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

Application 11-03-002

CHAPTER IV

REVISED AMENDED TESTIMONY OF

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SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

~~MAY 27, 2011~~
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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 2012-2014 proposed demand response ("DR") programs and the overall portfolio. The load impacts utilized in these cost effectiveness tests are covered in the testimony of Kathryn Smith and in SDG&E's April 1st filing of Executive Summary and Summary Tables.[1]

II. METHODOLOGY

The primary 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, Transmission & Distribution ("T&D") costs, and energy costs including commodity costs, line losses and environmental costs. SDG&E was required in Decision 10-12-024 to utilize the 2010 Demand Response Cost Effectiveness Protocols (Protocols) in Appendix "A" of that decision and to use the Cost Effectiveness Template provided by the California Public Utility Commission's consultant E3 ("E3") to calculate the various cost effectiveness tests described below. The E3 template already contained the most critical assumptions and values required to calculate DR cost effectiveness when received by SDG&E. As directed, SDG&E used these protocols and the template provided to calculate the estimates of cost effectiveness for the Demand Response program in this filing. It should also be noted that the avoided cost assumptions and the models used in this analysis are different from the models and avoided costs being used in the state in

Energy Efficiency cost effectiveness. Further direction on assumptions used in this analysis was provided by the ALJ Ruling dated April 29, 2011 (Ruling)[2] and by the May 13, 2011 Scoping Memo.[3]

A. Tests

The primary purpose of the cost-effectiveness tests are to measure and evaluate the cost effectiveness of Demand Response (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 energy efficiency 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 energy efficiency.

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[1] San Diego Gas & Electric Company's (U 902 M) Executive Summary and Summary Tables Pursuant to Decision to Modifying Demand Response Load Impact Report Annual Filing Requirements (R.07-01-041), April 1, 2011.
[2] Administrative Law Judge's ruling Providing Further Guidance for Permanent Load Shifting Activities in the 2012-2014 Demand Response Applications, A.11-03-001, 4/29/11.
[3] Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo, A.11-03-001, 5/13/11.

In the evaluation of demand response programs, 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. (In the current analysis, the required template assumes that the customer costs are 75% of the incentive. This then yields a different result for the TRC and the PAC). 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.

B. Program Incentive Payments

For purposes of cost effectiveness and as described in Section 3.H of the Demand Response Protocols, the cost of the program incentive payments used in this analysis are based upon the *<u>expected</u>* number of program calls and the expected duration of those calls. These values are necessarily different from what is being requested in the budgets for these programs which is based on the *<u>maximum</u>* expected number of calls and *<u>maximum</u>* duration of those calls.

C. Portfolio Evaluation

The cost effectiveness analysis is done on a program-by-program basis for those programs requiring cost effectiveness tests for 2012 - 2014. These programs, plus the administrative costs associated with the ET program, the costs associated with measurement and evaluation of the Summer Saver program and the TI costs and benefits associated with CPP-D are then added and cost effectiveness is calculated at the portfolio level.

III. MODEL INPUTS

While SDG&E was required to follow the protocols as described in Appendix A of Decision 1-12-024 and the Commission adopted DR reporting template developed by E3 to develop the cost effectiveness calculations for the tests described above, there are certain elements of the model that can be adjusted to some degree by SDG&E for its specific programs. These adjustments to the Template are described below.

A. A Factor

~~The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted. For DR programs with constraints on their availability and how often they can be used, SDG&E used the file provided by E3 entitled "FactorAnalysis" which uses a top 250 hours approach, a load-based approach based on publicly available data consistent with the 2010 Demand Response Cost Effectiveness Protocols. The A Factor varies by DR program based on the hours of availability and the maximum number of events.. The A Factor is higher for programs available more hours of the year, with a higher number of calls per month or year and a higher maximum number of hours per call.~~

The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted. For DR programs with constraints on their availability and how often they can be used, SDG&E uses a top 100 hours approach, a load-based approach based on publicly available data consistent with the 2010

Demand Response Cost Effectiveness Protocols. SDG&E has used the top 100 hours analysis in prior General Rate Case Phase 2 proceedings as a proxy for the Loss of Load Expectation approach. The A Factor varies by DR program based on the hours of availability and was calculated based on monthly or annual callable hours, depending on the limits of the particular program. The A Factor is higher for programs available more hours of the year, with a higher number of calls per month or year and a higher maximum number of hours per call. In the analysis, SDG&E based its A Factor on 2006-2008 historical data from the Avoided Cost Calculator. The development of the A Factor used in the Cost Effectiveness evaluation for this filing will be included in a detailed Work Paper.

B. B Factor

The values used for the B Factor are from the May 13th Scoping Memo. The Scoping Memo directed SDG&E to use a B Factor of 88% for day-ahead programs and 100% for day of programs.

C. C Factor

The C Factor is the program trigger factor. There are two ways a trigger affects the cost effectiveness analysis. One way is through energy benefits. The more flexible a trigger, the more times it is expected to be called and the more energy benefits will be derived from the DR program. This translates the flexibility of the trigger to different strike prices; a less flexible trigger is essentially a higher implicit strike price.

The second way the trigger flexibility affects the value is through the C Factor. This factor measures the reduction in value compared to a CT because of lack of availability, not through limitations on calls or availability, but because the trigger does not allow for calling the DR program when it may be needed.

Given the flexibility of SDG&E's triggers to call both CAISO and local events, 100% was assigned to the triggers for each of SDG&E's DR programs.

D. D Factor

Factor D represents the percentage of T&D capacity value that can be claimed by the program being tested. The default value as prescribed in the Protocols is zero. In cases where customers on the program have enabling technology that allows reliable long-term load reduction, a value for Factor D was established. Of the programs tested, two provided enabling technology: the Small Customer Technology Deployment ("SCTD") program, and the Technology Incentives ("TI") program. For SCTD, 100% of the customers have enabling technology and thus a value of 100% was used for Factor D.

Customers on the TI program receive incentives to install equipment that will support Auto DR. These customers opt into SDG&E's Capacity Bidding Program ("CBP") or Critical Peak Pricing ("CPP") rate. For CBP Day-Of, it was determined that approximately 12% of the forecasted MWs for the 2012 - 2014 program cycle will come from customers with TI technology. Thus, a value of 12% was used for Factor D when testing these programs. Similarly, a value of 7% was used for the CBP Day-Ahead program. While the CPP program was not tested separately, the costs and benefits for the TI customers opting into this program are included in SDG&E's portfolio cost effectiveness result, and a D Factor of 100% was used for this case.

E. E Factor

The E Factor is the Energy adjustment factor and is composed of two parts. The first part represents the increase electric prices due to the limitations on the days a DR program is likely to be called. Instead of the Avoided Cost Calculator average price over all on-peak days in June through September, the E factor adjusts for the DR program's likelihood of being only called on the higher priced days. The second part of the E factor is designed to account for the stochastic nature of energy prices. As a result of an analysis on these two factors SDG&E has developed an E Factor of 140% which has been applied to the energy benefits of all of the Demand Response resource programs. As allowed in the protocols, justification for this value will be provided in Work Papers. It should be noted that this value has a very small impact on cost effectiveness.

IV. OTHER ANALYSIS ASSUMPTIONS

A. Discount Rate

The discount rate used in the model is the after-tax weighted average cost of capital. For SDG&E, this is 7.3%. This percentage is taken from the avoided cost calculator and is not considered a utility input for the purposes of this model. The discount rate is used in the model to discount future costs and benefits to the current year.

B. Measurement and Evaluation (M&E) Costs

SDG&E has included M&E costs in the program budgets for the cost effectiveness tests. The total M&E budget is $5,115,099 for the three year program cycle. Of this amount, $4,240,099 is used in the actual cost effectiveness tests. The remaining amount ($875,000) is not used in the cost effectiveness tests and is designated as M&E for the Critical Peak Pricing rates. These rates and programs are not tested for cost effectiveness in this filing.

Of the $4,240,099 M&E budget used in the cost effectiveness tests, $1,615,000 was included in the cost for specific programs tested in this application (specifically, BIP, CBP, SCTD, PTR, and PLS). Additionally, $1,150,099 for non program-specific M&E was allocated across each of the resource programs tested, and the method used for allocation was the total program budget. Of the remaining M&E budget used in the cost effectiveness tests, $1,380,000 is designated for EM&V for the Summer Saver program as a portfolio cost, and $95,000 is designated for EM&V of the TA/TI programs. The $95,000 for TA/TI EM&V was allocated across the programs in which TI customers enroll: CBP and CPP.

C. Capital

For programs with capital investments that are assumed to provide benefits beyond the three-year program cycle, the investment was amortized over a ten year period and the resulting allocation for the first three years was used in the cost benefit calculation as directed in the Protocols. The programs that this applies to are the Small Customer Technology program and the Technologies Incentives program. The amortization period for PLS was 15 years.[4]

For programs with minimal capital expenditure assuming to provide benefits limited to the three-year program cycle, the investment was entered as an expense for each of the three years. The programs that this applies to are the Base Interruptible Program and Capacity Bidding Program.

D. Treatment of Technology Incentives

The Technology Incentives ("TI") program does not provide direct benefits, but instead provides enabling support for other programs. It was treated in the cost benefit calculations as follows. The TI budget was allocated across CBP and CPP. For CPP, the costs and benefits of the customers forecasted to be on CPP as a result of participating in the TI program are included as portfolio costs and benefits, since this rate is not explicitly tested in this application. The forecasted MWs associated with TI customers enrolling in CBP and the corresponding costs

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[4] The amortization period for PLS was taken from the Statewide Joint IOU Study of Permanent Load Shifting (PLS Study) completed by Energy + Environmental Economics and StrateGen on November 30, 2010.

from the TI budget were included in the cost effectiveness tests for CBP Day Ahead and CBP Day Of programs.

The TI incentives used in the cost effectiveness tests were calculated as follows. For the base incentive, the new MWs forecasted for the programs were multiplied by the incentive of $300 per kW. Only new MWs for each year were used as the incentive is paid only once upon technology installation. A 15% inflation factor was added because historical EM&V results have shown that actual impacts are less than indicated by the load shed tests upon which the incentive payments are based. Please refer to the testimony of Kathryn Smith for details. These incentive costs were treated as long-term capital costs in the cost effectiveness tests. An additional incentive was calculated for TI customers on the CPP program. The additional incentive consists of a $30 per kW annual payment to the aggregator for continuing customers staying on the program. This additional payment was treated as incentive payments in the cost effectiveness tests.

E. Permanent Load Shifting

The April 29th Ruling provided guidance to the Joint Utilities[5] to revise their estimates of the cost effectiveness of proposed Permanent Load Shifting (PLS) activities in their 2012-2014 Demand Response Applications, which were filed on March 1, 2011. Specifically, the Joint Utilities were directed to do the following:

1) Use the Demand Response Reporting Template (Template), including the long-run avoided capacity costs provided with the template, to calculate the cost effectiveness of PLS;
2) Agree on and consistently use an appropriate project lifetime and period of amortization of capital costs in the analyses; and

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[5] San Diego Gas & Electric Company, Pacific Gas and Electric Company and Southern California Edison Company

3) Provide two additional sensitivity analyses for PLS in addition to those provided in the Template: project lifetime and installation cost.

As directed by the April 29th Ruling, the Joint Utilities met and discussed appropriate technology costs and project lifetimes to use in the analysis. During that discussion, the PLS Study[6] was identified as the best documented source for these values. Specifically, the study reported installation costs per kW by technology type (Table 18, page 108) and an assumed project lifetime (page 50). As the study reported ranges for the technology installation costs, the midpoint of the range was used. The assumptions taken from the study and used by SDG&E as a result of this discussion with the Joint Utilities include the following:

- Average cost of technology for small thermal storage: $2,730 per kW
- Average cost of technology for medium to large thermal storage: $2,225 per kW
- Project lifetime: 15 years

In addition to the consensus assumptions, SDG&E used other assumptions for completing the analysis, and these are shown in Table 1 below.

Table 1: Analysis Assumptions

	2012	**2013**	**2014**
Technology mix	Thermal Storage: 6% small; 94% med to large	Thermal Storage: 4% small; 96% med to large	Thermal Storage: 4% small; 96% med to large
Incentives (not to exceed $500 per kW)	500,000	910,000	825,000
Expected peak capacity reduction (MW)	2.1	3.6	4.9
Length of shift time	6 hours		
Days per year (summer weekdays)	106		
Shift efficiency	100%		

[6] Energy+Environmental Economics and StrateGen, Statewide Joint IOU Study of Permanent Load Shifting, November 29, 2010.

F. Capacity Bidding Program

SDG&E's Capacity Bidding Program ("CBP") consists of a Day-Ahead and a Day-Of option. The budget for the CBP program was allocated across the Day-Ahead and Day-Of options using the load impacts forecast for each option. Each of the CBP options has three event products in which customers can enroll: one to four hours, two to six hours, and four to eight hours. For the Day-Ahead option, only the one to four hour product has enrolled customers. For the Day-Of option, it is expected that roughly 60% of CBP Day-Of customers will choose the one to four hour product and the remaining 40% will choose the two to six hour product. Each product has a different capacity payment price according to the applicable tariff, so when calculating the incentives for the Day-Of option to be used in the cost benefit tests, a weighted average of the two product prices was used. No costs were assigned to CBP Day-Ahead 2 to 6 hours or 4 to 8 hours as no customers enroll in these products. Similarly, no costs were assigned to the CBP Day-Of 4 to 8 hour product.

The 60 / 40 weighted average of CBP Day-Of customers was also used in calculating Factor A for the CBP Day-Of program. In particular, the factor was calculated for both the four-hour option and the six-hour option and then a weighted average of the two results was used.

G. Budget Exclusions

As specified in the Protocols, the pilots were not included in the cost effectiveness tests for this application. The pilots include Locational Dispatch, Residential New Construction and Nonresidential New Construction.

Expenses related to IDSM bridge funding were also excluded from the cost effectiveness tests. This includes expenses related to the Flex program, Residential Microgrid, the Technical

Assistance program, and the IDSM component of Educational and Outreach costs. Residential Microgrid is also a pilot.

For the BIP, CBP and TI programs, the incentive dollars used in the cost effectiveness calculations are based on expected load impacts while the budgeted incentive dollars are based on maximum events. The additional amount budgeted was not included in the cost effectiveness tests.

In addition, as mentioned earlier in the subsection on EM&V costs, the budgeted EM&V costs for the Critical Peak Pricing rates were not included in the cost effectiveness tests. Finally, the allocation for system support activities applicable to the Summer Saver program was not included as this program was not tested for cost effectiveness for this application.

H. Allocation of System Support Activities and Other Allocations

A total of $7,641,097 for system support activities was allocated across all the programs in the demand response portfolio. The method of allocation was done as a percentage of total program budget to the total DR portfolio budget, as specified in the guidance document.

In addition, the administration costs for Education and Outreach were allocated over the resource programs tested. The same was done for EM&V costs that relate to general EM&V rather than for specific programs as explained in the EM&V section above. The method of allocation was also total program budget.

Administration costs for Emerging Tech were included as portfolio costs in the cost effectiveness tests.

I. Expected Events

The expected event assumptions used in the cost benefit calculations were as follows: for the BIP program, two events were assumed. For all other programs, nine events per year were assumed.

J. Energy Rates

For the purpose of calculating customer energy savings, an average forecasted rate was used. For residential customers, the average rate used was $0.184 per kWh for 2011 and escalated by 3% for each subsequent year. For small commercial customers, the average 2011 rate used was $0.176, and for medium and large commercial and industrial customers the average 2011 rate was $0.139. The medium and large C&I average rate includes all energy and demand charges that the customer would pay.

V. RESULTS OF COST EFFECTIVENESS TESTING USING E3 TEMPLATE

Table 3 is a summary of the results of the evaluation using the models and avoided costs mandated in Decision 10-12-024 Attachment 1.

~~**Table 2: Results of Cost Effectiveness Tests**~~

	~~**BIP**~~	~~**CBP: Day Ahead**~~	~~**CBP: Day of**~~	~~**SCTD**~~	~~**PTR**~~	~~**PLS**~~	~~**Portfolio**~~
~~**TRC**~~	~~0.98~~	~~0.93~~	~~1.09~~	~~0.62~~	~~4.04~~	~~0.42~~	~~1.32~~
~~**PAC**~~	~~0.82~~	~~0.84~~	~~0.99~~	~~0.64~~	~~5.25~~	~~1.45~~	~~1.33~~
~~**RIM**~~	~~0.82~~	~~0.81~~	~~0.94~~	~~0.62~~	~~3.75~~	~~0.91~~	~~1.21~~
~~**PCT**~~	~~1.33~~	~~1.33~~	~~1.33~~	~~1.33~~	~~1.33~~	~~0.25~~	~~1.33~~
~~**TRC Benefits**~~ [1]	~~$3.554~~	~~$2.763~~	~~$9.148~~	~~$4.832~~	~~$25.726~~	~~$2.102~~	~~$49.685~~
~~**TRC Cost**~~ [1]	~~$3.625~~	~~$2.981~~	~~$8.374~~	~~$7.767~~	~~$6.370~~	~~$4.954~~	~~$37.647~~
~~**TRC Net Benefits**~~ [1]	~~($0.071)~~	~~($0.218)~~	~~$0.774~~	~~($2.935)~~	~~$19.356~~	~~($2.852)~~	~~$12.038~~

[1] ~~In millions~~

Table 3: Results of Cost Effectiveness Tests

	BIP	CBP: Day Ahead	CBP: Day of	SCTD	PTR	PLS	Portfolio
TRC	1.15	0.96	0.91	0.64	4.09	0.42	1.33
PAC	0.97	0.86	0.81	0.66	5.52	1.45	1.35
RIM	0.96	0.84	0.79	0.64	3.76	0.91	1.22
PCT	1.33	1.33	1.33	1.33	1.33	0.25	1.33
TRC Benefits[1]	$4.161	$2.813	$7.448	$4.991	$27.032	$2.102	$50.158
TRC Cost[1]	$3.626	$2.926	$8.186	$7.770	$6.616	$4.954	$37.653
TRC Net Benefits[1]	$0.535	($0.113)	($0.737)	($2.779)	$20.416	($2.852)	$12.505

[1]In millions

Figure 1 presents the results of the TRC sensitivity analysis in the DR Reporting Template. The figure shows how the portfolio changes when certain assumptions are changed.

Figure 1: TRC Sensitivity Analysis

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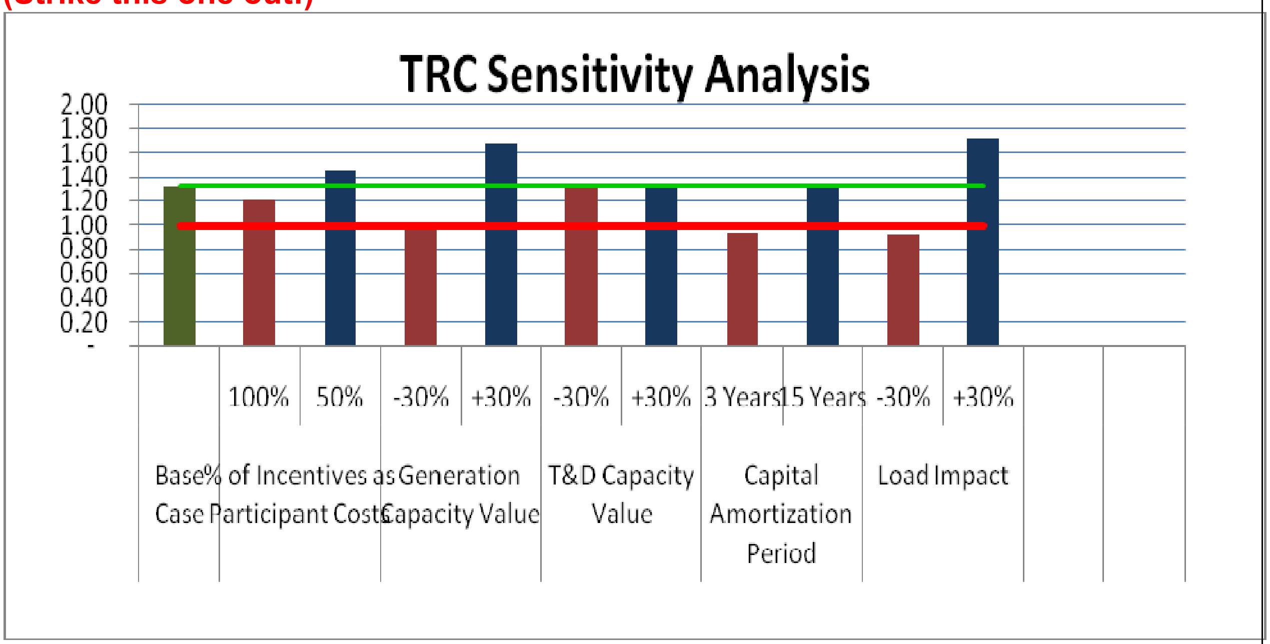

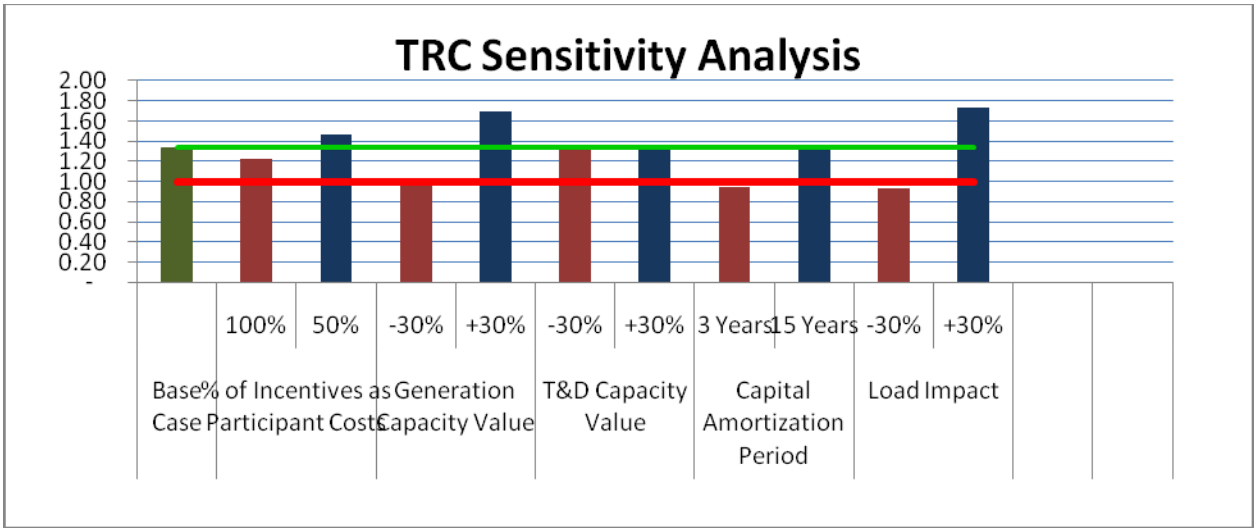

The guidance document provided by the Commission for this application stated that cost effectiveness analysis was required for each "demand response activity which has measurable load impacts for which the LSE is requesting budget approval."[7] Although SDG&E's PTR program received approval in a prior proceeding, the cost effectiveness results for the proposed PTR budget (which includes only administrative and measurement and evaluation costs) and forecasted MW for 2012 to 2014 are presented above due to the requirement in the guidance document for this application. Since inclusion of this program in the portfolio changes the portfolio test result significantly, SDG&E has also provided the portfolio test results without the PTR program. Table 4 presents the results with PTR left out of the portfolio.[8]

[7] "Guidance on Cost Effectiveness," page 2.

[8] In the results for this scenario, all of the costs requested for PTR in this application have been omitted along with the associated benefits.

Table 4: Results of Program Tests Without PTR

	Portfolio
TRC	~~0.77~~ 0.75
PAC	~~0.74~~ 0.72
RIM	~~0.70~~ 0.68
PCT	1.33
TRC Benefits [1]	~~$23.959~~ $23.126
TRC Cost[1]	~~$31.277~~ $31.038
TRC Net Benefits[1]	~~($7.318)~~ ($7.911)

[1]In millions

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 and Cost Effectiveness 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.