BEFORE THE PUBLIC UTILITIIES 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) 2017 DEMAND RESPONSE PROGRAM PROPOSALS PURSUANT TO THE ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING PROVIDING GUIDANCE FOR SUBMITTING DEMAND RESPONSE PROGRAMS AND ACTIVITIES PROPOSAL FILINGS

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I. EXECUTIVE SUMMARY

San Diego Gas & Electric Company (SDG&E) submits this request for approval of its 2017 Demand Response (DR) program proposals and budgets in accordance with the guidance provided in the September 15, 2015 Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for 2017 Demand Response Programs and Activities Proposal Filings (Guidance Ruling), as well as the subsequent Administrative Law Judge's Ruling Providing Clarification Regarding 2017 Demand Response Program Proposals, dated December 3, 2015 (Supplemental Ruling). As discussed in further detail below, SDG&E seeks Commission authority herein to: (1) implement the revisions identified herein to selected DR programs; and (2) approve a 2017 portfolio budget of $20,808,000 to continue its DR programs in 2017 and transition to a fully bifurcated DR portfolio in 2018. SDG&E's proposed DR portfolio budget for 2017 reflects an increase of $190,000 or 0.9% when compared to its authorized 2016 portfolio budget.[1] This increase is primarily driven by SDG&E's proposed

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[1] For the purpose of comparing 2017 to 2016, SDG&E's 2016 budgets are roughly 50% of the authorized budgets for the 2015-2016 bridge year funding approved in D.14-05-025.

incorporation of its Summer Saver Program into its 2017 Demand Response Portfolio (DRP) for the first time, when it was previously been recovered outside of the DRP. The Summer Saver program has a requested budget in 2017 of $2,534,408.[2] Subtracting the impact of introducing Summer Saver to the DRP, SDG&E's overall DRP budget is $18,273,592 and reflects a decrease of $2,344,408 or 11.4% from SDG&E's 2016 approved budget. Put another way, considering the historical spend of Summer Saver, SDG&E's 2017 DRP request represents a net reduction in requested budget authorization.

Detailed discussions of the various program proposals and associated cost details are provided below. Additional program and budget details are provided in the following Appendices: Appendix A—SDG&E DR 2017 Proposed Budget; Appendix B—Program Implementation Plans with Changes; Appendix C—Proposed Tariffs, Schedules and Contract Changes; and Appendix D-December 2015 Monthly Expenditure Report. In addition to its 2017 DR Portfolio proposals, SDG&E also provides its proposals for two miscellaneous items identified in the Guidance Ruling: (1) DR customer protection rules and recommendations pursuant to Senate Bill (SB) 1414; and (2) the continuation of DR study funding initially authorized by Decision (D.) 12-04-045.

II. BACKGROUND

SDG&E's current 2015-2016 DR programs portfolio and associated budgets were approved by the Commission in D.14-05-025, dated May 15, 2014. SDG&E's current two-year DR programs budget, as adopted by this decision, is $39,872,607.[3] Soon thereafter, the Commission adopted D.14-12-024, setting forth the activities necessary to achieve a full

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[2] As noted later in this filing, SDG&E's 2017 budget for summer saver is $2.2 million less than actual 2015 program spend of 4.7 million.

[3] *See*, D.14-05-025, Ordering Paragraph 15.

bifurcation of demand response into load modifying and supply side resources in 2018 and furthering the Commission's desire for more demand response resources to be bid into the CAISO market. In D.14-12-024, 2016 and 2017 were identified as transitional years, where SDG&E and the Investor Owned Utilities (IOUs) would incrementally adjust their DR programs. The September 15, 2015 Guidance Ruling provides specific requirements meant to direct the utilities in advancing their respective DR portfolios in 2017. Pursuant to the Guidance Ruling, 2017 program proposals must address four main categories of changes: (1) Program changes to enable market integration; (2) program changes for overall program improvement; (3) clarification of demand response portfolio contents; and (4) miscellaneous items as identified by the guidance. Below, SDG&E outlines its current DR policy to provide context for its 2017 DR proposals and inform the Commission of its longer term goals for the development of demand response.

A. SDG&E's Demand Response Policy

1. Utilities are at the forefront of the Demand Response future and have an important role to play.

As we find ourselves in early 2016, demand response as a distributed energy resource continues to mature and evolve. SDG&E is in the midst of a two year bridge funding cycle (2015 through 2016), and is implementing incremental steps towards full bifurcation by currently bidding its Capacity Bidding Program, or "CBP" into the CAISO market and by preparing to actively bid the Base Interruptible Program, or "BIP" in 2016.

At the same time, the applications of the IOUs in the Rule 24/32 proceeding have moved forward; a Commission decision has been issued on the initial implementation step, and we await the next decision on the intermediate implementation step where the IOUs may receive the authorization to add further functionality to back office systems, in order to support third party DR providers who will bid their own DR products into the CAISO market.

In addition, SDG&E issued its Request for Proposal (RFP) for the Demand Response Auction Mechanism (DRAM) pilot as ordered in D.14-12-024, with third party DR bids being received in the fall of 2015, for DR to be delivered and bid into the CAISO in the DR season of 2016. The Commission has said that 2017 is a further year of transition, and that more effort is expected to be undertaken by the IOUs in order to move them to full bifurcation in 2018.[4] This filing is representative of the plans of SDG&E to do just that.

At this time, the utility finds itself well positioned to identify and oversee the deployment of demand response, energy efficiency and other clean energy resources to meet grid needs and optimize costs. By moving more demand response into the CAISO market, SDG&E is promoting the market opportunities for DR to compete against other resources, and opportunities for customers to benefit from these emerging market opportunities. This will make more transparent the value associated with deploying DR and other Distributed Energy Resources (DERs). Participating in the process of determining the value of DERs and offering such resources to the market will help utilities design programs to be competitive and cost-effective.

The Utilities are also well positioned to identify system needs, and identify where DERs could provide service in order to meet those needs. Because of its obligation to provide safe and reliable service, SDG&E is experienced in safety issues, knowing that they must be addressed thoughtfully, while properly balancing both public and employee safety concerns with the adoption of new technologies as they become available. SDG&E is experienced in the measuring and verifying the physical assurance for capacity and reliability that must be

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4 *See*, Guidance Ruling, p.3.

maintained for demand response value to be realized. SDG&E knows its systems best, and as more granular data becomes available, will be able to utilize that data in order to effectively target demand response, and verify that it provided the intended value.

Lastly, utilities are well positioned to provide DR because we know our customers. SDG&E knows its customers want reliable energy at the lowest price possible. They also want choices, convenience and some elements of control when they think about their energy usage and the actions that may be required on their part to participate in SDG&E's programs. There is not a "one size fits all" DR program that will be right for our customers. It will take a varied and well developed portfolio over time to meet their needs, as well as those of the CAISO and other markets that may develop.

2. SDG&E supports Demand Response being used to achieve its highest value.

SDG&E supports the policies that allow DR to be used to achieve its highest value in fulfilling system capacity or local distribution capacity needs. It is unknown at this time whether the bifurcation of DR into load modifying or supply side resources will fully accomplish this goal. However, it appears that bifurcation may help to emphasize the fact that DR programs must be designed with a clear purpose, and in ideal cases, the programs should strive to realize maximum market value based on actual system needs and conditions. When these things are in place, the DR can be appropriately and competitively compensated in a way that fair and transparent based on its achieved purpose and the delivery of the intended value.

3. DR is most cost effective and most economically efficient when it is dispatched on the basis of accurate price signals that allow customers to realize the avoided cost benefits associated with any DR they are able to provide.

Clear, transparent and accurate price signals, based on cost causation principles, must be the underpinning of all demand response products. A DR model with subsidies or carve-outs is not in the interest of all ratepayers. We can learn in the interim period by having certain pilots that test DR, including those with particular carve-outs designed to test certain market viability, such as the DRAM. But this approach is not sustainable in the long-term, leads to unnecessarily high rates, and creates a false security based upon non-market driven practices. DR should compete against other resources to determine the most cost-effective way to achieve capacity, reliability or policy goals. DR is most cost effective and most economically efficient when it is dispatched on the basis of accurate price signals that allow customers to realize the avoided cost benefits associated with any DR they are able to provide.

The dispatch of DR on the basis of accurate price signals would allow it to compete on a cost basis with other technologies, eliminating the need for the DRAM and other carve-outs. It would also allow customers to realize the benefits of the lowest cost and best fit solution for meeting system needs. In the absence of accurate price signals, rates create incentives for customers to use electricity in the wrong ways and at the wrong times, which then creates the need for to provide those same customers with additional compensation to incent customers to use electricity in the right ways and at the right times. Transparent, fair, cost-based rates must go hand-in-hand with DR.

To the extent DR incentives above avoided cost are made available to DR participants, those incentives should be implemented in a clear and transparent manner, and participants should be compensated for DR when grid benefits are realized from either a demand reduction that results from actual load drop as opposed to use of fossil fueled, behind the meter generation, or greater consumption during times of over-generation when needed.

SDG&E is not opposed to the possibility that qualified, eligible customers may participate in more than one DR program at a time, in alignment with a previous CPUC issued decision, and believes there can be a role for this activity.[5] By participating in more than one program, a customer has the opportunity to be compensated appropriately by helping to address different system needs. However, customers should not receive multiple payments for one DR activity. Rather, customers should receive the payment for the highest value, or the incremental additional value associated with the highest value service they provide. SDG&E notes that this area can also be confusing for customers, and that efforts must be made to ensure clear messaging to customers so that they understand the services and the value they provide.

4. Least Cost Dispatch (LCD) principles do not treat DR fairly which is problematic as we move to bifurcation with existing DR programs. A full record must be developed in the DR OIR by stakeholders.

The Commission has recently decided in D.15-05-005 how SDG&E is to demonstrate compliance with LCD principles for DR within SDG&E's ERRA proceedings.[6] SDG&E understands and agrees that the utility must do what is in the best interest of its ratepayers. However, it is difficult to apply economic dispatch principles to programs that were not designed with this approach in mind. SDG&E believes that the standard is currently being applied when no record or vetting has been done on how the standard should be applied to different programs.

It is worth noting that the design of DR programs is evolving and some programs today are designed and dispatched on economic triggers, and may be bid into the CAISO markets. However, SDG&E is in a transition period where programs, going forward, may be dispatched more frequently to meet distribution or local system needs as well, especially as more granular data becomes available on our distribution system. While SDG&E supports price and market triggers, they must be accurate in order to work. SDG&E sees that our customers' needs also

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5 *See*, D. 12-04-045, page 56.

6 *See*, D.15-05-005, Ordering Paragraph 4.

come into play, and they are transitioning as well towards understanding how programs may be dispatched differently in the future, including being dispatched more frequently. Under these scenarios, SDG&E must consider customer fatigue which in the long term can harm the overall availability of a resource in competitive markets if customers choose to no longer participate. Competitive markets can be further developed by allowing utilities to dispatch DR in a manner that minimizes long-term costs and maximizes long-term availability of DR resources.

SDG&E requests that the Commission examine how LCD standards are to be applied to demand response in R.13-09-011, instead of within individual ERRA proceedings of each IOU. This would accomplish two things. First, the issue would be vetted by the appropriate DR stakeholders, many of whom are not participants in the ERRA proceedings, and whose perspectives would be valuable in the discussion. Second, a full record can be developed to address the issue fully and fairly.

5. Some areas of Demand Response remain uncertain, with areas still yet to be developed for adequate DR implementation.

SDG&E notes that at least two areas of policy are not currently supportive of full bifurcation, or third parties bidding into the CAISO, and so do not support the Commission's DR policies::

- Robustness of the overall CAISO market; and,
- Confirmation from a Load Serving Entity (LSE) that it approves the registration of a customer at the CAISO.

Going forward, there is a need to develop policy in these areas, to change current rules, or to implement some areas differently.

One area of uncertainty is how robust the overall CAISO market will be and what will develop. It is unclear today whether or not there will be a strong market at the CAISO for third parties or the utilities to participate in, or where there can be substantial financial gain for the third parties and customers to make their efforts worthwhile. Over time, the CAISO may need to update its own policies to encourage a more viable market. Furthermore, the value of DR and its cost effectiveness are in flux while policies and markets evolve. While the IOUs move to full bifurcation and more resources move toward becoming supply side resources, the IOUs are still required to run them through a cost-effectiveness model rather than let the market determine their cost effectiveness. This would seem to indicate a recognition that the market today may not be properly calibrated to reflect true value, at least for demand response or capacity products. More work is being done in the IDER proceeding to value all distributed energy resources, which SDG&E sees as a positive process. Ultimately, SDG&E believes clear price signals, based on the value the resource provides compared with other resources, are the best indicator of cost effectiveness.

Another example of an area that needs additional policy work is the confirmation that is required from a LSE (Load Serving Entity) that it approves the registration of a customer at the CAISO. Current CAISO rules state in the PDR design document:

> *A Registration entry is the first step toward PDR participation and involves a workflow process that requires involvement by the corresponding LSE [Load Serving Entity] and UDC [Utility Distribution Company] for the resource. This Registration process is to be initiated by the CSP [Curtailment Service Provider] that is representing the resource. Once a registration is entered, the corresponding LSE and UDC entities for that resource must approve the Registration before it can become active and participate in the wholesale markets.*[7]

Under current rules at the CAISO, the Utilities have no control over whether or not that LSE provides that approval information to the utility, even when requested, nor is there any

[7] Definition of acronyms added. The above text can be found at the bottom of p.20 of https://www.caiso.com/Documents/DraftFinalProposal_theDesign-PDR-Clean.pdf

timing required in which that LSE must respond. Yet, the Utilities must have that confirmation per the CAISO rules. The LSEs can prevent the Utilities from bidding some of the largest and most viable resources into the market that they might have otherwise bid because of the unenforceability of the request for approval of these registrations. These are areas where more work is needed to create a level playing field for all which may require FERC or CAISO rule changes.

6. SDG&E has determined certain approaches to be useful in designing Demand Response for the near-term and the long-term. The proposals in this filing will reflect our start with those approaches.

In the near term, SDG&E proposes program changes that will create more supply side DR in direct response to the Commission's guidance. The goal in the long term will be to design and dispatch those resources with greater coordination among all resources, with the purpose for each program geared towards meeting a specific grid or CAISO need that is clearly defined. Incremental steps and a thoughtful transition may be necessary to ensure positive customer experiences and choice. In the long term, SDG&E plans to design programs to address more of the lingering challenges that remain, including:

- Ensuring that programs incentivize demand response based on actual system or local conditions.
- Offsetting over-generation and providing ancillary services to accommodate more renewables (flexible capacity); and,
- Serving distribution grid needs such as circuit capacity needs or volt/VAR support.

SDG&E's 2017 demand response proposals below reflects the thoughts expressed above in this section, and SDG&E looks forward to working with the Commission to further the role of demand response in meeting the system as well as our customers' needs.

7. SDG&E has made a strong effort to reduce its costs for DR in response to the Guidance Ruling.

SDG&E has made every effort to be responsive to the Guidance Ruling's request that IOUs reduce their costs for DR as much as possible. SDG&E examined each program afresh; i.e., examining SDG&E's actual program spend in 2015, whether the program has been historically underspent and by how much, and whether tighter budgets might be proposed based on historical trends, as well for as any potential cost reductions. In response to its examination, SDG&E has reduced several programs' budgets for 2017, resulting in a reduction of the overall portfolio funding request by approximately 11.4% as compared to the authorized budget for 2016.[8] SDG&E believes that its 2017 budget request will be sufficient given what is known today. Although, it is worth noting that if programs need to exceed their caps for any reasons, particularly if participation increases faster than anticipated, SDG&E still has the ability to shift funds to keep programs open to new enrollment.

III. SDG&E's 2017 DEMAND RESPONSE PROGRAM PROPOSALS

As instructed by the Guidance Ruling, SDG&E's proposals for its 2017 demand response programs are provided below and are grouped into the following categories of changes:

a. Program changes to enable market integration;

b. Program changes for overall program improvement; and,

c. Programs without modifications for 2017.

SDG&E also provides its 2017 pilot program proposals, including its over generation pilot proposal, in section (D.) below.

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[8] The reduction of 11.4% is based on a comparison of 2016 authorized vs. 2017's budget request without SDG&E's Summer Saver program, which was funded outside of SDG&E's 2015-2016 bridge year proposal.

A. Programs with Modifications to Enable Market Integration

1. Capacity Bidding Program

The Capacity Bidding Program provides incentives to customers in exchange for a promise to shed load when requested by the Utility. The Program is open to bundled customers as well as Direct Access customers. Bundled customers receive capacity and energy payments from SDG&E and Direct Access (DA) customers receive capacity payments, with energy-based compensation and savings subject to their contractual relationships with DA providers. SDG&E's Demand Response Team proposes to keep its Capacity Bidding Program in 2017 and continue its transition to supply side by 2018. SDG&E is requesting a total budget of $2,180,832 to fund its Capacity Bidding Program in 2017, a decrease of $2,007,437 when compared to the authorized CBP budget for 2016.

a. CBP Market Integration

CAISO integration of the CBP is feasible because the program already meets most CAISO market requirements. In 2014, SDG&E started bidding a portion of CBP into the CAISO market. The market activity experience in 2015 has proven that the Program is viable for market integration. SDG&E's market activities and Program design currently conform to most ISO Proxy Demand Resource (PDR) requirements. PDR is the Proxy Demand Resource product at the CAISO. It is a new demand response product offering which allows customers to participate in the ISO's wholesale energy and ancillary services markets. Aggregators or Curtailment Service Providers (CSPs, and also known as Demand Response Providers or DRPs) can bid demand response directly into the ISO energy markets. As presently designed, CBP Day Ahead will be a PDR and it currently meets CAISO PDR Day Ahead requirements. However, because the customer notification cut off time is 9AM for the CBP Day Of product, SDG&E's

ability to maximize the benefit of the Day Of product to full potential is limited. As such, we are proposing changes to the program described below.

Even though it is feasible for market integration into the CAISO market, CBP will still have hurdles to overcome in order to be fully integrated into CAISO. These include the following:

- Obtaining timely authorization from Load Serving Entities (LSEs) for SDG&E to bid the DR of its Direct Access customers when there is no incentive or requirement for those LSEs to provide it.[9] It remains to be seen how the business processes for obtaining this authorization will work and its efficiency is important. However, there is no compelling reason for the LSE to cooperate.
- Meeting the 100kW minimum requirements per PDR for every Load Serving Entity.

b. CBP Program Modification

SDG&E is requesting modifications to the Capacity Bidding Program to make the Program a better fit for market integration, and to allow better alignment with market requirements for dispatch, e.g. notification time as well as LSEs. These modifications are summarized below:

1. Modify Day Of product to a two-hour notification product.

SDG&E proposes to modify the Day Of product from the 9:00 a.m. trigger to a two hour notification product. This will allow SDG&E to have additional flexibility to call the Program based on market, statewide or local grid conditions on event days. Currently, the 9:00 a.m. trigger (the need to notify by that time on a Day Of event) forces SDG&E

[9] See CAISO Proxy Demand Response rules at: https://www.caiso.com/Documents/DraftFinalProposal_theDesign-PDR-Clean.pdf.

to call the program when triggers are met, even though it may become apparent later in the day that the utility or state grid is adequately resourced. This proposed change is reflected on the redlined CBP tariff filed with this application.

2. Ability to dispatch the Day Ahead Program on Sunday for Monday events.

This notification change would create greater flexibility to call the Day Ahead program for a Monday event compared to current notification of notifying on Friday for a Monday event. Having the ability to dispatch the Program on Sunday for Monday would also allow SDG&E to have more recent system and weather data in order to improve the utility's ability to call programs when appropriate. This proposed change is reflected on the redlined CBP tariff filed with this application.

3. Adjustments to event hour maximums to align with system needs.

The SDG&E CBP program may be dispatched for 44 hours per month which is significantly higher than the 24 hours per month required by the RA proceeding[10]. In order to maximize participation in demand response programs and minimize customer fatigue availability requirements for demand response programs should supported by a system need. SDG&E reviewed the monthly loss of load probabilities and determined that in May, June and October little additional value is provided by being available for 44 hours instead of for 24 hours, and that little additional value is provided by being available for 44 hours instead of 32 hours for July and September. Therefore SDG&E proposes to lower the monthly event hour maximums for May, June and October to 24 hours, and to 32 hours for July and September. SDG&E also recommends that the CBP program not be required to dispatch more than 24 hours in any month solely on account

[10] See, 2016 RA guide, at p.22.

of least cost dispatch obligations. Additional events above and beyond 24 event hours should only be called in the case of statewide or local emergency conditions or other extreme conditions. Making these adjustments to the monthly maximums will better align the CBP program design with system needs and help to maximize participation in the program.

Table 1 - Proposed CBP Monthly Event Hour Maximums						
	May	June	July	August	September	October
Maximum Event hours	24	24	32	44	32	24

The proposed changes 1 and 2 to the CBP notification times do not affect the cost-effectiveness of the program. Proposed change 3 to the maximum availability lowers that A factor slightly from 66% to 63% and cost-effectiveness results for CBP are included in section V.

c. CBP Tariff Changes

SDG&E's recommended tariff changes for CBP are provided in Appendix C. First, SDG&E proposes to update the CBP tariff with the new maximum cumulative monthly event hours and notification on Sunday for a Monday event. This change is reflected in revisions to Schedule CBP, Sheet 3, Section 3 Program Operation, and also to Schedule CBP, Sheet 5, Section 4.a.i – ii and Schedule CBP, Sheet 6, Section 4.a.iii.

d. CBP Budget Request

The Capacity Bidding Program requested budget for 2017 is shown below. In compliance with Commission staff's recommendation to reduce budgets, SDG&E requests reduced funding for 2017 after thorough review of prior years' budgets, actual spend and reducing the amount of contingency incentive budget from the past cycles.

Table 2 – CBP Budget		
Program Name	**2016 Budget**	**Total 2017 Budget**
Capacity Bidding Program	$4,188,269	$2,180,832

Currently CBP relies on an older IT system which is being retired and will be replaced in 2017 with SDG&E's Demand Response Management System (DRMS). CBP's portion of the appropriate license fees connected with the DRMS are contained in this filing in the IT Infrastructure budget and corresponding section addressing the IT needs.

2. Base Interruptible Program

The Base Interruptible Program (BIP) offers a monthly capacity payment to customers that can commit to curtail at least 15% of Monthly Average Peak Demand, with a minimum load drop of 100 kW. BIP is an Emergency program that is available to be called year round, not to exceed four (4) hours for any calendar day, or 10 Interruption Periods per calendar month, or 120 hours during any calendar year.

SDG&E intends to bid BIP into the CAISO markets Reliability Demand Response Resource (RDRR) starting in 2016, with full integration in the 2017 program year. SDG&E cautions that because of the current size of the program, there may be some existing market barriers such as 100 kW for PDR or 500 kW for RDRR. These minimum loads are per load serving entity. At the time of this filing, SDG&E's BIP program consists of 2 DA accounts and 3 bundled accounts. Achieving the minimum load requirement to participate in the CAISO market may be a barrier.

(D.) 10-06-034, which adopted the "Reliability-Based Demand Response Settlement Agreement," capped the emergency program enrollment at 16.5 MW.[11] SDG&E currently has participation below its cap, therefore there is room for potential BIP enrollment growth. SDG&E is planning to increase program enrollments within a targeted pool of potential participants. A targeted pool of potential participants has been identified by looking at medium/large commercial customers who had a minimum load of 200 kW. SDG&E will also leverage its Account Executives, existing Trade Professional trainings and other trainings provided for DR programs to educate customers on BIP.

a. CAISO Integration Feasibility - BIP

It is feasible to bid the Base Interruptible program (BIP) into the CAISO Wholesale Market as a Reliability Demand Response Resource (RDRR) that enables emergency responsive demand response resources for both state and local emergency situations. It can be available for multiple reliability-only events, including system emergencies (CAISO alerts and stages).

The Base Interruptible program's current design will allow it to be bid into the CAISO Wholesale Market and dispatch as awarded because the current program design allows for real-time load reduction delivery. As is discussed in more detail below, in order to meet the CAISO requirement for real-time full curtailment within 40 minutes,[12] SDG&E is proposing a change to the notification time for the BIP program from 30 to 20 minutes. SDG&E anticipates that the program will be moving towards integration in 2016 with full compliance with the RDRR requirements during the 2017 program year.

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[11] See, Methodology for calculating the cap is specified in D-10-06-034, attachment, A at p.9.

[12] See, CAISO Proxy Demand Resource (PDR) & Reliability Demand Resource (RDRR) Participation Overview.

b. BIP Program Modifications

For BIP to be feasible for the CAISO's RDRR, SDG&E proposes changing the customer event notification timeframe from its current program design of 30 minutes for advance customer notification to 20 minutes for customer notification because the CAISO requirement for RDRR calls for the Utility to reach full curtailment within a 40 minute response time. Meter timing, along with the 20 minutes customers will have to reduce their load, will give SDG&E a minimum of five minutes to dispatch the program when called by the CAISO. SDG&E reached out to existing BIP participants to obtain feedback on the potential reduction in customer notification from 30 minutes to 20 minutes. SDG&E received positive feedback from its high performers; however SDG&E is aware that reducing customer notification time may cause SDG&E to lose some existing customers that cannot shed load within 20 minutes.

c. Tariff Change Sought by SDG&E

SDG&E is proposing updates to the BIP Tariff pertaining to the customer's Firm Service Level (FSL) which affects non-complying participants as documented in Appendix D. The change is contained in SDG&E Schedule BIP, Sheet 2, Section Special Condition 3E of the tariff. This change to the current tariff is to describe more clearly when and how a customer's FSL can be modified. The benefit of these changes is so customers may have a better understanding of when their FSL was modified by SDG&E and to avoid potential penalties.

SDG&E is also proposing updates to the customer's Contract Requirement which affects the customer's termination effective date, as documented in Appendix D. Schedule BIP, Sheet 5, Section Special Condition 11 B of the tariff. This change is to create language consistency between the BIP Tariff, Notice by Third Party Marketer to Add or Delete Customer, and Notice to Add, Change or Terminate Third Party Marketer for Base Interruptible Program. The benefit of this change is to be consistent in communicating contract termination requirements.

SDG&E will also be updating Schedule BIP, Sheet 3, Section Special Condition 4. C and Sheet 5, Section Special Condition 9, as documented in Appendix D. Modifying the notification time from 30 minutes to 20 minutes to reflect the Program Modification request, as outlined above. Lastly, SDG&E is submitting minor clean-ups revisions to Schedule BIP, sheet 1 and to the Third Party Marketer Agreement for BIP, page 1 and 8.

d. Budget for the BIP Program

SDG&E's proposed 2017 Program Administration and Customer Incentive budget for the Base Interruptible Program (BIP) is $942,870. The 2017 budget is considerably lower than the 2016 authorized budget due to low customer participation resulting in a decrease in the customer incentive budget. SDG&E will be decreasing the BIP budget by $645,144 in response to the 2017 Final Guidance provided by the Commission[13]. This budget is expected to be sufficient to cover current program costs and allow for potential growth in participation in 2017.

Table 3 – BIP Budget		
Program Name	**2016 Budget**	**Total 2017 Budget**
Base Interruptible Program	$1,588,014	$942,870

3. Summer Saver Program

The Summer Saver Program is an Air Conditioner (AC) Cycling program that utilizes one-way Direct Load Control switches to obtain predictable load reduction from Residential and Small Medium Business (SMB) customers when a Demand Response event is dispatched. The air conditioner unit is cycled based on the customer's elected cycling option. The program was

[13] *See*, CPUC Guidance 2017,at p.10.

implemented pursuant to D.04-06-011.[14] The decision authorized SDG&E to enter into a long term Electric Resource contract with Comverge as a result of our Grid Reliability Request for Proposal component of SDG&E's Long Term Resource Plan (LTRP). The Summer Saver contract has been amended several times to implement program modifications agreed to by both parties. [15] The current Summer Saver Program contract will expire on October 31, 2016. SDG&E is requesting a total budget of $2,534,408 to fund its Summer Saver Program in 2017, a decrease of $2,184,482 compared to the actual spend in 2015. SDG&E plans to enter into a new contract with Comverge to provide similar services and anticipates filing an advice letter for contract approval by Q3 of 2016.

Beginning in 2017, SDG&E proposes to introduce a redesigned Summer Saver program as part of the Demand Response portfolio that will be available to all existing Summer Saver customers. The incorporation of the Summer Saver program complies with the Guidance Ruling's directive to begin to address DR programs within the same proceeding if possible. Continuing the Summer Saver program in the DR portfolio will also preserve the remaining value of current direct load control technology already in place which provides current AC load reduction of 15.4 MW. However, the long term plan for the Summer Saver program is to gradually transition away from one-way pager device technology to newer technologies as these devices reach their end of life cycle.

a. Summer Saver CAISO Integration Feasibility

It is feasible to design the Summer Saver Program (SSP) to meet the CAISO Wholesale Market guidelines for designing and bidding the program into the CAISO Wholesale Market as a

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[14] *See*, D. 04-06-011, p.37.

[15] *See*, SDG&E Advice Letters, 1639-E, dated November 18, 2004, 1871-E, dated February 7, 2007, and 1871-E-A dated April 26, 2007.

supply resource in its entirety, provided the CAISO fulfills its commitments made in the Supply Resource Demand Response Integration Working Group Compliance Report dated June 30, 2015, Issue Area 1: CAISO's Demand Response Registration System and Issue Area 3: The need for additional baseline methodologies for measurement and settlement. In addition, SDG&E will need to put IT systems in place that can communicate with the upgraded CAISO registration system.[16] The transition timeline for Summer Saver to become a supply side resource is summarized in the table below.

Table 4 - Summer Saver Program Integration Timeline Plan

2016	2017	2018 and Beyond
February 1 - Proposal for New Program Design and Budget. October 31 - Existing Summer Saver Program (SSP) Vendor Contract Expires	Transition - a subset of existing Summer Saver Small Medium Business (SMB) Customers who are not participating on a Dynamic Pricing rate with an event component	Remaining SSP participants who are not participating on a Dynamic Pricing rate with an event component

For 2017, SDG&E's initial strategy is to bid in a subset of the Small / Medium Business customers who are already enrolled in the Summer Saver Program and are not currently participating on a dynamic pricing rate with an event component. This will allow SDG&E to become familiar with the operational processes and requirements for a newly designed program that will be bid into the CAISO Wholesale Market, and will also minimize the hurdles we may face associated with the registration process. The transition will provide SDG&E the opportunity to gain experience with the CAISO Day of Wholesale Market for this particular program.

CAISO market integration barriers have been identified in 2017, as follows:

[16] *See*, Supply Resource Demand Response Integration Working Group Compliance Report, June 30, 2015

- CAISO PDR day-ahead Baseline

The Summer Saver Program consists of residential and small business customers, therefore, the CAISO settlement methods must be accurate for these customer classes in order to estimate accurate load reduction for the program. Several studies of large and medium commercial customers have shown that the 10 of 10 adjusted baseline used by the CAISO for PDR is one of the most accurate baseline options for these customer groups. However, the same does not hold for residential customers The appendix to the Freeman Sullivan 2012 San Diego Gas & Electric Peak Time Rebate Baseline Evaluation report shows that a 10 of 10 baseline with a same day adjustment similar to the baseline the CAISO uses for day-ahead PDR underestimates SDG&E Residential customer consumption by 25% on average.[17] An average error of 25% in a baseline will result in a load reduction estimate of zero when customers reduce their consumption by 25% like summer saver customers do. Therefore this baseline error is likely to result in a significant underestimation of the load reduction from the residential customers on the summer saver program. In addition, this baseline has not yet been studied for small business customers so it is not known at this time whether the load reduction from the small commercial customers on the Summer Saver program will be accurately estimated by the CAISO settlement methods.

- CAISO Demand Response Registration System (DRRS)

DRRS is the automated customer registration for customer enrollment into the CAISO and will be dependent on the CAISO's ability to fulfill its commitments made in the Supply Resource Demand Response Integration Working Group Compliance Report dated June 30,

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[17] *See*, 2012 SDG&E Peak Time Rebate Baseline Evaluation Report, April 2013.

2015. In addition, SDG&E will need to deliver system integration that can communicate with the upgraded CAISO registration system.

- Meter Data granularity

SDG&E's 15 minute interval meter data is not available for all Residential customers. This does not prevent SDG&E from bidding into the PDR Day Ahead market, but does present a problem for the real time PDR market and RDRR.

- Temperature Sensitive Load Reduction

The Summer Saver program reduces load by curtailing customers' air-conditioners. If temperatures are cool and air-conditioners are not running they cannot be curtailed. Therefore the performance of the Summer Saver program varies significantly with temperature. Currently, the Summer Saver program has a system load trigger so program events nearly always occur when air-conditioning load is present however, once the Summer Saver program switches to a price trigger events may occur when air-conditioning load is not present.

The current RA process uses the average load impact from 1pm-6pm for each month based on 1-in-2 monthly peak temperatures. However, by definition temperatures on most days of the month are expected to be lower than the temperature on the monthly peak day therefore less load reduction than counted for the RA process is available from the program outside of the monthly peak days.

- Lack of clarity regarding dual participation

The number of business customers enrolled in both Summer Saver and a dynamic pricing rate with an event component such as CPP-D and TOU-A-P is expected to greatly increase when SDG&E defaults its SMB customers to dynamic pricing rates in the first quarter of 2016. If a day-ahead dynamic pricing rate event is called the dual participating customer should not be bid into the CAISO wholesale market. However, not bidding these customers into the CAISO wholesale market might violate the must offer requirement for Summer Saver as supply resource. Due to the lack of direction on this issue, SDG&E does not plan to bid any of the dual participants into the CAISO wholesale market in 2017.

b. Proposed Summer Saver Design

The proposed Summer Saver Program design for the CAISO Wholesale Market as a Proxy Demand Response Supply Resource and existing Summer Saver program design characteristics is shown below.

Table 5 - Summer Saver Program Design Comparison for Current and Proposed Program

Program Characteristics	Current Summer Saver Design	Proposed Design for integration as Proxy Demand Response (PDR)
Customer notification requirement	None	None
Annual Maximum number of events hours	15 events/60 hours	80 hours
Trigger	3800 MW System Load May – October	July, August, September Heat Rate – 19,000 Btu/kWh May, June, October – imminent statewide or local emergencies, extreme conditions and local distribution needs
Maximum Consecutive Events	Three	Three
Hours available	Noon to 8 pm	Noon to 9 pm
Event Duration	2 – 4 hours	1 to 4.5 hours

The proposed changes to the Summer Saver Program will enable SDG&E to comply with the CAISO Wholesale Market guidelines established for Supply Resources. SDG&E has proposed maximum available hours per month of 24 and 3 consecutive events to comply with the established Resource Adequacy (RA) requirements. SDG&E's proposed annual increase in price responsive event hours from 60 to 80 will enable SDG&E to meet the 24 hour availability requirement for 3 months.[18] Once the Summer Saver Program is a fully integrated supply resource program SDG&E is planning not to claim RA credit or bid the Summer Saver program into the CAISO Wholesale Market in May, June and October because the Summer Saver program may not be able to perform reliably in these cooler months on days other than the monthly peak day. Keeping the program available in May, June, and October will allow the program to be called in emergency situations. SDG&E plans to bid the Summer Saver Program into the CAISO Wholesale market as a PDR, however SDG&E is proposing to lower the minimum event length from 2 hours to 1 hour as is required by RDRR in order to keep this option open. SDG&E is also proposing to increase the maximum event length from 4 hours to 4.5 to give it the flexibility to ramp the resource up and down before and after events.

c. Price Responsive Trigger for Summer Saver

In 2017 a portion of Summer Saver participants who are not dual participants, i.e., participating on a Demand Response program and a Dynamic Pricing rate such as CPP-D or TOU-P will be bid into the CAISO Wholesale Market and the remaining customers will be dispatched when a market award is received. However, it is still necessary to create a trigger for the program to inform the bidding price.

[18] *See*, 2016 Resource Adequacy Handbook.

SDG&E's proposed price trigger for the new Summer Saver program is designed to result in an average number of event hours equal to 50% of the RA availability requirement. While the resource adequacy proceeding requires demand response resources to be available for 24 hours of dispatch it does not require 24 hours of event to be actually called every month. In fact, the RA proceeding requires supply side demand response resources to actually call only one annual test event and places no maximum on the price that the demand response provider can bid.

Demand response programs should be called often enough to demonstrate that they are capable of providing a reliable load reduction. However, calling 100% of the RA availability requirement every month is unnecessary to establish the capability of the resource. In addition to being unnecessary, requiring the utilities to call programs up to the full availability requirement every month would put the utility supply side programs at a large disadvantage versus aggregator managed supply side resources like DRAM in which the aggregator can choose their own bidding price. Designing the trigger to call 50% of the RA requirement on average is a reasonable compromise between calling the maximum number of events every month and only calling one annual test event. The actual number of events called per month will vary depending on conditions and may be lower or higher than 50% of the RA requirement and at times may reach the maximum number of events.

SDG&E plans to bid the Summer Saver Program into the CAISO Wholesale Market for three months for a total of 72 hours of RA required availability so the trigger is designed to result in 36 event hours on average. SDG&E ran an analysis using data from 2013-2015 to determine what heat rate would result in 36 hours of events between July and September for each year. Results from each year were averaged and resulted in a heat rate of 18,780. SDG&E has rounded the heat rate trigger up to 19,000 due to expectations that future energy market conditions will be more volatile due to the increase in renewables. In addition, SDG&E may call events in the case of imminent statewide or local emergencies, extreme conditions, and local distribution needs in May, June, and October. The heat rate trigger does not apply to these months.

d. Summer Saver Customer Incentive Levels

SDG&E is proposing to reduce Summer Saver's commercial customer incentives by 50% for two reasons. First, the vast majority of commercial customers are expected to be enrolled on a dynamic pricing rate by 2017[19] and will avoid paying the higher price for the curtailed energy when dynamic pricing rate events are called on the same day as Summer Saver events in addition to receiving a Summer Saver incentive so a lower incentive is warranted. Although the Summer Saver Program provides some additional availability above and beyond the dynamic pricing rate, it does not provide a second load reduction so the magnitude of the payment should only reflect the value for additional availability. Secondly, reducing the incentives improves the cost effectiveness of the program.

In response to the PY2013 Opinion Dynamics AC Cycling Programs Process Evaluation – Integrated Report, SDG&E reduced the incentive level for the residential 100% cycling customers by 20% in 2015 and experienced little customer fatigue. SDG&E is proposing to further lower overall residential incentives in 2017 by 10%. In addition, Table 4 below includes results from the Summer Saver Load Impact Evaluation Report [20] and shows that the 1st quintile (lowest 20%) of residential customers provides smaller average load impacts per premise than

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19 According to the PG&E time-varying pricing quarterly update from December 17th 2015 SMB customers have a low CPP opt-out rate of approximately 5%.

20 *See*, 2014 Summer Saver Load Impact Evaluation Report, April 1st 1, 2015, Table 4-3.

other customers. In light of these results, SDG&E is proposing to dis-enroll the lowest 15%-30% [21] of residential customers from the program. Since the disenrollment is not expected to result in the loss of significant load reduction this change is likely to increase the benefit to cost ratio of the program.

Table 6 - Summer Saver Load Impacts

Quintile	50% Cycling		100% Cycling	
	Average* Per Premise Load Impact (kW)	Load Impact Standard Error (kW)	Average* Per Premise Load Impact (kW)	Load Impact Standard Error (kW)
1	0.05	0.08	0.07	0.06
2	0.07	0.09	0.29	0.06
3	0.31	0.12	0.51	0.09
4	0.49	0.15	0.72	0.13
5	1.21	0.21	1.30	0.17

*Reflects the average 2-6 PM 2014 Summer Saver event

The TRC for the summer saver program after taking account these incentive changes is 0.82. To mitigate the risk of losing additional customers and demand response from this program, SDG&E is not proposing to make any additional changes. SDG&E will work to improve the TRC for this program in the 2018-2020 DR Application and asks that the Commission approve the Summer Saver Program with these changes with a TRC value of .82.

[21] SDG&E is planning to dis-enroll 20% of participants however adjustments may be needed since the actual 2017 enrollments are not known.

e. Summer Saver Program Budget

SDG&E's proposed budget for the Summer Saver Program (SSP) is approximately $2.5 million in 2017. This is a decrease of approximately $2,184,482 compared to actual spend in 2015.[22] This decrease is due to the new program structure and planned changes to the contract.

Table 7 – Summer Saver Budget		
Program Name	**2015 Actual Spend**	**Total 2017 Budget**
Summer Saver Program	$4,718,890	$2,534,408

The proposed 2017 budget will allow SDG&E to continue with the proposed program modifications and retain most of the Summer Saver program's customer participation. SDG&E's load impact analysis estimates a load reduction potential of 15MW for all customers enrolled in the Summer Saver Program, however, as referenced above only a subset of our SMB customers will be transitioned to the CAISO Wholesale Market to bid and dispatch in 2017.A new exemplary tariff for Summer Saver is included in Appendix C.

B. Programs with Modifications for Overall Program Improvements

1. Technology Incentives Program

The Technology Incentives Program gives business customers financial incentives to install controls and equipment that allow or enhance their ability to participate in Demand Response programs offered by SDG&E. Automated DR (Auto DR or ADR) refers to automated

[22] Note that Summer Saver costs were historically requested and recovered in the GRC and not in SDG&E's previous DR filings. Thus there is no authorized 2016 Summer Saver budget in the DR portfolio for comparison.

technologies that allow a customer's equipment or facilities to reduce demand automatically in response to a DR event or price signal, without the customer taking individual action.

SDG&E will continue with its Statewide collaboration and program workshops with key stakeholders to further discuss the state of the program and to create a strategic roadmap for future program design and will continue to offer educational materials designed to help develop a solid understanding of the TI/ADR program benefits and with an increased focus on outreach efforts on lighting projects. 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. SDG&E is requesting public workshops in 2016 to allow the statewide IOUs and interested third parties to work together towards a consistent statewide TI/ADR program for 2018 and beyond; to be filed in the IOU's respective 2018 DR budget applications in late 2016.

In addition, the TI program anticipates that up to 500 KW of TI funds, including admin will be allocated to SDG&E's proposed Armed Forces Pilot, which is described in Section D below. The Navy has expressed interest in pursuing TI funding as a way to increase their DR capability.

a. Technology Incentive Program and CAISO Integration Feasibility

The Technology Incentive Program is technology *enabling* program and cannot be integrated alone into the CAISO as a supply side resource. Customers who participate in this program are asked to also participate in an eligible Demand Response program for a period of 36 months. Prior to 2015, the eligible Demand Response programs were only limited to CPP-D, CBP, BIP or a SDG&E eligible pilot. The Demand Response Auction Mechanism (DRAM) resolution in 2015 (citation needed) expanded the eligible list to include DRAM participation.

Because the Technology Incentive program is an enabling technology program, it cannot be analyzed for market integration feasibility. The Technology Incentives program acts as a "gateway" to, or an optimizer of, Demand Response programs. However, the Technology Incentives program only provides incentives when customers install Automated Load Shed technologies capable of communicating on an Open ADR platform. These technologies help the customers achieve load shed with limited human intervention, potentially allowing for fast acting Demand Response making them a good candidate to choose a Demand Response program that further integrates into the wholesale market.

b. Modifications to the TI Program

The commission ordered the utilities to work towards a statewide consistent program by 2018. (Citation needed). In order to achieve that goal, SDG&E is recommending the Commission to order the Utilities and other interested parties to hold a series of workshops in 2016 and work collectively to redesign the program and file the requested changes in November 2016 for Demand Response application for 2018 and beyond. The California Statewide Automated Demand Response Program Process Evaluation (CALMAC Study ID SDG0277.01) found that '[…] vendors identified three key areas of concern: 1) impact on customer participation, 2) impact on financing from lending institution, and 3) impact on smaller vendor participation."[23]

In order to move towards statewide consistency, SDG&E proposes to put an incentive cap of 50% of the total eligible project cost on this program. This change may cause behavior change in customers, pushing them to maximize their load shed for Demand Response events in order to maximize program/rate benefit to offset their investment in technology. Changes to the

[23] *See*, http://www.calmac.org/publications/Statewide_2012_Auto-DR_Program_Process_Evaluation_3-21-2014_Final.pdf.

IT system supporting the Technology Incentive program will be required in order to process the payments at the new 50% payment structure. The costs associated with the system upgrade are captured as part of the requested IT budget.

c. Budget for the TI Program

SDG&E requests $2,959,809 for the TI program for 2017. This reflects a decrease compared to the authorized budget for 2016, as SDG&E is making efforts to more closely align budget requests with projected program participation in 2017.

Table 8 – TI Program Budget

Program Name	2016 Budget	Proposed 2017 Budget
Technology Incentives Program	$3,196,290	$2,959,809

2. Small Commercial Technology Deployment Program

Small Customer Technology Deployment (SCTD) Program is another *enabling* program that implements ADR enabling technologies to residential and small commercial customers. SCTD gives participants and the utility the ability to manage end use electric loads year round through the use of enabling technology. These installed technologies empower customers to improve DR participation and manage energy usage.

By 2018, SDG&E anticipates having customers with SCTD enabling technologies to either be participating in either dynamic or TOU rates or DR programs. SDG&E's intent is to continue offering enabling technology to all customers, including Direct Access (DA) and Community Choice Aggregators (CCAs). Pursuant to D.12-04-045 (Bridge Funding 2015-2016

Decision)[24], SCTD was also expanded to include small commercial customers and to investigate moving from no cost to a customer cost-sharing approach. Based on preliminary discussions and collaboration with other utilities, vendors, and as technology allows, SCTD will be offering a cost-sharing approach to allow for an increase in cost-effectiveness with further market transformation. SDG&E is requesting a total budget of $1,430,377 to fund its Small Customer Technology program in 2017, a decrease of $1,724,346 when compared to the authorized SCTD budget for 2016. The reduction in 2017 funding is due to a significant decrease in incentives as SCTD transitions to a customer cost-sharing approach, thereby reducing the up-front equipment and installation costs covered by SDG&E.

a. SCTD and CAISO Integration Feasibility

Under the guidance to review all DR programs for CAISO integration feasibility, SCTD is not feasible because SCTD is an approved enabling technology deployment program and is not a DR resource program or rate. SCTD supports resource programs by offering technology solutions for deeper savings. Similar to SDG&E's Technology Incentive program, SCTD is merely a technology gateway program encouraging customers to participate in demand response and to optimize dynamic pricing and time of use rates.

SCTD will continue to be an enabling technology program in support of the current rates as well as future rates and programs that may be developed.

b. SCTD Modifications

SDG&E is requesting modifications to SCTD for 2017 to make the offering a better fit for current and future needs to include DR rates and DR program support with enabling technology. The recommendations for modifications are the following:

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[24] *See*, D.12-04-045, at p. 32, Table 4.

1. Similar to TI technology gateway program, SCTD will encourage participation in a dynamic pricing or time of use rates, or demand response program upon enrollment in exchange for a no-cost or subsidized technology.
2. Direct Access (DA) and Community Choice Aggregation (CCA) customers are not currently eligible for demand response rates such as PTR, CPP-D, or TOU plus. SDG&E proposes that SCTD support the proposed 2017 Summer Saver program and programmable communicating thermostat pilot, which will be available to DA/CCA customers.

These proposed program modifications proposed for the SCTD program do not affect the inputs to the cost-effectiveness calculations; however cost-effectiveness results for SCTD are included in section V

c. SCTD Program Budget

The SCTD program requested budget for 2017 is shown below. SDG&E reduced its proposed budget for 2017 after a thorough review of prior years' budgets where it was determined that actual spend was lower than the authorized budget throughout the program. As directed by the Guidance Ruling, SDG&E is requesting less funding for 2017 while ensuring these reductions are not harmful to the program or customers served.

Table 9 – SCTD Budget

Program Name	2016 Budget	Proposed 2017 Budget
Small Commercial Technology Deployment	$3,154,722	$1,430,377

C. Programs without Modifications for 2017

1. Permanent Load Shifting Program

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.[25]

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. Advice Letter 2489-E was approved with modification by commission

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[25] See, https://www.ethree.com/documents/SCEPLS/PLS%20Report_ Executive%20Summary.pdf.

on September 5, 2013.[26] PLS was continued without modification, for the bridge years 2015-2016.

PLS provides incentives for customers to permanently shift their cooling load from on-peak to off peak hours. Currently, the only eligible technology allowed under this program is Thermal Energy Storage (TES). Currently, customers may receive an incentive of $875 / kW of permanently shifted load outside of the 7 hour on peak period.

a. PLS and CAISO Integration Feasibility

The goal of the PLS program in SDG&E's territory is to permanently lower demand during SDG&E peak hours. Program participants receive a one-time incentive to shift their cooling load to off peak hours using Thermal Energy Storage Systems. CAISO market participation in a PDR or RDRR products require a Demand Response resource to respond to an economic or reliability market dispatch.[27] SDG&E's PLS program is statewide consistent, and is not a dispatchable program thus not fit for CIASO market integration.

b. Modifications to the PLS Program

Because PLS is a statewide program, SDG&E is not seeking unilateral modifications to the program for 2017. However, SDG&E strongly believes that there is a need to revisit the program design and reevaluate the incentive level based on the value of the PLS program to ratepayers and utilities.

Additionally, SDG&E would propose an examination of dispatchable TES as part of this program. Dispatchable load can then be considered for market integration as a Supply Side

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[26]See, http://regarchive.sdge.com/tm2/pdf/2489-E.pdf.

[27]See, https://www.caiso.com/Documents/PDR_RDRRParticipationOverviewPresentation.pdf, at p. 2.

resource in the future. The program design needs to be revisited, if this program continues beyond 2017.

For the purposes stated above, SDG&E is requesting that the commission order utilities and interested parties to form a working group in order to file new program proposals for 2018 and beyond. These changes can be filed with the Demand Response application in late 2016.

c. PLS Cost Effectiveness

D.12-04-045 considered PLS to be different from other DR programs because PLS shifts energy usage on a permanent basis instead of merely decreasing energy usage during certain times. SDG&E's PLS program proposal in Advice Letter 2445-E showed a TRC of 0.82 at an incentive level of $475/kW. Subsequently, CPUC Staff disposition of SDG&E's Advice Letter 2489-E approved SDG&E's proposal with modification. The modification changed SDG&E's incentive level to a statewide consistent level of $875/kW. SDG&E proposes to continue PLS in 2017 without any modification thus eliminating the need for cost effectiveness analysis.

d. PLS Budget Request

PLS projects are large undertakings by the customer that can take months to complete. For example, SDG&E has approved projects that have been under construction for almost a year. Because of this reason, SDG&E did not actually spend any of the authorized incentive budgets in the 2012-14 cycle. SDG&E plans to distribute incentives to approved, ongoing projects using 2015-16 approved funds, in addition to the fund shift approved by Advice 2801-E.[28]

SDG&E will not accept any new applications for 2017 cycle until January 1, 2017. Furthermore, because of SDG&E cost recovery mechanism, it will only approve and pay

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28 *See*, http://regarchive.sdge.com/tm2/pdf/2801-E.pdf.

for projects that are at least substantially completed by December 31, 2017. This allows SDG&E and customers 12 months to complete a PLS project. SDG&E cautions that the short length of the bridge timeline may be a barrier to program participation for large projects in 2017. It is possible that this may lead to PLS being underspent in 2017 year, with those projects extending into 2018. SDG&E is requesting more funding in 2017 than previous years. SDG&E hopes the higher request will eliminate the need for any subsequent find shift advice letters in 2017.

Table 10 – PLS Budget		
Program Name	**2016 Budget**	**Proposed 2017 Budget**
Permanent Load Shifting	$1,000,000	$1,613,298

2. Emerging Technology – Demand Response Program

The Demand Response-Emerging Technology (DR-ET) program will proceed in 2017 with the same direction as the 2015-2016 PIP. 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; and,
- Recommendation about the utility's further support and involvement.

The DR-ET 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. The ET Program is requesting a budget of $722,961.02 for 2017. This budget is $17,435.02 more than the 2016 approved budget. The difference in the requested budget is due to general budget escalation.

Table 11 – DR-ET Budget

Program Name	**2016 Budget**	**Proposed 2017 Budget**
Emerging Technology Demand Response	$705,526.00	$722,961.02

3. Local Marketing Education & Outreach

SDG&E's 2017 Local Marketing, Education and Outreach (LMEO) efforts will continue to focus on generating awareness and enrollment in demand response programs, related offerings, dynamic rates, and ongoing education to existing participating customers around various program-specific changes.

LMEO will also continue to enhance and leverage the overarching education being conducted as part of the ongoing statewide marketing, education and outreach (SWMEO) campaign. SWMEO efforts help to support broad education for SDG&E customers on demand response and dynamic rate opportunities that are available within our service territory, and encourage participation in demand response events, which predominantly occur at the local level.

a. LMEO Initiatives

2017 LMEO includes support for new initiatives and programs as well as changes to continuing programs. Programs slated for 2017 LMEO support include: Peak Time Rebates (also known as Reduce Your Use Rewards, or "RYUR"), Small Customer Technology Deployment (also known as Reduce Your Use Thermostat, or "RYUT"), Permanent Load Shifting (PLS), Technology Incentives (TI), Summer Saver, Base Interruptible Program (BIP), Critical Peak Pricing (CPP-D) and various Smart Pricing (SPP) dynamic rates.

RYUR will require revised marketing and outreach materials to communicate program changes until the program is ultimately phased out at the end of 2018 when customers move to TOU rates. Based on previous deployment experience, RYUT will require ongoing support as an enabling technology and a gateway to demand response participation. Similarly, SDG&E is going to build from the previous program cycle to continue to offer TI education and increase understanding of program benefits and adoption. Summer Saver communications will focus on transitioning existing customers to other direct load technologies, including two-way switches and the "Bring Your Own Device" (BYOD) model and describe changes to event hours and incentive amounts, as appropriate. PLS will require minimal LMEO funding to produce and/or revise existing marketing and outreach materials. BIP is using limited funds for specific target marketing to increase participation in that program.

With regard to CPP-D and SPP, ongoing education and support will be given to mid-size (20-200 KW) commercial customers that were transitioned to the CPP-D rate in 2015/2016. Similarly, as we approach residential TOU default in 2019, integrated marketing, education and outreach efforts will be necessary to promote SPP (TOU+) rates through various channels, including: mass and direct marketing, community based organizations, chambers of commerce, in-language communications to hard-to-reach customer segments, and more.

b. LMEO Budget

The total budget request for the 2017 LMEO program cycle is $885,000. This is a decrease of $1,340,000 from 2016. The reduction is mainly a result of a change in the way certain programs are going to be implemented, as previously defined in Section III, and the expectation that the funding needed for TOU+ will start at a more modest level during the pilot period and grow as we get closer to TOU default in 2019. SDG&E submits individual line items for each program to fall within the LMEO program as follows:

Table 12 – LMEO Budget		
Program Name	**2016 Budget**	**2017 Budget**
Reduce Your Use Rewards (RYUR)	$250,000	$50,000
Reduce Your Use Thermostat (RYUT)	$400,000	$150,000
Permanent Load Shifting	$25,000	$0
Technology Incentives	$50,000	$60,000

Summer Saver	$0	$25,000
CPP-D	$500,000	$400,000
Smart Pricing (TOU+)	$1,000,000	$200,000
TOTAL	**$2,225,000**	**$885,000**

In 2017, marketing, education and outreach will continue to engage customers around the need for demand response and event participation. New and existing customers will need to be informed as the various program criteria evolves and shifts. Due to the cyclical and often localized nature of demand response events, this ongoing engagement through integrated LMEO strategies is crucial to overall program participation and performance.

4. 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 2016 for 2017, with increases only for inflation. The budget for 2017 is $837,624.

Table 13 – DR Policy and Support Budget		
Program Name	**2016 Budget**	**Proposed 2017 Budget**
DR Policy and Support	$786,000	$837,624

5. Information Technology Infrastructure Activities

SDG&E's request for 2017 Information Technology (IT) Infrastructure activities is $2,306,766 compared to the approved 2015-2016 Demand Response IT budget of $1,769,440. SDG&E's 2017 Information Technology Infrastructure activities will entail providing on-going IT systems infrastructure maintenance and service. The increase in proposed budget from 2015-2016 to 2017 is project driven, and specifically driven by projects intended to facilitate SDG&E's integration into the CAISO market separate from Rule 32, development and implementation changes in Demand Response Management System (DRMS), Customer Relationship Management (CRM) System and Enterprise Notification System (ENS) applications in support of Demand Response programs. These systems perform and assist with multiple capabilities such as program management, dispatching events, settlement calculations, reporting and event performance presentment. These capabilities become increasingly important as SDG&E moves towards full bifurcation in 2018.

Middleware infrastructure is needed to support CAISO integration with SDG&E's CISCO and DRMS systems to CAISO. This effort will support multiple system interfaces: Real-time system one-way & bi-directional interfaces; accommodate varying file formats/standards/maintenance schedules; exception handling mechanisms.

Middleware infrastructure is needed to support Small Commercial Technology Deployment Program to integrate with SDG&E's DRMS system to Entryway. This effort will support multiple system interfaces: Real-time system one-way & bi-directional interfaces; accommodate varying file formats/standards/maintenance schedules; device program management, event dispatch and customer notification, and event performance.

Hardware infrastructure is needed to support Technology Incentive Program and implementation changes to CRM. This includes additional incentive control mechanism to assist with payments to vendors or customers.

In addition, SDG&E will continue on-going software licensing to support program management and customer facing tools. These software applications support program management, data presentment, signaling devices and analytics.

Table 14 - IT Infrastructure Activities Budget	
Description	**Cost**
CAISO Integration – Separate from Rule 32	**$578,000**
On-going system support and program enhancements - Hardware infrastructure to support Technology Incentive Program - Middleware infrastructure to support Small Commercial Technology Deployment Program	**$857,394**
Software licensing fees	**$866,372**
Misc: (Travel, etc.)	**$5,000**
Total Cost:	**$2,306,766**

6. Measurement and Evaluation - EM&V

The measurement and evaluation budget approved in 2016 and proposed for 2017 is below.

Table 15 – EM&V Budget		
	2016 Budget	**Proposed 2017 Budget**
Utility Managed	$1,526,525	$1,526,525

Evaluations		
Energy Division Managed Evaluations	$200,000	$200,000

The measurement and evaluation budget includes the costs for measurement and evaluation of demand response programs by independent consultants as well as the costs for producing interim load impact results to the CPUC and the CAISO. More specifically, the budget includes the costs of hiring a third party consultant to conduct a load impact evaluation for each demand response program and dynamic rate as required by D.08-04-050 and also includes the costs for process evaluations which are conducted periodically in order to improve the performance of the programs. SDG&E is also required to provide a daily forecast and estimated load impacts within 7 days of the event to the CPUC and the CAISO and the labor and software costs needed to perform these activities is included in the measurement and evaluation budget. SDG&E recommends keeping the same measurement and evaluation budget for 2017 that was previously approved for 2016.

D. SDG&E Pilots

1. SDG&E Proposes an Over Generation Pilot

On September 15, 2015, in R. 13-09-011, the Commission issued its Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for 2017 Demand Response Programs and Activities Proposal. In addition to the Commission's guidance on general program modifications and improvements, the ruling also encouraged the IOUs to propose pilots in this filing to address over generation resulting from renewable energy.

The ruling cited a utility-funded study that was done to investigate the issue of over generation further.[29] In 2014, Energy+Environmental Economics (E3) released its report on what the impacts of increased renewables would be over time in California. In it, E3 defined over generation as occurring "…when 'must-run' generation—non-dispatchable renewables, combined-heat-and-power (CHP), nuclear generation, run-of-river hydro and thermal generation that is needed for grid stability—is greater than loads plus exports."[30]As the penetration of renewables continues to grow, there is increasing concern about over generation and the study found that it is more likely to occur in daylight hours when solar is being generated at its highest rate, but when not as much energy is required, such as in "shoulder months" or those times when the demand on the grid is not as high as other times of the year. In those times, there will be increasingly more energy being generated than is usually being consumed. The study investigated five potential areas for mitigation. The areas included: conventional DR, advanced DR, greater coordination statewide among the parties which use and generate energy to create more balance, energy storage, and a 50% RPS standard with more diverse energy in the portfolio (so as to not be so heavily weighted towards solar).

In the Commission's guidance for this filing, the IOUs were furthermore reminded that, in D.14-05-025, the Commission authorized PG&E to perform an Excess Supply pilot which also is investigating the relationship between renewables and over-generation. That pilot being done by PG&E is ongoing, with results expected in late 2016. Therefore, the Commission's

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[29] *See*, R. 13-09-011, Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance For 2017 Demand Response Programs and Activities Proposal Filings, September 15, 2015, page 7.

[30] *See*, "Investigating a Higher Renewables Portfolio Standard in California", report by Energy + Environmental Economics, January 2015, page 10. The report was funded by the IOUs, SMUD, and LADWP in California.

guidance specifically encouraged the IOUs to develop pilots to address over generation that: 1) explore one or more of the 5 solutions offered in the 2014 study by E3, and 2) are not duplicative of PG&E's Excess Supply pilot.[31] SDG&E respectfully submits the following proposal which SDG&E believes is in line with the Commission's guidance and will provide real experience in the area of mitigating over generation in new ways.

The objective of SDG&E's proposed pilot is to determine whether distributed storage facilities can effectively and economically address two major concerns associated with renewable over-generation: (1) excessive export of distributed solar to the grid during non-peak periods; and (2) lack of flexible generation during demand response events.

SDG&E will install a utility-owned distributed storage unit at 10 different commercial customer facilities to effectively capture excess generation from existing customer-installed on-site solar. In an effort to test multiple scenarios, SDG&E will have full control of dispatching the stored energy for the duration of the pilot, and will do so in two distinct ways.

1. During the traditional demand response season (May through October) SDG&E will use the distributed storage at the customer's facilities to address the system peaks.
2. During non-DR months, SDG&E will charge each customer's storage unit to help mitigate the impact of over-generation or lower load conditions, which tends to occur early to mid-day, and will discharge the battery later in the day to potentially reduce the customer's daily peak loads. In this scenario, reducing the customer's daily peak should result in reduced demand charges.

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[31] See, GuidanceRuling, at p. 7.

However, the greatest customer benefit is estimated to be in the winter and spring months[32] when over-generation is expected to be the highest.

Finally, SDG&E will require the commercial customers selected for the pilot to enroll in the updated AL-TOU rate that reflects proposed updates to time-of-use periods pending Commission approval[33].Adding the revised AL-TOU rate to the over-generation pilot, in conjunction with facility demand charge management through the SDG&E installed distributed storage unit will allow us to study the overall financial impact to the customer. The hypothesis is that the customer will incur fewer costs annually resulting from better demand management and rates that more accurately represent our system peaks, as compared to the existing AL-TOU rate without demand management. SDG&E approach for this pilot has the flexibility to provide a dual benefit to both the customer and the grid.

SDG&E is requesting a budget of $696,956 to conduct its Over generation Pilot. The budget has been developed with an estimated 2.6 full time employees (FTE's) to reasonably launch and run the pilot effectively. The FTE titles included in the budget are Manager (.10), Program Advisor (.50), Program Specialist (.20), Account Executive (.30), and Business Analyst (1.5). The total FTE budget is $313,715.53 including salary, payroll taxes, and vacation and sick leave. The Direct Implementation (DI) portion of the budget makes up vast majority of the budget and consists of the following: Customer application, load profile analysis of consumption and generation, installation and commissioning of distributed storage units, and 1 year of bill protection. The DI budget for this pilot is $383,240 within the total requested $696,956.

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[32] *See*, Application 15-04-012,Prepared Direct Testimony of Robert B. Anderson Chapter 3 On Behalf of San Diego Gas & Electric Company.

[33] *See*, Application No. 15-04-012, Amended Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocation and Electric Rate Design.

2. Summer Saver Program Programmable Communicating Thermostat Pilot

In an effort to demonstrate its commitment to Demand Response and offer programs to all customers, SDG&E is proposing a Summer Saver/Programmable Communicating Thermostat (SSP/PCT) Pilot. The SSP/PCT Pilot program is proposed with the primary objective to provide DR program offerings to customer's with newly installed PCT enabling technology who are not currently participating on a Demand Response program or Dynamic Pricing rate with an event component. Currently, the Summer Saver program participants are only signaled through a Direct Load Control switch technology, with this Pilot SDG&E will offer new customers installing PCT enabling technology the opportunity to participate in the Summer Saver Program in its newly proposed design as a CAISO Wholesale Market Proxy Demand Response supply resource for transition in 2017. (Please reference Summer Saver Program proposal for details.)

The Pilot participation commitment will be for one year. Offering the Summer Saver Program to customers with newly installed PCTs may also help inform our strategy to transition the Summer Saver Program to newer technology as the existing switches reach their "end of life" cycle and as customers install PCTs. The implementation timeframe envisioned by SDG&E for its SSP/PTC pilot is outlined below.

Table 16 - SSP/PTC Pilot Implementation Timeline

2016	2017	2018 and Beyond
Q3 - Identify potential Pilot participants Engage and inform customers of the opportunity to participate in the SSP/PCT Pilot	Include the Pilot participants with a subset of existing Summer Saver Small Medium Business (SMB) Customers not participating on a Dynamic Pricing rate with an event component or Demand Response program in the bid into the CAISO Wholesale Market	Open the Summer Saver PCT Program to all customers with PCTs not participating on a Dynamic Pricing rate with an event component or Demand Response program

SDG&E will bid the load from the pilot participants into the CAISO Wholesale Market as a Proxy Demand Response supply resource along with the subset of Small Medium Business (SMB) customers identified for transition in 2017 and described in the proposal for the newly designed Summer Saver Program. DA pilot participants will only be bid into the CAISO Wholesale Market with the appropriate authorization from the customer's Energy Service Provider (ESP).SDG&E will cap program participation when authorized funding approaches its limit.

The pilot participants will be dispatched when SDG&E's bid for the Summer Saver program into the CAISO Wholesale Market has been awarded for dispatch. If the Summer Saver Proxy Demand Response program bid is not awarded, the Pilot program participations will not be dispatched.

The SSP/PCT pilot program participants PCT will be signaled for the SSP/PCT event and earn a customer incentive based on the tonnage of the customer's AC unit Nameplate Capacity of the End-Use Equipment and the customer elected cycling option already established in the Summer Saver Program .

a. Summer Saver/PCT Pilot Program Budget

The proposed budget for the Summer Saver/PCT Program is $150,000. This budget includes Program Administration costs for tasks that will entail manual processes as we await delivery of our Demand Response Management System (DRMS) to automate all Demand Response Program processes. Subcontractor services will provide SDG&E with reporting functionality to help inform the results of the Pilot. SDG&E's proposed budget also includes customer incentives of $25,000.

3. Demand Response Auction Mechanism Pilot

The Commission adopted the two-year DRAM pilot in Commission Decision (D.)14-12-024, "Resolving Several Phase Two Issues and Addressing the Motion for Adoption of Settlement Agreement on Phase Three Issues" (later revised to be the Joint Proposal of the Joint Sponsoring Parties). During the 2017 DRAM pilot, the Commission will gain more information on DR participation in CAISO markets, and also hopefully lead to reduced costs and complexities before complete bifurcation in 2018.

a. DRAM Background

In D.14-12-024, SCE, PG&E, and SDG&E (together, the IOUs) were ordered to file an Advice Letter for the Demand Response Auction Mechanism (DRAM), together with a standard contract. The DRAM pilot is intended to test: (1) the feasibility of procuring Demand Response Supply Resources for Resource Adequacy (RA) with third party direct participation in the CAISO markets through an auction mechanism; and (2) the ability of winning bidders to integrate their Demand Response (DR) Resources directly into the CAISO market. D.14-12-024 authorized the IOUs to participate collaboratively with interested stakeholders in the DRAM pilot design working group, whose activities were conducted at the express direction and under continuing supervision of the Commission. The DRAM working group included the IOUs, Ratepayer Advocates (ORA and TURN), DR providers, Energy Division Staff, and other interested stakeholders. On July 27, 2015, the Commission issued Resolution E-4728, which approved, with modifications, the overall design and Standard Contract for the 2016 DRAM with a budget of $1.0 million. The 2016 auction was successfully completed in late 2015, with contracts submitted to the Commission for approval.

In compliance with Ordering Paragraph 12 of Resolution E-4728, SDG&E filed Advice Letter (AL) 2796-E on October 9, 2015 for the 2017 DRAM pilot focused on including Local

RA and Flexible RA, aligning the DRAM pilot with the year-ahead RA process, incorporating changes to law or regulation that could impact the second year of the DRAM pilot, and addressing the inclusion of Reliability Demand Response Resources (RDRR). In addition, SDG&E recommended increasing the funding for the 2017 DRAM by 50 percent to cover a full calendar year of capacity payments (2016 DRAM was for June through December, while 2017 DRAM is for January through December), and covers the broader array of RA products (local and flexible capacity in addition to system).

b. Modifications to 2016 DRAM Pilot in 2017

Integration issues are central to the understanding the future role of DR in CAISO markets. A second year will provide more information for the Commission about the extent to which DR is viable as a supply-side resource. Several changes have been made in the 2017 DRAM compared to the 2016 DRAM to allow for more fully integrated DR products. The 2016 DRAM was restricted to providing a day-ahead product in the CAISO market for June through December, while the 2017 DRAM will accept products bidding into both day-ahead and day-of markets for the entire year of 2017. In addition, DRAM sellers can provide Reliability Demand Response Resources (RDRR) as well as the Proxy Demand Resource (PDR) (the only product allowed under the 2016 DRAM) in the 2017 DRAM.

The 2017 DRAM will also differ in that DRAM Sellers can provide a full array of types of capacity - System RA, Local RA, and Flexible RA – in the 2017 DRAM pilot. The three types of capacity can be bid for a single month or for all 12 months in contrast to the 2016 DRAM that only allowed bids for system capacity for June through December 2016.

c. Budget for the 2017 DRAM Pilot

Given the modifications to the program, and the fact that 2018 will be fast approaching, SDG&E proposed to expand the budget from the $1 million budget in 2016 to $1.5 million in

2017. Pursuant to the Resolution E-4754, issued January 28, 2016, SDG&E's 2017 DRAM costs are recoverable from its 2015-2016 budget authorized in D.14-05-025. No additional costs will be incurred as a result of this pilot.[34]Thus, SDG&E has already received authorization for the DRAM portion of its overall proposed 2017 DRP budget. The anticipated 2017 budget of $1.5 million, may be lower depending on available 2015-2016 funds to shift to DRAM and any DRAM 2 costs that are incurred prior to 2017.

SDG&E is hoping the 2017 DRAM will generate cost competitive bids for RA given the potential for greater aggregator earnings from day-of CAISO markets, potentially lower costs of CAISO market participation, and supply more valuable local and flexible capacity.

The bulk of the $1.5 million will go RA capacity payments to winning bidders in the 2017 DRAM. Administrative expenses include staff time to monitor contracts for compliance as far as demonstrated capacity, to monitor the residential registrations for winning residential bids, and to monitor the enabling technologies for those receiving a qualitative bonus.The administrative costs will also cover the costs of all reports to the CPUC regarding the capacity supply performance of the winning bidders. In addition, administrative expenses will cover payments to the scheduling coordinator for any audits, any contractor time in performing audits, and any payments to the Independent Evaluator in 2017. It is expected that these expenses will be less than ten percent of the total $1.5 million budget.

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[34] *See*, E-4754, OP 9: "*The IOUs' request to expend 2015-2016 bridge year funds in 2017 for purposes of funding the DRAM, is approved. SDG&E does not collect funds until they are spent. Thus, SDG&E is authorized to fund DRAM in 2017 in an amount equal to the utility's cost estimate of $1.5 million. SDG&E is authorized to allocate those funds from its 2015-2016 budget.*"

4. Armed Forces Demand Response Pilot

Per AL 2621-E and D.14 -05 -25 approving the sunset date for the Demand Bidding Program, SDG&E will not be renewing the Demand Bidding Program (DBP and DBP Navy) programs and their corresponding tariffs in 2017. The 2015-2016 Demand Bidding Program design does not meet the requirements for Supply side DR as defined by the CAISO for 2017, and are not specifically load-modifying. Therefore, Schedules DBP and DBP Navy will terminate at the end of 2016.

In 2017, SDG&E is proposing a pilot to test a modified program design specifically tailored for the Armed Forces. The proposed pilot is intended to address specific areas of concern voiced by our Armed Forces that have prevented participation in Auto-DR programs in the past and to satisfy the future requirements set forth by the Commission for Supply Side integration of programs in 2017 and beyond. The 2017 AF Pilot will focus primarily on the Department of the Navy. This will be the Navy's first attempt to participate in Day-Of Demand Response programs.

The Navy (Region Southwest) owns and operates approximately 3,000 facilities in SDG&E's territory that directly support the region's mission accomplishment and provides energy management expertise in areas such as housing, environmental, security, family services, port services, air services, quarters, supply, medical and logistical concerns for hundreds of thousands of active-duty, reserve and retired military members in the area.

The Navy has on several occasions expressed their willingness to work towards moving their Demand Response capabilities to comply with the CAISO's direction to become a supply side resource by 2018. It is SDG&E's desire that the successes derived from this trial will set the stage for 2018 program design. SDG&E expects that Navy's participation will grow as additional Auto DR Resources come on line. Once vetted, it is SDG&E's intent that this trial will also create a viable gateway program giving other branches of the Armed Forces the opportunity to participate in Demand Response in the future. Recent Approval of AL 2755-E (September 2015) authorized significant changes to the Demand Bidding Program for the Navy, but unfortunately the requested changes were approved too late into the 2015 DR season to demonstrate their impact and effectiveness on program design for 2017.

The Navy has expressed on several occasions that there are numerous challenges for them to overcome before being able to meet the new CAISO directives in 2017 and for 2018 and beyond. SDGE is sympathetic to the Navy's current limitations. Their limitations include some facility and technical challenges as well as the nature of their electric demand being often related to critical activities. This pilot is designed to help mitigate the challenges faced by the Navy.

The proposed program pilot addresses the concerns specific to the Navy and will be subject to CAISO approval because of meter data constraints (described below). The new program would be called the "Armed Forces Pilot" or AFP. SDG&E proposes that 2017 be an evaluation year to prove that new program design will be a solid basis for transitioning beyond the Navy's participation into a reliable supply side resource. The Results of this pilot will be shared amongst all of the IOUs and stakeholders impacted by the pilot (per D. 12-04-045, page 181ff) in the hopes that the learnings can be utilized by all of the statewide IOUs.

a. Working With The Navy Towards Supply Side Resources and CAISO Integration Feasibility

As little as five years ago the Navy lacked the ability to participate in Demand Response. The Navy had a "Mission Critical" focus to support the war effort. Since then, the Navy has made great strides in its DR despite not having guidance documents from the Department of Defense (DOD) for DR. Recently, Demand Response was deemed not to violate the Antideficiency Act, and therefore the exposure to risk by the Navy as a result of participation in Demand Response is now legal.

Several meetings have been held with the Navy to assess current and future capabilities for participation as a Day- Of supply side resource for Demand Response. The Navy has expressed their desire to move towards becoming a supply side resource but has cautioned SDG&E about their readiness for 2017 and beyond.

Currently there are thirty (30) naval facilities/buildings that have working Auto-DR that show potential for participation in 2017 as a supply side resource. These buildings have been identified and will be included in the 2017 program pilot. The data used by this program will be captured by customer owned meters. The CAISO has stated that the utilities "certify that the data coming off the meters is accurate and follows industry standard processes for validating, editing and estimation". SDGE will ensure that the customer data will be vetted for accuracy before inclusion in any settlements or program evaluations.

The Navy is a Direct Access (DA) customer and is eligible to participate in an eligible Demand Response program. Since this rule will be maintained in the tariff, the Navy will continue to be eligible for Demand Response programs under the modified AFP.

The Navy has identified approximately 300+ buildings that have been targeted for retrofit/upgraded with Auto-DR measures over the next 3-5 years. These new sites will all have the potential to be transitioned into the 2018 program as the resources become available.

The Navy has also expressed the potential to work with third party aggregators in the future assuming the various obstacles identified can be overcome to allow meaningful participation. SDG&E's Technology Incentives (TI) program, which helps offset the installation and equipment costs of fully automated Demand Response measures, might be a potential resource for the Navy to assist them in their transition to fully automated DR

The AF Pilot is modest in scope to mitigate risk while testing the feasibility of Navy participation. It is possible that any successes derived from the 2017 program may lead to a growth in the program in 2018. If successful, the program design may be used as a template by which other branches of the Armed Forces and their respective facilities could begin to participate in Demand Response. Future Demand Response opportunities are currently being evaluated by SDG&E with other branches of the Armed Forces. The Pilot's success will be measured by how successfully the available resources can be integrated into becoming a supply side resource.

SDG&E proposes in 2017 to include the 30 plus Auto-DR sites as part of the proposed AF Pilot. The proposed pilot will allow the Navy in 2017 the ability to participate in a supply side DR program with goal of reaching the required minimum 500kW load shed for RDRR purposes by 2018.

Since the Navy will be transitioning from a Day-Ahead program to a Day-Of program, SDG&E will allow for 60 minute event notification with the goal achieving 20 minute event notification by the end of 2017, no minimum initial participation level with a goal of achieving 500kW by the end of 2017, and the use of customer meters for evaluation and settlement purposes. It reasonable to allow the Armed Forces more time to execute on event days and to have the time necessary to ramp up to achieve their full Auto-DR functionality. The use of an escrow account for settlement purposes will be used to ease the settlement burden as voiced by the Armed Forces and is addressed in the program participation contract. In addition, behavioral training opportunities for Naval Personnel will be essential to achieving future program successes and will be implemented as part of the 2017 Pilot.

Although the Navy is committed to demand response they still face several obstacles to achieve full supply side integration. The Navy has yet to achieve full Auto-DR capabilities at all participating sites. There are ongoing firewall and cyber-Security issues with allowing 3rd party access to usage data behind the master meter. Even if an acceptable interface solution is found, implementation may prove to be difficult. Acceptance by the CAISO of data from customer owned meters would significantly improve the Armed Forces' DR capabilities. The Navy currently has the ability to deliver the individually metered data behind the master meter to SDG&E, and this data could be used for settlements and program evaluation. Currently Customer Owned meters are restricted for use in market bidding by the CAISO. SDG&E and the Armed Forces are working together to define an acceptable method to accommodate penalties for non-performance.

Leveraging the Technology Incentive (TI) program to facilitate future program participation is another avenue available to the Armed Forces in achieving their Auto-DR goals. An assessment into the feasibility of Enrollment in TI will be needed. A three year commitment to a demand response program is required to receive TI funds, which might prove problematic to the Armed Forces.

Table 17 – Armed Forces Pilot Budget

Program Name	2016 Budget	Proposed 2017 Budget
Armed Forces Pilot	N/A	$187,088

IV. CONTENTS OF SDG&E's 2017 DR PORTFOLIO

The following discussion presents an overview of the various programs that are components of SDG&E's integrated demand response portfolio for 2017. Pursuant to the Guidance Ruling, this section includes:

a. The complete budgets for the proposed 2017 demand response portfolio under authorized funding categories;

b. A list identifying all programs and incentives provided through demand response but established external to SDG&E's DR portfolio; and

c. SDG&E's proposed schedule and plan to consolidate additional demand response programs and incentives into one demand response portfolio in future filings.

Budgets supporting each proposed program are contained in Table A-1 below and in Appendix A, while detailed Program Implementation Plans (PIPs), with program descriptions, implementation plans and other significant details contained in Appendix B.

A. SDG&E's 2017 Demand Response Programs Portfolio

Pursuant to the Guidance Ruling, SDG&E proposes that the programs described above and outlined in budget Table A-1 below be continued, or newly established, as integral components of its 2017 DR programs portfolio in an effort to enable market integration and overall program improvements. The programs are organized by the ten demand response funding categories that were adopted in D. 12-04-045 as well as the subcategories used for the 2015-2016 bridge funding budgets adopted in D. 14-05-025 (Attachments 2, 3, and 4). Load impacts for the 2017 DR programs portfolio are provided separately in Section V of this filing.

TABLE –A-1
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SUMMARY OF UTILITY DEMAND RESPONSE PROGRAMS AND BUDGETS FOR 2017 BY PROGRAM CATEGORIES
(Thousands of Dollars)

Line	SDG&E Demand Response Programs by Category	Footnote	Budget Authorized for 2016 (Thousands of Dollars)	Budget Requested for 2017 (Thousands of Dollars)
1	Category 1 - Reliability-Based Programs			
2	Base Interruptible Program (BIP)		1,588	943
3	Total		1,588	943
4	Category 2 - Price Responsive Programs			
5	Demand Bidding Program (DBP)	1	878	
6	Summer Saver Program (SSP)	2	-	2,534
7	Capacity Bidding Program (CBP)		4,023	2,181
8	Peak Time Rebate (PTR)	3	162	198
9	Total		4,184	4,913
10	Category 3 - DR Service Provider Managed Programs			
11	Total		-	-
12	Category 4 - DR Enabling Programs			
13	Technology Incentives (TI)		3,196	2,960
14	Small Customer Technology Deployment (SCTD)		3,155	1,430
15	DR Emerging Technology (ET)		706	723
16	Total		7,057	5,113
17	Category 5 – Pilots			
18	New Construction DR Pilot		375	-
19	Summer Saver PTC Pilot	1	-	78
20	Armed Forces Pilot		-	187
21	Over-generation		-	697
22	Demand Response Auction	4	-	1,500

	Mechanism (DRAM) 2017			
23	Total		375	2,462
24	Category 6 - Evaluation, Measurement, and Verification			
25	Evaluation, Measurement, and Verification		1,512	1,535
26	ME Research		200	200
27	Total		1,712	1,735
28	Category 7 - Marketing and Outreach Activities			
29	Local Marketing, Education and Outreach (LMEO)		2,225	885
30	Total		2,225	885
31	Category 8 - System Support Activities			
32	Regulatory Policy & Program Support		786	838
33	IT Infrastructure & System Support		813	2,307
34	Total		1,599	3,144
35	Category 9 - Integrated Programs and Activities			
36	Total		-	-
37	Category 10 - Special Projects			
38	Permanent Load Shifting (PLS)		1,000	1,613
39	Total		1,000	1,613
40	GRAND TOTAL		20,618	20,808

Footnotes:
1. DBP and NCDRP will end in 2016.
2. D.04-06-011 Filing for Summer Saver.
3. D.13-05-010 for Peak Time Rebate in 2012 GRC (2017 DR filing only includes administration budget, and its marketing budget is contained within LMEO in line 29 above.).
4. DRAM 2016 was funded through a fund shift from approved 2015-2016 budget, while DRAM 2017 total budget of $1.5 million was approved in Resolution E-4754, OP 9.

SDG&E has incorporated and categorized its newly proposed programs and pilots under existing budget categories in the DR portfolio based on each program's specific design and function. SDG&E's assigned categories for these new programs are listed below:

- Summer Saver Program - Category 2 – Price Responsive Program;.
- DRAM Pilot - Category 5 – Pilots;
- Over-generation Pilot – Category 5 – Pilots
- Armed Forces DR Pilot – Category 5 – Pilots; and
- Summer Saver Program Programmable Communicating Thermostat Pilot – Category 5 - Pilots.

B. DR Related Programs and Incentives Not Included in the 2017 DR Portfolio

As was indicated in D.12-04-024, the demand response applications have not always included all demand response related programs and incentives. Pursuant to the 2017 Guidance Ruling, below, SDG&E provides a list identifying all other DR-related programs and incentives established external to the 2012-2014 DR application proceeding.

1. Scheduled Load Reduction Program (SLRP)

The SLRP was initially established pursuant to the provisions of California SB5X, dated January 17, 2001. Customers electing to participate in SLRP are required to reduce their electric load during specific time periods of their choosing, and are paid an incentive for that reduction, which must be a minimum reduction of 100 kW or 15% of total load. SDG&E had proposed to eliminate SLRP as part of its 2006– 2008 program portfolio, in A.05-06-017, but because the Commission determined that the program is Legislatively-mandated, that proposal was denied by D.06-03-024. SDG&E has included SLRP in its demand response program through the General Rate Case (GRC) applications. SDG&E has continued to offer the program and will continue the program through the transition year 2017, and will maintain the existing program collateral and educational material, but is not anticipating any program expenditures due to the lack of customer interest in the program. SDG&E has no customers on SLRP, has not allocated any budget for the SLRP program and is not anticipating any customers will enroll in this program in the 2017 program transition year.SDG&E reserves the right and option to propose updates or modifications to the SLRP in future rate proceedings.

2. Rolling Blackout Reduction Program (RBRP)

The RBRP was initially established pursuant to the Commission decision, D.01-06-009 in 2001.[35] The RBRP utilizes customer's backup generation capabilities to augment energy supplies to reduce the impact of rolling blackouts and is triggered upon implementation of firm load reductions by the CAISO and/or CAISO's stage 3 emergencies. This schedule has been a part of the Demand Response in the GRC proceedings, and thus SDGE does not seek incremental funding for the administration, incentives, marketing and outreach of the RBRP in this application. SDG&E does not seek any changes to the RBRP from what was approved and implemented. SDG&E reserves the right and option to propose updates or modifications to the RBRP program in future rate proceedings.

3. Dynamic Rates

In addition to the programs described above, SDG&E has dynamic rates that are not part of the DR portfolio:

- Smart Pricing Program rate for Small Commercial (Schedule EECC-TOU-A-P)[36]
- Smart Pricing Program rate for Residential (Schedule EECC-TOU-DR-P)
- Smart Pricing Program rate for Agricultural (Schedule EECC-TOU-PA-P)
- Peak Time Rebate for Residential (Schedule PTR)[37]

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[35] *See*, D. 01-06-009, OP 1, page 20.

[36] Funding for the Smart Pricing Program rates was approved in D.12-12-004 in application, A.10-07-009.

- Critical Peak Pricing for M/L C&I (Schedule CPP-D)[38]
- Critical Peak Pricing for M/L Agricultural (Schedule CPP-D-AG)

Because CPP-D is a rate-based program, and was developed through SDG&E's rate design proposals in its General Rate Case proceedings, SDG&E reserves the right to propose updates or modifications to the CPP-D program in future Rate Design Window, General Rate Case or similar proceedings. SDG&E does not seek incremental funding for the administration of CPP-D in this filing, with the exception of its marketing, education and outreach. Similarly, SDG&E does not seek incremental funding for the administration of the Smart Pricing Program in this filing, with the exception directed by the Commission (D.) 12-04-045 to include incremental budget for the marketing and outreach of the SPP program in 2017. SDG&E does not seek any changes to the TOU Plus program in this filing. Moreover, since the PTR funding has been incorporated in the GRC applications and SDG&E seeks to continue the rate design proposals of the PTR as a rate-based program in the GRC proceedings, as such, only requests incremental PTR funding for administration, education and outreach in this DR portfolio proposal.

4. Integrated Demand Side Management (IDSM) programs and activities

a. Technical Assistance (TA)

The TA program is essentially an energy audit service designed to survey a customer's facility to help the customer identify methods for reducing energy costs and to encourage greater

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[37] In (D.) 07-04-043, SDG&E received approval for its Advanced Metering Infrastructure Project as well as funding approval for developing the Peak Time Rebate (PTR) program, which was established and adopted by the Commission in (D.) 08-02-034. The PTR funding has since been incorporated in SDG&E's GRC applications.

[38] CPP-D program implementation and administration was originally included within SDG&E's 2008 General Rate Case, and adopted by D.08-02-034 with subsequent updates.

participation in DR and EE programs. Customers who have a minimum demand of 100 kW or higher for three consecutive months are eligible to receive TA. During previous program cycle, the TA audit process has been geared towards identifying and quantifying DR strategies and finding EE opportunities and leads. Customers that qualify for a TA audit will receive an in-depth assessment of their facilities and operations, which includes specific recommendations and calculations of demand and energy saving potentials.

Based on the guidance for 2012 DR proposal, where it directed that IDSM activities be considered in Energy Efficiency proceedings, the Commission directed the Utilities to request funding for post- 2012 IDSM activities as part of their request for Energy Efficiency funding in (D.)12-04-045[39]. In accordance with this directive, the TA funding is not requested in this application. Funding for 2017 will continue to be requested in the IDSM section of the energy efficiency application.

b. Customer Education and Outreach for IDSM

In accordance with the same directive in D.12-04-045, the Customer Education and Outreach for IDSM funding is not requested in this application. Funding for 2017 will continue to be requested in the IDSM section of the energy efficiency application.

C. SDG&E's Proposed Schedule to Consolidate DR Programs and Incentives into the DR Portfolio

Pursuant to the Guidance Ruling, SDG&E discusses its planned schedule to consolidate all demand response programs and incentives into one demand response portfolio. As noted in the guidance, pursuant to D. 12-04-045, dynamic pricing programs (e.g., Critical Peak Pricing,

[39] *See*, D.12-04-045 p.174.

Real-Time Pricing, and Time-of-Use rates) should not be included in the 2017 proposal[40]. SDG&E notes that has already made significant efforts to consolidate its DR programs into its DR portfolio by proposing to incorporate the Summer Saver program for 2017.

1. Supply Resource Demand Response Should Remain Part of DR Portfolio

SDG&E proposes that the Supply Resource Demand Response (SRDR) Programs which are already in or will be initiated through the DR programs and activities proposal filings should continue to be an integrated component of the DR portfolio starting in 2018 when the full bifurcation is implemented.

The SRDR in the DR portfolio covers two funding categories – Category 1 for Reliability-Based Programs, and Category 2 for Price Responsive Programs. As noted in earlier discussion in this application, SDG&E's SLRP, once was considered a reliability-based program, does not have active participant and SDG&E does not anticipate any customer participation in future program cycles. SDG&E proposes to keep SLRP in GRC DR section consistent with current treatment.

Besides SRDR programs, all DR Enabling Programs, Pilots, Evaluation, Measurement and Verification (EM&V), System Support Activities, and Special Projects (funding classification covers from Category 4 through 10, as they are related to the support of the SRDR programs, should be included as an integrated component of DR portfolio.

2. Load Modifying Resource (LMR) DR Should Not Be Included in the DR Portfolio

As indicated in the guidance for 2017 DR programs and activities filing to comply with D. 12-04-045 directives, dynamic pricing programs (e.g., Critical Peak Pricing, Time-Of-Use

[40] *See*, Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for 2017 Demand Response Programs and Activities Proposal Filings, at p.13.

rates) should not be included in the 2017 proposal. SDG&E considers its Peak Time Rebate (PTR) another rate based option that serves to educate the residential customers for the future deployment of TOU rates. As such, SDG&E proposes to continue to design and evaluate PTR in the same proceeding as other dynamic pricing programs to keep the rate design proposals holistically integrated. Consistent with the Commission's view, SDG&E classifies all the rate-based programs, including dynamic pricing and PTR, to be Load Modifying Resource (LMR) DR. Thus, SDG&E proposes to continue the practice to evaluate LMR DR in the GRC proceedings, now and after the full bifurcation of DR has been implemented. Consistent with the adopted DR Cost Effective Protocols in Decision (D.) 15-11-042, SDG&E plans to continue offering LMR DR in the form of rate-based programs in the fully bifurcated future. For 2017, SDG&E will continue to recover the marketing and customer outreach and education expenses for the event based dynamic rates described above by way of its DRP. SDG&E may propose to address these costs differently in the future.

Similarly, SDG&E believes the DR portfolio should include all the cost for the Supply Resource DR (SR DR), plus other activities that are not clear cut and support both LMR DR and SR DR. These support and activities include, but not limited to:

- Enabling technology that promote home area network, and energy management for both residential and non-residential premises
- Policy, engineering, and other supports
- Pilots and special projects

3. IDSM Budget in EE Portfolio

Under the guidance for 2012 – 2014 DR program cycle proposals, the Commission directed the Utilities to use 2012 as a bridge year for DR IDSM funding. SDG&E agrees that the integrated activities should be consolidated in one proceeding. Thus, pursuant to D.12-04-045[41], SDG&E plans to continue to propose changes and to request budgets in the IDSM section of the energy efficiency application.

V. LOAD IMPACTS, COST EFFECTIVENESS AND MEASUREMENT & EVALUATION

A. Load Impacts

One of the necessary inputs for the cost-effectiveness calculations is the load impact forecast. SDG&E filed a load impact forecast in April of 2015 for all of its demand response programs and when appropriate this forecast was used for cost-effectiveness tests. However, in some cases the forecast was updated to reflect the program design changes contained in this proposal. This section contains the load impact forecast used in the cost-effectiveness tests for each program as well as an explanation of how the forecast was updated when applicable. SDG&E is proposing changes to the Summer Saver program that are likely to affect the load impact forecast. The load impact forecast filed April of 2015 was used as the starting point and adjustments were made to the forecast in order to incorporate the effects of the proposed incentive changes and proposed disenrollment of residential low performing customers into the forecast. One of the changes SDG&E is proposing to the Summer Saver program in 2017 is to dis-enroll the lowest 20% of performers from the residential summer saver program. Based on the average per premise load impact by quintile from the Summer Saver load impact report[42] contained in the table below, SDG&E estimates that removing the lowest 20% of performers from the Summer Saver program will lower the load impact forecast by 2%.

41 *See*, D.12-04-045,p.174.

42 *See*, San Diego Gas and Electric Company Summer Saver 2014 Program Evaluation, April 1, 2015, at p. 23.

Table 18 – Average Per Premise Load Impact		
Quintile	50% Cycling	100% Cycling
	Average Per Premise Load Impact (kW)	Average Per Premise Load Impact (kW)
1	0.05	0.07
2	0.07	0.29
3	0.31	0.51
4	0.49	0.72
5	1.21	1.3
Percentage of total Load reduction from 1st quintile	2.3%	2.4%

In addition SDG&E is proposing to reduce the incentive payment for the residential 100% cycling option by 10% and to reduce the incentive payment for the commercial cycling program by 50%. SDG&E experienced little drop off when the residential incentive for customers on the 100% cycling option was lowered by 20% in 2015. SDG&E estimates that 95% of the load reduction will remain on the residential 100% cycling option after incentives are reduced by 10%. On the commercial side, the 50% drop in incentive payments for the commercial customers is expected to be partially offset by savings from dynamic rates; however some customers may still prefer the flat payments. For the purpose of calculating the cost-effectiveness of the program SDG&E assumed that load forecast will be reduced by 22% in response to the 50% decrease in incentives.

The number of accounts currently enrolled in the SCTD program exceeds the number of accounts that were included in than the forecast for 2017 filed in April. There are currently 8780 residential accounts enrolled in SCTD compared to 8220 from the previous load impact and 2728 commercial accounts currently enrolled compared to the forecast of 2013. Therefore the load impact forecast for SCTD was increased from the forecast filed in April based on the number of new thermostats expected to be installed in 2016 and 2017. SDG&E expects 5000 new residential thermostats to enroll in the SCTD program in 2016 and 4500 new residential thermostats to enroll in the SCTD program in 2017. In addition SDG&E expects 2000 new commercial thermostats to participate in the SCTD program in 2016 and 1000 new thermostats to participate in 2017. The impacts per thermostat from the April load impact report were multiplied by the forecasted increase in enrollment in order to get the incremental aggregate load reduction.

SCTD is an enabling technology program supporting the PTR program so cost-effectiveness results have been provided for the PTR program as a whole. The load forecast for PTR customers not enrolled in SCTD used in the cost-effectiveness tests is the forecast filed in April of 2015. This load forecast presents the forecasted PTR enrolment before dynamic pricing rates such as TOU plus are marketed to customers currently enrolled in PTR. Once these rates are marketed to PTR customers the load reduction from the PTR program is expected to decrease. Therefore, these cost-effectiveness results should be not be misinterpreted as reflecting the cost-effectiveness of PTR after dynamic rates are marketed to customers.

The load impact forecast as filed in April of 2015 was used for the cost-effectiveness analysis of the CBP program. The load impact forecast filed in April of 2015 was also used for the cost-effectiveness analysis of the BIP program. In additional, since the BIP forecast filed April 1st did not include SDG&E's proposed plan to increase program enrollments within a targeted pool of potential participants an additional load impact scenario is also included.

Table 19 - Load Impacts Used in Cost-Effectiveness Calculations (MW)

Program	May	June	July	Aug	Sep	Oct
Summer Saver	6.2	6.1	10.8	13.1	14.1	9.4
CBP	20.6	21.4	20.0	22.3	23.1	21.4

SCTD Residential	1.6	1.6	2.6	2.9	3.2	2.3
SCTD Commercial	4.0	4.5	5.9	6.6	8.7	6.5
PTR without technology	2.6	2.9	3.8	4.4	5.7	4.3
BIP	1.5	1.5	1.4	1.4	1.4	1.3
BIP alternate scenario	3.3	3.2	3.0	3.1	3.0	2.7

B. Cost Effectiveness Analysis

SDG&E used the Demand Response Reporting Template prepared by Energy and Environmental Economics (E3) in 2011 for the 2012 through 2014 Demand Response Application filing. Guidance for this 2017 Proposal directed the utilities to use the 2010 protocols and associated guidance documents. SDG&E modified the template according to the ALJ Ruling of December 3, 2015[43] which directed the utilities to use the current avoided cost calculator values developed by E3 for the Self-Generation Incentive Program (SGIP).[44] SDG&E replaced the values found on the worksheet tab labeled "Inputs" in the DR Reporting Template with the corresponding values found in the latest version of the Avoided Cost calculator.

1. A Factor

The A Factor is a percentage that is used to modify the generation capacity value to account for the availability of the DR program. For example, if a program can be called any hour of the day with no restrictions, the A Factor for that program would be 100%. All SDG&E demand response programs have some limitation on when they can be called, so the A Factors used in the analysis are percentages below 100%. To calculate the A Factors, SDG&E again used the SGIP Avoided Cost model as directed by the December 3rd Ruling. The tab in the SGIP

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43 *See*, Administrative Law Judge's Ruling Providing Clarification Regarding 2017 Demand Response Program Proposals, Rulemaking 13-09-011, December 3, 2015.

44 The values are in the file named E3_NEM_Avoided_Cost Model_SGIP_Update_20150521.xlsm found at https://www.ethree.com/public_projects/cpucSGIP.php.

Avoided Cost Model labeled "Capacity Allocation" provides hourly values or allocators for each day of the year from 2007 through 2050. The hourly allocators for any particular year estimate the probabilities when additional capacity will be needed by the State based on a model developed by E3. SDG&E used the values for 2017 and the following methodology to calculate A Factors for each program.

a) For each possible daily event window within the program tariff constraints, the hourly capacity allocators were summed.
b) The maximum value of the summed capacity allocators was selected for each day.
c) If the program tariff had a monthly event constraint, the maximum allowed events for the month were summed.
d) If the program tariff had an annual event constraint, the maximum allowed events for the year were summed.

Consider, for example, the Summer Saver program. This program can be called between the hours of noon to eight pm on any day of the year. Each event can last up to four and one-half hours, and the annual maximum is eighty hours or 18 events. For each day in 2017, the capacity allocators for possible event windows on each day were added and the maximum value was chosen. For example, for September 19th, 2017, the possible event windows of noon to 4 pm, 1 to 5 pm, 2 to 6 pm, 3 to 7 pm, and 4 to 8 pm yielded summed capacity allocators of 0.362%, 0.739%, 0.935%, 1.260%, and 1.215% respectively. Of these, the maximum value for that day, 1.260%, was selected. This was repeated for each day in the year. Since this program has an annual but no monthly restriction, the top 18 values of the year were summed. The resulting value, 62%, is the A Factor that was used in the analysis for this program.

A Factors used in this analysis are as follows:

- Summer Saver: 62%
- PTR/SCTD: 86%
- CBP: 64%

- BIP: 74%

2. Remaining Factors

For the remaining factors, SDG&E used the same methodology and/or guidance as in previous filings. Each is described below.

- B Factor: The B Factor adjusts the generation capacity value to account for the difference in notification time. For example, a program that requires a day ahead notice will have a lower B Factor than a program that can be noticed the same day of the event. The values for Factor B were previously established in a May 2012 guidance document from Energy Division.[45] The guidance directed Day-Of programs be assigned a B Factor of 100% and Day-Ahead programs be assigned a B Factor of 88%.
- C Factor: The C Factor adjusts the generation capacity value to account for the flexibility of the program trigger. The May 2012 guidance referenced above directed the utilities to use a C Factor of 95% for any program which cannot be called at the utility's discretion and 100% otherwise. All SDG&E demand response programs include this "soft" trigger and therefore have a C Factor of 100%.
- D Factor: The D Factor adjusts the transmission and distribution capacity value to account for having the resource with the "right time, right place, right certainty and right availability." In the cost effectiveness analysis for the 2012 to 2014 program cycle and again for the 2015 to 2016 bridge years, SDG&E used the following methodology to calculate the D Factor. If a program includes the

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[45] *See*, Energy Division Guidance on Cost-effectiveness, served onA.11-03-001 service listin May 2012.

installation of enabling technology that is meant to provide system benefits beyond the current program cycle, a positive value for the D Factor will be used; otherwise zero. The value of the D Factor is calculated based on the percentage of MW expected to be delivered as a result of enabling technology. For example, the AC Summer Saver program uses direct load control switches to cycle AC units on and off for all participants. Therefore, the D Factor for this program is 100%. The CBP program has a portion of customers that have received enabling technologies through the Technology Incentives (TI) program; that proportion of customers' expected MW is used for the D Factor for that program.

- E Factor: The on-peak market price used in the analysis is an average of summer on-peak prices. The E Factor adjusts the on-peak avoided energy price to account for the likelihood that DR programs are called only on the higher priced days. Thus the E Factor increases the value of energy saved during the DR events. The May 2012 guidance directed the utilities to use 140% for this Factor for all programs.

3. Load Impacts

SDG&E used the load impacts reported in the April 1, 2015 filing based on 1-in-2 weather and adjusted for the portfolio, as required by the protocols. Adjustments were made to the load impacts for the SCTD and AC Summer Saver programs to account for expected changes in enrollment in 2017; these adjustments are explained in the section on load impacts. In addition, the load impacts for CBP were disaggregated to estimate impacts from new customers with Auto DR as a result of participating in the TI program.

4. Costs

Budget values for certain costs that were not associated with any particular program but are needed to support all the programs were allocated across the individual programs. The program budget compared to the total budget was used as the allocation factor. These costs include $837,624 for general program and policy support and $1.4 million for information technology (IT).A portion of the IT costs ($578,000) are for data systems intended to be used for five years. Therefore, this portion of IT costs was amortized over five years.

Certain costs in the application budget were applicable only on a portfolio basis; these costs were not included in the individual program tests. This includes $670,266 of the EM&V budget along with the Emerging Technologies program budget.

The following costs were not included in the tests:

- Pilot costs: costs for the four proposed pilots were not included in the tests as forecasted MWs were not available. The protocols allow for omitting pilots from the tests when the benefits are unknown.
- Permanent Load Shifting (PLS): This program was not included in the tests for two reasons. First, no changes are being proposed for this program. Second, the program uses a slightly different methodology and model for cost effectiveness testing that is subject to change through a Commission-established working group.
- Additional incentives: additional incentive budget is needed to allow for increased enrollment beyond what is forecasted; however, only the forecasted MWs and associated incentive budgets are used in the tests.

- EM&V and marketing costs proposed for rates: none of the costs associated with rates proposed in other proceedings are included in the tests.
- Research budget for Commission studies: the proposed budget includes $200,000 for Commission studies related to overall policy issues; these costs are not included in the tests.
- Costs for DR technologies that are tied to rates

5. Results

The test results are presented below. They are also provided in the Summary tab of the DR Reporting Template. SDG&E refers to these results as the "Base Case" in order to differentiate them from the alternative scenarios discussed further below.

Table 20: Base Case Cost Effectiveness for 2017

	Summer Saver	PTR/SCTD	CBP	BIP
TRC	0.82	0.87	0.94	0.59
PAC	0.71	0.92	0.91	0.55
RIM	0.67	0.86	0.82	0.54
PCT	1.33	1.04	1.33	1.33

As shown, results for the TRC test range from 0.59 to 0.94, and results for the PAC test range from 0.55 to 0.92. In approving the 2012 to 2014 programs, the Commission deemed a TRC result of 0.9 or higher to be cost effective and a result of 0.5 to 0.9 to be "possibly cost effective."[46]

6. Sensitivity Testing

SDG&E conducted sensitivities based on participant costs, generation capacity value, T&D capacity value, the capital amortization period, the load impacts and the A Factor using the default settings provided in the DR Reporting Template. The results for the TRCs for participant

[46] Decision 12-04-045, page 44.

costs, generation capacity, load impacts and the A Factor are shown below. Results for the remaining sensitivities on the TRC as well as those for the PAC and RIM are provided in the DR Reporting Template.

The TRC methodology relies on multiple assumptions, some of which are more subjective than others. Load impacts, for example, can be predicted with a reasonable degree of accuracy by referring to past performance and understanding how program changes might impact participation. Participant costs, on the other hand, are highly subjective since it is a measure of how difficult it is for a customer to participate. What may be difficult to one customer may be easy for another. Note that with a sensitivity value of 50% used to estimate participant costs rather than 75% used in the base case, all programs except BIP result in a TRC above one.

Table 21: Sensitivity Tests on the TRC

Program		Participant Costs		Generation Capacity		Load Impacts		A Factor	
	Base Case	100%	50%	-30%	+30%	-30%	+30%	-10%	100%
Summer Saver	0.82	0.67	1.07	0.67	0.98	0.58	1.07	0.77	1.15
PTR/SCTD	0.87	0.86	1.14	0.67	1.08	0.61	1.13	0.80	0.98
CBP	0.94	0.86	1.17	0.71	1.17	0.67	1.20	0.86	1.36
BIP	0.59	0.54	0.67	0.42	0.76	0.42	0.77	0.54	0.80

7. Alternate Scenarios

With DR products transitioning to a supply side resource strategy, the value of DR is currently in flux. The avoided cost calculator was recently updated, new protocols have been released that would change the TRC assumptions, and the DR proceeding’s cost-effectiveness working group continues to evaluate how to improve the measurement of DR value. In addition, the Integrated Distributed Energy Resources proceedings is currently evaluating cost-effectiveness methodologies for all resources, including DR, in an effort to better align the values that various proceedings assign to these products. Therefore, it is difficult to estimate the true benefits these programs will bring to the market in 2017. In an effort to provide a more robust picture, SDG&E performed additional cost-effectiveness analyses. The first scenario below incorporates the features of the updated 2015 protocols. Guidance for this 2017 Proposal directed the utilities to use the 2010 protocols and associated guidance documents, and that analysis is presented above. The following alternate scenarios give additional perspective on how DR products are valued in the new protocols.

a. Alternative Scenario One: 2015 Protocols

The following changes were made in this scenario to reflect the Commission's updated 2015 protocols:

- The G Factor was added,
- The base case for participant costs for residential programs with enabling technology was changed to 35%,
- The B Factor was modified to allow for varying notification times for Day-Of programs, and
- The base case value for capital cost amortization was changed to half of the expected useful life.

Each of these changes is discussed below.

The G Factor can be used to adjust the capacity value for any program that can be called locally for a constrained area at risk for generation capacity shortages. According to the new cost effectiveness protocols for demand response programs,[47] SDG&E shall use a new default G Factor equal to 110%.[48]

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[47] 2015 Demand Response Cost Effectiveness Protocols, November 2015, Rulemaking 13-09-011.

[48] *Ibid*., page 35.

The base case for participant costs, which include transaction costs and the value of service lost, is estimated using a proxy value of 75% of the sum of incentives plus bill savings minus participant capital costs. The 2015 protocols direct the base case for AC cycling programs to use 35% instead of 75% for the base case and to use 60% and 10% for the high and low sensitivity values.[49] SDG&E has two residential programs that cycle or setback air conditioners: AC Summer Saver and SCTD. The new value of 35% was used to estimate participant costs in the base case for these two programs.

The new protocols modify the use of the B Factor to allow for different values for Day-Of programs. Specifically, the B Factor will be 100% if the program can be called in 30 minutes or less, 94% if the program can be called the same day but requires more than 30 minutes, and 88% if the program must be called the previous day.[50] For SDG&E programs, this changes the B Factor for CBP Day-Of to 94%.

The new protocols require that the base case for the value of amortized capital costs be less than the useful life of the equipment. In particular, the protocols specify a calculation to be used which is based on a "low value" equal to the cost of the equipment amortized over its useful life and a "high value" equal to the cost of the equipment amortized over the reporting period (in this case one year). The following calculation is specified in the protocols and was used in this alternate analysis:[51]

$$\text{Base value} = \text{low value} + \tfrac{1}{2} * (\text{high value} - \text{low value})$$

All other inputs from the Base Case analysis remain the same. Results for this scenario are shown below.

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[49] *Ibid*., page 47.

[50] *Ibid*., page 34.

[51] *Ibid*., page 40 to 41.

Table 22: Alternative Scenario Results Using 2015 Protocols

	Summer Saver	PTR/SCTD	CBP	BIP
TRC	1.26	0.99	0.89	0.63
PAC	0.72	0.99	0.87	0.59
RIM	0.68	0.92	0.79	0.57
PCT	2.86	1.17	1.33	1.33

Table 23: Sensitivity Tests on the TRC for Alternate Scenario One

Program		Participant Costs		Generation Capacity		Load Impacts		A Factor	
	Base Case	60%	10%	-30%	+30%	-30%	+30%	-10%	100%
Summer Saver	1.26	0.96	1.89	1.01	1.51	0.89	1.64	1.11	1.65
PTR/SCTD	0.99	1.13	1.22	0.76	1.23	0.70	1.29	0.85	1.04
		100%	50%	-30%	+30%	-30%	+30%	-10%	100%
CBP	0.89	0.82	1.09	0.67	1.11	0.64	1.14	0.76	1.20
BIP	0.63	0.57	0.70	0.45	0.81	0.44	0.82	0.52	0.77

b. Alternative Scenario Two: Adjusted A Factor

SDG&E provided a second alternative scenario in which the model from the first alternative scenario (use of the 2015 protocols) was further modified to adjust the A Factor to 100% for programs that meet CAISO's must offer obligation. In this scenario, an A Factor of 100% is assigned to AC Summer Saver and CBP for meeting the must offer obligation. All other inputs remain the same as in the first alternative scenario. Results for this second scenario and the sensitivity test results are shown below. Note that only Summer Saver and CBP change in this scenario.

Table 24: Alternative Scenario Results Using 2015 Protocols and A Factor of 100% for MOO

	Summer Saver	PTR/SCTD	CBP	BIP
TRC	1.77	0.99	1.30	0.85

PAC	1.01	0.99	1.26	0.79
RIM	0.96	0.92	1.15	0.77
PCT	2.86	1.17	1.33	1.33

Table 25: Sensitivity Tests on the TRC for Alternate Scenario Two

Program		**Participant Costs**		**Generation Capacity**		**Load Impacts**		**A Factor**	
	Base Case	**60%**	**10%**	**-30%**	**+30%**	**-30%**	**+30%**	**-10%**	**100%**
Summer Saver	1.77	1.35	2.66	1.37	2.18	1.25	2.30	1.53	1.65
PTR/SCTD	0.99	1.13	1.22	0.76	1.23	0.70	1.29	0.85	1.04
		100%	**50%**	**-30%**	**+30%**	**-30%**	**+30%**	**-10%**	**100%**
CBP	1.30	1.20	1.58	0.96	1.65	0.93	1.68	1.09	1.20
BIP	0.85	0.77	0.94	0.60	1.09	0.60	1.10	0.70	0.77

c. Alternate Scenario: BIP

SDG&E also tested BIP with an additional 1.5 MW. Since filing the 2017 load impact forecast which was used in the above analyses, SDG&E identified a pool of customers who are eligible to enroll in BIP. SDG&E plans to reach out to these customers through Account Executives. Therefore, SDG&E expects BIP participation to increase by 2017. Using the 2010 protocols, an additional 1.5 MW in BIP would result in a TRC of 0.85. Furthermore, using the 2015 protocols as described above, the additional MW in BIP would result in a TRC of 0.90; adding to this the adjusted A Factor as described above, the result is a TRC of 1.21.

8. Qualitative Benefits and Costs

In addition to the quantitative benefits and costs outlined above, demand response programs may also result in qualitative benefits and costs as described in the DR protocols. These benefits and costs may accrue to participants, the utility, society or participants in the energy market. The benefits and costs described below are qualitative in nature only.

9. Market Benefits and Costs

The market benefits that might exist include: (1) market power mitigation and price suppression; (2) market productivity gains; (3) increased grid reliability; and (4) increased generation capacity diversity. Of these SDG&E does not believe that DR should receive a benefit value for the first three, while the third is a small benefit in providing a more diverse portfolio of capacity resources, reducing reliance on natural gas. This may provide a benefit when there are shortages of natural gas. Since DR is receiving a capacity payment, it is avoiding capacity. It would be double-counting to include the first three benefits since any added capacity would provide those market benefits.

Market costs include reduced DR amounts achieved due to customer fatigue and due to uncertainty of measured response. DR is unlike a combustion turbine in that more calls can lead to a serious degradation of performance. With the current A factor, the number of calls in the past increased dramatically and some customers dropped out of providing DR. This type of qualitative cost creates uncertainty about long-term DR availability and the ability to avoid building new infrastructure. Uncertainty of measured response in markets is particularly likely with temperature sensitive DR. The measured market amount of DR may be less than exists under the load impact protocols due to current CAISO baseline measurements, diminishing the amount of perceived DR. Another area of potential market costs is storage and differentiating DR from normal discharge in response to TOU retail rates. Determining incremental response from DR may be inaccurate and so the DR program may pay for capacity benefits when none actually exists due to deficient baseline measurements.

10. Qualitative Social NEBs or costs

Qualitative Social NEBs or costs include several other environmental impacts that might be avoided depending on the energy avoided and whether capacity is avoided. Environmental impacts might also be avoided depending on specific type(s) of capacity – generation, transmission, and/or distribution – that the DR program is expected to defer or avoid.

SDG&E believes job creation benefits generally do not apply to DR in that it avoids building new infrastructure, so there may be a loss of the creation benefits of constructing generation, distribution and transmission upgrades.

Environmental benefits are very small since programs are (1) displacing energy for so few hours of the year, (2) some displacement may have been met with renewable energy, and (3) the fact that any fossil generation may not come from local sources.

There may be small environmental costs if storage is underlying the DR reduction since there may be environmental costs and environmental justice issues associated with the location and operation of the storage device.

DR programs supported with enabling technologies and storage may be providing market transformation benefits. The change in the market prices for the enabling technology from learning-by-doing can lead to lower prices for a DR technology in the future. The cost effectiveness of DR programs is lowered substantially for the DR programs that include significant amounts of enabling technology.

11. Qualitative Utility/Load Serving Entity (LSE) Non-energy Benefits (NEBs) or Costs

Qualitative Utility/LSE non-energy benefits (NEBs) consist of any indirect change in costs that a utility as a result of DR programs not included in DR budgets or any benefits or costs an LSE experiences. These can include any changes in the number of complaint calls or service requests to the distribution utility or LSE, any changes in customer perception or relationship to their distribution utility or LSE, and changes in the number of distribution utility or LSE delinquent bills. SDG&E does not believe any of these benefits apply for DR.

There are costs associated with getting LSE permission to register customers at the CAISO to participate in supply-side DR programs. These transaction costs have limited the ability of the utility to include direct access customers in supply-side DR.

12. Participant Non-energy Benefits or Costs

Qualitative Participant NEBs or costs is a broad category which includes the intangible benefits that DR participants often perceive when they agree to reduce their demand during DR events. Participant Non-energy Benefits such as “Feeling Green” and better matching of the customers’ needs with choices offered by electric markets is a qualitative factor that could modify the “participant cost” to lower the net cost. On the other hand, customer fatigue from too many calls or calls that are long may increase customer costs.

With so much uncertainty regarding actual participant costs, SDG&E does not believe it is useful to discuss qualitative aspect of customers’ costs when arbitrary quantitative values of 35% and 75% percent have been ascribed. SDG&E has run sensitivities based on participant cost in order to reflect the uncertainty and subjectivity of this value.

VI. PROGRAM BUDGET PROPOSAL AND COST RECOVERY MECHANISM

A. 2017 DR Portfolio Budget Proposal

Based on the discussion above, SDG&E’s 2017 DR portfolio budget proposal is $20,808,000 for 2017. This constitutes a $190,000 or 0.9% increase from authorized DRP funding in 2016. However, as noted earlier, SDG&E has included its Summer Saver program in this DR filing when it previously was funded outside of its DRP. SDG&E’s request for 2017 is actually a decrease over 2016 approved budgets. Detailed program budgets organized according to the approved budget categories can be found in section IV(A) above and in Appendix A.

B. **Cost Recovery Mechanism**

1. **Background**

Prior to this filing, costs for Demand Response (DR) programs and tariffs,[52] with the exception of the Smart Pricing Program dynamic pricing rates (SPP)[53], were allocated to distribution rates where all customers pay the costs. This includes bundled customers as well as customers participating in Direct Access. Pursuant to Decision (D.) 12-12-004, program costs related to SPP were allocated to generation rates where only bundled customers pay for the costs.

Regarding other DR programs and tariffs, D.14-12-024 provided new guidance for cost allocation beyond the SPP rates. The Decision states:

> "*We find it equally reasonable that tariffs and programs, including pilots, available to all customers should be paid for by all customers. Thus, we adopt as a demand response cost allocation principle that any demand response program or tariff, including a pilot, that is available to all customers shall be paid for by all customers and therefore allocated to distribution rates. Likewise, if a program or tariff is only available to bundled customers, that program's costs shall be allocated solely to generation rates. This demand response cost allocation principle shall be applied consistently across the three utilities.*"[54]

Ordering Paragraph (OP) 8 of D.14-12-024 states:

> *"We adopt the following cost causation principles for demand response: Any demand response program or tariff that is available to all customers shall be paid for by all customers. If a demand response program or tariff is only available to bundled customers, the costs for that program or tariff can only be borne by bundled customers"*[55]

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[52] With the exclusion of commodity rate incentives associated with dynamic pricing offerings.

[53] The SPP rates were adopted in D.12-12-004.

[54]See, D.14-12-024,at p. 48.

[55]*Id.*, Ordering Paragraph (OP) 8.

Based upon this guidance, SDG&E has differentiated the cost recovery for the Demand Response Program costs required to administer each program based upon customer eligibility.[56] These costs include the related LME&O costs. The specific program administration and LME&O costs are broken down between what programs are currently available to all customers versus what programs are not available to customers participating in Direct Access (i.e. non-bundled customers).

2. Programs Available to All Customers

The DR programs and tariffs identified below are available to all customers.[57]

- Base Interruptible Program (BIP) for all Commercial & Industrial (C&I) and Agricultural (Schedule BIP)
- Base Interruptible Program Pilot for Armed Forces
- Capacity Bidding Program (CBP) for all C&I and Agricultural (Schedule CBP), includes Day-Ahead and Day-Of
- Demand Bidding Program (DBP) for all C&I and Agricultural (Schedule DBP2), includes Day-Ahead and Day-OfSmall Customer Technology Deployment for Residential and C&I (SCTD)
- Summer Saver for Residential and Small Commercial (SSP)
- Summer Saver PCT Pilot
- DR Emerging Technology (ET)
- New Construction DR Pilot
- Over-generation Pilot
- Technical Incentive Program (TI), an enabling technology program

[56] Costs allocated are direct costs related to the Demand Response programs. Overhead costs associated with supporting all programs, such as EM&V, general administration, IT and research were not included and are allocated to distribution rates.

[57] Schedules BIP, CBP, DBP2 and SCTD were identified in "2016 Total IOU Demand Response program totals by Program and Local Area - Grossed up for T&D Losses".

- Permanent Load Shifting (PLS) for C&I Customers
- Demand Response Auction Mechanism (DRAM)

As these programs are available to both bundled customers and those participating in Direct Access, SDG&E proposes to recover these costs through its distribution rates, using the previously approved approach of the majority of the Advanced Metering and Demand Response Memorandum Account (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. SDG&E proposes that it would also continue to record the energy component of the DR Program customer incentive payments in AMDRMA, and transfer, as is done now, to its Energy Resource Recovery Account (ERRA) for recovery.

Table 26 below captures the budgeted dollar amounts associated with these programs that would be allocated to distribution rates if spent, effective January 1, 2017. The total amount being allocated is $15 million for 2016 and $14.9 million for 2017.

Table 26
SDG&E Proposed Costs Recovered Through Distribution Rates

Program Administration and LME&O Costs	Change ($000)	
	Authorized 2016	Requested 2017
Base Interruptible Program (BIP)	$1,588	$943
Demand Bidding Program (DBP)	$878	$0
Summer Saver Program (SSP)	$0	$2,534
Summer Saver PTC Pilot	$0	$78
Capacity Bidding Program (CBP)	$4,023	$2,181
Technology Incentives (TI)	$3,196	$2,960
Small Customer Technology Deployment (SCTD)	$3,155	$1,430
DR Emerging Technology (ET)	$706	$723
New Construction DR Pilot (NC)	$375	$0
BIP Pilot (Armed Forces)	$0	$187
Over-Generation Pilot (OG)	$0	$697
Demand Response Auction Mechanism (DRAM) 2017	$0	$1,500
Permanent Load Shifting (PLS)	$1,000	$1,613
Local Marketing, Education and Outreach (LMEO)[58]	$75	$85
Total	**$14,996**	**$14,931**

58 Costs for Permanent Load Shifting, Technology Incentives and Summer Saver as identified on pg. 41

3. Programs Not Available to Direct Access Customers

The DR programs or tariffs identified below are not available to Direct Access customers.[59]

- SPP rate for Small Commercial (Schedule EECC-TOU-A-P)
- SPP rate for Residential (Schedule EECC-TOU-DR-P)
- SPP rate for Small Agricultural (Schedule EECC-TOU-PA-P)
- Peak Time Rebate (PTR) for Residential (Schedule PTR)
- Critical Peak Pricing (CPP) for Medium/Large (M/L) C&I (Schedule EECC-CPP-D)
- CPP for M/L Agricultural (Schedule EECC-CPP-D-AG)

The costs associated with these programs are found in this filing, with the PTR program administration costs and local marketing, education and outreach costs associated PTR, SPP and CPP-D identified in Table 27 below. As defined in D.12-12-004 and D.14-12-024, SDG&E proposes to recover these costs through generation rates. Table 27 below captures the proposed dollar amounts associated that would be allocated to generation rates if spent, effective January 1, 2017. The total proposed amount being allocated to generation rates is $3.3 million.

Table 27
SDG&E Proposed Costs Recovered Through Generation Rates

Program Administration and LME&O Costs	Change ($000)	
	Authorized 2016	Requested 2017
Peak Time Rebate (PTR)	$162	$198

[59] Schedules PTR, Critical Peak Pricing Default (CPP-D) and CPP-D-AG were identified in "2016 Total IOU Demand Response program totals by Program and Local Area - Grossed up for T&D Losses."

Local Marketing, Education and Outreach (LMEO)[60]	$2,150	$800
Total	**$2,312**	**$998**

4. Summary of Cost Recovery Proposals

Table 28 below provides a summarized view of SDG&E's cost recovery proposals for this filing.

Table 28
Summary of SDG&E Proposed Costs Recovery

Costs Recovered Through Generation Rates	**Total ($000)**
SPP, CPP-D and PTR	$3,310
Costs Recovered Through Distribution Rates	
BIP, DBP, SSP, CBP, TI, SCTD, ET, NC, OG, DRAM and PLS	$29,927

VII. MISCELLANEOUS ITEMS

A. Customer Protection Rules and Regulations Per SB 1414

Pursuant to SB 1414 California adopted Public Utilities Code Section 380.5, which requires that, before implementing a new demand response program for residential customers, the Commission shall:

> *. . . establish customer protection rules regarding the participation, cost of participation, and ability to not enroll in the program. A residential customer who does not enroll in the program shall lose eligibility for rebates, discounts, and other incentives offered to customers who participate in the program. The commission shall prohibit the imposition of charges on a residential customer for not enrolling in the program.*[61]

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60 Costs for Smart Pricing (TOU+), CPP-D and PTR (Reduce Your Use Rewards and Reduce Your Use Thermostat) are identified on p. 41.

61 *See*, Public Utilities Code Section 380.5(a).

SB1414 further provides that not apply to time-variant pricing as defined in Section 745, including time-of-use rates, critical peak pricing, and real-time pricing, or to similar tariffs, including peak time rebates:

> *(b) This section does not apply to time-variant pricing as defined in Section 745, including time-of-use rates, critical peak pricing, and real-time pricing, or to similar tariffs, including peak time rebates.*[62]

In the Guidance Document, the required utilities to address the requirements of Section 380.5(a), as clarified under Section 380.5(b):

> *The Utilities shall include in their 2017 proposals:*
>
> *a. Recommendations for additional or revised consumer protection rules for demand response programs available to residential customers that meet the criteria in code sections 380.5(a)(3) and (b).*
>
> *b. A detailed description of any barriers to implementing these code sections, or possible unintended consequences.*
>
> *c. If current consumer protection rules are sufficient, provide an explanation of how the current rules fulfill the requirements of Code Sections 380.5(a)(3) and (b).*

SDG&E submits that the existing consumer protection provisions that exist under SDG&E Tariff Rule 32 provide for consumer protection sufficient to meet the requirements of Public Utilities Code Section 380.5. For example, Rule 32 requires Demand Response Providers (DRPs), to obtain approval of a customer service form letter to be provided to each residential customer explaining the DRP's terms and conditions of participating in the DRP's DR Service, in a form that has been approved by the Commission's Energy Division, before submitting residential customer service accounts for Resource Registration at the CAISO DR System as follows:

[62] *See*, Public Utilities Code Section 380.5(b).

Formal Notification for Residential and Small Commercial Customers

Residential customers are defined as SDG&E customers who are eligible for service under one of its residential rate schedules. Small Commercial customers are defined as any non-residential customers with a maximum billing peak demand of less than 20 kilowatts (kW). Non-Utility DRPs intending to enroll Residential and Small Commercial customers in DR Services at the CAISO are required to meet additional CPUC requirements before submitting such customer service accounts for Resource Registration at the CAISO DR System. These DRPs must obtain approval from the CPUC's Energy Division for a Customer Notification Form Letter (Form Letter), in hard copy or electronic form, to be provided to each customer explaining the DRP's terms and conditions of participating in the DRP's DR Service.

If the customer is enrolled in SDG&E's Critical Peak Pricing, the Form Letter shall also provide the estimated disenrollment date from Critical Peak Pricing and that the customer may lose bill protection, if applicable. The disenrollment date shall be on the customer's next or future meter read date (see Section C.2.d). The non-Utility DRP must provide the Form Letter to the customer before placing its service account in a DRP's Resource Registration in the CAISO DR System. The Form Letter shall provide any grace period in which the customer can cancel the DR Service enrollment without any charges or penalties.[63]

Rule 32 also provides clearly allocates responsibilities for addressing customer inquiries as follows:

3. Customer Inquiries Concerning Billing-Related Issues

a. Customer inquiries concerning SDG&E's charges or services should be directed to SDG&E.

b. Customer inquiries concerning the non-Utility DRP's charges or services should be directed to the non-Utility DRP.

c. Customer inquiries concerning the LSE's charges or services should be directed to the LSE.

4.Customer Inquiries Related to Emergency Situations and Outages

a. SDG&E will be responsible for responding to all inquiries related to distribution service, emergency system conditions, out ages, and safety

[63] See, SDG&E Tariff Rule 32, section D(3),http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE32.pdf.

situations. Customers contacting the DRP with such inquiries should be referred directly to SDG&E.[64]

Rule 32 subjects enforcement of all rules for DRP registration, including the authority to suspend or revoke a registration to the Commission:

3. Maintenance of DRP Registration at the CPUC

a. The CPUC will post the list of registered DRPs on its website. The CPUC will enforce all rules for the DRP registration and may suspend or revoke a DRP registration if the CPUC determines that the DRP violated Rule 32 or terms and conditions outlined in the CPUC DRP Registration Form. The CPUC may require that the DRP periodically renew its registration to maintain its status.

b. The CPUC will investigate complaints relative to DRP activities and may suspend or revoke a DRP registration if a civil or business court, or the CPUC, finds that the DRP has engaged in activities that warrant such action, after appropriate due process considerations. The CPUC may also allow the DRP to cure any identified deficiencies or inappropriate activities within a reasonable period of time.

c. DRPs shall keep the CPUC registration information up to date.[65]

Rule 32 also clearly allocates responsibilities between the parties as follows:

DRPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement DRP DR Service consistent with all applicable laws, CAISO requirements, CPUC requirements, if any, and this Rule.

4. LSE Is Not Liable for DRP DR Services To the extent the customer takes service from a DRP, the customer's LSE has no obligations to the customer with respect to the services provided by the DRP.

5. DRP is Not Liable for LSE's Services The DRP has no obligations to the customer with respect to the services provided by that LSE. The customer must look to its LSE, not the DRP, to carry out the responsibilities associated with those services.[66]

Finally, Rule 32 includes additional general requirements that are applicable to demand response providers and provide additional consumer protection in the form of requirements on

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[64] *Id*.

[65] *See*, SDG&E Tariff Rule 32, Section E(3).

[66] *See*, SDG&E Tariff Rule 32, Section C.

timeliness and due diligence; scheduling coordinator requirements; limitations on enrolling customers in dual programs; and, access to customer data, etc. For the forgoing reasons, SDG&E respectfully submits that existing "customer protection rules regarding the participation, cost of participation, and ability to not enroll in the program" constitute sufficient "customer protection rules regarding the participation, cost of participation, and ability to not enroll in the program," to meet the requirements of Section 380.5. The Commission retains the continuing jurisdictional authority, in reviewing Demand Response program proposals that may be made by SDG&E, to ensure that residential customers who do not enroll in DR programs do not lose eligibility for rebates, discounts, and other incentives offered to customers who participate in the program or incur charges for not enrolling in the program, consistent with the requirements of Section 380.5.

B. Continuation of DR Study Funding

In D.12-04-045 the Commission authorized $1M per fiscal year for the purpose of performing studies to advance the Commission's demand response goals and directed these studies to be overseen directly by Commission Staff. D.15-02-007 extended this funding to December 31, 2016. If there additional studies of this nature that the CPUC wants conducted in 2017 SDG&E does not object to continuing this funding. It is imperative however, that the utilities and other stakeholders are provided opportunities to participate in the evaluation process in order to ensure the study is accurate and achieves is intended purpose.

C. Addressing new law - AB 793

At the January 12, 2016 workshop to review Commission regulated demand response programs from program year 2015, ALJ Hymes notified participants of her expectation that the IOU's 2017 DRP filings address compliance with recently approved Assembly Bill (AB) 793, which among other things, adds Section 717 to the California Public Utilities Code. Effective January 1, 2016, PUC §717 provides that the Commission will require the SDG&E:

(1) To develop a program no later than January 1, 2017, within its demand-side management programs to provide incentives to a residential or small or medium business customer to acquire energy management technology[67] for use in the customer's home or place of business;

(2) Develop a plan by September 30, 2016, to educate residential customers and small and medium business customers about the incentive program; and

(3) Annually report to the commission on actual customer savings resulting from the incentive program.

SDG&E notes that, to date, no specific guidance has been issued from the Commission regarding compliance with AB 793. Given the timing of ALJ Hymes' request and SDG&E's anticipation of a forthcoming ruling on the matter, SDG&E has no specific proposals to share at this time. However SDG&E has undertaken initial efforts to work with commission Staff to ensure that the AB793 schedule is met and that offerings are coordinated in the various demand side management proceedings. SDG&E anticipates that these requirements will mainly be addressed through the IDSM programs in the Commission's EE proceeding and looks forward to continuing its work with the Commission to develop an approach to satisfy its requirements under PUC § 717. SDG&E notes that current efforts under its TI and SCTD programs (i.e., offering small business incentives, programmable communicating thermostats at no cost to qualifying customers, and the new bring your own thermostat program and rebate proposed

[67] Energy Management Technology may include a product, service, or software that allows a customer to better understand and manage electricity or gas use in the customer's home or place of business.

above) are already contributing to the objective identified in AB 793, but a full analysis of current and future opportunities is underway.

VIII. 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 a portfolio budget of $20,808,000 to continue its DR programs in 2017;
2. Approve the proposed program and activities changes discussed above, which are requested both for market integration purposes and for the purpose overall program improvement;
3. Approve the program and activities that have no changes from the 2015-2016 program design, as described above;
4. Approve SDG&E's pilot proposals provided herein;
5. Approve the proposed revisions to the tariffs, schedules and contracts in Appendix D; and,
6. Approve SDG&E's cost recovery mechanism as described herein.

Respectfully Submitted,

Dated: February 1, 2016

San Diego Gas & Electric Company

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Appendix A

TABLE –A-1
SAN DIEGO GAS AND ELECTRIC
SUMMARY OF UTILITY DEMAND RESPONSE PROGRAMS
AND BUDGETS FOR 2017 BY PROGRAM CATEGORIES
(Thousands of Dollars)

Line	SDG&E Demand Response Programs by Category	Footnote	Budget Authorized for 2016 (Thousands of Dollars)	Budget Requested for 2017 (Thousands of Dollars)
1	Category 1 - Reliability-Based Programs			
2	Base Interruptible Program (BIP)		1,588	943
3	Total		1,588	943
4	Category 2 - Price Responsive Programs			
5	Demand Bidding Program (DBP)	1	878	
6	Summer Saver Program (SSP)	2	-	2,534
7	Capacity Bidding Program (CBP)		4,023	2,181
8	Peak Time Rebate (PTR)	3	162	198
9	Total		4,184	4,913
10	Category 3 - DR Service Provider Managed Programs			
11	Total		-	-
12	Category 4 - DR Enabling Programs			
13	Technology Incentives (TI)		3,196	2,960
14	Small Customer Technology Deployment (SCTD)		3,155	1,430
15	DR Emerging Technology (ET)		706	723
16	Total		7,057	5,113
17	Category 5 – Pilots			
18	New Construction DR Pilot		375	-
19	Summer Saver PTC Pilot	1	-	78
20	Armed Forces Pilot		-	187
21	Over-generation		-	697
22	Demand Response Auction Mechanism (DRAM) 2017	4	-	1,500
23	Total		375	2,462
24	Category 6 - Evaluation, Measurement, and Verification			
25	Evaluation, Measurement, and Verification		1,512	1,535
26	ME Research		200	200
27	Total		1,712	1,735

28	Category 7 - Marketing and Outreach Activities			
29	Local Marketing, Education and Outreach (LMEO)		2,225	885
30	Total		2,225	885
31	Category 8 - System Support Activities			
32	Regulatory Policy & Program Support		786	838
33	IT Infrastructure & System Support		813	2,307
34	Total		1,599	3,144
35	Category 9 - Integrated Programs and Activities			
36	Total		-	-
37	Category 10 - Special Projects			
38	Permanent Load Shifting (PLS)		1,000	1,613
39	Total		1,000	1,613
40	GRAND TOTAL		20,618	20,808

Footnotes:
1. DBP and NCDRP will end in 2016

2. D.04-06-011 Filing for Summer Saver

3. D.13-05-010 for Peak Time Rebate in 2012 GRC (2017 DR application only includes administration and the marketing budget, which is contained in line 29 above)

4. DRAM 2016 was funded through a fund shift from approved 2015-2016 budget, while DRAM 2017 total budget of $1.5 million was approved in Resolution E-4754, OP 9.

San Diego Gas and Electric Company
Approved/Pending Amounts for Demand Response-related Activities
2015-2017

Current Proceeding	Source	Program	Authorization	Cost Description	2015	2016	2017	Memorandum or Balancing Accounts
Demand Response Filing 2015-2016	Demand Response Pleading	Other DR Programs	D.14-05-025	DR Activities and Budgets for 2015-2016: Programs, IT, Admin, Research, marketing for dynamic rates starting 2016.	$18,093,090	$17,956,183		Advanced Metering and Demand Response Memorandum Account (AMDRMA), Rewards and Penalties BA, Energy
	Order Adopting Changes to DR Program s	PLS	D.14-05-025	Permanent Load Shifting	$1,000,000	$2,500,000		AMDRMA, R&PBA, ERRA BA.
	Advanced Metering Infrastructure (AMI)	Peak Time Rebate (aka Reduce Your Use, or RYU)	D.14-05-025	RYU admin & implementation; moved to DR filings with 2015-2016 bridge.	$161,667	$161,666		AMDRMA, R&PBA, ERRA BA.
Demand Response Filing 2017	Demand Response Filing	DR Programs	Filed 2/1/2016	DR Activities and Budgets for 2017: Programs, including Summer Saver and PCTs; Admin, IT, Wholesale Market Integration, Marketing for dynamic rates. Budget for 2017 includes the $1.5M for DRAM 2017.			20,808,370	AMDRMA, R&PBA, ERRA BA for all programs open to DA; cost recovery proposed for programs excluding DA customers and dynamic rates would continue to be recovered in generation rates.
Other Proceedings	RFP for Long Term Resource Planning	Summer Saver	D.04-06-011 R.01-10-024	Original approval of Summer Saver and Budget Update. Funded through SDG&E's Procurement activities through 2016. Moved to DR portfolio in the 2017 DR filing.			Contained in 2017 Filing Budget	Prior to 2017, costs recovered through GRC.
	ERRA	ERRA		DR Portfolio Energy Payments are approved in ERRA annually.				AMDRMA, ERRA BA.
	Advanced Metering Infrastructure (AMI)	Advanced Metering Infrastructure (AMI) and HAN	A.05-03-015 D.07-04-043	Incremental cost recovery for AMI; Education and Outreach for RYU; Home Area Network devices; funding ended in 2012. Device (PCTs, IHD) funding was incorporated into DR filings starting with the 2012-2014 DR cycle in SCTD.			Contained in 2017 Filing Budget	Advanced Metering and Demand Response Memorandum Account (AMDRMA); Rewards and Penalties Balancing Acct.
	Smart Pricing Program Proceeding (SPP)	TOU and TOU Plus (previously called PeakShift @Home PeakShift @Work)	A.10-07-009 D.12-12-004 D. 14-12-046	Incremental cost recovery of $92M for SPP implementation (through 2015). Decision orders marketing to be in the DR filings starting in 2016. Administration is in the GRC.			Marketing for SPP in the DR Filings, starting in 2016.	Generation rates
	DR OIR	DRAM	R.13-09-011 D.14-12-025 Resolution -E for 2016 Advice 2796-E pending for 2017	Authorized Demand Response Auction Mechanism for a 2-year pilot. DRAM 2016 was funded through a fund shift from approved 2015-2016 budget, while DRAM 2017 total budget of $1.5 million was approved in Resolution E-4754, OP 9, and will be funded from unspent funds from the 2015-2016 budget. It is included in the 2017 DR budget as it will be collected after spent per SDG&E's cost recovery mechanism.		$1,000,000	$1,500,000	AMDRMA, R&PBA, ERRA BA.
	2016 GRC	CPP-D, TOU, TOU Plus, SLRP	A.14-11-003	DR Admin Activities for CPP-D, TOU, SLRP, RBRP	$280,000			GENERAL RATE CASE MEMORANDUM ACCOUNT 2016 (GRCMA2016)

Legend:
Green - Authorized
Yellow - Pending

APPENDIX B
Program Implementation Plans (PIPS)

CAPACITY BIDDING PROGRAM
PROGRAM IMPLEMENTATION PLAN (PIP)
2017

Projected Program Budget

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

Program ID#	Program Name	2017 Budget
CBP	Capacity Bidding Program	$ 2,180,832

Program ID#	Program Name	2017 Load Impact
CBP	Capacity Bidding Program	23.1

Program ID#	Program Name	2017 Cost Effectiveness
CBP	Capacity Bidding Program	0.94

PROGRAM DESCRIPTORS (Include the following items)

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

The 2017 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 customersreceiving 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.

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.

Participants may also utilize Technical Assistance Technical Incentive (TA/TI) program and kWickview to provide online presentment solutions that will increase the ability for customers to participate in DR events.
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

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, 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:

1. Non-Residential Customers

2. 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 hours per month for May, June, July and October; 32 hours per month for July and September and 44 hours in Auguest .

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 no later than 3 pm the day before. Utility may notify Participants on Sunday by 3:00 p.m. for a Monday Event. ~~, with the exception for non-Holiday Mondays, notices~~ 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. ~~Notices will be issued by 3:00 p.m. on Sunday for events on non-Holiday Mondays.~~

Day-Of Event: Customers will be notified of an event 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.

- **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.

- **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.
    - 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.
- 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 CBP is open to any commercial, industrial or agricultural customer with an interval meter including Direct Access and CCA customers. Working directly through SDG&E or through an Aggregator, customers choose the event 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 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October.. 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.

- **Incentives (program benefits)**

  - Participants will receive a monthly capacity payment and energy incentives during events in return for load reduction when requested.

- **Program cycle**: 2017

- **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

- **Target audience**: Non-Residential
- **Marketing, Education &Outreach**
- **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. .
- **Customer Research & Feedback**
  The CBP Program will utilize the following tools for research and feedback:
    - 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.

SDG&E long-term goals:

- 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.

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.

- **Addresses strategic drivers**

  - **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.**

- **Innovation**

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

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.

PILOTS

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

(END OF CAPACITY BIDDING PIP)

BASE INTERRUPTIBLE PROGRAM (BIP)
Program Implementation Plan (PIP)
2017

Program Name

Base Interruptible Program (BIP)

Projected Program	2017 Budget	Total 2017 Budget
Base Interruptible Program	$738,105.97	$738,105.97

Projected Load Impacts by Year

Program Name	2017 Load Impact
Base Interruptible Program	4 M

Projected Cost Effectiveness for 2015-2016

Program Name	2017 Cost Effectiveness
Base Interruptible Program	1.1 5

Program Descriptors

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

The Base Interruptible program offers a monthly capacity payment to customers that can commit to curtail at least 15% of Monthly Average Peak Demand, with a minimum load drop of 100 kW. BIP is an Emergency program available to be called year round, not to exceed four (4) hours for any calendar day, or 10 Interruption Periods per calendar month, or 120 hours during any calendar year.

BIP will use the CAISO's Reliability Demand Response Resource (RDRR) in the 2017 program 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.

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 RDRR during the 2017 program year.

BIP program design:

- o 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.
- o Require a least one test event annually if no event is triggered based on program criteria.
- o 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.
- o Participants who fail to comply with a curtailment or test event will have their Firm Service Level reset to the level achieved during the event
- o 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 customer.

Program Fundamentals

See Base Interruptible Program Tariff

<u>Program Rationale and Expected Outcomes</u>

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 SDG&E website, email and/or text if they provide a phone number or email and have 20 minutes from the time of receipt of notice to achieve 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.

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 focused on educating existing customers of program changes and marketing to a targeted group of potential new customers. We will leverage our existing Trade Professional trainings and other trainings provided at the EIC for DR programs.

Aggregator Considerations

BIP is 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 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.

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.

(END OF Base Interuptible Program PIP)~~.~~

Summer Saver Program
Program Implementation Plan
2017

Program Name
Summer Saver Program (SSP)

Projected Program Budget

Program Name	2017 Budget
Summer Saver Program	$2,534,408

Projected Load Impacts by Year

Program Name	2017 Load Impact
Summer Saver Program	15 MW

Projected Cost Effectiveness for 2017

Program Name	2017 Cost Effectiveness
Summer Saver	TBD

Program Descriptors

- **Market Sector**:
  - Residential & Small Commercial <100kW - available to customers receiving Bundled Utility Service, Direct Access (DA) service or Community Choice Aggregation (CCA) and billed on a Utility rate schedule.
- **Program Statement:**
  - The Summer Saver program is an Air Conditioner (AC) cycling program and is proposed as a newly designed program to be included in the Demand Response portfolio and designed to bid a subset of the Small Medium Business (SMB) customers into the CAISO Wholesale Market in 2017 as a Proxy Demand Response (PDR) supply resource as directed by the Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for 2017 Demand Response Programs and Activities dated September 15, 2015.
  - The Summer Saver programs offers an annual customer bill credit based on the tonnage of the customer's AC unit and customer elected cycling option
  - The strategy is to transition all Summer Saver Program participants to the new program with a subset of the Small Medium Business (SMB) customers to bid in the CAISO Wholesale Market in 2017 with the remaining customers reserved for local dispatch for imminent local emergencies or local distribution constraints with a plan to transition the remaining customers in 2018 to bid into the CAISO Wholesale Market. Transitioning all of the existing participants over to the new program will help to preserve the predictable load reduction received on Summer

Saver event days with the cycling of Direct Load Control Devices physically attached to customers air conditioner (AC) unit.

- The program will be marketed to the existing customers to educate and inform them of the new programs changes.
- The recruitment of new customers will continue with its existing process for "change of account" customers, whereby if an existing customer terminates service the new tenant is automatically enrolled in the Summer Saver program with an opt out option. The customer is notified through a direct mail communication.

- The technology that enables SDG&E to provide a signal to the air conditioner (AC) is a one-way Direct Load Control switch. The intent is to continue to provide a mechanism for customers to participate in this program with load reduction associated with central air conditioning and move to newer technologies as the existing devices reach their end of life cycle.

- **Program Fundamentals**
  - In 2017, a subset of the SMB customers will be bid into the CAISO Wholesale Market following the guidelines for a Proxy Demand Response Day Ahead supply resource. In situations where a bid is not awarded, there will be not dispatch.
  - Summer Saver participants will continue to have a choice for various cycling options that offer different incentives, however, customers must remain on the program throughout the event season, May through October in order to earn an annual customer incentive provided as a one time bill credit. The program events hours may be for a minimum of one hour and maximum of 4.5 hours between noon to 9 p.m.
  - Residential participants on the Summer Saver program are eligible to receive a higher Reduce Your Use (RYU) bill credit based on their use of the one way Direct Load Control switch which qualifies as an enabling technology, upon signing up for RYU alerts.
  - Measures
    - Air conditioner units only

<u>Program Rationale and Expected Outcomes</u>

- **Implementation Design**
  - **Delivery mechanisms**
    - SDG&E customers will be contacted through direct mail, cross program marketing, and internet marketing/enrollment, to ensure customers have various channels to continue to enroll and participate in the Summer Saver Program.

    - Events will be called based on the guidelines for PDR bid into CAISO Wholesale Market as a Supply Resource.

- **Incentives**
- Participating customers will receive an annual bill credit based on the AC tonnage on the Nameplate Capacity of the End-Use Equipment and customer elected cycling option.
- **Delivery and coordination**
  - The initial transition for a subset of SMB customers for 2017 with the remaining customers available for imminent local emergencies or local distribution constraints. In 2018, all remaining customers will be available to be included in the bid process for the CAISO Wholesale Market. .
  - Customers are encouraged to sign up for event notification.
  - Enrolled customers will receive the following:
    - Annual preseason reminder describing the new program changes.
    - New customers receive a Reconnect Letter with information that highlights the program design and highlights the positive contribution impacts for participating on the program
    - Access to technology support and help-lines 24/7
- **Program Objectives**
  - The program objective is to continue to receive the 15MW of predicable load drop and preserve the customer participation level, but yet design the program to fit the guidelines of the CAISO Wholesale Market as a Proxy Demand Response supply resource and establish a subset of SMB customers to transition for bidding in 2017.
  - The enabling technologies provided to participants will continue to be essential in obtaining the predictable load reduction minimizing the need for the customer to take actions to initiate load reduction strategies during a Summer Saver event. The existing participants typically don't have the resources to monitor energy use at a granular level and are familiar with "Set it and forget it."

  - The Summer Saver Program will provide at no cost to the customer, a one-way Direct Load Control Switch. The key program goals are to:
    - Optimize DR program participation and awareness
    - Achieve predictable load reduction
    - Optimize the positive customer experience during a Summer Saver event
- **Program cycle**:
  - 2017 Transition Year

<u>Program Strategy</u>

- **Target Audience:**
  - Small Medium Business (SMB) customers The Summer Saver Program goal for 2017 is to maintain the current enrollment of existing Residential and Small Medium Business (SMB) customers <100 kW.
  - Enrolled customers must have an identified air conditioner unit that can be cycled in order to participate in the program.
  - Residential**:**

- The Summer Saver Program goal for 2017 is to maintain the current enrollment of residential customers minus 25% of low performers in the program.
- .

- **Marketing, Education &Outreach**
  - The Summer Saver program Advisor will coordinate with SDG&E's Customer Education Awareness and Outreach (CEAO) to create awareness of the program changes to our existing program participants and ensure that new customers are informed and aware of the importance of Demand Response participation.
  - CEAO will develop marketing materials and messages that make it easy for the customer to participate in the Summer Saver program. .
- **Customer Research & Feedback**
  - The Summer Saver Program will coordinate with Customer Education Awareness and Outreach (CEAO) to 1) educate and inform the awareness about the importance of Demand Response 2) Reminder of the program fundamentals prior to event season. Additional research may be employed to evaluate ongoing activities related to program design changes. These research tools may include:
    - Participant Surveys
    - Focus Groups
    - Smart Meter Interval Data Analysis
    - DR Event Participation Data

- **CAISO**
  - Program will be designed as a Proxy Demand Response Supply Resource
- **Statewide Coordination** N/A
- **Integrated/coordinated DSM**
  - This program will maximize the utilization of Integrated Demand Side Management (IDSM) efforts to help participants identify energy efficiency and renewable opportunities through the promotion of:
    - Energy Efficiency Programs
    - Demand Response Programs
    - Partnerships Programs

- **<u>EM&V</u>**
  - 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. Typically, 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.

  - **<u>Pilots</u>**

We are proposing a Summer Saver Pilot with Programmable Communicating Thermostats (PCT)s to our Direct Access (DA) and Community Choice Aggregation (CCA) customers with newly installed PCTs.

(END OF SUMMER SAVER PROGRAM PIP)

SMALL CUSTOMER TECHNOLOGY DEPLOYMENT
PROGRAM IMPLEMENTATION PLAN (PIP)
2017

Program Name
Small Customer Technology Deployment (SCTD)

Projected Program Budget

Program Name	2017 Budget
SCTD	1,430,000~~?~~

Projected Load Impacts by Year

Program Name	2017 Load Impact		
SCTD	NA		

Projected Cost Effectiveness by Year

Program Name	2017 Cost Effectiveness		
SCTD	NA		

Program Descriptors

- **Market Sector**:
  - Residential & Small Commercial
- **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 pumps, gateways, or any other approved SDG&E technology.
  - 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 participation, use, and acceptance of commercially available demand response technologies.
- The SCTD Program will give participants and the utility the ability to manage various end use electric loads year round through the use of certified 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 customer 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, or the applicable PTR rate bill credit offered.
- Customer 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

<u>Program Rationale and Expected Outcomes</u>

- **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 customer 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 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 will continue to roll out SCTD in a phased approach, depending on 2015 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 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
    - The key program goals are to:
        - Optimize DR program participation and 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**:
    - 2017

<u>Program Strategy</u>

- **Target Audience:**

        - SDG&E residential customer 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 &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 2015 and 2016
        - Based on 2015 results, SDG&E will determine if it is best to continue with the direct install 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 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:
        - Participant Surveys
        - Focus Groups
        - Smart Meter Interval Data Analysis
        - DR Event Participation Data

- **EM&V**
    - An annual 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.
    - Other analysis related to program design (such as a baseline analysis) will be conducted as needed.
    - The 2015-2016 program evaluation will help inform changes/adjustments that can be made in future years to improve the customer experience

(END OF SCTD PIP)

EMERGING TECHNOLOGIES DEMAND RESPONSE
Program Implementation Plan
2017

Program Name
Emerging Technologies Demand Response (ET – DR)

Projected Program Budget

Program Name	2017 Total Budget
Emerging Technology Demand Response	$722,961.02

Projected Load Impacts by Year

Program Name	2017 Load Impact
Emerging Technology Demand Response	N/A

Projected Cost Effectiveness for 2017

Program Name	2017 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.
- Whole Home Connected Appliances/Devices – With the market penetration of various common home appliances it is important to understand their efficacy related to Demand Response as well as interoperability potential. The utility DR programs and Homeowners have many questions around this emerging market and the ET program is well suited to run various field demonstrations to highlight the overall potential. There are several networking hierarchy complexities to be tested to define which approach may be the most cost effective.
- 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.
  - 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

<u>Program Rationale and Expected Outcomes</u>

- **Implementation Design**
  - Emerging Technology starts by identifying technologies from a continued 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 Emerging Technologies Coordinating Council (ETCC) website.
- Program management expresses a recommendation about the utility's further support and involvement, and if applicable, next steps.

- **Program Cycle**
  - 2017

<u>Program Strategy</u>

- **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 (ETCC). Reports on all projects will be published on the ETCC website.
  - The statewide ET-DR team also conducts monthly conference calls to facilitate information sharing and collaboration opportunities.
- **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 (IDSM) will be reported on the IDSM Quarterly reports.

- **<u>EM&V</u>** N/A
- **<u>Pilots</u>** N/A

(END OF EMERGING TECHNOLOGY (ET) DEMAND RESPONSE PIP)

Over-Generation Pilot
Program Implementation Plan (PIP)
2017

Program Name
Over-generation Pilot

Projected Program Budget

Program Name	2017 Total Budget
Over-Generation Pilot	$696,956

Projected Load Impacts by Year

Program Name	2017 Load Impact
Over-Generation Pilot	N/A

Projected Cost Effectiveness for 2017

Program Name	2017 Cost Effectiveness
Over-Generation Pilot	N/A

Program Descriptors
Market sectors:

- Non-Residential

Program Classification:

- Pilot

Program Design:

The main objective of SDG&E's proposed pilot is to use distributed storage facilities to reduce the excessive export of distributed solar to the grid and to mitigate times of system over generation. This problem occurs when the customer's rooftop solar unit generates more energy than the customer needs and the excess is exported to the grid Diverting the excess solar to a storage unit will reduce the volume of renewable energy hitting the grid during its most vulnerable times.

Along with alleviating renewable over-generation issues, SDG&E expects that this pilot program will provide two additional benefits: (1) test whether distributed storage can effectively and economically contribute to the resolution of demand response events; and (2) test how dispatching the battery to serve the customer's load can best benefit their bottom line and incentivize their participation in the pilot.

SDG&E will install a utility-owned distributed storage unit at 10 different commercial customer facilities to effectively capture excess generation from existing customer-installed on-site solar. In an effort to test multiple scenarios, SDG&E will have full control of dispatching the stored energy for the duration of the pilot, and will do so in two distinct ways.

1. During the traditional demand response season (May through October) SDG&E will dispatch the distributed storage at the customer's facilities to address the system needs during demand response events.

2. During non-DR months when over generation issues are most likely to occur, SDG&E will dispatch the distributed storage at the customer's facility to divert excess solar to the storage unit as well as to potentially reduce the customer's daily peak loads. In this scenario, reducing the customer's daily peak should also result in a lower bill, rewarding the customer for their participation in the pilot.

The greatest customer benefit is estimated to be in the winter and spring months[1] when over-generation is expected to be the highest.

Finally, SDG&E will require that the commercial customers selected for the pilot be enrolled in the updated AL-TOU rate that reflects proposed updates to time-of-use periods pending Commission approval[2]. SDG&E will use the updated TOU periods for this pilot because they better reflect actual system conditions. Using TOU rates that reflect actual system conditions will allow SDG&E to test whether accurate TOU periods combined with storage technologies can benefit the grid and individual customers. Adding the revised AL-TOU rate to the over-generation pilot, in conjunction with facility management through the SDG&E installed distributed storage unit will allow SDG&E to study the overall financial impact to the customer as well as the technical capability of the storage units to mitigate over generation events. SDG&E's approach for this pilot has the flexibility to provide a dual benefit to both the customer and the grid.

Target Customers:

SDG&E will obtain 10 customers that have over-generation due to solar. The ideal customer will have enough over-generation to be able to fully charge the distributed storage unit per the manufacturer's specifications to maximize its benefits. SDG&E will analyze the load profile of customers and the amount of hours spent feeding energy back into the grid. If the customer has enough over-generation to maximize the utilization of

[1] Application 15-04-012 - Prepared Direct Testimony of Robert B. Anderson Chapter 3 On Behalf of San Diego Gas & Electric Company

[2] Application No. 15-04-012 Amended Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocation and Electric Rate Design

the distributed storage unit then the customer can be enrolled into the pilot. Only commercial customers will be eligible at this point.

Implementation:

An outline of the implementation process is shown below:

- Customer Application
- Load Profile and Over-generation Analysis Conducted
- Customer Enrollment
- Vendor Installation & Commissioning Report of the Distributed Storage
    - Includes charge/discharge testing
- Must be on current AL-TOU rate
- 1 Year Bill Protection
- Program Triggers (During Demand Response Season Only)
    - 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
    - Whenever the California Independent System Operator has issued an alert or warning notice

Evaluation Measurement & Verification:

To be able to accurately calculate the potential financial benefits to the customer, SDG&E will have to provide sub-metering on the following:

- Solar Panels Output in 15 minute intervals
- Distributed Storage Inlet & Outlet in 15 minute intervals

This information in conjunction with the utility grade meter at a facility is necessary to calculate the annual monetary benefits if any. Since the customer may be feeding less energy into the grid, it is important to compare the dollar value of what *would* have occurred on the NEM tariff vs the dollar value resulting from pilot participation. The trending of the equipment listed above paired with the utility meter will provide the verification needed to display the efficacy of the pilot program.

Budget Development:

The budget has been developed with an estimated 2.6 full time employees (FTE's) to reasonably launch and run the pilot effectively. The FTE titles included in the budget are Manager (.10), Program Advisor (.50), Program Specialist (.20), Account Executive (.30), and Business Analyst (1.5). The total FTE budget is $313,715.53 including salary, payroll taxes, and vacation and sick leave.

The Direct Implementation (DI) portion of the budget makes up vast majority of the budget and consists of the following: Customer application, load profile analysis of consumption and generation, installation and commissioning of distributed storage units, and 1 year bill protection. The DI budget for his pilot is $383,240.00, within the total of requested $696,956.

(END OF THE OVER GENERATION PILOT PIP)

SUMMER SAVER PILOT
Progam Implementation Plan (PIP)
2017

Program Name	2017 Total Budget
SSP/PCT Pilot	$150,000

Projected Load Impacts by Year

Program Name	2017 Load Impact
SSP/PCT Pilot	N/A

Projected Cost Effectiveness for 2017

Program Name	2017 Cost Effectiveness
SSP/PCT Pilot	N/A

Program Descriptors
Market sectors:

- Residential & Small Medium Business (SMB) <100kW - available to customers receiving Direct Access (DA) service or Community Choice Aggregation (CCA) service

Program Classification:

- Pilot

Background:

On September 15, 2015, in R. 13-09-011, the Commission issued its Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for 2017 Demand Response Programs and Activities Proposal. In addition to the Commission's guidance contained therein on general program modifications and improvements.

The Summer Saver Program has been managed as a Demand Response Program through a long term procurement contract that was implemented as part of D.04-06-011. The decision authorized SDG&E to enter into a long term Electric Resource contract with Comverge as a result of our Grid Reliability, Request for Proposal to meet our long term grid reliability needs as part of SDG&E's Long Term Resource Plan (LTRP). The technology for the Summer Saver program has been Direct Load Control (DLC) switches for nearly ten years and we plan to transition customers to newer technology as the existing devices reach their "end of life cycle".

The Small Customer Technology Deployment (SCTD) Program implements Automated Demand Response (DR) enabling technologies to residential and small commercial customers. SCTD gives participants and the utility the ability to manage end use electric loads year round through the use of approved enabling technology, such as Programmable Communicating Thermostats (PCT). These installed technologies empower customers to improve DR participation and manage energy usage.

The objective of the SSP/PCT is to provide Demand Response program offerings to customer's with newly installed PCT enabling technology who take service on Direct Access (DA) or Community Choice Aggregation (CCA) and not currently participating on a Demand Response program or Demand

Response rate. The customer must be billed by the Utility. Currently, the Summer Saver program only uses a Direct Load Control switch technology and through this Pilot we will offer customers with newly installed PCT enabling technology the opportunity to participate in the Summer Saver Program in its newly proposed design as a CAISO Wholesale Market Proxy Demand Response supply resource for transition in 2017.

Program Design:

We will bid the load from the pilot participants into the CAISO Wholesale Market as a Proxy Demand Response supply resource along with the subset of the Small Medium Business (SMB) customers identified for transition in 2017 and described in the proposal for the newly designed Summer Saver Program. Pilot participants will only be bid into the CAISO Wholesale Market with the appropriate authorization from the customer's Energy Service Provider (ESP).

The pilot participants will be dispatched when SDG&E's bid for the Summer Saver program with CAISO has been awarded for dispatch. If the Summer Saver Proxy Demand Response program bid is not awarded, the Pilot program participations will not be dispatched.

The SSP/PCT pilot program participants PCT will be signaled for the SSP/PCT event and earn a customer incentive based on the tonnage of the customer's AC unit Nameplate Capacity of the End-Use Equipment and customer elected cycling option already established in the Summer Saver Program . Customers participating in the Pilot will have a one year commitment to remain in the program. The program enrollment will be capped when program funding is forecasted to be exhausted.

Target Customers:

Small Medium Business (SMB) and Residential customers with appropriate electric metering, taking service on Direct Access (DA) or Community Choice Aggregation (CCA). Customers must already have a newly installed or are scheduled to receive a PCT and are not already participating on a Demand Response program or Dynamic Pricing rate with an event component.

Implementation:

SDG&E will target and encourage customers to join the Pilot and sign up for event notification through SDG&E's website to receive a voice message when a Summer Saver event is scheduled for dispatch. The appropriate equipment for this Pilot will already be installed at the customer premise and will be cycled automatically based on the customer's elected cycling option when a Summer Saver event occurs. An outline of the implementation process is shown below:

- Identify potential candidates for the pilot
- Engage the customers to sign up for the pilot
- Set the customers up in the Ecobee module for notification with appropriate customer elected cycling, verify changes
- Signal the devices an Summer Saver event
- Review reporting results
- Determine the customer incentive at the end of the event season.
- Apply the customer bill credit through the already established process for the Summer Saver program.

END OF THE SUMMER SAVER PILOT PIP

Appendix C

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	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October 44	1
2-6 Hour	2 hours	6 hours	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. 44	1
4-8 Hour	4 hours	8 hours	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. 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	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24	1

(Continued)

			hours in October. 44	
2-6 Hour	2 hours	6 hours	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. 44	1
4-8 Hour	4 hours	8 hours	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. 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	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. 44	1
2-6 Hour	2 hours	6 hours	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August;	1

(Continued)

SCHEDULE CBP

Sheet 3

CAPACITY BIDDING PROGRAM

			32 hours in September; 24 hours in October. 44	
4-8 Hour	4 hours	8 hours	24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. 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/or Day-Of 30 Min product types is defined in Rule 41.

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

(Continued)

SCHEDULE CBP

Sheet 4

CAPACITY BIDDING PROGRAM

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(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

3. Program Operation: (Continued)

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. If 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). L

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. Utility may notify Participants on Sunday by 3:00 p.m. for a non-holiday Monday Event. ~~, with the exception for non-Holiday Mondays, Nn~~ 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. ~~Notices will be issued by 3:00 p.m. on Sunday for events on non-Holiday Mondays.~~ 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 24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. ~~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

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

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 24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. ~~exceed 44 hours.~~

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

4. Program Availability: (Continued)

a. Limitation of Interruptible Periods: (Continued)

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 24 hours in May; 24 hours in June; 32 hours in July; 44 hours in August; 32 hours in September; 24 hours in October. ~~exceed 44 hours~~. N N L L

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:

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

(Continued)

SCHEDULE CBP

CAPACITY BIDDING PROGRAM

Incentive Payment rate as set forth in the table above for such nominated Product.

(Continued)

SCHEDULE CBP

Sheet 12 N

CAPACITY BIDDING PROGRAM N

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. T T

TERRITORY

Within the entire territory served by the Utility.

RATES

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

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~~ N

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. T T T T L

(Continued)

SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

SPECIAL CONDITIONS (Continued)

2. Qualifying Customer (Continued) N

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. N

3. Program Operation L

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. L

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 (FSL) reset to the level achieved during the event by the Utility. The Utility shall notify the customer within 15 business days, of the event occurring, informing the customer of the FSL change. The customer will be required to accept or reject the adjusted FSL within 15 business days of receiving the ~~communications~~notification. In the event of a customer rejecting the FSL update, the customer will be required to provide an FSL or may request a re-test without financial penalty to Customer. If a customer fails to respond, the FSL will automatically default to the reset value. ~~In order for this~~ The adjusted FSL will ~~to be~~take effect~~ive~~ on the first business day of the following ~~for the next~~ program month. ~~the Firm Service Level will need to be submitted by the 15th of the month.~~ N

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. N
L

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 20~~30~~ minutes after the Utility initiates communications to the customer. T

   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) L

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, an 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. T T

In the event of a Program curtailment operation, customers on the Program will be notified using one or more of the above-mentioned systems. 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~~20 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, 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~~ 20 minutes in advance of the Base Interruptible Program Event. T

D

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 ~~as of January 1 .~~the of the following year~~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. N N N

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. T T N

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. L

ARMED FORCES PILOT PROGRAM CONTRACT

FORM XX (TBD)

This Armed Forces Pilot 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 ________, 20__. 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 AFP," attached hereto as Attachment A and incorporated by this reference.

I. AFP ENROLLMENT

The Armed Forces Pilot Program ("AFP") 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 AFP Tariff approved by the California Public Utilities Commission ("CPUC").

Customer's enrollment in AFP shall be conditional until (a) SDG&E approves Customer's AFP 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 AFP.

II. PROGRAM REQUIREMENTS

Once Customer is fully enrolled, upon notification of a curtailment event, Customer shall have Sixty (60) 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: Armed Forces Pilot Program Manager, SDG&E, 8335 Century Park Court, CP12E, 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 AFP; 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 AFP, 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 AFP.

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 AFP. 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 AFP, 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 AFP. 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 AFP, 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 AFP, 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. SETTLEMENTS
An escrow account shall be established to facilitate the payment process and minimize the customers' exposure to risk. Settlements will be made on a semi-annual basis. Bill Credits will be issued within 45 days after June 30th and Dec 31st, 2017.
.

XII. 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 _______________

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:

By _____________________________

Title _____________________________

Date _____________________________

San Diego Gas & Electric Company

By _____________________________

Title _____________________________

Date _____________________________

The following attachments are attached hereto and incorporated by reference:

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

ATTACHMENT A
Schedule AFP

[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 AFP. 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 #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 ___)

THIRD-PARTY MARKETER AGREEMENT
FOR BASE INTERRUPTIBLE PROGRAM

This Third-Party Marketer for Base Interruptible Program Agreement ("Agreement") is made and entered into this ______ day of _________, 20~~0~~__ (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 ____ ("Marketer"), a ______________________________ organized and existing under the laws of the State of ______________________________________. Utility and Marketer may sometimes be referred to herein as a "Party" and collectively as the "Parties".

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

WHEREAS, the CPUC has authorized the participation of third-party marketers in BIP to act as representatives for participating Utility customers, and Marketer desires to participate in BIP 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. MARKETER STATUS

1.1 Status. Marketer's status under this Agreement shall be as a "Marketer" under Electric Rule No. 29, "Third-Party Marketers for Base Interruptible Program" ("Electric Rule No. 29"), which is attached hereto as Attachment B and incorporated herein by this reference. Marketer shall be subject to 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 Electric Rule No. 29 and Schedule BIP, as such rules and regulations may be amended from time to time.

1.2 Representation of Utility Customers. Marketer shall represent those Utility customers eligible to participate in BIP and who have elected to participate in BIP through Marketer with respect to such customer's service account by entering into and maintaining signed contracts with each such eligible customer whereby such customer authorizes Marketer, as its representative, to receive incentive payments and to pay penalty charges on behalf of such customer in connection with such customer's participation in BIP ("Customer Contract"). The Utility shall not be responsible for monitoring, auditing, reviewing or enforcing such Customer Contracts between the Marketer and such customers. Once Marketer has entered into a Customer Contract with an eligible customer, Marketer shall deliver a "Notice by Third-Party Marketer to Add or Delete Customers," in the form attached hereto as Attachment C and incorporated herein by this reference, adding such customer. Marketer may also drop customers from its representation by delivering to Utility the same "Notice by Third-Party Marketer to Add or Delete Customers" dropping such customer. Marketer's delivery of such "Notice by Third-Party Marketer to Add or Delete Customers" shall be a condition precedent to both Marketer's representation of an eligible customer and Marketer's termination of its representation of a customer, as the case may be. Marketer acknowledges that each customer it represents is subject to the terms and conditions of Schedule BIP.

1.3 Eligibility. The customers represented by Marketer in BIP pursuant to a Customer Contract shall have committed, in the aggregate, to provide Utility with the Minimum Load Reduction (as defined in Electric Rule No. 29). If Marketer is unable to achieve or otherwise maintain the Minimum Load Reduction at any time, Marketer shall have fourteen (14) calendar days from the date of such inability to make up the committed load capacity in order to achieve the Minimum Load Reduction. If Marketer fails to achieve the Minimum Load Reduction within such fourteen (14) day period, this Agreement may be terminated, at Utility's sole discretion, and the terms and provisions for such termination as set forth in Electric Rule No. 29 shall apply.

1.4 Definitions. Except where explicitly defined herein, the capitalized terms used in this Agreement shall have the meanings set forth in Electric Rule No. 29 or Schedule BIP.

II. REPRESENTATIONS

2.1 Representations and Warranties. Each Party represents and warrants, 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 Marketer.

2.2.1 With each submission of a "Notice by Third-Party Marketer to Add or Delete Customers" adding a customer with respect to a service account, Marketer represents and warrants, at the time of submission thereof and from time to time until Marketer submits such notice for the removal of such customer from its representation, that:

(a) Such customer is eligible to participate in BIP and has elected to participate in BIP through Marketer;

(b) Such customer has (i) entered into a Base Interruptible Program Contract (Form No. 142-05207) with Utility, (ii) completed a "Notice to Add, Change or Terminate a Third-Party Marketer for Base Interruptible Program" (Form No. 142-05216) 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 BIP and designation of such Marketer (including, without limitation, an "Authorization To: Receive Customer Information or Act on a Customer's Behalf"); and

(c) Marketer has entered into a Customer Contract with such customer whereby such customer has authorized Marketer to receive incentive payments from and to pay penalty charges to Utility on behalf of such customer in connection with such customer's participation in BIP.

2.2.2 With each submission of a "Notice by Third-Party Marketer to Add or Delete Customers" dropping a customer with respect to a service account, Marketer represents and warrants that:

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

(b) Such customer has (i) completed a "Notice to Add, Change or Terminate a Third-Party Marketer for Base Interruptible Program" (Form No. 142-05216) and delivered such notice to Utility, and (ii) delivered all such other documents, instruments, consents and agreements as any be required for terminating Marketer's representation of such customer in BIP with respect to such service account.

III. <u>SECURITY</u>

Marketer acknowledges that it has provided, prior to the execution of this Agreement, any and all financial information of Marketer required by Utility. Marketer acknowledges that Marketer 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, Marketer shall deliver any security required by Utility pursuant to Electric Rule No. 29. Additionally, Marketer 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 Marketer has adversely affected Marketer's creditworthiness subsequent to the execution of this Agreement, or (b) Marketer 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 Marketer to provide additional security as provided in Electric Rule No. 29.

IV. <u>BILLING AND PAYMENT</u>

4.1 <u>Billing and Payment Terms</u>. During the term of this Agreement, each Party shall make the payments or credits to the other Party as provided in Electric Rule No. 29.

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

If to Marketer:

____
____
____

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 Marketer:

____

____

If to Utility:

____

____

4.4 Disputed Bills or Charges. Marketer agrees to resolve any disputed bills and/or charges in accordance with Electric Rule No. 29.

V. TERM

The term of this Agreement shall commence on the Effective Date and shall terminate three (3) years from the Effective Date, unless terminated earlier pursuant to Section 6 below.

VI. TERMINATION

6.1 Termination by Utility. If payment is not received within seven (7) days of the issuance of a past due notice, or upon any other breach of this Agreement by Marketer, Marketer's participation in BIP pursuant to this Agreement will be subject to termination by Utility as set forth in Electric Rule No. 29. In addition, if Utility receives any notification that Marketer has filed or will be filing any type of bankruptcy, or is closing its business, Marketer's participation in BIP pursuant to this Agreement shall be terminated immediately, subject, however, to any bankruptcy laws that take precedence of the rules set forth in Electric Rule No. 29 in respect of such bankruptcy. Utility's termination rights set forth in this Section 6.1 shall be in addition to any rights and remedies as may be provided by law or in equity as a result of Marketer's failure to pay, breach, bankruptcy or other actions or omissions.

6.2 Rights and Responsibilities. The Parties' rights and responsibilities following termination of this Agreement are set forth in Electric Rule No. 29.

VII. LIMITATION OF LIABILITY

Utility's liability to Marketer 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 Marketer for any indirect, special, consequential or punitive damages of any kind whatsoever, whether in contract, tort or strict liability.

VIII. INDEMNIFICATION

8.1 Indemnification of Utility. To the fullest extent permitted by law, Marketer 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 Marketer under this Agreement, (b) any act or omission of Marketer, whether based upon Marketer'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 Marketer'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, Marketer 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 Marketer may exist with respect to such Claim. If a conflict precludes Marketer from assuming the defense, then Marketer shall reimburse the Indemnified Parties on a monthly basis for the Indemnified Parties' defense costs through separate counsel of the Indemnified Parties' choice. If Marketer 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 Marketer of any of its obligations hereunder.

8.3 Survival. Marketer'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 Marketer, 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 Marketer:

____
____
____
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. Marketer shall not disclose any Confidential Information obtained pursuant to this Agreement to any third party, including any affiliates of Marketer, 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 Marketer prior to obtaining the same from Utility; (b) information in the public domain at the time of disclosure by Marketer; (c) information obtained by Marketer 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. Marketer hereby agrees that it shall use the Confidential Information solely for the purpose of performing under this Agreement. Marketer agrees to use at least the same degree of care Marketer 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, Marketer may disclose any of the Confidential Information in the event, but only to the extent, that, based upon advice of counsel, Marketer 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, Marketer shall provide Utility with prompt written notice of any such requirement so that Utility (with Marketer'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 five (5) 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 Marketer are specifically enforceable. Accordingly, the Parties agree that in the event of a breach or threatened breach of this Section 10 by Marketer, 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 Marketer hereunder, shall not be further transferred or assigned by Marketer without the prior written consent of Utility. Any assignment in violation of this Section 11.1 shall be void.

11.2 Independent Contractor. Marketer 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 Marketer disputes a Utility bill, the resolution of such dispute shall be as set forth in Electric Rule No. 29.

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 BIP
Attachment B: Electric Rule No. 29 – Third-Party Marketers for Base Interruptible Program
Attachment C: Notice by Third-Party Marketer 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 Marketer have executed this Agreement as of the Effective Date.

UTILITY:	MARKETER:
SAN DIEGO GAS & ELECTRIC COMPANY	
By: ______________________________	By: ______________________________
Signature: ________________________	Signature: ________________________
Name: ____________________________	Name: ____________________________
Title: _____________________________	TtIle: _____________________________

Form 142-05215
(04-06)

SCHEDULE SSP

 N

SUMMER SAVER PROGRAM N

APPLICABILITY

The Summer Saver Program (SSP) is a voluntary demand response program that offers options to Residential and Small Medium Business (SMB) customers <100kW with central Air Conditioner (AC) units installed at their premise This schedule is available to customers receiving Bundled Utility Service, Direct Access (DA) service or Community Choice Aggregation (CCA) and is being billed on a Utility rate schedule. Service on this schedule must be taken in combination with the customer's otherwise applicable rate schedule.

Electric Rule 32 guidelines will apply to this tariff.

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.

An additional annual customer incentive will be paid and applied as a bill credit based on the customer's Air Conditioner (AC) unit's tonnage and customer elected cycling option.

Residential	Incentive Amount Per Ton	Commercial	Incentive Amount Per Ton
100% cycling	$27.00	50% Cycling	$ 7.50
50% cycling	$11.50	30% Cycling	$ 4.50

SPECIAL CONDITIONS

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

2. Qualifying Customer: Service under this schedule is available to residential and commercial customers <100kW 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. 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.

3. Program Operation: Adhere to the guidelines for Proxy Demand Response (PDR) Day Ahead Supply Resource bid, award and dispatch.

Annual Maximum Number of event hours	80
Maximum Consecutive events	Three
Hours Available	Noon to 9 p.m.
Event Duration	1 to 4.5 hours
Trigger	Heat rate 19,000 Btu/kWh
Months Available	July, August, September for CAISO Wholesale Market, May through October for local dispatch

(Continued)

SCHEDULE SSP

N

SUMMER SAVER PROGRAM

N

SPECIAL CONDITIONS (Continued)

3. Program Operation: (Continued)

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

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

c. The Program's operational days are Monday through Sunday during the Program's operational season.

d. The Program's operational hours are from Noon to 9:00 p.m. during each of the Program's Operational days.

e. Interruptible Period: Each interruptible period ("Event") shall be the period of time during which the Utility has sent a signal to the Direct Load Control device for cycling the AC unit for a minimum of one (1) hour and maximum of four and a half hours (4.5).

f. Interruptible Period Termination: An Event will terminate at the end of the scheduled load reduction period not to exceed 4.5 hours.

g. Program Trigger

The Utility may call an Event whenever the Utility's electric system supply portfolio reaches a resource dispatch equivalence of 19,500 Btu/kWh heat rate, or as Utility system conditions warrant.

i. 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.

ii. July, August, September

The Utility will call an Event whenever the CAISO Wholesale Market awards a bid for the applicable supply resource. SDG&E may also call one test event per month.

SDG&E will bid into the CAISO Wholesale Markets using the heat rate for each month as listed, until the available hours are exhausted.

Month	Heat Rate
July, August, September	18,700 Btu/kWh

(Continued)

SCHEDULE SSP

Sheet 3 N

SUMMER SAVER PROGRAM N

SPECIAL CONDITIONS (Continued)

3. Program Operation: (Continued)

g. Program Trigger (Continued)

ii. July, August, September (Continued)

The hourly Heat Rates are the highest 4-hour average Heat Rate by day and then ranked by month. The value provided is the 3rd highest ranked for July, August and September. The 3rd highest price was chosen because that results in 12 event hours which is half of the 24 hour availability requirement. The heat rates in the table above will be used for bidding unless they need to be adjusted for opportunity costs due to availability limits. SDG&E will reserve the right to change the trigger annually using the 12 hour criteria based on market conditions. The heat rate was calculated based on data for SDGE DLAP Day Ahead LMP prices from 2013-2015 for HE12-19 for weekdays versus the SoCal City Gate gas price for the respective days and then a "by hour" Heat Rate is calculated.

The hourly Heat Rates are the highest 4-hour average Heat Rate by day and then ranked by month. The value provided is the 3rd highest ranked for July, August and September.

iii. May through October

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.

iii. SDG&E may also call events for imminent local emergencies or local distribution constraints.

4. Program Availability: An Event may be called during the Program's operational season, operational days and operational hours as defined above.

5. Incentive Payments: Incentive payments will be paid annually as a bill credit based on AC tonnage based on the Nameplate Capacity of the End-Use Equipment and customer elected cycling option.

6. Event Notification: Customers are encouraged to sign up for a courtesy event notification voice message through SDG&E's website at www.summersaverprogram.com

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

8. 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.

Technology Incentives
Project Application

ABOUT THIS FORM

This Application enables San Diego Gas & Electric Company (SDG&E®) customers to apply for incentives from SDG&E's Technology Incentives Program for qualifying measurable automated demand response measures. The Technology Incentives Program offers incentives for the purchase and installation of qualified demand response measures that provide verified, dispatchable, on-peak load reduction at customer-owned facilities. Eligible customers can receive up to $300 per kW of verified, dispatchable, fully automated on-peak load reduction. The total incentive is limited to the actual, reasonable cost of the installed measure(s).

CUSTOMER REQUIREMENTS

To be eligible for a technology incentive from SDG&E's Technology Incentives Program, any commercial, industrial, or agricultural customer with a monthly on-peak demand of 20 kilowatts (kW) or greater, servicing the facilities for which the incentives are being requested, must:

- Receive bundled or direct access electric service from SDG&E
- Be billed on a commercial, industrial, or agricultural Time of Use rate schedule
- Have appropriate electrical metering billed on intervals, and receive 15-minute interval data

The demand response measure must be a commercially available technology, and enable fully automated, dispatchable load reduction at the customer-owned facility. Please note:

- SDG&E's Technology Incentives Program will not provide incentives for manual or semi-automated equipment or for load reduction enabled by customer behavior changes.
- SDG&E, at its sole discretion, will conduct one or more site visits to verify actual, dispatchable load reduction
- Customers must accommodate a request for each required on-site visit within five (5) business days

The Service Account listed on this Application must be enrolled in at least one of the following SDG&E demand response programs and participate per the terms and conditions for at least 3 years*:

- Base Interruptible Program (BIP)
- Capacity Bidding Program (CBP)
- Critical Peak Pricing – Default (CPP-D)
- Eligible Pilots

*If the Service Account currently participates in a qualifying demand response program, enrollment must continue per the terms and conditions for a period of at least 3 years from SDG&E's approval of the incentive. Customer is responsible for providing proof of enrollment.

HOW TO APPLY

Eligible customers must complete, sign, and submit this Application with all required supporting documentation to:

SDG&E
Attn: Technology Incentives Program Advisor
8335 Century Park Court CP12C
San Diego, CA 92123-1569

or

drp@semprautilities.com

WHAT TO EXPECT

1. SDG&E will review the Application and work with the Customer and Project Sponsor to clarify and resolve any outstanding issues.
2. SDG&E will schedule and perform a pre-inspection at the Site location.
3. After reviewing the Application and pre-inspection information, SDG&E will determine if the project qualifies for an incentive, and if approved, will send the form of Agreement to the Project Sponsor.
4. The Project Sponsor must fill out, sign, and submit the Agreement to SDG&E.
5. Upon receipt of a fully completed and executed Agreement, SDG&E will send a Permission to Proceed notice with installation

of the Technology Incentives Program measures. (Note: installation of measures prior to receipt of this Permission to Proceed may disqualify the project from participation and may cause forfeiture of potential Technology Incentives.)

6. Customer/Project Sponsor purchases and installs the qualifying demand response measure(s).
7. After installation, the Project Sponsor will notify SDG&E that the measures are installed by submitting an Installation Report (which requires Project Sponsor to provide proof of purchase and installation of the qualifying demand response measures by attaching the actual invoice from the installer to the report).
8. SDG&E will schedule a Post Inspection and Load Shed Test.
9. Upon completion of the Post Inspection and Load Shed Test, SDG&E will verify the eligible load reduction and calculate the incentive. To enable your participation in the Technology Incentives Program, and to validate incentive payments, SDG&E may share the last 12 months of your energy consumption data and/or billing information with your Project Sponsor and/or SDG&E's Technology Incentives contractor. For more information about your energy privacy, including SDG&E's privacy policy and privacy notice, please visit **sdge.com/privacy**.
10. SDG&E will send payment to the Customer (or to a third-party per Customer's authorization) for the incentive.

Questions

Call SDG&E Demand Response Programs at 1-866-377-4735 or email drp@semprautilities.com

INCENTIVE PAYMENT

The incentive is up to $300 per kW of verified dispatchable load reduction, not to exceed 50% of the actual, reasonable cost of the installed measure(s) (including the purchase price and any costs associated with installation by a third-party). Any in-house costs associated with installation will not be considered part of the cost of the installed measure(s).

For approved and inspected projects, the incentive will be paid as follows:

- **Beginning January 1st, 2017, the payment method of the Technology Incentives program will operate under a split payment method:**
    - ~~Installation~~ Incentive Payment: 100% of the total incentive will be paid after installation, load shed test and enrollment in a qualified DR program or rate.
    - ~~Performance Payment: Up to the remaining 50% of the total incentive will be paid at the end of the first Demand Response season or calendar year as applicable to the program or rate. This performance-based rate is based on the actual amount of participation in the DR program as determined during the DR season. The full 50% incentive balance will be paid if the customer's participation is equal to or greater than the load reduction estimated by the load shed test. If the actual performance is less than the estimated load reduction, the Performance Payment will be reduced proportionally with the measured load reduction during the DR program season. (Note: If the actual performance falls below 50% of the load shed test amount, SDG&E will invoice the customer for the difference between the paid Installation Payment and the actual performance amount.)~~

The Technology Incentives Program's incentives are paid on a first-come, first served basis until program funds are no longer available or until the Technology Incentives Program is terminated, whichever comes first. The Program is administered by SDG&E under the auspices of the California Public Utilities Commission and may be modified or terminated at any time.

A Sempra Energy utility

Technology Incentives Project Application

APPLICATION FORM

CUSTOMER INFORMATION

CUSTOMER / BUSINESS OWNER / BUILDER /DEVELOPER

Company Name

Company Mailing Address | City | State | ZIP

Contact Name | Title

Contact Telephone Number | Contact Fax Number | E-Mail

Tax Identification Type (Select Only One)	Tax Status (Select Only One)
○ Federal Tax ID ____	○ Corporation ○ Individual
○ SSN ____	○ Non-Corp ○ Exempt
	Exempt Reason____

PROJECT SITE INFORMATION
(Site of Retrofit / Project)

Site Address | City | State | ZIP

Contact Name at Project Site | Contact Phone Number | Contact Email Address

Electric Account Number | Electric Account Number | Electric Account Number | Electric Account Number | Electric Account Number

Gas Account Number | Gas Account Number | Gas Account Number | Gas Account Number | Gas Account Number

Total Sq. Ft of Facility | Years since built or last major renovation

PROJECT SPONSOR
(Vendor/Contractor/Energy Services Co.) (CUSTOMER TO COMPLETE ONLY IF NOT SELF-SPONSORING)

I, Customer, have entered into a contract with the Project Sponsor indicated below for the installation of demand response measures at the project site listed above. I authorize SDG&E to send all correspondence directly to the Project Sponsor specified below.

Address | City | State | ZIP

Contact Name | Title

Contact Telephone Number | Contact Fax Number | Email Address

PLEASE ANSWER THE FOLLOWING QUESTION

Was an audit performed to identify measures? ☐ Yes, please select one of the following ☐ No

☐ SDG&E ☐ SDG&E On-Line Business Energy Advisor ☐ Energy Assessment & Solutions ☐ CIEEP

☐ HEEP ☐ LEEP ☐ Other, please specify: ____

Technology Incentives Project Application

APPLICATION FORM

PAYMENT INFORMATION

(To be completed only if check is NOT payable to Customer.)

CHECK SHOULD BE MADE PAYABLE TO:

Payee: Customer / Business Name	Telephone Number	Fax Number
Mailing Address City	State	ZIP
Contact Name	Title	Email

Tax Identification Type (Select Only One)

○ Federal Tax ID ______________________

○ SSN ______________________

Tax Status (Select Only One)

○ Corporation
○ Non-Corp
○ Individual
○ Exempt
Exempt Reason ______________

Incentives are generally considered subsidies for tax purposes and could be taxable. You are urged to consult your tax advisor concerning the taxability of these incentives. Incentives greater than $600 will be reported to the IRS on Form 1099 unless you have checked corporation or exempt tax status. San Diego Gas & Electric Company (SDG&E) is not responsible for any taxes that may be imposed on your business as a result of your receipt of any incentive.

PAYMENT RELEASE AUTHORIZATION (Customer signs below if incentive is directed to a third party)
As the customer of record, I authorize the incentive payment will be made to the third party named above and I understand that I will not be receiving the incentive check from SDG&E. I also understand that my release of the payment to the third party does not exempt me from the program requirements.

Customer Authorization: (Please print Name and Title)

Signature

Date

Demand Response Program Participation Requirement

Customer elects to satisfy the Technology Incentives Program's demand response program participation requirement as follows (select one):

☐ The Service Account is currently participating in one of the qualifying demand response programs listed in this Application, and Customer agrees to continue to participate in such program per program terms and conditions for a period of 3 years from the date the Technology Incentives Program Project Application is approved.

☐ The Service Account is not currently participating in any of the qualifying demand response programs. Customer plans to enroll the Service Account in one of the qualifying demand response programs and participate per program terms and conditions for a period of 3 years from the date the Technology Incentives Program Project Application is approved or from the date of enrollment in a qualified DR program, whichever is later. Customer shall send proof of enrollment to the Technology Incentives Program Advisor.

Which demand response program will the Service Account participate in?

☐ Base Interruptible Program (BIP)
☐ Capacity Bidding Program (CBP)
☐ Critical Peak Pricing – Default (CPP-D)
☐ Other ______________

AGREEMENT

Application Checklist

Before submitting this Application, please ensure you have included all required documentation, which may include:

☐ Completed Application Form
☐ Open ADR 2.0 Certificate (Automated Demand
☐ Response) Calculations of estimated savings per
☐ measure Specification sheets for all hardware to be
☐ installed Control points for projects (noted in scope of
work)

I understand that I am solely responsible for the selection, purchase and ownership of measures and services under this program. I understand that the demand reduction, incentives and installed costs are estimates only and are subject to change based on SDG&E review and approval. I understand that SDG&E has made no representation or warranty regarding the qualifications of the Project Sponsor, and that I am solely responsible for the selection of the Project Sponsor to implement the project. I understand that the Project Sponsor is an independent contractor and is not authorized to make any representation on behalf of SDG&E. I agree that SDG&E will have no role in resolving any disputes between me, the Project Sponsor and/or any other third parties.

I have authority to contract, on behalf of the legal owners of the project site, for installation of the measures, or I have obtained the permission of the legal owner of the project site to install demand response measures under my contract with the Project Sponsor. I understand the program may require inspections and measure ments of the performance of measures installed; therefore, I agree to provide access to the project site for those purposes to SDG&E and/or its agents or assigns.

Technology Incentives Project Application

APPLICATION FORM

A separate Technology Incentives Agreement will be provided for signature by the Project Sponsor upon approval by SDG&E.

As a qualified SDG&E customer, I certify that the indicated demand reduction measures are for use in my business facility and not for resale. I agree to provide SDG&E with documents establishing paid proof of purchase for the measures applied for in this application package and product installations. I understand the incentive payments are based on the related demand reduction as determined by the Load Shed Test and applicable performance measurement. I agree that if (1) I do not provide SDG&E with 100% of the related energy benefits by enrolling the full demand reduction in a qualified SDG&E Demand Response program for a period of three (3) years from receipt of the incentive, whichever is less, or (2) I cease to be a customer of SDG&E during said time period, I shall refund a prorated amount of incentive dollars to SDG&E based on the actual period of time for which I provided the related energy benefits as a customer of SDG&E.

The customer may receive an incentive payment of up to $300/kW of verified load reduction, not to exceed the cost of the project. This program has a limited budget. Applications are accepted on a first-come, first-served basis until program funds are no longer available, or December 31, 20170~~014~~, whichever comes first. This program is funded by California utility customers and administrated by SDG&E under the auspices of the California Public Utilities Commission. This program may be modified or terminated without prior notice.

SDG&E MAKES NO REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, INCLUDING THE WARRANTY OF MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE, USE OR APPLICATION WITH RESPECT TO ANY INCENTIVES, MEASURES, AND/OR TECHNOLOGIES DESCRIBED HEREIN, AND ASSUMES NO LIABILITY, WITH RESPECT TO THE QUALITY, SAFETY, PERFORMANCE, RELIABILITY OR EFFICIENCY OF ANY MEASURE INSTALLED OR COMPONENTS THEREOF, AND SDG&E EXPRESSLY DISCLAIMS ANY SUCH REPRESENTATION, WARRANTY OR LIABILITY. I AGREE TO INDEMNIFY SAN DIEGO GAS & ELECTRIC, ITS AFFILIATES, SUBSIDIAR- IES, PARENT COMPANY, OFFICERS, DIRECTORS, AGENTS AND EMPLOYEES AGAINST ALL LOSS, DAMAGE, EXPENSE, FEES, COSTS AND LIABILITY ARISING FROM ANY CLAIMS, SUITS, OR DEMAND RELATED TO OR IN CONNECTION WITH ANY MEASURES INSTALLED.

SDG&E shall not be liable for any special, incidental, indirect, or consequential damages, including without limitation, loss of profits or commitments to subcontractors, and any special, incidental, indirect or consequential damages incurred by Project Sponsor or Customer.

I have read and understand the program requirements and terms and conditions set forth in this application package and agree to abide by such requirements and terms and conditions. I certify that the information provided in this application package is true, correct and complete in all respects and that the project(s) for which I am requesting incentive(s) meet the program requirements set forth in this application package. I understand and agree that I must meet all eligibility criteria in order to receive a payment under this program. I agree that I have not received rebates, incentives or services for the same measures from other utilities, state or local programs funded by the Public Goods Charge.

RELEASE OF INFORMATION If the CPUC requests review of your project, SDG&E will provide the CPUC with all of the information requested without further notifica tion to you. If you refuse to allow the CPUC, its staff or its contractors and/or consultants to have access to your data, you will not be allowed to participate, and you will be ineligible to receive any program incentives. Please note that if you designated a project sponsor, a similar notification has been forwarded to them as well. In the event your project is selected for review, SDG&E will mark your data as confidential before submitting your files to the CPUC in accordance with California Public Utilities Code Section 583 and CPUC General Order 66-C.

Signature ______________________ Date ______________________

Customer Contact Name (Print) ______________________ Title ______________________ Company Name ______________________

Technology Incentives Project Application

Measure Summary - Attachment 1

Project Name:________________________________ Project Sponsor: ________________________________

DEMAND RESPONSE LOAD REDUCTION SUMMARY

Provide brief description of each measure. The total measure cost includes, but is not limited to, audits, design, engineering, construction, materials, permits, fees, overhead and labor. Provide costs for each measure. Please note that kW values must match the calculations provided.

Measure No.	Demand Response Measure	Baseline (kW)	Post Retrofit (kW)	Estimated Curtailable Load (kW)	Estimated Equipment Cost	Estimated Installation Cost	Estimated Other Cost	Estimated Total Cost
1								$
2								$
3								$
4								$
5								$
6								$
7								$
8								$
9								$
10								$

Total Estimated Dispatchable Load Reduction ______________

Estimated Total Project Cost $ ___________

Incentive Rate x $300/kW

Maximum Incentive **$** _____________

Technology Incentives (TI) Program
Project Agreement

SDGE connected
A Sempra Energy utility℠

CUSTOMER INFORMATION

CUSTOMER / BUSINESS OWNER / BUILDER / DEVELOPER

Company Name

Company Mailing Address | City | State | ZIP

Contact Name | Title

Contact Telephone Number | Contact Fax Number | Email

Tax Identification Type (Select Only One): Federal Tax ID ____ SSN ____

Tax Status (Select Only One): Corporation Individual Non-Corp Exempt Exempt Reason ____

PROJECT SITE INFORMATION
(Site of Retrofit / Project)

Project Name

Site Address | City | State | ZIP

Contact Name at Project Site | Contact Phone Number | Contact Email Address

Electric Account Number | Electric Account Number | Electric Account Number | Electric Account Number | Electric Account Number

Gas Account Number | Gas Account Number | Gas Account Number | Gas Account Number | Gas Account Number

Total Sq. Ft of Facility | Years since built or last major renovation

CONTRACTED MEASURES, LOAD DROP, AND INCENTIVE

Measure No.	Demand Response Measure (Technology)	Estimated Curtailable Load (kW)	Estimated Total Cost
1			$
2			$
3			$
4			$
5			$
6			$
7			$
8			$
9			$
10			$

Total Estimated Dispatchable Load Reduction ____________________ **Estimated Total Project Cost $**____________

TI Incentive Rate x $300/kW

Maximum TI Incentive (based on load reduction) $________________ Reduction in incentive due to Cost Cap: $____________

Maximum TI Incentive under this Agreement: $____________

TERMS AND CONDITIONS:

This Technology Incentives (“Agreement”) is entered into by San Diego Gas & Electric Company (“SDG&E”) and ______________________________ (the “Project Sponsor”). SDG&E and Project Sponsor may be individually referred to as a “Party” and collectively as the “Parties.”

1.0 **PROJECT DESCRIPTION** **This Agreement is limited to the ~~2012-2014~~ 2017 Technology Incentives Project(s)** (“Project(s)”) described on the ~~2012-2014~~2017 Technology Incentives Program (“Program”) Application executed by Project Sponsor and all forms attached thereto (“Application”) and incorporated by reference into this Agreement. As stated in the Application, SDG&E shall pay Project Sponsor, or such other party properly authorized to receive payment, incentives in accordance with the terms and conditions of this Agreement.

2.0 **DOCUMENTS INCORPORATED BY REFERENCE** **The following documents are hereby incorporated by reference and made part of this Agreement:**

1) The Application,
2) SDG&E acceptance letter(s) or email(s) of the demand reduction measures proposed in the Application, and
3) The Technology Incentives Policy Manual (“Policy Manual”).

3.0 **ELIGIBILITY** Program funding is limited and is available on a first-come, first-served basis until program funds are no longer available, or December 31, 2014, whichever comes first. Funds will be reserved only upon SDG&E’s approval of the Application. Projects must meet the following requirements to be eligible for payment of Program incentives (“Incentive(s)”):

1) Project Site must be a nonresidential facility located within SDG&E’s service territory;
2) Customer must pay the Public Purpose Program (“PPP”) surcharge, Public Goods Charge (“PGC”) surcharge or the Gas Demand Side Management (“DSM”) surcharge, within SDG&E’s service territory, on the gas or electric meter on which the energy efficiency measure listed in the Final Approved Savings Amount table above is installed throughout the Term of this Agreement;
3) Project Sponsor and Customer must not receive any funds from any other program (technology incentive, energy efficiency, or otherwise) funded by the PPP surcharge, PGC surcharge or the DSM surcharge, the CEC or the California Public Utilities Commission (“CPUC”) for the Project or any measure applied for herein. Project Sponsor represents and warrants that neither Project Sponsor nor Customer has received or will receive any funds from any other program funded by the PPP surcharge, PGC surcharge or the DSM surcharge, the CEC or the CPUC for the Project or any measure applied for herein;
4) The customer-owned facility must be receiving bundled or direct access electric service from SDG&E, must have an Interval Data Recorder (IDR) electrical meter, receiving 15 minute interval data, and must be billed on a SDG&E commercial, industrial or agricultural, Time of Use rate schedule;
5) The demand response measure(s) must:
   a. Be a commercially available technology; and
   b. Enable fully automated, dispatchable, load reduction at the customer-owned facility. (The TI Program will not provide incentives for manual or semi-automated equipment or for load reduction enabled by customer behavior changes.); and
6) Projects must meet all other Program requirements, terms and conditions.

4.0 **SUBMITTAL REQUIREMENTS FOR PAYMENT** Project Sponsor shall submit to SDG&E the documents described below prior to being eligible for payment of any Incentives. Required documents include the following:

1) This completed and executed Agreement;
2) Complete engineering calculations to demonstrate potential load reduction (kW) and documentation, if applicable (including archival files, if applicable);
3) Schematic drawings and/or manufacturer specification sheets, if applicable;
4) Invoices and/or documentation to support measure costs. Such documents must comply with SDG&E’s TI Invoicing Guidelines;
5) Project Installation Report; and
6) Any other documents related to the Project, Project Site, measures, load reduction (kW) or otherwise requested by SDG&E, in its sole discretion.

5.0 **INSPECTIONS** Project Sponsor is solely responsible for ensuring that SDG&E has reasonable access for all inspections and load shed tests required under the Program, including, but not limited to, the following: (1) pre-installation equipment inspection to examine the existing/ baseline equipment and to check the accuracy of Project Sponsor’s equipment survey; (2) post- installation equipment inspection to check installed equipment and to verify accuracy of Project Sponsor’s equipment survey; (3) load shed test; and (4) inspection for any other reason that SDG&E, in its sole discretion, deems necessary.

6.0 **REVIEW AND DISCLAIMER** SDG&E’S AND/OR ITS CONSULTANTS’ REVIEW OF THE DESIGN, CONSTRUCTION, OPERATION OR MAINTENANCE OF THE PROJECT OR DEMAND RESPONSE MEASURES (“DRMs”) SHALL NOT CONSTITUTE ANY REPRESENTATION AS TO THE ECONOMIC OR TECHNICAL FEASIBILITY, OPERATIONAL CAPABILITY, OR RELIABILITY OF THE PROJECT OR DRMs, NOR SHALL PROJECT SPONSOR, IN ANY WAY, MAKE SUCH A REPRESENTATION TO A THIRD PARTY. PROJECT SPONSOR IS SOLELY RESPONSIBLE FOR THE ECONOMIC AND TECHNICAL FEASIBILITY, CONSTRUCTION, OPERATIONAL CAPABILITY AND RELIABILITY OF PROJECT SPONSOR’S PROJECT AND EEMs. SDG&E MAKES NO WARRANTY, WHETHER STATUTORY, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR ANY PARTICULAR PURPOSE, USE OR APPLICATION.

7.0 **PAYMENTS** Payments of Incentives will be made only after all Program requirements are met by Project Sponsor to SDG&E’s sole satisfaction. Project Sponsor may authorize payment of the Incentives to Customer, and Customer may authorize payment of the Incentives to Project Sponsor. Such authorization is strictly between Customer and Project Sponsor and may be revoked or modified at any time by providing written notification to SDG&E specifying the change. Should a dispute arise regarding the authorization, the most recently dated written communication or authorization shall govern.

7.1 SDG&E retains sole discretion to determine the appropriate baseline values and methodology / calculations used to verify the actual dispatchable load reduction enabled by the installed qualifying technology. Incentives shall only be paid on Projects that result in verifiable load shed due to the approved technology. SDG&E reserves the right to modify or cancel the Incentive amount if the actual measure installed differs from the measure described in Project Sponsor’s approved Application(s).

7.2 The total Incentive payment shall not exceed the total incentive amount listed in the Final Approved Savings Amount table in this Agreement. The total Incentive payment will be limited by a Customer Project Site Cap of approximately 15% of the average annual ~~2012-2014~~2017 Technology Incentives Budget for the relevant calendar year, and/or the Project Cost Cap of 100% of the total measure costs of the project, whichever is less.

7.3 The total Incentive payment is based on the calculated demand reduction derived from the actual use of electricity provided by SDG&E. Electricity provided by any party other than SDG&E, including, but not limited to, cogeneration or deliveries from another commodity supplier, do not qualify (with the exception of Direct Access customers or customers paying departing load fees for which SDG&E collects the PPP surcharge, the PGC surcharge and/or the DSM surcharge).

7.4 SDG&E will make the applicable Incentive payment to the designated payee, in one (1) or more installments, only after all required and/ or requested documents have been submitted to and approved by SDG&E and the appropriate inspection(s) of the Project or Project Site have been completed to SDG&E's satisfaction.

7.5 All Projects and/or measures must be installed and fully operational three (3) years from approval date to be eligible for Incentive payments. SDG&E reserves the right to cease making Incentive payments, require the return of Incentive payments and/or terminate this Agreement if the Project(s) is not installed and fully operational three (3) years from the approval date, unless an extension is granted by SDG&E, at its sole discretion.

8.0 PAYMENT DISQUALIFICATION Any Incentives received by Project Sponsor shall be repaid to SDG&E, in whole or in part, as follows:

8.1 If Customer fails to pay the PPP surcharge, the PGC surcharge or the DSM surcharge at any time during the Term of this Agreement, Project Sponsor shall refund to SDG&E any prorated amount of the Incentive dollars that SDG&E determines must be repaid, in its sole discretion, based on the energy savings that occurred during the payment of the PPP surcharge, the PGC surcharge or the DSM surcharge.

8.2 If (1) Project Sponsor does not provide SDG&E with 100% of the related benefits specified in the Application for a period of three (3) years from the Project Installation Report approval date, or (2) the energy benefit to SDG&E ceases in any way during the three (3) year period from the Project Installation Report approval date, including, but not limited to, Customer and/or the Project Site ceasing to receive electricity service from SDG&E, the measure, equipment and/or Project ceasing to function, or Customer ceasing the use of the equipment, measure or Project Site, Project Sponsor shall refund to SDG&E any prorated amount of the Incentive dollars that SDG&E determines must be repaid, in its sole discretion, based on the actual period of time for which Customer provided the energy benefit.

8.3 Project Sponsor shall repay any amounts due to SDG&E within thirty (30) calendar days of notification by SDG&E that repayment is required in accordance with Sections 8.1 and 8.2 above. SDG&E shall be entitled to offset against payments owed to Project Sponsor any amount due to SDG&E that remains unpaid forty (40) calendar days after SDG&E'S written demand for payment.

9.0 TERM AND TERMINATION The term of this Agreement shall commence on the last date that a Party executes this Agreement and shall terminate no later than five (5) years from the Project Installation Report approval date, unless terminated earlier pursuant to this Agreement ("Term").

10.0 ASSIGNMENT Project Sponsor consents to SDG&E's assignment of all of SDG&E's rights, duties and obligations under this Agreement to the CPUC and/or its designee. Such assignment shall relieve SDG&E of all rights, duties and obligations arising under this Agreement. Other than SDG&E's assignment to the CPUC or its designee, neither Party shall assign its rights or delegate its duties without the prior written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation without written consent shall be null and void. Consent to assignment shall not be unreasonably withheld. If an assignment is requested, Project Sponsor is obligated to provide additional information if requested by SDG&E.

11.0 PERMITS AND LICENSES Project Sponsor, at its own expense, shall obtain and maintain and cause its contractors and/or subcontractors to obtain and maintain licenses and permits required by federal, state, local, or other relevant governing or regulatory bodies to perform its work. Any failure by Project Sponsor or its contractors and/or subcontractors to maintain necessary licenses and permits constitutes a material breach of Project Sponsor's obligations under this Agreement.

12.0 ADVERTISING, MARKETING AND USE OF SDG&E'S NAME Project Sponsor shall not use SDG&E's corporate name, trademark, trade name, logo, identity or any affiliation for any reason, including to solicit customers to participate in the Project, without SDG&E's prior written consent. Project Sponsor shall make no representations to its customers on behalf of SDG&E.

13.0 INDEMNIFICATION Project Sponsor shall indemnify, defend and hold harmless, and release SDG&E, its affiliates, subsidiaries, parent companies, officers, directors, agents and employees, from and against all claims, demands, losses, damages, costs, expenses, and liability (legal, contractual, or otherwise), which arise from or are in any way connected with any: (i) injury to or death of persons, including, but not limited to, employees of SDG&E or Project Sponsor; (ii) injury to property or other interests of SDG&E, Project Sponsor, or any third party; (iii) violation of local, state, or federal common law, statute, or regulation, including, but not limited to, environmental laws or regulations; or (iv) strict liability imposed by any law or regulation; so long as such injury, violation, or strict liability (as set forth in (i) - (iv) above) arises from or is in any way connected with Project Sponsor's performance of, or failure to perform, this Agreement, however caused, regardless of any strict liability or negligence of SDG&E whether active or passive, excepting only such loss, damage, cost, expense, liability, strict liability, or violation of law or regulation that is caused by the sole negligence or willful misconduct of SDG&E, its officers, managers or employees.

13.1 Project Sponsor acknowledges that any claims, demands, losses, damages, costs, expenses, and legal liability that arise out of, result from, or are in any way connected with the release or spill of any legally designated hazardous material or waste as a result of the work performed under this Agreement are expressly within the scope of this indemnity, and that the costs, expenses, and legal liability for environmental investigations, monitoring, containment, abatement, removal, repair, cleanup, restoration, remedial work, penalties, and fines arising from strict liability, or violation of any local, state, or federal law or regulation, attorney's fees, disbursements, and other response costs incurred as a result of such releases or spills are expressly within the scope of this indemnity.

13.2 Project Sponsor shall, on SDG&E's request, defend any action, claim or suit asserting a claim that may be covered by this indemnity. Project Sponsor shall pay all costs and expenses that may be incurred by SDG&E in enforcing this indemnity, including reasonable attorney's fees. This indemnity shall survive the termination of this Agreement for any reason.

13.3 If this Agreement is assigned pursuant to Section 10.0, Project Sponsor agrees that this indemnification shall continue to apply to SDG&E and shall apply to the assignee.

14.0 LIMITATION OF LIABILITY SDG&E shall not be liable for any special, incidental, indirect, or consequential damages, including without limitation, loss of profits or commitments to subcontractors, and any special, incidental, indirect or consequential damages incurred by Project Sponsor or Customer.

15.0 WRITTEN NOTICE Any written notice, demand or request required or authorized in connection with this Agreement shall be deemed properly given if delivered in person or sent by facsimile, email, nationally recognized overnight courier, or first class mail, postage prepaid, to the address specified below, or to another address specified in writing by SDG&E.

Technology Incentives (TI) Program
Project Agreement

SDG&E			
Program Manager			
Utility			
Address			
City		State	Zip
Fax Number		Phone Number	
PROJECT SPONSOR			
Name			
Company			
Address			
City		State	Zip
Fax Number		Phone Number	

Notices shall be deemed received (a) if personally or hand-delivered, upon the date of delivery to the address of the person to receive such notice if delivered before 5:00 p.m., or otherwise on the Business Day following personal delivery; (b) if mailed, three (3) Business Days after the date the notice is postmarked; (c) if by facsimile or email, upon electronic confirmation of transmission, followed by telephone notification of transmission by the noticing Party; or (d) if by overnight courier, on the Business Day following delivery to the overnight courier within the time limits set by that courier for next-day delivery.

16.0 CONFLICTS BETWEEN TERMS Should a conflict exist between this Agreement and the documents incorporated by reference, this Agreement shall control. Should a conflict exist in the documents incorporated by reference, the documents shall control in the following order: 1) Program Manual; 2) SDG&E acceptance letter(s) and incentive estimate(s) based on DRMs as approved in the Application(s); and 3) Project Sponsor's approved Application(s). Should a conflict exist between an applicable federal, state, or local law, rule, regulation, order or code and this Agreement, the law, rule, regulation, order or code shall control. Varying degrees of stringency among the main body of this Agreement, the documents incorporated by reference, and laws, rules, regulations, orders, or codes are not deemed conflicts, and the most stringent requirement shall control. Each Party shall notify the other immediately upon the identification of any conflict or inconsistency concerning this Agreement.

17.0 MISCELLANEOUS This Agreement shall at all times be subject to such changes or modifications by the CPUC as it may from time to time direct in the exercise of its jurisdiction. This Agreement shall be governed and construed in accordance with the laws of the State of California, without regard to its conflict of laws provisions. If any provision of this Agreement shall be held by a court of competent jurisdiction to be illegal, invalid or unenforceable, the remaining provisions shall remain in full force and effect. This Agreement constitutes the entire agreement and understanding between the Parties as to the subject matter of this Agreement and supersedes all prior agreements, representations, writings and discussions between the Parties, whether oral or written, with respect to the subject matter hereof. No amendment, modification or change to this Agreement shall be binding or effective unless expressly set forth in writing and signed by SDG&E's representative authorized to execute the Agreement.

18.0 PAYMENT METHODOLOGY The Technology Incentive will be paid as follows:

- ~~For customers who have completed a load shed test and provided proof of enrollment in a DR program by December 31st, 2012, the Technology Incentives Program will pay 100% of the incentive at that time.~~

~~• Beginning January 1st, 2013, the payment method of the Technology Incentives program will operate under a split payment method:~~

~~o Installation Payment - 60% of the total incentive will be paid after installation, load shed test, and upon enrollment in a qualified DR program or rate.~~

~~o Performance Payment – As much as the remaining 40% of the total incentive will be paid at the end of the first Demand Response season or calendar year as applicable to the program or rate. This performance-based rate is based on the actual amount of participation in the DR program 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 load reduction estimated by the load shed test. If the actual performance is less than the estimated load reduction, the Performance Payment will be reduced proportionally with the measured load reduction during the DR program season. (Note: If the actual performance falls below 60% of the load shed test amount, SDG&E will invoice the customer for the difference between the paid Installation Payment and the actual performance amount.)~~

INCENTIVE PAYMENT

The incentive is up to $300 per kW of verified dispatchable load reduction, not to exceed 50% of the actual, reasonable cost of the installed measure(s) (including the purchase price and any costs associated with installation by a third-party). Any in-house costs associated with installation will not be considered part of the cost of the installed measure(s).

For approved and inspected projects, the incentive will be paid as follows:

- **Beginning January 1st, 2017, the payment method of the Technology Incentives program will operate under a split payment method:**
  - ~~Installation~~ Incentive Payment: 100% of the total incentive will be paid after installation, load shed test and enrollment in a qualified DR program or rate.

- Customer must establish enrollment in a DR program or rate by submitting a copy of the enrollment confirmation provided by SDG&E. Prior to issuing the TI incentive, Project Sponsor must receive authorization from SDG&E which will occur upon acceptance and verification of DR program enrollment.

19.0 RELEASE OF INFORMATION If the CPUC requests review of this project, SDG&E will provide the CPUC with all of the information requested without further notification to you. If you refuse to allow the CPUC, its staff or its contractors and/or consultants to have access to the project data, this project will be excluded from this Program and ineligible to receive incentives. In the event this project is selected for review, SDG&E will mark your data as confidential before submitting your files to the CPUC in accordance with California Public Utilities Code Section 583 and CPUC General Order 66-C.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the date set forth below.

UTILITY	PROJECT SPONSOR	CUSTOMER

By:	By:	By:
Title:	Title:	Title:
Name Printed:	Name Printed:	Name Printed:
Date:	Date:	Date:
Signature:	Signature:	Signature:

Agreement is to be reviewed and signed by an authorized representative of the Project Sponsor. The Agreement should then be returned to SDG&E. Upon receipt, SDG&E will send an email authorizing work on the project (No work is to be performed prior to receipt of the Work Authorization Email.). SDG&E will then execute the Agreement and send a copy to the Project Sponsor.

~~2015 - 2016~~2017 Permanent Load Shifting Incentive Application

Section 1 - Customer Information

SDG&E customers applying directly for the program must complete section A. Customer's Authorized Agent applying on behalf of the customer must complete Parts A and B.

A. Customer [To be completed by Customer or Customer's Authorized Agent]

Company/Business Name	Contact Name	Title

Company/Business Mailing Address	City	State ZIP

Contact Phone Number	Contact E-mail Address

B. Customer's Authorized Agent [To be completed by Customer's Authorized Agent]

Authorized Agent Business Name	Contact Name

Authorized Agent Mailing Address	City	State ZIP

Authorized Agent Phone Number	Authorized Agent E-mail Address

Section 2 - Project Site Information

This section is for a single project site.
For more than one project site, please create a separate application.

Project Name	Account Number	Service Address	ZIP Code
EXAMPLE Store #1234	***3-000-0000-00***	***111 Main St.***	***91001***

Rate	NAICS Code	Year Built	Total Sq Ft./Facility
TOU-8	***33***	***1950***	***10,000***

Days & Hours of Operation	Site Contact Name	Site Contact Ph. Number	Contact E-mail Address
M-F 6am-11pm	***Victor Johnson***	***626-555-0901***	***vjohnson@tdi.com***

Section 3 - Summary of the Scope of Work

List a general description of the proposed system, expectations and overall benefits of applying for this program

Section 4 - Feasibility Study Information

An engineering Feasibility Study will be required for all customers applying for this program. This study is to provide an evaluation of the technical feasibility and economic viability of installing a new Thermal Energy Storage (TES) system at the customer site. The study is to be completed by a professional Mechanical Engineer, licensed and registered in the State of California. Refer to the PLS Program Guidelines (www.sdge.com/pls) for Feasibility Study requirements.

Have you identified who will perform the Feasibility Study for this project?	
What is the name of the Engineering Firm performing the Study?	
What is the expected Feasibility Study submittal date?	

Section 5 - New Equipment Incentive Calculations

Refer to the PLS program Handbook (www.sdge.com/pls) for program eligibility, requirements and incentive amount. Read the eligibility requirements before proceeding with our equipment purchase. Thermal Energy Storage Systems installed before applying for the Permanent Load Shifting Program will not be eligible for incentives.

Project Information

	Example	
Has the TES System already been installed?	*NO*	
What is the date of Actual or Proposed Installation?	*12/11/2014*	
What is the Estimated Project Cost? (OPTIONAL)	*$50,000*	

Section 5 Cont'd – New Equipment Incentive Calculations

Incentive Calculation

EXAMPLE

Max Annual Demand (kW)	Estimated Cooling Load Shift (kW) = A	Estimated Cooling Load Shift (kW) A	X Incentive $ Per kW B	= Incentive Total C
1500	*500*	*500*	*$875.00*	*$437,500.00*

Section 6 – Equipment Ownership

Select who will be the owner of the Thermal Energy Storage System installed

A. ☐ **Customer**

B. ☐ **Other (Please Specify ____)**

Section 7 – Payment Information and Customer Acknowledgement

Complete the section below to let us know how you would like to be paid.

A. FORM OF PAYMENT (Please check one)

If you answered A on Section 6, select this option

☐ Incentive Check to Customer [Complete B and C]

If you answered B on Section 6, select this option

☐ Incentive Check to third-party Payee (e.g., contractor) [Complete B, C, and D. Note: Provide third-party Payee information in section C]

B. PAYEE INFORMATION

☐ Check here if Payee is same as Section 1, Part A (if Payee Customer) or Part B (if Payee is Customer's Authorized Agent). Complete below if you answered B on Section 6, Payee Name should be the owner of the Thermal Energy Storage equipment.

Section 7 Cont'd – Payment Information and Customer Acknowledgement

Payee-Customer Business Name	Attention To (Name to be printed on check. Use only if required)	Title

Company/Business Mailing Address	City	State ZIP

Contact Phone Number	Contact E-mail Address

C. PAYEE TAX IDENTIFICATION TYPE (Please Check one)

☐ **Federal Tax ID/Employer ID Number [EIN]**

☐ **Social Security Number [SSN]**

Identification Number ________________

Identification Number ________________

D. PAYEE TAX STATUS (Please Check one)

☐ **Corporation/LLC**

☐ **Individual/Sole Proprietor/General Partnership**

☐ **Tax-exempt/Non-profit**

Exempt Reason ________________

I understand that incentives may be subject to income tax, and if greater than $600 could be reported to the IRS unless the payee (i.e., the party receiving the incentive) is exempt. As part of a completed application package, the payee will be required to submit to SDG&E a complete W-9 (Request for Taxpayer Identification Number and Certification) and CA-590 (California Withholding Exemption Certificate) to confirm their tax status. SDG&E could report incentives as income on IRS form 1099 based on tax status reflected on W-9 and CA-590. I understand that payees should consult their tax advisor concerning the taxability of incentives, and that SDG&E is not responsible for any taxes that may be imposed due to program incentive payment(s).

D. PAYMENT RELEASE AUTHORIZATION (PLEASE COMPLETE THIS SECTION IF A CUSTOMER AUTHORIZED AGENT IS TO RECEIVE THE CHECK)

As the Customer, I am authorizing this payment of my incentive to the Payee named in Section 7, Part B, above, and I understand that I will not be receiving the incentive check from SDG&E. I also understand that my release of this payment to the Payee does not exempt me from the requirements outlined in the Application package.

Customer Name (Please Print)	**Signature**	**Title**	**Date**

Section 8 – Application Checklist

Required documentation to be submitted with your completed application:

1. Payees (Section 7, Part B of this application) must submit a completed W-9 and CA-590. If Payee is an SDG&E Partnership partner, only submit a completed W-9.
2. For all Projects you must submit:
   Tax ID Information - For the party receiving incentives ("Payee").

Section 9 – Incentive Checklist

Required documentation to be submitted to receive incentives:

1. Proof of Payment - Submit an Invoice, a Purchase Order, or a Lease Agreement. See below for what each must include.

Invoice/Store Receipt must include:	Purchase Order must Include:	Lease Agreement must Include:
• Date of Purchase • Full description of new equipment • Vendor contact name, job title, contact info, address • Invoice # • Page # of # • Labor Cost detail (include hourly or per unit rate, classification of work) • Sub-contractor invoices	• Date of order or delivery • Payment Forms • Customer's (Section 1, Part A) signature	• Lease start date and length • Payment terms • Customer's (Section 1, Part A) signature

Section 10 - Applicant Agreement Regarding Program Terms and Conditions

I, the Applicant (and Customer's Authorized Agent of the Applicant, if applicable), hereby agree (the "Agreement") to the following terms and conditions to my participation in: Permanent Load Shifting Program. The PLS Program is identified and further described in the appropriate Permanent Load Shifting Program Guidelines (www.sdge.com/pls), as applicable.

1. Incorporation by Reference: The Application (together with all applicable attachments) is hereby incorporated by reference into, and made a part of, this Agreement.
2. Limitation on Funding Availability: Each Program has limited funding and is offered on a first-come, first-served basis until funding is depleted or the Program is terminated, whichever comes first. I further understand that submission of this Application is not a guarantee of payment by SDG&E, nor is it a guarantee of fund availability. Upon SDG&E's approval of this Application and SDG&E's execution of a Program project agreement, incentive funds will be reserved by SDG&E; however, payment of any incentive is subject to a Post-install Inspection and final approval from the utility.
3. Changes to Program: Funding and conditions of the Program is subject to the jurisdiction of the California Public Utilities Commission ("CPUC"), and shall be subject to such changes or modifications as the CPUC may, from time to time, direct in the exercise of its jurisdiction. I understand that if the Program is modified in any way or terminated by order of any government entity, then this Agreement shall be revised or terminated consistent with that order. In addition, SDG&E may suspend or terminate any agreement related to the Program without cause (and without prior written notice) if SDG&E determines suspension or termination of the agreement is necessary in order to make changes to the related Program or if SDG&E is ordered by the CPUC to modify or discontinue a Program and/or any agreements related to a Program. I agree that SDG&E will not be liable for any damages or compensation of any kind that may result from the changes described in this paragraph 3.
4. Right of Assignment: SDG&E may assign any agreement related to my participation in a Program, in whole or in part, or its rights and obligations hereunder, directly or indirectly, by operation of law or otherwise, without my prior written consent, provided SDG&E remains obligated for payments incurred prior to the assignment. I may not assign this Application, in whole or in part, or my rights and obligations hereunder, directly or indirectly, by operation of law or otherwise without the prior written consent of SDG&E.
5. Site Access Requirements: The Program may require installations, audits, inspections, measurements of the performance of the project, and/or verification of installation of the system. Therefore, I agree to provide reasonable access to the project site(s) for these purposes to SDG&E and/or its agents, assigns, or contractors and the CPUC and/or its agents or assigns.
6. Authorized Services: I understand that SDG&E employees, contractors and/or agents are authorized to provide only the services described in this Application for the Programs. SDG&E assumes no responsibility for any services, installations, improvements or equipment offered or provided to me by an SDG&E employee, contractor or agent other than those specified in this Application or that have not been authorized by SDG&E.
7. Release and Use of Information: I authorize SDG&E to release my contact and other relevant information to SDG&E's employees, contractors and/or agents for purposes related to my participation in the Program(s). I further authorize SDG&E's employees, contractors and agents to contact me with regard to the initiation, performance, and/or verification of any of the terms and conditions of the applicable Program.
8. Calculation of Energy Savings: SDG&E will not pay incentives for any energy savings in excess of the actual annual amount of my electricity usage at each SDG&E service account for which incentives are requested.
9. Equipment Eligible for Incentives: Equipment must meet existing building code standards for existing and new construction. Be commercially available and have a proven track record within the marketplace, have a 5-year warranty from the TES vendor. Refurbished equipment is not eligible for Program incentives with exception of refurbished tanks.
10. Method for Calculation of Incentive Payments: I understand that SDG&E pays up to $875/kW (not to exceed 50% of the actual final installed total equipment cost). Permanent Load Shifting Incentives payments to an individual SDG&E customer cannot exceed $1.5 million per program cycle ~~2012-2014~~2017. Customers will be issued qualified incentive payout after the Thermal Energy Storage (TES) system has been installed and has passed all the necessary Post-install Inspection requirements and receives final approval from the utility.Limitations on Incentive Payments: To be eligible for Program incentives, I understand that if I am not in good standing on all of my service accounts and contracts with SDG&E or do not meet the program requirements; SDG&E may hold my incentives or apply them towards amounts I owe to SDG&E. I agree that I have not and will not apply for or receive rebates, incentives or services for the solution(s) covered by this Application from any other utility, state or local program funded by the Public Goods Charge (PGC). I further agree that I will not apply or receive rebates, incentives, or services for the incentive(s) covered by this Application in an amount greater than the total cost of the solution(s). Because the Programs are funded by California utility ratepayers and administered by SDG&E under the auspices of the CPUC, I may face adverse consequences (i.e., a requirement that I return payments that were made to me or a restriction on my eligibility to participate in other programs) if I violate these restrictions.

Section 10 Cont'd - Applicant Agreement Regarding Program Terms and Conditions

12. Estimated Savings May Not Equal Actual Savings: I understand that all energy savings, incentives, and installed costs provided by SDG&E during the Program Application process are estimates only, and are subject to change based on SDG&E review and approval and that I am solely responsible for the selection, purchase, installation and ownership of the equipment and services under the Programs.
13. Energy Benefits: As a qualified SDG&E customer, I certify that the indicated energy savings products are for use in my project site and not for resale. I agree to provide SDG&E with documents establishing paid proof of purchase and installation of the Thermal Energy Storage (TES) system applied for in this Application. I understand the incentive payments are based on related energy benefits over the life of the product. I agree that if (a) I do not provide SDG&E with 100% of the related energy benefits specified in the rebate form for the life of the product or for a period of five (5) years from receipt of rebate, whichever is less, or (b) I cease to be a customer of SDG&E during said time period, I shall refund a prorated amount of rebate dollars to SDG&E based on the actual period of time for which I provided the related energy benefits as an electric customer of SDG&E.
14. Risk Allocation: I UNDERSTAND THAT SDG&E MAKES NO REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, REGARDING MANUFACTURERS, DEALERS, CONTRACTORS, MATERIALS OR WORKMANSHIP, OR REGARDING SELECTION OR QUALIFICATION OF CUSTOMER AUTHORIZED AGENTS. I ALSO UNDERSTAND, AND HAVE CAUSED MY CUSTOMER AUTHORIZED AGENT (IF ANY) TO UNDERSTAND, THAT SDG&E MAKES NO WARRANTY, EXPRESS OR IMPLIED, INCLUDING WITHOUT LIMITATION THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR ANY PARTICULAR PURPOSE, USE, OR APPLICATION OF THE PRODUCTS OR SOLUTIONS. I AGREE TO INDEMNIFY, DEFEND AND HOLD HARMLESS, AND HEREBY RELEASE SDG&E, ITS AFFILIATES, SUBSIDIARIES, PARENT COMPANY, OFFICERS, DIRECTORS, AGENTS AND EMPLOYEES OF EACH OF THEM, FROM AND AGAINST ALL CLAIMS, DEMANDS, LOSSES, DAMAGES, COSTS, EXPENSES, AND LIABILITY (LEGAL, CONTRACTUAL, OR OTHERWISE), WHICH ARISE FROM OR ARE IN ANY WAY CONNECTED WITH ANY OF THE PROGRAMS.

~~2015 - 2016~~2017 Permanent Load Shifting Incentive Application

MUST BE COMPLETED BY APPLICANT

I hereby acknowledge the following:

☐ By checking this box, I confirm that I will use an appropriately licensed contractor, where applicable, and will obtain all required permits for this installation.

I hereby acknowledge the following (check ONLY ONE of the following options):

☐ I am SELF-ADMINISTERING this project. Upon project approval, if applicable to requested Program, I intend to enter into an agreement with SDG&E for delivery of energy savings/cooling load shift resulting from the installation of TES system at the project site listed in Section 2 of this Application.

☐**Verification and Certification:** I affirm that I am authorized to enter into this Agreement and that I have read, understand, and agree to all of the specific terms, conditions and other requirements and restrictions set forth in this Agreement for the Program in this Application for my participation. I certify that the information I have provided in the Application that accompanies this Agreement is true and correct, and the project for which I am requesting Program funding meets all applicable requirements as set forth in this Application. Furthermore, I understand and agree that I meet all eligibility requirements for participation in the Program for which I am applying. SDG&E reserves the right to request additional information to verify Applicant's eligibility to participate in the Program.

Customer Name (Please Print)	Signature	Title	Date

Customer Name (Please Print)	Signature	Title	Date

Return electronic copy of the completed form by email and hard copy with signature by U.S. mail to:

SDG&E PROGRAM CONTACT INFORMATION			
Contact	**SDG&E Demand Response Programs**		
Phone	**866-377-4735**	Address	**8335 Century park Ct. CP12C**
Fax	**858-385-3950**		**San Diego, CA 92123**
Email	DRP@semprautilities.com		

SCHEDULE AFP

Sheet 1 N

ARMED FORCES PILOT PROGRAM N

APPLICABILITY

The Armed Forces Program Pilot (AFP) offers a monthly capacity payment to Armed Forces customers who can commit to curtail at least 15% of Monthly Average Peak Demand, with a recommended minimum load reduction of 100 kW, but is not required, and who request service on this schedule and comply with the Special Condition contained herein.

Armed Forces Pilot 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 Charge 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

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 tariff is exclusively for all branches of the Armed Forces who are time-of-use metered customers and can commit to curtail at least 15% of Monthly Average Peak Demand, with a recommended minimum load reduction of 100 kW, but is not required, and who request service on this schedule and comply with Special Condition.

   a. This tariff is available to bundled, Direct Access, and Community Choice Aggregation (CCA) customers. Qualifying customers are required to complete an Armed Forces Trial Pilot program Contract with SDG&E in order to participate in this Schedule AF Pilot.

   b.

(Continued)

SCHEDULE AFP

Sheet 2 N

ARMED FORCES PILOT PROGRAM N

SPECIAL CONDITIONS (Continued)

2. Qualifying Customer: (Continued)

c. New Customers: New applicants to the AF Pilot 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. AF Pilot 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 by the utility. Future participation payments will be based upon the newly adjusted
Firm Service level.

f. Changes to Firm Service Level: 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.

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 AFP 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.

(Continued)

SCHEDULE AFP

N

ARMED FORCES PILOT PROGRAM

N

SPECIAL CONDITIONS (Continued)

3. Program Operation (Continued)

   h. Firm Service Level: Customer's or aggregator's group maximum expected level of demand, as specified by the customer in the Armed Forces Pilot Program Contract (Form XX), 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: An AFP 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 60 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.

   f. Special One-Time Opt-Out Window:

      Special One-Time Opt-Out Window: Customers receiving service under this Schedule may upon written notice to SDG&E exercise one of the following options:

      i. Terminate service under Schedule AF Pilot 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;

      ii. 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 the signed Amendment to the Armed Forces Pilot Program Contract (Form XX)

(Continued)

SCHEDULE AFP

Sheet 4 N

ARMED FORCES PILOT PROGRAM N

SPECIAL CONDITIONS (Continued)

5. Program Availability. AFP is available to be called year round. AFP 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: The Interruptible Periods shall not exceed four (4) hours for any calendar day, 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 Armed Forces Pilot 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.

   c. Settlements: An escrow account shall be established to facilitate the payment process and minimize the customers exposure to risk. Settlements will be made on a semi-annual basis. Bill Credits will be issued within 45 days after June 30th and Dec 31st.

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

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, an 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 AF Pilot 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. 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 60 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, e-mail system or Internet site by which the customer received notification.

(Continued)

SCHEDULE AFP

 N

ARMED FORCES PILOT PROGRAM N

SPECIAL CONDITIONS (Continued)

9. Event Notification/Communication: (Continued)

   a. Advance Notification: Customers will be notified 60 minutes in advance of the Base Interruptible Program Event.

10. Event Cancellation: Once an AFP 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 an Armed Forces Pilot Program Contract (Form XX) 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 AFP.

   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 AFP 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 December 31, 2017 unless extended, modified or terminated by SDG&E and such modifications are approved by the CPUC.

14. 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. 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, AFP 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 AFP compliance.

(Continued)

SCHEDULE AFP

Sheet 6 N

ARMED FORCES PILOT PROGRAM N

SPECIAL CONDITIONS (Continued)

15. Utility Testing: At the Utility's discretion, AFP 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 an AFP 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 an AFP 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 n 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 AFP tariff, Special Condition 7 (b), failure to comply with an AFP 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 Armed Forces Pilot Program will be handled as provided for in the Utility's Rule 10, Disputes.

20. Direct Access and CCA customers: AFP 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 AF Pilot compliance.

ARMED FORCES PILOT PROGRAM CONTRACT

FORM XX (TBD)

This Armed Forces Pilot 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 ________, 20__. 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 AFP," attached hereto as Attachment A and incorporated by this reference.

I. AFP ENROLLMENT

The Armed Forces Pilot Program ("AFP") 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 AFP Tariff approved by the California Public Utilities Commission ("CPUC").

Customer's enrollment in AFP shall be conditional until (a) SDG&E approves Customer's AFP 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 AFP.

II. PROGRAM REQUIREMENTS

Once Customer is fully enrolled, upon notification of a curtailment event, Customer shall have Sixty (60) 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: Armed Forces Pilot Program Manager, SDG&E, 8335 Century Park Court, CP12E, 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 AFP; 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 AFP, 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 AFP.

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 AFP. 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 AFP, 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 AFP. 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 AFP, 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 AFP, 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. SETTLEMENTS
An escrow account shall be established to facilitate the payment process and minimize the customers' exposure to risk. Settlements will be made on a semi-annual basis. Bill Credits will be issued within 45 days after June 30th and Dec 31st, 2017.

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XII. 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 ______________

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:

By ___________________________

Title ___________________________

Date ___________________________

San Diego Gas & Electric Company

By ___________________________

Title ___________________________

Date ___________________________

The following attachments are attached hereto and incorporated by reference:

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

ATTACHMENT A
Schedule AFP

[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 AFP. 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: ______________________________

Appendix D

ATTACHMENT D
Customer Account Information

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 ___)

Will Fuller
Regulatory Case Manager
San Diego Gas & Electric Company
8330 Century Park Court
San Diego, CA 92123-1530
Telephone: (858) 654-1885
wfuller@semprautilities.com

January 21, 2016

A. 08-06-002

Ed Randolph
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: REPORT OF SAN DIEGO GAS & ELECTRIC COMPANY ON INTERRUPTIBLE LOAD AND DEMAND RESPONSE PROGRAMS FOR DECEMBER 2015

Dear Mr. Randolph:

In accordance with Decision 09-08-027, Ordering Paragraph 39, attached please find San Diego Gas & Electric Company's ("SDG&E") monthly report referenced above. This report is also being served on the most recent service list in Application 08-06-001, et. al., and has been made available on SDG&E's website. The URL for the website is: http://sdge.com/node/711

If you have any questions, please feel free to contact me.

Sincerely,

/s/ Will Fuller

Will Fuller
Regulatory Case Manager

cc: A. 08-06-001, et. al., - Service List
Tom Brill – SDG&E
SDG&E Central Files

ATTACHMENT

San Diego Gas and Electric
Interruptible and Price Responsive Programs
Subscription Statistics - Enrolled MW
DECEMBER 2015

Programs	Service Accounts	January Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	February Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	March Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	April Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	May Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	June Ex Ante Estimated MW	Ex Post Estimated MW
Interruptible/Reliability																		
BIP - 30 minute option	6	0.57	0.44	6	0.53	0.44	6	0.58	0.44	6	1.22	1.79	6	1.31	1.79	6	1.28	1.79
Sub-Total Interruptible	6	0.57	0.44	6	0.53	0.44	6	0.58	0.44	6	1.22	1.79	6	1.31	1.79	6	1.28	1.79
Price Response																		
CPP-D	1,211	5.47	19.76	1,218	5.54	19.88	1,227	5.53	20.03	1,219	15.13	25.62	1,219	16.19	25.62	1,214	16.83	25.52
Summer Saver Residential	26,948	-	11.84	26,962	-	11.85	26,959	-	11.85	27,063	-	11.24	27,033	4.96	11.23	26,891	4.81	11.17
Summer Saver Commercial	11,308	-	4.19	11,347	-	4.20	11,339	-	4.20	11,349	-	3.30	11,387	1.81	3.31	11,268	1.85	3.27
CBP - Day-Ahead	125	-	6.72	125	-	6.71	125	-	6.71	125	-	9.89	313	27.56	24.78	313	28.82	24.78
CBP - Day-Of	501	-	10.84	501	-	10.85	501	-	10.85	501	-	8.77	313	5.04	5.48	313	5.37	5.48
PTR Residential	71,925	-	7.13	71,539	-	7.09	72,128	-	7.15	72,039	2.71	7.14	71,982	2.88	7.13	71,941	3.26	7.13
SCTD Residential	5,743	0.00	-	6,009	0.00	-	6,122	0.00	-	6,124	0.01	3.37	6,281	1.55	3.42	6,501	1.80	3.54
SCTD Commercial	1,219	0.03	0.03	1,264	-	-	1,302	-	-	1,364	0.65	2.71	1,440	0.80	2.86	1,515	1.52	3.01
DBP	9	2.57	7.65	9	1.69	7.65	9	3.67	7.65	9	3.49	4.64	9	3.23	4.64	9	2.12	4.64
TOU-A-P Small Commercial	1,853	-	-	1,898	-	-	1,926	-	-	1,941	-	-	1,398	-	-	1,962	-	-
Permanent Load Shifting		-	-		-	-		-	-		-	-		-	-		-	-
Sub-Total Price Response	120,842	8.07	68.17	120,872	7.24	68.23	121,638	9.21	68.43	121,734	22.00	76.69	121,375	64.03	88.5	121,927	66.39	88.54
Total All Programs	120,848	8.64	68.60	120,878	7.77	68.67	121,644	9.79	68.87	121,740	23.21	78.48	121,381	65.34	90.3	121,933	67.67	90.33

Programs	Service Accounts	July Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	August Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	September Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	October Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	November Ex Ante Estimated MW	Ex Post Estimated MW	Service Accounts	December Ex Ante Estimated MW	Ex Post Estimated MW
Interruptible/Reliability																		
BIP - 30 minute option	6	1.20	1.79	5	1.02	1.49	5	1.00	1.49	5	0.90	1.49	5	0.08	1.49	5	0.08	1.49
Sub-Total Interruptible	6	1.2	1.8	5	1.0	1.5	5	1.0	1.5	5	0.9	1.5	5	0.1	1.5	5	0.1	1.5
Price Response																		
CPP-D	1,210	18.80	25.43	1,211	20.90	25.45	1,211	21.34	25.45	1,211	19.35	25.45	1,225	14.28	25.75	1,216	10.40	25.56
Summer Saver Residential	26,724	8.86	11.10	26,270	10.61	10.91	26,044	11.45	10.81	26,034	7.42	10.81	26,038	-	10.81	25,905	-	10.76
Summer Saver Commercial	11,185	2.59	3.25	11,065	3.08	3.21	11,026	3.14	3.20	10,978	2.33	3.19	11,095	-	3.22	11,044	-	3.21
CBP - Day-Ahead	311	24.23	24.62	303	28.74	23.95	303	30.07	23.98	303	27.52	23.98	302	-	23.91	302	-	23.91
CBP - Day-Of	311	5.78	5.44	303	5.91	5.30	302	6.21	5.29	302	6.05	5.29	302	-	5.29	302	-	5.29
PTR Residential	72,760	4.36	7.21	76,071	5.27	7.54	76,521	6.78	7.58	76,891	5.13	7.62	76,681	-	7.60	76,212	1.06	7.55
SCTD Residential	6,708	2.50	3.66	7,075	2.92	3.86	7,459	4.07	4.07	8,064	3.29	4.39	8,506	0.81	4.64	8,780	0.04	4.79
SCTD Commercial	1,545	2.04	3.07	1,607	3.11	3.19	2,518	5.14	5.00	2,625	2.26	5.21	2,690	0.71	5.34	2,728	-	5.42
DBP	9	2.60	4.64	9	2.58	4.64	9	3.15	4.64	9	3.40	4.64	9	3.08	4.64	9	2.06	4.64
TOU-A-P Small Commercial	1,986	-	-	2,007	-	-	2,015	-	-	2,438	-	-	3,734	-	-	17,793	-	-
Permanent Load Shifting		-	-		-	-		-	-		-	-	0	-	-	0	-	-
Sub-Total Price Response	122,749	71.8	88.4	125,920	83.1	88.0	127,408	91.4	90.0	128,855	76.7	90.6	130,582	18.9	91.2	144,291	13.6	91.1
Total All Programs	122,755	73.0	90.2	125,925	84.1	89.5	127,413	92.4	91.5	128,860	77.6	92.1	130,587	19.0	92.7	144,296	13.6	92.6

Notes:
- **Effective May 23, 2011 The DemandSMART Agreement was mutually terminated.**
- **Effective Dec 31, 2011, Demand Response Wholesale Market Program was terminated.**
- ***PTR residential - Effective May 1, 2014 per D.13-07-003 .....data reflects cumulative PTR residential customers who opt into the program***
- **Permanent Load Shifting Service Accounts - SDG&E only reports the active service accounts.**
- **SCTD Residential - data in December report reflects reconciled numbers for year**

San Diego Gas and Electric
Average Ex-Ante Load Impact kW/Customer

Program	Average Ex Ante Load Impact kW / Customer												Eligible Accounts as May 2015	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - 30 minute option	94.9	88.0	96.6	202.8	217.9	213.1	200.0	204.0	199.8	180.2	15.7	15.7	5,381	All C & I customers > 100kW
CPP-D	4.5	4.6	4.5	12.4	13.3	13.9	15.5	17.3	17.6	16.0	11.7	8.5	24,114	All non-residential customers with interval meter
Summer Saver Residential	0.0	0.0	0.0	0.0	0.2	0.2	0.3	0.4	0.4	0.3	0.0	0.0	680,400	Residential customers with AC
Summer Saver Commercial	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.3	0.3	0.2	0.0	0.0	137,615	Commercial Customers < 100kw
CBP - Day-Ahead	0.0	0.0	0.0	0.0	88.1	92.1	77.9	95.0	99.3	90.8	0.0	0.0	27,141	Non-residential customers on TOU rates
CBP - Day-Of	0.0	0.0	0.0	0.0	16.1	17.2	18.6	19.5	20.6	20.0	0.0	0.0	27,141	Non-residential customers on TOU rates
PTR Residential				0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	1,263,398	Residential customers
SCTD Residential	0.00068	0.00071	0.00056	0.00159	0.24750	0.27750	0.37250	0.41250	0.54500	0.40750	0.09500	0.00500	663,394	Residential customers with AC and other constraints
SCTD Commercial	0.0	0.0	0.0	0.5	0.6	1.0	1.3	1.9	2.0	0.9	0.3	0.0	162,465	Commercial customers with AC
DBP	285.6	188.2	407.8	388.3	359.0	235.6	288.9	286.1	350.3	378.1	341.8	229.2	32	Non-residential customers who can provide load reduciton > 5 MW
TOU-A-P Small Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116,059	Small Commercial customers with demand less than 20kW
Permanent Load Shifting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37,305	Customers on TOU rates

Estimated Average Ex Ante Load Impact kW/Customer = Average kW / Customer, under 1-in-2 weather conditions, of an event that would occur from 1 - 6 pm on the system peak day of the month, as reported in the load impact reports filed in April 2015.

Notes:

San Diego Gas and Electric
Average Ex-Post Load Impact kW / Customer

Program	Average Ex Post Load Impact kW / Customer												Eligible Accounts as May 2015	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - 30 minute option	72.7	72.7	72.7	298.4	298.4	298.4	298.4	298.4	298.4	298.4	298.4	298.4	5,381	All C & I customers > 100kW
CPP-D	16.3	16.3	16.3	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	24,114	All non-residential customers with interval meter
Summer Saver Residential	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	680,400	Residential customers with AC
Summer Saver Commercial	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	137,615	Commercial Customers < 100kw
CBP - Day-Ahead	53.7	53.7	53.7	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	27,141	Non-residential customers on TOU rates
CBP - Day-Of	21.7	21.7	21.7	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	27,141	Non-residential customers on TOU rates
PTR Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1,263,398	All residential customers
DBP	850.0	850.0	850.0	515.9	515.9	515.9	515.9	515.9	515.9	515.9	515.9	515.9	32	Non-residential customers who can provide load reduciton > 5 MW
TOU-A-P Small Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116,059	Small Commercial customers with demand less than 20kW
SCTD Residential	0.0	0.0	0.0	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	663,394	Residential customers with AC and other constraints
SCTD Commercial	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	162,465	Commercial customers with AC
Permanent Load Shifting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37,305	Customers on TOU rates

Estimated Average Ex Post Load Impact kW / Customer = Average kW / Customer service account over all actual event hours for the preceeding year when or if events occurred.

Notes:

San Diego Gas and Electric
Program Subscription Statistics
DECEMBER 2015

Detailed Breakdown of MWs To Date in TA/Auto DR/TI Programs (A)

2015	January				February				March				April				May				June			
Price Responsive	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**
CPP-D		6.0	2.3	**8.3**		6.0	2.3	**8.3**		6.0	2.3	**8.3**		6.0	2.3	**8.3**		6.0	2.3	**8.3**		6.0	2.3	**8.3**
CBP		9.9	1.5	**11.3**		9.9	1.5	**11.3**		9.9	1.5	**11.3**		9.9	1.5	**11.3**		9.9	1.5	**11.3**		9.9	1.5	**11.3**
Total		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**
Interruptible/Reliability																								**0.0**
BIP																								**0.0**
SLRP																								**0.0**
Total		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**
Total Technology MWs		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**		**15.8**	**3.8**	**19.6**
General Program																								
TA (may also be enrolled in TI and AutoDR)	59.3				59.3				59.3				59.3				59.3				59.3			
Total	**59.3**				**59.3**				**59.3**				**59.3**				**59.3**				**59.3**			
Total TA MWs	**59.3**				**59.3**				**59.3**				**59.3**				**59.3**				**59.3**			

	July				August				September				October				November				December			
Price Responsive	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**	**TA Identified MWs**	**Auto DR Verified MWs**	**TI Verified MWs**	**Total Technology MWs**
AMP																								
CBP		9.9	1.5	**11.3**		10.1	1.5	**11.6**		10.6	1.5	**12.1**		11.6	1.5	**13.1**		12.5	1.5	**13.9**		12.5	1.5	**14.0**
DBP								**0.0**				**0.0**				**0.0**								
Peak Choice - Best Effort								**0.0**				**0.0**				**0.0**								
Peak Choice - Committed								**0.0**				**0.0**				**0.0**								
CPP-D		5.9	2.3	**8.2**		5.9	2.3	**8.2**		5.9	2.3	**8.2**		5.9	2.3	**8.2**		5.9	2.3	**8.2**		5.9	2.3	**8.2**
Total		**15.8**	**3.8**	**19.6**		**16.0**	**3.8**	**19.8**		**16.5**	**3.8**	**20.3**		**17.5**	**3.8**	**21.3**		**18.4**	**3.8**	**22.1**		**18.4**	**3.8**	**22.2**
Interruptible/Reliability								**0.0**				**0.0**				**0.0**				**0.0**				**0.0**
BIP								**0.0**				**0.0**				**0.0**				**0.0**				**0.0**
OBMC								**0.0**				**0.0**				**0.0**				**0.0**				**0.0**
SLRP								**0.0**				**0.0**				**0.0**				**0.0**				**0.0**
								0.0				**0.0**				**0.0**				**0.0**				**0.0**
Total		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**				**0.0**				**0.0**				**0.0**
Total Technology MWs		**15.8**	**3.8**	**19.6**		**16.0**	**3.8**	**19.8**		**16.5**	**3.8**	**20.3**	**0.0**	**17.5**	**3.8**	**21.3**	**0.0**	**18.4**	**3.8**	**22.1**	**0.0**	**18.4**	**3.8**	**22.2**
General Program																								
TA (may also be enrolled in TI and AutoDR)	59.3				59.3			**59.3**				**59.3**				**59.3**				**59.3**				**59.3**
Total	**59.3**				**59.3**			**59.3**				**59.3**				**59.3**				**59.3**				**59.3**
Total TA MWs	**59.3**				**59.3**			**59.3**				**59.3**				**59.3**				**59.3**				**59.3**

Notes: ddd

- **TA Identified MW** — **Represents identified MW for service accounts from completed TA in accumulative value (may or may not be enrolled in DR).**
- **AutoDR Verified MW** — **Represents verified/tested MW for service accounts from complete TI (i.e. must be enrolled in DR) and must be Auto DR in accumulative value.**
- **TI Verified MW** — **Represents verified MW for service accounts from completed TI (i.e. must be enrolled in DR) but not AutoDR in accumulative value; MW reported here not necessarily amount enrolled in DR.**
- **Total Technology MW** — **Represents the sum of verified MW associated with the service accounts from the completed TI (i.e. must be enrolled in DR), including Auto DR and non-Auto DR.**

SDGE Demand Response Programs and Activities
Incremental Cost
2015 Funding

Year-to-Date Program Expenditures

		2015 Expenditures												Year-to Date 2015 Expenditures	Program-to-Date Total Expenditures 2015-2016	2-Year Funding	Fundshift Adjustments (a)	Percent Funding
Cost Item		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**					
Category 1: Reliability Programs																		
Base Interruptible Program (BIP)		$3,979	$4,509	$1,083	$3,069	$1,654	$9,964	$8,619	$62,396	$1,920	$23,829	$4,027	$24,307	$149,356	$149,356	$2,676,000		5.6%
Budget Category 1 Total	$0	$3,979	$4,509	$1,083	$3,069	$1,654	$9,964	$8,619	$62,396	$1,920	$23,829	$4,027	$24,307	$149,356	$149,356	$2,676,000	$0	5.6%
Category 2: Price Responsive Programs																		
Demand Bidding Program (DBP)		$1,033	$3,806	$5,700	$3,173	$2,981	$2,245	$3,032	$3,001	$2,107	$3,238	$2,694	$2,946	$35,956	$35,956	$1,755,808		2.0%
Capacity Bidding Program (CBP)		$53,729	$43,443	$47,059	$53,209	$13,392	$86,662	$67,119	$94,493	$289,612	$51,132	$294,155	$15,134	$1,109,139	$1,109,139	$6,859,333	($2,500,000)	16.2%
Peak Time Rebate (PTR)		$7,990	$9,201	$12,026	$10,426	$9,943	$14,269	$6,165	$8,202	$7,633	$8,818	$2,741	$10,265	$107,679	$107,679	$323,333		33.3%
Demand Response Auction Mechanism Pilot (DRAM)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,437	$3,437	$3,437	$1,000,000	$1,000,000	0.3%
Budget Category 2 Total	$0	$62,752	$56,450	$64,785	$66,808	$26,316	$103,176	$76,316	$105,696	$299,352	$63,188	$299,590	$31,782	$1,256,211	$1,256,211	$9,938,474	($1,500,000)	12.6%
Category 4: Emerging & Enabling Technologies																		
Emerging Technologies (ET)		$15,726	$22,088	$16,664	$23,145	$18,154	$22,185	$24,407	$37,821	$78,047	$45,700	$98,296	$49,248	$451,481	$451,481	$1,407,333		32.1%
Small Customer Technology Incentives (SCTD)		$23,115	$71,132	$771,071	$264,865	$109,233	$66,183	$139,809	$622,634	$237,392	$95,386	$167,534	$648,254	$3,216,608	$3,216,608	$6,309,445		51.0%
Technical Incentives (TI)		$38,536	$40,977	$20,714	$68,888	$22,047	$28,923	$43,223	$67,223	$190,479	$209,108	$300,333	$30,519	$1,060,970	$1,060,970	$5,982,000		17.7%
Budget Category 4 Total	$0	$77,377	$134,197	$808,449	$356,898	$149,434	$117,291	$207,439	$727,678	$505,918	$350,194	$566,163	$728,021	$4,729,059	$4,729,059	$13,698,778	$0	34.5%
Category 5: Pilots																		
New Construction DR		$3,098	$3,956	$4,365	$3,837	$921	$23,903	($18,474)	$3,130	($1,191)	$1,691	$1,935	$1,246	$28,417	$28,417	$750,667		3.8%
Budget Category 5 Total	$0	$3,098	$3,956	$4,365	$3,837	$921	$23,903	($18,474)	$3,130	($1,191)	$1,691	$1,935	$1,246	$28,417	$28,417	$750,667	$0	3.8%
Category 6: Evaluation, Measurement & Verification																		
DRMEC		$157,417	$74,208	$233,829	$115,207	$50,644	$156,511	$22,013	$87,151	$30,933	$65,799	$31,880	$211,174	$1,236,766	$1,236,766	$3,410,000		36.3%
Research		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$400,000		0.0%
Budget Category 6 Total	$0	$157,417	$74,208	$233,829	$115,207	$50,644	$156,511	$22,013	$87,151	$30,933	$65,799	$31,880	$211,174	$1,236,766	$1,236,766	$3,810,000	$0	32.5%
Category 7: Marketing Education & Outreach																		
Local Marketing Education & Outreach		$4,859	$15,601	$9,248	$64,340	$5,144	$38,346	$4,413	$15,927	$2,846	$221,605	$56,769	$682,230	$1,121,328	$1,121,328	$3,698,170		$0
Budget Category 7 Total	$0	$4,859	$15,601	$9,248	$64,340	$5,144	$38,346	$4,413	$15,927	$2,846	$221,605	$56,769	$682,230	$1,121,328	$1,121,328	$3,698,170	$0	30.3%
		;																
Category 8: DR System Support Activities																		
Regulatory Policy & Program Support		$57,285	$54,449	$44,745	$62,250	$56,490	$49,736	$39,945	$59,700	$40,630	$70,593	$51,166	$52,347	$639,336	$639,336	$1,531,077		41.8%
IT Infrastructure & System Support		$30,991	$22,871	$31,627	$17,696	$3,894	$39,531	($4,533)	$5,908	$15,204	$15,710	$12,815	$288,358	$480,072	$480,072	$1,769,440		27.1%
Budget Category 8 Total	$0	$88,276	$77,320	$76,372	$79,946	$60,384	$89,267	$35,412	$65,608	$55,834	$86,303	$63,981	$340,705	$1,119,408	$1,119,408	$3,300,517	$0	33.9%
Category 10: Special Projects																		
Permanent Load Shifting		$7,833	$8,672	$7,964	$10,438	$8,461	$10,942	$8,976	$10,891	$9,815	$5,026	$5,819	$4,307	$99,144	$99,144	$2,000,000	$1,500,000	5.0%
Budget Category 10 Total	$0	$7,833	$8,672	$7,964	$10,438	$8,461	$10,942	$8,976	$10,891	$9,815	$5,026	$5,819	$4,307	$99,144	$99,144	$2,000,000	$1,500,000	5.0%
Total Incremental Cost	$0	$405,591	$374,913	$1,206,095	$700,543	$302,958	$549,400	$344,714	$1,078,477	$905,427	$817,635	$1,030,164	$2,023,772	$9,739,689	$9,739,689	$39,872,606	$0	24.4%

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

Notes:
D.12-04-045

SAN DIEGO GAS AND ELECTRIC

	2015- 2016 Funding Cycle Customer Communication, Marketing, and Outreach												Year-to Date 2015 Expenditures	2015-2016 Total Expenditures	Authorized Budget (if Applicable)
	January	February	March	April	May	June	July	August	September	October	November	December			
I. STATEWIDE MARKETING															
IOU Administrative Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Statewide ME&O contract	$0	$0	$0	$0	$0	$0	$0	$1,436,700	$0	$3,300	$0	$0	$1,440,000	$1,440,000	
I. TOTAL STATEWIDE MARKETING	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,436,700**	**$0**	**$3,300**	**$0**	**$0**	**$1,440,000**	**$1,440,000**	
II. UTILITY MARKETING BY ACTIVITY * (1)															
TOTAL AUTHORIZED UTILITY MARKETING BUDGET FOR 2015-2016	[redacted]														
PROGRAMS, RATES & ACTIVITES WHICH DO NOT REQUIRE ITEMIZED ACCOUNTING [1,2]															
Small Customer Technology Deployment	$3,332	$1,366	$7,124	$14,055	$2,252	$7,438	$2,547	$14,078	$1,698	$25,987	$49,350	$127,890	$257,117	$257,117	
Permanent Load Shifting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Technology Incentives	$0	$0	$0	$0	$0	$0	$0	$0	$30	$0	$0	$0	$30	$30	
CPP-D	$0	$13,500	$0	$48,387	$0	$29,000	$0	$0	$0	$192,792	$638	$554,900	$839,217	$839,217	
Smart Pricing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Customer Awareness, Education and Outreach (CEAO - DR)	$7,615	($3,860)	$1,403	($5,675)	$0	$0	$0	$0	$0	$0	$0	$0	($517)	($517)	
Local Marketing Education and Outreach	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Local IDSM Marketing	$37,132	$44,442	$39,170	$73,454	$47,531	$118,734	$33,195	$55,301	$40,480	$41,735	$34,397	$32,540	$598,111	$598,111	
PROGRAMS & RATES WHICH REQUIRE ITEMIZED ACCOUNTING [3,4]															
Reduce Your Use (PTR)															
Customer Research	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$0	$0	$0	$0	$332	$0	$0	$0	$0	$1,245	$0	$0	$1,577	$1,577	
Labor	$1,527	$735	$2,123	$1,898	$2,560	$1,908	$1,867	$1,848	$1,117	$1,582	$6,782	($560)	$23,387	$23,387	
Paid Media	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Other Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
II. TOTAL UTILITY MARKETING BY ACTIVITY	$49,606	$56,183	$49,820	$132,119	$52,675	$157,080	$37,609	$71,227	$43,325	$263,341	$91,167	$714,770	$1,718,922	$1,718,922	
III. UTILITY MARKETING BY ITEMIZED COST															
Customer Research	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$2,239	$4,435	$7,432	$22,153	$724	$30,192	$2,122	$12,230	$4,446	$31,439	$44,056	$128,648	$290,116	$290,116	
Labor	$28,562	$36,043	$38,096	$38,439	$38,192	$49,481	$33,729	$32,640	$29,198	$34,430	$41,344	$26,201	$426,355	$426,355	
Paid Media	$16,880	$0	$0	($2,291)	$230	$5,408	$0	$0	$0	$0	$0	$0	$20,227	$20,227	
Other Costs	$1,925	$15,705	$4,292	$73,818	$13,529	$71,999	$1,758	$26,357	$9,681	$197,472	$5,767	$559,921	$982,224	$982,224	
III. TOTAL UTILITY MARKETING BY ITEMIZED COST	$49,606	$56,183	$49,820	$132,119	$52,675	$157,080	$37,609	$71,227	$43,325	$263,341	$91,167	$714,770	$1,718,922	$1,718,922	
IV. UTILITY MARKETING BY CUSTOMER SEGMENT															
Agricultural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Large Commercial and Industrial	$14,616	$30,275	$13,410	$78,562	$18,646	$81,923	$9,309	$22,377	$16,863	$208,166	$11,577	$564,567	$1,070,291	$1,070,291	
Small and Medium Commercial	$14,615	$16,775	$13,410	$30,176	$18,646	$52,923	$9,309	$22,377	$16,863	$15,375	$10,941	$9,668	$231,078	$231,078	
Residential	$20,375	$9,133	$23,000	$23,381	$15,383	$22,234	$18,991	$26,473	$9,599	$39,800	$68,649	$140,535	$417,553	$417,553	
IV. TOTAL UTILITY MARKETING BY CUSTOMER SEGMENT	$49,606	$56,183	$49,820	$132,119	$52,675	$157,080	$37,609	$71,227	$43,325	$263,341	$91,167	$714,770	$1,718,922	$1,718,922	

Notes:

[1] Programs, Rates & Activities does not include "Marketing My Account/Energy and Integrated Online Audit Tools" - the 2012 ICEAT program is funded through D.09-09 047

[2] Programs, Rates & Activities does not include "Critical Peak Pricing > 200kW" (CPP-D) as program funding is not approved or directed in D.12-04-045

[3] Programs, Rates & Activities does not include SDG&E's Summer Saver program as program funding is not approved or directed in D.12-04-045

[4] Programs, Rates & Activities does not include "Critical Peak Pricing < 200kW" as program funding is not approved or directed in D.12-04-045

SDGE
FUND SHIFTING
2015

FUND SHIFTING DOCUMENTATION PER DECISION 09-08-027 ORDERING PARAGRAPH 35

OP 35: **The utilities may shift up to 50% of a program funds to another program's funds to another program within the same budget category.**
The utilities shall document the amount of and reason for each shift in their monthly demand response reports.

Program Category	Fund Shift	Programs Impacted	Date	Rationale for Fundshift
Price-Responsive Programs	($1,000,000)	Capacity Bidding Program	9/1/2015	To fund DRAM per D.14-12-024
	$1,000,000	Demand Response Auction Mechanism Pilot	9/1/2015	To fund DRAM per D.14-12-024
	($1,500,000)	Capacity Bidding Program	11/13/2015	To fund additional Incentives per AL2801-E
	$1,500,000	Permanent Load Shifting	11/13/2015	To fund additional Incentives per AL2801-E
Total	**$0**			

Notes: Provide concise rationale for the fund shift in colum "Rationale for Fund Shift"

Year-to-Date Event Summary						
Program Category	Event No.	Date	Event Trigger(1)	Reduction kW	Event Beginning:End	Program Tolled Hours (Annual)
Capacity Bidding Program - Day Of	1	05/01/15	Met Price Triggers	5,500	3:00 PM to 7:00 PM	4
Capacity Bidding Program – Day Ahead	2	05/01/15	Met Price Triggers	7,900	3:00 PM to 7:00 PM	4
Capacity Bidding Program – Day Ahead	3	06/09/15	Met Price Triggers	10,200	3:00 PM to 7:00 PM	8
Capacity Bidding Program - Day Of	4	06/09/15	Met Price Triggers	7,300	3:00 PM to 7:00 PM	8
Capacity Bidding Program – Day Ahead	5	06/16/15	Met Price Triggers	9,400	3:00 PM to 7:00 PM	12
Capacity Bidding Program – Day Ahead	6	06/17/15	Met Price Triggers	9,400	3:00 PM to 7:00 PM	16
Capacity Bidding Program – Day Ahead	7	06/22/15	Met Price Triggers	9,900	3:00 PM to 7:00 PM	20
Capacity Bidding Program – Day Ahead	8	06/24/15	Met Price Triggers	8,800	3:00 PM to 7:00 PM	24
Capacity Bidding Program - Day Of	9	06/24/15	Met Price Triggers	4,700	3:00 PM to 7:00 PM	12
Capacity Bidding Program – Day Ahead	10	06/25/15	Met Price Triggers	9,500	3:00 PM to 7:00 PM	28
Capacity Bidding Program - Day Of	11	06/25/15	Met Price Triggers	4,300	3:00 PM to 7:00 PM	16
Capacity Bidding Program – Day Ahead	12	06/26/15	Met Price Triggers	10,200	3:00 PM to 7:00 PM	32
Capacity Bidding Program - Day Of	13	06/26/15	Met Price Triggers	6,600	3:00 PM to 7:00 PM	20
Capacity Bidding Program - Day Of	14	06/29/15	Met Price Triggers	7,500	3:00 PM to 7:00 PM	24
Capacity Bidding Program – Day Ahead	15	06/30/15	Met Price Triggers	8,100	3:00 PM to 7:00 PM	36
Capacity Bidding Program - Day Of	16	06/30/15	Met Price Triggers	4,400	3:00 PM to 7:00 PM	28
Capacity Bidding Program – Day Ahead	17	07/01/15	Met Price Triggers	8,700	3:00 PM to 7:00 PM	40
Capacity Bidding Program - Day Of	18	07/01/15	Met Price Triggers	5,400	3:00 PM to 7:00 PM	32
Capacity Bidding Program – Day Ahead	19	07/16/15	Met Price Triggers	8,700	3:00 PM to 7:00 PM	44
Capacity Bidding Program – Day Ahead	20	07/28/15	Met Price Triggers	9,600	3:00 PM to 7:00 PM	48
Capacity Bidding Program - Day Of	21	07/29/15	Met Price Triggers	6,100	3:00 PM to 7:00 PM	36
Capacity Bidding Program – Day Ahead	22	7/30/2015	Met Price Triggers	8,900	3:00 PM to 7:00 PM	52
Capacity Bidding Program – Day Ahead	23	7/31/2015	Met Price Triggers	9,500	3:00 PM to 7:00 PM	56
Capacity Bidding Program - Day Of	24	8/5/2015	Met Price Triggers	4,500	3:00 PM to 7:00 PM	40
Capacity Bidding Program – Day Ahead	25	8/6/2015	Met Price Triggers	7,230	3:00 PM to 7:00 PM	60
Capacity Bidding Program – Day Ahead	26	8/11/2015	Met Price Triggers	7,896	3:00 PM to 7:00 PM	64
Capacity Bidding Program – Day Ahead	27	08/12/15	Met Price Triggers	7,729	3:00 PM to 7:00 PM	68
Capacity Bidding Program – Day Ahead	28	8/13/2015	Met Price Triggers	7,600	3:00 PM to 7:00 PM	72
Capacity Bidding Program - Day Of	29	8/13/2015	Met Price Triggers	4,600	3:00 PM to 7:00 PM	44
Summer Saver Residential&Commercial	30	8/13/2015	System load	10,740	3:00 PM to 7:00 PM	4
Summer Saver Residential&Commercial	31	8/14/2015	System load	16,190	4:00 PM to 8:00 PM	8
Summer Saver Residential&Commercial	32	8/16/2015	System load	19,000	3:00 PM to 7:00 PM	12
Capacity Bidding Program – Day Ahead	33	08/21/15	Met Price Triggers	8,700	3:00 PM to 7:00 PM	76
Capacity Bidding Program - Day Of	34	08/25/15	Met Price Triggers	4,900	3:00 PM to 7:00 PM	48
Capacity Bidding Program – Day Ahead	35	08/25/15	Met Price Triggers	7,303	3:00 PM to 7:00 PM	80
Capacity Bidding Program – Day Ahead	36	08/26/15	Met Price Triggers	7,000	3:00 PM to 7:00 PM	84
Capacity Bidding Program - Day Of	37	08/26/15	Met Price Triggers	6,600	3:00 PM to 7:00 PM	52
Capacity Bidding Program – Day Ahead	38	08/27/15	Met Price Triggers	7,300	3:00 PM to 7:00 PM	88
Capacity Bidding Program - Day Of	39	08/27/15	Met Price Triggers	6,400	3:00 PM to 7:00 PM	56
CPPD	40	08/27/15	System load/temperature	15,800	11:00 AM to 6:00 PM	7
Summer Saver Residential&Commercial	41	08/26/15	System load	12,430	4:00 PM to 8:00 PM	16
Summer Saver Residential&Commercial	44	08/27/15	System load	14,030	3:00 PM to 7:00 PM	20
Capacity Bidding Program – Day Ahead	47	08/28/15	Met Price Triggers	7,600	3:00 PM to 7:00 PM	92
Capacity Bidding Program - Day Of	48	08/28/15	Met Price Triggers	7,000	3:00 PM to 7:00 PM	60
Summer Saver Residential&Commercial	49	08/28/15	System load	20,690	3:00 PM to 7:00 PM	24
BIP	52	08/28/15	Test event	1,390	1:00 PM to 5:00 PM	4
CPPD	53	08/28/15	System load/temperature	18,100	11:00 AM to 6:00 PM	14
PCT- SMB (SCTD)	54	08/28/15	System load/temperature	3,400	2:00 PM to 6:00 PM	4
Reduce Your Use Rewards (PTR)	55	08/28/15	System load/temperature	5,800	11:00 AM to 6:00 PM	7
Reduce Your Use Thermostat- Res (SCTD)	56	08/28/15	System load/temperature	3,800	2:00 PM to 6:00 PM	4
Reduce Your Use (TOU-DR-P)	57	08/28/15	System load/temperature	86	11:00 AM to 6:00 PM	7
Reduce Your Use (TOU-A-P & TOU-PA-P)	58	08/28/15	System load/temperature	126	11:00 AM to 6:00 PM	7
Capacity Bidding Program - Day Of	59	9/8/2015	Met Price Triggers	7,700	3:00 PM to 7:00 PM	64
Capacity Bidding Program – Day Ahead	60	9/9/2015	Met Price Triggers	7,100	3:00 PM to 7:00 PM	96
Capacity Bidding Program - Day Of	61	9/9/2015	Met Price Triggers	7,700	3:00 PM to 7:00 PM	68
CPPD-not-in CBP	62	9/9/2015	System load/temperature	24,500	11:00 AM to 6:00 PM	21
PCT- SMB (SCTD)	63	9/9/2015	System load/temperature	4,000	2:00 PM to 6:00 PM	8
Reduce Your Use (TOU-A-P & TOU-PA-P)	64	9/9/2015	System load/temperature	1,200	11:00 AM to 6:00 PM	14
Reduce Your Use (TOU-DR-P)	65	9/9/2015	System load/temperature	100	11:00 AM to 6:00 PM	14
Reduce Your Use Rewards (PTR)	66	9/9/2015	System load/temperature	6,800	11:00 AM to 6:00 PM	14
Reduce Your Use Thermostat- Res (SCTD)	67	9/9/2015	System load/temperature	3,800	2:00 PM to 6:00 PM	8
Summer Saver Residential&Commercial	68	9/9/2015	System load	22,900	3:00 PM to 7:00 PM	28
Capacity Bidding Program – Day Ahead	69	9/10/2015	Met Price Triggers	7,400	3:00 PM to 7:00 PM	100
Capacity Bidding Program - Day Of	70	9/10/2015	Met Price Triggers	5,900	3:00 PM to 7:00 PM	72
CPPD-not-in CBP	71	9/10/2015	System load/temperature	25,100	11:00 AM to 6:00 PM	28
PCT- SMB (SCTD)	72	9/10/2015	System load/temperature	2,900	2:00 PM to 6:00 PM	12
Reduce Your Use (TOU-A-P & TOU-PA-P)	73	9/10/2015	System load/temperature	400	11:00 AM to 6:00 PM	21
Reduce Your Use (TOU-DR-P)	74	9/10/2015	System load/temperature	100	11:00 AM to 6:00 PM	21
Reduce Your Use Rewards (PTR)	75	9/10/2015	System load/temperature	5,200	11:00 AM to 6:00 PM	21
Reduce Your Use Thermostat- Res (SCTD)	76	9/10/2015	System load/temperature	2,000	2:00 PM to 6:00 PM	12
Summer Saver Residential&Commercial	77	9/10/2015	System load	17,100	3:00 PM to 7:00 PM	32
Capacity Bidding Program – Day Ahead	78	9/11/2015	Met Price Triggers	8,100	3:00 PM to 7:00 PM	104
Capacity Bidding Program - Day Of	79	9/11/2015	Met Price Triggers	5,500	3:00 PM to 7:00 PM	76
CPPD-not-in CBP	80	9/11/2015	System load/temperature	25,300	11:00 AM to 6:00 PM	35
PCT- SMB (SCTD)	81	9/11/2015	System load/temperature	2,800	2:00 PM to 6:00 PM	16
Reduce Your Use (TOU-A-P & TOU-PA-P)	82	9/11/2015	System load/temperature	300	11:00 AM to 6:00 PM	28
Reduce Your Use (TOU-DR-P)	83	9/11/2015	System load/temperature	100	11:00 AM to 6:00 PM	28
Reduce Your Use Rewards (PTR)	84	9/11/2015	System load/temperature	4,100	11:00 AM to 6:00 PM	28
Reduce Your Use Thermostat- Res (SCTD)	85	9/11/2015	System load/temperature	3,100	2:00 PM to 6:00 PM	16
Summer Saver Residential&Commercial	86	9/11/2015	System load	23,900	3:00 PM to 7:00 PM	36
Summer Saver Residential&Commercial	87	9/20/2015	System load	19,700	2:00 PM to 4:00 PM	40
Capacity Bidding Program - Day Of	88	9/21/2015	Met Price Triggers	9,100	3:00 PM to 7:00 PM	80
Capacity Bidding Program – Day Ahead	89	9/23/2015	Met Price Triggers	6,700	3:00 PM to 7:00 PM	108
Capacity Bidding Program – Day Ahead	90	9/24/2015	Met Price Triggers	6,300	3:00 PM to 7:00 PM	112
Capacity Bidding Program – Day Ahead	91	9/25/2015	Met Price Triggers	6,600	3:00 PM to 7:00 PM	116
Summer Saver Residential&Commercial	92	9/24/2015	System load	9,100	2:00 PM to 6:00 PM	44
Summer Saver Residential&Commercial	93	9/25/2015	System load	13,000	2:00 PM to 6:00 PM	48
Capacity Bidding Program – Day Ahead	94	9/29/2015	Met Price Triggers	7,100	3:00 PM to 7:00 PM	120
Capacity Bidding Program – Day Ahead	95	9/30/2015	Met Price Triggers	6,700	3:00 PM to 7:00 PM	124
Capacity Bidding Program – Day Ahead	96	10/8/2015	Met Price Triggers	7,500	3:00 PM to 7:00 PM	128
Capacity Bidding Program – Day Ahead	97	10/9/2015	Met Price Triggers	7,000	3:00 PM to 7:00 PM	132
Capacity Bidding Program – Day Ahead	98	10/12/2015	Met Price Triggers	4,900	3:00 PM to 7:00 PM	136
Capacity Bidding Program – Day Ahead	99	10/13/2015	Met Price Triggers	5,400	3:00 PM to 7:00 PM	140
Capacity Bidding Program – Day Ahead	100	10/14/2015	Met Price Triggers	2,500	3:00 PM to 7:00 PM	144
Capacity Bidding Program – Day Ahead	101	10/21/2015	Met Price Triggers	6,900	3:00 PM to 7:00 PM	148
Capacity Bidding Program – Day Ahead	102	10/22/2015	Met Price Triggers	7,100	3:00 PM to 7:00 PM	152
Capacity Bidding Program – Day Ahead	103	10/23/2015	Met Price Triggers	7,600	3:00 PM to 7:00 PM	156
Capacity Bidding Program – Day Ahead	104	10/27/2015	Met Price Triggers	7,500	3:00 PM to 7:00 PM	160
Capacity Bidding Program – Day Ahead	105	10/28/2015	Met Price Triggers	7,200	3:00 PM to 7:00 PM	164
Capacity Bidding Program – Day Ahead	106	10/30/2015	Met Price Triggers	7,500	3:00 PM to 7:00 PM	168
Capacity Bidding Program - Day Of	107	10/9/2015	Met Price Triggers	5,600	3:00 PM to 7:00 PM	84
Capacity Bidding Program - Day Of	108	10/12/2015	Met Price Triggers	5,300	3:00 PM to 7:00 PM	88
Capacity Bidding Program - Day Of	109	10/13/2015	Met Price Triggers	5,900	3:00 PM to 7:00 PM	92
Capacity Bidding Program - Day Of	110	10/14/2015	Met Price Triggers	6,100	3:00 PM to 7:00 PM	96
Summer Saver Residential&Commercial	111	10/9/2015	System load	11,500	3:00 PM to 7:00 PM	52
Summer Saver Residential&Commercial	112	10/10/2015	System load	14,600	3:00 PM to 7:00 PM	56
Summer Saver Residential&Commercial	113	10/13/2015	System load	9,400	4:00 PM to 8:00 PM	60

SDGE
Demand Response Programs
Total Cost and AMDRMA 2015 Accounts Balance
$000

Annual Total Cost	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date Cost		% of Budget
Administrative (O&M)															
Base Interruptible Program	$2.2	$4.5	$1.1	$3.1	$1.7	$2.8	$1.6	$2.7	$1.9	$4.4	$4.0	$3.9	$33.9	$0.0	n/a
DBP	$1.0	$3.8	$5.7	$3.2	$3.0	$2.2	$3.0	$3.0	$2.1	$3.2	$2.7	$2.9	$36.0	$0.0	n/a
Capacity Bidding Program	$65.0	$43.4	$47.1	$53.2	$13.4	$75.4	$62.1	$66.8	$61.8	$62.4	$84.2	$15.1	$649.8	$0.0	n/a
PTR	$8.0	$9.2	$12.0	$10.4	$9.9	$14.3	$6.2	$8.2	$7.6	$8.8	$2.7	$10.3	$107.7	$0.0	n/a
Emerging Markets/Technologies	$15.7	$22.1	$16.7	$23.1	$18.2	$22.2	$24.4	$37.8	$78.0	$45.7	$98.3	$49.2	$451.5	$0.0	n/a
SCTD	$15.9	$71.3	$135.2	$198.8	$144.4	$15.9	$138.5	$107.0	$194.4	$100.9	$55.4	($277.4)	$900.4	$0.0	n/a
Technology Incentives	$27.5	$41.0	$20.7	$68.9	$22.0	$28.9	$43.2	$19.4	$21.6	$55.0	$153.7	$26.0	$528.0	$0.0	n/a
RNC	$3.1	$4.0	$4.4	$3.8	$0.9	$23.9	($18.5)	$3.1	($1.2)	$1.7	$1.9	$1.2	$28.4	$0.0	n/a
Local Marketing Education & Outreach	$4.9	$15.6	$9.2	$64.3	$5.1	$38.3	$4.4	$15.9	$2.8	$221.6	$56.8	$682.2	$1,121.3	$0.0	n/a
Regulatory Policy	$57.3	$54.4	$44.7	$62.3	$56.5	$49.7	$39.9	$59.7	$40.6	$70.6	$51.2	$52.3	$639.3	$0.0	n/a
Information Technology	$31.0	$22.9	$31.6	$17.7	$3.9	$39.5	($4.5)	$5.9	$15.2	$15.7	$12.8	$288.4	$480.1	$0.0	n/a
Permanent Load Shifting	$7.8	$8.7	$8.0	$10.4	$8.5	$10.9	$9.0	$10.9	$9.8	$5.0	$5.8	$4.3	$99.1	$0.0	n/a
DRAM	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$3.4	$3.4	$0.0	n/a
SW-COM-Customer Services (TA)	$120.8	$48.9	$17.2	$22.3	$11.2	$25.7	($829.6)	$23.5	$19.8	$16.7	$15.3	$14.1	($494.2)	$0.0	n/a
SW-IND-Customer Services (TA)	$94.7	$4.6	$6.2	$5.6	$5.1	$4.8	($326.0)	$4.7	$5.1	$4.7	$4.7	$4.2	($181.6)	$0.0	n/a
SW-AG-Customer Services (TA)	$1.3	$1.9	$3.0	$3.0	$2.7	$2.6	$2.4	$2.4	$2.7	$2.1	$2.2	$1.8	$28.0	$0.0	n/a
Local-IDSM-ME&O-Local Marketing	$37.1	$44.4	$39.2	$73.5	$47.5	$118.7	$33.2	$55.3	$40.4	$41.7	$34.4	$32.5	$598.1	$0.0	n/a
Local-IDSM-ME&O-Behavioral Programs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$79.1	$367.3	$1.7	$83.5	$531.7	$0.0	n/a
Local-IDSM-ME&O-Small Commercial Behavior	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	n/a
SW-ME&O[1]	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1,436.7	$0.0	$3.3	$0.0	$0.0	$1,440.0	$0.0	n/a
Summer Saver **	$143.3	$149.0	($106.2)	$539.4	$220.5	$173.9	$154.2	$156.8	$151.8	$155.1	$157.2	$152.7	$2,047.5	$0.0	n/a
Celerity **	$0.1	$0.1	$0.1	$0.5	$0.0	$0.2	$0.0	$0.1	$0.1	$0.0	$0.1	$0.1	$1.4	$0.0	n/a
LDR	$1.3	$2.3	($1.3)	$8.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$10.5	$0.0	n/a
Flex Alert Network	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	n/a
CEAO	$7.6	($3.9)	$1.4	($5.7)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)	$0.0	n/a
TA	$0.0	$0.6	$8.1	($3.1)	$0.0	($9.5)	$3.9	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	n/a
Total Administrative (O&M)	**$645.7**	**$548.8**	**$303.9**	**$1,163.0**	**$574.5**	**$640.5**	**($652.5)**	**$2,019.9**	**$733.9**	**$1,186.1**	**$745.0**	**$1,151.1**	**$9,059.8**	**$0.0**	**n/a**
Capital															
Base Interruptible Program	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	n/a
Emerging Markets	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	n/a
Total Capital	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**n/a**
Measurement and Evaluation															
Research	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	n/a
General Administration	$157.4	$74.2	$233.8	$115.2	$50.6	$156.5	$22.0	$87.2	$30.9	$65.8	$31.9	$211.2	$1,236.8	$0.0	n/a
Total M&E	**$157.4**	**$74.2**	**$233.8**	**$115.2**	**$50.6**	**$156.5**	**$22.0**	**$87.2**	**$30.9**	**$65.8**	**$31.9**	**$211.2**	**$1,236.8**	**$0.0**	**n/a**
Customer Incentives															
Base Interruptible Program	$1.7	$0.0	$0.0	$0.0	$0.0	$7.2	$7.0	$59.7	$0.0	$19.4	$0.0	$20.4	$115.5	$0.0	n/a
Capacity Bidding Program	($11.3)	$0.0	$0.0	$0.0	$0.0	$11.3	$5.1	$27.7	$227.8	($11.3)	$210.0	$0.0	$459.3	$0.0	n/a
DBP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	n/a
SCTD	$7.2	($0.2)	$635.9	$66.0	($35.1)	$50.3	$1.3	$515.6	$43.0	($5.5)	$112.1	$925.6	$2,316.2	$0.0	n/a
Technology Incentives	$11.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$47.9	$168.9	$154.1	$146.6	$4.5	$533.0	$0.0	n/a
RNC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	n/a
SW-COM-Customer Services (TA)	$0.0	$0.0	$26.0	$17.7	$24.7	$3.0	$515.7	$57.2	$3.7	$1.5	$27.6	$24.6	$701.8	$0.0	n/a
SW-IND-Customer Services (TA)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$200.6	($6.3)	$0.0	$0.0	$0.0	$0.0	$194.3	$0.0	n/a
Summer Saver	$3.9	$2.1	$0.9	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2,391.3	$0.0	$2,398.2	$0.0	n/a
Total Customer Incentives	**$12.6**	**$1.9**	**$662.8**	**$83.9**	**($10.4)**	**$71.7**	**$729.8**	**$701.8**	**$443.3**	**$158.2**	**$2,887.7**	**$975.1**	**$6,718.3**	**$0.0**	**n/a**
Total	**$815.7**	**$624.8**	**$1,200.5**	**$1,362.0**	**$614.7**	**$868.7**	**$99.2**	**$2,808.9**	**$1,208.1**	**$1,410.1**	**$3,664.6**	**$2,337.4**	**$17,014.8**	**$0.0**	**n/a**
AMDRMA Account End of Month Balance for WG2[1]	**($619.4)**	**$616.3**	**$1,205.5**	**$1,318.9**	**$620.0**	**$ 845.1**	**102.8**	**2,814.4**	**1,214.3**	**1,507.6**	**3,671.3**	**2,348.5**	**$15,645.3**		

** Budgeted under a different proceeding

Notes:
[1]$1.4 million was both paid and accrued in December. Corrected on December 2014 CPUC Report. AMDRMA did not reflect this correction in December.

SDGE GRC Programs
2015
$000

Annual Total Cost	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date Total Cost
Programs in General Rate Case													
Administrative (O&M)													
AL-TOU-CP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
CPP-D	$8.3	$11.8	$12.0	$12.7	$12.6	$9.2	$13.0	$13.8	$290.7	($274.1)	$10.2	$9.7	$129.8
SLRP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Peak Generation (RBRP)	$0.7	$1.8	$0.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$6.8
OBMC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Administrative (O&M)	$9.0	$13.6	$12.0	$13.2	$13.1	$9.6	$13.5	$14.3	$291.1	($273.6)	$10.6	$10.1	$136.6
Capital													
Peak Generation (RBRP) (1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Capital	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Measurement and Evaluation													
Peak Generation (RBRP)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total M&E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Customer Incentives													
AL-TOU-CP (2)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
BIP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SLRP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Peak Generation (RBRP)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Customer Incentives	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Revenue from Penalties	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total GRC Program Costs	**$9.0**	**$13.6**	**$12.0**	**$13.2**	**$13.1**	**$9.6**	**$13.5**	**$14.3**	**$291.1**	**($273.6)**	**$10.6**	**$10.1**	**$136.6**

(1) Capital costs for meters provided free to customers and charged to the programs.