-mail address to receive notification via the Internet. In addition, all customers must have, at their expense, a device ~~n alphanumeric pager~~ that is capable of receiving a text message sent via the Internet. A customer cannot participate in the Program until all of these requirements have been satisfied. Customers participating in BIP with a third party aggregator will be notified by the aggregator using the agreed upon notification method.

   In the event of a Program curtailment operation, customers on the Program will be notified using one or more of the above-mentioned systems. The Utility will also update their website with event information~~. Receipt of such notice is the responsibility of the participant. Once notified, the customer is expected to log into the Program's Internet web site within 30 minutes of event notification and acknowledge participation in the curtailment. Failure to acknowledge a curtailment notice does not release the customer from its obligation to participate.~~ The Utility does not guarantee the reliability of the ~~pager system~~device, e-mail system or Internet site by which the customer received notification.

   a. Advance Notification: Event notification will be sent as follows:

      i. Customers will be notified 30 minutes in advance of the Base Interruptible Program Event.

10. Event Cancellation: Once a BIP event has been initiated, the subsequent event will not be cancelled, however, the event can be terminated based on termination of the emergency situation.

11. Contract Requirement: A customer must complete a Base Interruptible Program Contract (Form 142-05207) in order to receive service on this Rate Schedule.

   a. Insurance. Insurance may not be used to pay Excess Energy Usage Charge for willful failure to comply. Each customer must provide the utility with an executed declaration that states "I do not have, and will not obtain, insurance to compensate me in any way for any portion of the bills associated with the Excess Energy Usage Charge." Such declaration (Form 142-05209) must be on file with the Utility within 30 days of the effective date of the tariffs or the customer will immediately be terminated from service under Schedule BIP.

   b. Contract Termination. Customers may change their Firm Service Level or discontinue participation in the Program only once per year, by written notification to the Utility, and during the month of November. Such changes will become effective the following program month. Non-compliant participants would be allowed to make adjustments to Firm Service Limits after they have been re-tested or the participant can choose to de-enroll from BIP within 15 days of the non-compliant event performance.

12. Multiple Program Participation: Under no circumstance will a customer taking service under this schedule receive more than one incentive payment for the same interrupted/curtailed load. Eligibility for Multiple Program Participation is defined in Rule 41.

13. Termination of Schedule: This Schedule is in effect until modified or terminated in the rate design phase of SDG&E's next general rate case or similar proceeding.

(Continued)

SPECIAL CONDITIONS (Continued)

14. Metering Requirement: Customer's electric meter must be an interval data recorder or a smart meter with related telecommunications capability, compatible with the Utility's meter reading and telecommunications systems. Metering ~~and telephone equipment~~ must be in operation for at least a full calendar month prior to participating in the program to establish a Monthly Average Peak Demand. If required, the Utility will provide and install the metering equipment at no cost to the customer.

    a. Metering equipment must be in operation for at least a full calendar month prior to participating in the program to establish a Monthly Average Peak Demand.

    b. For Direct Access and CCA customers, BIP compliance shall be determined from a telephone accessible electric revenue interval meter that can be read remotely by the Utility, and/or from alternative metering and telecommunications acceptable to the Utility. Direct Access and CCA customers are required to allow the Utility telecommunication access to its electric revenue meter for the purposes of determining BIP compliance.

15. Utility Testing: At the Utility's discretion, BIP participants may be requested to participate in up to two program tests per year demonstrating their ability to reduce load to their contracted Firm Service Level. During a BIP program test, penalties will apply. The Utility may request the customer demonstrate to Utility's satisfaction that the customer has the capability to reduce load to their Firm Service Level during a BIP event.

16. Utility Reporting: Utility will provide the Commission with a monthly report on the economics of this Rate Schedule. The monthly report may contain information on individual customer performance. Customers on this tariff must agree to allow the Utility, the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to evaluate the BIP program. Furthermore, customer shall provide all load data and background information, under appropriate confidentiality protections needed to complete this evaluation. The data will also be made available to academic researchers, under appropriate confidentiality protections, to facilitate the understanding of demand response.

17. Failure to Reduce Energy: As per the BIP tariff, Special Condition 7 (b), failure to comply with a BIP load reduction event will result in the applicable rate being applied to all excess energy used above the Firm Service Level.

18. Emergency Generation Limitations: Customers are prohibited from achieving load reduction by operating backup or onsite standby generation.

19. Dispute Resolution: Any dispute arising from the provision of service under this schedule or other aspects of the Base Interruptible Program will be handled as provided for in the Utility's Rule 10, Disputes.

AGGREGATOR AGREEMENT
FOR CAPACITY BIDDING PROGRAM (CBP)

This Aggregator Agreement for Capacity Bidding Program ("Agreement") is made and entered into this ______ day of _________, 200__ (the "Effective Date"), by and between San Diego Gas & Electric Company ("Utility"), a corporation organized and existing under the laws of the State of California, and ____ ("Aggregator"), a _________________________________ organized and existing under the laws of the State of ____. Utility and Aggregator may sometimes be referred to herein as a "Party" and collectively as the "Parties".

WHEREAS, the California Public Utilities Commission ("CPUC") has authorized the Capacity Bidding Program (CBP) ("Program") as set forth in Schedule CBP, which is attached hereto as Attachment A and incorporated herein by this reference, whereby Utility pays participating Utility customers monthly incentive payments in return for pre-determined load reduction; and

WHEREAS, the CPUC has authorized the participation of third-party aggregators to aggregate the load reductions of one or more participating Utility customers, and Aggregator desires to participate in the Program as such a third-party aggregator, subject to the applicable Utility tariff rules and rate schedules.

NOW, THEREFORE, in consideration of the mutual undertakings set forth below, the Parties agree as follows:

I. AGGREGATOR STATUS

1.1 Status. Aggregator's status under this Agreement shall be as an "Aggregator" under Schedule CBP and Electric Rule 30, which is attached hereto as Attachment B and incorporated herein by this reference. Aggregator shall be subject to, and shall comply with, all applicable tariff rules and regulations (which rules and regulations are hereby incorporated herein as an integral part of this Agreement), including, but not limited to, the rates, terms and conditions set forth in Rule 30 and Schedule CBP, as such rules and regulations may be amended from time to time.

1.2 Eligibility. As a condition to participating in the Program as an "Aggregator," Aggregator shall meet the eligibility and qualification requirements set forth in Rule 30.

1.3 Definitions. Except where explicitly defined herein, the capitalized terms used in this Agreement shall have the meanings set forth in Rule 30 or Schedule CBP.

II. REPRESENTATIONS

2.1 Representations and Warranties. Each Party represents, warrants and covenants, individually for itself, as follows:

2.1.1 Such Party is and shall remain in compliance with all applicable laws and tariffs, including applicable CPUC requirements.

2.1.2 Each person executing this Agreement for such Party has the full power and authority to execute and deliver this Agreement and bind the entity on whose behalf this Agreement is executed.

2.1.3 The execution, delivery and performance of this Agreement have been duly authorized by all necessary action by such Party, and this Agreement constitutes such Party's valid and binding obligation, enforceable against such Party in accordance with its terms.

2.1.4 All duties under this Agreement shall be performed by such Party in accordance with applicable recognized professional standards.

2.2 Additional Representations of Aggregator.

2.2.1 With each submission of a "Notice by Aggregator to Add or Delete Customers" (Form 142-05303), which is attached hereto as Attachment C and incorporated herein by reference, adding a customer with respect to a service account to its representation, Aggregator represents and warrants, at the time of submission thereof and from time to time until Aggregator submits such notice for the removal of such customer from its representation, that:

(a) Such customer is otherwise eligible to participate in the Program and has elected to participate in the Program through Aggregator;

(b) Such customer has (i) entered into a Customer Contract (Form 142-05300) with Utility, (ii) completed a "Notice to Add, Change or Terminate a Third-Party Aggregator for Capacity Bidding Program" (Form 142-05302) and delivered such notice to Utility, and (iii) completed, executed and delivered to Utility all such other documents, instruments, consents and agreements as any be required for such participation in the Program and for the designation of such Aggregator (including, without limitation, an "Authorization To: Receive Customer Information or Act on a Customer's Behalf"; and

(c) Aggregator has entered into an Aggregator/Customer Contract with such customer consistent with the requirements of this Agreement.

2.2.2 With each submission of a "Notice by Aggregator to Add or Delete Customers" (Form 142-05303) dropping a customer with respect to a service account from its representation, Aggregator represents and warrants that:

(a) Such customer has elected, or has been deemed to have elected, to terminate its participation in the Program through Aggregator with respect to such service account; and

(b) Such customer has (i) completed a "Notice to Add, Change or Terminate an Aggregator for Capacity Bidding Program" (Form 142-05302) and delivered such notice to Utility, and (ii) delivered all such other documents, instruments, consents and agreements as any be required for terminating Aggregator's representation of such customer in the Program with respect to such service account.

III. SECURITY

Aggregator acknowledges that it has provided, prior to the execution of this Agreement, any and all financial information of Aggregator required by Utility. Aggregator acknowledges that Aggregator shall have a continuing obligation to provide such additional financial information to Utility upon the Utility's written request. Concurrently with the execution of this Agreement, and from time to time thereafter, Aggregator shall deliver any security required by Utility pursuant to Rule 30. Additionally, Aggregator represents and warrants that there has been no materially adverse change in its financial position from the date of the latest available and provided financial statements to the date hereof. In the event that (a) Utility determines that a material financial change in Aggregator has adversely affected Aggregator's creditworthiness subsequent to the execution of this Agreement, or (b) Aggregator does not provide the financial information or security requested by Utility, Utility may terminate this Agreement as of the day written notice is given or require Aggregator to provide additional security as provided in Rule 30.

IV. BILLING AND PAYMENT

4.1 Billing and Payment Terms. During the term of this Agreement, each Party shall make the payments or credits to the other Party, and in such amounts, as provided in Schedule CBP.

4.2 Billing Address. Statements, invoices and billings shall be by first class U.S. mail to the following addresses:

If to Aggregator:

____
____
____

If to Utility:

San Diego Gas & Electric Company
Billing Collections Manager
____
____

4.3 Payment Address. Payments shall be submitted electronically or by wire transfer to the following accounts:

If to Aggregator:

____
____

If to Utility:

____
____

4.4 Disputed Bills or Charges. Aggregator agrees to resolve any disputed bills and/or charges in accordance with Rule 30.

V. TERM

This Agreement shall become effective on the date that this Agreement is signed by both Parties ("Effective Date"), and remains effective unless terminated sooner by the terms herein. The term of this Agreement shall continue for at least twelve (12) calendar months after the Effective Date ("Minimum Term"), or unless ~~(a) the program is extended beyond the current program cycle () the Program expires earlier (which is expected to occur on December 31, 2008 unless the Program is extended by the CPUC),~~

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~~or (b)~~ this Agreement terminates earlier as set forth in this Agreement.

After the expiration of the Minimum Term, either Party may terminate this Agreement by written notification to the other Party of such termination, which termination shall be effective on the date that is the later of (i) the beginning of the calendar month that is immediately after the expiration of the Minimum Term, and (ii) the beginning of the calendar month that is closest to but at least thirty (30) calendar days after the non-terminating Party receives such notification.

In the case of a three (3) year commitment for participation in CBP, SDG&E agrees to provide as much protection as possible to allow the Aggregator to maintain the current program rates throughout that period for those customers enrolled.

VI. EVENTS OF DEFAULT

6.1 Events of Default. An "Event of Default" shall mean:

(a) if Aggregator defaults on the due and timely payment of monies when the same shall become due and payable, and such default shall continue for a period of seven (7) days after written notice thereof by Utility to Aggregator; or

(b) if Aggregator defaults in the performance or observance on its part of any other covenant, obligation or agreement contained in this Agreement to be performed by Aggregator (other than the payment of monies, which is governed by clause (a) above), and such default shall continue for a period of sixty (60) days after written notice thereof to Aggregator by Utility; provided, however, that if such default shall be such that it cannot be remedied by Aggregator within such sixty (60) day period, it shall not constitute an Event of Default if corrective action to cure such default is commenced by Aggregator within such sixty (60) day period and Aggregator diligently pursues the cure of such default until the default is remedied; or

(c) if Aggregator (i) makes an assignment or any general arrangement for the benefit of creditors, or (ii) files a petition or otherwise commence, authorize, or acquiesce in the commencement of a proceeding or case under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it which is not dismissed within thirty (30) days of such filing.

6.2 Remedies. If an Event of Default occurs and is continuing, Utility may terminate this Agreement and exercise any other remedies available to it at law, in equity, by statute or otherwise, subject, however, to the dispute resolution procedures set forth in Section 11.4 below. In addition, if an Event of Default for the payment of monies occurs and is continuing where Aggregator is the Defaulting Party, then the Utility may make a draw under any security provided by Aggregator for any such outstanding amounts due and payable from Aggregator.

6.3 Remedies Not Exclusive. No remedy by the terms of this Agreement conferred upon or reserved to Utility is intended to be exclusive of any other remedy, but each and every such remedy shall be cumulative and shall be in addition to every other remedy given hereunder or existing at law or in equity or by statute.

6.4 Rights and Responsibilities Following Termination. The Parties' rights and responsibilities following termination of this Agreement are set forth in Rule 30.

VII. LIMITATION OF LIABILITY

Utility's liability to Aggregator for any loss, cost, claim, injury, liability or expense, including reasonable attorneys' fees, relating to or arising from any act or omission in Utility's performance of this Agreement shall be limited to the amount of direct damage actually incurred. In no event shall Utility be liable to Aggregator for any indirect, special, consequential or punitive damages of any kind whatsoever, whether in contract, tort or strict liability. In addition, in no event shall Utility, its shareholders, directors, employees, agents or subcontractors (including, without limitation, suppliers of the Utility System) (collectively "Utility Parties") be liable to Aggregator for any claims, losses, liabilities or damage (whether direct, indirect, consequential, special, incidental, or punitive damages under any other theories including, but not limited to, tort, contract, breach of warranty or strict liability) for (i) the design, manufacture, installation, operation, maintenance, performance or demonstration of the Utility System, or (ii) the acts or omissions of, or the performance or non-performance of, Aggregator or any customer under any Aggregator/Customer Contract to which such customer is party. The "Utility System" includes any metering, meter communication equipment, Internet communication software, energy demand management software and related goods and services. Utility shall not be responsible for any business loss, actual or implied, as a result of the partial or complete failure of the Utility System to operate.

VIII. INDEMNIFICATION

8.1 Indemnification of Utility. To the fullest extent permitted by law, Aggregator shall indemnify, defend and hold harmless Utility, and its current and future parent company, subsidiaries, affiliates and their respective shareholders, officers, directors, employees, agents, representatives, successors and assigns (collectively, the "Indemnified Parties"), from and against any and all claims, actions, suits, proceedings, losses, liabilities, penalties, fines, damages, costs or expenses, including without limitation reasonable attorneys' fees (a "Claim"), resulting from (a) any breach of the representations, warranties, covenants and obligations of Aggregator under this Agreement, (b) any act or omission of Aggregator, whether based upon Aggregator's negligence, strict liability or otherwise, in connection with the performance of this Agreement, or (c) any third party claims of any kind, whether based upon negligence, strict liability or otherwise, arising out of or connected in any way to Aggregator's performance or nonperformance under this Agreement. This indemnification obligation shall not apply to the extent that such injury, loss or damage is caused by the willful misconduct of Utility or Utility's sole negligence.

8.2 Defense of Claim. If any Claim is brought against the Indemnified Parties, Aggregator shall assume the defense of such Claim, with counsel reasonably acceptable to the Indemnified Parties, unless in the opinion of counsel for the Indemnified Parties a conflict of interest between the Indemnified Parties and Aggregator may exist with respect to such Claim. If a conflict precludes Aggregator from assuming the defense, then Aggregator shall reimburse the Indemnified Parties on a monthly basis for the Indemnified Parties' defense costs through separate counsel of the Indemnified Parties' choice. If Aggregator assumes the defense of the Indemnified Parties with acceptable counsel, the Indemnified Parties, at their sole option and expense, may participate in the defense with counsel of their own choice without relieving Aggregator of any of its obligations hereunder.

8.3 Survival. Aggregator's obligation to indemnify Utility under this Section 8 shall survive the termination of this Agreement.

IX. NOTICES

9.1 Mailing Address. Except for statements, invoices and bills, which shall be submitted pursuant to Section 4 above, any formal notice, request, or demand concerning this Agreement shall be given in writing by Utility or Aggregator, and shall be (a) mailed by first-class mail, (b) mailed by registered, certified or other overnight mail, (c) delivered in hand, or (d) faxed with confirmation as set forth below, to the other party as indicated below, or to such other address as the parties may designate by written notice.

If to Aggregator:

____

____

____

Fax : ____________________________

If to Utility:

____

____

____

Fax : ____________________________

9.2 Notices. Notices delivered by hand shall be deemed received when delivered. Notices sent by facsimile shall be deemed received upon receipt but must be confirmed by mail within seventy-two (72) hours. Notices delivered by first class mail shall be deemed received forty-eight (48) hours (not including weekends and holidays) after deposit, postage prepaid, in the U.S. mail, or if certified, registered or overnight mailing is used, as acknowledged by the signed receipt of mailing.

X. CONFIDENTIALITY

10.1 Confidentiality. Aggregator shall not disclose any Confidential Information obtained pursuant to this Agreement to any third party, including any affiliates of Aggregator, without the express prior written consent of Utility. As used herein, the term "Confidential Information" means proprietary business, financial and commercial information pertaining to Utility, customer names and other information related to customers, including energy usage data ("Customer Information"), any trade secrets and any other information of a similar nature, whether or not reduced to writing or other tangible form. Confidential Information shall not include: (a) information known to Aggregator prior to obtaining the same from Utility; (b) information in the public domain at the time of disclosure by Aggregator; (c) information obtained by Aggregator from a third party who did not receive the same, directly or indirectly, from Utility; or (d) information approved for release by express prior written consent of an authorized representative of Utility.

10.2 Use of Confidential Information. Aggregator hereby agrees that it shall use the Confidential Information solely for the purpose of performing under this Agreement. Aggregator agrees to use at least the same degree of care Aggregator uses with respect to its own proprietary or confidential information, which in any event shall result in a reasonable standard of care to prevent unauthorized use or disclosure of the Confidential Information.

10.3 Authorized Disclosure. Notwithstanding any other provisions of this Section 10, Aggregator may disclose any of the Confidential Information in the event, but only to the extent, that, based upon advice of counsel, Aggregator is required to do so by the disclosure requirements of any law, rule, regulation or any order, decree, subpoena or ruling or other similar process of any court, governmental agency or regulatory authority. Prior to making or permitting any such disclosure, Aggregator shall provide Utility with prompt written notice of any such requirement so that Utility (with Aggregator's assistance if requested by Utility) may seek a protective order or other appropriate remedy.

10.4 Term. The confidentiality provisions set forth in this Section 10 shall remain in full force and effect with respect to any Confidential Information until the date that is ten (10) years after the date of disclosure of such Confidential Information; provided, further, that such confidentiality provisions shall remain in full force and effect with respect to any Customer Information in perpetuity.

10.5 Remedies. The Parties acknowledge that the Confidential Information is valuable and unique, and that damages would be an inadequate remedy for breach of this Section 10 and the obligations of Aggregator are specifically enforceable. Accordingly, the Parties agree that in the event of a breach or threatened breach of this Section 10 by Aggregator, Utility, its parent company(ies), subsidiaries and/or affiliates, who shall be third party beneficiaries of this Agreement, shall be entitled to seek an injunction preventing such breach, without the necessity of proving damages or posting any bond. Any such relief shall be in addition to, and not in lieu of, monetary damages or any other legal or equitable remedy available to Utility, its direct and indirect parent company(ies), subsidiaries or affiliates.

XI. MISCELLANEOUS

11.1 Assignment. This Agreement, and the rights and obligations granted and/or obtained by Aggregator hereunder, shall not be further transferred or assigned by Aggregator without the prior written consent of Utility. Any assignment in violation of this Section 11.1 shall be void.

11.2 Independent Contractor. Aggregator shall perform its obligations under this Agreement as an independent contractor, and no principal-agent or employer-employee relationship or joint venture or partnership shall be created with Utility.

11.3 Choice of Law. This Agreement shall be carried out and interpreted under the laws of the State of California, without regard to any conflict of law principles thereof. Except for matters and disputes with respect to which the CPUC is the proper venue for dispute resolution pursuant to applicable law or this Agreement, the federal and state courts located in San Diego County, California shall constitute the sole proper venue for resolution of any matter or dispute hereunder. The Parties submit to the exclusive jurisdiction of such courts with respect to such matters and disputes.

11.4 Resolution of Disputes. Any dispute arising between the Parties relating to the interpretation of this Agreement or to the performance of a Party's obligations hereunder shall be reduced to writing and referred to the Parties' designated representative for resolution. The Parties shall be required to meet and confer in an effort to resolve any such dispute. Any dispute or need for interpretation arising out of this Agreement which cannot be resolved after discussion between the Parties shall be submitted to the CPUC for resolution. If Aggregator disputes a Utility bill, the resolution of such dispute shall be as set forth in Rule 30.

11.5 Waiver. Any failure or delay by either party to exercise any right, in whole or part, hereunder shall not be construed as a waiver of the right to exercise the same, or any other right, at any time thereafter.

11.6 Governmental Actions. This Agreement shall be subject to the continuing jurisdiction of the CPUC and all orders, rules, regulations, decision or actions of any governmental entity (including a court) having jurisdiction over Utility or this Agreement. The Agreement is subject to such changes or modifications by the CPUC as it may direct from time to time in the exercise of its jurisdiction.

11.7 Entire Agreement. This Agreement, including the Attachments listed below, sets forth the entire understanding of the Parties as to the subject matter hereof, and supersedes any prior discussions, offerings, representations or understanding (whether written or oral), and shall only be superseded by an instrument in writing executed by both Parties. This Agreement shall not be modified by course of performance, course of conduct or usage of trade.

Attachment A: Schedule Capacity Bidding Program (CBP)
Attachment B: Rule 30 – Aggregators for Capacity Bidding Program (CBP)
Attachment C: Notice by Aggregator to Add or Delete Customers

11.8 Counterparts. This Agreement may be executed in counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument.

11.9 Headings. The headings contained in this Agreement are solely for the convenience of the Parties and shall not be used or relied upon in any manner in the construction or interpretation of this Agreement.

IN WITNESS WHEREOF, the authorized representatives of Utility and Aggregator have executed this Agreement as of the Effective Date.

UTILITY:	AGGREGATOR:
SAN DIEGO GAS & ELECTRIC COMPANY	____________________
By: ____________________	By: ____________________
Signature: ____________________	Signature: ____________________
Name: ____________________	Name: ____________________
Title: ____________________	Title: ____________________

ATTACHMENT A

Schedule Capacity Bidding Program (CBP)

ATTACHMENT B

Rule 30 – Aggregators for Capacity Bidding Program (CBP)

ATTACHMENT C

Notice by Aggregator to Add or Delete Customers

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

APPLICABILITY

The Capacity Bidding Program ("Program") is a voluntary demand response program that offers customers various product options by which participants can earn incentive payments in exchange for reducing energy consumption when requested by the Utility. This schedule is available to commercial and industrial Utility customers~~, greater than 20 kW~~, receiving Bundled Utility service, Direct Access ("DA") service or Community Choice Aggregation ("CCA") service, and being billed on a Utility commercial, industrial or agricultural rate schedule. Service on this rate schedule must be taken in combination with the customer's otherwise applicable rate schedule. This schedule is also available to "Aggregators", defined herein as a third party entity that combines the loads or one or more Utility customer service accounts for the purpose of participating under this schedule. "Participant" as used in this schedule shall mean Utility customers participating in the Program or Aggregators participating in the Program.

TERRITORY

Within the entire territory served by the Utility.

RATES

All charges and provisions of a participating customer's otherwise applicable rate schedule shall apply. All charges and provisions of a customer participating through an Aggregator shall apply. Customers who elect to sign up directly with the Utility for participation in the CBP will be paid at a maximum of 80% of the available capacity payment. Aggregators will receive 100% of the capacity payment for the amount of load reduction received in any given month. The tables below set forth the rates that will be paid to Participants under this schedule for each Product type and will be fixed for a three year program cycle.

1. Load Reduction Incentive Payment, Day-Ahead Program Option ($/kW-month):

Product	May	Jun	Jul	Aug	Sep	Oct
1 to 4 hours	2.43	6.55	14.21	17.56	11.60	3.50
2 to 6 hours	2.74	7.39	16.25	19.99	13.14	3.94
4 to 8 hours	2.81	7.61	16.99	20.76	13.71	4.05

2. Load Reduction Incentive Payment, Day-Of Program Option ($/kW-month):

Product	May	Jun	Jul	Aug	Sep	Oct
1 to 4 hours	2.91	7.85	17.05	21.08	13.92	4.20
2 to 6 hours	3.29	8.87	19.50	23.99	15.77	4.73
4 to 8 hours	3.38	9.13	20.39	24.91	16.45	4.86

3. . Load Reduction Incentive Payment, Day-Of Program 30 Min Option ($/kW-month):

Product	May	Jun	Jul	Aug	Sep	Oct
1 to 4 hours	3.35	9.03	19.61	24.24	16.00	4.83
2 to 6 hours	3.78	10.20	22.43	27.59	18.13	5.44
4 to 8 hours	3.89	10.50	23.45	28.65	18.92	5.59

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

4~~3~~. Energy Usage Reduction Incentive Payment, All Program Options (cents/kWh):
The applicable rate to be applied in calculating the Energy Usage Reduction Incentive Payment is generally the daily Utility city gate natural gas price multiplied by the Program dispatch heat rate of 15,000 Btu/kWh for each kilowatt hour of energy reduction during Events. See Energy Usage Reduction Incentive Payment Special Condition 6.b., for a further description of the calculation of the Energy Usage Reduction Incentive Payment, the development of the payment amount, and any payment amount adjustments.

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS

1. Definitions: The Definitions of terms used in this schedule are found either herein or in Rule 1, Definitions.

2. Qualifying Customer: Service under this schedule is available to all non-residential time-of-use metered customers ~~with demand in excess of 20 kW~~ who elect to participate. Customers electing to participate in the Program must meet and comply with all of the requirements for such participation as set forth in this Schedule. Participating customers must have the required metering and operable communications equipment installed prior to and while participating in the Program. See Metering Requirement Special Condition 13, for additional details. Participating customers must have the required notification equipment in place prior to participation in the Program. See Event Notification/Communication Special Condition 8, for additional details.

   a. Aggregators: In the event customers elect to participate in the Program via an Aggregator, such participation, and such Aggregator's participation in the Program, are subject to the terms and conditions of this schedule and Rule 30, Aggregators for the Capacity Bidding Program (CBP). Customers participating in the Program may designate only one Aggregator at a time for each participating meter and may change such designation only after the expiration of the Minimum Term in respect of such participating meter (unless terminated earlier, as set forth in Term, Special Condition 19). Prior to any changes in the designation or any termination of an Aggregator, a customer shall deliver to the Utility a "Notice to Add, Change or Terminate an Aggregator for Capacity Bidding Program" (Form 142-05302) notifying the Utility of such change or termination.

   b. Direct Access and Community Choice Aggregation Customers: The Utility will no longer provide energy payments to Participants or Aggregators for load reductions from DA or CCA customers during CBP events ($0/kWh), due to the Scheduling Coordinator (SC)-to-SC trade and payment changes to the CBP program. Participants and Aggregators will still receive capacity payments from the Utility for DA or CCA customers' load as applicable under this Schedule. This provision does not prevent DA or CCA customers from entering into arrangements with their respective ESPs or CCAs to receive part or all of the energy benefits derived from the DA or CCA customers' load reductions during CBP events. The Utility will notify existing CBP Participants and Aggregators of this recent SC-to-SC program change.

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

3. Program Operation: Participants may nominate from among the following product types ("Products") under the Program:

Day-Ahead Products	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration Per Operational Month	Maximum Events Per Day
1-4 Hour	1 hour	4 hours	44	1
2-6 Hour	2 hours	6 hours	44	1
4-8 Hour	4 hours	8 hours	44	1

Day-Of Products	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration Per Operational Month	Maximum Events Per Day
1-4 Hour	1 hour	4 hours	44	1
2-6 Hour	2 hours	6 hours	44	1
4-8 Hour	4 hours	8 hours	44	1

Day-Of 30 Min Products	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration Per Operational Month	Maximum Events Per Day
1-4 Hour	1 hour	4 hours	44	1
2-6 Hour	2 hours	6 hours	44	1
4-8 Hour	4 hours	8 hours	44	1

Participants may nominate a different Product for each month of the Program's operational season (as set forth below), and any combination of Products for each such operational month in respect of the Nominated Load Reduction for such operational month. Each nominated Product must specify the portion of Nominated Load Reduction associated thereto without overlap between nominated Products for such operational month. Customer participation in within Day-Ahead and/or Day-Of ~~product~~/or Day-Of 30 Min product types is defined in Rule 41.

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

The Program's operational season is from May 1 through October 31.

Each operational month of the Program begins and ends at the beginning and ending of such calendar month.

The Program's operational days are Monday through Friday during the Program's operational season, excluding Utility holidays, as defined in Rule 1.

The Program's operational hours are from 11:00 a.m. to 7:00 p.m. during each of the Program's operational days.

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

3. Program Operation: (Continued)

a. Interruptible Period: Each interruptible period ("Event") shall be the period of time during which the Utility has informed the Participant to curtail energy consumption by use of a communications process utilizing equipment described in the Event Notification/Communication Special Condition 8.

b. Interruptible Period Termination: An Event will terminate upon notification by the Utility that the Event has ended, provided that an Event shall not continue longer than the duration prescribed therefore for the Product nominated by the Participant as described in the table above.

c. Load Reduction Nominations:

i. Generally: Participants must submit monthly nominations for the reduction of load ("Load Reduction Nominations") to the Utility no later than fifteen (15) calendar days prior to each Program operational month. All Load Reduction Nominations must allocate the amount of load reduction nominated among each Product nominated for such operational month (such nominated amount, the "Nominated Load Reduction"), without overlap of such Nominated Load Reduction among any such selected Product during such operational month. All Load Reduction Nominations are fixed for their associated operational month, but may change from operational month to operational month. Participants may not submit Load Reduction Nominations unless all requirements specified in this schedule have been met.

ii. Additional Aggregation Requirements: Load Reduction Nominations submitted by Aggregators must differentiate the amount of Nominated Load Reduction for each nominated Product therein between Bundled customers and DA/CCA customers. A participating customer may be included in only one Aggregator's aggregated group/portfolio for a given operational month. No later than fifteen (15) calendar days prior to the first day of the operational month, each Aggregator must specify which participating customers are to be included in each Product set forth in such Aggregator's Load Reduction Nomination for that operational month. The aggregated group of participating customers for each nominated Product will be used to determine the Baseline (see Customer-Specific Baseline Special Condition 5) and associated Program performance during that operational month.

d. Cancellation of Nominations: Any changes or cancellations of Load Reduction Nominations for an operating month must be submitted by the Participant to the Utility not later than fifteen (15) calendar days prior to such operating month. f a Participant fails to nominate a load reduction for a Product for a particular operational month, then the default Nominated Load Reduction therefore shall be zero (0).

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

3. Program Operation: (Continued)

   e. Third-Party Coordinators: Utility may contract with one or more third parties ("Coordinators") to assist Utility in the administering, coordination and/or scheduling of the Program and may designate such Coordinators as the sole point of contact in respect of such services by notifying the applicable Participants of such designation.

   f. Program Triggers:

      i. The Utility may call an Event whenever the Utility's electric system supply portfolio reaches a resource dispatch equivalence of 15,000 Btu/kWh heat rate, or as Utility system conditions warrant.

      ii. Whenever the California Independent System Operator has issued an alert or warning notice, the California Independent System Operator shall be entitled to request that the utility, at its discretion, call a program event pursuant to this Schedule.

4. Program Availability: An Event may be called during the Program's operational season, operational days and operational hours as defined above. The Program shall be limited as to its availability to Participants based on any limitations that the Utility has in getting communications systems in place. The Utility will staff as quickly as practical to provide this service to as many Participants as quickly as practical so long as communications are in place before service commences.

   a. Limitation of Interruptible Periods: Events shall be limited as follows:

      i. Day Ahead: For Participants selecting Day-Ahead Products, Events shall be called by the Utility with notice to such Participants not later than 3:00 p.m. on the day prior to the Event day. Notices will be issued by 3:00 p.m. on the business day immediately prior to a holiday or weekend if a CBP Event is planned for the first business day following the holiday or weekend. The Events shall not exceed the maximum duration (in hours) corresponding with the Product nominated by the Participant as set forth in the table above. The maximum cumulative duration of an Event during any operational month shall not exceed 44 hours.

      ii. Day Of: For Participants selecting Day-Of Products, Events shall be called by the Utility with notice to such Participants by 9:00 a.m. but not later than two (2) hours prior to the commencement of the Event. The Events shall not exceed the maximum duration (in hours) corresponding with the Product nominated by the Participant as set forth in the table above. The maximum cumulative duration of an Event during any operational month shall not exceed 44 hours.

      iii. Day Of 30 Min: For Participants selecting Day-Of 30 Min. Products, Events shall be called by the Utility with notice to such Participants no later than Thirty (30) Minutes prior to the commencement of the Event. The Events shall not exceed the maximum duration (in hours) corresponding with the Product nominated by the Participant as set forth in the table above. The maximum cumulative duration of an Event during any operational month shall not exceed 44 hours.

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

5. Customer Specific Baseline: In order to participate in the Program, Participants must have a valid baseline ("Baseline") for each Product nominated each day of an operational month, which Baseline must be established no later than fifteen (15) calendar days prior to the first day of such operational month of the Program. Baselines shall be established as follows:

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

5. Customer Specific Baseline: (Continued)

   a. Participating Customers: The baseline is equal to the average electricity consumption (in MWh) of the participant during the applicable Program Event hour over the ten (10) immediately preceding similar days prior to the Program Event day. Similar days exclude weekends, holidays, and days when load reductions were requested or when outages were called.

   b. Aggregators: For Aggregators, the hourly load profile for the aggregated group of participating accounts on such day shall be determined by summing the hour by hour interval metering data for each participating account. The Baseline Hourly Energy Usage is equal to the average electricity consumption (in MWh) of the aggregated group of Participating Accounts during the applicable Program Event hour over the ten (10) immediately preceding similar days prior to the Program Event day. Similar days exclude weekends, holidays, and days when load reductions were requested or when outages were called.

   c. Day-Of Adjustment: Participants and Aggregators may choose to have their baselines calculated using a Day-Of Adjustment. The Day-Of Adjustment is calculated using the first three of the four hours prior to the event divided by the average load for the same hours using the last 10 weekdays for CBP participants. This Day-Of Adjustment shall not exceed plus or minus 40% of the Participant's calculated baseline. Participants must elect or opt-in to receive this adjustment. The Participant/Aggregator may select a baseline or a baseline with a day-of adjustment for each service account when they nominate for the operating month.

6. Incentive/Energy Payment and Non-Performance Penalties:

   a. Load Reduction Incentive Payment:

      i. If the Utility does not call an Event during an operational month, the amount of the Load Reduction Incentive Payment for such operational month is calculated by summing, for each Product nominated in such operational month, the product of the Nominated Load Reduction for such nominated Product and the Load Reduction Incentive Payment rate as set forth in the table above for such nominated Product.

      ii. If the Utility calls one or more Events during an operational month, the amount of the Load Reduction Incentive Payment for such operational month is calculated by summing the Adjusted Event Capacity Payment Amounts for each Product nominated in such operational month, which is calculated as follows: The "Unadjusted Hourly Event Capacity Payment Amount" for each Product nominated in such operational month is equal to the product of the Nominated Load Reduction for such nominated Product and the Load Reduction Incentive Payment rate as set forth in the table above for such nominated Product, divided by the number of Event hours called during such operational month, and the "Adjusted Event Capacity Payment Amount" for each such Product nominated in such operational month is calculated based on the Actual Load Reduction (as defined in the Actual Load Reduction Special Condition 7) for such Product in such operational month:

(Continued)

SPECIAL CONDITIONS (Continued)

6. Incentive/Energy Payment and Non-Performance Penalties: (Continued)

Actual Load Reduction for such Product	Adjusted Event Capacity Payment Amount for such Product
More than 100 percent of Nominated Load Reduction for such Product	Payment equal to 100 percent of Unadjusted Event Capacity Payment Amount for such Product
~~90~~ 75 – 100 percent of Nominated Load Reduction for such Product	Payment calculated by prorating between 90 and 100 percent of Unadjusted Event Capacity Payment Amount for such Product
~~75 – 89.99 percent of Nominated Load Reduction for such Product~~	~~Payment equal to 50 percent of Unadjusted Event Capacity Payment Amount for such Product.~~
50 – 74.99 percent of Nominated Load Reduction for such Product	Zero (0)
Less than 50 percent of Nominated Load Reduction for such Product	Penalty equal to (.50 minus Actual Reduction divided by Nominated Load reduction) multiplied by the Unadjusted Event Capacity Payment Amount.

If the Load Reduction Incentive Payment amount as calculated above yields an amount less than zero (i.e. a penalty amount), then such penalty amount shall be payable by Participant to the Utility in accordance with the Disbursement of Payments Special Condition 6.c. below.

b. Energy Usage Reduction Incentive Payment:

i. If the Utility does not call an Event in respect of a Product during an operational month, no monthly Energy Usage Reduction Incentive Payment in respect of such Product is payable for such operational month.

ii. If the Utility calls one or more Events during an operational month in respect of a Product, bundled customers enrolled directly with SDG&E or through Aggregators are eligible to receive the amount of monthly Energy Usage Reduction Incentive Payment for such Product that is equal to the Actual Load Reduction for such Product times a 15,000 Btu/kWh heat rate times the Utility's delivered natural gas price ("Delivered Natural Gas Price") for each operational day of each such Event (which Delivered Natural Gas Price is determined by the posted California Border Natural Gas Index Price plus the cost of applicable transportation to the Utility's service territory, and adjusted as follows:

(Continued)

SPECIAL CONDITIONS (Continued)

6. Incentive/Energy Payment and Non-Performance Penalties: (Continued)

b. Energy Usage Reduction Incentive Payment: (Continued)

ii. (Continued)

(a) Shortfall Energy Amount: In the event of a Shortfall Energy Amount (as defined in the Actual Load Reduction Special Condition 8) in respect of such Product for such operational month, the monthly Energy Usage Reduction Incentive Payment amount for such Product will be reduced by an amount equal to the product of such Shortfall Energy Amount and the greater of (i) the Energy Usage Reduction Incentive Payment Price or (ii) the CAISO hourly SP15 ex-post energy price for each Event hour. If such calculation of Energy Usage Reduction Incentive Payment amount for such Product yields an amount less than zero (i.e. a penalty amount), then such penalty amount shall be payable by Participant to the Utility in accordance with the Disbursement of Payments Special Condition 6c.

(i) the Utility's Delivered Natural Gas Price is not in the right units. EURP price and ISO ex-post are both in $/MWh.

(b) Excess Energy: In the event that the Actual Load Reduction for such Product during an Event in such operational month exceeds the Nominated Load Reduction for such Product in such operational month (such excess amount, "Excess Energy Amount"), then the Energy Usage Reduction Incentive Payment amount for such Product will be increased by an amount equal to the product of such Excess Energy Amount and the Utility's Delivered Natural Gas Price during the Event; provided, however, that, for purposes of calculating the Energy Usage Reduction Incentive Payment amount, the Excess Energy Amount for a Product cannot exceed 50 percent of the Nominated Load Reduction for such Product.

Direct Access and Community Choice Aggregation are not eligible for the Energy Usage Reduction Incentive payments nor subject to Energy Usage Reduction penalties.

c. Disbursement of Payments:

i. Customers: For customers participating directly with the Utility, the CBP incentive will be calculated based on the customer's Actual Load Reduction. In no case will a customer receive a credit payment for a given hour if it does not meet the minimum energy reduction threshold, as nominated in the monthly Load Reduction Nomination. The billing and payment of Load Reduction Incentive Payments and Energy Usage Reduction Incentive Payments, as well as all other amounts, charges, penalties and fees due and payable in respect of this Program, to or from customers participating in the Program will be paid by the Utility within 30 days after the end of the event operating month, but no more than 60 days after the end of the event operating month will be made in the course of customer's normal billing for services with the Utility consistent with Utility's tariffs.

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

Disbursement of Payments (continued)

6. Incentive/Energy Payment and Non-Performance Penalties: (Continued)

   ii. Aggregators: The billing and payment of Load Reduction Incentive Payments and Energy Usage Reduction Incentive Payments, as well as all other amounts, charges, penalties and fees due and payable under this schedule, Rule 30 or the Aggregator Contract, to or from Aggregators are set forth in Rule 30.

   d. Failure to Pay: In the event a participating customer fails to pay any amounts to the Utility as and when due, the rules governing such failure to pay, and the Utility's and such customer's rights and obligations therewith, as set forth in the Utility's tariff will apply. The Aggregator Contract will set forth the rights and obligations of the Utility and the Aggregator party thereto in respect of any failure to pay amounts as and when due to the Utility.

   e. Customer Liability for Aggregator Failure to Pay. If, due to a Shortfall Energy Amount which results in a penalty to be paid by an Aggregator to Utility in respect of Load Reduction Incentive Payments and/or Energy Usage Reduction Incentive Payments, such Aggregator fails (or is deemed to have failed) to fully pay to Utility such penalty amounts, and any security provided by such Aggregator is insufficient to cover such outstanding penalty amounts, then each customer represented by such Aggregator under the applicable Aggregator Contract will be liable for its pro rata share of such outstanding penalty amounts, which pro rata share will be based upon such customer's contribution to such Shortfall Energy Amount.

7. Actual Load ReductioA Participant's "Actual Load Reduction" during an Event for each Product nominated by such Participant is equal to:

   a. In the case that such Participant is a customer participating directly with the Utility, the extent that the actual energy usage of such customer during such Event for such Product is less than such customer's Baseline for such Product.

   b. In the case that such Participant is an Aggregator, the extent that the actual energy usage of the aggregated group of customers during such Event for such Product is less than such aggregated group of customer's Baseline for such Product.

   In the event the Actual Load Reduction for such Product during an Event in such operational month is less than the Nominated Load Reduction for such Product in such operational month, such deficient amount is the "Shortfall Energy Amount" for such Product in such operational month.

8. Event Notification/Communication: Participating entities (customers, aggregators, ESPs) must, at their own expense, have access to the Internet and an e-mail address to receive Event notifications via the Internet. In addition, Participants must have, at their own expense, an alphanumeric device that is capable of receiving a text message sent via the Internet. Participants will be notified via the Utility's designated Internet website. As a courtesy, notification may also be given via pager, e-mail, or cellular telephone; however, the official notification shall be posted to the Utility's designated Internet website in accordance with the time parameters set forth herein. No Participating entity may participate in the program until all of these requirements have been met.

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

9. Event Cancellation: Once an Event has been initiated in accordance with the provisions herein, the Event will not be cancelled; however, the Event may be terminated as provided in the Interruptible Period Termination Special Condition 3.b.

10. Contract Requirement: Participating customers and Aggregators must execute all applicable agreements prescribed by the Utility prior to participation under this schedule. Necessary agreements may include the following:

    a. For Utility customers, a Capacity Bidding Program Customer Contract (Form 142-05300) ("Customer Contract");

    b. For Aggregators, an Aggregator Agreement for Capacity Bidding Program (CBP) (Form 142-05301) ("Aggregator Contract").

11. Multiple Program Participation: Eligibility for Multiple Program Participation is defined in Rule 41.

12. Termination of Schedule: This schedule is in effect until modified or terminated through the Utility's Demand Response Programs portfolio Application proceeding, or through the annual program evaluation and modification process most recently adopted by the Commission in D. 06-03-024.

13. Metering Requirement: Each participating customer must have a SDG&E Smart Meter installed. In certain ~~an~~circumstances an approved interval meter and approved meter communications equipment will be installed and read by SDG&E. The Utility must have access to the customer's meter data on a daily basis for a period of no less than ten (10) calendar days to establish a valid customer specific baseline.

    An approved interval meter is capable of recording usage in 15-minute intervals and being read remotely by the Utility.

    For customers with billed maximum demand of 20 kW or greater during one of the past 12 billing months, the Utility will, if required, provide and install the metering and communication equipment at no cost to the customer.

14. Utility Testing: At the Utility's discretion, up to two (2) Events may be called during each operational season for the purpose of testing of the Program ("Test Events"). All notification protocols, as well as all applicable payments and penalties, will apply during Test Events. The only difference between a Test Event and an actual Event is the absence of the prerequisite trigger condition of 15,000 Btu/kWh heat rate criteria. A Test Event may be scheduled on a day-ahead/ or ~~or a~~ day-of / or a day-of 30 Min basis on any applicable weekday, within the operational parameters contained herein. If an actual event is not initiated by late summer a test event will be called during the peak moths of August or September.

(Continued)

SPECIAL CONDITIONS (Continued)

15. Utility Reporting: The Utility will provide the Commission with a periodic report on the performance results of this schedule. The report may contain information on individual Participant performance, which will be provided to the Commission under applicable confidentiality protections. Participants must agree to allow the Utility, the California Energy Commission ("CEC") and their respective agents, employees, contractors, representatives and designees to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to evaluate the Program. Furthermore, Participants shall provide all load data and background information, under appropriate confidentiality protections needed to complete this evaluation. The data may also be made available to academic researchers, under appropriate confidentiality protections, to facilitate the understanding of demand response.

16. Failure to Reduce Energy: A failure to comply with an Event will result in the applicable penalty provisions (including the payment therefore by the Participant incurring such penalty) being applied as described herein.

17. Emergency Generation Limitations: Participating customers are prohibited from achieving energy reductions by operating backup or onsite standby generation.

18. Dispute Resolution: Any dispute arising from the provision of service under this schedule or other aspects of the Program will be handled as provided for in the Utility's Rule 10, Disputes.

19. Term: Except as set forth below, each Participant must remain in the Program for a minimum of 12 calendar months ("Minimum Term") unless (a) the Program expires earlier, or (b) such Participant's Program contract with the Utility (that is, the Customer Contracts in the case of customers and Aggregator Contracts in the case of Aggregators) expires or terminates earlier. After the expiration of the Minimum Term, Participants may terminate its Program contract with the Utility and its participation in the Program by submitting to the Utility written notification of such termination, which termination shall be effective on the date that is the later of (i) the beginning of the calendar month that is immediately after the expiration of the Minimum Term, and (ii) the beginning of the calendar month that is closest to but at least thirty (30) calendar days after the Utility receives such notification.

    In the event of termination of an Aggregator Contract between an Aggregator and Utility, the customers whom such Aggregator represented under such Aggregator Contract will have fourteen (14) days from the date of receipt of notice of such termination by Utility in which to continue their participation in the Program in respect to the represented service meters through another Aggregator or directly with Utility without the designation of an Aggregator. Customers electing the foregoing must submit a "Notice to Add, Change or Terminate an Aggregator" (Form 142-05302) setting forth their election. If such customer does not submit such form by such 14-day period, such customer will be deemed to have elected to continue its participation in the Program with respect to such service meters directly with the Utility without being represented by an Aggregator.

(Continued)

SDGE
A Sempra Energy utility

DEMAND BIDDING PROGRAM-Day Of CONTRACT

This "Contract" is made and entered into by and between San Diego Gas & Electric Company, a California corporation, hereinafter referred to as "SDG&E" and ______________________________, a Bundled, Direct Access or CCA Customer, hereinafter referred to as "Customer", and jointly, or individually, referred to as "Parties" or "Party".

RECITALS

WHEREAS, Customer is herein requesting to take service on SDG&E Tariff Schedule DBP-DO, Demand Bidding Program-Day Of ("Schedule DBP-DO"), attached hereto as **Attachment C**, on a voluntary basis without penalty.

NOW, THEREFORE, FOR GOOD AND VALUABLE CONSIDERATION, THE PARTIES AGREE AS FOLLOWS:

I. TERM

This Contract shall become effective when fully executed by both parties. The "Effective Date" of the Contract shall be the date of signature by the last signing party. This Contract shall remain from the Effective Date through December 31st, ~~2014~~2016, unless terminated earlier according to the terms herein.

II. DEMAND REDUCTION BID

Pursuant to the terms of Schedule DBP-DO, Customer shall voluntarily provide Demand Bids to SDG&E upon receipt of notice from SDG&E of a Demand Bidding Event (all as defined within Schedule DBP-DO).

III. PROGRAM COMMITMENT

Schedule DBP-DO is a demand/energy bidding program that offers incentives to non-residential customers for reducing energy consumption and demand during a specific Demand Bidding Event. Schedule DBP-DO will end December 31, ~~2014~~2016.

Customer shall qualify for Schedule DBP-DO if Customer is capable of providing at least a 5 MW load reduction based on its specific baseline. At the time of enrollment, Customer may choose to aggregate no more than 5 billable meters for the purposes of qualification and settlement. Customer shall reduce its energy consumption when requested at times when an SDG&E system emergency or statewide emergencies are declared by the California Independent System Operator (CAISO).

___ Single Account
___ Aggregate Accounts

Account Numbers: 1.) ______________
2.) ______________
3.) ______________
4.) ______________
5.) ______________

IV. ASSIGNMENT

Customer shall not assign this Contract without prior written consent of SDG&E. Any such assignment shall be automatically void.

V. DISPUTE RESOLUTION

Any dispute that cannot be resolved between the Parties shall be settled by means of conference, mediation, arbitration and/or litigation as provided for herein.

The first step in the dispute resolution process shall be a conference by which the dispute is referred to a designated officer of each Party for resolution. If those two officers cannot reach an agreement within a reasonable period of time, the Parties shall submit the dispute to mediation.

The second step in the dispute resolution process shall be mediation between the Parties in accordance with the Commercial Rules of the American Arbitration Association. If the dispute is not resolved by the mediation, the Parties shall submit the dispute to arbitration or litigation. Should the Parties not agree on arbitration, both Parties agree that jurisdiction of any claim or suit hereunder shall be limited to the courts of appropriate jurisdiction located within the County of San Diego, State of California. Both Parties hereby submit to the exclusive personal jurisdiction of such courts.

Notwithstanding the foregoing, if Customer is a **federal governmental authority or agency**, jurisdiction of any claim or suit hereunder shall be heard within the courts of appropriate federal jurisdiction.

In any action in litigation to enforce or interpret any of the terms of this Contract, the prevailing Party shall be entitled to recover from the unsuccessful Party all costs, expenses, (including expert testimony) and reasonable attorneys' fees (including fees and disbursements of in-house and outside counsel) incurred therein by the prevailing Party, to the extent permissible by law or authorized by specific federal statutory authority, as applicable.

VI. DISCLAIMER OF WARRANTY

No promise, representation, warranty, or covenant not included in this Contract has been, or is relied on by either Party. Each Party has relied on its own examination of this Contract, the counsel of its own advisors, and the warranties, representations, and covenants in the Contract itself.

VII. INDEMNIFICATION

Customer shall indemnify, defend and hold SDG&E and its current and future parent company, subsidiaries, affiliates and their respective directors, officers, shareholders, employees, agents, representatives, successors and assigns ("SDG&E Parties") harmless for, from and against any and all claims, actions, suits, proceedings, losses, liabilities, penalties, fines, damages, costs or expenses including without limitation, reasonable attorneys' fees (including fees and disbursements of in-house and outside counsel) of any kind whatsoever (collectively, "Claims") resulting from or arising out of this Contract or Customer's participation in Schedule DBP-DO, whether based upon negligence, tort, strict liability or otherwise, including but not limited to third party Claims of any kind. This indemnification obligation shall not apply only to the extent that any such Claims are caused by either the willful misconduct of SDG&E or by SDG&E's sole negligence.

Notwithstanding the foregoing, if Customer is a **federal governmental authority or agency**, each Party's liability to the other for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be determined in accordance with applicable law.

The provisions of this Section shall survive the termination of this Contract.

VIII. LIMITATION OF LIABILITY

In no event shall either Party, its shareholders, directors, employees, agents or subcontractors (including, without limitation, suppliers of the System) be liable to the other Party for any indirect, consequential, special, incidental, or punitive damages under any other theories including, but not limited to, tort, contract, breach of warranty or strict liability for the design, manufacture, installation, operation, maintenance, performance or demonstration of the System, even if reasonably foreseeable at the time of contracting. The System includes any metering, meter communications equipment, Internet communication software, energy demand management software and related goods and services. SDG&E shall not be responsible for any business loss, actual or implied, as a result of the partial or complete failure of the communications systems to operate.

IX. COMPLIANCE WITH LAWS

Customer shall comply with the terms and conditions of Schedule DBP-DO ~~or Schedule DBP-E~~, whichever is applicable, and all local, state and federal rules, regulations and laws.

X. COMMISSION CONTINUING AUTHORITY

This Contract shall at all times be subject to the Commission and to any changes or modification that the Commission may, from time to time, direct in the exercise of its jurisdiction.

Notwithstanding any other provision of this Contract, either Party shall have the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for a change in rates, charges, classification, or any rule, regulation, or agreement relating thereto.

XI. DIRECT ACCESS CUSTOMER PARTICIPATION

Direct Access and CCA Customers are solely responsible for their legal commitments with their Energy Services Providers/Aggregators. SDG&E shall have no duty, liability or involvement in contract or assignment issues between Customer and its Energy Service Provider(s)/Aggregators.

IN WITNESS WHEREOF, SDG&E and Customer have executed this Contract as of the Effective Date.

______________________________	San Diego Gas & Electric Company
By: ______________________________	By: ______________________________
Title: ______________________________	Title: ______________________________
Date: ______________________________	Date: ______________________________

The following attachments are attached hereto and incorporated herein by reference:
Attachment A: Customer Contact Information
Attachment B: Customer Account Information
Attachment C: Schedule DBP-DO, Demand Bidding Program-Day Of

ATTACHMENT A
Demand Bidding Program
Customer Contact Information

Primary Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

Secondary Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

Additional Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

Additional Contact:
Name: ______________________________
Title: ______________________________
Mailing Address: ______________________________
____
Telephone Number: ______________________________
Pager Number: ______________________________
Email Address: ______________________________

Attach additional Customer Account Information sheets to this contract if required. (Sheet ____ of _____)

ATTACHMENT B
Demand Bidding Program
Customer Account Information

Site #1
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

Site #2
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

Site #3
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

Site #4
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

Site #5
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

SCHEDULE DBP-DO

DEMAND BIDDING PROGRAM- Day Of

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APPLICABILITY

The Demand Bidding Program-Day Of (DBP-DO) is a demand/energy bidding program that offers incentives to non-residential customers for reducing energy consumption and demand during a specific Demand Bidding Event described in the Special Conditions below. ~~This program will end December 31st, 2014.~~

TERRITORY

Within the entire territory served by the Utility.

RATES

Day Of DBP Incentive is $~~500~~600.00/MWh for customers who purchase commodity from the Utility (bundled customers).

The DBP-DO incentive for customers who purchase commodity from an Energy Service Provider or a Community Choice Aggregator (Direct Access or CCA customers) shall be calculated by the Utility by deducting the corresponding California Independent System Operator (CAISO) TH-SP15-GEN-APND day-ahead market locational marginal price (DAM LMP) from the DBP-DO incentive for bundled customers. In no case will the customer be required to pay the Utility if the DAM LMP is greater than the DBP-DO incentive. If the DAM LMP is greater that the DBP-DO incentive, the customer does not receive an incentive for the event from SDG&E.

The DBP-DO Incentive Payment is calculated as defined in special condition 8. The Utility will provide the DBP-DO Incentive Payment as an adjustment to the customer's regular monthly bill, within 90 days of the Demand Bidding Event. The Utility will make DBP-DO Incentive Payments only for those hours of Accepted Demand Reduction, as set forth in Special Condition 4.

SPECIAL CONDITIONS

1. Definitions: The definitions of terms used in this schedule are found either herein or in Rule 1, Definitions.

2. Qualifying Customer: This Schedule is applicable, in combination with a customer's otherwise applicable tariff(s), on a voluntary basis, to non-residential customers, including Direct Access and Community Choice Aggregation customers, who are capable of providing at least a 5 MW load reduction based on the customer's specific baseline. At the time of enrollment a customer may choose to aggregate no more than 5 billable meters for the purposes of qualification and settlement. The customer will reduce their energy consumption when requested at times when an SDG&E system emergency or statewide emergencies are declared by the California Independent System Operator (CAISO).

3. Billable Meter: A billable meter represents the meter data used for the purpose of calculating a customer's UDC rate charges. In the event that a customer's meter data is combined for the purpose of calculating UDC charges a billable meter number represents the combined meter data.

(Continued)

SCHEDULE DBP-DO

DEMAND BIDDING PROGRAM- Day Of

T

SPECIAL CONDITIONS (Continued)

4. Program Operation:

   a. Demand Bidding Event: The Utility will declare a Demand Bidding Event ~~for the following day~~ and the Utility will request bid confirmations~~s~~ from the customers that will cover the period of the event.

   b. Demand Bid: A Demand Bid is the amount of MW per hour (MWh usage) that a customer commits to reduce for each hour of an Event.

      i. For each hour the customer must submit the customer's Bid for a minimum demand reduction of 5 MWh.

   c. Bid Submission: Customers ~~will submit by 16:00 daily Demand Bid for the next day and indicate the amount of MW curtailment they are offering between 11:00 and 6:00 for which they are available to curtail.~~ initial bid will be the MW reduction identified on their enrollment application. The customer may change their bid throughout the year as their operations change as long as the bid meets the minimum bid value.

   d. Bid Evaluation: Unless a capacity level (megawatt quantity) is specified in the CAISO notification, the Utility will deem all qualified Demand Bids received by the deadline acceptable from customers. In evaluating late bids, the Utility will consider then-current conditions, including previous acceptance or rejection of timely bids submitted within the first hour.

      Unless a capacity level (MW quantity) is specified in the CAISO or Utility event notification, the Utility will then evaluate the qualified bids received based on a first come, first served basis, taking bidder past performance and compliance into account, and accept or reject each bid.

   e. Bid Confirmation: The Utility will notify the customer of a Demand Bidding Event 30 minutes prior to the event and request ~~confirm the~~ confirmation of value on the bid submission. The customer will have the opportunity to increase or decrease their bid at this time.

      i. Confirmation of bid will be sent via electronic mail (e-mail) in the event notification and sent out a minimum of 30 minutes prior to an event.

5. Program Triggers: A Demand Bidding Event shall be initiated upon notice from the CAISO of a Stage 1, 2, 3 emergency, a transmission or imminent system emergency, or as conditions warrant by the Utility. Whenever the California Independent System Operator has issued an alert or warning notice, the California Independent System Operator shall be entitled to request that the utility, at its discretion, call a program event pursuant to this Schedule.

6. Program Availability: DBP-DO is available year-round. There is no limit to the number of Demand Bidding Events per month or per year.

SCHEDULE DBP-DO

DEMAND BIDDING PROGRAM

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SPECIAL CONDITIONS (Continued)

7. Customer Specific Baseline:

a. Customer Specific Baseline Weekdays: For customers enrolled in the program, the preliminary baseline for any given operational hour is defined as the consumption for that hour for the days from the immediately preceding similar day prior to the Event. Similar days will exclude weekends, holidays, days when a customer was paid to reduce load, when load reductions were requested, was subject to a Demand Response event and days in which the customer experienced a rotating outage.

The customer specific baseline will be calculated by multiplying the preliminary baseline by a day-of adjustment factor. The Day-Of Adjustment factor will be calculated by dividing the average load used a two hour adjustment window commencing at least 4 hours prior to the event by the average load for the same hours of the preliminary baseline. This Day-Of Adjustment factor shall not exceed 1.40 and shall be no less than 0.6.

b. Customer Specific Baseline Weekends: For customers enrolled in the program, the preliminary baseline for any given operational hour is defined as the consumption for that hour from the immediately preceding similar day prior to the Event. Similar days will exclude weekdays, days when a customer was paid to reduce load, when load reductions were requested, was subject to a Demand Response event and days in which the customer experienced a rotating outage.

The custom er specific baseline will be calculated by multiplying the preliminary baseline by a day-of adjustment factor. The Day-Of Adjustment factor will be calculated by dividing the average load used a two hour adjustment window commencing at least 4 hours prior to the event by the average load for the same hours of the preliminary baseline. This Day-Of Adjustment factor shall not exceed 1.40 and shall be no less than 0.6.

c. If a customer chooses to aggregate billable meters for the purposes of qualification and settlement then a customer specific baseline will be calculated for each billable meter.

8. DBP-DO Incentive Payment: If the actual load reduction for the hour is less than the ~~50~~60% of the customer's demand bid for the hour then no incentive will be paid. Otherwise, the demand bidding incentive for the hour will be calculated by multiplying the DBP-DO incentive by the customer's Actual Demand Reduction. If the actual demand reduction exceeds 150% of the customer hourly bid then the incentive will be equal to the 150% of the customer bid multiplied by the DBP-DO incentive.

9. Actual Demand Reduction: The Actual Demand Reduction for any given operational hour equals the difference between the Customer Specific Baseline and the recorded hourly MW consumption (MWh) during a DBP-DO event hour. If a customer chooses to aggregate billable meters for the purposes of qualification and settlement the actual demand reduction will be equal to the sum of the actual demand reductions from the billable meters.

(Continued)

SCHEDULE DBP-DO

DEMAND BIDDING PROGRAM- Day Of

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SPECIAL CONDITIONS (Continued)

10. Event Notification/Communication: The Utility will notify the customer of Demand Bid Events Acceptance or Rejection by e-mail, or other communication means specified by the Utility. Customer shall be responsible for the cost and maintenance to receive such communications and to send Demand Bids via the Internet. The Utility does not guarantee the reliability of the Internet site or e-mail system used for such communications.

11. Event Cancellation: In the case where the CAISO cancels ~~its~~it's Alert or Warning or more advanced CAISO Notice (Stage 1, 2 or 3 Emergency), the Utility will reject any bid that has not yet been accepted. Once a customer's Demand Bid has been accepted, the accepted bid shall not subsequently be rejected by the Utility, but payment shall continue to be based on the customer's actual performance, as measured by the Actual Demand Reduction.

12. Contract Requirement/Request For Service: Customers must complete an Enrollment Application with the Utility and must provide all required information to participate in the program. Enrollment Applications are deemed "accepted" when all required information has been provided by the customer and validated by the Utility.

13. Multiple Program Participation: A customer may not participate simultaneously in DBP-DO and any other Demand Response rate or program.

14. Termination of Schedule: This Schedule will be terminated on December 31st, 2014.

15. Metering Requirement: Customer's electric meter must be an interval data recorder with related telecommunications capability, compatible with the Utility's meter reading and telecommunications systems. If a customer meets the requirements of this tariff and does not have the correct metering equipment, the Utility will provide and install interval metering equipment and telecommunications systems at no cost to the customer.

    a. For Direct Access and CCA customers, DBP-DO compliance shall be determined from a telephone accessible electric revenue interval meter that can be read remotely by the Utility, and/or from alternative metering and telecommunications acceptable to the Utility. Direct Access and CCA customers are required to allow the Utility telecommunication access to its electric revenue meter for the purposes of determining DBP-DO compliance.

16. Failure to Reduce Energy: No financial penalties will be assessed under this Schedule for a customer's failure to comply or participate during a Demand Bidding Event.

17. Dispute Resolution: Any dispute arising from the provision of service under this schedule or other aspects of the Demand Bidding Program will be handled as provided for in the Utility's Rule 10, Disputes.

DEMAND BIDDING PROGRAM- ~~DAY AHEAD~~NAVY CONTRACT

This "Contract" is made and entered into by and between San Diego Gas & Electric Company, a California corporation, hereinafter referred to as "SDG&E" and ____________________________________, a Bundled, Direct Access or CCA Customer, hereinafter referred to as "Customer", and jointly, or individually, referred to as "Parties" or "Party".

RECITALS

WHEREAS, Customer is herein requesting to take service on SDG&E Tariff Schedule Demand Bidding Program-~~DA~~N, Demand Bidding Program- ~~Day Ahead~~Navy ("Schedule DBP-~~DA~~N"), attached hereto as **Attachment C**, on a voluntary basis without penalty.

NOW, THEREFORE, FOR GOOD AND VALUABLE CONSIDERATION, THE PARTIES AGREE AS FOLLOWS:

I. TERM

This Contract shall become effective when fully executed by both parties. The "Effective Date" of the Contract shall be the date of signature by the last signing party. This Contract shall remain from the Effective Date through December 31st, 2014, unless terminated earlier according to the terms herein.

II. DEMAND REDUCTION BID

Pursuant to the terms of Schedule DBP-~~DA~~N, Customer shall voluntarily provide Demand Bids to SDG&E upon receipt of notice from SDG&E of a Demand Bidding Event (all as defined within Schedule DBP-~~DA~~N).

III. PROGRAM COMMITMENT

Schedule DBP-~~DA~~N is a demand/energy bidding program that offers incentives to the Navy for reducing energy consumption and demand during a specific Demand Bidding Event. This Schedule is in effect until modified or terminated through the Utility's Demand Response Programs portfolio application or similar proceeding.

Customer shall qualify for Schedule DBP-~~DA~~N if Customer is capable of providing at least a ~~3~~ 2 MW load reduction based on its specific baseline. At the time of enrollment, Customer may choose to aggregate no more than 20 billable meters and 8 billable meters for individual bids for the purposes of qualification and settlement. Customer shall reduce its energy consumption when requested at times when an SDG&E system emergency or statewide emergencies are declared by the California Independent System Operator (CAISO).

___ Single Account
___ Aggregate Accounts

Account Numbers:

1. ______________	6. ______________	11. ______________	16. ______________
2. ______________	7. ______________	12. ______________	17. ______________
3. ______________	8. ______________	13. ______________	18. ______________
4. ______________	9. ______________	14. ______________	19. ______________
5. ______________	10. ______________	15. ______________	20. ______________

IV. ASSIGNMENT

Customer shall not assign this Contract without prior written consent of SDG&E. Any such assignment shall be automatically void.

V. DISPUTE RESOLUTION

Any dispute that cannot be resolved between the Parties shall be settled by means of conference, mediation, arbitration and/or litigation as provided for herein.

The first step in the dispute resolution process shall be a conference by which the dispute is referred to a designated officer of each Party for resolution. If those two officers cannot reach an agreement within a reasonable period of time, the Parties shall submit the dispute to mediation.

The second step in the dispute resolution process shall be mediation between the Parties in accordance with the Commercial Rules of the American Arbitration Association. If the dispute is not resolved by the mediation, the Parties shall submit the dispute to arbitration or litigation. Should the Parties not agree on arbitration, both Parties agree that jurisdiction of any claim or suit hereunder shall be limited to the courts of appropriate jurisdiction located within the County of San Diego, State of California. Both Parties hereby submit to the exclusive personal jurisdiction of such courts.

Notwithstanding the foregoing, if Customer is a **federal governmental authority or agency**, jurisdiction of any claim or suit hereunder shall be heard within the courts of appropriate federal jurisdiction.

In any action in litigation to enforce or interpret any of the terms of this Contract, the prevailing Party shall be entitled to recover from the unsuccessful Party all costs, expenses, (including expert testimony) and reasonable attorneys' fees (including fees and disbursements of in-house and outside counsel) incurred therein by the prevailing Party, to the extent permissible by law or authorized by specific federal statutory authority, as applicable.

VI. DISCLAIMER OF WARRANTY

No promise, representation, warranty, or covenant not included in this Contract has been, or is relied on by either Party. Each Party has relied on its own examination of this Contract, the counsel of its own advisors, and the warranties, representations, and covenants in the Contract itself.

VII. INDEMNIFICATION

Customer shall indemnify, defend and hold SDG&E and its current and future parent company, subsidiaries, affiliates and their respective directors, officers, shareholders, employees, agents, representatives, successors and assigns ("SDG&E Parties") harmless for, from and against any and all claims, actions, suits, proceedings, losses, liabilities, penalties, fines, damages, costs or expenses including without limitation, reasonable attorneys' fees (including fees and disbursements of in-house and outside counsel) of any kind whatsoever (collectively, "Claims") resulting from or arising out of this Contract or Customer's participation in Schedule DBP-~~DA~~N, whether based upon negligence, tort, strict liability or otherwise, including but not limited to third party Claims of any kind. This indemnification obligation shall not apply only to the extent that any such Claims are caused by either the willful misconduct of SDG&E or by SDG&E's sole negligence.

Notwithstanding the foregoing, if Customer is a **federal governmental authority or agency**, each Party's liability to the other for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be determined in accordance with applicable law.

The provisions of this Section shall survive the termination of this Contract.

VIII. LIMITATION OF LIABILITY

In no event shall either Party, its shareholders, directors, employees, agents or subcontractors (including, without limitation, suppliers of the System) be liable to the other Party for any indirect, consequential, special, incidental, or punitive damages under any other theories including, but not limited to, tort, contract, breach of warranty or strict liability for the design, manufacture, installation, operation, maintenance, performance or demonstration of the System, even if reasonably foreseeable at the time of contracting. The System includes any metering, meter communications equipment, Internet communication software, energy demand management software and related goods and services. SDG&E

shall not be responsible for any business loss, actual or implied, as a result of the partial or complete failure of the communications systems to operate.

IX. **COMPLIANCE WITH LAWS**

Customer shall comply with the terms and conditions of Schedule DBP-~~DA~~N and all local, state and federal rules, regulations and laws.

X. **COMMISSION CONTINUING AUTHORITY**

This Contract shall at all times be subject to the Commission and to any changes or modification that the Commission may, from time to time, direct in the exercise of its jurisdiction.

Notwithstanding any other provision of this Contract, either Party shall have the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for a change in rates, charges, classification, or any rule, regulation, or agreement relating thereto.

XI. **DIRECT ACCESS CUSTOMER PARTICIPATION**

Direct Access and CCA Customers are solely responsible for their legal commitments with their Energy Services Providers/Aggregators. SDG&E shall have no duty, liability or involvement in contract or assignment issues between Customer and its Energy Service Provider(s)/Aggregators.

IN WITNESS WHEREOF, SDG&E and Customer have executed this Contract as of the Effective Date.

______________________	San Diego Gas & Electric Company
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

The following attachments are attached hereto and incorporated herein by reference:
Attachment A: Customer Contact Information
Attachment B: Customer Account Information
Attachment C: Schedule DBP-~~DA~~N, Demand Bidding Program- ~~Day Ahead (~~Navy ~~Only)~~

ATTACHMENT A
Demand Bidding Program- ~~Day Ahead~~Navy
Customer Contact Information

Primary Contact:
Name: ______________________
Title: ______________________
Mailing Address: ______________________
____
Telephone Number: ______________________
Pager Number: ______________________
Email Address: ______________________

Secondary Contact:
Name: ______________________
Title: ______________________
Mailing Address: ______________________
____
Telephone Number: ______________________
Pager Number: ______________________
Email Address: ______________________

Additional Contact:
Name: ______________________
Title: ______________________
Mailing Address: ______________________
____
Telephone Number: ______________________
Pager Number: ______________________
Email Address: ______________________

Additional Contact:
Name: ______________________
Title: ______________________
Mailing Address: ______________________
____
Telephone Number: ______________________
Pager Number: ______________________
Email Address: ______________________

Attach additional Customer Account Information sheets to this contract if required. (Sheet ____ of _____)

ATTACHMENT B
Demand Bidding Program- ~~Day Ahead~~Navy
Customer Account Information

Site #1
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

Site #2
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

Site #3
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

Site #4
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

Site #5
Account Name ______________________________
Account Number ______________________________
Site Address ______________________________
Existing Electric Meter Number ______________________________
Customer Committed Load Reduction ______________________________

SCHEDULE ~~DBP-DA~~DBP-N (NAVY) N

DEMAND BIDDING PROGRAM, DAY AHEAD - NAVY ONLY N

APPLICABILITY

The Demand Bidding Program-Navy only ~~Day-Ahead~~ (~~DBP-DA~~DBP-N) is a demand/energy bidding program that offers incentives to the Navy for reducing energy consumption and demand during a specific Demand Bidding Event described in the Special Conditions below.

TERRITORY

Within the entire territory served by the Utility.

RATES

The ~~DBP-DA~~DBP-N Incentive is $~~400~~500/MWh for customers who purchase commodity from the Utility (bundled customers).

The ~~DBP-DA~~DBP-N incentive for customers who purchase commodity from an Energy Service Provider or a Community Choice Aggregator (Direct Access or CCA customers) shall be calculated by the Utility by deducting the corresponding California Independent System Operator (CAISO) TH-SP15-GEN-APND day-ahead market locational marginal price (DAM LMP) from the ~~DBP-DA~~DBP-N incentive for bundled customers. In no case will the customer be required to pay the Utility if the DAM LMP is greater than the ~~DBP-DA~~DBP-N incentive. If the DAM LMP is greater that the ~~DBP-DA~~DBP-N incentive, the customer does not receive an incentive for the event from SDG&E.

The ~~DBP-DA~~DBP-N Incentive Payment is calculated as defined in Special Condition 8. The Utility will provide the ~~DBP-DA~~DBP-N Incentive Payment as an adjustment to the customer's regular monthly bill, within 90 days of the Demand Bidding Event. The Utility will make ~~DBP-DA~~DBP-N Incentive Payments only for those hours of Accepted Demand Reduction, as set forth in Special Condition 4.

SPECIAL CONDITIONS

1. Definitions: The definitions of terms used in this schedule are found either herein or in Rule 1, Definitions.

2. Qualifying Customer: This Schedule is applicable, in combination with a customer's otherwise applicable tariff(s), on a voluntary basis, to customers who are considered a Navy branch of the federal government, including those that are Direct Access and Community Choice Aggregation customers, who are capable of providing at least a ~~3~~ 2 MW load reduction based on the customer's specific baseline.

   a) At the time of enrollment a customer may elect up to 20 billable meters to choose from for the purposes of qualification and settlement, but bids for an event the customer will identify up to eight (8) meters for purposes of bidding.

3. Billable Meter: A billable meter represents the meter data used for the purpose of calculating a customer's UDC rate charges. In the event that a customer's meter data is combined for the purpose of calculating UDC charges a billable meter number represents the combined meter data.

SCHEDULE ~~DBP-DA~~DBP-N (NAVY)

DEMAND BIDDING PROGRAM, DAY AHEAD - NAVY ONLY

SPECIAL CONDITIONS (Continued)

4. Program Operation:

   a. Demand Bidding Event: The Utility will declare a Demand Bidding Event for the following day and the Utility will request bids from the customer that will cover the period of the event.

      i. The Utility will make all efforts to notify the customer of an event the day prior by 13:00. In the event of an event that occurs after 13:00 all parties will make their best effort to facilitate the bidding process.

   b. Demand Bid: A Demand Bid is the amount of MW per hour (MWh usage) that a customer commits to reduce for each hour of an Event.

      i. For each hour the customer must submit their bid for a minimum demand reduction of ~~3~~ 2 MWh.

   c. Bid Submission: Customers will select no more than 8 meters and submit a Demand Bid within 2 hours of the notification of an event.

   d. Bid Evaluation: Unless a megawatt quantity is specified in the CAISO or utility event notification, the Utility will deem all qualified Demand Bids received by the deadline acceptable from customers.

      i. If a megawatt quantity is specified in the CAISO or Utility event notification, the Utility will evaluate the qualified bids received based on a first come, first served basis, taking bidder past performance and compliance into account, and accept or reject each bid.

   e. Bid Acceptance/Rejection Notification: Day-ahead bid solicitations can be terminated prior to Acceptance Notification, up to the deadline of 15:30 based on CAISO or Utility notification that load relief is no longer needed.

5. Program Triggers: A Demand Bidding Event shall be initiated upon notice from the CAISO of a Stage 2 or 3 emergency, a transmission or imminent system emergency, or as local emergency conditions warrant by the Utility. Whenever the California Independent System Operator has issued an alert or warning notice, the California Independent System Operator shall be entitled to request that the utility, at its discretion, call a program event pursuant to this Schedule.

6. Program Availability: DBP- ~~DA~~ N is available year-round. There is no limit to the number of Demand Bidding Day Ahead Events per month or per year.

(Continued)

SCHEDULE ~~DBP-DA~~DBP-N (NAVY)

DEMAND BIDDING PROGRAM, DAY AHEAD - NAVY ONLY

SPECIAL CONDITIONS (Continued)

7. Customer Specific Baseline:

   a. Customer Specific Baseline Weekdays: For customers enrolled in the program, the preliminary baseline for any given operational hour is defined as the consumption for that hour for the days from the immediately preceding similar day prior to the Event. Similar days will exclude weekends, holidays, days when a customer was paid to reduce load, when load reductions were requested, was subject to a Demand Response event and days in which the customer experienced a rotating outage.

      The customer specific baseline will be calculated by multiplying the preliminary baseline by a day-of adjustment factor. The Day-Of Adjustment factor will be calculated by dividing the average load used a two hour adjustment window commencing at least 4 hours prior to the event by the average load for the same hours of the preliminary baseline. This Day-Of Adjustment factor shall not exceed 1.40 and shall be no less than 0.6.

   b. Customer Specific Baseline Weekends: For customers enrolled in the program, the preliminary baseline for any given operational hour is defined as the consumption for that hour from the immediately preceding similar day prior to the Event. Similar days will exclude weekdays, days when a customer was paid to reduce load, when load reductions were requested, was subject to a Demand Response event and days in which the customer experienced a rotating outage.

      The customer specific baseline will be calculated by multiplying the preliminary baseline by a day-of adjustment factor. The Day-Of Adjustment factor will be calculated by dividing the average load used a two hour adjustment window commencing at least 4 hours prior to the event by the average load for the same hours of the preliminary baseline. This Day-Of Adjustment factor shall not exceed 1.40 and shall be no less than 0.6.

   c. Billable Meters Aggregation: If a customer chooses to aggregate billable meters for the purposes of qualification and settlement then a customer specific baseline will be calculated for each billable meter.

8. ~~DBP-DA~~DBP-N Incentive Payment: If the actual load reduction for the hour is less than the 50% of the customer's demand bid for the hour then no incentive will be paid. Otherwise, the demand bidding incentive for the hour will be calculated by multiplying the ~~DBP-DA~~DBP-N incentive by the customer's Actual Demand Reduction. If the actual demand reduction exceeds 150% of the customer hourly bid then the incentive will be equal to the 150% of the customer bid multiplied by the ~~DBP-DA~~DBP-N incentive.

9. Actual Demand Reduction: The Actual Demand Reduction for any given operational hour equals the difference between the Customer Specific Baseline and the recorded hourly MW consumption (MWh) during a DBP-N event hour. If a customer chooses to aggregate billable meters for the purposes of qualification and settlement the actual demand reduction will be equal to the sum of the actual demand reductions from the billable meters.

(Continued)

SCHEDULE ~~DBP-DA~~DBP-N (NAVY)

DEMAND BIDDING PROGRAM, DAY AHEAD - NAVY ONLY

SPECIAL CONDITIONS (Continued)

10. Event Notification/Communication: The Utility will notify the customer of Demand Bid Events Acceptance or Rejection by e-mail, or other communication means specified by the Utility. Customer shall be responsible for the cost and maintenance to receive such communications and to send Demand Bids via the Internet. The Utility does not guarantee the reliability of the Internet site or e-mail system used for such communications.

11. Event Cancellation: In the case where the Utility or CAISO cancels its Alert or Warning or more advanced CAISO Notice (Stage 2 or 3 Emergency), the Utility will reject any bid that has not yet been accepted. Once a customer's Demand Bid has been accepted, the accepted bid shall not subsequently be rejected by the Utility, but payment shall continue to be based on the customer's actual performance, as measured by the Actual Demand Reduction.

12. Contract Requirement/Request For Service: Customers must complete an Enrollment Application with the Utility and must provide all required information to participate in the program. Enrollment Applications are deemed "accepted" when all required information has been provided by the customer and validated by the Utility.

13. Multiple Program Participation: A customer may not participate simultaneously in ~~DBP-DA~~DBP-N and any other Demand Response rate or program.

14. Termination of Schedule: This Schedule is in effect until modified or terminated through the Utility's Demand Response Programs portfolio application or similar proceeding.

15. Metering Requirement: Customer's electric meter must be an interval data recorder or smart meter with related telecommunications capability, compatible with the Utility's meter reading and telecommunications systems. If a customer meets the requirements of this tariff and does not have the correct metering equipment, the Utility will provide and install interval metering equipment and telecommunications systems at no cost to the customer.

    a. For Direct Access and CCA customers, ~~DBP-DA~~DBP-N compliance shall be determined from a telephone accessible electric revenue interval meter that can be read remotely by the Utility, and/or from alternative metering and telecommunications acceptable to the Utility. Direct Access and CCA customers are required to allow the Utility telecommunication access to its electric revenue meter for the purposes of determining ~~DBP-DA~~DBP-N compliance.

16. Failure to Reduce Energy: No financial penalties will be assessed under this Schedule for a customer's failure to comply or participate during a Demand Bidding Event.

17. Dispute Resolution: Any dispute arising from the provision of service under this schedule or other aspects of the Demand Bidding Program will be handled as provided for in the Utility's Rule 10, Disputes.

(Continued)

APPENDIX E

SDGE Demand Response Programs and Activities
Incremental Cost
2013 Funding

Year-to-Date Program Expenditures

Cost Item	2012 Expenditures	2013 Expenditures January	February	March	April	May	June	July	August	September	October	November	December	Year-to Date 2013 Expenditures	Program-to-Date Total Expenditures 2012-2014	3-Year Funding	Fundshift Adjustments (a)	Percent Funding
Category 1: Reliability Programs																		
Base Interruptible Program (BIP)	$470,302	$4,471	$8,089	$10,316	$16,216	$14,530	$30,194	$9,122	$20,884	$54,042	$30,631	$29,086	$12,554	$240,135	$710,437	$2,214,267	($1,800,000)	32.1%
Demand Bidding	$0	$0	$42,470	$409	$450	$484	$387	$450	$286	$425	$517	$8,397	$409	$54,684	$54,684	$1,800,000	$1,800,000	
Budget Category 1 Total	$470,302	$4,471	$50,559	$10,725	$16,666	$15,014	$30,581	$9,572	$21,170	$54,467	$31,148	$37,483	$12,963	$294,819	$765,121	$4,014,267	$0	32.1%
Category 2: Price Responsive Programs																		
Capacity Bidding Program (CBP)	$1,769,746	$42,655	$15,238	$42,018	$3,591	$20,447	$192,606	$71,228	$110,961	$135,667	$64,762	$477,724	$281,442	$1,458,339	$3,228,085	$5,389,000	($6,400,000)	59.9%
Peak Time Rebate (PTR)	$1,493,153	$15,612	$14,850	$10,254	$15,133	$20,603	($22,914)	$17,990	$8,773	($2,078)	$21,195	$17,397	$13,630	$130,445	$1,623,598	$6,885,000	$6,400,000	23.6%
Budget Category 2 Total	$3,262,899	$58,267	$30,088	$52,272	$18,724	$41,050	$169,692	$89,218	$119,734	$133,589	$85,957	$495,121	$295,072	$1,588,784	$4,851,683	$12,274,000	$0	83.5%
Category 4: Emerging & Enabling Technologies																		
Emerging Technologies (ET)	$635,829	$89,881	$50,250	$11,207	$60,638	$25,049	$59,922	$17,815	$8,311	$52,366	$16,019	$26,437	$42,258	$460,152	$1,095,981	$2,111,000		51.9%
Small Customer Technology Incentives (SCTD)	$43,402	$5,767	$6,269	$7,333	$6,554	$10,829	$46,803	$74,362	$27,917	$12,493	$22,611	$16,284	$8,141	$245,383	$288,785	$9,464,167		3.1%
Technical Incentives (TI)	$683,867	$25,542	$24,565	$5,526	$28,890	$14,366	$17,735	$21,198	$32,439	$30,167	$22,354	$283,569	$34,545	$540,896	$1,224,763	$8,973,000		13.6%
Budget Category 4 Total	$1,363,098	$121,190	$81,084	$24,066	$96,082	$50,244	$124,460	$113,395	$68,667	$95,025	$60,984	$326,290	$84,944	$1,246,431	$2,609,529	$20,548,167	$0	12.7%
Category 5: Pilots																		
Locational DR	$1,839	$230	$261	($245)	$30	$0	$0	$0	$0	$3,432	($317)	$3,107	$2,147	$8,645	$10,484	$433,000		2.4%
New Construction DR	$38,324	$5,087	$5,573	$5,031	$5,196	$27,906	($14,617)	$3,719	$3,192	($1,938)	$5,227	$4,777	$36,566	$85,719	$124,043	$1,126,000		11.0%
Budget Category 5 Total	$40,163	$5,317	$5,834	$4,786	$5,226	$27,906	($14,617)	$3,719	$3,192	$1,494	$4,910	$7,884	$38,713	$94,364	$134,527	$1,559,000	$0	13.4%
Category 6: Evaluation, Measurement & Verification																		
DRMEC	$946,005	$155,511	$187,041	$182,435	$253,030	$73,415	$40,222	$197,700	$118,107	$74,903	$114,365	$129,080	$107,252	$1,633,061	$2,579,066	$5,115,000		50.4%
Research	$3,280	($3,280)	$33,740	($33,740)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,280)	$0	$600,000		0.0%
Budget Category 6 Total	$949,285	$152,231	$220,781	$148,695	$253,030	$73,415	$40,222	$197,700	$118,107	$74,903	$114,365	$129,080	$107,252	$1,629,781	$2,579,066	$5,715,000	$0	50.4%
Category 7: Marketing Education & Outreach																		
Statewide Marketing - Flex Alert Network (FAN) [1]	$865,417	($1,580)	($863,817)	$0	$960,000	$0	$0	$0	$0	$0	$0	$0	$0	$94,603	$960,020	$1,000,000		$1
Customer Education, Awareness & Outreach	$418,202	($40,521)	($111)	$0	$0	$0	$0	($193,191)	$29,012	($50,133)	($2,301)	($34,998)	$12,140	($280,103)	$138,099	$1,100,000		12.6%
Other Local Marketing	$500,329	$41,667	$0	$0	$5,199	$8,606	$1,871	$23,249	$43,786	$98,951	($41,948)	$31,533	$36,747	$249,661	$749,990	$4,650,000		16.1%
Budget Category 7 Total	$1,783,948	($434)	($863,928)	$0	$965,199	$8,606	$1,871	($169,942)	$72,798	$48,818	($44,249)	($3,465)	$48,887	$64,161	$1,848,109	$6,750,000	$0	27.4%
Category 8: DR System Support Activities																		
Regulatory Policy & Program Support	$691,400	$68,731	$104,967	$49,905	$59,581	$79,203	$60,731	$57,427	$53,695	$50,339	$61,241	$79,498	$54,326	$779,644	$1,471,044	$2,231,000		65.9%
IT Infrastructure & System Support	$792,169	$16,848	$23,303	$16,803	$17,234	$12,531	$62,477	$83,075	$44,535	$257,862	$52,667	$10,243	$57,399	$654,977	$1,447,146	$5,410,000		26.7%
Budget Category 8 Total	$1,483,569	$85,579	$128,270	$66,708	$76,815	$91,734	$123,208	$140,502	$98,230	$308,201	$113,908	$89,741	$111,725	$1,434,621	$2,918,190	$7,641,000	$0	92.7%
Category 9: Integrated Programs and Activities																		
Technical Assistance (TA)	$1,631,582	$77,116	($18,474)	($36,917)	($20,397)	$4,160	$0	$0	$0	$0	$0	$0	$50	$5,538	$1,637,120	$3,321,000		49.3%
Customer, Education & Outreach - IDSM	$699,876	$34,170	$63,041	$43,706	($35,498)	$66,351	$54,666	$270,023	($34,458)	$497	$3,837	($5,023)	($651)	$460,661	$1,160,537	$984,359		117.9%
Budget Category 9 Total	$2,331,458	$111,286	$44,567	$6,789	($55,895)	$70,511	$54,666	$270,023	($34,458)	$497	$3,837	($5,023)	($601)	$466,199	$2,797,657	$4,305,359	$0	167.2%
Category 10: Special Projects																		
Permanent Load Shifting	$106,111	$7,865	$8,391	$8,427	$13,946	$8,879	$10,315	$9,182	$11,208	$13,418	$12,135	$10,683	$10,617	$125,066	$231,177	$3,000,000		7.7%
Budget Category 10 Total	$106,111	$7,865	$8,391	$8,427	$13,946	$8,879	$10,315	$9,182	$11,208	$13,418	$12,135	$10,683	$10,617	$125,066	$231,177	$3,000,000	$0	7.7%
Total Incremental Cost	$11,790,833	$545,772	($294,354)	$322,468	$1,389,793	$387,359	$540,398	$663,369	$478,648	$730,412	$382,995	$1,087,794	$709,572	$6,944,226	$18,735,059	$65,806,793	$0	28.5%

(a) See "Fund Shift Log" for explanations.

Notes:
D.12-04-045
PTR Jul-Sept updated for Incentives (12/17/2012)
[1] Negative dollars in February are due to an accrual reversal. Still awaiting actual invoice for payment.

Appendix F

LEGEND	
Utility Input	*Enter Utility specific information and program data in yellow cells*
Do Not Alter	
Avoided Cost Input	*Inputs from Avoided Cost Model*
CPUC Input	*Inputs made by CPUC Energy Division Staff*
Formula	*Formulas contained in this Excel Workbook*

All inputs in nominal dollars

TO Add Program

Copy first program tab (BIP Example) and rename
On summary tab, insert a column between program columns and last portfolio column
Copy column C (BIP Example) and paste into added column
Change label in Row 2 from "BIP Example" to name of added tab. (Must be exactly the same)
INDIRECT Excel references will update the Summary results automatically

Portfolio Tab

The naming and formatting of the Portfolio Tab is consistent with that for individual programs
Enter portfolio impacts adjusted for dual participation
Total portfolio costs should be entered, including all program or portfolio level administration costs.
Enter total benefits, starting in cell D107 adjusted for dual participation
Average Avoided Cost values on a $/kW Yr. and $/MWh basis are calculated by spreadsheet

Program Start Year	2014
Dollar Year	2014
Utility	SDG&E

Financial	
After Tax WACC	7.60%

Sensitivities	
% Incentives as Participant Costs	
high value	100%
Base Case	75%
low value	50%
Generation Capacity Costs	
%	30%
+ %	+30%
T&D Capacity Costs	
%	30%
+ %	+30%
Capital Ammortization Period	
Years	3
Years	15
Load Impact	
%	30%
+ %	+30%
A Adjustment Factor	
%	10%
100 % (No Adjustment)	100%

+/- % Sensitivity values are multiplicative
e.g. for low case, the A Adjustment factor will be multiplied by (1-10%) or 90%

Avoided Cost Parameters	
Nominal Discount Rate	5.1%
Real Discount Rate	3.0%
Inflation	2.0%
Hours in Year	8760

DR Time Frame	
Start Year	2014
Time Span	3

Central Station Plant Assumptions	
	CT
Operating Data	
Heat rate (BTU/kWh)	9,300
Cap Factor	6.0%
Lifetime (yrs)	20
Plant Costs	
In Service Cost ($/kW)	$1,365
Fixed O&M ($/kW yr.)	$17.40
Variable O&M ($/MWh)	$4.17
Cost Basis Year for Plant Costs	2009
Levelized Costs (2012)	
Annual Fixed Cost ($/kW yr)	192.09
Real Time Energy Revenue	(85.71)
AS Revenue	(6.51)
Operating Cost	27.74
Residual Capacity Value	127.60
Summer Output	91%
Summer Capacity Value	139.84
Financing	
Debt to Equity	60%
Debt Cost	7.7%
Equity Cost	12.0%
Marginal Tax Rate	40.7%

Avoided Cost Values (Nominal)	2014	2015	2016
Market Price ($/MWh)	$49.49	$50.98	$52.43
On Peak Multiplier	128%	128%	128%
On Peak Market Price ($/MWh)	$63.37	$65.27	$67.12
Nameplate Generation Capacity ($/kW yr)	$123.20	$124.96	$126.36
Summer Generation Capacity ($/kW yr)	$134.99	$136.84	$138.36
Transmission Deferral ($/kW yr)	$21.50	$21.93	$22.37
Distribution Deferral ($/kW yr)	$53.28	$54.35	$55.43
Emissions ($/ton)	$19.87	$22.85	$26.05
Capacity Factor	5.6%	5.8%	6.1%

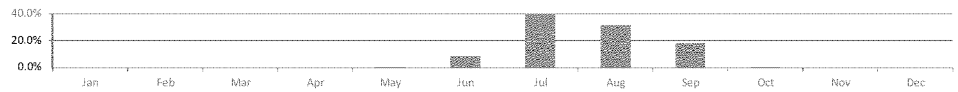
Avoided cost values above have not been adjusted for losses

GHG Value			
Avg. On Peak System Heat Rate Btu/kWh	10,203	10,236	10,273
Avg. On Peak Emissions Rate Tons/MWh	0.597	0.599	0.601
Avg. On Peak GHG Value $/MWh	$11.86	$13.68	$15.66

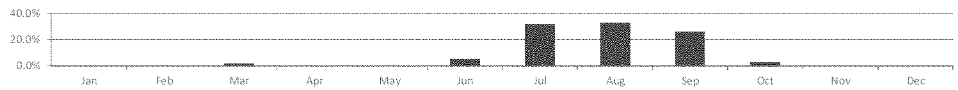
	On Peak Losses			Transmission Deferral ($/kW yr)			Distribution Deferral ($/kW yr)			WACC
	Gen.	T&D	D	2012	2013	2014	2012	2013	2014	
PG&E	9.8%	7.6%	4.6%	$19.58	$19.97	$20.37	$57.03	$58.17	$59.33	7.7%
SCE	7.8%	5.1%	2.2%	$23.85	$24.33	$24.82	$30.71	$31.32	$31.95	7.7%
SDG&E	7.5%	6.6%	4.1%	$21.50	$21.93	$22.37	$53.28	$54.35	$55.43	7.3%
SDG&E	7.5%	6.6%	4.1%	$21.50	$21.93	$22.37	$53.28	$54.35	$55.43	7.3%

CT Capacity Adjustments	
Reserve Margin	15%

Avoided Cost Monthly Capacity Allocation Factors	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Generation Capacity Value	0.0%	0.0%	0.0%	0.0%	0.9%	8.8%	40.2%	31.8%	17.8%	0.5%	0.0%	0.0%	100.0%



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
T&D Capacity Value (SDG&E)	0.0%	0.0%	1.4%	0.4%	0.0%	4.9%	32.1%	32.9%	25.8%	2.5%	0.0%	0.0%	100.0%
Statewide Average	0.0%	0.0%	1.5%	0.2%	0.0%	3.6%	22.8%	32.0%	31.1%	7.9%	0.8%	0.0%	
PG&E	0.0%	0.0%	0.9%	0.0%	0.0%	4.6%	20.8%	32.3%	32.0%	8.2%	1.2%	0.0%	
SCE	0.0%	0.1%	1.6%	0.2%	0.0%	2.7%	23.7%	30.9%	29.2%	10.6%	1.0%	0.0%	
SDG&E	0.0%	0.0%	1.4%	0.4%	0.0%	4.9%	32.1%	32.9%	25.8%	2.5%	0.0%	0.0%	



Discount Factors		
Year 1	Year 2	Year 3
	1	2
2014	2015	2016
1.0000	0.9319	0.8684

LEGEND	
Utility Input	*Enter Utility specific information and program data in yellow cells*
Do Not Alter	
Avoided Cost Input	*Inputs from Avoided Cost Model*
CPUC Input	*Inputs made by CPUC Energy Division Staff*
Formula	*Formulas contained in this Excel Workbook*

All inputs in nominal dollars

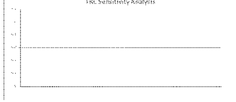
T&D
D Only
User Input

3

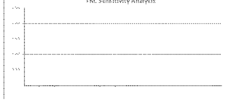
	CBP_all	DBP_DA	DBP_DO	PTR_SCTD
Benefit/Cost Ratio				
TRC	0.90	2.45	2.02	1.14
PAC	0.82	2.45	1.98	1.10
RIM	0.78	2.12	1.73	1.00
PCT	1.33	1.33	1.33	1.33
Load Impacts (MW)	24.8	1.5	3.3	7.9
Energy Savings (MWh)	1,163.2	81.0	298.9	1,000.3
$ Million				
TRC Costs	$5.825	$0.154	$0.610	$3.902
PAC Costs	$6.390	$0.155	$0.624	$4.047
RIM Costs	$6.733	$0.178	$0.712	$4.443
TRC Benefits	$5.265	$0.379	$1.234	$4.437
TRC Net Benefit	($0.560)	$0.224	$0.625	$0.535
PAC Net Benefit	($1.125)	$0.224	$0.610	$0.390
RIM Net Benefit	($1.468)	$0.200	$0.522	($0.006)
$/kW-Yr.				
TRC Costs	$139.877	$61.300	$111.074	$293.015
PAC Costs	$153.434	$61.414	$113.717	$303.844
RIM Costs	$161.680	$70.920	$129.802	$333.604
TRC Benefits	$126.422	$150.439	$224.872	$333.157
TRC Net Benefit	($13.456)	$89.139	$113.799	$40.142
PAC Net Benefit	($27.013)	$89.025	$111.155	$29.313
RIM Net Benefit	($35.258)	$79.519	$95.071	($0.447)

DEF_DA

TRC Sensitivity Analysis



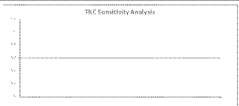
TRC Sensitivity Analysis

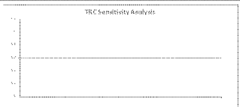


	2014	2015	2016

	2014	2015	2016

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec


TRC Sensitivity Analysis


TRC Sensitivity Analysis

	PTR / SCTD			CBP			DBP_DA			DBP_DO		
FACTORS												
A		89%			62%			89%			89%	
B		88%			96%			88%			100%	
C		100%			100%			100%			100%	
D		68%			12%			0%			0%	
E		140%			140%			140%			140%	
Availability		11 to 6 yr rnd; no limit on events			May to Oct 11 to 7; Max 1 event per day and 44 hours per mo			Year round; no limit on events			Year round; no limit on events	
Event hours		7			5			6			6	
Expected events		9			9			9			9	
BUDGET	**2014**	**2015**	**2016**	**2014**	**2015**	**2016**				**2014**	**2015**	**2016**
Admin		950,848	950,848		1,712,871	1,658,959		45,346	45,346		167,346	167,346
M&E		225,000	225,000									
Incentives		979,572	982,339		1,788,324	1,867,847		40,500	40,500		179,356	179,356
Capital annual												
Capital to be amortized		630,000			176,964	146,933						
Total budget		2,785,420	2,158,187		3,678,159	3,673,739		85,846	85,846		346,701	346,701
MW		16	16		25.4	26.3		1.5	1.5		5.5	5.5
MWh		998	1,002		1,142	1,184		81	81		299	299
Bill savings		216,620	223,943		184,713	197,222		13,099	13,491		48,339	49,790

$/kWh	**2014**	**2015**	**2016**
Energy rate C/I > 20 kW	0.157	0.162	0.167
Sm commercial	0.201	0.207	0.214
Residential	0.211	0.217	0.223

These are the proposed 2014 class average rates provided by the SDG&E rate dept in Feb 2014
The 2014 rates are escalated annually by 3%

	2014	2015	2016	MWh 2015	MWh 2016
Capacity Bidding					
Adjusting CBP incentives using expected hours because budget was based on max hours of events while benefits based on expected hours.					
Day Ahead MW		9.4	9.4	337.46	337.46
Day Of 2 hr 4 hr MW		3.9	3.9	138.75	138.75
Day of 2 hr 6 hr MW		2.9	2.9	154.40	154.40
Day of 30 min 4 hr mW		5.3	5.9	192.12	211.33
Day of 30 min 6 hr MW		4.0	4.4	213.79	235.17
Day of all MW		16.0	16.9		
total MW		25.4	26.3		
Budgeted incentives		3,039,380	3,224,581		
Estimated Capacity incentives:					
Day Ahead 4 hr		523,538	523,538		
Day Of 2 hr 4 hr		252,609	252,609		
Day of 2 hr 6 hr		212,990	212,990		
Day of 30 min 4 hr		396,869	437,494		
Day of 30 min 6 hr		334,664	368,915		
Day of all		1,197,132	1,272,008		
Estimated Energy incentives:					
Day Ahead 4 hr		22,026	22,652		
Day Of 2 hr 4 hr		9,056	9,314		
Day of 2 hr 6 hr		10,078	10,364		
Day of 30 min 4 hr		12,539	14,185		
Day of 30 min 6 hr		13,954	15,786		
difference in max and exp incentives		1,251,056	1,356,734		
Day of all		45,628	49,649		

current tariff

Day Ahead 4 hr	2.4	6.6	14.2	17.6	11.6	3.5
Day Of 2 hr 4 hr	2.9	7.9	17.1	21.1	13.9	4.2
Day of 2 hr 6 hr	3.3	8.9	19.5	24.0	15.8	4.7

proposed tariff

annual	$/kW-mo	May	Jun	Jul	Aug	Sep	Oct
56	Day Ahead 4 hr	2.4	6.6	14.2	17.6	11.6	3.5
67	Day Of 2 hr 4 hr	2.9	7.9	17.1	21.1	13.9	4.2
76	Day of 2 hr 6 hr	3.3	8.9	19.5	24.0	15.8	4.7
77	Day of 30 min 4 hr	3.3	9.0	19.6	24.2	16.0	4.8
88	Day of 30 min 6 hr	3.8	10.2	22.4	27.6	18.1	5.4

Adj. ratio by MW DA	0.37	
Adj. ratio by MW DO	0.63	

Allocating the CBP budget into Day Ahead and Day Of options using the forecasted MWs

	2015	2016
CBP Admin	1,248,449	1,248,447
CBP M&E	50,000	50,000
DA Admin	479,514	462,573
DO amin	818,935	835,874

Allocate the TI Budget across programs: customers from TI program go to CBP, CPP D and Demand Smart

First adjust admin dollars to account for additional engineering costs not applicable to these forecasted MWs

	2014	2015	2016
TI Admin		1,089,391	1,089,391
Adjusted Admin		647,535	563,299
Adjust incentive budget to align with forecasted MWs:			
Incentive Budget		1,890,000	1,890,000
CBP DA MW	0.30	0.30	0.30
CBP DO MW	1.79	2.77	2.93
CPPD MW	1.36	1.34	1.39
Total forecasted MW		4.40	4.62

Adjustments for TI include:
TI customers go onto CBP DA, CBP DO, and CPP D
Adjust admin costs to take out extra engineering fees not applicable to tested MWs
Adjust incentives to align with tested MWs
Use historical split between CPP and CBP which is 64% CBP and 36% CPP to allocate

Incentives in CE tests are only for new MWs coming online since the TI incentive is paid only once upon installation:

Incremental forecasted MW

SB_GT&S_0394664

Incremental on CBP DA				
Incremental on CBP DO	0.98	0.16		
Incremental on CPP D		0.06		
Total incremental MW	0.98	0.22	1.20	
Allocating the TI budget across programs:				
CBP DA TI Admin				The split between CPP and CBP is 64% CBP and 36% CPP
CBP DO TI Admin	414,423	360,512		
CPP D TI Admin	233,113	202,788		
CBP DA TI incentives				
CBP DO TI incentives	176,964	146,933		Incentives are paid 60% the first year and 40% the following year.
CPP D TI incentives		10,165		No incremental MWs in 2014, so only the 60% for new MWs in 2015 is paid
Cumulative incr. MWs for CPPD		0.06		
Aggregator Incentives for CPPD		1,694		
Total CPPD TI incentives		11,859		
Check total admin for CE	647,535.4	563,299.3		
Total incentives for CE	176,964	158,793		
Diff in budget for inc	1,713,036	1,731,207		these differences are not included in the CE tests
Diff in budget for admin	441,856	526,092		
Totals for DA:				
Admin	479,514	462,573		
Incentive	545,564	546,190		
Totals for DO:				
Admin	1,233,358	1,196,386		
Incentive	1,242,759	1,321,657		
TI incentives (to be amortized0	176,964	146,933		
Totals for CPPD:				
Admin	233,113	202,788		
incentives		1,694		
TI incentives (to be amortized)		10,165		
Total:	3,911,271	3,888,386		
Total check:	3,911,271	3,888,386		
DBP incentives				
Incentives needed	219,856	219,856		
Budgeted incentives	726,251	726,251		
diff	506,395	506,395		
SCTD incentives				
Incentives needed	1,609,572	982,339		
Budgeted incentives	3,601,562	3,601,562		
diff	1,991,990	2,619,223		

SB_GT&S_0394665

Category	Proposed Budget	Adj for Alloc.	Allocation	Admin 2015 w/ alloc	Admin 2016 w/ alloc	incentives 2015	incentives 2016	
BIP	2,956,077	2,956,077	205,527	325,634.68	325,693.68	1,005,154	1,505,122	
CBP	8,191,338	8,191,338	569,520	1,248,448.70	1,248,447.25	3,039,379.93	3,224,581.38	
DBP	1,755,808	1,755,808	122,076	212,691.59	212,691.59	726,250.50	726,250.50	
PTR	323,289	323,289	22,477	172,883.38	172,883.38			
Emerging Tech	1,410,970	1,410,970	98,101	752,675.47	756,395.10			
SCTD	8,189,651	8,189,651	569,402	777,964.82	777,964.82	3,601,562	3,601,562	
TI	5,571,417	5,571,417	387,364	1,089,390.91	1,089,390.91	1,890,000	1,890,000	
Locational DR Pilot								
NC Pilot	974,236	974,236	67,736	145,804.84	145,804.84	375,181	375,181	
MEO Flex Alert								
Customer Ed & Outreach								
Local Marketing	3,698,171	3,698,171	257,123	1,601,646.76	2,353,646.76			
TA								
IDSM Cust Ed & Outreach								
PLS	2,000,000	2,000,000	139,054	324,527.07	324,527.07	745,000	745,000	
Summer Saver		12,400,000	862,136	431,067.83	431,067.83			
Subtotal	35,070,957	47,470,957	3,300,517	7,082,736	7,838,513	11,382,527	12,067,697	42,210,935
Policy & IT Support	3,300,517							
DRMEC	3,439,462							
DR Research	400,000			200,000.00	200,000.00			
Total	42,210,935							
check from PB:	42,210,935							

From Program Builder:				Admin	Incentives	total
BIP	2015	Base Interruptib	1	222,871	1,005,154	
BIP	2016	Base Interruptib	1	222,930	1,505,122	2,956,077
CBP	2015	Capacity Biddin	2	963,689	3,039,380	
CBP	2016	Capacity Biddin	2	963,687	3,224,581	8,191,338
DBP	2015	Demand Biddin	0	151,653	726,251	
DBP	2016	Demand Biddin	0	151,653	726,251	1,755,808
DR ET	2015	Emerging Techn	2	703,625		
DR ET	2016	Emerging Techn	2	707,345		1,410,970
EM&V	2015	Evaluation, Mea	2	1,913,032		
EM&V	2016	Evaluation, Mea	2	1,526,430		3,439,462
GENADMIN	2015	General Admin	4	745,005		
GENADMIN	2016	General Admin	5	786,072		1,531,077
IT_INFR	2015	IT Infrastructur	10	956,425		
IT_INFR	2016	IT Infrastructur	6	813,015		1,769,440
MERes	2015	ME Research		200,000		
MERes	2016	ME Research		200,000		400,000
OLM	2015	Other Local Ma	1	1,473,085		
OLM	2016	Other Local Ma	1	2,225,085		3,698,171
PTR	2015	Peak Time Reba	1	161,645		
PTR	2016	Peak Time Reba	1	161,645		323,289
PLS	2015	Permanent Loa	1	255,000	745,000	
PLS	2016	Permanent Loa	1	255,000	745,000	2,000,000
RNC	2015	Residential New	1	111,937	375,181	
RNC	2016	Residential New	1	111,937	375,181	974,236
SCTD Res	2015	Small Customer	2	493,264	3,601,562	
SCTD Res	2016	Small Customer	2	493,264	3,601,562	8,189,651
TI	2015	Technology Ince	4	895,709	1,890,000	
TI	2016	Technology Ince	4	895,709	1,890,000	5,571,417
				18,760,711	23,450,224	42,210,935

This sheet has the new CBP forecast. For the remaining programs, see the sheet labeled impacts2

Total Load Reduction

Notification	Max Hour	Year	May	June	July	August	September	October	max
CBP-DA	4	2015	9.4	9.4	9.4	9.4	9.4	9.4	9.4
CBP-DO 2 hour	4	2015	3.5	3.5	3.9	3.8	3.8	3.6	3.9
CBP-DO 2 hour	6	2015	2.6	2.6	2.9	2.8	2.9	2.7	2.9
CBP DO 30 minute	4	2015	4.9	4.8	5.3	5.3	5.3	3.9	5.3
CBP DO 30 minute	6	2015	3.6	3.6	4.0	3.9	3.9	2.9	4.0
Total			24.0	23.9	25.4	25.2	25.3	22.4	25.4

Load Reduction from Auto DR/TI

Notificatio	Max Hour	Year	May	June	July	August	September	October	max
CBP-DA	4	2015	0.3	0.3	0.3	0.3	0.3	0.3	0.3
CBP-DO 2	4	2015	0.6	0.6	0.7	0.7	0.7	0.6	0.7
CBP-DO 2	6	2015	0.5	0.4	0.5	0.5	0.5	0.5	0.5
CBP DO 30	4	2015	0.8	0.8	0.9	0.9	0.9	0.7	0.9
CBP DO 30	6	2015	0.6	0.6	0.7	0.7	0.7	0.5	0.7
Total			2.8	2.8	3.1	3.0	3.1	2.6	3.1

Load Reduction without Auto DR/TI

Notificatio	Max Hour	Year	May	June	July	August	September	October
CBP-DA	4	2015	9.1	9.1	9.1	9.1	9.1	9.1
CBP-DO 2	4	2015	2.9	2.9	3.2	3.2	3.2	3.0
CBP-DO 2	6	2015	2.2	2.1	2.4	2.3	2.4	2.2
CBP DO 30	4	2015	4.0	4.0	4.4	4.4	4.4	3.2
CBP DO 30	6	2015	3.0	3.0	3.3	3.2	3.3	2.4
Total			21.2	21.1	22.3	22.2	22.3	19.9

Notification	Max Hour	Year	May	June	July	August	September	October	max
CBP-DA	4	2016	9.4	9.4	9.4	9.4	9.4	9.4	9.4
CBP-DO 2 hour	4	2016	3.5	3.5	3.9	3.8	3.8	3.6	3.9
CBP-DO 2 hour	6	2016	2.6	2.6	2.9	2.8	2.9	2.7	2.9
CBP DO 30 minute	4	2016	5.4	5.3	5.9	5.8	5.9	4.5	5.9
CBP DO 30 minute	6	2016	4.0	4.0	4.4	4.3	4.3	3.3	4.4
Total			24.8	24.8	26.3	26.2	26.3	23.4	26.3

			0.12	0.12	0.12	0.12	0.12	0.11	
Notificatio	Max Hour	Year	May	June	July	August	September	October	max
CBP-DA	4	2016	0.3	0.3	0.3	0.3	0.3	0.3	0.3
CBP-DO 2	4	2016	0.6	0.6	0.7	0.7	0.7	0.6	0.7
CBP-DO 2	6	2016	0.5	0.4	0.5	0.5	0.5	0.5	0.5
CBP DO 30	4	2016	0.9	0.9	1.0	1.0	1.0	0.8	1.0
CBP DO 30	6	2016	0.7	0.7	0.8	0.7	0.8	0.6	0.8
Total			3.0	3.0	3.2	3.2	3.2	2.7	3.2

Notificatio	Max Hour	Year	May	June	July	August	September	October
CBP-DA	4	2016	9.1	9.1	9.1	9.1	9.1	9.1
CBP-DO 2	4	2016	2.9	2.9	3.2	3.2	3.2	3.0
CBP-DO 2	6	2016	2.2	2.1	2.4	2.3	2.4	2.2
CBP DO 30	4	2016	4.4	4.4	4.9	4.8	4.8	3.7
CBP DO 30	6	2016	3.3	3.3	3.6	3.6	3.6	2.7
Total			21.9	21.8	23.1	23.0	23.0	20.7

% of AutoDR in CBP total 12.3%

	May	June	July	August	September	October
All DO 2015	15	15	16	16	16	13
All Do 2016	15	15	17	17	17	14

Notification	Max Hour	Year	May	June	July	August	September	October	max
CBP-DA	4	2014	9.4	9.4	9.4	9.4	9.4	9.4	9.4
CBP-DO 2 hour	4	2014	5.4	5.4	5.9	5.9	5.9	5.6	5.9
CBP-DO 2 hour	6	2014	4.0	4.0	4.4	4.4	4.4	4.1	4.4
CBP DO 30 minute	4	2014	0.0	0.0	0.0	0.0	0.0	0.0	
CBP DO 30 minute	6	2014	0.0	0.0	0.0	0.0	0.0	0.0	
Total			18.8	18.8	19.7	19.6	19.7	19.0	19.7

Notificatio	Max Hour	Year	May	June	July	August	September	October	max
CBP-DA	4	2014	0.3	0.3	0.3	0.3	0.3	0.3	0.3
CBP-DO 2	4	2014	0.9	0.9	1.0	1.0	1.0	1.0	1.0
CBP-DO 2	6	2014	0.7	0.7	0.8	0.8	0.8	0.7	0.8
CBP DO 30	4	2014	0.0	0.0	0.0	0.0	0.0	0.0	
CBP DO 30	6	2014	0.0	0.0	0.0	0.0	0.0	0.0	
Total			1.9	1.9	2.1	2.1	2.1	2.0	2.1

Notificatio	Max Hour	Year	May	June	July	August	September	October
CBP-DA	4	2014	9.1	9.1	9.1	9.1	9.1	9.1
CBP-DO 2	4	2014	4.5	4.5	4.9	4.9	4.9	4.6
CBP-DO 2	6	2014	3.3	3.3	3.6	3.6	3.6	3.4
CBP DO 30	4	2014	0.0	0.0	0.0	0.0	0.0	0.0
CBP DO 30	6	2014	0.0	0.0	0.0	0.0	0.0	0.0
Total			16.9	16.8	17.6	17.5	17.6	17.1

	May	June	July	August	September	October		May	June	July	August	September	October	max
DO 2014	9.4	9.4	10.3	10.2	10.3	9.7		1.63	1.62	1.79	1.77	1.78	1.67	1.79

Here is where the CBP capacity incentives are calculated based on the proposed tariff. The Day of 30 minute product is 15% higher than the Day of 2 hr product

$/kW-mo	May	Jun	Jul	Aug	Sep	Oct
Day Ahead 4 hr	**2.4**	**6.6**	**14.2**	**17.6**	**11.6**	**3.5**
Day Of 2 hr 4 hr	**2.9**	**7.9**	**17.1**	**21.1**	**13.9**	**4.2**
Day of 2 hr 6 hr	**3.3**	**8.9**	**19.5**	**24.0**	**15.8**	**4.7**
Day of 30 min 4 hr	**3.3**	9.0	19.6	24.2	16.0	4.8
Day of 30 min 6 hr	**3.8**	10.2	22.4	27.6	18.1	5.4

2015	Day Ahead 4 hr	**22,779**	61,400	133,205	164,608	108,738	32,809	523,538	523,538	Day Ahead capacity incentive for 2015
	Day Of 2 hr 4 hr	**10,238**	27,487	65,715	80,514	53,499	15,157	252,609		
	Day of 2 hr 6 hr	**8,587**	23,041	55,757	67,976	44,964	12,663	212,990		
	Day of 30 min 4 hr	**16,302**	43,767	104,638	128,203	85,187	18,771	396,869		
	Day of 30 min 6 hr	**13,673**	36,689	88,783	108,239	71,597	15,683	334,664	1,197,132	Day of capacity incentive for 2015

2016	Day Ahead 4 hr	**22,779**	61,400	133,205	164,608	108,738	32,809	523,538	523,538	Day Ahead capacity incentive for 2016
	Day Of 2 hr 4 hr	**10,238**	27,487	65,715	80,514	53,499	15,157	252,609	252,609	
	Day of 2 hr 6 hr	**8,587**	23,041	55,757	67,976	44,964	12,663	212,990	212,990	
	Day of 30 min 4 hr	**17,932**	48,144	115,102	141,023	93,706	21,587	437,494	437,494	
	Day of 30 min 6 hr	**15,041**	40,358	97,661	119,063	78,756	18,036	368,915	1,272,008	Day of capacity incentive for 2016

Program	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	max		
DBP DO	2015	1.7	1.1	2.4	4.6	3.4	3.2	3.7	4.6	5.5	5.0	3.0	1.1	5.54		
DBP DO	2016	1.7	1.1	2.4	4.6	3.4	3.2	3.7	4.6	5.5	5.0	3.0	1.1	5.54		
PTR Res	2015	1.4	1.5	1.2	3.4	2.9	2.5	4.1	4.4	5.0	4.5	1.1	1.7	5.01		
PTR Res	2016	1.5	1.5	1.2	3.4	2.9	2.5	4.2	4.5	5.1	4.6	1.1	1.7	5.07		
SCTD	2015	0.04	0.04	0.04	3.61	7.38	4.87	7.50	8.35	9.44	9.32	1.09	0.04	9.44		
SCTD	2016	0.04	0.04	0.04	3.61	7.38	4.87	7.50	8.35	9.44	9.32	1.09	0.04	9.44		
CPPD Large	2015	5.08	5.13	5.08	14.86	15.04	15.02	16.78	16.83	17.55	16.11	6.00	5.06	17.55		
CPPD Large	2016	5.15	5.19	5.14	15.04	15.23	15.22	16.98	17.05	17.79	16.30	6.08	5.13	17.79		
CPPD Medium	2015	6.08	6.10	6.05	15.52	15.15	15.06	16.65	16.68	17.63	16.04	6.75	5.73	17.63		
CPPD Medium	2016	5.83	5.85	5.81	14.81	16.22	16.12	17.83	17.86	18.87	17.17	7.22	6.13	18.87		
Total CPPD	2015	11	11	11	30	30	30	33	34	35	32	13	11	35.18		
Total CPPD	2016	11	11	11	30	31	31	35	35	37	33	13	11	36.66		
TI in CPPD	2015	0.42	0.43	0.42	1.15	1.15	1.14	1.27	1.27	1.34	1.22	0.48	0.41	1.34		
TI in CPPD	2016	0.42	0.42	0.42	1.13	1.20	1.19	1.32	1.33	1.39	1.27	0.51	0.43	1.39		
CPPD Large	2014	5	5	5	15	15	15	17	17	17	16	6	5	17.32		
CPPD Medium	2014					16	16	17	17	19	17	7	6	18.51		
Total CPPD	2014	5	5	5	15	31	31	34	34	36	33	13	11	35.83		
TI in CPPD	2014	0.19	0.19	0.19	0.56	1.17	1.16	1.29	1.29	1.36	1.24	0.49	0.42	1.36		
SCTD sm comm	2015	0.30	0.29	0.29	0.97	1.22	1.06	1.27	1.39	1.41	0.92	0.36	0.29	1.41		
SCTD sm comm	2016	0.30	0.29	0.29	0.97	1.22	1.06	1.27	1.39	1.41	0.92	0.36	0.29	1.41		
SCTD all	2015	0.3	0.3	0.3	4.6	8.6	5.9	8.8	9.7	10.8	10.2	1.4	0.3	10.84		
SCTD all	2016	0.3	0.3	0.3	4.6	8.6	5.9	8.8	9.7	10.8	10.2	1.4	0.3	10.84		
All PTR/SCTD	2015	1.8	1.8	1.5	7.9	11.5	8.4	12.9	14.2	15.8	14.7	2.5	2.0	15.85	0.68	% of SCTD in PTR
All PTR/SCTD	2016	1.8	1.8	1.5	8.0	11.5	8.4	12.9	14.2	15.9	14.8	2.5	2.0	15.91		
DBP DA	2015	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.50		
DBP DA	2016	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.50		
CBP all	2015					24.0	23.9	25.4	25.2	25.3	22.4			25.38	12	
CBP all	2016					24.8	24.8	26.3	26.2	26.3	23.4			26.31	13	

SDG&E M&E Activities	2015	2016	
Program Evaluations			
Critical Peak Pricing Default	$175,000	$75,000	
Critical Peak Pricing Small Commercial	$150,000	$75,000	
Peak Time Rebate	$175,000	$175,000	
Critical Peak Pricing Residential	$200,000	$100,000	
Capacity Bidding Program	$50,000	$50,000	
Summer Saver	$250,000	$175,000	
RACT/ Residential Technology	$100,000	$100,000	
Small Commercial Technology Deployment	$50,000	$50,000	
Base Interruptible Program	$30,000	$30,000	
Other Evaluation Activities*			
TA and TI / Auto DR	$65,000	$15,000	
Permanent Load Shifting Evaluation	$25,000	$25,000	
Customer Research Studies	$99,967	$99,967	
Demand Response Forecasting App Dvlpmnt	$50,000	$50,000	
End Use Metering	$260,000	$260,000	
Labor to support studies			
M&E Analytical Support 2 FTE's	$233,116	$246,525	
Total M&E related costs	$1,913,083	$1,526,492	3,439,575
not included in CE tests	525,000	249,887	
in specific program budget	305,000	305,000	
portfolio cost	1,083,083	971,492	
total	1,913,083	1,526,379	3,439,462
Values in PB (adj required for entry into PB)	1,913,032	1,526,430	3,439,462

Cost Effectiveness Methodology	E3 Demand Response Documents (including Distributed Generation Avoided Cost Calculator) *(Note: outputs from calculator are modified for DR in this spreadsheet)* www.ethree.com\public_projects\cpucdr.html R 08 03 008, D. 09 08 026 http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/105926.pdf CSI Cost Effectiveness Report based on Distributed Generation Cost Effectiveness Framework http://www.ethree.com/public_projects/cpuc.html
CT Cost and Performance	2008 & 2009 CAISO Market Issues and Performance Report www.caiso.com/2390/239087966e450.pdf http://www.caiso.com/2777/277789c42ac70.html 2007 CEC Cost of Generation Report http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF
Planning Reserve Margin	R. 08 04 012, D. 04 01 050 and Proposed Decision mailed August 23, 2010 closing the proceeding. http://docs.cpuc.ca.gov/efile/PD/122343.pdf
CT Summer Capacity Derate	LM6000 60Hz Gas Turbine Generator Set Product Specification http://www.hilcoind.com/images/ftp/SFPUC/7/A/LM6000%2060%20Hz%20Grey%202008%20Rev%202.pdf http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3695e.pdf

This document updated January 21, 2011

SB_GT&S_0394670

Tab	Cell	Change	Date	
Inputs	C7, R22	Input WACC for each IOU and linked to IOU selection	11/02/10	Changes since Proposed Decision Issued
	C8	Deleted Monthly WACC (not used)	11/02/10	
	F5	Added Inflation value	11/02/10	
	I9, L22	Added Separate Transmission and Distribution Deferral values for each IOU and linked them to utility selection	11/02/10	
	K18	Placeholder for Wtd. Average Sub Transmisison and Distribtution Values by Utility	12/15/10	
	M19	Moved WACC input and added utility specific WACC's linked to utility selection	12/15/10	
	I5	Added Ancillary Services Avoided Cost Values	12/15/10	
	I8	Added separate "Summer" and "Nameplate" Generation Capacity Values, reflecting Summer Peak Performance Penalty	12/15/10	
	I34	Modified monthly allocation of capacity value to reflect 4 years of historical load data	12/15/10	
		Updated Avoided Cost Model inputs (from version 3.8)	01/10/11	Changes after January 2011 Workshop
	R22	Entered After Tax IOU WACCs	01/10/11	
	I12	Added annual CT capacity factor results	01/10/11	
	I25	Fixed IOU drop down selection	01/10/11	
	I40	Added IOU specific T&D monthly allocation factors based on temperature	01/10/11	
	I9 & I10	Replaced T & D deferral values with formulas based on IOU selection (inadvertantly overwritten in last version	01/21/11	
	I12	Replaced Capacity Factors with Statewide average instead of Northern California (not used in calcuations)	01/21/11	
BIP Example	C9	Fixed inadvertently reversed PCT BC ratio.	11/02/10	
	C9	Fixed to calculate NPV in same manner as other cells	11/02/10	
	D6	Removed “bill reductions” from rows 63 and 68 in calculation of TRC costs	11/02/10	
	H50	Add user input for T&D Values	12/15/10	
	L52	Revised T&D montly value calculation to refer to user selection for T&D deferral value	12/15/10	
	F43	Added user selection for T&D capacity value (T&D, D only, user input)	12/15/10	
	H108	Added T&D deferal value results based on user selection	12/15/10	
	B70, B80	Added notification that Participant Annual Expenses are based on bill savings + incentives equipment costs entered in Rows 70, 71 and 80 84	12/15/10	
	D74, D80	Modified ammortization of equipment costs to be cumulative	01/06/11	
	D68	Revised calculation of participant costs to be 75% *(incentives + bill reductions) Equipment Costs	01/06/11	
	H51, D56	Modified averaging of MW Impacts to ignore zero or blank months	01/10/11	
	E102	Removed bill savings from TRC for years 2013 and 2014 (copied formula from 2012)	01/21/11	
Portfolio		Added Portfolio Tab, based on BIP,CBP tabs	11/02/10	
		Modified for IOU to input total costs, benefits and impacts, then DR Template calculates average benefit values in $/kW Yr and $/MWh. Removed A E Factors	01/10/11	
		Removed A factor sensitivity	01/10/11	
Summary		Added Portfolio Column	11/02/10	
		Changed all formulas to INDIRECT to all easy addition of programs	11/02/10	
Instructions		Added Instructions for adding program and entering data in Portfolio Tab	12/15/10	
		Added macro for adding new program	01/06/11	