Application No: A. 08-06-002
Exhibit No.:
Witness: Kevin McKinley / David Barker

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

REBUTTAL TESTIMONY

OF KEVIN McKINLEY / DAVID BARKER

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
DECEMBER 15, 2008

REBUTTAL TESTIMONY
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I. PURPOSE

In accordance with the November 10, 2008 Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling, this Rebuttal Testimony responds to a number of issues related to the evaluation of cost effectiveness raised by California Large Energy Consumers Association (CLECA), Comverge, the Division of Ratepayer Advocates (DRA), the California Demand Response Coalition (CDRC), and TURN in their testimonies filed on November 24, 2008.

Because the Commission has yet to adopt a standard cost effectiveness methodology and the "determination of appropriate principles and criteria and how they should guide the Commission decision" on cost-effectiveness is within the scope of this proceeding, SDG&E provides two witnesses in rebuttal. Mr. Barker will address all issues related to cost effectiveness methodology, while Mr. McKinley will address application of the cost effectiveness methodology in determining the cost effectiveness of the SDG&E's proposed demand response programs for 2009-2011. Mr. Barker is sponsoring sections III, IV, V, and VII. Mr. McKinley is sponsoring sections II and VI.

II. REBUTTAL TO CLECA (MCKINLEY)

On page 9 of the CLECA testimony it states that: "SDG&E's forecast BIP budget is roughly $.55 million per year. Since the utility is only forecasting a load drop of 5 MW, this is a very expensive program compared to those of PG&E and SCE. However, SDG&E's cost-effectiveness analysis shows a TRC of 1.45 for BIP."

SDG&E cannot attest to the values used by PG&E and SCE for their BIP cost effectiveness calculations. However, SDG&E does stand by its analysis of the cost effectiveness of its BIP program and believes the differences may be related to how incentive payments are accounted for in budgeting versus incentive payments computed in the cost effectiveness calculations. It should be noted here that the budgets requested in the application are not always the same as the budgets used in the cost effectiveness calculations. The budgets requested in the application are based upon the gross number of megawatts expected to be signed up for the program. The dollars used in the cost effectiveness analysis are based upon the net amount of mW expected to actually be received in the program. These values are based upon the load reduction protocols. The reason for this is because cost effectiveness incentives are only paid based upon actually delivered load reduction. Budgets for funding are based upon the maximum amounts if all MWs enrolled were to respond the maximum amount of hours. Only funds actually expended are then collected in arrears.

SDG&E has estimated the TRC present value benefits of the BIP program at $2.093 million. This value is based on the Consensus Framework. Capacity Benefits of a 5 MW load drop valued at $146/kW (McKinley Testimony page 6), adjusted for LOLP, over each year of the 3 year program cycle. It also includes the present value of the energy savings for the three program years as described in the McKinley testimony at page 9. No benefits are attributed to the BIP program for avoided T&D because of the uncertain reliability of the program for avoided T&D. These benefits compare favorably to the present value of the costs of the program which are estimated at approximately $1.414 Million over the three years. This leaves a TRC Benefit cost ratio of 1.48, a value close to the value indicated in the CLECA testimony.

On page 15 of the CLECA testimony it states that: “SDG&E projects a CBP budget of $2.0 million in 2009, increasing to $2.6 million in 2011. These expenses are considerably higher than those of SCE and comparable to those of PG&E, yet SDG&E forecasts only a 14 mW day-ahead and a 3.5 mW day-of load drop for 2009, increasing to 20 mW day-ahead and 4.9mW day-of by 2011. Thus, SDG&E's program would appear to be considerably less cost-effective. Yet, SDG&E's cost-effectiveness analysis presents a CBP day-ahead TRC of 1.42 and a CBP day-of TRC of 1.23 (SDG&E Vol. VI, pp. 14, 15). The difference in these values is problematic and should be investigated during the hearings."

Again, SDG&E cannot attest to the values used by PG&E and SCE in their cost effectiveness calculations. However, SDG&E does stand by its analysis of the cost effectiveness of its CBP program and believes the differences may be related to how incentive payments are accounted for in budgeting versus incentive payments computed in the cost effectiveness calculations.

SDG&E has estimated the overall TRC present value of benefits of the three year CBP program at approximately $6.740 million. This value is based on the capacity, T&D and avoided energy benefits as described in the McKinley testimony on pages 4 through 9. This value compares favorably with the present value of the costs of the three year program which are estimated at approximately $4.778. This leaves a TRC benefits-cost ratio of 1.41 for the overall program.

III. REBUTTAL TO COMVERGE (BARKER)

A. Introduction

Comverge witness Eric Woychik calculates cost effectiveness based on use of financial options modeling with electric market data. Mr. Woychik's approach is applied only to one SCE program, but SDG&E provides this rebuttal to the claims made by Mr. Woychik of the superiority of the financial options method over the Consensus

Framework since the Commission has not yet issued a decision of cost effectiveness methodology and the ALJ ruling allowed cost effectiveness methodology to be an issue in A.08-06-002. Below are outlined each of Comverge's identified benefits of DR and for each benefit it is shown to be fully incorporated in the Consensus Framework. Further, it is shown that the financial options approach underestimates the value of demand response programs.

B. Optionality of Demand Response

Comverge states at page 5 of its testimony that: "the IOU's applications of the SPM do not capture the optional uses of DR that are available to take maximum advantage of market and reliability-based circumstances as they arise." Comverge goes on to identify nine applications supposedly not captured by the Consensus Framework methodology. Below it is shown that the Consensus Framework does capture those same applications better than the financial options approach.

1. Comverge claim: DR can be used to reduce spot energy prices and mitigate undue market power. SDG&E response: While this fact is true, new supply capacity owned by an independent party would provide those same benefits. Added supply during a super-peak period would lower market prices and would mitigate market power. DR does nothing that a new added supply resource cannot do as far as lowering prices.
2. Comverge claim: DR can be used to reduce congestion prices. SDG&E response: While true, locally cited generation capacity could also reduce congestion prices. Further, there is nothing in the actual

financial options model calculation related to local congestion since SP-15 market prices are used. The Consensus Framework addressed local marginal prices (LMPs) in section D.2, which would incorporate congestion prices once MRTU is in place and reliable information on LMPs are available.

3. Comverge claim: DR can be used as non-spin reserve capacity. SDG&E response: A combustion turbine (CT) can likewise be used to provide non-spin ancillary service. No deduction was made for differences between DR and CTs in the ability to provide ancillary services in the Consensus Framework (F.2) and so the complete value of the ability to provide non-spin reserve capacity is contained in the capacity value provided by DR using the CT net capacity cost.

4. Comverge claim: DR qualifies for resource adequacy and local resource adequacy. SDG&E response: A CT also qualifies for resource adequacy. The capacity value assigned to DR based on a CT is given DR full value for resource adequacy when it is available. In addition, section C.1 of the Consensus Framework also provides for an additional increment for the reduction in reserve margin.

5. Comverge claim: Dispatchable DR can be used to displace RMR resources. SDG&E response: Most RMR resources are old plants and have a low capacity price. However, DR cannot both avoid new capacity and RMR resources. The higher capacity cost of a new CT should be used instead of the lower capacity cost of RMR units.

6. Comverge claim: DR can be used instead of Out-of-Market (OOM) resources. SDG&E response: New CT capacity would have that same ability to avoid using OOM resources. Further, the Comverge financial options methodology does not include this aspect since it relies on SP-15 market prices.

7. Comverge claim: Use of DR during CAISO emergencies can assist CAISO with the reliable operation of the grid. SDG&E response: New CT capacity would have that same ability to increase the reliability of the grid, so that calculating DR value based on a new CT's net capacity cost would capture this value of a DR application.

8. Comverge claim: DR can be used to address distribution constraints. SDG&E response: The Consensus Framework addresses this aspect and Comverge simply uses the values SCE produced related to distribution benefits based on the Consensus Framework.

9. Comverge claim: Comverge suggests that DR can assist in the integration of intermittent renewable resources. SDG&E response: Most DR does not have the quick response time to provide the same ability to ramp up as a CT if renewables have a sudden change in supply availability. In addition, most DR has limited availability (seasonal limitations, on-peak limitations and total hours of use limitations) which limits the ability to assist in integration of renewable resources. Therefore, this should not be considered a general benefit of DR.

Contrary to the Comverge statements, the Consensus Framework does properly attribute value to DR programs. None of the nine applications cited above are unique to the financial options model of DR; all the value of those applications are captured and provided for in the Consensus Framework. Further, several of the DR applications mentioned are not captured by Comverge's proposed option model methodology, namely capturing the value of ancillary services provided by DR, the value of reduction in congestion prices, the value of the ability to displace OOM resources, the value of reducing distribution costs, and the value of reducing renewable integration costs.

C. The Financial Options Model

The proposed Comverge financial options model approach underestimates the value of demand response programs by relying on value derived from the California wholesale electricity energy market only. Supply-side resources also receive payments for providing resource adequacy and ancillary services that DR can provide to some extent; those values are not captured in data from the wholesale energy market alone.

Relying on market prices that do not fully reflect the cost in peak hours will underestimate the benefits of demand response programs and lead to artificially low benefit-cost ratios.[1] While this statement is also true for energy efficiency, reliance on energy markets only has a much larger effect for demand response where the value is in avoiding the few top hours of the load duration curve. The volatilities based on the SP-15 market underestimate the value of DR programs, if used on a broad basis, will lead to underinvestment in demand response.

[1] There is currently a $400 price cap in the CAISO energy market.

IV. REBUTTAL TO DRA (BARKER)

DRA states that: "…for practically identical BIP programs, the two IOUs assume such widely different factors that DRA questions the consistency between the methodologies used by the IOUs that produce such disparate numbers for LOLP." The SDG&E value is 98 percent, while SCE's value is 76 percent. While SDG&E cannot address the SCE value, it is possible for two IOUs to have differences based on customer and resource differences and differences in expectations about future volatility of weather and hydro conditions. SDG&E did not assume any LOLP event in San Diego would last longer than the 4 hours the DR program could be called and did not assume any probability of LOLP events exceeding 10 per month. Since BIP is available all year round, the only reduction made by SDG&E was for a 2 percent probability of having more than 30 days with need for DR resources in any one calendar year.

V. REBUTTAL TO CDRC (BARKER)

The CDRC testimony contains many misstatements and incorrect assertions regarding cost effectiveness that do not apply to SDG&E.

A. CT Costs

At page 6, CDRC states: "I find the turbine costs used by the three utilities to be too low." But at page 10, CDRC states "I recommend that each of the utilities use the installed costs from Table 1, which equals 1,206 $/kW (in 2009 dollars)." But $1,206 is approximately the same as SDG&E's proposed value of $1,215. Further, CDRC states that utilities should use their costs of capital (page 6), which SDG&E does do. The CDRC comments regarding SDG&E's CT costs are in error based on their own analysis.

B. Gross Margin

CDRC states at page 15: "…the utilities refuse to provide this information, making it impossible to verify the utilities' gross margin estimates." SDG&E has provided the entire Excel spreadsheet model of gross margins, so that all parameters could be analyzed and the model could be rerun using any stochastic simulation program compatible with Excel. The CDRC comments regarding SDG&E's gross margin calculations are in error.

C. Customer Costs

CDRC states that: "PG&E and SCE assume the cost to the customer of participating in a DR program exactly equals the incentive provided to that customer. This overstates the costs borne by the participant." Since SDG&E used the same methodology as proscribed by the Consensus Framework section B.3, the point applies to SDG&E as well.

In response, SDG&E would point out that the full customer benefit is not just the customer paid incentive, but the customer paid incentive <u>plus the customer bill savings</u>. It is likely customers costs are less than the maximum benefit for all but the marginal participant; there is likely an entire supply curve of net customer costs. The average customer costs (compared to the marginal customer costs) to be included in the Total Resource Cost ("TRC") should be a fraction of the incentives paid and bill savings. Setting the customer cost to the incentive as in the Consensus Framework is a reasonable approximation given lack of information on customer costs and has the benefit of treating utility programs and third party programs equally (Consensus Framework, B.3.) While not opposed to sensitivities on this value as proposed by CDRC, there is no basis for the

CDRC statement that the Consensus Framework overstates the costs borne by the participants.

D. Decrements to CR Program Capacity Benefits

SDG&E does use an LOLE analysis to reduce the value of DR programs relative to the full value of a CT consistent with section C.2 of the Consensus Framework. CDRC states that: "While SDG&E provided some workpapers, they were not of sufficient detail, particularly with respect to the LOLE analysis, that I can draw any conclusions concerning the reasonableness of the decrement." Then after an extensive discussion of SCE's calculations, CDRC concludes: "I recommend that the full capacity values be used in the utility's cost-effectiveness calculations until such time as the validity of these 'black-box' adjustments to DR cost-effectiveness can be validated through open, transparent evaluation by interested parties."

SDG&E provided a complete description of its LOLE analysis in R.07-01-041 and provided the LOLE results in workpapers. The LOLE analysis is necessarily complex because it is a stochastic analysis of the likelihood that the utility cannot serve it load at different points in time. It is unrealistic to assume LOLE analysis can be calculated in a simple-minded way and still be accurate. Parties can acquire production cost models and make their own analyses, but it is not appropriate to ignore this element until some unspecified analysis takes place.

SDG&E's analysis is reasonable and much more reasonable than an assumption of no reduction associated with limits on the availability of a DR program. The CDRC testimony itself cites the experience of winter 2001 when there were LOLE events. This shows there is a probability of outages in the winter if a large plant has an unexpected forced outage when other plants have planned outages as occurred with the SONGs unit in 2001 (among other events). Similarly, the heat wave of Labor Day weekend of 2007 is evidence that LOLE events in San Diego can occur on off-peak days.[2] The CDRC has made no specific findings that the SDG&E LOLE factors are unreasonable, the historical experience is consistent with the SDG&E LOLE factors, and so the CDRC recommendation should be rejected for SDG&E.

E. Locational Benefits

CDRC states at page 23 of its testimony that: "all DR programs provide some amount of locational benefits." SDG&E would dispute this statement for DR programs for which the load reduction is not reliable. The SDG&E method analyzes the variance in load impact and uses the 10th percentile response compared to the average response to prorate distribution benefits. For two DR programs, SDG&E found the load reduction response so variable as to provide no distribution benefits. Only DR programs that have historically demonstrated reliable load reductions should be attributed any distribution benefit. CDRC's recommendation to give all DR programs a generic distribution benefit should be rejected.

VI. PEAK. (MCKINLEY)

TURN has recommended that SDG&E's PEAK Student Program be eliminated from funding in the 2009 – 2011 DR program portfolio. Without addressing the merits of the PEAK Student Program or TURNs' characterizations of it, SDG&E agrees to eliminate the PEAK Student Program from the DR program portfolio and from the program budgets. Because of the small dollar value associated with the program, this

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[2] SDG&E's all-time peak load of 4,636 MW occurred on September 3, 2007 which was an off-peak day, the Labor Day holiday.

change in budgets has a minimal affect on the overall portfolio cost effectiveness of the SDG&E filing.

VII. QUALIFICATIONS OF DAVID T. BARKER (BARKER)

My name is David T. Barker. My business address is 8330 Century Park Court, CP32F, San Diego, California 92123-1530. I am employed as an economist in the Resource Planning group in the Regulatory Affairs Department of San Diego Gas & Electric. I have been employed as an economist in the Regulatory Affairs Department since April, 2002. Prior to that I was employed at SoCalGas in various staff positions including Economist (1991-1995 and 1998-2002), Market Consultant in the Residential Market (1988-1989 and 1995-1998), Electric Energy Analyst (1990-1991), and Demand Forecasting Supervisor (1989-1990).

I received a B.S. in Mathematics from New York State University in 1974, a Masters of Economics degree from North Carolina State University in 1976, and a joint Ph.D. in Economics and Statistics from North Carolina State University in 1980. I taught undergraduate economics and statistics courses for four years on a full-time basis in Oregon and part-time in the MBA program at Pepperdine University. I have previously testified before the Commission on economic analysis issues.

This concludes our Rebuttal Testimony.