BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Demand Response Programs, Activities and Budgets for 2012 through 2014.	Application 11-03-003 (Filed March 1, 2011)
Application of San Diego Gas & Electric Company (U 902 M) for Approval of Demand Response Programs and Budgets for Years 2012 through 2014.	Application 11-03-002 (Filed March 1, 2011)
Application of Pacific Gas and Electric Company for Approval of 2012-2014 Demand Response Programs and Budgets (U39E).	Application 11-03-001 (Filed March 1, 2011)

OPENING BRIEF OF
THE DIVISION OF RATEPAYER ADVOCATES
(PUBLIC VERSION)

KE HAO OUYANG
RADU CIUPAGEA
Public Utilities Regulatory Analysts

SUDHEER GOKHALE
Senior Utilities Engineer
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-2247
Email: skg@cpuc.ca.gov

LISA-MARIE SALVACION
Attorney
Division of Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-2069
Fax: (415) 703-2262
Email: lms@cpuc.ca.gov

August 22, 2011

TABLE OF CONTENTS

TABLE OF AUTHORITIES

CPUC DECISIONS

PUBLIC UTILITIES CODE

SUMMARY OF RECOMMENDATIONS

DRA's recommendations are as follows:

1. DRA opposes spending ratepayer dollars on demand response ("DR") programs that are not cost-effective. The Commission should not approve the following programs unless and until the utilities make any necessary changes to the programs' cost structures to improve the cost-effectiveness to a Total Resource Cost ("TRC") ratio above 1.0. Table A below shows those demand response programs, with a TRC ratio below 1.0, that DRA opposes in these applications.

Table A: Demand Response Programs with a TRC below 1.0 and opposed by DRA

PG&E
Base Interruptible Program (BIP)
Capacity Bidding Program (CBP) Day Ahead (-DA) and Day Of (-DO)
PeakChoice Program
SCE
CBP-DA and CBP-DO
Critical Peak Pricing (CPP) Program
SDG&E
BIP
CBP-DA and CBP-DO
SCTD

2. Dual participation in DR programs should be eliminated to reduce administrative costs associated with implementing and enforcing dual participation rules and to align retail programs with the CAISO's wholesale market participation rules.

3. There should be no fund shifting between proxy demand resource ("PDR") product programs and reliability-triggered demand response product ("RDRP") programs. Any increase in a program's budget from fund shifting in excess of 50 percent of its original budget should require the filing of a Tier 2 advice letter.

4. Funding for integrated demand side management ("IDSM") activities should only be approved for 2012. Funding for future IDSM activities should be made in the Energy Efficiency proceeding, Rulemaking (R.) 09-11-014.

5. PG&E's AMP contracts should be allowed to expire in 2011 without extension, and new aggregator contracts should only be considered after final rules for DRP participation in the CAISO's wholesale market are developed.

6. The Commission should direct the utilities to request all future funding for dynamic pricing and rate-related programs in Phase 1 of their respective general rate case ("GRC") to determine the total revenue requirement for each program and assess whether the programs should be continued. If the funding

consolidation cannot be done during the utilities' current GRC cycle, the funding consolidation should begin in the utilities' next GRC cycle.[1]

Table B below provides a detailed summary of the estimated funding reduction for each of DRA's recommendations.

Table B: DRA's Recommended Funding Reduction for 2012-2014 Demand Response Applications A.11-03-001, et al. (in Millions of Dollars)

Line No.	Issues	PG&E	SCE	SDG&E	Total
1	Fund Shifting Rules	-	-	-	N/A
2	IDSM Activities	$7.343	$9.007		$16.350
3	Dynamic Pricing and Rate-Related Programs	$6.550	-	-	$6.550
4	Dual Participation	-	-	-	N/A
5	Aggregator Contracts	$1.189	-	-	$1.189
6	Cost-Effectiveness and Practical Effectiveness	-	-	-	N/A
7	Base Interruptible Program (BIP)	-	-	-	N/A
8	Capacity Bidding Program (CBP)	$11.563	$0.961	$11.939	$24.463
9	PG&E PeakChoice Program (PeakChoice)	$10.500	-	-	$10.500
10	SCE Critical Peak Pricing (CPP)	-	$10.301	-	$10.301
11	SDG&E Small Customer Technology Deployment SCTD)	-	-	$13.009	$13.009
12	SDG&E Peak Time Rebate (PTR)	-	-	$4.353	$4.353
13	**TOTAL**	**$37.145**	**$20.269**	**$29.301**	**$86.715**

[1] Ex. DRA-1/Ex. DRA-1c, pp. 3-14, 3-15.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Demand Response Programs, Activities and Budgets for 2012 through 2014	Application 11-03-003 (Filed March 1, 2011)
Application of San Diego Gas & Electric Company (U 902 M) for Approval of Demand Response Programs and Budgets for Years 2012 through 2014.	Application 11-03-002 (Filed March 1, 2011)
Application of Pacific Gas and Electric Company for Approval of 2012-2014 Demand Response Programs and Budgets (U39E).	Application 11-03-001 (Filed March 1, 2011)

OPENING BRIEF OF
THE DIVISION OF RATEPAYER ADVOCATES
(PUBLIC VERSION)

Pursuant to Rule 3.11 of the California Public Utility Commission's ("CPUC" or "Commission") Rules of Practice and Procedure, and the schedule adopted in the August 9, 2011 email from Administrative Law Judge ("ALJ") Kelly Hymes, the Division of Ratepayer Advocates ("DRA") hereby submits this opening brief in the above captioned proceedings. The August 9th email from ALJ Hymes extended the due date for opening briefs to August 22, 2011. Thus, this filing is timely.

1. INTRODUCTION

Demand response has grown significantly in recent years, in large part in response to the heat storm of 2006 when the Commission realized that demand response could provide substantial reliability benefits in avoiding outages, when the electric grid is under stress. With those lessons learned, the rush to adopt increasingly more and more demand response is also attributed to state and federal legislation adopting smart grid policies, which put demand response in the forefront, because:

- Demand response ("DR") is considered a high priority resource, and is second on the Commission's loading order in the California Energy Action Plan II;
- Demand response programs provide reliability benefits that may fulfill electric utilities' resource adequacy requirements;
- The development of advanced metering infrastructure and the smart grid provide more opportunities for the development of demand response enablement technologies;
- Recognition by the CPUC and the Federal Regulatory Energy Commission ("FERC") that demand response has substantial value as a supply-side resource.

However, in the last few years, it has also been the Commission's practice to adopt expensive demand response programs and budgets without sufficient regard to their need or cost-effectiveness—mainly, because the Commission lacked a standard cost-effectiveness methodology by which to properly analyze demand response.[2] But now demand response budgets require much more scrutiny—an economic crisis has driven unemployment and home foreclosure rates up, and energy consumption down— ratepayers cannot continue to fund non-cost effective demand response programs still largely driven by Commission policies developed five years ago.

Since the last demand response budget cycle for years 2008-2011, the Commission adopted new standards to evaluate demand response, including load impacts and cost-effectiveness measurements. Furthermore, the three major utilities—Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas and Electric Company ("SDG&E") have had substantial time and experience with various demand response programs. New market participants, such as third-party demand response aggregators and electric service providers, are also playing greater roles in furthering demand response both

---

[2] Prior to the adoption of Demand Response Template in D.10-12-024 on December 16, 2010, the Commission relied on cost-effectiveness analyses derived from the Standard Practice Manual ("SPM") for Energy Efficiency ("EE"). However, because the SPM did not provide an adequate template to review DR programs, each utility developed its own proprietary models to evaluate DR cost-effectiveness when submitting applications for approval for DR programs.

at the retail and wholesale levels. It is now time for the Commission to weigh in on the successes and failures of their respective demand response portfolios.

2. OVERARCHING ISSUES

2.1. EVALUATING COST EFFECTIVENESS

2.1.1. Before Considering Cost Effectiveness, The Utilities Should Demonstrate That The Demand Response Programs Are Needed

The three major investor-owned utilities ("IOUs") have a statutory obligation to ratepayers that program expenses being requested are just and reasonable.[3] The California Public Utilities Code Section 451 states,

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered **shall be just and reasonable**. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.

Section 451 also states, " Every public utility shall furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment and facilities…as are necessary to promote the safety, health, comfort and convenience of its patrons, employees and the public."

As a key component to this reasonableness review, the utilities must demonstrate that the resources are necessary to fulfill a specific need. In prepared testimony, DRA raised the concern that for the current demand response budget cycle, the utilities' respective DR applications did not take into account the 2011 California Energy Commission ("CEC") planning reserve margin forecasts.[4] DRA also highlighted PG&E's capacity surplus for 2012-2014 in its discussion of PG&E's Planning Reserve Forecast.[5]

---

[3] Cal. P.U. Code § 451.

[4] Ex. DRA1/Ex. DRA-1c, pp. 2-4, 2-5. The CEC forecasts that for the entire summer of 2011, the planning reserve margins for all regions under 1-in-2 weather conditions are expected to be higher than the target of 15%, with the lowest being 29% during August and highest being 46% during June.[4] Under 1-in-10 weather conditions, the CEC forecasts that the lowest planning reserve margin is 19% in August and 34% in June. These high reserve margins indicate there should be more-than-sufficient resources to cover a broad range of system contingencies, such as unplanned facility outages or increased demand due to hotter-than-expected weather conditions.

[5] Ex. DRA-1/Ex. DRA-1c, p. 1-24, Table 4.

In rebuttal, PG&E called DRA's recommendation "short-sighted" and "would result in a failure to implement the loading order required by the California Energy Action Plan (EAP) and Commission decisions."[6] PG&E also indicates its "DR portfolio does recognize the current surplus of supply that concerns DRA, in that PG&E is not proposing to significantly increase DR MW beyond what is currently planned."[7]

PG&E's arguments should be rejected. As DRA emphasized in prepared testimony, designation of DR as a "preferred resource" does not mean the Commission should approve the DR programs without regard to cost-effectiveness.[8] As the EAP II states:

> With the implementation of well-designed dynamic pricing tariffs and demand response programs for all customer classes, California can ***lower consumer costs*** and increase electricity system reliability. To achieve this transformation, state agencies will ensure that appropriate, ***cost-effective technologies*** are chosen, emphasize public education regarding the benefits of such technologies, and develop tariffs and programs that ***result in cost-effective savings*** and inducements for customers to achieve those savings.[9]

The DR protocols assign as a benefit the full avoided generation capacity costs of a new combustion turbine ("CT") to demand response programs. This is a very generous benefit assumption for DR programs because it ***does not*** take into account the effect on market prices for capacity under the current and expected capacity surplus in California for the next several years.[10] Because DR protocols do not adjust capacity benefits of DR programs based on the current capacity surplus, DRA argues that, at a minimum, all proposed DR programs must be shown to be cost effective. Beyond passing this initial hurdle, it would be prudent for the Commission to examine whether there is a real need for the capacity provided by the programs to meet the forecasted demand.

---

[6] Ex. PGE-8, p. 1-4, lns. 17-23.

[7] Ex. PGE-8, p. 1-4, lns. 24-30.

[8] Ex. DRA-1/Ex. DRA-1c, p. 2-4, lns. 1-20.

[9] Energy Action Plan II, (October 2005), p. 7 (mimeo), emphasis added.

[10] Ex. DRA-1/Ex. DRA-1c, p. 2-4.

SCE's rebuttal testimony criticizes DRA's approach, saying, "Cost-effectiveness is only one of the criteria that is used to evaluate DR programs."[11] SCE cited other considerations that were provided in the Scoping Memo, including: "reasonableness of program and portfolio design, measured in terms of cost effectiveness, track record, future performance, cost, flexibility and versatility, adaptability, locational value, integration, consistency across the Joint Applicants' applications, simplicity, recognition, environmental benefits, consistency with Commission policies and general policies affecting revenue allocation."[12]

DRA does not dispute that there are other factors listed in the Scoping Memo that may provide useful information in determining whether a DR program is just and reasonable under Section 451. However, the DR Template adopted in D.10-12-024 for the purposes of evaluating the cost-effectiveness of 2012-2014 DR programs brings together for consideration, in one place, most of the factors raised in the Scoping Memo. For example, the *ex-ante* demand response forecasts used in the DR Template are informed by the *ex-post* actual performance (i.e., track record) of the programs.[13] Similarly, various costs of the program are a direct input to the cost-benefit analysis provided in the DR Template. Flexibility and versatility of proposed DR programs are accounted in the DR Template via the Trigger (C Factor) and Notification Time (B Factor). The locational value of DR programs is accounted for in the DR Template via a Distribution (D Factor) factor, which attributes additional benefits to a DR program if the program avoids any Transmission and Distribution ("T&D") cost. Finally, the DR Reporting Template also provides a place to account for environmental benefits of DR programs.[14] Since the DR Template considers most of the benefits and costs of any consequence, DR cost-effectiveness results should be the Commission's primary and necessary test in determining whether a DR program should be approved. In DRA's view, cost-effectiveness ***should be the most important factor*** in determining whether adoption of a program is a necessary and beneficial ratepayer investment.

---

[11] Ex. SCE-07, pp. 7-8.

[12] Joint Assigned Commissioner and ALJ Ruling and Scoping Memo, A.11-03-001, et al., dated May 13, 2011, p. 8.

[13] *Ibid.*

[14] DR protocols do not allow avoided environmental costs for GHG. Every other environmental benefit is allowed as an optional input.

DR Aggregators' rebuttal testimony is also critical of DRA's approach for utilities to adopt a need-based policy. DR Aggregators incorrectly argues that demand response place at the top of the loading order requires regulatory certainty, even if reserve margins are temporarily high.[15] DR Aggregators claim,

> [G]iven that these contracts were approved by the Commission and determined to be cost-effective, and given that there is no comparable opportunity for these customers at CAISO in 2012, it is essential to retain this valuable resource through 2012.

DR Aggregators' claims are misleading. The Commission never made such a determination. With regard to PG&E's current AMP contracts, in D.07-05-029[16] which adopted them, the Commission stated,

> The Commission hoped that the utilities' solicitations would result in cost-effective demand response proposals. DRA commented that the Commission should consider the cost-effectiveness of the agreements. Unfortunately, we do not have sufficient information to determine whether or not these contracts are cost-effective.

DR Aggregator's claim that the Commission's loading order requires adoption of DR even if reserve margins are temporarily high is also misplaced. In D.07-05-029, the Commission also declined to approve four of the eight proposed aggregator contracts, because SCE presented no evidence that either Commission policy or industry require resources as additional insurance above and beyond the planning reserve margin already embedded into SCE's resource mix.[17] The Commission stated, "We find there is no need for the Contracts as a whole as insurance against rolling outages during summer peak periods."[18] This case established that approval of any demand response resource above and beyond the utilities' resource adequacy needs is essentially considered an expensive insurance policy.

---

[15] Ex. DAG 2, p. II-8, lns. 15-17.

[16] Order Approving the Applications of Pacific Gas and Electric Company and Southern California Edison Company For Approval of Demand Response Agreements [D.07-05-029], issued May 7, 2007. This decision approved five third-party aggregator agreements with PG&E with five-year terms, from 2007-2011, as well as one third-party contract with SCE, from 2007-2008.

[17] D.07-05-029, p. 24.

[18] D.07-05-029, pp. 24, 25.

Given the generous assumption with respect to the benefits provided by demand response programs in California's current capacity surplus condition, cost-effectiveness should be crucial in determining a program's eligibility for Commission approval. While DRA is not advocating a change in the Commission's cost-effectiveness protocols or the assumptions provided by Energy and Environmental Economics, Inc. ("E3") at this time, the current capacity surplus should be taken into account as a ***qualitative negative factor*** when considering demand response programs that are only marginally cost-effective.[19] DRA understands that DR is a valuable alternative to conventional generation resources. However, DRA opposes spending ratepayer dollars on programs that are clearly not cost-effective.

2.1.2. Comparison Of Cost-Effectiveness Across The Three Utilities Shows Significant Differences That Should Be Carefully Scrutinized By The Commission

The Commission adopted cost-effectiveness protocols for evaluating DR programs in December 2010.[20] These protocols use a marginal cost approach to estimate the cost-effectiveness of demand response activities. The calculation of avoided electricity costs, which consists of the avoided costs of generation capacity (the avoided capacity costs), avoided costs of the saved energy (avoided energy costs), and avoided costs of transmission and distribution[21], are based on the long-term avoided generation capacity costs determined from a new combustion turbine ("CT").[22]

Avoided electricity costs are calculated using the Avoided Cost Calculator, a spreadsheet tool developed by E3. Load-Serving Entities ("LSEs") are permitted to adjust the generation capacity, energy capacity, and transmission and distribution capacity values taken from the Avoided Cost Calculator, according to the individual characteristics of DR programs.[23] The Availability (A Factor), Notification Time (B Factor), and Trigger (C Factor) adjust the avoided

---

[19] Ex. DRA-1/Ex. DRA-1c, p. 2-5, lns. 7-10.

[20] D.10-12-024, Attachment A.

[21] *Id.*, p. 15 (mimeo).

[22] *Id.*, pp. 15-16 (mimeo).

[23] D.10-12-024, Attachment 1, p. 9 (mimeo).

generation capacity cost.[24] The Distribution (D Factor) adjusts the Transmission and Distribution ("T&D") avoided cost.[25] The Energy Adjustment (E Factor) adjusts the Avoided Energy Cost.[26]

2.1.2.1. A Factor

The A Factor represents the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted.[27] A program that could be called in every hour that a generation capacity constraint might be experienced by the utility would have an A Factor of 100 percent. As directed by the Commission, PG&E, SCE, and SDG&E provided an A factor analysis based on E3's suggested method of allocating the residual capacity value across the 250 hours of the year in which system loads are the highest. As allowed by the Commission, PG&E and SDG&E also provided their own alternative analyses. PG&E provided an alternate analysis based on its Loss of Load Probability ("LOLP") analysis. SDG&E provided an alternate load levels analysis which is a modified version of E3's suggested method, using 100 peak hours, rather than the 250 hours in E3's method.

Only SCE's portfolio shows that it is cost-effective under E3's allocation of 250 hour assumption methodology. In contrast, PG&E and SDG&E's analyses show that their portfolios are not cost-effective using E3's 250-hour assumption methodology.[28]

2.1.2.1.1. SCE

SCE provided an A Factor analysis based exclusively on E3's top 250 hours suggested method. It appears that SCE's Demand Response Portfolio is cost-effective, with a TRC ratio of 1.13.[29] SCE also shows that ***most*** of its individual demand response programs have a benefit to cost ratio greater than one. Despite DRA's criticism that some programs are not cost-effective, SCE's rebuttal nevertheless argues that the problem lies in the protocol requirement that all

---

[24] *Id.,* p. 22.

[25] *Id.,* p. 27.

[26] *Id.,* p. 25.

[27] Ex. DRA-1/Ex. DRA-1c, p. 2-2, lns.12-13.

[28] Ex. DRA-1/Ex. DRA-1c, p. 2-6.

[29] Ex. DRA-1/Ex. DRA-1c, p. 2-5, 2-6.

portfolio costs (e.g., Auto-DR, M&E and statewide marketing) that support the programs be allocated to programs based on individual budgets. SCE states:

> A non-cost effective finding in this fully-cost loaded approach means that the program does not provide sufficient net benefits to carry its direct costs plus its pro-rata share of the indirect portfolio costs. It does not mean that the program is not cost-effective or that it does not add value to the overall portfolio.[30]

SCE's arguments have no merit. In its rebuttal testimony, SCE provides Table III-3 as a modified cost-benefit analysis in an effort to demonstrate that all SCE DR programs are cost-effective. On the benefit side, Table III-3 includes all of the program benefit values from SCE's DR Reporting Template. On the cost side, Table III-3 ***does not*** include costs such as capital costs to a load serving entity, capital costs to participant, increased supply costs, transaction costs and value of service lost, which are provided in SCE's DR Reporting Template.[31] In hearings, SCE witness David Reed explained it was a modified cost-benefit analysis, and that he "just pulled out a couple of items to demonstrate that every program has a net benefit that contributes to the portfolio cost-effectiveness."[32] In D.10-12-024, the Cost-Effectiveness Protocols shows a table of the costs and benefits of demand response included in each of the four Standard Practice Manual ("SPM") tests.[33]

Table 2-1: Cost-Effectiveness Protocols
Costs and Benefits of Demand Response[34]

	TRC	**PAC**	**RIM**	**Participant**
Administrative Costs	COST	COST	COST	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Bill Increases				COST
Bill Reductions				BENEFIT
CAISO Market Participation Revenue	BENEFIT	BENEFIT	BENEFIT	
Capital costs to LSE	COST	COST	COST	
Capital costs to participant	COST			
Environmental benefits	BENEFIT			

[30] Ex. SCE-07, p. 9, lns. 1-6.

[31] 1 Tr. 146:1-149: 2 (SCE/Reed) *See* Ex. DRA-4.

[32] 1 Tr. 176:6-26 (SCE/Reed).

[33] D.10-12-024, Attachment 1, p. 17. Ex. DRA-4.

[34] Ex. DRA-4.

Incentives paid		COST	COST	
Increased supply costs	COST	COST	COST	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Non-energy/monetary benefits	BENEFIT			BENEFIT
Revenue gain from increased sales			BENEFIT	
Revenue loss from reduced sales			COST	
Tax Credits	BENEFIT			BENEFIT
Transaction costs to participant	COST			COST
Value of service lost	COST			COST
Shaded areas indicate costs not reflected in SCE's modified cost-benefit analysis, Table III-3 in SCE's Rebuttal Testimony.				

For the Total Resource Cost ("TRC") test, the costs include administrative costs, capital costs to LSE, capital costs to participant, increased supply costs, transaction costs to participant, and value of service lost. Table III-3 in SCE's rebuttal testimony includes only administrative costs for the TRC test. In addition to removing portfolio costs, SCE also removes direct program costs such as incentives and bill reductions, which are factored in the TRC test as transaction costs and value of service lost. DRA contends that the cost-benefit analysis presented in Table III-3 of SCE's rebuttal testimony is a major understatement of the actual costs of demand response programs and should be disregarded.

2.1.2.1.2. PG&E's Use of an Internal LOLP Study for the A Factor Is Not Transparent or Able to Be Verified Independently

Based on E3's method, PG&E's portfolio is not cost-effective, with a TRC ratio of 0.60. In an effort to justify the continuation of its current program, PG&E conducted its own alternative methodology. Under its own analysis, PG&E shows its demand response portfolio to be *just* cost-effective with a TRC ratio of 1.0.[35]

DRA questions the PG&E's portfolio TRC ratio based on its alternative methodology. As mentioned in DRA's prepared testimony, PG&E's LOLP study was conducted in 2006[36] and should be considered dated for the purposes of evaluating the proposals in the 2012-2014 Demand Response Program Cycle Applications.[37] Also, PG&E's LOLP model requires

[35] Ex. PGE-5, p. 10.

[36] Ex. DRA-1/Ex. DRA-1c, p. 2-6.

[37] Ex. DRA-1/Ex. DRA-1c, p. 2-6, lns. 11-15.

"substantial amounts of generator-specific information, which is especially difficult to gather for the substantial amount of new private generation being added to serve California."[38] Most importantly, PG&E's LOLP model does not comply with the protocols adopted in D.10-12-024. There, the Commission held, "Should an LSE provide an LOLE/LOLP model that can be shared in the public domain, along with sufficient documentation of their derivation to allow them to be verified independently, then the Commission may consider such information for inclusion in the DR benefits analysis along with the results of the required approach."[39] Since PG&E's LOLP study remains confidential and cannot be verified independently, the Commission should not include its results in the DR benefits analysis.

In rebuttal, PG&E states that increases in forecast capacity since 2006, combined with a decline in forecast load due to the recession, would certainly push out the year when generation supply and system load would be in balance, i.e., the year that a new LOLP study would model. But PG&E qualifies this statement, saying:

> However, it is not obvious, *a priori,* that a newer LOLP study would increase the number of LOLP hours in a year, and thereby decrease DR cost effectiveness, as DRA suggests.[40]

PG&E also admits that the LOLP study itself is proprietary, and the capacity value over 132 hours in the year that is allocated in the alternate DR Reporting Template is an aggregation of the data derived from that study.[41]

PG&E's arguments should be rejected. While the Commission allows use of an alternative analysis[42], PG&E completely ignores the DR protocols, which state:

> In [the LOLE/LOLP] calculation as in many others, the advantage of ***simplicity and transparency*** outweigh the advantages of proprietary traditional LOLE/LOLP models. However, should an LSE provide an LOLE/LOLP model that can be shared in the public domain, along with sufficient documentation of their

[38] D.10-12-024, Attachment 1, p. 23 (mimeo).

[39] *Id.,* p. 23.

[40] Ex. PGE-8, p. 9-3, 9-4.

[41] Ex. PGE-8, p. 9-4, lns. 12-17.

[42] Ex. PGE-11.

> deviation to allow them to be ***verified independently***, then the Commission may consider such information for the inclusion in the DR benefits analysis along with the results of the required approach. In performing the A factor analysis, utilities will be expected to explain and document the difference between the number of calls permitted by the program rules and the number of calls that have actually occurred historically in those years when generation capacity constraints were actually experienced.[43]

While PG&E made the public monthly capacity allocation percentages, it is only an aggregation of hourly data. PG&E further provided DRA with additional, non-public documentation, which was only the hourly data non-aggregated, hourly information—not the LOLP model itself, which PG&E deems as proprietary. In DRA's view this is an inadequate showing, and does not comply with the requirement that, "should an LSE provide an LOLE/LOLP model that can be ***shared in the public domain***, along with ***sufficient documentation*** of their deviation to allow them to be ***verified independently***."[44] It is only on this condition, that the Commission may consider deviation from E3's assumptions.[45] As a policy matter, allowing PG&E—or any IOU—to completely deviate from the DR Template using proprietary models would undo years of the Commission's effort to develop a consistent and transparent method in which to evaluate cost-effectiveness.

2.1.2.1.3. SDG&E

SDG&E also provides an alternative analysis based on a modified version of E3's suggested method. SDG&E uses 100 peak hours instead of the 250 hours used in E3's method. Based on its alternative methodology, SDG&E shows its Demand Response Portfolio is cost effective with a TRC of 1.33, if the results for its AMI-enabled Peak Time Rebate ("PTR") program are included in the portfolio analysis. However, if PTR results are excluded from the portfolio analysis, the portfolio is not cost-effective with a TRC ratio of only 0.75. In Section 5.2.3.2. below, DRA discusses its concerns regarding SDG&E's PTR program, and the impact on SDG&E's entire portfolio.

---

[43] Ex. DRA-3, p. 23.

[44] Ex. DRA-3, p. 23.

[45] 2 Tr. 332:19-25 (DRA/Ciupagea).

In rebuttal, SDG&E makes similar arguments as PG&E, although it did not use an LOLE/LOLP model to derive the A Factor:

> In the protocols there is no mention of the number of hours required in the Load Level analysis. ... Since there was no request to deviate from the protocols, there was no requirement to provide a second analysis. However, in the interest of time in this proceeding and in order to provide an additional comparison analysis, attached to this rebuttal testimony is an alternative analysis based on the E3 recommended 250 peak time hours.

DRA agrees with the Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo, Attachment 1, which states:

> [PG&E, SCE, and SDG&E] are to provide an alternate version of their cost-effectiveness analysis for their Demand Response (DR) programs. This will allow the Commission to analyze the cost-effectiveness calculations consistently across the Joint Applicants.[46]

The ALJ Ruling is a requirement for all IOUs to provide a cost-effectiveness analysis using E3's methodology. Furthermore, DRA believes that using E3's methodology for calculating the A Factor is the only consistent and transparent method for analyzing the IOUs Demand Response programs and portfolios.

2.1.2.2. B Factor

The B Factor determines the value of a program's notification time by estimating how the additional information available for shorter notification times will result in more accurate decisions about event calls. PG&E, SCE, and SDG&E use B factors that are 100 percent for day-of programs and 88 percent for day-ahead programs. One exception is PG&E's Aggregator Managed Portfolio ("AMP") program, with a B factor of 97 percent, which is a weighted average based on the varying nature of the AMP contracts. As mentioned above, the B Factor takes into account some of the "other considerations" (e.g., flexibility and versatility, adaptability)

---

[46] Joint Assigned Commissioner and ALJ's Ruling and Scoping Memo, A.11-03-001 et al, dated May 13, 2011, Attachment 1, p. A1.

provided by the Scoping Memo,[47] which makes the cost-effective analysis the most effective tool in determining reasonableness.

2.1.2.3. C Factor

The C Factor accounts for the triggers or conditions that permit the utility to call a DR program. Programs with flexible triggers have a higher value than programs which can only be triggered under particular conditions. PG&E, SCE, and SDG&E use 95 percent as the C factor for their Base Interruptible Programs ("BIP") and AC Cycling programs. The IOUs assign a C Factor of 100 percent for all other DR programs, because the programs can be called at the discretion of the utilities.[48] As mentioned above, the C Factor also take into account some of the "other considerations" (e.g., flexibility and versatility, adaptability, locational value, integration) provided by the Scoping Memo[49] , which makes the cost-effective analysis an effective tool in determining reasonableness.

2.1.2.4. D Factor

The D Factor adjusts the estimated benefits of a DR program to avoid or defer upgrades to the transmission and distribution system. The default value of the D factor is 0 percent, as it is assumed that a given DR program does not avoid any transmission or distribution upgrades, unless the utility can show otherwise. PG&E uses 0 percent as the D factor for all of its programs, except for Permanent Load Shifting ("PLS") program, which has a D factor of 100 percent. SCE uses a range of 0 percent to 5.30 percent as the D factor for its programs, with the exception of PLS, which has a D factor of 25.30 percent. SDG&E uses a range of 0 percent to 12 percent as the D factor for its programs, except for PLS, which has a D factor of 50 percent and Small Customer Technology Deployment ("SCTD") program, which has a D Factor of 100 percent. As mentioned above, the D Factor also take into account some of the "other considerations" (e.g., locational value, integration, cost, environmental benefits) provided by the

---

[47] *Id*., p. 8.

[48] Ex. DRA-1/Ex. DRA-1c, p. 2-3, lns. 10-15.

[49] Scoping Memo (May 13, 2011), p. 8.

Scoping Memo,[50] which makes the cost-effective analysis an effective tool in determining reasonableness.

2.1.2.5. E Factor

The E Factor allows the utility to value DR under alternate energy price scenarios, such as the higher cost of energy during peak hours. PG&E, SCE and SDG&E use an E factor of 140 percent.[51] As mentioned above, the E Factor take into account some of the "other considerations" (e.g., future performance, cost, flexibility and versatility) provided by the Scoping Memo,[52] which makes the cost-effective analysis an effective tool in determining reasonableness.

2.2. DUAL PARTICIPATION RULES

2.2.1. Dual Participation In DR Programs Should Not Be Permitted.

Initially, the Commission indicated participation in more than one DR program may increase the amount of cost-effective DR available and increase the flexibility of DR programs to reduce electricity load during declared energy emergencies or at times of high electricity prices. As such, D.09-08-027 permitted customers to participate concurrently in one program that provides an energy payment and one that provides a capacity payment.[53] The Commission also adopted guidelines to prevent double counting of, and double payment for, a single load drop made by a customer enrolled in two programs with simultaneously called events.[54] The Commission also stated that "these rules will be reevaluated to determine their effectiveness in promoting program participation, increasing available demand response load reduction, and avoiding instances of duplicative payment and gaming."[55]

After reviewing all three IOU applications, it is now time for the Commission to reevaluate the current dual participation rules. Thus, DRA recommends the Commission

---

[50] *Id*.

[51] Ex. DRA-1/Ex. DRA-1c, p. 2-3, lns. 26-28.

[52] Scoping Memo (May 13, 2011), p. 8.

[53] D.09-08-027, pp. 154-158.

[54] D.09-08-027, pp. 150-152.

[55] *Id.*

eliminate dual participation in DR programs for two reasons: 1) the changing DR landscape leading towards the integration of DR with the CAISO's wholesale market, and 2) the administrative burden to implement and enforce dual participation rules outweigh any incremental benefits. DRA fully discusses each of these reasons below.

2.2.1.1. Dual Participation Is Not Permitted Under The Direct Participation Rules

The final rules for demand response provider[56] ("DRP") participation in the CAISO's wholesale market are currently being developed in the direct participation phase of R.07-01-041. Under the current CAISO Proxy Demand Response ("PDR") tariff language[57], dual participation of a single resource is not permitted between two different PDR products.[58] If dual participation is not permitted in the CAISO's wholesale market, a correlating Commission rule should also exist that prevent dual participation in IOU programs that are capable of bidding directly into the CAISO's wholesale market. This will avoid the problem of double counting of, and double payment for, a single load drop made by a customer enrolled in two programs. This will also avoid the problems currently encountered because of double counting of a single load drop made by a customer enrolled in two programs when program events overlap.

In D.10-06-002, the Commission held that dual participation in IOU and DRP programs "shall be implemented only after California has had reasonable and successful experience with single PDR program participation."[59] The Commission resolved that customers engaged in an IOU DR program will not be permitted to also participate in direct bidding of their DR resource into CAISO markets via third-party aggregators. Furthermore, customers of electric service providers ("ESPs") that are enrolled in IOU DR programs may not participate in the IOU program and bid directly into the CAISO markets on their own or via third-party aggregators or ESPs. If a customer of an ESP wishes to bid into the CAISO market on its own or through a DRP, it must first exit the IOU DR program. Upon exiting the IOU program, customers of an

---

[56] A DRP can be a load serving entity, an energy service provider, or third party aggregator.

[57] The final PDR tariff is currently pending approval at the Federal Energy Regulatory Commission.

[58] Order Conditionally Accepting Tariff Changes and Directing Compliance Filing, 132 FERC ¶ 61,045 (July 15, 2010), pp. 2-4.

[59] D.10-06-002, p. 13, FOF 2, COL 2, and OPs 2, 3.

ESP may participate directly in the CAISO market to the extent that their contract with the ESP allows.

As the utilities transition DR programs into PDR and RDRP products that can bid directly into the CAISO's wholesale market, customers participating in these DR programs must abide by the CAISO PDR tariff,[60] which prevents dual participation. Therefore, current dual participation rules will no longer be applicable, as DR programs are transitioned into PDR and RDRP products capable of bidding directly into the CAISO's wholesale market. DRA urges the Commission to eliminate dual participation in DR programs now to reduce administrative costs instead of waiting for the dual participation rules to automatically phase out as DR programs are transitioned into PDR and RDRP products. DRA recommends the Commission order the IOUs to revise their respective DR budget requests with a reduction in administrative costs associated with dual participation.

2.2.1.2. Administrative Burden To Enforce Dual Participation Rules Add Significant Ratepayer Costs

In opening testimony, PG&E maintains that the administrative burdens of implementing rules concerning dual participation outweigh the benefits of increasing the amount of available DR.[61] PG&E does not support dual participation, but did not provide the administrative costs associated with implementing dual participation rules. However, if dual participation is to continue, PG&E proposes a continuation of dual participation rules adopted in Advice Letter 3560-E-B filed on June 24, 2010.[62] Similarly, SCE also intends to file tariff modifications for retail programs revising their dual participation conditions as well as other program design changes required for participation as PDR in the future.

SDG&E goes furthest to claim that the frequency and magnitude of DR program overlap warrant reconsideration of dual participation rules.[63] After reviewing the data on multiple program participation, and the history of various program events, SDG&E concluded there is too

[60] 132 FERC ¶ 61, 045(July 15, 2010).

[61] Ex. PGE-1, p. 2-2.

[62] Ex. DRA-1/Ex. DRA-1c, p. 1-17.

[63] Ex. SGE-1, pp. 5-8.

much overlap with participation in critical peak pricing ("CPP") and other day-of DR programs. Therefore, SDG&E proposes to remove multiple program participation for critical peak pricing-default ("CPP-D") with capacity bidding program ("CBP"), base interruptible program ("BIP"), scheduled load reduction program ("SLRP"), permanent load shifting ("PLS") and the aggregator-managed programs.

2.2.1.3. Rebuttal Testimony By PG&E, SCE, And DR Aggregators Offers No Justification For The Increased Costs And Should Be Rejected

In rebuttal, PG&E admits the administrative burdens and cost—primarily due to the Information Technology ("IT") work required to support dual participation across multiple DR providers—of implementing additional dual participation options outweigh the benefits of increasing the amount of available DR.[64] However, rather than offering a solution, PG&E merely admits that challenges to implement the rules "can become complex" and that IT requirements can "***become even more costly*** when a customer is enrolled in programs with multiple DR providers."[65]

SCE's rebuttal testimony noted that DRA is "somewhat late in its support to disallow dual participation" as SCE consistently argued that dual participation should be limited and only allowed if it can prevent payment for the same load twice.[66] SCE indicates that those administrative costs are already sunk with the implementation in 2010 pursuant to D.09-08-027. SCE argued that implementing such a requirement across multiple business systems would be overly burdensome.[67] SCE also states, "If DRA seeks to disallow *all* dual participation, then it would be contradicting its participation in the DR OIR Phase 3 Emergency-triggered Program Settlement. The Settlement allowed for the dual participation of BIP with another price-responsive program to remove MW from under the statewide cap."[68] SCE's rebuttal testimony warns that if the Commission adopts DRA's dual participation proposal, then current dual

---

[64] Ex. PGE-8, pp. 2-5:31 – 2-6:11.

[65] *Id.*

[66] Ex. SCE-07, p. 33, lns. 14-21.

[67] Ex. SCE-07, p. 33, lns. 19-22.

[68] Ex. SCE-07, p. 34, lns. 12-15.

participants in DBP and BIP would be forced to choose between DBP and BIP; of which likely all would select BIP.[69]

SCE's arguments should be rejected. DRA's opposition to dual participation is based on the CAISO's rules for PDR and RDRP and does not contradict DRA's participation in the DR OIR Phase 3 Emergency-triggered Program Settlement. The DR OIR Phase 3 Emergency-triggered Program Settlement merely allows dual participation in DBP and BIP. The main purpose of the DR OIR Phase 3 Emergency-triggered Program Settlement was to make BIP price responsive and limit its size. The purpose of the settlement was not to facilitate dual participation between BIP and DBP. At the time DRA participated in the Settlement, the Commission permitted dual participation between DBP and BIP. Settlements may not prohibit the Commission from adopting new policies if the Commission chooses to do so. If the Commission adopts DRA's proposal to stop dual participation, it will be a new Commission's policy rule and should apply uniformly. The new rule will and should stop dual participation between any two programs wherever such dual participation was previously allowed by the Commission.

In rebuttal testimony, DR Aggregators point out that contrary to DRA's statement that dual participation is currently not permitted, "a single service account will be able to dual participate in two retail DR programs offered by a utility, while still registered with the CAISO as a RDRP or PDR resource."[70] DR Aggregators argue:

> [C]ritical peak pricing (CPP) tariffs, including PG&E's Peak Day Pricing (PDP), are not programs that will be bid into CAISO markets, so dual participation between capacity programs and CPP and PDP should continue to be allowed.[71]

Thus, on timing, DR Aggregators state: "It is premature to change the rules for retail programs, and thus eliminate the flexibility for customers to reduce their demand, prior to having a comparable opportunity in CAISO wholesale markets."[72]

---

[69] Ex. SCE-07, p. 34, lns. 16-21.

[70] Ex. DAG-2, pp. II-4, II-5.

[71] Ex. DAG 2, p. II-4, lns. 24-29.

[72] Ex. DAG 2, p. II-5, lns. 27-31.

DR Aggregators' arguments have no merit. Regardless if CPP and PDP are programs that cannot be bid into CAISO markets, ratepayers should not bear any additional costs for the administrative burden addressed by the utilities. Rather than keeping on the path of continually expending unnecessary ratepayer funds, the Commission should eliminate this problem altogether by rejecting *any* form of dual participation.

In light of the challenges associated with implementing and enforcing current dual participation rules, DRA urges the Commission to eliminate dual participation in DR programs to reduce administrative costs associated with implementing and enforcing dual participation rules. Ratepayer funds are limited and should be spent wisely. In DRA's view, dual participation is not cost-effective and should not be allowed to continue. Since the IOUs did not provide the amount of the administrative costs associated with implementing and enforcing dual participation rules, DRA recommends the Commission order the IOUs to update their DR budget requests with the corresponding reduction in administration costs associated with dual participation.

2.3. BASELINE METHODOLOGY

3. EMERGENCY PROGRAMS

3.1. COMPLIANCE

3.2. REASONABLENESS

3.2.1. Base Interuptible Program

The Base Interruptible Program ("BIP") is a statewide program for commercial and industrial ("C&I") customers commit at least 15 percent of customer-specific Monthly Average Peak Demand, with a minimum load drop of 100 kW. BIP customers are paid a monthly incentive payment. The program can be called for several types of reliability-only events, including system emergencies (*e.g.,* CAISO alerts and stages), transmission emergencies (*e.g.,* loss of transmission resources), and local transmission and distribution system (*e.g.,* overload) emergencies. Between 2007 and 2010 the CAISO did not call any Stage 2 Emergencies.

DRA's prepared testimony examined the BIP programs across each utility.

Table 3-1: 2012-2014 BIP Comparison Across Utilities[73]

	PG&E	SCE	SDG&E
2012-2014 Budget (in millions)	$0.666[74]	$2.510[75]	$4.179[76]
2012-2014 *Ex ante* Forecasted Load Impact – Maximum value	234 MW[77]	566 MW[78]	16 MW[79]
TRC Ratio – E3's method[80]	0.90	1.33	0.98
A Factor – E3's method[81]	58%	67%	58%
TRC Ratio – IOU method[82]	1.45	1.33	1.15
A Factor – IOU method[83]	96%	67%	68%

SCE's cost-effectiveness analysis based on E3's 250 peak hours shows the BIP program will be cost-effective with a TRC ratio of 1.33. PG&E's cost-effectiveness analysis based on E3's 250 peak hours shows its BIP program will not be cost-effective with a TRC ratio of 0.90.

The availability factor ("A Factor") is a primary driver of the cost-effectiveness of this program. PG&E attributes an A Factor of 96 percent to BIP, based on its internal LOLP analysis. In comparison, SCE and SDG&E allocate A Factors with maximum values of 67 percent and 68 percent respectively.

---

[73] Ex. DRA-1/Ex. DRA-1c, p. 3-2, tbl. 3-1.

[74] Ex.PGE-1, tbl. 1-2, p. 1-18.

[75] Ex. SCE-5, p. 51, tbl. IV-21.

[76] Ex. SGE-1, pp. MFG-23, MFG-24, tbl. MG-2.

[77] Ex. PGE-5, p. 8, tbl. 8-5.

[78] Ex. SCE-05, p. 19, tbl. II-3.

[79] Ex. SGE-13, p. LW\KS-12, tbl. KS-5.

[80] Ex. PGE-18, Ex. SCE-08, SGE-12, Excel worksheet "BIP."

[81] *Id*.

[82] Ex. PGE-19, Ex. SCE-08, SGE-8, Excel worksheet "BIP."

[83] *Id*.

As discussed above in Section 2.1.2.12, PG&E's use of its internal LOLP study for its alternative DR analysis causes DRA to question the validity of its TRC ratio. In order to consistently and transparently analyze the cost-effectiveness results across the IOUs, DRA recommends the use of the A Factor analysis based on the E3 suggested method, which uses 250 peak hours. Based on E3's suggested A Factors, neither PG&E nor SDG&E's BIP programs are cost-effective.

3.2.2. PG&E's Proposal To Screen And Deter Non-Compliant Participants Should Be Extended To SCE And SDG&E's BIP Programs

PG&E proposes a pre-enrollment qualification of BIP applicants, which would require them to submit a load reduction plan with their enrollment application and to participate in a pre-enrollment BIP test event, without financial penalty. PG&E also proposes to re-test BIP participants who fail to comply with any actual curtailment or test event requirements and allow for a more flexible way of adjusting the non-complying participants' Firm Service Level ("FSL"). Since PG&E only proposes these changes for new BIP applicants and non-complying BIP participants, the new measures should have limited impact on the existing complying BIP customers.

To the extent that the Commission decides to continue BIP in the next program cycle, DRA agrees with PG&E's proposal to implement a mechanism to deter noncompliant BIP participants. In prepared testimony, DRA recommended that the Commission require all three IOUs to make similar changes for their respective BIP programs.[84]

SDG&E agrees. SDG&E's rebuttal testimony states:

> SDG&E agrees with DRA recommendation that SDG&E should implement a pre-enrollment qualification for new BIP applicants and a re-test for non-complying BIP participants. BIP participants that are not able to achieve their Firm Service Level during an event will have their Firm Service Level set to the level they achieved during the event. Participants requesting a higher Firm Service Level will require a re-test. A tariff for the BIP program that reflects the proposed changes, as well as an updated Program Implementation Plan, can be found in Appendix A.[85]

---

[84] Ex. DRA-1/Ex. DRA-1c, p. 3-5, lns. 1-3.

[85] Ex. SDG&E-6, GMK-13:1-6.

SCE differs. In rebuttal testimony, SCE opposes DRA's recommendations that it adopt PG&E's proposed mechanisms in its own BIP program. SCE states:

- SCE already has procedures in place to ensure that all new BIP enrollees have a curtailment plan and participate in monthly notification tests.

- SCE's TOU-BIP excess energy charges are more than twice PG&E's. The additional penalty amount holds customers better accountable for event performance because the financial risk of non-performance is greater.

- In 2011, SCE will begin issuing a test event every year if an actual event is not called. Financially, test events will be treated as actual events and excess energy charges will be applied for non-performance. The addition of this guaranteed yearly event will expose customers to penalties at least once a year if they cannot perform to their Firm Service Level ("FSL") commitment.

- Since SCE plans to bid TOU-BIP into CAISO's wholesale market as RDRP starting in 2012, there is an anticipation of more frequent events making it more important for customers to ensure they can meet their load drop commitment in order to avoid excess energy charges.[86]

SCE makes valid arguments. If SCE can demonstrate that (1) it does not have noncompliant BIP participants, and (2) can solve the problem of noncompliant BIP participants through less costly means (e.g., high penalties for failure to perform), DRA agrees that PG&E's proposal referenced here may not need to be extended to SCE's BIP program.

Notwithstanding DRA's support of PG&E's screening mechanism, DRA recommends the Commission not approve PG&E and SDG&E's BIP programs unless the programs' cost structures are changed to improve the programs' cost-effectiveness to a TRC ratio above 1.0.

3.3. MEETING FUTURE NEEDS

4. PRICE RESPONSIVE PROGRAMS

4.1. COMPLIANCE

4.2. REASONABLENESS

---

[86] Ex. SCE-07, 35:16-36:7.

4.2.1. Capacity Bidding Program

The CBP is a statewide program where customers are paid a monthly reservation fee and an additional energy payment when the program is called. The program operates during the summer months of May through October. All three utilities have a CBP day-ahead ("CBP-DA") notification option and a CBP day-of ("CBP-DO") notification option.

Table 4-1 below presents the IOUs' budget requests, *ex ante* forecasted load impacts, and TRC Ratios for the CBP program for the 2012-2014 period.

Table 4-1: 2012-2014 CBP Comparison Across Utilities

	PG&E		**SCE**		**SDG&E**	
2012-2014 Budget (in millions)	$11.563[87]		$0.961[88]		$11.939[89]	
CBP notification option	CBP-DA	CBP-DO	CBP-DA	CBP-DO	CBP-DA	CBP-DO
2012-2014 *Ex ante* Forecasted Load Impact – Maximum value	25 MW[90]	30 MW[91]	2 MW[92]	21 MW[93]	11 MW[94]	26 MW[95]
TRC Ratio – E3's method[96]	0.73	1.11	0.28	0.31	0.69	0.65
A Factor – E3's method[97]	67%	67%	39%	39%	42%	42%

---

[87] Ex. PGE-1, tbl. 1-2, p. 1-18.

[88] Ex. SCE-5, p. 51, tbl. IV-21.

[89] Ex. SGE-1, pp. MFG-23, MFG-24, tbl. MG-2.

[90] Ex. PGE-5, p. 8, tbl. 8-5.

[91] *Id*.

[92] Ex. SCE-5, p.19, tbl. II-3.

[93] *Id*.

[94] Ex. SGE-13, p. LW\KS-12, tbl. KS-5.

[95] *Id*.

[96] Ex. PGE-18/Ex. SCE-08/Ex. SGE-12, Excel worksheet "CBP_DA, CBP_DO."

TRC Ratio – IOU method[98]	1.01	1.53	0.28	0.31	0.96	0.91
A Factor – IOU method[99]	97%	97%	39%	39%	60%	61%

4.2.1.1. Cost-Effectiveness

DRA is concerned about the very low TRC ratio of 0.73 for PG&E's CBP-DA program notification option. In addition, DRA is concerned about the very low TRC ratios of 0.69 and 0.65 for SDG&E's CBP-DA option and CBP-DO option, respectively. Also, DRA is troubled about the extremely low TRC ratios of 0.28 and 0.31 for SCE's CBP-DA option and CBP-DO option, respectively.

The availability factor ("A Factor") is the primary driver of the cost-effectiveness of this program. PG&E attributes an A Factor of 97 percent to CBP. In comparison, SCE and SDG&E allocate A Factors with maximum values of 39 percent and 61 percent, respectively. As discussed above in Section 2.1.2.12, PG&E's use of its internal LOLP study for its alternative DR analysis causes DRA to question the validity of its TRC ratio. In order to consistently and transparently analyze the cost-effectiveness results across the IOUs, DRA recommends the use of the A Factor analysis based on E3's suggested method, which uses 250 peak hours.

For the 2012-2014 program cycle, SCE proposes to change the program season from May 1 through October 31, to a year-round program. This modification will provide SCE with additional hours for available dispatch in the winter months. An update to the monthly capacity values will also be necessary, so that the annual avoided costs are spread across the twelve month period. In addition, business process and system modifications are necessary for the dispatch of new products and options on a year round basis. The DR template allocation of capacity value to months shows that the value of capacity to meet peak loads is negligible during the period November to April. Out of the 250 peak load hours in E3's Avoided Cost Calculator, not one hour falls during the months from November to April.[100]

---

[97] *Id.*

[98] Ex. PGE-19/Ex. SCE-08/Ex. SGE-8, Excel worksheet "CBP_DA, CBP_DO."

[99] *Id.*

[100] Ex. DRA-1/Ex. DRA-1c, p. 3-9, n. 110.

4.2.1.2. DRA Recommendation for CBP

DRA recommends the Commission reject all three utilities' CPB programs. These programs have very low cost-effectiveness ratios.[101] DRA recommends the Commission reject further funding for these programs, unless and until the utilities make any necessary changes to programs' cost structures to improve the cost-effectiveness to a TRC ratio above 1.0.

DRA asked PG&E in a data request to identify PG&E's budget request, for the 2012-2014 DR Application Cycle, for CBP-DA only. PG&E responded it does not budget CBP-DA and CBP-DO separately.[102] Therefore, DRA initially recommended in prepared testimony the Commission reduce PG&E's approved budget for CBP by half—$5,781,500.00—to account for the recommended rejection of PG&E's CBP-DA program.

In rebuttal testimony, PG&E acknowledges it did not separately forecast the cost of the CBP day-ahead and day-of options.[103] PG&E states,

> [T]o develop benefit-cost ratios for the day-ahead and day-of subprograms, it was necessary to ***arbitrarily*** split the total CBP costs into two subprograms. However, this distinction is unimportant for the purpose of analyzing CBP benefits, because aggregators who participate in the program may change their nominations from day-ahead or day-of on a monthly basis pursuant to the approved CBP rate schedule.[104]

PG&E split the CBP budget based on the number of customers participating in the day-ahead or day-of options. Unfortunately, this split of costs, between day-ahead and day-of, is different from the split of benefits, i.e., load impacts, of day-ahead and day-of. PG&E maintains that this approach "resulted in the inaccurate indication that the day-ahead option was less cost effective than the day-of option."[105]

DRA would like to point out that PG&E's CBP program as a whole, including the day-ahead and day-of options, is not cost-effective with a TRC ratio of 0.9, using E3's methodology

---

[101] DRA modifies its original recommendation to retain PG&E's CBP-DO program based on its rebuttal testimony, as discussed below.

[102] Ex. DRA-1/Ex. DRA-1c, p. 3-10, n. 3-10.

[103] Ex. PGE-8, p. 2-4, lns.16-18.

[104] *Id.*

[105] Ex. PGE-8, p.2-4, lns. 28-30.

for calculating the A-Factor.[106] Based on PG&E's rebuttal testimony, which indicates that PG&E's cost-benefit analysis approach for CBP-DA and CBP-DO "resulted in the inaccurate indication that the day-ahead option was less cost-effective than the day-of option," DRA contends that since the ***entire*** CBP program is not cost-effective, it must follow that CBP-DO and CBP-DA taken individually are also not cost-effective. Therefore, DRA recommends the Commission reject further funding for PG&E's CBP program as a whole, unless and until PG&E makes any necessary changes to programs' cost structures to improve the cost-effectiveness to a TRC ratio above 1.0.

With regard to DRA's proposed funding cuts, PG&E states in rebuttal testimony:

> First, the non-program-specific costs allocated to CBP—e.g., marketing, Evaluation, Measurement and Verification operations and Auto-DR—will still remain, whether or not there is a day-ahead option. Those non-program-specific costs will simply be reallocated to other DR programs. Second, if CBP's day-ahead option were eliminated and those customers joined CBP's day-of program, costs would increase because CBP's day-of program offers higher customer incentives…the entire proposed budget would still be warranted.[107]

PG&E's arguments should be rejected, based on the fact that PG&E's CBP program as a whole is not cost-effective with a TRC ratio of 0.9, using E3's methodology for calculating the A-Factor. DRA recommends the Commission reject further funding for PG&E CBP program as a whole, unless and until the utilities make any necessary changes to programs' cost structures to improve the cost-effectiveness to a TRC ratio above 1.0.

DR Aggregators state, "DR Aggregators have struggled with why these programs are showing such low TRC values. If customers do not perform in these programs, they do not get paid, and the penalties are significant." DR Aggregators suggest that the low TRC ratio is due to improperly allocating AutoDR SCE's failure to amortize the auto-DR costs allocated to CBP. But even when SCE recalculated its cost-effectiveness based on a ten-year amortization of Auto-DR incentives, the TRC ratios only go up slightly—to 0.36 and 0.39 for CBP-DA and CBP-DO,

---

[106] Ex. PGE-18, Excel Worksheet "Summary."

[107] Ex. PGE-8, p. 2-5, lns. 4-18.

respectively.[108] The Commission should deny the continuation of CBP, until the IOUs can demonstrate that the program can operate cost-effectively.

4.2.1.3. <u>**SDG&E's request for three-year guaranteed payment should be rejected.**</u>

SDG&E indicates aggregators spend considerable time and money up-front to acquire and integrate new customers, and it takes some time to recover these costs.[109] SDG&E suggests the certainty of any cash flow for aggregators diminishes toward the end of each DR cycle, because there is no certainty the programs will continue in the next cycle or that the capacity payment will remain at or above current levels.[110] Therefore, SDG&E proposes a guaranteed payment rate for a three-year period for the CBP and the CPP premium incentive mechanism from the date of signature. Under the SDG&E proposal, aggregators are guaranteed to receive the highest possible payments available to CBP, while ratepayers will not even have the benefit of known, stable CBP prices during the three-year contract term. Ratepayers will be obligated to paying the higher prices, if the Commission increases CBP incentives in the next DR cycle.

DRA opposes SDG&E's proposal, because it does not utilize limited ratepayer funds efficiently and effectively. Under the SDG&E proposal, aggregators are guaranteed the highest possible payments, while ratepayers will be paying the highest possible prices for DR resources. The Commission must ensure that any costs to ratepayers are minimized. The SDG&E proposal also circumvents the Commission's authority to order mid-cycle changes and eliminate non-cost effective programs. It will also encroach upon the Commission's review of these programs for the next DR cycle, as the three-year contracts signed during the last year (2014) of the current cycle could extend as far out as 2017. In addition, if large amounts of aggregator-provided DR are locked into contracts with LSEs with whom they should be competing, it will make direct participation of all DR in the CAISO's markets less likely and less competitive. DRA urges the Commission to reject SDG&E's proposal for guaranteed three-year payments to maintain a flexible DR portfolio.

---

[108] Ex. SCE-07, p. 14, Table III-4.

[109] Ex. SGE-1, pp. 11, 12.

[110] *Id.*

SDG&E's rebuttal indicates its proposal is necessary in order to address barriers to participation (e.g., the year-to-year nature of the current agreements and the hesitation that aggregators have when enroll new customers towards the end of the three year program cycle when future payment rates are not certain). SDG&E states,

> The confidence in the pricing addresses the customer and aggregator's uncertainty as well as helping ensure that there is commitment from both customers and aggregators that they will continue to in our demand response programs for the three year duration. This assurance will allow aggregators to focus on new customers as opposed to re-selling existing customers or risk a drop in enrollments at the end of the program cycle. By helping to assure participation for a solid three years, we feel this is an efficient use of funds.[111]

SDG&E's proposal to turn CBP into a 3-year contract is no different than PG&E's request to acquire long-term aggregator contracts which DRA opposed. Beyond the unfair pricing of CBP from ratepayers' point of view, these types of long-term commitments should not be made until Commission's direct participation rules are established.

4.3. MEETING FUTURE NEEDS

5. INDIVIUDAL UTILITY PROGRAMS

5.1. COMPLIANCE

5.2. REASONABLENESS

5.2.1. PG&E PeakChoice Program

Table 5-1 presents PG&E's budget requests, *ex ante* forecasted load impacts, and TRC ratios for the PeakChoice with Demand Bidding Program ("DBP") for the 2012-2014 period. PG&E has a PeakChoice Committed Load day-of notification option, PeakChoice Committed Load day-ahead notification option, PeakChoice Best Efforts day-of notification option, and PeakChoice Best-Efforts day-ahead notification option.

---

[111] Ex. SDG&E-6, p.

Table 5-1: 2012-2014 PG&E PeakChoice Program

PG&E	Peak Choice with DBP	Committed Load Day-Of Notification	Committed Load Day-Ahead Notification	Best Efforts Day-Of Notification	Best Efforts Day-Ahead Notification
2012-2014 Budget	$10.501 M[112]	-	-	-	-
2012-2014 *Ex ante* Forecasted Load Impact – Maximum value	39 MW[113]	22 MW[114]	6 MW[115]	3 MW[116]	8 MW[117]
TRC Ratio – E3's method[118]	0.40	0.34	0.39	0.50	0.47
A Factor – E3's method[119]	41%	41%	41%	41%	41%
TRC Ratio – IOU method[120]	0.70	0.66	0.73	0.93	0.89
A Factor – IOU method[121]	82%	82%	82%	82%	82%

PG&E's PeakChoice program offers features similar to the current stand-alone CBP and DBP programs, but also provides customers with the flexibility to tailor the program suitable to their needs. The two committed load options are similar to the options in the current statewide CBP program, except that in PeakChoice, the customers select program options for the entire summer season. The "Best Efforts" option is similar to the current statewide DBP program. PG&E proposes to merge its existing DBP program into the proposed PeakChoice program.

---

[112] Ex. PGE-1, tbl. 1-2, p. 1-18.

[113] Ex. PGE-5, p. 8, tbl. 8-5.

[114] *Id.*

[115] *Id.*

[116] *Id.*

[117] *Id.*

[118] Ex. PGE-18, Excel worksheets: "Summary," "PC_Commit_DO," "PC_Commit_DA," "PC_Best_DO," "PC_Best_DA.""

[119] *Id.*

[120] Ex. PGE-19, Excel worksheets: "Summary," "PC_Commit_DO," "PC_Commit_DA," "PC_Best_DO," "DBP_PC_Best_DA."

[121] *Id.*

DRA disagrees with PG&E's assumption that a high Availability (A factor) should be allocated to the PeakChoice program. Based on its internal LOLP analysis, PG&E attributes an A Factor of 82 percent to this DR program. As mentioned in Section 2.1.2.2 above, PG&E's LOLP analysis is a proprietary model; in order to consistently and transparently analyze the cost-effectiveness results across the three IOUs, DRA recommends the use of the A Factor analysis based on E3's suggested method, which uses 250 peak hours.

As shown above in Table 5-1, PG&E's PeakChoice with DBP has an extremely low TRC ratio of 0.4 using E3's method for calculating the A Factor. PeakChoice's four program options also show extremely low TRC ratios ranging from 0.34 to 0.50 based on the program option. Therefore, PeakChoice with DBP is not cost-effective. DRA recommends the Commission not approve PeakChoice until PG&E makes any necessary changes to programs' cost structure to improve the program's cost-effectiveness to a TRC ratio above 1.0. DRA also recommends the Commission not approve PeakChoice's Committed Load Day-of Notification, Committed Load Day-ahead Notification, Best-Efforts Day-of Notification and Best-Efforts Day-ahead Notification program options because of their extremely low benefit to cost ratios.

DBP as a stand-alone program may or may not be cost-effective, and DRA recommends the Commission require PG&E to resubmit cost-effectiveness results for DBP before considering the approval of DBP.

In rebuttal testimony, PG&E states PeakChoice is a core DR program designed to be integrated both with the CAISO market and with PG&E's internal dispatch systems. PG&E says, "This integration will provide more value for this DR program than is reflected in the simple cost-effectiveness analysis."[122] PG&E remains optimistic that the "MWs enrolled in each program may change over time as market conditions, technology, and customer behavior changes" as would the "cost-effectiveness analysis for the program over a period of years."[123] In defending its PeakChoice program—as well as its other DR programs with a TRC ratio below 1.0—PG&E states:

---

[122] Ex. PGE-8, p. 1-3, lns.13-17.

[123] Ex. PGE-8, p. 1-3, lns. 17-20.

> PG&E needs to have a portfolio of programs that cover the range of "unique and focused" opportunities in the DR spectrum to have a robust DR portfolio under changing conditions that can be flexible and bid as a resource in the CAISO Market Redesign and Technology Upgrade market. Removing a program that can in the future provide a valuable DR resource because it is not cost-effective under a disputable assumption in the default DR Reporting Template would be a poor policy decision. The cost of replacing the DR infrastructure lost by removing the programs is likely to be significant, particularly if the programs must be re-started in later years to meet growing load.[124]

PG&E's arguments should be rejected. PG&E's firm commitment to maintain a non-cost-effective program makes no fiscal sense in these cash-strapped times. This is a perfect example of the types of demand response programs that need to be eliminated after enough time and experience has passed to allow the Commission to determine whether a demand response program is deemed a success or failure. It would be unjust and unreasonable for the Commission to continue such an unsuccessful program, based only on the "hope" that it may provide some benefits in some unknown point in the future. In hearings, PG&E admits,

> Q At what point do you believe the Commission should discontinue a non-cost-effective program. Would it be three years?
>
> A I can't put a specific time frame on when the Commission should choose to discontinue a program. I think it depends on the other factors and what the energy policy goals of the Commission are.
>
> Q Do you think it's reasonable for the Commission to approve a non- cost-effective program […] for a program that is not cost-effective to run for a period of five years, say?
>
> A Yes, I do.[125]

Even with the consideration of other factors, it is difficult to justify this program is reasonable with such low cost-effectiveness results. PG&E claims that its PeakChoice program "is not cost-effective under a disputable assumption in the default DR Reporting Template." DRA would like to point out that PG&E's PeakChoice program is not cost-effective, with a TRC of 0.7, even

---

[124] Ex. PGE-8, p. 1-3, 1-4.

[125] 1 Tr. 28:19-24 (PG&E/Ho).

when using PG&E's own assumptions (PG&E's proprietary LOLP model) for calculating the A Factor.[126]

5.2.2. SCE Critical Peak Pricing

SCE's CPP rate consists of two program options, as follows:

1. **Large commercial, industrial, and agricultural customers with greater than or equal to 200 kW of demand** (CPP >= 200 kW): customers receive a discount on monthly on-peak demand charges during the summer months with an increase in energy charges when a CPP event is called.[127]
2. **Commercial, industrial, and agricultural customers with less than 200 kW of demand** (CPP < 200 kW): customers receive (a) credits to either their energy usage charges outside the CPP event period or to time related demand charges, depending on the underlying rate structure, and (b) increased energy charges during a CPP event period.[128]

SCE provides notification 24 hours in advance that the next day will be a critical peak event day, and on the day of the CPP event, for 4 to 6 peak load hours, electricity prices will be set at a fixed, predetermined level, often 5 to 10 times greater than the average per kWh price. CPP event days are intended to be called primarily under extreme heat conditions or when supply disruptions are anticipated.[129]

Table 5.2 presents the SCE's budget request, *ex ante* forecasted load impact, and TRC ratios for the CPP program for the 2012-2014 period.

Table 5-2: 2012-2014 SCE CPP Program

SCE	CPP
2012-2014 Budget	$10.301 M[130]
2012-2014 Ex ante Load Impact – Maximum value	222 MW[131]

[126] Ex. PGE-19, Excel Worksheet "Summary."

[127] Ex. SCE-03, p. 40.

[128] Ex. SCE-03, p. 45.

[129] Ex. DRA-01/Ex. DRA-1c, p. 3-14, n. 314; Robert Levin, Ph.D., *Time-Variant Pricing for California's Small Electric Consumers*, p. 16, dated May 2011.

[130] Ex. SCE-05, p. 51, tbl. IV-21, Total amount for CPP < 200 kW and CPP >= 200 kW combined.

[131] Ex. SCE-05, p. 19, Table II-3.

TRC Ratio – E3's method	0.35[132]
A Factor – E3's method	24%[133]

SCE cost-effectiveness analysis shows CPP is not cost-effective with an extremely low TRC ratio of 0.35. Still, SCE requests a total of $10.301 million for CPP for the 2012-2014 program cycle.

Because of the extremely low TRC ratio, DRA recommends the Commission reject this program at this time. In addition, as will be discussed below in Section 14.1.1 below, DRA urges the Commission to direct SCE and SDG&E, to the extent possible, to request all funding for dynamic pricing and rate-related programs in Phase 1 of their respective GRCs to determine the total revenue requirement for each program and assess whether the programs should be continued. If the funding consolidation cannot be done during the utilities' current GRC cycle, the funding consolidation should begin in the utilities' next GRC cycle.

With regard to CPP's low cost-benefit ratio, SCE makes no arguments in rebuttal to defend continuation of the program, other than the fact that irrespective of the program's abysmal TRC ratio, SCE's portfolio is, on a whole, cost-effective.[134] SCE states generally,

> An individual program's low cost-effectiveness does not necessarily mean that that the program does not add value to the portfolio. SCE believes, in order to fully evaluate the cost-effectiveness of a program, the result for each program, absent the portfolio cost-loading, should be considered. Using that approach, every SCE program adds value.[135]

As DRA illustrated above in Section 2.1.2.1.1, Table III-3 in SCE's rebuttal testimony is a modified cost-benefit analysis in an effort to demonstrate that all SCE DR programs are cost-effective. DRA reiterates that Table III-3 of SCE's rebuttal testimony is a major understatement of the actual costs of demand response programs and should be rejected.

---

[132] Ex. SCE-08, Excel worksheet "CPP."

[133] *Id.*

[134] Ex. SCE-07, p. 7.

[135] Ex. SCE-07, p. 10, lns 1-5.

The thrust of SCE's defense—that so long as the DR portfolio is cost-effective, the Commission should adopt even those DR programs that have a TRC ratio below 1.0—is also against established Commission policy. In D.08-03-017[136], the Commission affirmatively declared,

> [O]ur policy preference for moving toward a demand response goal of 5% system peak load leads us to look favorably upon a portfolio of cost-effective Contracts…However, we note that, as the load impact protocols and cost effectiveness measures become more developed, we intend to move away from approval of demand response programs based on a portfolio approach. The improvements to our demand response rules that are currently being developed in R.07-01-041 will add significant transparency to our overall program goals and evaluation of individual contracts and programs.

With load impact protocols and cost-effectiveness measures now in place, the Commission should be consistent in its policy goals established in D.08-03-017.

With regard to DRA's second recommendation, SCE's rebuttal argues that dynamic pricing rate to be consolidated into the GRC is untenable at this time.[137] SCE explains,

> If the Commission wishes to change where utilities seek recovery for these rates, it can direct us to do so in the future, but it is too late to do so in this DR funding cycle. Furthermore, CPP is a dynamic rate, but its roots were in DR before it became part of the Commission's dynamic pricing proceeding.

DRA agrees, to the extent that the Commission decides to continue the CPP program despite its 0.35 TRC ratio. However, the Commission should hold affirmatively that in all IOU's future requests for dynamic pricing program budgets, all dynamic pricing rates should be consolidated in the GRC Phase 1, as recommended by DRA. DRA fully responds to SCE's arguments in more detail at Section 14, below.

---

[136] *Order Approving Four Southern California Edison Company Demand Response Contracts* [D.08-03-017], issued March 19, 2008. This decision approved four of eight third-party aggregator contracts proposed by SCE, for 2009-2011.

[137] Ex. SCE-07, 2:14, 15.

5.2.3. SDG&E Programs

5.2.3.1. Small Customer Technology Deployment

SDG&E's Small Customer Technology Deployment ("SCTD") Program will offer automated DR enabling technologies at no cost for up to 15,000 participating SDG&E residential customers and as many as 3,000 small commercial customers (<100 kW). SDG&E proposes using Smart Meter interval data to identify, market to, and install load control devices in the homes of residential and small commercial businesses with significant air conditioning and residential customers with mid-day pool pump usage.[138]

The table below presents the SDG&E's budget request, ex ante forecasted load impact, and TRC ratios for the SCTD program for the 2012-2014 period.

Table 5-3: 2012-2014 SDG&E SCTD Program

SDGE	SCTD
2012-2014 Budget	$13.009 M[139]
2012-2014 Ex ante Load Impact – Maximum value	12 MW[140]
TRC Ratio – E3's method	0.62[141]
A Factor – E3's method	85%[142]
TRC Ratio – IOU method	0.64[143]
A Factor – IOU method	89%[144]

SDG&E shows SCTD is not cost-effective with a TRC ratio of 0.62 for the 2012-2014 program cycle. SCTD is not cost-effective (TRC Ratio of 0.64) even when SDG&E uses its alternative load based approach to calculate the A Factor.

---

138 Ex. SGE-5, p. GMK-50.

139 Ex. SGE-1, pp. MFG-23 – MFG-24, Table MG-2.

140 Ex. SGE-13, Table KS-5, p. LW\KS-12.

141 Ex. SGE-12, Excel worksheet "SCTD."

142 *Id.*

143 Ex. SGE-8, Excel worksheet labeled "SCTD."

144 *Id.*

SDG&E proposes filing an evaluation report and an SCTD implementation plan by Advice Letter for Commission review upon completion of the 2009 - 2011 Residential Automated Controls Technology ("RACT") pilot. Smart meter deployment delays have caused the start of this pilot to slip from 2010 to April 2011. Although, SDG&E requests approval of the SCTD program and budget with this filing, it cannot launch the SCTD program until its Advice Letter has been approved. SDG&E proposes limited spending prior to the approval of the Advice Letter to support the RACT pilot infrastructure and customers.[145]

DRA is concerned about the completion date of the RACT pilot, which is supposed to provide information for program design. Even after the completion of RACT pilot, DRA would like to examine the final design of SDG&E's SCTD program before the Commission approves the program. In addition, DRA recommends the Commission not approve SCTD until the program's cost structures are changed to improve the program's cost-effectiveness to a TRC ratio above 1.0.

SDG&E's rebuttal disagrees. SDG&E argues the SCTD program is designed to "kick start" the market for new consumer technology. While SDG&E admits that the program is not cost effective, it states:

> [I]t is our stance that this cannot be the only consideration. When considering new technology and the adoption curve needed for these enabling technologies we believe we are aptly placed to move the market forward. In the long term, as pricing for the technology comes down and consumer acceptance grows, the cost-effectiveness for these technologies will improve.

DRA disagrees. In a flush economy, it may be that risking ratepayer funds to "kick start" new technologies could be justified. This was the case in 2006 when the Commission ordered the three IOUs to explore a variety of innovative price-responsive demand response programs beyond the traditional emergency-triggered programs. In light of SDG&E's low TRC ratio for SCTD—under both the E3 *and* IOU method—it would be prudent for the Commission to reject $13.009 million budget requested for the SCTD program. Leveraging smart meter technology is not solely the utility's responsibility. In this situation, it may be that third-party aggregators can

[145] Ex. SGE-4, pp. GMK-51, GMK-52.

provide such services (if they are not already doing so) within SDG&E's territory at a much cheaper cost than what SDG&E proposes here. DRA recommends the Commission reject SCTD funding at this time.

5.2.3.2. Peak Time Rebate

SDG&E's PTR program provides customers who reduce load during PTR events an incentive in the form of a bill credit. PTR events can be called on a day-of basis to help address an emergency, but they are not the primary design or intended use of the program. SDG&E states,

> During a regularly-scheduled billing period, customers who reduce load during PTR events will receive a program incentive in the form of a bill credit. The PTR program is designed to leverage SDG&E's Smart Meter installation to encourage large scale customer participation in DR events. PTR is a two-level rebate program, providing a basic incentive level for customers that reduce energy use through manual means and a premium incentive for customers that reduce energy use through automated enabling technologies.[146]

The table below presents the SDG&E's budget request, *ex ante* forecasted load impact, and TRC ratios for the PTR program for the 2012-2014 period.

Table 5-4: 2012-2014 SDG&E PTR Program

SDGE	PTR
2012-2014 Budget	$4.353 M[147]
2012-2014 *Ex ante* Load Impact – Maximum value	71 MW[148]
TRC Ratio – E3's method	3.92[149]
A Factor – E3's method	88%[150]

[146] *Id.* at GMK-28.

[147] Ex. SGE-1, pp. MFG-23, MFG-24, tbl. MG-2.

[148] Ex. SGE-13, tbl. KS-5, p. LW\KS-12.

[149] Ex. SGE-12, Excel worksheet "PTR." TRC ratio does not reflect Energy Division's correction.

TRC Ratio – IOU method	4.09[151]
A Factor – IOU method	92%[152]

As shown above, SDG&E shows PTR is cost-effective with a TRC ratio of 3.92 for the 2012-2014 cycle. DRA questions the validity of the high cost-effectiveness result for PTR, because SDG&E did not include most of the costs that have been captured in prior proceedings for PTR. Energy Division requested that SDG&E include PTR in the CE calculations and portfolio. SDG&E explains:

> Originally SDG&E did not include the PTR program in its cost effectiveness calculations because most of the costs and approvals have been captured in prior proceedings. However, after conversations with the Energy Division it was requested that PTR be included in the CE calculations and portfolio. SDG&E realizes that by including the PTR program in its analysis that it gives an unrealistic picture of not only that program's cost effectiveness, but also the cost effectiveness of the overall portfolio. For this reason, SDG&E has also included an analysis without PTR in the testimony of Kevin C. McKinley (Page KCM-14).[153]

In addition, DRA agrees with Energy Division's ("ED") conclusion that SDG&E does not include the cost of bill credits paid out to customers "as *either* an incentive *or* a bill reduction in its calculations, but rather leaves it out entirely."[154] Based on this correction alone, ED estimates SDG&E's PTR TRC ratio will be reduced from 3.92 to either 1.96 or 1.97, depending on whether bill credits are considered incentives or bill reductions, respectively. Based on this major understatement of costs in SDG&E's PTR cost-effectiveness analysis, and in conjunction with SDG&E's own admission that "SDG&E realizes that by including the PTR program in its analysis that it gives an unrealistic picture of not only that program's cost effectiveness, but also

---

[150] *Id.*

[151] Ex. SGE-8, Excel worksheet "PTR." TRC ratio does not reflect Energy Division's correction.

[152] *Id.*

[153] Ex. DRA-1/Ex. DRA-1c, p. 3-19, n. 145.

[154] Administrative Law Judge's Ruling Requesting Comments on Applicants' Responses to Energy Division Data Requests, Appendix, p. 13.

the cost effectiveness of the overall portfolio," SDG&E's Demand Response Portfolio, without PTR in the analysis, is not cost-effective with a TRC ratio of 0.62.[155]

DRA recommends the Commission exclude PTR from SDG&E's Demand Response portfolio cost-effectiveness analysis. In addition, DRA recommends the Commission direct SDG&E's revenue requirements request for its PTR program to SDG&E's GRC Phase I proceeding.

5.3. MEETING FUTURE NEEDS

6. ENABLING TECHNOLOGIES (INCLUDING TA, TI, AUTO DR AND PLS)

6.1. COMPLIANCE

6.2. REASONABLENESS

6.3. MEETING FUTURE NEEDS

7. MARKETING, OUTREACH AND EDUCATION

7.1. COMPLIANCE

7.2. REASONABLENESS

7.3. MEETING FUTURE NEEDS

8. MEASUREMENT AND VERIFICATION

8.1. COMPLIANCE

8.2. REASONABLENESS

8.3. MEETING FUTURE NEEDS

9. PILOTS

9.1. COMPLIANCE

9.2. REASONABLENESS

9.3. MEETING FUTURE NEEDS

[155] Ex. SGE-12, Excel Worksheet "Summary."

10. PG&E'S CURRENT AGRREGATOR MANAGED PORTFOLIO (AMP)

10.1.1. **<u>PG&E's Request To Extend Aggregator Managed Portfolio Contracts Through 2012 Should Be Rejected.</u>**

The Commission, in PG&E's rebuttal testimony states,

> [E]xtending existing AMP contracts through 2012 is needed to prevent a "gap" in the DR portfolio arising from PG&E's current lack of authorization by the Commission to hold a new AMP solicitation to replace the existing AMP contracts and the inability for aggregators directly to participate in the CAISO market.[156]

The Commission should not be swayed by arguments of PG&E and the DR aggregators that such a "gap" exists. D.10-12-033, authorized PG&E to request a one-year extension of the aggregator managed portfolio ("AMP") contracts through 2012.[157] However, PG&E did not provide adequate justification of a need to support extending the AMP contracts through 2012.[158] Both the CAISO and the California Energy Commission ("CEC") are projecting projected high reserve margins for summer 2011. The high reserve margins are expected to remain through at least 2012. Therefore, DRA recommends the Commission reject PG&E's request to extend the expensive AMP contracts through 2012.[159]

As shown in Tables 10-1 and 10-2 below, the CAISO forecasts the operating reserve margins to be 20.8 percent for the ISO system as a whole, 17.0 percent for Southern California ("SP26") and 21.7 percent for Northern California ("NP26") under the normal peak demand scenario in 2011.[160] The normal peak demand scenario is defined as moderate net imports to the ISO system, 1-in-2 year generation and transmission outages, and 1-in-2 year peak demand. A 1-in-2 year event means the event has a probability of occurring once in two years, in other words, a 50 percent probability. Under an extreme peak demand scenario, operating reserve margins are projected to drop to 9.1 percent for the ISO system, 4.1 percent for SP26 and 5.8

---

[156] Ex. PGE-8, 2-2:31 – 2-3:4.

[157] D.10-12-033, p. 9.

[158] Ex. PGE-1, p. 2-27.

[159] Ex. DRA-1/Ex. DRA-1c, p. 2-21.

[160] Ex. DRA-1/Ex. DRA-1c , p. 1-21; CASIO, *2011 Summer Loads and Resource Assessment*, April 22, 2011, pp. 2-4.

percent for NP26. The extreme peak demand scenario is defined as low imports, 1-in-10 generation and transmission outages, and 1-in-10 peak demand. The probability of the extreme scenario is very low. The CAISO also forecasts that the expected probability of experiencing involuntary load curtailments because of low operating reserve margins in summer 2011 is extremely low at 0.8 percent for ISO system, 0.9 percent for SP26 and 0.9 percent for NP26, assuming moderate imports.

Table 10-1[161]

Summer 2011 Outlook - Normal Scenario 1-in-2 Demand, 1-in-2 Generation & Transmission Outage and Moderate Imports in Megawatts (MW)			
Resource Adequacy Conventions	ISO	SP26	NP26
Existing Generation	49,385	23,668	25,717
Retirements (Known/Expected)	0	0	0
High Probability CA Additions	214	141	73
Outages (1-in-2 Generation & Transmission)	-3,877	-1,687	-2,605
Moderate Net Interchange	9,700	9,200	2,100
Total Net Supply (MW)	55,422	31,322	25,285
DR & Interruptible Programs	2,357	1,655	702
Demand (1-in-2 Summer Temperature)	47,814	28,184	21,360
Operating Reserve Margin	**20.80%**	**17.00%**	**21.70%**

Table 10-2[162]

Summer 2011 Outlook - Extreme Scenario 1-in-10 Demand, 1-in-10 Generation & Transmission Outage and Low Imports in Megawatts (MW)			
Resource Adequacy Conventions	ISO	SP26	NP26
Existing Generation	49,385	23,668	25,717
Retirements (Known)	0	0	0
High Probability Generation Additions	214	141	73
High Outages (1-in-10 Generation & Transmission)	-5,454	-2,685	-3,431
Net Interchange	8,500	8,700	1,100
Total Net Supply (MW)	52,645	29,824	23,459

161 Ex. DRA-1/Ex. DRA-1c, p. 1-21, tbl. 1.

162 Ex. DRA-1/Ex. DRA-1c, p. 1-22, tbl. 2.

DR & Interruptible Programs	2,357	1,655	702
High Demand (1-in-10 Summer Temperature)	50,428	30,246	22,837
Operating Reserve Margin	**9.10%**	**4.10%**	**5.80%**

Note: The ISO projects that 49,599 MW of net qualifying capacity ("NQC") will be available for summer 2011, which is a 1,180 MW increase from June 1, 2010. The additional generation will help meet an increase of 687 MW load growth as California's economy modestly recovers from the recession.

As shown in Table 10-3 below, the CEC also forecasts that for the entire summer of 2011, the planning reserve margins for all regions under 1-in-2 weather conditions are expected to be higher than the target of 15 percent, with the lowest being 29 percent during August and highest being 46 percent during June.[163] Under 1-in-10 weather conditions, the CEC forecasts that the lowest planning reserve margin is 19 percent in August and highest planning reserve margin is 34 percent in June. These high reserve margins indicate there should be more-than-sufficient resources to cover broad range of system contingencies, such as unplanned facility outages or increased demand due to hotter-than-expected weather conditions.

Table 10-3
Statewide 2011 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation	61,359	61,450	61,314	60,979
2	Expected Retirements	0	0	0	0
3	Expected Additions	89	27	48	65
4	Net Imports	13,118	13,118	13,118	13,118
5	Total Net Generation	74,566	74,393	74,135	73,943
6	Demand Response / Interruptible / Curtailable Programs	2,811	3,054	2,946	2,982
7	Total Net Supply	77,377	77,446	77,081	76,925
8	1-in-2 Summer Demand	53,123	57,343	59,571	54,220
8a	**Reserve Margin (1-in-2 Demand)**	**46%**	**35%**	**29%**	**42%**
9	1-in-10 Summer Demand	57,579	62,163	64,527	58,800

[163] CEC, Summer 2011 Electricity Supply and Demand Outlook, April 2011, CEC-200-2011-004, p. 7.

9a	Reserve Margin (1-in-10 Demand)	34%	25%	19%	31%

Note: All capacities are dependable, not nameplate. Existing generation values for July, August and September incorporate expected additions from previous months.

In addition to the near-term outlook for 2011, the Commission, in D.07-12-052, determined that PG&E would have excess capacity until 2014.[164] The information in Table 4 below indicates PG&E will have a surplus of 1,179 MW based on a 15 percent planning reserve margin ("PRM") and a surplus of 754 MW based on a 17 percent PRM. Much has transpired since the 2006 LTPP concluded.[165] There has been a major and ongoing economic recession that has reduced demand for electricity. Also, additional procurement has resulted from PG&E's 2008 Long Term Request for Offers ("LTRFO") in A.09-04-001. Both these factors place PG&E in a position of capacity surplus for some time, leading DRA to conclude that the forecasted surplus in 2012 will remain and the aggregator contracts will not be needed in 2012. Therefore, DRA recommends the Commission reject PG&E's request to extend the AMP contracts through 2012. DRA also recommends the Commission only focus on reviewing future contracts after the final rules for DRP participation in the CAISO's wholesale market are finalized.

Table 10-4
PG&E Planning Reserve Forecast (MWs)

	2007	2008	2009	2010	2011	2012	2013
Planning Reserve	3,614	3,659	4,253	5,192	4,783	4,362	3,870
Planning Reserve (%)	18.2%	18.2%	20.9%	25.2%	22.9%	20.6%	18.0%
Lower Bound of Planning Reserve Requirement (15%)	2,977	3,014	3,055	3,095	3,139	3,183	3,227
Upper Bound of Planning Reserve Requirement (17%)	3,374	3,416	3,462	3,508	3,558	3,608	3,657
Surplus at 15% Planning Reserve Requirement	637	645	1,198	2,097	1,644	1,179	643
Surplus at 17% Planning Reserve Requirement	240	243	791	1,684	1,225	754	213

Source: Table PGE-1 on page 116 of D.07-12-052.

[164] D.07-12-052, tbl. PGE-1, p. 116.

[165] The 2008 LTPP did not result in a revised system needs assessment. The 2010 LTPP plan is currently being finalized in R.10-05-006.

DRA is also concerned about the cost and performance of PG&E's existing AMP contracts.

10.1.2. PG&E's AMP Contracts Have Not Performed Well Since Approval By The Commission.

DRA disagrees that "PG&E's AMP program have provided a reliable source of load reduction."[166] On the contrary, the performance levels have been dismal. And with a combined TRC ratio 0.49[167], the AMP portfolio should be reviewed with increased scrutiny.

As described in DRA's opening testimony, the performance of the AMP portfolio reveals that the weighted average performance of the contracts is within the band that would result in no incentive payments. DRA calculated the performance of every event PG&E called for each contract since the Commission approved the AMP contracts. A weighted average was calculated for each event type, which include actual, test, and retest events. Table 10-5 provides a detailed breakdown of the weighted average performance for each event type.

DRA's analysis revealed that only two of the thirty-nine events PG&E called were for actual events. The other thirty-seven events were test related. The weighted average performance of all events called was approximately 0.66 or 66 percent. Based on the AMP contract performance adjustments, an hourly delivery capacity ratio between 0.9 and 1.0 would result in full capacity payment, a ratio between 0.75 and 0.90 would result in 50 percent capacity payment, a ratio between 0.5 and 0.75 would result in zero capacity payment, and a ratio between 0 and 0.5 would result in a penalty based on the amount of capacity below 50 percent.[168] DRA's preferred scenario would be that a weighted performance of 66 percent should result in ***no*** incentive payments—or even penalties—as would be the case in a reasonable performance-based incentive/penalty structure. However, under the current incentive and penalty structure, DRA calculated that the AMP contracts are expected to cost ratepayers millions of dollars[169] for the duration of the contracts from 2007-2011. PG&E's DR Reporting Template estimates the

---

[166] Ex. PGE-8, p. 2-3:8-9.

[167] Ex. PGE-18.

[168] Ex. DRA-1/Ex. DRA-1c, p. 1-24, ln. 16 – p. 1-25, ln. 4.

[169] *See* Ex. DRA-1c, 1-25:8 for DRA's estimated figure.

cost for incentives will exceed $15 million, if the AMP contracts are extended through 2012. DRA urges the Commission to reject PG&E's request to extend the AMP contracts. As a matter of policy, should the Commission direct the utilities to seek additional AMP contracts in a RFP, the Commission should require that the contracts solicited in the RFP contain reasonable performance-based incentive structure, so that ratepayers are ensured that the aggregators will deliver the contracted capacity.

Table 10-5

PG&E Aggregator Managed Portfolio Contract Performance		
EVENT TYPE	Number of Events	Weighted Average Performance
Actual Event	2	76.05%
Test Event	22	65.07%
Retest Event	15	66.10%
Total Events	**39**	**66.03%**

Source: PG&E Data Response to DRA data request No. DRA_001-03.

In rebuttal testimony, PG&E admits, "while a few AMP contracts did not perform as well as anticipated, especially in the earlier years, the aggregators have improved their performance and the program as a whole performs well and cost-effectively."[170] PG&E argues,

> Taken in aggregate, the data demonstrate that after some initial growing pains (2008), the aggregators have shown that they are capable of delivering their contractual obligations, particularly under conditions similar to those used for cost-effectiveness analysis. Thus, the AMP contracts are demonstrably successful and cost-effective. DRA's assertions as to underperformance are not indicative of the current program conditions and their suggestion to eliminate an effective DR resource is simply wrong.[171]

Although as PG&E contends the AMP contracts may have improved their performance somewhat, the aggregators have not had sufficient track record to show that the AMP contracts' weighted average performance climbed from the 66 percent (shown in Table 10-5) in the past to more than 90 percent required to justify the full contract payment. Additionally, the aggregators'

---

[170] Ex. PGE-8, p. 8-5, ln. 32 – p. 8-6, ln. 2.

[171] Ex. PGE-8, p. 8-7, lns. 9-17.

AMP contract obligation to perform is not dependent on the weather conditions during the events as PG&E seems to suggest. The aggregators are required to provide reduction in the amount of contracted capacity whether or not the weather conditions when called to perform match that of 1-in-2 or 1-in-10 weather scenarios used in the cost-effectiveness analysis. Certainly, the contract payment rates ratepayers are obligated to pay to the aggregators do not change based on the weather conditions encountered during the events. The Commission should continue to monitor AMP contract performance over the long-term before accepting PG&E's contention that the aggregators have shown that they are capable of delivering their contractual obligations.

10.1.3. Ratepayers Will Have To Pay A Price Premium To Extend ONE CONTRACT

DRA's analysis also found that ratepayers will have to pay a hefty premium to extend one of the AMP contracts through 2012. Under the agreement, PG&E could have, at its sole option, extended the term of the agreement for an additional five years, from 2012 through 2016, by providing written notice of its intent to extend the agreement no later than October 31, 2010.[172] The aggregator was offering a capacity price for 2012-2016 that is significantly lower[173] than the capacity price for 2007-2011, as shown in Table 6 of Confidential Exhibit DRA-1c, which is attached to this opening brief in Confidential Appendix A.[174] Under the PG&E amendment proposing to extend the agreement through 2012,[175] the contract price will be at the same high level as the current contract. DRA believes the lower contract price offer for the extension of the contract better reflects the value of the contract under the current market conditions for short-term (one-year) contract extensions PG&E is requesting for all of its AMP contracts. In DRA's view, ratepayers will be paying an excessive and unnecessary premium for such contract extensions. Therefore, DRA urges the Commission to reject PG&E's request to extend the AMP contracts through 2012.

---

[172] Ex. DRA-1/Ex. DRA-1c, n. 58.

[173] *See* Confidential Attachment A to this brief.

[174] Ex. DRA-1c, p. 26.

[175] Ex. DRA-1/Ex. DRA-1c, n. 59.

PG&E's rebuttal testimony does not offer any specific comments on the one proposed extension contract's price premium, other than to mention the fact that, in general, the contract extension "would provide an opportunity for current aggregators to continue to participate in the California DR market while the third-party participation rules are being developed and the new AMP solicitation is issued."[176] In support of the extension, PG&E's rebuttal further claims,

> In fact, the AMP program as a whole performs well and is cost-effective with a benefit cost ratio of 1.2 applying the total resource cost test[177]

PG&E's arguments should be dismissed. The 1.2 TRC ratio is based on PG&E's LOLP method. Using E3's method, their AMP TRC ratio is only 0.49. As discussed above, with regard to PG&E's use of an internal LOLP study, PG&E's higher TRC ratio cannot be independently verified since it is not based on any transparent methodology. PG&E's use of LOPL methodology is completely inconsistent with the requirement that, "should an LSE provide an LOLE/LOLP model that can be ***shared in the public domain***, along with ***sufficient documentation*** of their deviation to allow them to be ***verified independently***."[178]

Not only would the transparent approach using the E3's methodology be consistent with the DR Cost-Effectiveness Protocols, it would be consistent with established Commission precedent. In D.07-10-013, where the Commission adopted four of eight third-party aggregator contracts proposed by SCE, the Commission affirmatively states,

> …as the load impact protocols and cost effectiveness measures become more developed, ***we intend to move away from approval of demand response based on a portfolio approach.*** The improvements to our demand response rules that are currently being developed in R.07-01-041 ***will add significant transparency*** to our overall program goals and evaluation of individual contracts and programs.[179]

Here, in addition to the transparency requirement, the Commission also makes it clear that it would not be appropriate to continue to rely on cost-effectiveness at the portfolio level once the

---

[176] Ex. PG&E-8, p. 2-2, lns. 21-25.

[177] Ex. PGE-8, p. 2-3, lns. 12-14.

[178] Ex. DRA-3, p. 23.

[179] D.07-10-013, p. 14.

DR protocols have been adopted. As a result, the Commission rejected four contracts since they were not cost-effective on an individual basis.[180] Furthermore, in D.10-03-007, the Commission denied the expansion of a contract between PG&E and Energy Curtailment Services ("ECS") because "the cost-effectiveness of the request is not clear."[181] Clearly, the Commission expects the cost-effectiveness test must be met by each individual contract, rather than PG&E's approach of relying on cost-effectiveness of the whole portfolio.[182]

In the instant case, PG&E declined to analyze the cost-effectiveness of each individual contract, contrary to the approach in D.07-10-013 when the Commission reviewed the cost-benefit ratios on each of the eight proposed third-party aggregator contracts with SCE. Instead, PG&E chose to present cost-effectiveness at the portfolio level[183] in order to justify approval of the AMP program. On this basis alone, the Commission should deny extension of the contracts for the failure to provide individual cost-effectiveness analyses of each contract. At the portfolio level,the portfolio level TRC ratio for the AMP contracts using the E3's methodology is only 0.49. This is the only transparent methodology the Commission can rely on. Thus, the AMP contracts, both on the individual basis and portfolio basis, are not cost-effective, and should ***not*** be extended through 2012 as requested by PG&E. In view of the high reserve margins expected in the short term the Commission should deny approval of all contract extension requests in the AMP portfolio.

11. FORWARD LOOKING ISSUES

11.1. INTEGRATION WITH STATE CALIFORNIA ENERGY POLICIES

---

[180] *Id.* at p. 28.

[181] Decision Denying Petition for Modification of Decision 07-05-029 and Rejecting Expansion of An Existing Demand Response Contract [D.10-03-007], p. 1.

[182] *See* D.07-05-029, p. 15, where the Commission states, "The Commission states, "Because the updated benefit-to-cost ratios provided by PG&E in its response to DRA comments on the Petition are not accompanied by any details or analysis, it is not clear whether they utilize a methodology and assumptions consistent with those used in D.09-08-027."

[183] 1 Tr. 110:8-11 (PG&E/Alexander).

11.1.1. Funding For The DR Portion Of IDSM Activities Should Only Be Approved For 2012, And All Future Funding For IDSM Activities Should Be Requested In EE Applications.

The utilities receive funding for IDSM activities through both the EE and DR decisions. D.09-08-027 in the DR proceeding A.08-06-001, approved DR funds for integrated activities through 2011,[184] while D.09-09-047 in the EE proceeding A.08-07-021, approved EE funds for integrated activities through 2012.[185] On August 27, 2010, an *ALJ Ruling Providing Guidance for the 2012-2014 Demand Response Applications* was issued, directing the IOUs "to align the DR and EE funding years for IDSM activities, and to consolidate the Commission's review of these integrated activities in one proceeding.[186] The ALJ Ruling also directed the utilities to include in the 2012-2014 DR applications, a request for continued authority and funding for, the DR portion of existing IDSM activities for one year, 2012.[187] Future authority and funding for IDSM activities will be considered in the EE proceeding R.09-11-014, starting with the EE applications for the 2013-2015 program and budget cycle.

On December 23, 2010, an Assigned Commissioner Ruling Regarding 2010-2012 Energy Efficiency Program Cycle was issued. That ruling extended the 2010-2012 EE program through at least 2013.[188] Subsequently, an ALJ Ruling Regarding 2013 Bridge Funding and Mechanics of Portfolio Extension was issued on May 27, 2011. It seeks comments on the Energy Division's White Paper on bridge year funding and the schedule set forth in R.09-11-014.[189] As a result, the utilities will have to continue to request authority and funding for the EE portion of existing IDSM activities after 2012. Therefore, it makes sense to combine all DR and EE funding requests for IDSM activities after 2012 for a more complete review by the Commission.

---

[184] D.09-08-027, pp. 198-203.

[185] D.09-09-047, pp. 208-213.

[186] ALJ Ruling Providing Guidance for the 2012-2014 Demand Response Applications, dated August 27, 2010, p. 14.

[187] *Id.* at 14.

[188] Assigned Commissioner's Ruling Regarding 2010-2012 Energy Efficiency Program Cycle in R.09-11-014, December 23, 2010.

[189] ALJ Ruling Regarding 2013 Bridge Funding and Mechanics of Portfolio Extension in R.09-11-014, May 27, 2011.

PG&E requests bridge funding for both 2012 ($7.329 million) and 2013 ($7.343 million) to avoid a funding gap in 2013.[190] PG&E only requests funding for the DR portion of IDSM activities since funding for the EE portion of the integrated activities is already approved for 2012. PG&E indicates it will request bridge funding for the EE portion of integrated activities for 2013 in a future EE bridge funding request due to the delay of the EE proceeding by at least one year.

SCE requests two years of bridge funding, for 2012 ($9.539 million) and 2013 ($9.007 million), for the DR portion of IDSM activities in the 2012-2014 DR application.[191] SCE indicates future requests for IDSM programs and budget will be submitted in the next EE proceeding, which may occur in 2014 or 2015. SCE will most likely request bridge funding for the EE portion of IDSM activities after 2012 in future EE proceedings.

SDG&E only requests funding to cover the DR portion of the IDSM budget in 2012 ($4.919 million).[192] SDG&E will request the appropriate DR IDSM funds through the EE proceeding when the Commission makes its final decision regarding the extension period for the EE cycle. This could ensure that the program funding period is consistent, and the DR IDSM components are consistent with their corresponding EE IDSM programs in the event the Commission directs mid-cycle program changes.

Despite the EE program cycle extension, the IOUs will be required to request continued authority and funding for the EE portion of existing IDSM activities after 2012. The gap in the DR and EE IDSM funding periods will remain until the Commission consolidates the review of IDSM activities in one proceeding. DRA recommends the Commission only approve funding for the DR portion of IDSM activities for 2012 and direct the IOUs to request future DR IDSM funds through the 2013-2015 program and budget cycle in the EE proceeding. This will also allow the Commission to better evaluate the costs associated with IDSM activities to prevent duplicate funding for the same activity, and help to ensure ratepayers receive the greatest

---

[190] Ex. PGE-1, p. 2-2.

[191] Ex. SCE-04, p.1.

[192] Ex. SGE-3, p. 4.

benefits from their investments. The following are DRA's recommendation for funding for IDSM activities:

1. Reject PG&E's request for $7.343 million to fund the DR portion of IDSM activities in 2013.
2. Reject SCE's request for $9.007 million to fund the DR portion of IDSM activities in 2013.
3. Direct PG&E, SCE and SDG&E to request continued authority and funding for all IDSM activities in the EE proceeding R.09-11-014 starting in 2013.

PG&E's rebuttal testimony complains that the May 27, 2011 ALJ Ruling regarding the 2013 Bridge Funding Mechanics of Portfolio Extension was "issued months after PG&E submitted its DR application testimony."[193] PG&E also states resubmitting the request in the EE proceeding would be "duplicative."[194] SCE, in rebuttal, only indicates the IDSM bridge funding is "reasonable and necessary to continue these important activities until they can be fully integrated with the next EE funding cycle that will begin either in 2014 or 2015"[195] without explanation. SDG&E did not offer rebuttal testimony on this topic.

In hearings, SCE offered into evidence an email from Energy Division recommending the three IOUs seek 2013 IDSM funding in the 2012-2014 Demand Response Cycle.[196] This email should be disregarded and not be considered an adequate basis on which to approve the requested IDSM funding in the instant application. While Energy Division often provides guidance to the utilities (e.g., Energy Division's Guidance to SDG&E, SCE and PG&E on DR Cost Effectiveness Protocol Templates[197]), this document does not carry the same force as a publicly noticed document that is formally issued by the assigned ALJ, Commissioner, or the Commission itself. In order to best determine DR and EE *integrated funding* requests, it makes sense to have these requests considered in the same proceeding, as was originally envisioned in

---

[193] Ex. PGE-8, p. 6-2, lns. 19-22.

[194] Ex. PGE-8, p. 6-2, lns. 22-27.

[195] Ex. SCE-07, p. 20, lns. 13-15.

[196] Ex. SCE-24.

[197] Ex. PGE-11.

the August 27, 2010 ALJ Ruling Providing Guidance for the 2012-2014 Demand Response Applications.

Consolidated review allows the Commission and other interested parties to consider these separate IDSM funding requests as a whole, as the Commission originally intended. Other than the hassle of having to resubmit its request in the EE proceeding, the IOUs offer no compelling reasons to have these requests moved to that proceeding. Thus, the Commission should reject the IOU's request for bridge funding for 2013, and direct the utilities to submit these requests pursuant to the schedule outlined in the May 27, 2011 *ALJ Ruling Regarding 2013 Bridge Funding and Mechanics of Portfolio Extension.*

11.1.2. Resource Adequacy Proposed Decision And Potential Impact On The Instant Applications

On August 9, 2011, ALJ Gamson issued a Proposed Decision (PD) in Rulemaking 09-10-032, which further refines the Resource Adequacy ("RA") rules for demand response resources adopted in D.11-06-022. While a proposed decision has no force since the Commission did not yet adopt it, it still merits discussion in the instant case, because of the potential impacts on the current demand response applications. The PD adopts the following changes to the current RA rules for demand response resources[198]:

1. A demand response resource may receive local RA credit only if it is capable of being dispatched by local area. This requirement goes into effect in 2013.
2. Creation of a new Maximum Cumulative Capacity bucket for demand response resources for 2013.
3. Fossil-fueled emergency back-up generation resources will not be permitted to receive system or local RA credit as demand response resources.

Two of the changes adopted in the PD, specifically 1 and 3 above, if adopted in the final decision, could have a significant impact on the outcome of the IOUs' 2012-2014 DR program applications currently being litigated before the Commission. With respect to the local dispatchability requirement, DRA believes that, at a minimum, the following issues need to be addressed for the programs and budgets for 2012-2014:

---

[198] PD, p.2.

- The IOUs need to update their cost estimates for the programs to reflect any additional costs necessary to achieve the local dispatchability requirement specified in the new RA rules;

- The IOUs need to identify programs that cannot be modified to achieve the local dispatchability requirement specified in the new RA rules.

- The Commission needs to provide additional direction whether all DR programs, except perhaps the dynamic pricing programs normally addressed in separate rate design proceedings, must qualify for RA under the new RA rules

- The Commission needs to provide additional direction whether there should be a lower compensation structure for programs that do not qualify for RA under the new RA rules.

- What would be the impact of additional costs of meeting new RA counting requirement on the programs' cost effectiveness?

With respect to the prohibition of back-up generation resources receiving system or local RA credit as demand response resources, DRA believes that, at a minimum, the following issues need to be addressed in the 2012-2014 DR program and budgets:

- Who would be responsible for verifying that demand response participants enrolled in any DR programs (whether directly in the IOU programs or through third-party aggregators) are not using back-up generation resources to provide the load reduction?
- How many demand response participants, if any, would drop out of the programs because they cannot provide the estimated demand reduction without the use of back-up generation resources?
- If substantial number of customers drop out of the programs because they cannot meet the PD's requirement, how would that impact the IOUs' ex-ante load reduction forecast?
- What would be the impact of such dropping out on the programs' cost effectiveness?

It is clear that the IOUs would need to modify their DR programs to meet the PD's new RA rules. The PD notes that PG&E contends that "it would be impossible to modify all of its demand response programs by 20112 so that the programs would all be dispatchable by local capacity area".[199] The PD also notes that SCE claims that the PD's requirement "is not cost-

[199] PD, p.6.

effective and difficult to implement."[200] The PD anticipates the design and operational modifications to DR programs, as well as the cost and timing of the modifications that are necessary, will be considered in the IOUs' 2012-2014 DR program applications.[201] The PD delays the implementation of new RA rules by one year until the 2013 RA compliance year to provide sufficient time for any necessary modifications to IOUs' DR programs.[202] However, the timing of the PD and that of a final decision expected to be issued in about 30 days from the date of the PD, is not aligned with the adopted schedule for rendering a decision in IOUs' 2012-2014 DR program applications. The current schedule for IOUs' 2012-2014 DR program applications does not afford consideration of new RA rules in the PD in the evaluation of current IOU DR program proposals, nor does it afford to create a record for any required changes necessary to comply with the new rules.

If the Commission issues a decision in the IOUs' 2012-2014 DR program applications without fully exploring the local RA requirements in the PD, ratepayers would be stuck with new programs that do not qualify for local RA. Should the PD be adopted, DRA recommends the Commission consider a revised schedule for a final decision in IOUs' 2012-2014 DR program applications with the provision of "bridge funding" for a few months, if necessary. The revised schedule should permit parties to comment on the impact that the final decision has on the current DR applications.

11.2. INTEGRATION WITH CAISO MARKETS

(*See* Dual Participation discussion, in Section 2.2, above.)

11.3. DEMAND RESPONSE MARKET COMPETITION

11.4. FUTURE AMP CONTRACTS

---

[200] *Id*

[201] PD, pp. 8-9.

[202] *Id*, p.8.

11.4.1. The Commission Should Only Consider New Contracts After Approving Final Rules For Direct Participation.

The Commission has signaled that it expects third-party aggregators to participate directly in the wholesale market and that it is focused on facilitating the development of that market before approving new contracts.[203] The final rules for DRP participation in the CAISO's wholesale market are currently being developed in R.07-01-041, but the schedule for the full implementation and integration of DR programs is uncertain at this point.[204] DRA urges the Commission to wait until the final rules for DRP participation are adopted before considering the approval of new contracts. This will ensure that third-party aggregator contracts will not reduce DRP's direct participation in the CAISO's wholesale market. This will also ensure limited ratepayer funding is spent efficiently and effectively.

PG&E's rebuttal states that the proposed amendments to the AMP contracts for the program year 2012 would provide an opportunity for current aggregators to continue to participate in the California DR market while the third-party participation rules are being developed and the new AMP solicitation is issued.[205] PG&E argues it will provide time for PG&E to experience bidding Proxy Demand Resource ("PDR") into the CAISO markets prior to developing any new AMP contracts.[206] PG&E further states,

> Dismantling an otherwise effective resource, either temporarily or permanently, would undo years of effort, waste ratepayer and participating customer resources, and result in the loss of approximately 189 megawatts (MW) of reliable DR in 2012[207]

DRA disagrees. Although the new contracts will be an opportunity for current aggregators to continue to participate and earn substantial revenue in the California's DR market, approving such contracts in the current surplus capacity situation exposes ratepayers to substantial financial risk of paying for unneeded capacity. If the new contracts are not consistent

---

[203] D.09-08-027, pp. 116-119, FOF 35, p. 228; D.10-12-033, p. 9, FOF 16-17, pp. 13-14.

[204] Assigned Commissioner's Ruling Amending Scoping Memo in R.07-01-041, May 9, 2011, pp. 3-4.

[205] Ex. PGE-8, p. 2-2, lns. 21-25.

[206] Ex. PGE-8, p. 2-3, lns. 5-7.

[207] Ex. PGE-8, p. 2-3, lns. 15-18

with the final third-party direct participation rules in the CAISO markets it would add another layer of unnecessary expense to ratepayers. Furthermore, locking hundreds of megawatts of DR customer potential in bi-lateral contracts with PG&E would reduce competition between different DR providers in the CAISO markets. The TRC ratio of the current AMP contracts using E3's method, is only 0.49. If such a low cost-effectiveness is an indication of what is to be expected from future AMP contracts, AMP contracts do not hold the promise of a cost-effective DR resource. DRA recommends the Commission wait at least until the direct participation rules are adopted before allowing PG&E to issue a new RFP for AMP contracts.

DRA also is skeptical of PG&E's confidence that the AMP program will continue to deliver reliable capacity, and its claim that the current program is cost-effective with a benefit cost ratio of 1.2 applying the Total Resource Cost test[208] As explained above, this high TRC ratio should be disregarded, as it is based on unreliable information that cannot be independently verified as PG&E used their own proprietary LOLE/LOLP models to derive this 1.2 TRC ratio. DRA recommends the Commission consider on the TRC ratio 0.49, using the E3's DR Template, as a more reliable indicator of AMP contracts' cost-effectiveness.

12. FUND SHIFTING RULES

12.1.1. New Fund Shifting Rules Must Be Adopted In Response To Reduction In Number Of Budget Categories.

DRA is concerned about the IOUs' proposal to reduce the current ten budget categories specified in D.09-08-027 to six budget categories, without modifying the corresponding fund shifting rules established for the ten budget categories. Reducing the number of budget categories without updating the fund shifting rules may result in certain problematic fund shifting actions that Commission's original fund shifting rules intended to prevent.

For example, the Commission, in D.09-08-027, acknowledged that providing the utilities with broad authority to shift funds among programs without prior notification or approval by the Commission undermines the regulatory process adopted.[209] This prevents utilities from circumventing rules that have been established to ensure deliberation. The Commission also

---

[208] Ex. PGE-8, p. 2-3, lns. 12-14.

[209] D.09-08-027, pp. 211-214, 244.

acknowledged that the DR program budgets become meaningless, if large portions can be shifted to different programs or budget categories.[210] Major changes to the relative funding of specific programs should be subject to thorough review and party comment. The Commission adopted the following rules for fund shifting in 2009-2011:

- The utilities may shift up to 50 percent of a program's funds to another program within the same budget category. The utilities shall document the amount of, and reason for, each shift in their monthly demand response reports. The utilities may file a Tier 2 advice letter to request elimination of a program. No program may be vacated and, thereby, eliminated through multiple fund shifting events or for any other reason without prior authorization from the Commission.
- The utilities shall file a Tier 2 advice letter to request authorization to shift more than 50 percent of a program's funds to a different program within the same budget category. If a shift of more than 50 percent of a program's funds is proposed as part of the implementation of a new program within the same budget category, the utility shall include the proposed fund shift in its application for approval for the new program.
- The utilities shall not shift funds among the ten program categories.

PG&E proposes to reduce the ten budget categories specified in D.09-08-027 to six categories in order to provide flexibility between programs that are designed to meet similar goals, and to respond to any shifts in customer enrollment in various programs that occur during the 2012-2014 period.[211] PG&E also proposes to retain the existing fund shifting rules approved in D.09-08-027, including the flexibility to reallocate up to 50 percent of authorized budget funds between programs within each budget category without prior Commission authorization for the 2012-2014 program cycle.

SCE proposes to reduce the ten budget categories specified in D.09-08-027 to six categories.[212] SCE indicates the category consolidations would allow it to more effectively manage, develop, and evolve its DR programs and concentrate on creating more price-responsive programs that may be integrated into the wholesale market. SCE claims that the current category structure does not afford it the flexibility to transition its reliability programs into price-responsive programs, and causes additional difficulties and delays in achieving and

---

[210] Id.

[211] Ex. PGE-1, p. 10-3.

[212] Ex. SCE-05, pp. 49, 50.

implementing changes to DR programs. To ensure consistency and prevent undesired changes to the utility's DR program, SCE recommends continuation of current regulatory guidelines for fund shifting.

SDG&E does not believe the fund shifting rules approved in D.09-08-027 provide sufficient flexibility to modify budgets to react to, enhance, and improve DR programs.[213] In order to achieve the maximum flexibility and benefit of budget fund-shifting, to help maintain a vibrant and flexible DR program portfolio, and minimize the burden and time delays of more frequent Advice Letter requests to the Commission, SDG&E proposes that the budget categories adopted for the 2012-2014 program cycle be reduced from the current ten program categories to a more manageable and flexible six.

The utilities' proposals essentially: (1) consolidate emergency programs, price responsive programs, and DR service provider managed programs into a single category consisting of all DR programs; (2) consolidate all DR enabling programs, pilots, and DR integration policy and planning programs into a single category; and (3) consolidate integrated DR enabling programs, flex alert programs, and other integrated programs into a single category consisting of all integrated programs.

The Commission currently does not permit fund shifting between emergency-response and price-responsive DR programs. The utilities are in the process of transitioning existing, non-emergency DR programs into PDR products and emergency-based DR programs into RDRP products that can be bid directly into the CAISO's wholesale electricity market. Therefore, all DR programs are expected to be price-responsive programs in the future. However, under the emergency DR OIR Phase 3 settlement, the transition of emergency-based DR programs to RDRP will not be completed until the end of 2014. The settlement also provides utility-specific megawatt caps for RDRP programs that can count for RA. Mixing emergency-based DR program funds with other programs could create gaming opportunities by enrolling emergency-DR program customers in other price-responsive energy programs to avoid RA counting caps and, in general, Phase 3 OIR implementation less transparent. In addition, although RDRP could be viewed technically as a price-responsive product, in reality, it will be called only when the

---

[213] Ex. SGE-1, pp. 12-15.

CAISO is very close to an emergency. Therefore, RDRP programs are much less price-responsive than PDR programs. DRA recommends the Commission continue to disallow fund shifting between emergency and non-emergency based programs to transition away from emergency-based programs, and to help create more price-responsive programs that may be integrated into the CAISO's wholesale market. This will also help to ensure ratepayer-funded DR resources provide the greatest benefits to ratepayers. DRA recommends the Commission either place PDR product programs and RDRP product programs under separate categories, or creating a new fund shifting rule to disallow fund shifting between PDR product and RDRP product programs.

DRA believes it may be possible to group similar type programs under the same budget category, if additional fund shifting rules are adopted and existing fund shifting rules are enhanced. The utilities are currently required to file a Tier 2 advice letter to request authorization to shift more than 50 percent of a program's fund to another program within the same budget category. DRA recommends that the Commission extend the requirement to file a Tier 2 advice letter for authorization to increase individual DR program budget by more than 50 percent of its original budget through fund shifting. This would allow the Commission to closely monitor the budget growth of individual DR programs, and to limit the amount of fund shifting to non-cost-effective DR programs. Ratepayer funds are limited and should be spent wisely. Without adequate oversight, ratepayers funding may not be spent effectively and efficiently. Thus, any major changes to the relative funding of specific programs should be subject to thorough review and party comment to ensure ratepayers receive the highest possible return on their investments. This will also help to safeguard the integrity of Commission-approved DR budgets without undermining the DR application process.

For these reasons, DRA recommends the Commission reject the IOUs' request to consolidate the budget categories, unless new fund shifting rules are established and existing fund shifting rules are enhanced, to preserve the integrity of Commission approved DR budget, without undermining the DR application process.

13. APPROVED BUDGETS AND AUTHORIZED EXPENSES

14. REVENUE REQUIREMENT AND COST RECOVERY

14.1.1. Funding For Dynamic Pricing And Rate-Related Programs Should Be Requested In Phase 1 Of The General Rate Case.

Advanced metering infrastructure ("AMI") enabled programs, such as Peak Time Rebates ("PTR"), and dynamic pricing programs,[214] such as real time pricing ("RTP") and CPP, were authorized in Commission proceedings outside the DR applications. In addition, the utilities continue to receive funding to maintain and operate these programs in various proceedings. However, the May 13, 2011 Scoping Memo indicated that this proceeding will focus on price responsive DR, not dynamic rates.[215] DRA urges the Commission to consolidate all revenue requirement cost recovery requests for dynamic pricing and rate-related programs into a single proceeding, specifically, Phase 1 of each utility's General Rate Case ("GRC"), to simplify the review process for determining the revenue requirement for each program. This is consistent with the Commission's decision to consolidate all IDSM activities funding into a single proceeding for a more thorough review process. This is also consistent with prior Commission decisions ordering PG&E to seek recovery of expenditures necessary to implement dynamic pricing incurred in 2011, and later years in general rate cases.[216]

14.1.1.1. PG&E

In D.08-07-045,[217] the Commission ordered PG&E to seek recovery of expenditures necessary to implement dynamic pricing incurred in 2011 and later in the general rate cases.[218] The Commission, in D.10-02-032, also held that PDP implementation cost recovery for 2011 and beyond will be determined in PG&E's 2011 and subsequent GRCs.[219]

---

[214] Ex. DRA-1/Ex. DRA-1c, p. 1-12. *See* Robert Levin, Ph.D, *Time-Variant Pricing for California's Small Electric Consumers*, May 2011, p. 54.

[215] Scoping Memo, p. 7, fn. 6.

[216] D.08-07-045, p.82, OP 13; D.10-02-032, FOF 103.

[217] *Decision Adopting Dynamic Pricing Timetable And Rate Design Guidance For Pacific Gas And Electric Company*, dated August 1, 2008.

[218] D.08-07-045, p.82 and OP 13.

[219] D.10-02-032, FOF 103.

Dynamic rates are updated in rate-setting proceedings such as the GRC Phase 2.[220] PG&E does not propose modification to the dynamic rate schedules in the 2012-2014 DR application, but is requesting $6.55 million[221] in this application for funding of measurement and evaluation ("M&E"), and personnel to support the notifications for peak day pricing ("PDP"). PG&E alleges these costs are not covered in other proceedings where PDP funding was authorized.[222] PG&E's funding request assumes that the current default PDP tariff implementation date of November 1, 2011 for small and medium commercial and industrial customers under D.10-02-032 so far remains unchanged.[223] However, PG&E also acknowledges there are two pending petitions to modify the Commission's decision implementing PDP and related new default time-variant rates, which could change the scope of several DR programs in this proceeding, if either is granted.[224]

DRA recommends the Commission only consider PG&E's request for $1.9 million in funding for M&E and personnel to support the notifications for PDP, if the Commission rejects both petitions to modify D.10-02-032. If the Commission were to approve either of the petitions to modify D.10-02-032, the Commission should order PG&E to seek cost recovery in its next GRC.

PG&E rebuttal testimony indicates notification costs requested in PG&E's application are needed for PDP "irrespective of whether the petitions to modify are granted because default PDP for small and medium business customers is currently anticipated to begin on November1, 2012."[225] PG&E explains it has a single contract with the vendor and splitting the costs between multiple filings "will increase the administrative costs and provide a layer of complexity in

---

[220] Ex. PGE-1, pp. 2-31 - 2-33.

[221] $0.65 million for M&E and $5.9 million for notification.

[222] Ex. PGE-1, pp. 2-31 - 2-33; 8-10 - 8-13.

[223] D.10-02-032, pp. 2, 3, 30, 31, COL 14, OP 3.

[224] *Petition of Pacific Gas and Electric Company for Modification of Decision 10-02-032*, filed January 14, 2011; and *Petition for Modification of the Division of Ratepayer Advocates, the California Small Business Association and the California Small Business Roundtable of Decision 10-02-032*, filed February 4, 2011 in A.09-02-022.

[225] Ex. PGE-8, 4-3:30 – 4-4:2.

tracking costs."[226] CPP notification costs were funded in the 2009-2011 DR application proceeding.[227] With regard to M&E costs, PG&E states:

> While PG&E supports consolidating cost recovery requests for all evaluation activities including DP programs and Time-of-Use (TOU) rates into a single proceeding, requesting funding for those programs' M&E activities in Phase 1 of the GRC as DRA suggests does not accomplish this goal and actually presents a lapse in funding for required M&E activities.[228]

Decision 08-04-050 requires PG&E to conduct annual impact evaluations of all DR related resources including DP and TOU rates, but is silent on the funding source for these activities.[229] As a result, if M&E is not recovered in the instant case, PG&E states "no funding would be available for conducting any Commission-required evaluation of DP programs and TOU rates for 2012 and 2013."[230] PG&E explains:

> Decision 08-04-050 treats DP programs and TOU rates as a DR resource, the process and timing of evaluating and reporting impacts of these resources under the load impact protocols adopted in Decision 08-04-050 are identical to that of all other DR program. Thus, it makes even more sense to include annual DP and TOU rates evaluations in the M&E budget that is approved in this proceeding.[231]

PG&E's arguments should be dismissed. In D.10-02-032, the Commission granted PG&E $124 million[232] to implement default and optional critical peak pricing ("CPP") and time-of-use rates (together, referred to as Peak Day Pricing – "PDP"). In general, this decision directs that PG&E's large commercial and industrial customers would be on default PDP rates on May 1, 2010, and small and medium commercial and industrial customers would be defaulted to PDP

---

[226] Ex. PG&E-8, p. 4-4, lns. 8-10.

[227] Ex. PG&E-8, p. 4-4, lns. 13, 14.

[228] Ex. PG&E-8, p. 8-7, lns. 24-29.

[229] Ex. PG&E-8, p. 8-7, lns.29-31.

[230] Ex. PG&E-8, p. 8-8, lns.4-6.

[231] Ex. PG&E-8, p. 8-8, lns.9-14.

[232] The adopted incremental expenditures that shall be used in determining the revenue requirements for this decision total $123,585,000 for the years 2008-2010." D.10-02-032, OP 23.

on Nov. 2011.[233] [234] Subsequently, PG&E filed a petition to modify D.10-02-032 to delay implementation of PDP for small customers. Though the funding of $124 million was intended to cover the period from 2008 through 2010, due to the delay of implementation on default, it is highly unlikely and, if so, probably imprudent that PG&E would have spent all the funding as no default PDP has been implemented for small commercial and industrial customers. Unless PG&E can provide convincing documents to show that it needs additional funding, [235] it would be reasonable to use the unspent funding for its PDP requirement to cover PG&E's request in the DR proceeding and reassess the funding needs in its next GRC Phase 1 cycle.

14.1.1.2. SCE

The SCE Save Power Day Incentive Program, formerly known as the Peak Time Rebate ("PTR") Program, was approved and funded as part of the SmartConnect business case, so any costs incurred through 2012 will be funded by the Edison SmartConnect Balancing Account.[236] In this application, SCE requests funding for 2013 ($12.353 million) and 2014 ($12.383 million), to continue operating the Save Power Day Program. The funding covers activities including marketing, education and outreach ("ME&O"), direct event notification, rebate program for enabling technologies, and program management and administration.

SCE does not seek cost recovery to implement the dynamic pricing plans in its dynamic pricing application A.10-09-002.[237] Rather, in this application, SCE requests funding to continue operations of RTP ($1.115 million) and CPP ($10.301 million).[238] SCE also indicates it will seek recovery of the costs related to extending the availability of dynamic rates to new customers for the period from 2012 to 2014 in SCE's 2012 GRC Phase 1 application, which is consistent

---

[233] D.10-02-032, at 2.

[234] Subsequently, PG&E's has asked to delay its implementation on default PDP for small customers.

[235] PG&E is required to file monthly dynamic pricing memo account tracking reports with Energy Division and DRA to track its expenditures. ("Revenue requirements reflecting the actual incremental costs incurred to implement dynamic pricing will be recorded into the DPMA on a monthly basis through December 2010." D.10-02-032, at 137.)

[236] D.08-09-038, Appendix, p. 14, Ex. SCE-03, Appendix C, pp. 31-36.

[237] Ex. SCE-03, p. 37.

[238] Ex. SCE-03, pp. 37-49.

with the Commission's general directive to request recovery of these costs in a GRC proceeding. In prepared testimony, DRA recommends the Commission consolidate all revenue requirement cost recovery requests for dynamic pricing and rate-related programs into Phase 1 of each utility's respective GRC applications to reduce redundancy, inefficiency, and costs to ratepayers.

SCE's rebuttal testimony indicates that its request is consistent with previous Commission decisions. In D.09-08-027, the Commission authorized CPP for customers with demand greater than 200 kilowatts (kW).[239] SCE argues, "Although SCE requested capital software expense for the *development* and *implementation* of dynamic rates in its 2012 GRC, the dynamic pricing funding sought here is to *operate* the dynamic pricing."[240]

DRA concedes that it may be too late for SCE to request funding in its current GRC cycle. If the funding consolidation cannot be done during the utilities' current GRC cycle, the funding consolidation should begin in the utilities' next GRC cycle.

14.1.1.3. SDG&E

The SDG&E PTR program is a rate-related program developed in SDG&E's rate design proposal in its 2008 GRC.[241] Initial funding for the customer communication and PTR education through 2012 was approved by D.07-04-043, in the SDG&E Smart Meter proceeding. SDG&E seeks to transition PTR into the DR portfolio and requests incremental PTR funding ($4.4 million) for administration, education, and an outreach program.[242] SDG&E also stated that any proposed updates or modifications to the PTR program will be made in future rate design window, GRC, or similar proceedings. In prepared testimony, DRA recommends the Commission consolidate all revenue requirement cost recovery requests for dynamic pricing and rate-related programs into Phase 1 of each utility's respective GRC applications to reduce redundancy, inefficiency, and costs to ratepayers.

SDG&E's rebuttal testimony defends its request for funding for the PTR program in this application. SDG&E states its last GRC Phase 1 was filed in 2010, and the next GRC cycle will

---

[239] Ex. SCE-07, p. 2, lns.20-24.

[240] Ex. SCE-07, 2:24-3:2.

[241] Ex. SGE-5, pp. 27-30.

[242] Ex. SGE-5, p. 30.

not occur in time to support this effort. SDG&E argues, "PTR is a critical step in the path for customer acceptance of dynamic pricing and it is therefore necessary that it roll out to all residential customers prior to the dynamic rate (PeakShift @ Home)." SDG&E explains, "[S]ince the project ends in 2011, the costs required for administering the PTR program from the years 2012-2014 are included in this application."[243]

As with SCE, DRA concedes that it may be too late for SDG&E to request PTR funding in the GRC. If the funding consolidation cannot be done during the utilities' current GRC cycle, the funding consolidation should begin in the utilities' next GRC cycle. Future funding requests for PTR should not be made in the next DR budget cycle.

15. CONCLUSION

DRA respectfully requests the final decision adopt the following:

1. The Commission should not approve DR programs that are not cost-effective unless and until the utilities make any necessary changes to the programs' cost structures to improve the cost-effectiveness to a TRC ratio above 1.0.

2. Dual participation in DR programs should be eliminated to reduce administrative costs associated with implementing and enforcing dual participation rules and align retail programs with the CAISO's wholesale market participation rules.

3. There should be no fund shifting between PDR product programs and RDRP programs. Any increase in a program's budget from fund shifting in excess of 50 percent of its original budget should require the filing of a Tier 2 advice letter.

4. Funding for IDSM activities should only be approved for 2012. Funding for future IDSM activities should be made in the Energy Efficiency proceeding, Rulemaking (R.) 09-11-014.

5. PG&E's AMP contracts should be allowed to expire in 2011, without extension, and new aggregator contracts should only be considered after final rules for DRP participation in the CAISO's wholesale market are developed.

6. The Commission should direct the utilities to request all future funding for dynamic pricing and rate-related programs in Phase 1 of their respective GRCs to determine the total revenue requirement for each program and assess whether the programs should be continued. If the funding consolidation cannot be done

---

[243] Ex. SGE-6, p. GMK-2, lns. 6-11.

during the utilities' current GRC cycle, the funding consolidation should begin in the utilities' next GRC cycle.

Respectfully submitted,

/s/ LISA-MARIE SALVACION

____

Lisa-Marie Salvacion
Attorney
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-2069
Email: lms@cpuc.ca.gov

August 22, 2011

ATTACHMENT A
(CONFIDENTIAL)