**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of San Diego Gas & Electric Company (U 902 M) for Approval of Demand Response Programs and Budgets for Years 2009 through 2011	Application 08-06-002

AMENDED APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M) FOR APPROVAL OF DEMAND RESPONSE PROGRAMS AND BUDGETS FOR YEARS 2009 THROUGH 2011

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Application of San Diego Gas & Electric Company (U-902-M) for Approval of Demand Response Programs and Budgets for the Years 2009 through 2011.

Application 08-06- 002

CHAPTER IV

PREPARED DIRECT TESTIMONY OF

KEVIN C. McKINLEY

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
September 19, 2008

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CHAPTER IV

PREPARED DIRECT TESTIMONY

OF KEVIN C. McKINLEY

I. PURPOSE

My testimony presents the overall results of the cost effectiveness tests for the 2009-2011 proposed demand response (DR) programs and the overall portfolio. The associated issues regarding the Load Impacts utilized in these cost effectiveness tests are covered in the testimony of Kathryn Smith.

II. METHODOLOGY

The intent of a demand response program is to reduce peak demand. The benefits of demand response programs are in avoiding costs that would otherwise be increased to meet the peak demand including avoided electric generation capacity costs, T&D costs, and energy costs, commodity costs, line losses and environmental costs. In the *Administrative Law Judge's Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications* ("2/27 ALJ Ruling"), it states: "It is possible that a cost effectiveness methodology may not be adopted in time to allow IOUs to use it to complete a full cost effectiveness analysis of their proposals before the application is filed. In this case, IOUs should include in their applications a basic cost effectiveness analysis of each program consistent with the parties' CE framework filed November 19, 2007…". SDG&E has relied on the parties' Cost-Effectiveness Framework (CE Framework) filed November 19, 2007 for calculating cost effectiveness as described below.

A. Tests

The primary purpose of the cost-effectiveness tests are to measure and evaluate the cost effectiveness of DR programs in order to properly include these programs as a resource option in the utility's resource planning process. Historically, the Commission has used a broad societal perspective to identify benefits and costs and to determine cost-effective energy efficiency (EE) programs. This generally involves using the Total Resource Cost (TRC) test from the Standard Practice Manual (SPM).

The TRC test is a broad test taking into account all the benefits to DR customers and non-participating customers in terms of avoided generation costs (including line losses), avoided transmission and distribution (T&D) costs, avoided energy costs, and environmental benefits. On the cost side, this perspective includes all the costs associated with the DR program to both participating and non-participating customers. The test ignores all equipment incentive payments and subsidies that are transfers from non-participants to the DR program participants.

The TRC test is one of the tests reported as part of the determination of the cost-effectiveness of EE programs. DR programs should use this same test for measuring cost-effectiveness for purposes of resource planning to put the programs on an equal footing with EE. There are, however, significant differences between the characteristics of DR and those of EE so that the benefits used for cost effectiveness analysis developed for EE cannot be simply applied to DR programs. The current proceeding, R.07-01-040, has described those differences and tried to account for those differences as described in the avoided cost section below. The TRC perspective is appropriate to use to analyze the cost effectiveness of DR using appropriate avoided cost inputs developed specific to the characteristics of demand response.

In the evaluation of DR, SDG&E has also included the cost-effectiveness from SDG&E's perspective in the Program Administrator Cost (PAC) test. Because the TRC test includes the customer cost as a part of the social costs, and because the PAC test includes the incentive payment as a part of the program administrator cost, when the customer costs equal the incentive payment, the two tests (the TRC and the PAC) have exactly the same result. Another test included is the Ratepayer Impact Measure (RIM) which is reflective of the benefits and costs to non-participating customers.

The last major test in the SPM is the Participant test. This test is most appropriate for use in designing programs and setting customer incentives. The economic analysis from the participating customer's perspective is typically a business analysis of an investment decision. The customer will look at the present value of expected future net benefits and decide whether or not to participate in the DR program. Customer costs remain an area of needed research in evaluating DR programs. In lieu of any data that quantitatively estimates customer costs when responding to DR programs, SDG&E has used the incentive payment as a proxy for these costs. Theoretically, customers use incentive payments to offset their costs in responding to demand side management programs. As a result, the incentive payment, in SDG&E's view, is a reasonable proxy for customer costs until such a time as better information becomes available.[1]

B. Portfolio Evaluation

The cost effectiveness analysis is done on a program-by-program basis for those programs requiring cost effectiveness tests for 2009 through 2011. These programs, plus Customer Education, Awareness and Outreach programs, Permanent Load Shifting Programs,

[1] This approach is consistent with section B.3 of the parties' CE framework.

Measurement and Evaluation Costs and Codes and Standards are then aggregated and cost effectiveness is calculated at the portfolio level.[2]

III. BENEFITS

A. Avoided Generation Capacity Costs

The parties' CE Framework provided that the generation capacity costs avoided by a DR program will be based on the annual market price ($/kW-year) of the capacity of a new combustion turbine (CT), annualized using a real economic carrying charge rate that takes into account return, income taxes, ad valorem taxes and depreciation, with fixed O&M added, and reduced to reflect expected "gross margins" earned by selling energy ("CT cost").[3]

SDG&E is committed to using public data in its analysis of the cost-effectiveness of DR programs to the extent possible. The latest available public information on the cost of peaking capacity in San Diego County is the cost of the Miramar II peaking plant, proposed for completion in 2009.[4] This type of peaking plant, an LM 6000 combustion turbine, is typical of the type of plant SDG&E would expect to be installed in its service territory in the 2009-2011 time frame but for DR programs.[5]

The cost of the Miramar II plant includes construction and environmental costs specific to San Diego as well as other fixed costs including property taxes that are also specific to San Diego. The capital costs of $1,215 per kW are contained in SDG&E's RFO Contract Approval

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[2] Caution should be used in interpreting the "portfolio level" results since several large DR programs are not included since they were adopted in other proceedings and are excluded here per the 2/27 ALJ Ruling, page 14.
[3] CE Framework, C.1, pages 2-3.
[4] Consistent with CE framework section C.4, a plant in SDG&E's service territory was utilized for analysis..
[5] The Miramar II plant is based on wet cooling technology and also includes "black start" capability. The costs should be adjusted downward to remove the cost of black start capability which DR cannot provide, but increased for the cost of dry cooling since future plants are likely to have dry cooling. The cost of dry cooling is assumed to be roughly equal to the cost of black start capability.

Request, filed June 16, 2008,[6] while the Operating & Maintenance costs are assumed to be consistent with the operating characteristics of Miramar I as filed in SDG&E Advice Letter 1621-E.[7]

The 2009 CT installed costs are then converted to an annual kW-year figure based on a real economic carrying charge (RECC) similar to the approach shown in the direct testimony of James S. Parsons in SDG&E's GRC Phase 2 (A.07-01-041) except to update the cost of capital from 8.23 percent to 8.40 percent, consistent with the recent Commission-adopted change in SDG&E's cost of capital. The RECC factor is based on a 25 year book life, 15 year federal tax life, 20 year state tax life, federal tax rate of 35 percent, state tax rate of 8.84 percent, and an ad valorum tax rate of 1.207 percent (ad valorum taxes are included within the RECC factor rather than the fixed O&M). The full capacity value is calculated as $135 per kW-year.[8]

As described in section C.1 of the parties' CE Framework, the above capacity value is reduced to reflect expected "gross margins" that could be earned by the CT in selling energy into the wholesale market. SDG&E has calculated "gross margins" using the same expected electric market prices as are used in the electricity price calculation based on the hourly price profile from the year 2012 of the LTPP adjusted for average electric market prices in 2009-2011. A stochastic method was employed to reflect the uncertainty of and the correlation between wholesale market electric price and natural gas prices, and the relationship between those prices

[6] SDG&E's RFO Contract Approval Request, filed June 16, 2008, page 27, $56.5 million for the 46.5 MW plant.
[7] The Miramar II plant is based on the same LM6000 technology as the Miramar I plant. Operating costs are assumed to be similar, so the escalated cost data from Miramar I is used where comparable data is not available on Miramar II.
[8] See workpapers for more detail.

when the CT is operating. Based on a simulation analysis, gross margins were calculated to be $22 per kW-year.[9]

The resulting $113 per kW-year is adjusted upward for two factors per section C.1 of the parties' CE Framework – line losses and avoided reserve margin. The line loss factor is estimated to be 9.34 percent based on losses at peak from the California Energy Commission (CEC) report, CEC-200-2007-015-SF. The line loss factor from the CEC report is specific to peak line losses in San Diego. The annual generation capacity reserve margin SDG&E must maintain during the program evaluation period to comply with resource adequacy requirements established by the CPUC is 15 percent. For each MW of peak reduction, the DR program also reduces the need for SDG&E to add capacity to maintain a 15 percent reserve margin. The capacity value of DR programs without usage or availability constraints equivalent to the full annualized and adjusted CT cost is thus calculated to be $142 per kW-year.

For DR programs with constraints on their availability and/or how often they can be used, SDG&E uses an hourly stochastic method consistent with parties' CE Framework section C.2 that takes into consideration the capacity value of the DR programs during those the highest-valued periods in which the program is available and can be used. The value of generation capacity in those periods is determined by allocating the annual market value of generation capacity among the hours of the year in proportion to the relative need for capacity in those hours but for the DR programs. For DR programs available from May through October from 11 am to 6 pm on weekdays, the value of this capacity is 73 percent of the full cost of a CT.[10] That is, the

[9] The simulations were completed using Crystal Ball software based on historical data on mean reversion rates, correlations, and market price volatilities. The characteristics of the CT are averages over the lifetime of the CT and forward price relationships from forward markets in 2009-2011 are assumed to be representative of the average price relationships over the lifetime of the CT. See workpapers for more details.

[10] See workpapers for added description.

likelihood of the need for added capacity will occur 73 percent of the time in those hours that the DR programs are available. The remainder will occur in the winter on-peak periods, summer semi-peak periods, and on summer off-peak hours (weekend and holiday afternoon hours).

SDG&E has used the 73 percent value for all DR programs available during the summer, even those with a limit of 4 hours, because they are available for any consecutive 4 hours within the 11-6 pm time period. Because of the flexibility in design, SDG&E has the ability to call any consecutive 4 hours within the 11- 6 time frame, thus likely avoiding demand in the peak hours within the period. On the other hand, the Base Interruptible Program, which can be called 30 times at any time of the year, has its value reduced to only 98 percent of the full, adjusted value of a CT.

B. Transmission and Distribution Avoided Costs

In D.03-02-068, the Commission describes a distribution planning process that accounts for distributed generation (DG) on the utility distribution system. The process is based on the record developed in R.99-10-025 and the Distribution Report published by the Energy Division on April 17, 2000, which discusses in depth how SDG&E operates and plans its distribution system and the impact of DG on the distribution system. D.03-02-068 requires DG to meet four criteria - - right time, right size, right place, and "physical assurance" - -in order to allow SDG&E to avoid any T&D costs. Physical assurance provides a guarantee that the customer load will not increase if the DG unit does not perform; this minimizes the impact of the customer on the distribution system. The same principles apply to DR programs. For most DR programs, customer participation is voluntary and typically involves no long-term commitment, thus providing no assurance of load reduction (physical assurance). Further, in some cases there are no penalties for non-performance, making the estimate of load reduction highly uncertain.

But for some programs, physical assurance is created by a technology solution giving the utility control of equipment. In those cases, there are avoided T&D costs if the remaining criteria of D.03-02-068 are present: right location, right size, and right time. In addition, with enough dispersed small load reductions, there will be some statistical regularity in the aggregation of many small sources that can be relied on. The statistical regularities provide a form of physical assurance.

The parties' CE Framework for T&D in section E.2 calls for utilities to establish a default avoided T&D cost which will be applied to DR programs which meet "right place" and "right certainty" criteria. The default avoided T&D costs is calculated from marginal transmission and distribution costs by using the component of these marginal costs associated with non-ISO transmission and distribution substation equipment, which is principally related to transformer capacity.[11] For DR programs with physical assurance through technological solutions, the default 2009 T&D avoided cost is $28 kW-year. This value is based on the analysis of incremental distribution costs avoided or deferred by lowering peak demand through the demand response programs enabled by the automated metering infrastructure proposed in A.05-03-015. The 2005 value of $22 per kW-year was adjusted to an RECC basis and updated for the escalation in costs since 2005.

For DR programs with physical assurance through statistical regularities of widespread participation of small customers, the $28/kW-year figure is discounted by the ratio of MWs avoided at the 10th percentile to the MWs avoided at the 50th percentile as measured by the load

[11] Consistent with CE Framework section E.3.

impact protocols. The more uncertain the load reduction, the lower the value of the DR program in avoiding T&D costs.[12]

C. Avoided Energy-related Costs

Consistent with the parties' CE framework, the value of avoided electricity generation is based on wholesale energy prices averaged over the highest-price hours of an hourly price forecast based on average year conditions. For DR programs where the trigger is not a price trigger, SDG&E has used the hourly load profile from its resource planning model in conjunction with average forward market electric prices in 2009 through 2011 to calculate energy prices in the highest-price hours. For programs with specific price triggers, SDG&E has used the higher of the price trigger and the wholesale energy prices averaged over the highest-price hours.

With DR resources, SDG&E would purchase less energy during summer peak hours. Therefore, DR programs allow SDG&E to avoid electric T&D line losses on the SDG&E system since the energy would not be transported through the SDG&E system. The calculation of this benefit is based on the summer on-peak line losses at the secondary level adopted for EE in D. 05-04-024 of 8.1 percent.

Environmental avoided costs are based on section F.4 of the parties' CE Framework. DR reduces CO_2 by avoiding the energy that would otherwise be produced by a CT, resulting in greenhouse gas (GHG) benefits compared to the operation of a CT. The values of these benefits are based on the maximum pollution rates and the avoided cost values in the Energy Efficiency analysis, adopted in D.05-04-024. [13]

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[12] CE Framework section E.4 includes a requirement that the DR have sufficient certainty of providing long-term reduction

[13] See spreadsheet, cpucavoided26.xls, emissions tab, available at www.ethree.com.

For DR programs that shift load away from peak hours, an offset in benefit is included for the hours in which increased energy is used. The hourly prices are calculated consistently with the avoided energy costs described above.

D. Notification Period

SDG&E has attempted to quantify only the relative value of day-ahead versus day-of notification programs. In the ancillary services market, a CT with 10 minute start-up capability can earn revenues for being available if needed. These revenues are part of the revenue stream along with gross margins earned in the energy market. SDG&E has assumed that the value for any day-of notification DR program is the same as provided by a CT for purposes of this valuation.[14] No discount or adjustment is proposed for notification periods longer than 10 minutes; and similarly, no adjustment is made for DR programs that can provide load reductions faster than 10 minutes.

However, SDG&E has provided for a discount to day-ahead programs based on potential forecast errors and potential unexpected events. In a day-ahead DR program, the customer must be notified the day prior to being called upon to reduce load. In most cases, forecasts will be sufficiently close to actual outcomes, and the day-ahead program will provide as much value as a day-of program. However, in cases where unexpected events occur or weather forecasts badly miss the mark, a DR program's load reduction could be needed, but would not be available because it was not called the day before. SDG&E has tried to quantify this effect in a simple and understandable way based on historical data.

[14] This is consistent with Section F.2 of the parties' Consensus Framework, that a CT will not be given any more value than a DR program because it can provide ancillary services versus day-of DR programs with longer notification periods.

For this analysis, SDG&E has assumed that "system stress" occurs when its peak exceeds 3,800 mW and peak CAISO loads exceed 44,000 MW. SDG&E DR programs are generally not triggered when peak load is less than 3,800 MW. The statewide value was determined by the lowest peak demand associated with a CAISO called stage 1 alert in the summer months over 2004-2007.

The first type of DR program trigger for SDG&E is a weather trigger for San Diego. Analysis of the weather trigger of 87 degrees at the Miramar weather station on the top twelve peak load days shows that over the period 2004 through 2007, the forecast trigger would have failed to call the DR program on an actual peak day 23 percent of the time. However, for many of those days, the statewide system was not stressed and statewide resources would be more than adequate to handle the San Diego weather forecast failure. However, overall 8 percent of the time, peak days in San Diego occurred when the day-ahead weather trigger failed and the statewide system was under stress (peak greater than 44,000 MW) and the statewide day-ahead forecast was an underestimate of the resources needed the next day. In the times when the system is in stress and the CAISO is dealing with an under-forecast statewide, the CAISO would not have excess resources available to provide to San Diego. Thus 8 percent of the time the failure of the day-ahead trigger would have deprived SDG&E of significant resources needed to meet peak demand.[15]

[15] It is noted that the weather forecast failure figure increases to 17 percent if the statewide stress criteria were to be lowered to 43,000 MW.

The second type of trigger is a price trigger based on market prices. For example, the Capacity Bidding Program trigger is based on the day-ahead price for the SP-15 "super peak" product. The program may be called when the market price exceeds the trigger price based on 15 MMbtu/MWh times the burnertip gas price expressed in MMBtu. The market prices are based on market participants' expectations of the next day prices, which in turn are based on expected demand and supply for electricity. To the extent the forecast of market participants in the day-ahead market significantly underestimates the next day's conditions, a DR program based on the price trigger may not be called.

To assess the forecast error for this trigger, SDG&E analyzed peak load data on the days between July and September for 2004 through 2007. Market participants' expectations are assumed to be the same as the CAISO's day-ahead forecast. Analysis of the errors in the trigger involves looking at days with CAISO actual demand in excess of 44,000 MWs. For each of those days, a forecast error was determined to have occurred if the demand forecast was more than 1,000 MWs less that the actual system load (2.2 percent). Based on the data reviewed, forecast errors that were significant underestimates occurred roughly 13 percent of the time with both a 44,000 MW stress level and a 43,000 MW stress level criteria.

Based on the data reviewed, a discount for day-ahead programs of 10 percent seems reasonable and appropriate.

IV. OTHER ANALYSIS ASSUMPTIONS

A. Discount Rate

SDG&E used an 8.4% discount rate for discounting future benefits and costs to present value, the same value as is currently being used in the E3 calculator and is SDG&E's current cost of capital.

B. Program Life

For most programs the measure life is the number of years for which funding is being requested. Summer Saver however has an expected life of 10 years. For purposes of this analysis it is assumed the project will last over the three years of the program cycle. However, because the capacity payment is reduced dramatically in 2011, the average capacity payment over the life of the program was used. This was done to ensure that the costs of the program were not overstated. For TA/TI it was assumed that the investments made in the program would last for 10 years. To keep the analysis conservative, benefits were assumed to be constant from the fourth to the tenth year.

C. Measurement and Evaluation (M&E) Costs

SDG&E has included M&E costs as part of the costs for the cost effectiveness analysis at the portfolio level. Theoretically, however, there is an argument that M&E costs should be excluded since M&E is not necessary to achieving the demand reduction, only to measure it.

D. Capital

For simplification, the small amount of capital associated with the programs was assumed to be expensed each year. This eliminates the need for calculating the impacts of ratebasing small capital expenditures.

E. Load Forecast

The load forecasts for the cost effectiveness calculations were based on a 1 in 10 year peak value.

F. Customer Costs

As stated earlier, the incentive payments were used as a proxy for customer costs in all appropriate tests.

V. COST-EFFECTIVENESS ANALYSIS RESULTS

The following is a summary of the Cost Effectiveness analyses estimated for the different SDG&E DR programs requiring a Cost Effectiveness calculation.

CBP Day-Ahead

	TRC	Participant	RIM	PAC
Benefits	$5,432,580	$2,290,801	$5,432,580	$5,432,580
Costs	$3,822,583	$1,880,265	$4,233,118	$3,822,583
Ratio	1.42	1.22	1.28	1.42

CBP Day-of

	TRC	Participant	RIM	PAC
Benefits	$1,172,544	$495,725	$1,172,544	$1,172,544
Costs	$955,646	$470,066	$981,304	$955,646
Ratio	1.23	1.05	1.19	1.23

Summer Saver - Residential

	TRC	Participant	RIM	PAC
Benefits	$8,628,202	$7,939,474	$8,628,202	$8,628,202
Costs	$7,691,530	$7,447,428	$8,183,576	$7,691,530
Ratio	1.12	1.07	1.05	1.12

Summer Saver - Non Residential

	TRC	Participant	RIM	PAC
Benefits	$7,094,237	$5,075,654	$7,094,237	$7,094,237
Costs	$4,876,161	$4,696,377	$5,255,437	$4,876,161
Ratio	1.45	1.08	1.35	1.45

BIP

	TRC	Participant	RIM	PAC
Benefits	$2,046,513	$1,305,017	$2,046,513	$2,046,513
Costs	$1,414,437	$1,074,616	$1,644,838	$1,414,437
Ratio	1.45	1.21	1.24	1.45

CPPE

	TRC	Participant	RIM	PAC
Benefits	$882,703	$39,418	$882,703	$882,703
Costs	$321,847	$39,418	$321,847	$282,429
Ratio	2.74	1.00	2.74	3.13

TA/TI

	TRC	Participant	RIM	PAC
Benefits	$31,542,821	$38,532,210	$31,542,821	$31,542,821
Costs	$19,357,963	$13,816,490	$22,300,478	$19,357,963
Ratio	1.63	2.79	1.41	1.63

TOTAL OF ALL PROGRAMS REQUIRING COST EFFECTIVENESS

	TRC	Participant	RIM	PAC
Benefits	$56,799,599	$55,678,298	$56,799,599	$56,799,599
Costs	$38,440,166	$29,424,661	$42,920,599	$38,400,749
Ratio	1.48	1.89	1.32	1.48

A. 2009-2011 Cost Effectiveness for Total Demand Response Portfolio

The following table summarizes the cost effectiveness for 2009-2011 for all DR programs. The added programs considered in the total portfolio include Customer Education Awareness and Outreach, Permanent Load Shifting, Measurement and Evaluation and Codes and Standards. All values are present valued to the beginning of 2009.

ALL OTHER PROGRAMS AND EXPENDITURES

	TRC	Participant	RIM	PAC
Benefits	$0	$0	$0	$0
Costs	$15,928,304	$0	$17,043,304	$17,043,304
Ratio	0.00	#DIV/0!	0.00	0.00

TOTAL PORTFOLIO

	TRC	Participant	RIM	PAC
Benefits	$56,799,599	$55,678,298	$56,799,599	$56,799,599
Costs	$54,368,470	$29,424,661	$59,963,903	$55,444,053
Ratio	1.04	1.89	0.95	1.02

VI. QUALIFICATIONS

My name is Kevin C. McKinley. My business address is 8335 Century Park Court, San Diego CA. 92123. I am currently employed at San Diego Gas and Electric as the Supervisor of Measurement and Evaluation.

I originally joined San Diego Gas and Electric (SDG&E) in 1978 and held a variety of management positions in financial analysis, customer forecasting, fuel planning and marketing. During the 1990s I was the Manager of Marketing Analysis for SDG&E where my responsibilities included producing a series of regulatory filings for Demand Side Management (DSM) forecasts, DSM earnings claims, and program measurement studies. I was heavily involved in the development of the original Protocols used for measurement and evaluation in California during the 1990s. I was a member and also Chairman of the California Demand Side Management Advisor Committee (CADMAC) during part of this period.

I left SDG&E in late 1998 and consulted in the measurement and evaluation area for the next several years. I rejoined SDG&E in April 2005. My current responsibilities include the Measurement and Evaluation of DSM programs for both SDG&E and the Southern California Gas Company for Energy Efficiency, Demand Response, and Low Income programs. I am also a part-time instructor and have taught at several colleges and Universities in the San Diego area including San Diego State University, the University of San Diego, University of Redlands and the University of Phoenix. I hold two masters degrees, one in Economics and the other in Latin American studies, both from San Diego State University and a Bachelors degree in Business Administration from Gonzaga University. I have previously testified before this commission.

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CHAPTER V

PREPARED DIRECT TESTIMONY

OF

TERRY MOHN

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

September 19, 2008

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CHAPTER V

INFORMATION TECHNOLOGY (IT) SYSTEM MODIFICATIONS

I. PURPOSE

The purpose of my testimony is to describe SDG&E's proposed information technology system enhancements to support the 2009-2011 proposed DR program portfolio. The Appendix to my testimony provides a concept document providing more background and detailed conceptual development plans.

II. BACKGROUND

Both San Diego Gas & Electric and Southern California Gas Company are undergoing a major business process transformation in that they are applying technology to traditionally manual processes. Similarly, the California Energy Commission (CEC), through various studies, identified that if DR activity is automated, this leads to increased positive DR penetration and participation by all stakeholders. These facts, coupled with the deployment of our Smart Meter and Smart Grid projects, provide excellent guidance for us to automate more of the demand response process.

III. STRATEGY TO AUTOMATE MANY DEMAND RESPONSE FUNCTIONS

During strategy development sessions, SDG&E decided to identify what core operational units will support increased DR penetration, ranging from Electric transmission & distribution to Home Area Networking (HAN). This resulted in a long-term strategy that lays out a plan to implement a central controlling system that can account for dispatchable loads up to any geographic scale and all the way down to the individual Programmable Communicating Thermostat (PCT) level. This system will send pricing signals to aggregators as well as is capable of receiving signals from the California Independent System Operator (CAISO). In the end, SDG&E's Grid Operations Center will have visibility into outages, dispatchable loads, and distributed generation. Ultimately, our customers will have the ability to enroll in DR programs on websites as well as via our call centers. All of the information flowing through these many systems will be visible to a central DR system and account for actual events and the resulting discrete device load reductions.

As SDG&E went about developing this strategy, we talked to many software product manufacturers looking for a commercial, off the shelf, product meeting these requirements. No vendor was found that fulfills these goals in today's market place. However, with our recent positive experience developing standards and the newly created market for Home Area Networks, SDG&E believes that working with the other CA IOU's, CAISO, the CEC, aggregators, and other stakeholders, that we can define the functional requirements and the necessary standards that a market will emerge. We have spoken with a number of companies wishing to partner with us to help pilot the resulting product.

Our experience during the HAN development effort shows us that with concerted effort by the stakeholders, standards and products will result in a timely fashion. We began HAN use-case development in July 2007, and completed a defacto utility standard in April 2008. By March 2008, SDG&E witnessed the emergence of two manufacturers for products in this market. Today, we recognize over ten product manufacturers entering the HAN building automation market.

IV. STANDARD AND NEW ARCHITECTURE

New interoperability standards will be needed to ensure future growth and enhancement opportunity, as well as minimizing long term system costs. However, as with every other major corporation, we possess many existing computing systems that will need to be integrated into this new system. It is fair to say that integration costs tend to be the most expensive aspect of a project of this nature. We envision this new system to integrate with at least the following existing systems: Customer Billing, Outage Management, Meter Data Management, Customer Relationship Management, Financial, DR Programs, Web Presentment, and others.

Our first primary objective is to jointly develop system and functional requirements with the other CA investor-owned utilities (IOU's) and other interested parties. The process begins through creating a set of well defined use cases, similarly to the method used with HAN. SDG&E will take those requirements to the marketplace to help nurture a product market. Our objective is not to build an industry-standard platform but leave that duty to the vendor community.

Several considerations of a finished product are necessary:

- The finished product must become COTS, a shrink wrapped application
- It must be scalable in number of endpoints end support a wide-array of functions
- It must follow industry interoperability standards
- It must be supported through professional service companies
- It must be interoperable with other SDG&E back-end systems
- It must support web interaction (both portal and web services), third-party vendor support (aggregators and CAISO), and other DRapplications.

Many exiting SDG&E computing systems will require modifications to create a common architecture to process the new information flowing throughout its system. Much is unknown about the cost of integrating this system today. As such, SDG&E plans to return to the CPUC to request program funding, once we have a good estimate of costs and efforts required. Until then, we will be working with the other stakeholders, as mentioned earlier, to develop the interoperability standards needed to ensure this investment does not become stranded.

V. COMPLIMENTARY TO MRTU AND NEED FOR AUTOMATION

As outlined in my testimony (Section III) and the following company strategy (Scope), our plan is to implement new technology that not only supplies automated DR based on utility reliability and supply scarcity needs, it also will be used to carry state-wide grid reliability signaling to all customer classes. The planned system is in direct alignment with CAISO's MRTU plans and is envisioned to support it as it unfolds. Assuming appropriate levels of program funding, this plan should be carried out over the program period.

Our team has discussed these plans with other CA IOU's, CAISO and potential software partners. The plan has been embraced by all those contacted as a valuable additional to any utility's automation initiatives.

Following the first filing of this testimony, some CA state stakeholders suggest additional automated DR pilots must occur over this program period to test out the ability to automate DR functions when initiated by CAISO, ostensibly simulating MRTU. My testimony states that we plan to implement a system performing these support functions; therefore, the only further pilot we should consider, in accordance with the Guidance Ruling (the 2/27/08 Ruling), we are proposing a new PLS Pilot which is addressed in the testimony of Mark Gaines and Tony Choi. In addition, to create a state-wide, fully integrated system, cooperation and testing will be required upon CAISO and the other CA IOU's.

Although we have held preliminary discussions with CA IOU's, fruitful planning has not proceeded as yet. Incorporating the other IOU's into our plans may entail some testing, or piloting, of technology. That stated, our plans previously assumed cooperation with the other CA IOU's, at least in developing use cases and functional requirements. SDG&E is comfortable, and to a small degree, is already leading the effort to develop these requirements in cooperation with the parties mentioned.

My testimony further states that we plan to return to the CPUC next year with a budget needed to complete the efforts laid out herein. Prior to proposing a budget, we need to work with the stakeholders listed in my testimony to develop use cases and functional requirements that lead to a 'request for information', from various solution providers. Upon receipt of responses from those solution providers, we will have reasonable budget estimates to carry out the efforts required.

Therefore, we conclude that general technology pilots are not necessary, since we plan to provide the actual implementation within the program period.

This concludes my prepared direct testimony.

VI. QUALIFICATIONS

My name is Terry Mohn and I am currently employed by San Diego Gas & Electric Company (SDG&E). My business address is 8335 Century Park Court, San Diego, CA 92123-1569.

My present position is Technology Strategist and Enterprise Architect in the Information Technology Department of SDG&E. I have been employed by SDG&E since 2002. Since 2007, I have also served as Vice Chairman of the GridWise Alliance, whose vision is a new way to think about how we generate, distribute and use energy - using advanced communications and up-to-date information technology. I frequently meet with federal agencies and legislators over the ways to enable a smarter, more efficient, secure and reliable electric power system.

I received a Bachelor's Degree in Computer Systems Engineering Technology from the Oregon Institute of Technology in 1980.

I have not previously testified before the California Public Utilities Commission.

APPENDIX

The following is a company strategy document approved by the business to take this concept forward. It is not a project plan nor is it a business case. This is the concept that warrants filing our plan with the CPUC.

Proposal for Demand Response Business System

May 2008

Overview

Many parts of the business have depended upon themselves, and very successfully, to implement IT systems. Customer Markets (programs), for over 8 years, has responded successfully to managing Public Utility Commission's (CPUC) mandates to provide programs for utility customers. Increasingly however, a number of these programs require information systems support and software application development to outline the programs, as well as enroll customers. Simultaneously, our organization is looking for opportunities to simplify, or possibly standardize, on key IT assets. In addition to OpEx20/20, the Smart Meter system will introduce a number of new IT systems. This document outlines a joint IT and Customer Markets (Mass and Major) technology strategy and roadmap consistent with other corporate objectives, simplification and centralization as outlined particularly in OpEx20/20.

The purpose of developing a utility solution is to enhance DR participation & response and reduce future administrative costs for DR program.

Scope

As the corporation begins systematically applying the OpEx20/20 tenets by consolidating applications, e.g. enterprise applications, the IT components of Customer Markets become more visible and encouraged to follow suit with other corporate applications. As IT increases its effectiveness partnering with business units, it is likely that all new computer systems and outsource applications are recommended jointly by both parties. Information and computer standards that the business adopts for efficiency, cost control, interoperability with other systems and obsolescence avoidance are the norm and ease product selection for each business unit. IT helps select the recommended standards and added system benefits leveraging existing assets.

This strategy impacts the following three business groups:

1) smart home – Home Area Networking and Green Store
2) smart meter – DR for business case, In-Home Displays, and PCT's
3) smart grid – OpEx20/20 OMS/DMS, Grid Design, Reliability

Information Technology will take into consideration the following systems and functions:

1) Engage the consumer – Portals internal and third-party
2) CRM – account management and reconciliation
3) Demand Response (DR) functions
4) DR Aggregators

5) AutoDR
6) CAISO messaging
7) Customer Direct Access
8) MDMS
9) Smart Meter DR & EE device types
10) Data types for all messaging
11) Standards – transport, data, messaging, modeling, general interoperability

Deliverables –

1) support testimony – explain why this different than Smart Meter
2) budget proposal – due June 1, 2008
    a. specific to DR
    b. specific to EE
3) Technology roadmap – due Q3, 2008

Description

Demand Response is the proactive management of electric and gas utility loads in order to more efficiently and reliably market, produce, transmit and deliver energy. Applications of demand response are as simple as the Utility interrupting load in response to severe grid transients or supply shortages (direct load control or active demand-side management), or as complex as millions of customers voluntarily reducing their consumption / load in response to price signals (passive demand-side management). With the exception of having to address emergencies, DR is generally used to flatten the demand peaks. In either case, the Utility must have a communications gateway to either directly control the consumer's loads, or provide a pricing signal to allow the consumer to manage their consumption directly by:

- making the decision when to use appliances / equipment
- as input to a home / premise energy management system

To clarify terms, this document describes:

- Energy Efficiency – Reduce total kilowatt of load with permanent and efficient technologies
- Demand Response – Temporary reduction of peak energy usage for a defined duration. Curtailment events are triggered either by reliability events or pricing signals.
- Load Shifting – Flattening the peak by using off-peak power in place of on-peak power. This is often a permanent peak shift driven by combining technologies and time-of-use rates. An example includes thermal energy storage.

Large Commercial and Industrial Customer DR Programs are not new. They have been in-place for 20+ years. This is primarily because the individual loads are larger, requiring fewer controls and automation, in achieving the desired load reduction / shedding. However, as demand has continued to grow, there has been a noticeable shift in the overall makeup and magnitude of the energy demand peak. Residential consumers now make up about 60% of the peak, with unprecedented growth occurring, such as 17% growth in the last three years in the U.S. Mid-

Atlantic states. Additional DR will have to come primarily from residential consumers. There currently are successful, residential DR programs – Florida Power and Light (FP&L) Company has about 750,000 residential customers enrolled with the capability to shed ~1,000 Mw of load (uses a ripple current system).

Functional Requirements

Functional Requirements are "the what" – technical requirements are "the how". This section is Functional Requirements.

DR will be implemented through one or more of the following mechanisms:

- Direct Load Control – devices are installed on consumer loads, giving the Utility direct control when needed
- Passive Load Control – individual consumers, through contracts established directly with the Utility, voluntarily reduce their electric consumption based on receipt of price signals
- Aggregated Load Control – similar to Passive Load Control, however, 3rd Parties (e.g., Comverge) contract with a block of consumers to deliver a guaranteed load reduction to the Utility. The 3rd Party contracts with the Utility.

SDG&E Smart Meter program will have the ability to use the meter or meter communication infrastructure as the gateway to controlling consumer loads. However, other communication solutions, both internal and external, to the Utility can be leveraged.

The SDG&E overall solution needs to be considered within the context of real-time (sub-seconds) T&D operational data & control versus non-real-time needs. As the T&D grid becomes more complex, operations & control will become tightly integrated. The Energy, Distribution and Outage Management Systems will operate as "one", needing real-time data from the grid and be able to develop response and control signals on a near-real-time basis. These systems communicate directly with grid devices before any data is passed to the other business information systems. These systems will also determine the needed amount and location of Demand Response to provide safe and reliable grid operations. The Network Communications Management system provides control of the various communications networks (e.g., RF Mesh, BPL, Wi-Max) deployed by the Utility, to insure access to data and the ability to provide device control signals, is ready available.

As three primary mechanisms are available to implement DR, a system will be needed to manage the DR mechanism(s), location and amount of load reduction needed. Additional core functionality includes:

- Keep track of grid location/connectivity/maximum load
- Keep track of communications path to the device
- Send an assured message to the device
- Receive a response from the device and log it
- Be able to interact with devices as individuals and groups

- Manage groups of devices
- Manage path information
- Feed information to billing system
- Manage meta information about the device
- Potentially feed information to a forecasting system

A Demand Response Management (DRM) System must provide the necessary load reduction within minutes, processing grid operational information primarily from the Energy and Distribution Management Systems. As this is not required to be real-time (although, within seconds to minutes), the event transactions are processed through the company's messaging framework (e.g. Enterprise Messaging Framework).

Although vendors are looking at the development of DRM Systems, there is currently no COTS solution. A number of MDMS vendors are considering modifying their current products; however, most of these MDMS systems were designed as one-way – bringing data into the enterprise, not pushing it out to the grid. Critical to a successful DRM solution is knowing and storing the path information to a field device which is not core to MDMS. Also, if DR is to operate multiple devices within a customer's residence, the requirements become much more complex.

Demand Response
This section describes how the DRM system intersects in each of the business areas.

1) Customer markets (programs) that require visibility into the contracted or enrolled loads available for dispatch.
2) smart home – Home Area Networking and Green Store
    a. Capabilities
        i. Supports a secure two way communication with the meter
        ii. Supports load control integration
        iii. Provides direct access to usage data
        iv. Provides a growth platform for future products which leverage HAN and meter data
        v. Supports three types of communications: public price signaling, consumer specific signaling and control signaling
        vi. Supports distributed generation and sub-metering
    b. Assumptions
        i. Consumer owns the HAN
        ii. Meter to HAN interface is based on open standards
        iii. Implementation is appropriate given the value and the cost
        iv. Technology obsolescence does not materially impact the overall value
    c. The Green Store creates a utility positioning for the deployment of energy and related "green" applications for residential and small commercial customers. All applications are in scope with specific emphasis on new potential driven by wide deployment of smart appliance devices, infrastructure and how customers will interact with them. It creates a long-term strategy and near/mid-term action plan for the utility to create value through the delivery of energy and related

applications in parallel with the deployment of Smart Meter / HAN. It identifies and quantifies DG, DR & EE opportunities, other value added product and services opportunities, determines how to implement to improve customer satisfaction and company reputation – strengthen role as Environmental Stewards, and identifies ways to reduce customer rates and/or bills

3) smart meter – DR for business case, In-Home Displays, and PCT's
   a. Smart Meter provides communication conduit
      i. Communication modules installed in meter prior to deployment
      ii. Allows for remote communication and upgrades
   b. 57k Programmable Communicating Thermostats (PCTs)
      i. Provides customers with automated management of their energy costs during Critical Peak days.
   c. Smart Meter provides infrastructure for SEU's HAN
      i. Provides the physical foundation of the HAN to benefit other departments/operations around the company
      ii. Leveraging the HAN functionality has the potential to create new products, services, and capabilities for our customers
   d. MDMS support is required in that DR messaging must flow through the MDMS for audit purposes.
   e. IHD requirements - The ability to send pricing signals and other energy related information to small devices within the home. These devices are intended primarily for display, but may possess other functionality, such as household energy management capabilities. Devices may also accept user data and transmit it to the utility through the Smart Meter system.
   f. PCT requirements provide the same functions as IHD and also adjust the temperature set-points of thermostats. The set-point changes may occur by software rules within the device or by the utility. Rules for set-point changes follow the active and passive demand response description previously discussed.
4) Online presentment - DR shall have online presentment integrated into MyAccount and Kwickview applications.
5) CRM will be used to manage customer account information and supply CS staff with event history to and from customer devices. It will also record the available programs and enrollment chosen by customers. The primary functions of CRM are:
   - Administration/ Management of more than 20 DR Programs (Program goals, dates)
   - Management of Customer Leads
   - Management of Contacts & Accounts
   - DR Program Enrollments / disenrollment's, and opt outs (CPP-D)
   - Marketing of DR Programs
   - Calculations: Vendor Payments, Energy Savings, Rebate Amounts
   - Auditing
   - Security
   - Reporting and analytics
   - CRM processes Kwickview event data after the event; it's loaded at the customer account level.
   - CRM processes 3rd party Comverge enrollments and event data
6) AutoDR – CRM, reconciliation, portal requirements

From time to time, the CPUC mandates the utility to develop programs around specific technologies developed in the California Energy Commission (CEC) labs. A recent example is the technology called AutoDR. In this case, both hardware and software are prescribed by the CPUC to be used by the utility. The programs group may choose to outsource the entire system or may choose to implement the software within its own server cluster.

7) smart grid – OpEx20/20 OMS/DMS, Grid Reliability
    a. OMS/DMS
    b. Grid Reliability
8) Customer Direct Access with DR systems

Energy Efficiency

1) Customer markets (programs) that require automated communication to consumers through their various communication devices.
2) Planned programs include:
   Monitor AC and other devices
   - Report out when efficiency drops
   - Inform consumer or repair shop of event – Portal, email

Renewables

1) Dispatchable DG and renewables
2) Ad hoc DG and DR (unknown sources)

Strategy considerations

The objective is to develop system and functional requirements jointly with the other CA IOU's and other interested parties in order to develop a common set of requirements and standards, through a set of well defined use cases, similarly to the method used with Utility AMI. SDG&E will take those requirements to the market place to determine the best vendor to partner with. SEU's objective is not to build an industry-standard platform but leave that duty to the vendor community. Several considerations of a finished product come to mind:

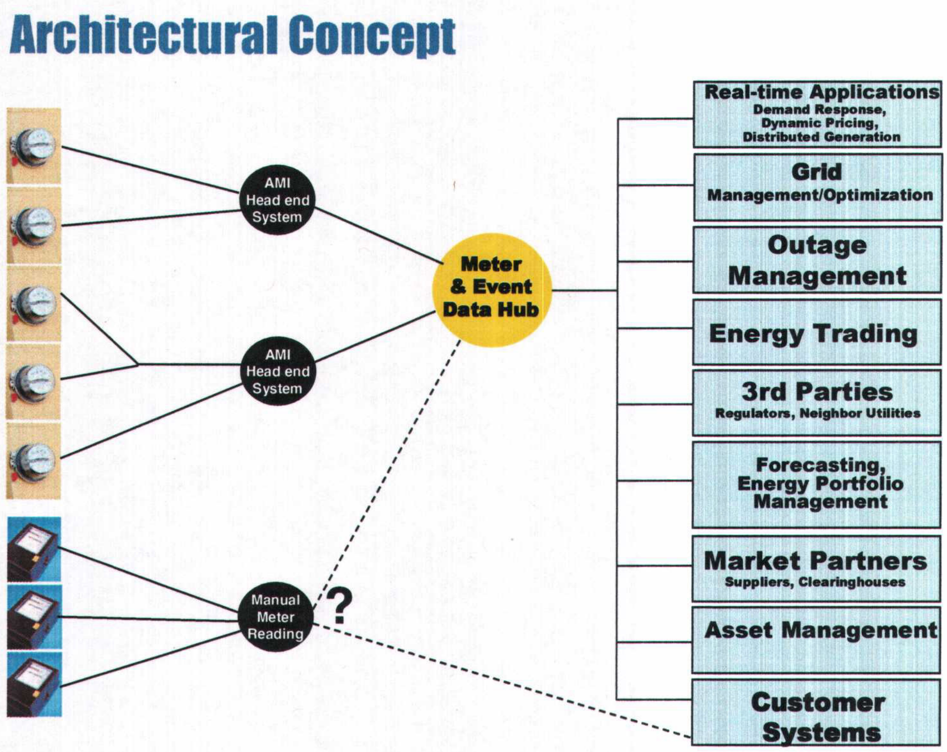
- The finished product must become COTS, a shrink wrapped application
- It must be scalable in number of endpoints end support a wide-array of functions
- It must follow industry standards
- It must be supported through professional service companies
- It must be interoperable with other SDG&E back-end systems
- It must support web interaction (both portal and web services), third-party vendor support (aggregators and CA-ISO), and other DR-applications.
- It becomes the defacto standard with key stakeholders driving towards industry critical mass of users to ensure acceptance and success

Event Channels

- Events will be communicated over the AMI network and through the smart meter to the intelligent in-home device, e.g. PCT. (default channel)

- Event notifications can be sent out via emails (depending on whether customer has opted for this feature at the time of enrollment into a DR program?)
- Automated voice message delivery to customer via telephone (depending on whether customer has opted for this feature at the time of enrollment into a DR program?)
- Event alerts on the landing page of MyAccount (depending on whether customer has opted for this feature at the time of enrollment into a DR program?)
    - The assumption here is that the customer will have access to DR information through MyAccount. All the relevant DR web pages (or portlets) will be integrated into MyAccount.

Conceptual Model
The following is a diagram that depicts a functional model of the DR application. The "DR engine" is the DR software application.



Technical Requirements

Functional Requirements are "the what" – technical requirements are "the how". This section is Technical Requirements.

- To be developed during the use-case and requirements phase

Review MDMS messaging capabilities and requirements. Evaluate both internal applications and the end devices (meters).

- To be developed during the use-case and requirements phase

Technologies are changing – how to build immunity to change
- Build for Interoperability
- Standardize the information flow

The following is the current state set of standards that apply. These consider HAN, AutoDR, CIM, IntelliGrid, MultiSpeak, WS-*, cyber security for all transports, GridWise Architecture Council, and any others.

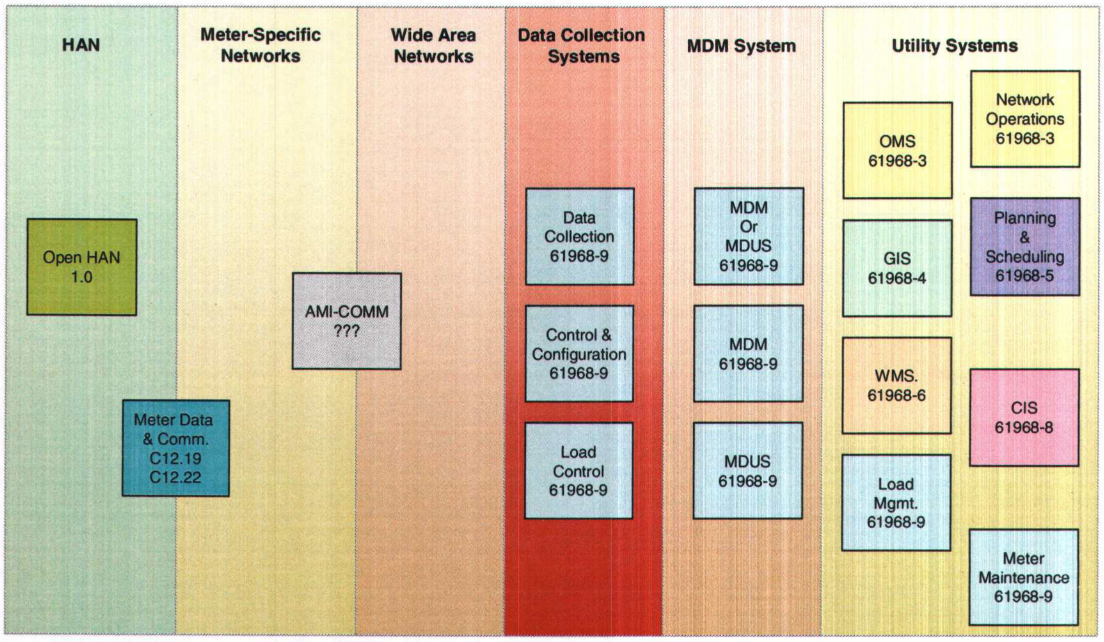
Integration & Message Structure
- IEC 61968-9 (Data Collection, Control & Configuration, Meter Data Management, Meter Maintenance, Load Control & Analysis, Meter Asset Management)
- SOAP (v1.1)
- WSDL (v1.1)
- WS-Security
- XML (v1.0)
- Multispeak: If we adopt IEC 61968-9, why bother with MultiSpeak?
- Open Grid Services Architecture
- PCT Title 24 Reference Design

Interoperability
- Interoperability Context-Setting Framework (GridWise Architecture Council)

Communication Protocol
- ZigBee from Smart Meter to Intelligent In-home Device (PCT)
- HTTP 1.1

Security
- SSL (v3.0)
- PKI
- Key length: 256

AMI System Applicable Standards



Load Management System (LMS)

- A Load Management System is used to manage and control load by the utility in order to promote system reliability. A Load Management System may perform load forecasting, contingency analysis, and other simulations prior to issuing a load control command. This function largely falls under the domain of IEC 61968-5 (Operational Planning and optimization).

Outage Management System (OMS)

- An Outage Management System (OMS) is used by distribution operators to detect and track outages, and to assist in the process of verification and/or restoration. An OMS typically combines (or has ties to) functionality such as Network Operations (61968-3) fault management (NO-FLT); Operational Planning and optimization (61968-5) network operation simulation (NO-SIM); Maintenance and Construction (61968-6) maintenance and inspection (MC-MAI), and work scheduling and dispatching (MC-SCHD).

Meter Asset Management (MAM) System

- Utilities will employ some form of asset management software in an effort to maintain detailed records regarding their physical assets. Asset Management is treated categorically in 61968-4. However, metering has such unusual requirements, that it is not uncommon for a utility to use specialized Meter Asset Management software. The software inventories the asset – providing a record of its physical attributes as well as its location. For sake of discussion, the part 9 document will talk about a MAM system which is closely coupled to the MS and MDM, though some implementations will successfully generalize the asset management application sufficiently so that it can live within a more generic AM system.

Meter Data Management (MDM) System

- From a historical perspective, it was common for a utility to have more than one Automated Meter Reading System. Alternatively, a utility might outsource meter reading services to one or more third-party service providers who operate an AMR system and/or read the meters manually. The Meter Data Management (MDM) system is used to provide a common repository, and point of management and access of meter data that is collected from disparate Metering Systems. In addition to data aggregation, quite often the MDM will also make an effort to scrutinize the data collected from the various Metering Systems, and provide a Validating, Editing, and Estimating (VEE) capability. (IEC 61968-1 includes these functions under "MR-RMR-Meter data aggregation," and "MR-MOP-Meter Data Management.")

Customer Information System (CIS)

- A CIS will typically encompass functionality related to customer care and billing. This is a subject which is external to the 61968 standard (refer to Customer account management (EXT-ACT)). The billing function is driven by readings, typically Demand or Time-of-Use, obtained from the meter. The CIS is also often involved with processes related to billing inquires, meter disconnect and meter reconnect, rate program changes.

Network Operations (NO)

- Network Operations (61968-3) may occasionally need to issue load control and pricing signals to meters. This can be done for both economic and emergency reasons.

Meter Maintenance (MM)

- Meter Maintenance is responsible for functionality related to the configuration and installation of meters. This type of functionality generally falls under Meter Asset Management or Asset Management in general. Performing meter maintenance may require exchanges with Work Management.

Planning

- The planning function is described in Operational planning and optimization (61968-5) network operation simulation (OP-SIM).

Work Management (WM)

- A Work Management system is responsible for work that is performed by field resources. This subject is covered in Maintenance and Construction (61968-6) maintenance and inspection (MC-MAI).

- With respect to metering, WM includes the installation, maintenance and replacement of meters. This may also involve the process of special reads.

Load control devices

- Load control devices are used to control loads at a ServiceDeliveryPoint. The metering system may often have a communication network which can be used for transmitting load control signals to various CommunicationsAsset(s) in order to control the load presented by the EndDeviceAsset(s). Alternatively, the communication network could be used to communicate demand response (price) signals to the CommunicationsAsset(s) in order to affect the load presented by the EndDeviceAsset(s).

Meter

- The meter records the data used for tariffing public networks, and data used for network balancing mechanisms.
- Readings captured by the MS are collected by a system such as the MDM before being presented for billing purposes. Billing entities may correct the data, or, in some regions, the energy supplier may perform Validating, Editing, and Estimating (VEE) according to rules established by the appropriate supervising regulatory agency. In any case, those corrections are made available to the user who requests them.
- Where this International Standard refers to a Meter, it should be realized that a "Meter" is an end device that has metrology capability, it may or may not have communications capability, it may or may not have connect/disconnect capability, or a host of other capabilities. Given that a meter will have metrology capability, it will in all likelihood meter kWh, but possibly also demand, reactive energy and demand, Time Of Use quantities, Interval Data, Engineering quantities, and more.

Business Technology Plan Recommendation

1) Develop use cases and functional requirements needed for solution
    - Enroll UCA users group (part of IEC) to develop standards – probably in the OpenEnterprise workgroup
    - Enroll other California IOU's, CA ISO and CEC (probably LBNL) to help define requirements
    - Work with vendor community to ensure good understanding between functional requirements and technical requirements
    - Pilot technology, such as provided by DRBizNet, from last year's DR-ETD PIER program
2) Functions in scope
    - Customer Self Service (Portal)
    - Consumer Devices
    - Electric T&D integration
    - CA ISO Integration
    - C&I customer / Aggregator Integration (AutoDR)
    - CRM Integration   Program Management
    - CICS integration   Program Management

- MDM integration   Program Management
- Headend integration   HAN device operations
- EE Tools and End-use monitoring   EE enhancements
- DG market participation

3) Estimate overall integration and application costs
    - Internal, based on utility's existing architecture, technologies and applications

Application of San Diego Gas & Electric Company (U-902-M) for Approval of Demand Response Programs and Budgets for the Years 2009 through 2011	Application 08-06-002

CHAPTER VI

PREPARED DIRECT TESTIMONY

OF ATHENA M. BESA

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 19, 2008

TABLE OF CONTENTS

I. INTRODUCTION & PURPOSE

On March 7, 2008 the Energy Division conducted a workshop to explore integrated demand-side management "IDSM" ideas and to address potential issues/challenges of integrating various demand-side management programs so that they collectively produce greater results. Subsequently the *Joint Assigned Commissioners' Ruling Providing Guidance on Integrated Demand-Side Management in 2009-2011 Portfolio Applications* ("Joint ACR") was issued in April 11, 2008. The Ruling provides guidance to the utilities regarding integrated demand-side management ("IDSM"), Marketing, Education & Outreach ("ME&O), Zero Net Energy ("ZNE") and other IDSM pilot projects and operational improvements was issued by the Commission. Additionally, on April 21, 2008 Assigned Commissioner's Ruling Requesting Comments on Proposed Energy Efficiency Measure for the California Solar Initiative ("CSI") Program, was issued to further the discussion how best to integrate/coordinate energy efficiency efforts with CSI.

This section of the testimony presents SDG&E's current and proposed integration activities across various program portfolios in different CPUC proceedings, Energy Efficiency ("EE"), Low Income Energy Efficiency ("LIEE"), Demand Response ("DR"), Advanced Metering Infrastructure ("AMI") Distributed Generation ("DG"), and CSI. SDG&E submitted its 2009-2011 LIEE application (A.08-05-024) on May 15, 2008. The 2009-2011 DR application (A.08-06-002) was submitted on June 2, 2008. The Commission issued D.07-04-043 on its AMI ("Smart Meter") proceeding. SDG&E notes that it is not the current program administrator of the DG and CSI program portfolios and they are currently assigned to the California Center for Sustainable Energy ("CCSE"). Although, these various proceedings are currently independent of each other, the California Energy Efficiency Strategic Plan ("CEESP") provides vision and strategy to leverage these various program efforts to ensure the realization of the aggressive Big

Bold Energy Efficiency Strategies ("BBEES") laid out by the Commission in D.07-10-032.

This section can be considered a "stand alone" chapter as required by the April 11 Joint ACR. This comprehensive presentation of SDG&E's IDSM efforts across the different proceedings is being presented for the first time in this EE application as the EE application is the last application to be submitted to the CPUC.[1] This was to ensure that all EE activities and programs addressing IDSM were fully vetted and developed prior to it being submitted in other proceedings.[2, 3] In the following sections, SDG&E addresses various aspects of its IDSM efforts in the order of priorities laid out by the April 11 Joint ACR.

II. COMPREHENSIVE AND COORDINATED MARKETING, PACKAGING AND DELIVERY (COORDINATION)

This section discusses the various integrated outreach and education of customers that optimizes utility engagement with customers.

A. Customer Programs Organization

Currently, SDG&E's Customer Programs organization is responsible for both EE and DR programs. The department was reorganized in 2006 such that these programs reside respectively by sector with its Residential segment manager and Commercial segment manager. This was SDG&E's initial effort in integrating its EE and DR program management. Moving forward into 2009, SDG&E is enhancing its comprehensiveness by restructuring how it designs and manages its program. In the past its programs were managed across the residential and non-residential markets uniformly. Beginning in 2009, the program managers will be responsible for segments rather than specific programs. The goal is to be even more knowledgeable about the needs of

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[1] The May 5th ACR and June 2nd ACR reset the due dates for the 2009-2011 EE application from May 15 to June 2 and finally to July 21.
[2] SDG&E will present this same chapter in the DR proceeding..
[3] On July 1, 2008, SDG&E submitted "Response of San Diego Gas & Electric Company to Assigned Commissioner's Ruling Ordering Large Investor-Owned Utilities to Comply with Prior Commission/Commissioner Directives" in which SDG&E discusses various LIEE integration efforts with EE and DR (at pages 4-6).

customer segments (residential owners and renters; non-residential manufacturing, agricultural, hospitality, foodservice, institutional, etc) and increase market penetration through segment specific marketing and outreach. This additional step of segmentation enhances the company's ability to design program and communications materials geared towards managing the customer's energy needs in a comprehensive manner rather than the traditional piecemeal of offering independent programs. This approach will encourage segment program managers to first understand a customer's energy needs and offer assistance consistent with the loading order of the Energy Action Plan. Employees will receive proper training and have opportunities to improve their jobs skills to effectively manage the market segments assigned to them.

B. Marketing, Education and Outreach ("ME&O")

1. SDG&E-Specific ME&O Communication Strategies

SDG&E's messaging strategy will be to present IDSM as the complete energy management solution that can help customers save energy, as well as manage their energy costs. This effort is intended to improve customers understanding of "energy management" as a whole in regards to how EE/LIEE, DR and CSI can work together. Some of SDG&E's specific communications strategies:

- For general awareness communications, "un-brand" programs and instead focus messaging on program benefits (e.g., SDG&E is simplifying its nonresidential programs to move away from traditional program names such as Express Efficiency but work closely with customers to identify incentive opportunities.) This ultimately leads to better customer segmentation, personalized communication and messaging that is relevant
- For program-specific promotions, "match" programs together in terms of appropriateness for the customer and focus on benefits (e.g., LIEE customer programs, segmentation of commercial customers and targeting residential customers using other segmentation tools such as Prism codes).

- Solutions will be bundled to aggressively include EE, LIEE, DR and CSI opportunities. This will focus communications on customer benefits and industry segment needs; not programs. SDG&E will provide energy management "packaged" solutions for each industry segment. Example: "Get the complete Energy Management Solution tailored for your business.

- SDG&E began using the "Go Green. Save Green" theme in its 2007 residential energy efficiency program communications. This will be expanded into all communications to reinforce how taking advantage of these programs can help them achieve their "green" goals (green house gas emissions (GHG) reductions, conservation, approval of their customers, and other benefits) while also saving money in the long run.

- Expand EE and LIEE in-home education to residential customers that will include information on GHG, Smart Meters, and tie-in with EE, DR, CSI.

- New Construction programs will continue to work with various industry participants to encourage comprehensive solutions in new homes and buildings that incorporate not only EE measures, but also DR technologies (programmable smart thermostats, Auto DR) and CSI opportunities. This approach is essential to meeting the Commission's BBEES towards net zero energy new construction homes and building.

- Local Government Partnerships ("LGPs") provide opportunities to communicate the IDSM message not only to their own organization but to their peers and their constituency through communication avenues unique to them.

- EE Third Party programs also present opportunities to provide IDSM messaging and customer education materials to general residential customers, LIEE customers and nonresidential customers. Third Party program providers are encouraged to co-brand and co-market with SDG&E and other Third Party providers where multiple program opportunities exist. An example is the co-marketing of the AC Tune-Up program with the Summer Saver AC Cycling program

2. Statewide ME&O

- EE Statewide ME&O is primarily implemented through Flex Your Power with additional ME&O efforts for hard-to-reach customers. On the other hand, DR Statewide ME&O is implemented through Flex Your Power Now!. These two programs are complimentary since it provides a common platform that allows customers to associate Flex Your Power with managing energy through EE incentive programs, conservation messages and during critical peak times.

- As part of CEESP, the Commission intends to develop a statewide brand and web portal that could encompass not only EE but all other aspects of IDSM to have a centralized location for IDSM information. SDG&E will actively participate in this activity.

C. Customer Relations Management Tool ("CRM")

CRM is a comprehensive information technology tool that is designed to integrate and optimize the administration of all DR and EE programs at SDG&E. Some of the functionality of the system includes rebate and incentive processing for both EE and DR program participants, online enrollment, consolidated results tracking and reporting, automated energy savings calculations, customer equipment database, marketing plan development and market segment development. This integrated tool will facilitate the ongoing development and management of integrated DSM programs at SDG&E

III. OPERATIONAL IMPROVEMENTS (PROGRAM DELIVERY COORDINATION TO ENABLE SYSTEM INTEGRATION)

A Exemplary Specific Programs That Offer IDSM Audits

The following list of programs that SDG&E has proposed in its LIEE, DR and EE applications is not meant to be an exhaustive list of programs that offer IDSM.

- The Home Energy Comparison Tool ("HECT"), SDG&E's online tool that compares a residential customer's energy usage to other customers who have similar demographics in their neighborhood and used in conjunction with SDG&E's Home Energy Efficiency Survey, provides EE and DR recommendations for customers to reduce their energy use. Customers without on-line access can avail themselves of this service by calling SDG&E's Energy Information Center. This tool has been in place since 2007 and will be enhanced and offered to LIEE customers. Additionally, SDG&E is undergoing a comprehensive review of current and planned energy and bill management tools with regards to energy, rates and bill analysis to determine a single integrate strategy and plan to provide comprehensive, "simple to use" and accessible tools for its customers.

- Home Energy Efficiency Survey ("HEES") is a comprehensive multi-lingual energy audit tool designed to reach a wide range of residential customers via online, phone or direct mail. The audit results provide customers with suggested EE and DR recommendations to reduce their energy use and energy costs. The survey tool also supports the CSI requirement that homeowners complete an EE audit prior to participating in the CSI program.
- CFL Recycling Program will be available to all SDG&E residential customers, both LIEE and non-LIEE customers. Key elements include distribution of CFL disposal bags at all lighting turn-in exchanges and outreach events. In addition, the information will include a listing of various participating retail sites throughout San Diego County that LIEE participants can visit to properly dispose of CFL waste products.
- PEAK Student Energy Actions ("PEAK") program, offered by SDG&E in partnership with The Energy Coalition, is a standards-based program focused on DR and EE that educate children about energy usage and management and provides them with tools to "practice" learnings at home. SDG&E proposed continuing this program in its DR application.
- KWickView tool (DR) assists customers with energy management and is available to all nonresidential customers with demand greater than 200 KW and all other DR customers.
- SDG&E has updated its protocols to deliver combined EE and DR audits through its Technical Assistance program (DR) and its Green Business Assessments (EE). These audit services could be used to meet CSI audit requirements. SDG&E will be adding GHG inventory calculators to the audit process in 2009.
- SDG&E's Mobile Workshops (EE) which provides on-site training for large customers and assists customers in identifying their integrated energy management opportunities.

B. IDSM Coordination of Incentive Programs

- In the residential market, SDG&E will continue to jointly market its Summer Saver DR program (AC cycling) with its AC Tune-Up program. LIEE customers with air conditioners are also eligible to participate in both programs. As smart meters are rolled out during this program cycle, SDG&E has plans to utilize increased customer usage data to better target high energy users and provide customers with customized feedback in their homes' EE and DR opportunities.
- Multi-family - SDG&E's LIEE will leverage with EE programs and activities to ensure that all possible efficiency opportunities within this sector are fully captured. The LIEE program excludes efficiency improvements within common areas, and also excludes tenants within a given complex that do not meet certain income guidelines. Coordination with EE will allow SDG&E to more effectively "cover" any" potential efficiency gaps and ensures greater program participation.
- The Home Electronics – Residential energy efficiency program intends to explore untapped savings opportunities through plug load efficiency. A recent EIA study of residential electricity end use estimated that electronic (plug load) products will account for 19% of the residential electricity consumption by 2020. The largest product contributor will be entertainment type equipment. The continued purchase of these high energy use products will eventually off-set the efficiency gains associated with other home products (refrigerators, dishwashers, etc). Therefore a statewide collaborative campaign will be undertaken in 2009-2011 to educate consumers about their purchases and to work closely with retailers and manufacturers to promote and stock consumer plug load products that use considerably less energy. The educational campaign will include development of informational collaterals and fact sheets. LIEE's collaboration will include providing this information in the customer's home assessment and energy audit and EE's collaterals at LIEE community outreach and events.
- For customers with existing central or room air conditioning units not eligible for replacements, due to outside approved climate zones and/or not LIEE eligible, SDG&E's LIEE team will work with EE to provide information to LIEE customers regarding the EE air conditioning programs and services. The programs and services include HVAC

tune-ups and annual bill credits for cycling their central air conditioner. These services are currently provided through SDG&E's EE Third Party programs.

- All LIEE customers in need of appliances not provided through the LIEE Program will be referred to LIHEAP agencies if qualified, or to SDG&E's EE programs for efficiency ratings and rebates information.
- LIEE plans to coordinate with EE Third Party program implementers, such as the Mobile/Manufactured Home Innovative Outreach and Measure Program, where low-income customers residing in mobile/manufactured homes will be provided the opportunity to enroll in LIEE and other assistance programs. SDG&E will meet with the third party contractor to discuss and pursue integrating both programs and expect to have a partnership with LIEE program in place within the next four months.
- For the 2009-2011 SDG&E Energy Efficiency Third Party Contractor Programs, both EE and LIEE personnel will work closely together to determine which residential contractor programs could have LIEE integrated into the program. As third party contracts are negotiated in the following months, SDG&E will discuss with the EE-selected third parties (which will be submitted to the CPUC in SDG&E 2009-2011 EE application on July 21, 2008), the third parties capacity and incremental budget requirements to incorporate LIEE outreach, education and services into their proposed EE program. Additionally, SDG&E will provide training and education to third party contractors who are not currently participating as LIEE contractors. This will ensure that LIEE customers are either offered or made aware of the portfolio of energy savings programs and services that are available to them and the benefits that can be achieved from program participation, i.e., energy savings, greenhouse gas reduction and other benefits.
- The Energy Saver Bonus Program provides incremental incentives to customers/contractors that implement an EE and DR program at a customer site. This program has proven effective at convincing DR Aggregators to expand their business model to include EE products and likewise with EE contractors to also offer DR products to customers and will be leveraged even further in the future. Incremental incentives are funded out of respective EE or DR programs. If the customer is approached by a DR contractor and successfully participates in an EE program, the incentive is funded

through DR. On the other hand, if an EE customer enrolls in a DR program through the outreach efforts of the EE contractor, the incentive is funded through EE.

- The Technical Incentives ("TI") (DR) easily coordinates with any of the nonresidential EE incentive programs. For example, a customer who installs an EE measure (e.g., high efficient chiller) and also installs either Auto DR technology or reliable EMS systems is eligible for EE incentives for the high efficiency chiller and TI incentives for the Auto DR/EMS system. EE/DR incentives are determined by the benefits associated with EE and DR, respectively.
- SDG&E was recently awarded the New Solar Homes (CSI) program administration in San Diego and is integrating the program into its New Construction EE program and DR programs to provide a complete energy management solution to this customer segment. This integration effort provides a testing ground for development of future Codes & Standards for ZNE.
- SDG&E's Sustainable Communities (EE) Program (now integrated into its Savings By Design Programs), first offered in 2004-2005 program cycle, has been offering IDSM services to SDG&E's new construction community through the promotion of sustainable design and green building practices. Customers that go through this program are candidates for LEED certification. One of SDG&E's program participants, a multi family/community center" project earned the first "Zero Energy Net Home" project designation by the California Energy Commission ("CEC"). SDG&E proposes to continue this program in its 2009-2011 EE application.

IV. OPTIMIZATION (TECHNOLOGY & SYSTEMS INTEGRATION)

A. EE/DR Emerging Technologies ("ET")

SDG&E EE and DR Emerging Technologies programs are implemented by the same organization under SDG&E's Research and Development department. This strategic organizational decision allows SDG&E to effectively foster technology investment and development that supports both EE and DR in a more integrated fashion. SDG&E expects that through these efforts the commercialization of strategic EE and DR measures will be expedited so that they become more accessible to customers. This integrated group can significantly contribute to the development of communication standards of various communicating devices that would allow customers to manage their energy remotely such as Home Area Networks and smart appliances.

The EE and DR portfolios budgets have identified separate ET budgets.

B. PIER/SMUD/SDG&E Pilot

SDG&E has partnered with Sacramento Municipal Utility District and the CEC's PIER program to work with a Developer to build 2 ZNE subdivisions, one in Sacramento and the other in San Diego. These homes will contain high efficiency windows, insulation, lighting, HVAC, water heating and appliances; photovoltaic arrays; demand response enabled; energy storage (in some cases); and V2G and V2H test. Results from these projects are expected to be replicable; expand our knowledge; set the stage for the next level Zero Energy Home that will have a nationwide impact. SDG&E's contribution to this project is coming out of its 2006-2008 ET program budget.

C. Codes & Standards

SDG&E has proposed Codes & Standards programs in both its DR and EE applications, with separate budgets. The objective is to promote through CASE studies and active participation in CEC proceedings the next generation of California Title 24 codes and standards* that incorporate integrated systems that provide both EE and DR benefits.

D. SMART METERS

Starting as early as next year, smart meters will allow customers to see how much energy they are using at any given time, with the use of a smart device, such as an in-home display. In addition, customers will be able to view their previous day energy usage online.

Through the Emerging Technologies program efforts described above, projects are planned to develop technologies that enable customers to tap into their "smart" home while they are away. For example, a smart home equipped with a home area network ("HAN") will allow customers to remotely connect to, monitor and control many different automated digital devices. For example, a homeowner at work or on vacation can potentially use a cell phone or their computer to switch appliances on or off, arm a home security system, control temperature gauges, control lighting or program a home entertainment system. Alternatively, the monitoring devices could notify the customer when an appliance is no longer operating at peak efficiency and suggest maintenance actions.

From a DR perspective, SDG&E's smart meter could become a part of a customer's home area network and potentially communicate peak day events to customer digital devices. For example, on a hot day, the smart meter could send a signal to the home's HAN to help the customer conserve energy. Various smart devices could then process this signal, based on customer's preferences. A smart refrigerator might reduce energy consumption for the duration of the conservation effort, or the customer could monitor and control the devices via cell phone or e-mail, including turning devices on or off and up or down. The smart meter infrastructure will help enable the smart devices of tomorrow.

V. Proposed IDSM Pilot— Sustainable Community Case Studies

SDG&E, together with SoCalGas, will be working with a Master Community Developer on a development with a long build out schedule to serve as a test bed for integrating proven and emerging technologies for EE/DR and CSI with the goal of promoting sustainable design and ZNE.

The objectives of the pilot are: develop cross-cutting Integrated Program Design; provide comprehensive energy management solutions designed into the development; stimulate Market Transformation in community design and marketing techniques; and leverage upstream energy savings in SDG&E's infrastructure design, thereby yielding multiple benefits for ratepayers and other stakeholders.

A. Develop cross-cutting Integrated Programs Design:

1. Performance-based program embraces residential single family and multi-family and non-residential (retail, office, schools) in one program
2. Includes multiple stakeholders incentives (e.g., master developer, builder, end-user, trade and supply chain partners, and public-sector)
3. Integrates horizontal (infrastructure), vertical (green buildings) and people/ratepayers (education, training) needs
4. EE/DR/CSI and transportation integration
5. Anticipated implementation across program-cycles

B. Provide comprehensive energy management

1. Promote connectivity of "Smart Home" with "Smart Grid"
2. Leverages upstream (infrastructure) and downstream (building) synergies
3. Incorporates integrated horizontal (land use) and vertical (buildings) design optimization
4. Promote energy and demand management solutions
5. Integrates emerging and proven technologies
6. Provides feedback loops for end-users (e.g., in-home displays)

C. Provide integrated sustainable communities incentives

1. Includes multiple stakeholders (master developer, builder, end-user, design, trade and supply chain partners, and public-sector)
2. Integrated computer modeling
3. Performance-based metrics (energy, water, waste, air quality, and Gags)

4. Pre-development, construction, post-construction

5. Education and training of stakeholders

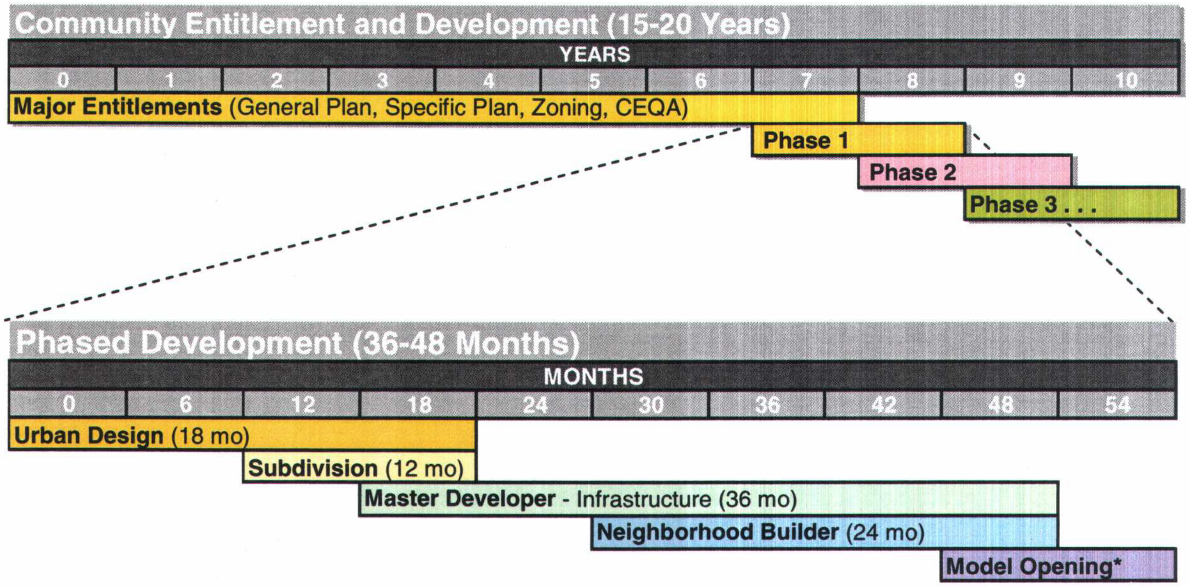
6. Design Assistance

7. Streamlined processing

8. Market research and analysis

9. Monitoring and verification

Below is the project's projected timeline. SDG&E is entering this project at approximately year 5 of the process:



SDG&E's requested budget for the 2009-2011 program cycle is limited to funding the initial preparation work including analysis and evaluations of the proposals. It is possible that within the program cycle, new homes and small commercial business buildings may be completed but it is not anticipated that there will be a large number of these buildings. If the project accelerates quicker than the timeline shown above and SDG&E requires additional funding, SDG&E will request additional funding from the Commission through the Advice Letter process.

VI. Making IDSM a Success

Currently these different components of IDSM are in several regulatory proceedings with different policy objectives and rules. Different methodologies for measurement and verification, and cost effectiveness are in place for each of these programs. However, as we analyze and incent these customer projects that present themselves through these IDSM efforts, it will be become imperative that new approaches to valuation and measurement will need to be developed. For example, customers would prefer that these integrated project cost effectiveness are analyzed at the project level and not as individual components. In the TI/EE example above, the customer would most likely be persuaded to install the integrated system if the project sponsor could do a payback analysis that identifies the consolidated savings from the project. This would require new methodologies to determine energy savings and demand reductions and cost effectiveness. Additionally, the EE or TI measure on a stand alone basis could present themselves as non-cost effective but when bundled together may improve its cost effectiveness.

In order for IDSM to succeed, new and improved cost effectiveness analysis tools need to be developed that will value integrated projects. Determining energy savings and demand reductions for integrated projects may be more efficient than trying to determine benefits incrementally. Finally, the Commission may need to begin integrating proceedings, not only on a funding cycle basis but also procedurally. SDG&E welcomes the integration of the LIEE and EE proceedings in one Rulemaking.

VII. QUALIFICATIONS

My name is Athena M. Besa. My business address is 8335 Century Park Court, Suite 1200, San Diego, California 92123-1257. I am employed by San Diego Gas & Electric Company as the Customer Programs Policy & Support Manager in the Customer Programs Department for SDG&E and SoCalGas. In my current position, I am responsible for the measurement of energy efficiency, demand response and customer assistance programs; regulatory reporting requirements, energy efficiency forecasting and the financial management of the Customer Programs department.

I attended the University of the Philippines in Quezon City, Philippines. I graduated with a Bachelor of Science degree in Statistics in 1983, and a Master of Science degree in Statistics in 1986. I have completed coursework at University of California, Davis towards a Doctorate degree in Statistics.

I was hired by SDG&E in 1990 in the Load Research Section of the Marketing Department. Since that time I have held positions of increasing responsibility in the Department. I have been in my present position for five years. I have previously testified before this Commission in several AEAPs and the PY2000/2001 Energy Efficiency Program Application Proceeding.

Application of San Diego Gas & Electric Company (U-902-M) for Approval of Demand Response Programs and Budgets for the Years 2009 through 2011	Application 08-06-002

CHAPTER VII

PREPARED DIRECT TESTIMONY

OF

MARK GAINES AND TONY CHOI

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 19, 2008

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PREPARED DIRECT TESTIMONY OF
MARK GAINES AND TONY CHOI

I. PURPOSE

The purpose of this testimony is to present a Demand Response Pilot Program under the California Independent System Operator's ("CAISO") proposed Market Redesign Technology Update ("MRTU") – Participating Load Pilot ("PLP"). SDG&E received CIASO feedback on its pilot proposal. This proposal reflects some of the CAISO's input. The testimony includes a description of the PLP proposal, pilot objectives, budget and M&E proposal.

II. OVERVIEW

In this section SDG&E outlines its Participating Load Pilot ("PLP") program and addresses issues regarding integration into the MRTU market.

Currently DR load curtailment is activated by utilities based on internal thresholds such as price, load or system need. This process remains intact under MRTU. If the DR program is not activated, DR customer load is bid into MRTU as Non-Participating Load ("NPL"). If the DR program is activated, the utilities will exclude the DR customer load from its NPL market bid. The CAISO will also be notified by 10 AM one day ahead so it knows to reduce its day-ahead load forecast and RUC requirement.

The NPL method does not allow DR capacity to be offered into the MRTU market since the utilities make the activation decision prior to the day-ahead market process. Utilities must guess whether the MRTU clearing price will meet DR price trigger thresholds, resulting in sub-optimal activation.

Some DR programs are capable of providing valuable operating flexibility to the CAISO in the form of real-time load reduction. This capability is wasted by the NPL method because activation is decided the day before real-time operating needs are known and there are no provisions for dispatching NPL in the real-time market.

These problems can be addressed by designating DR capacity as a Participating Load ("PL") resource rather than NPL. Contrary to NPL, PL will have bidding functionality integrated into MRTU Release 1. PL may be bid as price-sensitive load in the day-ahead market. If prices clear above its bid, PL will curtail its energy usage and avoid the day-ahead energy charge, and the CAISO will not include the curtailed PL load in its RUC requirements. If prices clear below its bid, PL will purchase day-ahead energy and consume energy as indicated by its bid. When PL is scheduled to consume energy, it can also provide RUC capacity to the CAISO via load reduction and can be dispatched based on real-time market and system conditions. Additionally, upon certification by the CAISO, PL can sell Non-Spin operating reserves into the market to generate revenue.

There are a number of technical and program issues that must be resolved to allow DR capacity to participate in MRTU as a PL resource. SDG&E has established up-front requirements for the PLP program as summarized below to facilitate this process:

- PLP is a day-ahead only resource; its capacity is not available to the real-time market unless it has been awarded a Non-Spin or RUC schedule in the day-ahead market.
- PLP activation is based solely on price triggers, not local grid or CAISO system conditions.
- PLP Aggregator/participants must have curtailable load of 1MW or more and this curtailable load will be subject to Auto DR control. Load response must be achieved within Non-Spin requirements.

- Enrollment is open to both DA and bundled customers.
- Meter data must be captured on a 15-minute (or shorter) interval frequency.

III. PILOT OBJECTIVES

SDG&E pilot is designed to meet three primary objectives:

(1) To test the program design that will potentially replace SDG&E's existing "price responsive" programs once MRTU is fully implemented as an alternative for customers who opt out of CPP-D.

(2) To develop program management and infrastructure requirements prior to full PL implementation.

(3) To determine the viability of interim telemetry techniques in lieu of the current MRTU telemetry requirements for real-time load visibility.

IV. PILOT PROPOSAL FEATURES

A. Identification of CAISO Requirements

A key challenge with DR capacity is determining the curtailable load on an ex ante basis. Currently approved methods for calculating DR response, such as the 3-in-10 approach, depend on after-the-fact settlement data that will not be available at the time bids are submitted into the day-ahead market.

SDG&E proposes that available load reduction be established through the A/S certification process. Meter data can be analyzed for the period before and after the CAISO's Non-Spin test dispatch, and the load reduction observed at T+10 minutes would be used as the going forward available DR capacity. Because the minimum meter interval requirement is 15 minutes, the load drop at T+10 minutes would be interpolated from the 15-minute interval data.

B. Pilot Metering and Telemetry Proposal

The CAISO *Participating Load Technical Standard* requires Non-Spin eligible PL to have data metered at an interval of no greater than 1 minute. This metered value must also be available for telemetry (4-second scan rate) by the CAISO through the ISO's Data Processing Gateway ("DPG") communication system.

SDG&E proposes that the CAISO initially relax these requirements to accommodate PLP capacity. To attract sufficient participation, SDG&E believes the PLP should accept 15-minute interval load data predominantly available among commercial and industrial customers. One-minute interval data may be available at some customer sites, additional IT resources and time would be required to increase the frequency of data interrogation, storage and real-time telemetry to the CAISO.

In lieu of real-time telemetry, the CAISO could apply a modeled response of the PLP DR resource based on load reduction achieved during Non-Spin certification described in SectionIV. A above. This is a significant change because the CAISO currently requires the telemetry and 1-minute interval meters so it can "see" the availability and response of resources supplying operating reserves on a real-time basis. This approach is consistent with the WECC Minimum Operating Reserve Criteria ("MORC") that states that the condition of operating reserve capacity must be known at all times.

One way to satisfy MORC, while relaxing the CAISO's telemetry/metering standards, would be to conservative model the demand response. For example, DR capacity established through the A/S certification test could initially be discounted prior to being bid into the market. Actual load response would then likely exceed the Non-Spin quantity, providing assurance to the CAISO that its operating reserves will perform reliably upon dispatch. Another option could be to enable telemetry of 1-minute interval data on a sampling of DR customer meters, sufficient to demonstrate overall PLP response. At this time SDG&E has not scoped this second approach to know whether it is achievable by the 2009 summer peak season.

C. Scheduling Coordinator ("SC") Functions

The PLP would be open to all customers on SDG&E's system. To reduce settlements complexity, SDG&E proposes that it aggregate and schedule DR capacity from bundled customers while an assigned 3rd party Scheduling Coordinator manages the bidding and settlements for aggregated DR capacity from Direct Access "DA" customers. Funding will be required to retain a 3rd party SC for this function.

Prior to bidding PLP capacity to the market, each SC (SDG&E and the 3rd party SC) would register its respective aggregation of customer load with the CAISO to create a new Resource ID and Custom Load Aggregation Point ("CLAP") specific to each set of meters. Multiple Resource IDs and CLAPs may be needed if the aggregation of customer load is spread across more than one congestion pocket. Each SC must also coordinate and execute the required Participating Load Acceptance Test and Non-Spin Certification Test as required. The CAISO may need to modify test procedures to the extent that telemetry and metering requirements are modified for the PLP. Once a Resource ID has been approved, the CAISO will accept bids and issue awards and dispatches from the PLP as a discrete resource. The CAISO will clear a market price for each CLAP and settle charges against this aggregated price node.

For DA customers, the 3rd party SC and Energy Service Providers ("ESPs") may not be the same entity. These parties will need a payment mechanism to ensure that all CAISO charges are correctly allocated. Specifically, the SC will be charged for day-ahead and real-time energy associated with PLP customer load and must recover this cost from the ESPs. The SC will also receive credits for Non-Spin awards and, upon DR activation, uninstructed and instructed energy. The SC must then allocated and forward correct amounts to each ESP, taking into account factors such as customer contribution to total load response and CLAP DLFs.

D. PLP MECHANICS

The PLP should comply with the principles for PL functionality in MRTU as presented in the CAISO's white paper "Post-Release 1 MRTU Functionality for Demand Response". This paper outlines the process to create and maintain the CLAP and describes the structure and components of PL bids.

MRTU Release 1 will accept demand resource bids containing the following components as communicated to the CAISO by the SCs through Resource Data Templates:

- Base Load Schedule: meter load prior to DR activation
- Minimum Load Reduction: smallest increment of load reduction allowed
- Minimum Load: load that cannot be curtailed, or the equivalent of Base Load minus Maximum Load Reduction
- Load Reduction Initiation Time: period between CAISO dispatch and activation of load curtailment
- Minimum Load Reduction Time: minimum time that load can be curtailed
- Maximum Load Reduction Time: maximum time that load can be curtailed
- Minimum & Maximum Daily Energy Limit
- Load Drop Rate: as established by the A/S certification test
- Load Pickup Rate: as established by the A/S certification test
- Load Reduction Initiation Cost: up-front fee paid by CAISO to activate demand response

- Minimum Load Reduction Cost: cost to dispatch the smallest increment of load reduction

These components allow DR to communicate its activation capability and costs at a level of detail comparable to generation resources. For the PLP, the key items are Base Load Schedule, Minimum Load, Load Reduction Initiation Time, Minimum & Maximum Load Reduction Times, Load Drop Rate and Load Reduction Initiation Cost. The PLP program communicated to customers should reflect these components.

Each day, the SC will create and submit a PLP bid into the MRTU day-ahead market, or Integrated Forward Market ("IFM"). The results of the IFM relative to the PLP may be one of the following:

- CLAP clearing price exceeds PLP energy bid price and PLP customers do not purchase day-ahead energy. In this case the customer may choose to voluntarily avoid consuming energy or purchase energy at real-time prices (potentially above its bid price) and consume energy. This is not considered demand response but rather price-sensitive load behavior.
- CLAP clearing price does not exceed PLP energy bid price and PLP customers purchase day-ahead energy. In this case the CAISO may simultaneously award the PLP a Non-Spin schedule if its Non-Spin bid clears the market. PLP customers must then be prepared to curtail load if the CAISO activates demand response. The PLP SC will be paid the initial Non-Spin award plus the real-time price for the energy quantity that is curtailed.

- Subsequent to clearing the day-ahead energy and A/S market, CAISO also may designate the PLP as a RUC resource. SDG&E understands from discussion with the CAISO that this option will not be used for DR capacity.

The SC is responsible for retrieving the IFM results and communicating to PLP customers. If the CAISO activates PLP demand response in real-time, it will send the dispatch to the SC via its Automated Dispatch System ("ADS"). The SC is then responsible for initiating load curtailment within the Non-Spin time requirement, whether through auto DR or a manual process. Revenues related to Non-Spin awards and energy dispatches are subject to validation of response according to final meter data.

E. Other Technical Implementation Issues

Non-Spin resources are subject to unannounced compliance testing by the CAISO. SDG&E proposes that the CAISO limit these tests to periods of high load usage by the PLP customers to mitigate cost and maximize potential response.

SDG&E realizes these proposes changes in operating procedures, in particular to metering requirements, may not be feasible for the CAISO to adopt before summer 2009 given WECC MORC constraints. In this event, SDG&E proposes that CAISO procure a minimal quantity (e.g. 3 MW) of the PL pilot resource for Non-Spin capacity in excess of its MORC requirement so that other program mechanics can be further developed while this issue is resolved.

F. Pilot Program Description and Customer Participation Features

The PLP program is available to commercial/industrial customers, greater than 20 kW, receiving bundled service, Direct Access service or Community Choice Aggregation service, and who are billed on a commercial, industrial or agricultural rate schedule other than CPP-D or

CPP-E. Participation in this program must be taken in combination with the customer's otherwise applicable rate schedule. This program is also available to Aggregators.

Participating customers can earn two (2) types of incentives, capacity and energy, in return for the ability to be called for an event and for the actual load reduction during an event during the months of May through October. The PLP program has been designed to compliment CAISO's requirement for PL by requiring a two-hour curtailment duration and a minimum of 1 (one) MW load bid is required. In addition, customer participation is limited to a maximum of one (1) event per day and twenty-four (24) hours during a calendar month. Please see Appendix for detailed program description.

1. Participant Requirements

Each participating customer must have an approved 1-minute interval meter and approved meter communications equipment installed and read by SDG&E. Customers must also have Auto DR enabled technologies that have the ability to communicate remotely in order to achieve load reduction. For customers without enabling technologies, PLP audits and incentives will be provided to identify applicable enabling technologies that facilitate load reduction during a PLP event. Incentives will be provided at $300/kW based on verified results of a load shed test.

2. Marketing & Outreach

The program will be marketed primarily through Aggregators because very few customers in SDG&E's territory can provide the minimum 1 MW of required load reduction. SDG&E will hold workshops/meetings with interested Aggregators to explain the Pilot, provide appropriate collateral materials and answer questions. Aggregators can then market the Pilot directly to their customers. In addition, SDG&E Account Executives will provide information on the Pilot to their assigned customers.

V. MEASUREMENT AND EVALUATION

The recent load impact protocol decision D.08-04-050 stated that DR activities should be evaluated according to the load impact protocols and that these evaluations should include both an estimate of the historical load impact (ex-post) and a forecast (ex-ante) of the demand response. These protocols also require an evaluation plan for each DR program to be submitted to the DRMEC committee. Detailed discussion of M&E plans should be conducted through the evaluation plan process not through this testimony. However, a brief description of the type of evaluation planned for this program is included here in order to explain and justify the proposed M&E budget.

A. Pilot Load Impact Evaluation

SDG&E intends to conduct load impact studies for the MRTU participating load pilot. To the extent this program can not be evaluated with the other statewide M&E, SDG&E plans to conduct the research locally and work with the DRMEC to ensure that the program evaluation plans and the report drafts are provided to the DRMEC for input as consistent with the Load Impact Protocols Proposed Decision. The impact evaluation planning process and scope will be done in accordance to the load impact protocols as prescribed in the schedule that is adopted by the CPUC.

SDG&E estimate that Load Impacts will be estimated annually. Approximately $300,000 is required for the load impact evaluations.

B. Pilot Process Evaluation

A process evaluation will be conducted during the first year of this program. The purpose of the study is to assess the effectiveness of the program and to develop recommendations for changes to program design or delivery. Specific objectives of the evaluation include:

1. Document program theory and implementation strategies.
2. Provide real-time feedback to program implementers with specific focus on improving program delivery and identifying both implementation and program design problems for review and modification.
3. Assess the effectiveness of the program in reaching goals and identify barriers and obstacles to meeting program goals.
4. Evaluate areas of customer and aggregator satisfaction/dissatisfaction.
5. Provide recommendations for improving program design and implementation.

In addition, the following research questions will be addressed:

1. Are the financial incentives appropriate?
2. What concerns do customers or aggregators have about responding to demand response events?
3. How effectively is Auto DR promoted and implemented?
4. For Auto DR projects, does the load shed testing procedure include consideration of the impact on customers' operations and comfort levels?
5. What changes in program design and implementation would make the programs more effective?
6. How would customers respond to frequency calls?

7. Do customers have different price thresholds?

8. What spillover benefits occur for customers such as operational improvements, energy efficiency savings, customer education, etc.?

9. How do customers perceive their role in providing participating load for demand response?

10. What additional information or assistance do customers or aggregators need?

This study will be conducted by an independent evaluation consultant. The primary approach for this study will include interviews with program administrators, CAISO representative(s), aggregators and customers. The primary deliverable will be a final report that will present the findings and the recommendations for program changes; however, SDG&E is also seeking usable information and recommendations as the evaluation progresses, so that program managers can get timely feedback.

VI. PROPOSED PILOT BUDGET AND FUNDING

Consistent with the regulatory accounting and cost recovery treatment initially established by D.03-03-036 and most recently affirmed by D.05-06-017, SDG&E currently records all program costs associated with its existing DR programs in its Advanced Metering and Demand Response Memorandum Account ("AMDRMA"),[1][1] with one exception as discussed below. For the authorized DR program costs for 2009-2011 not recovered through SDG&E's 2008 General Rate Case ("GRC") adopted rates,[2][2] SDG&E proposes that the O&M expenses, capital related costs (i.e. depreciation, return and taxes), customer capacity incentive payments,

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1 See D.03-03-036, Ordering Paragraph 8, and D.05-06-017.

2 In its 2008 GRC SAG&E, requested distribution rate funding for activities associated with its current ALTOU-CP, SLRP, BIP, RBRP, and OBMC programs. SDG&E's proposal herein does not include any proposed revision to the treatment of those components of the program costs.

and all other authorized program costs be recorded in the existing AMDRMA , including costs associated with the proposed PLP program. On September 18, 2008, SDG&E filed Advice Letter 2025-E seeking Commission authorization to amend its Preliminary Statement and establish an AMDRMA sub-account to record all costs associated with the PLP program. SDG&E proposes that there be no change to the existing disposition of the AMDRMA balances being transferred to the 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 each year, consistent with SDG&E's adopted tariffs. As noted above, there is currently one exception to the way SDG&E records demand response program costs in AMDRMA. As authorized in D.03-03-036, SDG&E records the energy component of the customer incentive payments to its Energy Resource Recovery Account ("ERRA"). SDG&E requests to continue this treatment of these costs. SDG&E is therefore requesting approval of $19.591 million, $20.068 million and $20.956 million in budgeted funds for 2009, 2010 and 2011, respectively, to fund its DR programs. SDG&E's revised funding request includes its original request of $48.535 million plus an additional $12.080 million from previously-authorized 2006-2008 DR program budgets to fund its Commission-required PLP program described in previous paragraphs.

The following is a summary of the budget associated with this PLP:

	2009	2010	2011
Operating & Maintenance (Admin)	$ 1,000,000	$ 1,000,000	$ 1,000,000
Marketing and Outreach	$ 65,000	$ 65,000	$ 65,000
TA/TI Incentives	$ 1,200,000	$ 2,000,000	$ 2,800,000
Capital	$ 1,100,000	$ 100,000	$ 100,000
Measurement & Evaluation	$ 173,000	$ 168,000	$ 167,000
Capacity/Energy Payments	$ 215,000	$ 360,000	$ 502,000
Total Program Budget	$ 3,753,000	$ 3,693,000	$ 4,634,000

VII. WITNESS QUALIFICATIONS

A. Mark Gaines

My name is Mark Gaines. My business address is 555 West Fifth Street, Los Angeles California, 90013. I am employed by San Diego Gas & Electric Company ("SDG&E") as Director Customer Programs in the Customer Programs organization. In my current position, I am responsible for the organization that designs, develops and implements SDG&E's Demand Response Programs; and SDG&E's and Southern California Gas Company's Energy Efficiency Programs.

I graduated from University of California, Irvine with a Bachelor of Science degree in Civil and Environmental Engineering. I received a Master of Business Administration ("MBA") degree from University of California, Los Angeles. I have been employed by SDG&E and Sempra Energy since 1983 and have held positions of increasing and broadening responsibility in such organizations as Engineering, Public Affairs, Customer Services, Environmental Services and Customer Programs.

I have previously testified before this Commission in a variety of proceedings.

B. Tony Choi

My name is Tony Choi. My business address is 8315 Century Park Court, San Diego CA. 92123. I am currently employed at San Diego Gas and Electric as the Transaction Scheduling Manager in the Electric & Gas Procurement Department. I have been in this position since March 2007.

I joined San Diego Gas and Electric ("SDG&E") in 2002 as Energy Trading Manager in Electric & Gas Procurement to re-establish SDG&E's wholesale power and natural gas trading functions. I left Electric & Gas Procurement in July 2005 through February 2007 to join SDG&E's Planning & Development department as Project Manager, where I performed financial analysis for capital investment opportunities.

Prior to joining SDG&E, my experience included two years as a power plant engineer, 4 years as a power and natural gas trader and 3 years as a wholesale energy transaction structurer.

My current responsibilities include managing a range of functions performed by the real-time power trading and scheduling desk. These functions include CAISO Scheduling Coordinator activities for SDG&E's bundled customer portfolio of load and generation resources. I hold a Bachelors degree in Chemical Engineering and a Master of Business Administration degree, both from the University of California.

APPENDIX

1. Utility San Diego Gas & Electric

2. Program MRTU – Participating Load Pilot (PLP)

3. Program Description:

Market Sector:	Non-Residential
Program Classification:	Day-Of Price Responsive
Program Status:	Active: May 1, 2009

The Participating Load Pilot (PLP) is a new voluntary demand response pilot that was developed in coordination with the CAISO to test the program design and customer acceptance of a pure price responsive offering. The primary objectives of the PLP are:

- Test program design that will potentially replace SDG&E's existing "price responsive" programs, once MRTU is fully implemented as an alternative for customers who opt out of CPP-D.
- Determine the viability of using modeling techniques in lieu of telemetry requirements for real-time visibility.
- Develop program management and infrastructure requirements prior to full PL implementation.
- Facilitate the articulation of CAISO requirements and technical specifications for demand response to act as Participating Load.
- Uncover and resolve policy, process and system issues with using demand response as Participating Load such as: Policy issues include pricing; and Process issues include marketing and customer participation.

Pilot participants can earn two types of incentives, capacity and energy, in return for the ability to be called for an event and for the actual load reduction during an event during the months of May through October. The program has been designed to compliment CAISOs requirement for Participating Load by requiring a two hour curtailment duration, and a minimum of 1 MW load bid is required. This reduction can be accomplished by a single customer or an aggregated group of customers. In the event that the participant cannot reduce enough load to meet their commitment, penalties or prorating may affect the actual payment.

This program is available to commercial/industrial customers, greater than 20 kW, receiving bundled service, Direct Access service or Community Choice Aggregation service, and who are 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 "Aggregators," a third party entity that combines the loads or one or more customers for the purpose of participating in this program.

Each participating customer must have an approved 15-minute interval meter and approved meter communications equipment installed and read by SDG&E. Customers must also have Auto DR enabled technologies that have the ability to communicate remotely in order to achieve load reduction. For customers without enabling technologies, PLP audits and incentives will be provided to identify applicable enabling technologies that facilitate load reduction during a PLP event. Incentives will be provided at $300/kW based on verified results of a load shed test.

Customers participating in the PLP are not eligible to participate in the Base Interruptible program, Capacity Bidding program or the Critical Peak Pricing Default rate.

After the first summer of PLP implementation, measurement and verification of the program design and load reduction will provide information that will allow SDG&E to access program modifications to improve program performance and MRTU participation. For example, SDG&E will review and update, as necessary, (1) the schedule of the load bid (e.g. nominating loads five days prior to the end of the month for the next month) and (2) incentive payments to reflect market value of capacity versus energy payments. SDG&E anticipates that in 2011, as AMI meters are deployed throughout the service territory PLP will shift from pilot to program status.

4. Contract Period:
Customers must remain on the program for a minimum of 12 calendar months.

5. Eligibility:
A minimum of 1 MW load bid is required and can be accomplished by a single customer or an aggregated group of customers. The PLP is open to any commercial, industrial or agricultural customer with an interval meter.

6. Operating Months : May through October

7. Curtailment Window:
The program has been designed to compliment CAISO's requirement for Participating Load by requiring two hour curtailment duration.

8. Minimum Qualifying Load Criteria for Program:
This program is available to commercial/industrial customers, greater than 20 kW, receiving bundled service, Direct Access service or Community Choice Aggregation service, and who are being billed on a commercial, industrial or agricultural rate schedule.

9. Event Trigger:
Or Assigned Scheduling Coordinator may call an event whenever the load has been granted a Non-spin award through the day-ahead MRTU market clearing process or as system conditions warrant. PLP events are triggered by market price unless called upon for system emergencies.

10. Notification Time:
10 minutes prior to the start of the event.

11. Curtailment Level:
A minimum of 1 MW load bid is required and can be accomplished by a single customer or an aggregated group of customers.

12. Illustrative Incentive Payments (These are subject to change based on further analysis.)

1. Capacity Incentive Payment ($/kW-month):

2hr Duration	May	Jun	Jul	Aug	Sep	Oct
1PM-6PM	6.79	9.31	17.66	19.48	12.59	5.93

2. Energy Usage Reduction Incentive Payment, All Program Options (cents/kWh):
The applicable rate to be applied in calculating the Energy Usage Reduction Incentive Payment is generally the daily Utility city gate natural gas price multiplied by the Program dispatch heat rate of 15,000 Btu/kWh for each kilowatt hour of energy reduction during Events Reduction.

13. Event Minimum Load Reduction:
1MW minimum bid per customer or aggregator.

14. Event Frequency Limits:
Customer participation is limited to no more than 1 event per day and 24 hours during a calendar month

15. Non-Compliance Penalty:

Actual Load Reduction	**Adjusted Event Capacity Payment Amount for Actual Load Reduction**
More than 100 percent of Nominated Load Reduction	Payment equal to 100 percent of Unadjusted Event Capacity Payment Amount
90 – 100 percent of Nominated Load	Payment calculated by prorating between 90 and 100

Actual Load Reduction	Adjusted Event Capacity Payment Amount for Actual Load Reduction
Reduction	percent of Unadjusted Event Capacity Payment Amount
75 – 89.99 percent of Nominated Load Reduction	Payment equal to 50 percent of Unadjusted Event Capacity Payment Amount
50 – 74.99 percent of Nominated Load Reduction	0
Less than 50 percent of Nominated Load Reduction	Penalty (i.e. negative amount) equal to 50 percent of Unadjusted Event Capacity Payment Amount

16. Meter Requirements and Who Pays.

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

An approved interval meter is capable of recording usage in 1-minute intervals and being read remotely by the Utility.

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

17. Enabling Technology Requirements/Responsibility:
Each participating customer must have an approved 15-minute interval meter and approved meter communications equipment installed and read by SDG&E. Customers must also have Auto DR enabled technologies that have the ability to communicate remotely in order to achieve load reduction. For customers without enabling technologies, PLP audits and incentives will be provided to identify applicable enabling technologies that facilitate load reduction during a PLP event. Incentives will be provided at $300/kW based on verified results of a load shed test.

18. Budget for 2009-2011

	2009	2010	2011
Operating & Maintenance (Admin)	$ 1,000,000	$ 1,000,000	$ 1,000,000
Marketing and Outreach	$ 65,000	$ 65,000	$ 65,000
TA/TI Incentives	$ 1,200,000	$ 2,000,000	$ 2,800,000
Capital	$ 1,100,000	$ 100,000	$ 100,000
Measurement & Evaluation	$ 173,000	$ 168,000	$ 167,000
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Total Program Budget	$ 3,753,000	$ 3,693,000	$ 4,634,000

19. Goal/Expected Load Reduction:

	2009	2010	2011
MWs	3	5	7*

**In 2011, PLP is planned to move from a pilot phase into a non-pilot program offering*

20. EM&V Plan:
See Chapter VII Testimony.

21. Comments: None

22. Enrollment from 2009-2011, including:

1. Number of Participants: 200 meters
2. Type of Participants: Small commercial/industrial customers, greater than 20kW
3. Megawatts: See Section 19
4. Megawatts by Type of Participant: N/A

23. How Programs Fit Into Local Resource Adequacy:
Program is purely price responsive.

24. Estimated Load Impact, Based on Protocols to be Adopted:
2009 – 3MW
2010 – 5MW
2011 - 7MW

25. Estimated Cost Effectiveness (CE) Based on Protocols to be Adopted:
Not applicable.

26. Marketing and Outreach Funding Disaggregated by Target Customer (if appropriate given future guidance on EE/DR coordination): Marketing and Outreach Funding will not be disaggregated by target customer.

27. Proposal of and Schedule for How Each Program Will Align with MRTU Release 1/1A and Beyond: PLP has been developed to test a program design that will align with MRTU Release 1A. This pilot may potentially replace SDG&E's existing "price responsive" programs as an alternative for customers who opt out of CPP-D.

28. Other Relevant Information, as Appropriate and Necessary: None

29. Copies of Contracts with Providers/Aggregators, and Information Sufficient to Verify Contract Performance: Contracts and program applications will be developed.

30. The Actual (Observed) DR Load Reduction Due to the Program, and How it was Distributed Among Enrolled Customers: No data available at this time.

31. Proposed Changes in the Programs for 2009-2011(if any) from Existing Activities, and Reasons for those Proposed Changes: PLP is a new price responsive program

32. Baseline and/ or Terms of Settlement

Customer Specific Baseline: In order to participate in the Program, Participants must have a valid baseline ("Baseline") for each Bid nominated the month prior of an operational month, in which the Baseline must be established not later than 5 calendar days prior to the first day of such operational month of the Program. Baselines shall be established as follows:

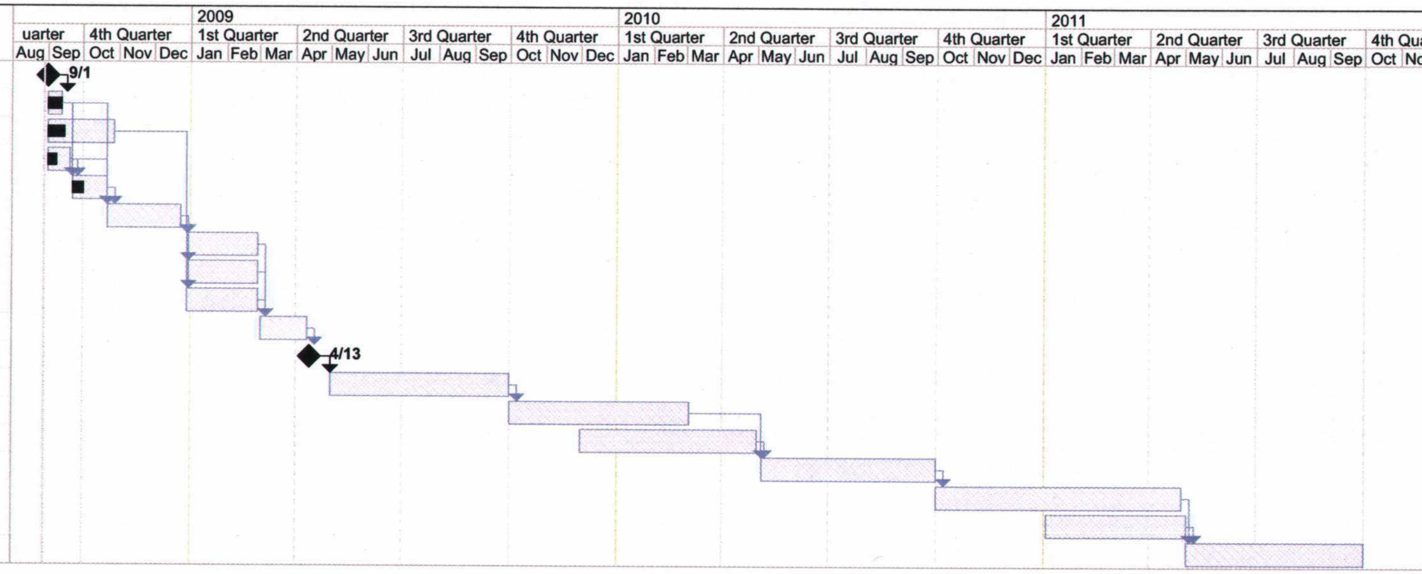
Participating Customers: For customers enrolled in the Program directly with the Utility, the Baseline for any given operational day is defined as the average consumption for the hours of 11 a.m. to 7:00 p.m. for the three (3) highest days from within the immediately preceding ten (10) similar non-holiday week days prior to the Event. The baseline will exclude weekends, holidays, and days when a customer was paid to reduce load, when load reductions were requested or when rotating outages are called.

Aggregators: For Aggregators, the Baseline for each Bid nominated for any given operational day is based on such Bid's associated aggregated group of customers on such operational day, and is determined as follows: The hourly load profile for such aggregated group on such day is determined by summing the hour by hour interval metering data for each customer of such group (other than customers who have nominated (whether by election or by default) no (or zero) load reduction for such

Product on such operational day), and the Baseline for such aggregated group in respect of such Bid is the hourly average of the three (3) highest energy usages in the immediate past ten (10) similar days for such calculated load profile. The three (3) highest energy usage days are those days with the highest kilowatt hour (kWh) usages for such aggregated group between the hours of 11:00 a.m. and 7:00 p.m. The past ten (10) similar days will include Monday through Friday, excluding Utility holidays, and will additionally exclude days when a customer in such aggregated group was paid an incentive to reduce load on an interruptible or other curtailment program, or days when rotating outages were called.

The determination of the baseline will need to be consistent with the Pilot Metering and Telemetry Proposal in Chapter VII Section IV.B.

ID	Task Name
1	Kick-off
2	Finalize PLP Scope / Schedule
3	Vendor Contract Negotiation
4	Draft PLP Req and Techl Spec
5	Draft Business and Process Req
6	PLP Database Development
7	Vendor PLP Integration
8	Finalize Business Processes
9	Develop System Work-Around if Needed
10	System Tests
11	User Acceptance and Training
12	Launch PLP Pilot - Event Season
13	2009 EM&V
14	Improve process and procedures
15	Conduct PLP Pilot - Event Season
16	2010 EM&V
17	Transition Pilot into Program Format
18	Launch 2011 PLP Program



Project: MRTU PILOTS
Date: Thu 8/28/08

Task
Progress
Milestone
Summary
Rolled Up Task
Rolled Up Milestone
Rolled Up Progress
Split
External Tasks
Project Summary
Group By Summary
Deadline