STATE OF CALIFORNIA Edmund G. Brown Jr., Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

April 25, 2013 Advice Letter 4164-E

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Subject: Staff Disposition of PG&E's AL 4164-E on the Resubmitted Cost Effectiveness Analyses of Pacific Gas and Electric Company's Capacity Bidding Program and Demand Bidding Program in Compliance with Decision 12-04-045.

Dear Mr. Cherry:

The Energy Division approves PG&E's AL 4164-E with an effective date of today. Energy Division has analyzed the Division of Ratepayer Advocates (DRA) protest, PG&E's response to the protest, and PG&E response to Energy Division Data Requests. Based on its analysis, Energy Division has determined that AL 4164-E is in compliance with D.12-04-045

In D.12-04-045, the Capacity Bidding Program (CBP) and Demand Bidding Program (DBP) budgets were approved contingent upon a revised cost-effective result. PG&E was ordered to submit a Tier 2 Advice Letter indicating which steps (decrease budget or improve benefits) it would take to make these programs cost-effective and/or adjust the budget accordingly. If the results indicated a less than cost effective, PG&E would further revise the program budgets.

On June 15, 2012, PG&E filed AL 4061-E submitting the cost effective analyses of its CBP and DBP programs. On November 15, 2012, the Energy Division rejected AL 4061-E, determining that PG&E's plans for CBP and DBP did not comply with the Commission directive that the programs meet a Total Resource Cost value of 0.9.

On December 14, 2012, PG&E submitted AL 4164-E on the resubmitted cost-effectiveness analyses of their CBP and DBP in compliance with D.12-04-045. PG&E proposed that the Commission:

1. Authorize a reduced budget of $7,103,343 for the 2012-2014 CBP;
2. Authorize a revised CBP tariff that increases the monthly limitation on dispatch hours from 24 to 30;
3. Authorize a reduced budget of $1,600,000 for 2012-2014 DBP; and
4. Authorize a reduced budget of $24,666,912 for 2012-2014 Automated Demand Response enabling technology (AutoDR). 100% of the reduction $1,630,548 ($1,240,080 amortized incentives and $390,468 program administration) will come from the allocation to DBP.

In addition to the above changes, PG&E's TRC cost effectiveness ratios were affected by other factors, such as changes implemented due to D.12-04-045, a change in the A Factor calculation, and PG&E complying with Energy Division guidance (utilizing 2012, rather than 2011 load impacts). The revised TRC ratios are 0.9 and 0.9 for CBP and DBP, respectively.

The Division of Ratepayer Advocates (DRA) protested AL 4164-E on January 2, 2013 and PG&E responded to DRA's protest on January 10, 2013 and provided additional information to Energy Division (see Attachment A for more details). Energy Division submitted data requests to PG&E, and PG&E adequately responded further assisting Energy Division in its analysis.

Please contact Taaru Chawla at the Energy Division at TAR@cpuc.ca.gov if you have any questions.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division
California Public Utilities Commission

cc: Bill Gavelis, Pacific Gas and Electric
Steve Haertle, Pacific Gas and Electric
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ATTACHMENT A
Summary of DRA Protest, PG&E Response and Energy Division Conclusions

1. For the Demand Bidding Program (DBP), DRA expressed concerns related to PG&E's DBP proposal and cost effectiveness evaluation. DRA believes further Commission direction is necessary before the Commission considers PG&E's DBP proposal.

   a. **DBP AutoDR budget issue**: DRA recommends that PG&E, like SCE, seek to increase cost-effectiveness of DBP by removing DBP non-performers and reducing other costs, in lieu of reducing the AutoDR budget.

      In its reply, PG&E responded that non-participating customers have no effect on the load impact forecast. In explaining its process of calculating the load impacts or program benefits, PG&E states that the load impacts used in the cost effectiveness analysis are derived by first analyzing the performance of each customer who participated in each event. The forecast is then developed based upon the performance of the participating customers and projections of how many customers will participate in future events. Removing the non-performers from the program will not improve the benefits of the program for the purpose of the cost effectiveness analysis in AL 4164-E.

      Based on PG&E's explanation that the non-participating customers would have no effect on the load impact forecast, Energy Division concludes that the AutoDR budget cut is a reasonable, yet temporary solution since AutoDR is a valuable program. PG&E had claimed in its Advice Letter filing that at a later time, when the deficiencies of the current DR cost-effectiveness protocols have been resolved, PG&E reserves the right to submit an advice letter to request reinstatement of the AutoDR budget originally approved in the DR application. Energy Division has determined that the Commission has authorized an AutoDR budget for PG&E. Should the cost-effectiveness protocols change such that PG&E can increase the budget to the authorized amount and still have a cost effective program, PG&E is permitted to submit an advice letter requesting re-instatement of the authorized AutoDR budget.

   b. **Dual Participation and its Impact on Cost Effectiveness of DBP**: DRA cites its concerns, similar to its protest of SCE AL 2751-E regarding DBP cost-effectiveness, that DRA is opposed to each utility making its own arbitrary and ad-hoc allocation without a proper process in which all parties can participate and the Commission can make an informed decision on this issue. As an alternative, DRA recommended approving a stand-alone DBP program for DBP customers who do not dual-participate, until the Commission establishes a uniform policy on cost-effectiveness evaluation of dual-participating programs. DRA recommends the Commission apply the same policy towards PG&E's proposed DBP as well.

      PG&E responds that the Commission should reject DRA's recommendation to create a "stand-alone" DBP program for DBP customers who do not dual participate, until the Commission establishes a uniform policy on cost-effectiveness evaluation of dual-participating programs because it is unnecessary and unsupported by the record.

Energy Division appreciates DRA suggested alternative to evaluate the cost-effectiveness of DBP. However, D.12-04-045 ordered PG&E to perform a revised cost-effectiveness analysis for DBP, and left the details to PG&E on how to accomplish that directive. PG&E chose to decrease its DBP budget (including its AutoDR budget for DBP) as its method for making the program cost-effective. Because PG&E's method complies with the decision, Energy Division has no basis to direct PG&E to use an alternative method.

2. DRA states that PG&E was directed by Energy Division to provide an updated cost-effectiveness analysis of all affected demand response programs that reflect any changes in shared costs allocated across other demand response programs when PG&E resubmits its new advice letter for CBP and DBP. DRA recommends that the Commission suspend the Advice Letter until PG&E provides an updated cost-effectiveness analysis of all affected demand response programs.

In its response to DRA's protest, PG&E submitted the current cost effectiveness results for all of the demand response programs.

3. DRA protests PG&E's argument that additional qualitative (non-energy and non-monetary) benefits listed in the Advice Letter be considered in evaluating the cost-effectiveness of CBP and DBP. The non-energy and non-monetary benefits were discussed during a two-day workshop held by the Energy Division on June 28 and 29, 2012. According to DRA, there was no consensus among parties at the workshop about what these benefits are and how they can be quantified. DRA believes that it is premature to include these benefits in the CBP and DBP evaluations. DRA recommends that the Commission reject PG&E's request to include them in the Commission's evaluation of the programs.

PG&E states that it submitted non-energy and non-monetary benefits of CBP and DBP in light of the Commission's request to include such qualitative benefits and expects flexibility in the Commission's cost effectiveness analysis of DR programs.

Energy Division appreciates PG&E's efforts in providing the non-energy and non-monetary benefits of CBP and DBP but the benefits described in the Advice Letter are not the result of changes to the programs, which is the purpose of the Advice Letter. If PG&E's inclusion of non-energy and non-monetary benefits are the result of program changes for CBP and DBP, those benefits would have been considered by Energy Division in its review of the Advice Letter. In any case, since PG&E's CBP and DBP both have a revised benefit-cost ratio of 0.9, and thus compliant with the Decision, the use of non-energy and non-monetary benefits in the Advice Letter review process is a moot point.

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December 14, 2012

Advice 4164-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Resubmitted Cost Effectiveness Analyses of Pacific Gas and Electric Company's Capacity Bidding Program and Demand Bidding Program in Compliance With Decision 12-04-045**

Purpose

In compliance with Ordering Paragraph (OP) 44 and OP 50 of Decision (D.) 12-04-045 and in response to the Energy Division's (ED) rejection of Advice Letter 4061-E, Pacific Gas and Electric Company (PG&E) resubmits the cost effectiveness analyses for its Capacity Bidding Program (CBP) and Demand Bidding Program (DBP). This advice letter (AL) demonstrates how increased benefits and reduced costs make these demand response (DR) programs cost-effective as defined by the California Public Utilities Commission (CPUC or Commission) in D.12-04-045.[1]

PG&E requests that the Commission:

1) Authorize a reduced budget of $7,103,343 for its 2012-2014 CBP;[2]

2) Authorize a revised CBP tariff that increases the monthly limitation on dispatch hours from 24 to 30;

3) Authorize a reduced budget of $1,600,000 for its 2012-2014 DBP;[3] and

4) Authorize a reduced budget of $24,666,912 for its 2012-2014 Automated DR enabling technology (AutoDR) with 100% of the $1,630,548 reduction; i.e., $1,240,080 amortized incentives and $390,468 program administration, coming exclusively from the allocation to DBP.[4]

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[1] D.12-04-045, p. 44
[2] These amounts are less than those authorized in D.12-04-045 as explained later in this advice letter.
[3] Ibid.
[4] Ibid.

Background

On March 1, 2011, PG&E filed its 2012-2014 Demand Response (DR) Application (A.) 11-03-001 requesting funding for DR programs. On April 30, 2012, the Commission issued D.12-04-045 authorizing funding for PG&E to conduct DR programs and pilots for the remainder of 2012 through December 31, 2014.

In D.12-04-045, the Commission authorized funding for PG&E's Capacity Bidding Program "contingent upon a revised cost-effective result." OP 44 of D.12-04-045 directs PG&E to submit a Tier 2 advice letter no later than 60 days from the issuance of the decision indicating which steps PG&E will take to make its CBP cost-effective.

In its DR Application, PG&E had proposed to close DBP and merge it with its PeakChoice program. In D.12-04-045, the Commission denied the continuation of PeakChoice and authorized funding for PG&E's Demand Bidding Program "contingent upon the receipt of the results of the resubmitted cost-effectiveness analysis." OP 50 of D.12-04-045 directs PG&E to "perform an updated cost effectiveness analysis and submit it along with a recalculated budget" in a Tier 2 advice letter no later than 60 days from the issuance of the decision.

On May 11, 2012, ED provided guidance on the format to use for such resubmitted cost effectiveness analyses. This guidance included all previous Commission cost effectiveness directives as well as directed the utilities to submit two cost effectiveness analyses for comparison purposes. One analysis will be based on the updated *ex ante* load impacts submitted to the Commission on June 1, 2012 (the 2012 Load Impacts) and the other analysis will be based on the *ex ante* load impacts previously submitted to the Commission on April 1, 2011 (the 2011 Load Impacts). In addition, the ED directed the utilities to provide a written explanation for any inputs that are different from those previously provided in their applications and related testimony. Finally, the ED asked that utilities include a qualitative analysis of possible non-energy and non-monetary benefits as described in the 2010 DR Cost Effectiveness Protocols (Attachment 1 of D.10-12-024).[5]

On June 15, 2012, PG&E filed AL 4061-E submitting the cost effectiveness analyses of its CBP and DBP programs in compliance with D.12-04-045. PG&E requested the Commission to authorize reduced 2012-2014 budgets of $7,103,343 for CBP and $1,600,000 for DBP. In its AL, PG&E acknowledged that even after cutting its CBP and DBP budgets beyond those mandated by D.12-04-045, CBP and DBP remained only "possibly cost-effective" and required the use of non-energy and non-monetary qualitative benefits to provide a reasonable justification for continuing these programs.

[5] Attachment 1 of D.10-12-024, Decision Adopting A Method For Estimating The Cost-Effectiveness Of Demand Response Activities (Dec. 21, 2010)
http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128596.PDF

On November 15, 2012, ED rejected PG&E's AL 4061-E and directed PG&E to file a new AL in which CBP and DBP are further adjusted, through increased benefits and reduced costs, to achieve a Total Resource Cost ("TRC") test Benefit-Cost (B/C) ratio of at least 0.9. In addition, if PG&E chooses to do this by reallocating costs to other DR programs, PG&E was directed to include the resulting cost-effectiveness impacts on those other DR programs as well.

Summary

For this AL, PG&E has achieved TRC benefit-cost ratios of at least 0.9 for both CBP and DBP by increasing benefits or reducing costs. The allocation of costs are essentially unmodified from what was originally submitted in Advice Letter 4061-E.[6]

Capacity Bidding Program

The revised B/C ratio for CBP under the TRC test is 0.9—for both the "Day Ahead"[7] and "Day Of" options—based on the 2012 Load Impacts and given the assumptions in the Commission's DR Reporting Template.[8]

PG&E is requesting authorization for a budget of $7,103,343 for its 2012-2014 CBP. This is the same as was requested in AL 4061-E. The CBP budget reduction is due to the amount of capacity incentives shrinking by $4,460,141 because of the lower 2012 Load Impacts relative to the 2011 Load Impacts.

In AL 4061-E, PG&E presented the cost effectiveness analysis using both the 2011 and 2012 Load Impacts. In that AL, CBP achieved a TRC test B/C ratio of 1.0 using the 2011 Load Impacts. However, even with the cost reductions proposed by PG&E in that AL, CBP only achieved a 0.79 TRC test B/C ratio using the 2012 Load Impacts.

Thus, to reach a B/C ratio of at least 0.9, PG&E further proposes in this AL to increase the CBP monthly program availability requirement from 24 hours to 30 hours. This 30 hour requirement is the same as what SCE requested in an advice letter in which it had resubmitted its own CBP cost effectiveness analysis.[9] This program design change has the effect of increasing the availability of the program. This increases the benefits to the program—through an increased A-factor—which in turn increases the TRC test B/C ratio from 0.79 in AL 4061-E to 0.91 in this AL.

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[6] There is a *de minimus* difference due to the Aggregator Managed Portfolio (AMP) program receiving a negligibly higher allocation of costs because the AMP incentive budget resulting from the AMP Request for Offers (RFO) was slightly higher than what was assumed in-advance for the cost-effectiveness analysis used in Advice Letter 4061-E. However, the allocation of costs in this AL is the same as what PG&E submitted for its 2013-14 AMP application (A. 12-09-004).

[7] Rounded up.

[8] The May 12, 2011 version that was used in the 2012-14 DR Application.

[9] SCE Advice Letter 2768-E.

This program design change requires a minor change to PG&E's tariff, Electric Schedule E-CBP. PG&E requests the Commission authorize the revised tariffs attached to this AL.

Demand Bidding Program

The revised B/C ratio of DBP under the TRC test is 0.9 based on the 2012 Load Impacts.

PG&E is requesting authorization for a budget of $1,600,000 for its 2012-2014 DBP. This is the same as what was requested in AL 4061-E. In the 2009-2011 program cycle, PG&E spent approximately $1,600,000 on program administration and incentives. Given DBP is approximately the same size for 2012-2014, PG&E expects the same level of funding as the previous three-year period will be adequate in the current three-year period.

In AL 4061-E, DBP achieved a TRC test B/C ratio of 0.78 using the 2012 Load Impacts. This was up from 0.48 using 2011 Load impacts. This increase was due to the improved performance of DBP relative to the prior year plus the assumed load impact benefits expected from customers who transition from PeakChoice.[10]

Because PG&E has already reduced the DBP budget and still has not achieved a B/C ratio of at least 0.9, PG&E also proposes to reduce the costs of AutoDR directly attributed to DBP. In AL 4061-E, PG&E stated that the AutoDR allocation decreased from $4,653,613 to $3,944,934.[11] A further reduction of $1,630,548; i.e., $1,240,080 amortized incentives and $390,468 program administration, of AutoDR costs attributed to DBP is required to make DBP cost effective with a TRC test B/C ratio of 0.9. Thus, PG&E is requesting authorization for an AutoDR budget of $24,666,912 for 2012-2014.

This further AutoDR cost reduction is ***not*** being re-allocated to other DR programs. Instead, PG&E is voluntarily cutting much of its AutoDR budget attributed to DBP. This could adversely affect PG&E's customers in DBP. DBP customers, who have utilized AutoDR incentives to install enabling technologies, can be expected to perform reliably because they are required to place a minimum energy reduction bid upon signing up for AutoDR. The proposed AutoDR budget cut will mean there will be a smaller amount of incentives available to current and future DBP participants. However, at a later time when the deficiencies of the current DR cost-effectiveness protocols have been resolved,[12] PG&E reserves the right to submit an advice letter to request the reinstatement of the AutoDR budget originally approved in the DR Application.

[10] D.12-04-045 ordered PG&E to close PeakChoice and transition its customers to other DR programs.
[11] Table 2, page 5 of AL 4061-E.
[12] D.12-04-045, Finding of Fact 13, Ordering Paragraph 7

PG&E also requests the Commission to consider additional contributing factors in evaluating the cost effectiveness of CBP and DBP, including the non-energy and non-monetary qualitative benefits of these DR programs as described below.

Load Impacts

The ED directs utilities to submit two cost effectiveness analyses for comparison purposes. One analysis will be based on the updated 2012 Load Impacts and the other analysis will be based on previously submitted 2011 Load Impacts. The 2012 Load Impacts and the 2011 Load Impacts for CBP and DBP are shown in Table 1.

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
CBP AND DBP, 2012-2014, MEGAWATT (MW) LOAD IMPACTS
JUNE 1, 2012 REPORT AND APRIL 1, 2011 REPORT

MW	June 1, 2012 Load Impact Report			April 1, 2011 Load Impact Report		
	DBP	CBP Day Ahead	CBP Day Of	DBP	CBP Day Ahead	CBP Day Of
Jan-12	10	-	-	5	-	-
Feb-12	10	-	-	5	-	-
Mar-12	11	-	-	5	-	-
Apr-12	6	-	-	6	-	-
May-12	11	12	17	7	23	25
Jun-12	12	12	17	7	25	29
Jul-12	12	12	17	8	25	30
Aug-12	13	12	18	8	25	30
Sep-12	12	12	18	8	25	30
Oct-12	12	12	18	7	24	27
Nov-12	12	-	-	5	-	-
Dec-12	11	-	-	5	-	-
Jan-13	11	-	-	-	-	-
Feb-13	11	-	-	-	-	-
Mar-13	11	-	-	-	-	-
Apr-13	6	-	-	-	-	-
May-13	12	14	20	-	23	25
Jun-13	13	14	20	-	25	29
Jul-13	14	14	20	-	25	30
Aug-13	14	14	20	-	25	30
Sep-13	14	14	20	-	25	30
Oct-13	14	14	20	-	24	27

Nov-13	13	-	-	-	-	-
Dec-13	12	-	-	-	-	-
Jan-14	12	-	-	-	-	-
Feb-14	12	-	-	-	-	-
Mar-14	12	-	-	-	-	-
Apr-14	7	-	-	-	-	-
May-14	13	14	20	-	23	25
Jun-14	14	14	20	-	25	29
Jul-14	15	14	20	-	25	30
Aug-14	15	14	20	-	25	30
Sep-14	15	14	20	-	25	30
Oct-14	14	14	20	-	24	27
Nov-14	13	-	-	-	-	-
Dec-14	13	-	-	-	-	-

Cost Effectiveness Analysis

ED's May 11, 2012, guidance on resubmitting cost effectiveness analyses required the following tables. Table 2 presents those inputs in the current cost effectiveness analysis which have changed relative to the cost effectiveness analysis provided previously.

TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
CHANGES TO INPUTS VS. ANALYSIS PREVIOUSLY PROVIDED

Program	Change	Explanation
All	all costs	Reductions to PG&E's DR budget as directed by the DR decision were included in the cost effectiveness analysis.
All	Incentives	Capacity incentives in the cost effectiveness analysis are a function of load impacts. Capacity incentives changed in the same proportion that the 2012 load impacts changed from the 2011 load impacts.
All	allocated costs	Allocation of EM&V, ME&O, Operations and AutoDR costs are a function of program costs. Allocated costs in the cost effectiveness analysis changed in the same proportion that program costs changed. However, the allocation of costs in this advice letter is essentially unmodified from what was originally submitted in Advice Letter 4061-E.[13]
CBP	Incentives	CBP capacity incentives are reduced by $4,460,141 down to $6,364,859 reflecting the 2012 Load Impacts.
CBP	Marketing	Marketing allocation decreased from $3,001,500 to zero, i.e., no change from AL 4061-E.

[13] There is a *de minimus* difference due to AMP receiving a negligibly higher allocation of costs because the AMP incentive budget resulting from the AMP RFO was slightly higher than what was assumed for the cost-effectiveness analysis used in Advice Letter 4061-E. However, the allocation of costs in this AL is the same as what PG&E submitted for its 2013-14 AMP application (A. 12-09-004).

CBP	EM&V	EM&V allocation decreased from $464,080 to $185,076, i.e., no change from AL 4061-E.
CBP	operations	Operations allocation decreased from $3,899,734 to $2,205,915, i.e., no change from AL 4061-E. Operations costs shared between CBP and AMP were allocated as a proportion of program megawatts.
CBP	AutoDR	AutoDR allocation decreased from $12,291,469 to $2,629,956, i.e., no change from AL 4061-E.
CBP	A-factor	The A-factor was changed in two ways. First, it was recalculated consistent with SCE's method. This lowered the result. Second, it was recalculated based on a monthly dispatch limitation of 30 hours rather than 24 hours. This raised the result. However, the combined effect was to reduce the CBP A-factor from 67% to 47%.
CBP	within program allocation	Allocated CBP costs between Day Ahead and Day Of using megawatts rather than number of customers.
DBP	admin costs	DBP budget is reduced to $1,600,000 from the authorized budget of $3,216,000. All costs to combine DBP and PeakChoice were removed i.e., no change from AL 4061-E.
DBP	Marketing	Marketing allocation decreased from $5,232,357 to $774,976, i.e., no change from AL 4061-E.
DBP	EM&V	EM&V allocation decreased from $862,088 to $792,229, i.e., no change from AL 4061-E.
DBP	Operations	Operations allocation decreased from $5,183,377 to $1,395,310, i.e., no change from AL 4061-E.
DBP	AutoDR	The AutoDR allocation to DBP decreased from $4,653,613 to $3,944,934 in AL 4061-E. However, in this AL, the AutoDR budget associated with DBP decreases to $2,314,387. This is achieved by further reducing the AutoDR budget by $1,630,548, i.e., $1,240,080 amortized incentives and $390,468 program administration. This is an AutoDR budget reduction affecting only DBP and NOT a budget reallocation affecting any other DR program.
DBP	A-factor	The A-factor was recalculated consistent with SCE's method. This reduced the DBP A-factor from 100% to 78%.

Table 3-A, below, presents the non-program-specific costs allocated to both CBP and DBP. These non-program-specific costs include Evaluation, Measurement and Validation (EM&V), Marketing, Education and Outreach (ME&O), AutoDR and Operations.

TABLE 3-A
PACIFIC GAS AND ELECTRIC COMPANY
NON-PROGRAM-SPECIFIC COSTS ALLOCATED TO CBP, DBP AND AMP
IN THIS ADVICE LETTER

Budget	Amount	CBP	DBP	AMP	OTHER	AutoDR Budget Cut
Category 6: EM&V	$ 15,720,981	1%	5%	7%	87%	-
Category 7: ME&O	$ 13,771,993	0%	6%	0%	94%	-
Category 4: AutoDR	$ 26,297,459	10%	9%	20%	55%	6%
Category 8: Operations	$ 37,623,002	6%	4%	15%	75%	-

When the above table is compared to the DR Reporting Template PG&E submitted in both AL 4061-E[14]—reproduced in Table 3-B—and the Application for Approval of the AMP Agreements[15]—reproduced in Table 3-C—it is obvious the cost allocations are virtually identical, within rounding errors.[16] Thus, PG&E's cost-effectiveness analysis of CBP and DBP in this AL uses the same allocation of non-program-specific costs to all other DR programs as was used in both AL 4061-E and the AMP Application.

TABLE 3-B
PACIFIC GAS AND ELECTRIC COMPANY
NON-PROGRAM-SPECIFIC COSTS ALLOCATED TO CBP, DBP AND AMP
AS SUBMITTED IN AL 4061-E

Budget	Amount	CBP	DBP	AMP	OTHER
Category 6: EM&V	$ 15,720,981	1%	5%	6%	88%
Category 7: ME&O	$ 13,771,993	0%	6%	0%	94%
Category 4: AutoDR	$ 26,297,459	10%	15%	20%	55%
Category 8: Operations	$ 37,623,002	6%	4%	15%	76%

TABLE 3-C
PACIFIC GAS AND ELECTRIC COMPANY
NON-PROGRAM-SPECIFIC COSTS ALLOCATED TO CBP, DBP AND AMP
AS SUBMITTED IN AMP RFO APPLICATION

Budget	Amount	CBP	DBP	AMP	OTHER
Category 6: EM&V	$ 15,720,981	1%	5%	7%	87%
Category 7: ME&O	$ 13,771,993	0%	6%	0%	94%
Category 4: AutoDR	$ 26,297,459	10%	15%	20%	55%
Category 8: Operations	$ 37,623,002	6%	4%	15%	75%

[14] See tab named "guidance #6" in PG&E's CBP/DBP DR Reporting Template using 2012 load impacts for AL 4061-E at http://apps.pge.com/regulation/search.aspx?CaseID=1015 (The case is "Demand Response 2012-2014"; the Document type is "All"; the Party is "All"; and date fields are "06/14/12".) The name of the spreadsheet is, "DemandResponse2012-2014-Projects_Other-Doc_PGE_20120614_241050.xls".

[15] See tab named "guidance #6" in DR Reporting Template for A.12-09-004 at htpp://apps.pge.com/regulation/ (Click on "Search for Public Case Documents"; select "Demand Response RFO 2013" from the dropdown menu; select 09/07/2012 as the date, and PG&E as the party, to narrow the search criteria; then, click "Search") PG&E's Demand Response Reporting Template is named, "DemandResponseRFO-2013_Test_PGE_20120907_249216.xls".

[16] The minor difference is due to AMP picking up a slightly higher allocation of costs in the application because the AMP incentive budget in the application is slightly higher than the AMP incentive budget that was assumed for the Advice Letter.

Table 4-A below shows updated B/C Ratios by Standard Practice Manual (SPM) test for both CBP and DBP using the 2012 Load Impacts based on a portfolio view for 1-in-2 year weather conditions. Table 4-B is based on holding all DR Reporting Template inputs the same except for substituting the 2011 Load Impacts.

TABLE 4-A
PACIFIC GAS AND ELECTRIC COMPANY
BENEFIT / COST RATIO BY STANDARD PRACTICE MANUAL TESTS
CBP AND DBP, 2012-2014
2012 LOAD IMPACTS, PORTFOLIO VIEW

DR Program	Total Resource Cost Test	Participant Test	Ratepayer Impact Measure Test	Program Administrator Cost Test
CBP Day Ahead	0.9	1.3	0.8	0.8
CBP Day of	0.9	1.3	0.8	0.8
DBP	0.9	1.3	0.9	0.9

TABLE 4-B
PACIFIC GAS AND ELECTRIC COMPANY
BENEFIT / COST RATIO BY STANDARD PRACTICE MANUAL TESTS
CBP AND DBP, 2012-2014
2011 LOAD IMPACTS, PORTFOLIO VIEW

DR Program	Total Resource Cost Test	Participant Test	Ratepayer Impact Measure Test	Program Administrator Cost Test
CBP Day Ahead	1.2	1.3	1.0	1.0
CBP Day of	1.2	1.3	1.0	1.0
DBP	0.6	1.3	0.5	0.6

Table 5-A below shows updated Net Present Value (NPV) benefits and costs by SPM test for each program under the TRC test based on the 2012 Load Impacts. Table 5-B is similar except for being based on the 2011 Load Impacts.

TABLE 5-A
PACIFIC GAS AND ELECTRIC COMPANY
NET PRESENT VALUE BY TOTAL RESOURCE COST TEST
CBP AND DBP, 2012-2014
2012 LOAD IMPACTS, PORTFOLIO VIEW

DR Program	Benefits ($million)	Costs ($million)	Net Benefits for TRC B/C 0.9 ($million)
CBP Day Ahead	$3	$3	$0
CBP Day of	$5	$5	$0
DBP	$5	$5	$0

TABLE 5-B
PACIFIC GAS AND ELECTRIC COMPANY
NET PRESENT VALUE BY TOTAL RESOURCE COST TEST
CBP AND DBP, 2012-2014
2011 LOAD IMPACTS, PORTFOLIO VIEW

DR Program	Benefits ($million)	Costs ($million)	Net Benefits for TRC B/C 0.9 ($million)
CBP Day Ahead	$6	$5	$2
CBP Day of	$11	$9	$3
DBP	$3	$5	$(2)

DR Reporting Template

Per the ED's May 11, 2012, guidance (in accordance with D.12-04-045 Ordering Paragraph 83), the DR Reporting Template for the above analysis can be accessed at the link below:

http://apps.pge.com/regulation/search.aspx?CaseID=1015

The case is "Demand Response 2012-2014"; the Document type is "All"; the Party is "All"; and date fields are "12/14/12".

Parties may request copies of the referenced Demand Response reporting templates by sending their request to:

Josephine Wu
Rate Case Coordinator
77 Beale St., Mail Code B9A
P.O. Box 770000
San Francisco, CA 94177
Office Phone: (415) 973-3414
E-mail: JWWD@pge.com

In this AL, PG&E used the May 12, 2011, version of the DR Reporting Template, which is the same as was used for the cost-effectiveness analysis in D.12-04-045. Furthermore, the allocation of costs in this analysis are essentially unmodified from what was originally submitted in both Advice Letter 4061-E.[17] and the Application for the 2013-14 AMP contracts.[18]

Qualitative Benefits

PG&E appreciates the opportunity to provide additional information about the qualitative benefits of CBP and DBP, as desired by the Commission in its guidance for this advice letter. PG&E trusts that this information allows the Commission to take a flexible approach to analyzing the cost-effectiveness of these DR programs.[19]

There are several factors the Commission could consider when evaluating DR programs or DR portfolios.[20] Such factors, or program attributes, were used in D.09-08-027 to analyze the 2009-2011 DR applications. These factors and attributes include: flexibility and versatility, adaptability, integration, statewide consistency, simplicity, recognition and consistency with general Commission policies.[21]

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[17] There is a *de minimus* difference due to AMP receiving a negligibly higher allocation of costs because the AMP incentive budget resulting from the AMP RFO was slightly higher than what was assumed for the cost-effectiveness analysis used in Advice Letter 4061-E. However, the allocation of costs in this AL is the same as what PG&E submitted for its 2013-14 AMP application (A. 12-09-004).
[18] A.12.09-004.
[19] D. 12-04-045, p. 43…"Protocols state that "flexibility in the application of these protocols may be necessary to fully reflect the attributes of some DR programs. We conclude that our approach on how we use the protocols allows us to be flexible in our approach to analyzing cost effectiveness for DR programs. However, a large part of our approach is informed by the fact that certain qualitative information was not provided in the Applications."
[20] Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo, p. 8, May 13, 2011
[21] Decision Adopting Demand Response Activities And Budgets For 2009 Through 2011, D.09-08-027 (Aug. 20, 2009), p. 13.

The 2010 DR Cost Effectiveness Protocols identify additional non-energy and non-monetary qualitative benefits[22] as possible factors in determining the cost effectiveness of DR. PG&E's CBP and DBP have attributes with similar non-energy and non-monetary qualitative benefits, albeit are non-quantifiable and, thus, not included in the DR Reporting Template cost effectiveness analysis.

However, these non-energy and non-monetary qualitative benefits as described in the following two sections should be considered by the Commission when evaluating the cost effectiveness of CBP and DBP.

Capacity Bidding Program: Non-energy and Non-monetary Qualitative Benefits

- **Local dispatch** – The ability for local dispatch is planned for CBP in 2013. Local dispatch capability provides local RA credit, which supports local reliability, and allows the program to potentially participate as Proxy Demand Resource (PDR) in the CAISO market.
- **CAISO market integration / adaptability** – Like Base Interruptible Program (BIP) and DBP, CBP is a program that has the potential to be bid as PDR into the CAISO market.
- **CBP plays an important role in developing third-party aggregator capabilities** – PG&E's CBP is an aggregator-only program in which participating aggregators enroll retail commercial, industrial, and agricultural customers.
    - CBP offers aggregators a place to participate in the California marketplace, and "provide[s] additional innovation and services to the market, yielding additional un-captured potential benefits to DR in California"[23].
    - CBP provides opportunities for aggregators who do not have an AMP contract to participate in PG&E's DR portfolio.
    - The program maintains aggregator participation in California at a time when it is important to develop third-party direct participation.
- **Customer participation** – CBP is a program where participation is mandatory. Penalties apply for non-performance, ensuring the resource's reliability.

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[22] For example: Section 3.K: Non-Energy and Non-Monetary Benefits, p. 33. This category of benefits includes the benefits participants receive in lessening their impact on the environment, being good citizens by helping to prevent outages, improving their ability to manage their energy usage, having a better public image (for commercial enterprises), improving working conditions, etc. From a societal perspective, and from the perspective of LSEs, DR programs may result in non-energy benefits, such as health and safety and secondary economic benefits. Section 3.G: Environmental Benefits, pp. 29-30. Other environmental impacts that might be avoided include: "environmental justice concerns, biological impacts, impacts on cultural resources, diminishing visual resources, land use, effects on water quality/consumption, and noise pollution. Section 3.J: Market and Reliability Benefits, p. 32. This category of benefits includes increased reliability (over and above the increased reliability offered by equivalent supply-side measures, particularly when DR can provide ancillary services), increased market efficiency improvement in overall system load factors, improved market performance (e.g., decreasing price volatility), increased flexibility, portfolio benefits, and others.

[23] P. 16, D.12-04-045

- **Flexibility and versatility for aggregator and customer** – PG&E's CBP offers flexibility in monthly aggregator nominations allowing aggregators to register new DR customers and verify their load reliability prior to committing them to a longer term commitment (such as the AMP). This flexibility also offers customers the ability to adjust their reduction commitments monthly in response to variations in their load and reduction capability.
- **Consistency of offering throughout the state** – CBP is a statewide program with the ability to encourage participation in DR by businesses located in more than one service area.

Demand Bidding Program: Non-energy and Non-monetary Qualitative Benefits

- **Local dispatch** – The ability for local dispatch is planned for DBP in 2013. Local dispatch capability provides local RA credit, which supports local reliability, and allows the program to potentially participate as Proxy Demand Resource (PDR) in the CAISO market.
- **CAISO market integration / adaptability** – Most DBP MW will be able to be bid into the CAISO market as day-ahead energy after BIP is implemented for Reliability Demand Response Resource (RDRR). This is because the RDRR design includes the ability to bid the MW in as day-ahead energy, just as if it were PDR. Thus DBP will provide an early way to have DR bid into the CAISO markets in the manner of PDR.
- **Flexibility and versatility** – PG&E's DBP offers customers the ability to adjust their reduction commitments by event and blocks of hours within events to accommodate variations in their daily load and reduction capabilities.
- **Consistency of offering throughout the state** – DBP is a statewide program with the ability to encourage participation in DR by businesses located in more than one service area.

Conclusion

Given the increased benefits, reduced costs, and tariff change described in this resubmitted AL, both CBP and DBP now achieve a TRC B/C ratio of at least 0.9 and thus, are cost effective. This provides reasonable justification for the Commission to authorize the continuation of these programs at the requested budget level. No other DR programs were reallocated any costs in the cost-effectiveness analysis for this AL, so no other DR programs are impacted.

PG&E's DR programs portfolio, which include CBP and DBP, supports the statewide effort to utilize DR as a preferred resource as set forth in the key actions in the Energy Action Plan II.[24]

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[24] PG&E's portfolio with CBP and DBP supports key objectives of EAP II for DR as follows:

Furthermore, PG&E's portfolio promotes the vision 8.1 of DSM Coordination and Integration provided by the Commission and the California Energy Commission in the California Energy Efficiency Strategic Plan, January Update.[25]

In closing, PG&E requests that the Commission authorize a budget of $7,103,343 for its 2012-2014 Capacity Bidding Program; authorize a budget of $1,600,000 for its 2012-2014 Demand Bidding Program; authorize the revised CBP tariff attached to this advice letter; and, authorize a budget of $24,666,912 for AutoDR with 100% of the additional reduction attributed to DBP alone.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than **January 3, 2013**, which is 20 days after the date of this filing. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C

- PG&E's proposed CBP and DBP encourage customers to participate in DR by offering a variety of programs, both through PG&E and through DR aggregators, to encourage customer participation and increase the amount of available DR. (Key Action 3).
- PG&E's proposed CBP and DBP help to educate customers about the time sensitivity of energy use and the ways to take advantage of all DR program offerings. (Key Action 4). *(Need ref)*

[25] California Energy Efficiency Strategic Plan, January Update, which states: "Energy efficiency, energy conservation, DR, advance metering, and distributed generation technologies are offered as elements of an integrated solution that supports energy and carbon reduction goals immediately."

P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Rule 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) E-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Rule 3.11).

Effective Date

PG&E requests that this Tier 2 advice letter become effective on regular notice, **January 13, 2013,** which is 30 calendar days after the date of filing.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for A.11-03-001. Address changes to the General Order 96-B service list should be directed to PG&E at E-mail address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs.

Brian Cherry /sw

Vice President, Regulatory Relations

Attachments

cc: Service List for A.11-03-001

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 E)**

Utility type:	Contact Person: **Shirley Wong**
☑ ELC ☐ GAS	Phone #: **(415) 972-5505**
☐ PLC ☐ HEAT ☐ WATER	E-mail: **slwb@pge.com**

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas ☐ PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: **4164-E** **Tier: 2**

Subject of AL: **Resubmitted Cost Effectiveness Analyses of Pacific Gas and Electric Company's Capacity Bidding Program and Demand Bidding Program in Compliance With Decision 12-04-045**

Keywords (choose from CPUC listing): **Compliance**

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: **D.12-04-045**

Does AL replace a withdrawn or rejected AL? **Yes** If so, identify the prior AL: **Advice 4061-E**

Summarize differences between the AL and the prior withdrawn or rejected AL: **See page 1, 1) through 4).**

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: ____

Resolution Required? ☐ Yes ☑No

Requested effective date: **January 13, 2013** No. of tariff sheets: **3**

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: **Electric Schedule E-CBP (Capacity Bidding Program)**

Service affected and changes proposed: **Increase the CBP monthly program availability requirement from 24 hours to 30 hours.**

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
ED Tariff Unit
505 Van Ness Ave., 4th Floor
San Francisco, CA 94102
EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian K. Cherry, Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

ATTACHMENT 1
Advice 4164-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
32225-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 2	29925-E
32226-E	ELECTRIC TABLE OF CONTENTS Sheet 1	32222-E
32227-E	ELECTRIC TABLE OF CONTENTS RATE SCHEDULES Sheet 9	31624-E

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

OPTIONS AND PRODUCTS:

The program season is May 1 through October 31.

The program days are Monday through Friday during the program season, excluding PG&E holidays. PG&E holidays during the program season are the dates on which the following holidays are legally observed: Memorial Day, Independence Day, and Labor Day.

The program hours are 11 a.m. to 7 p.m. on program days.

The following options and products are available:

Day-Ahead Options

Product	Minimum Duration per Event	Maximum Duration per Event	Maximum Event Hours Per Operating Month	Maximum Events Per Day
1-4 Hour	1 hour	4 hours	30	1
2-6 Hour	2 hours	6 hours	30	1
4-8 Hour	4 hours	8 hours	30	1

(T)
|
(T)

Day-Of Options

Product	Minimum Duration per Event	Maximum Duration per Event	Maximum Event Hours Per Operating Month	Maximum Events Per Day
1-4 Hour	1 hour	4 hours	30	1
2-6 Hour	2 hours	6 hours	30	1
4-8 Hour	4 hours	8 hours	30	1

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ELECTRIC TABLE OF CONTENTS

TABLE OF CONTENTS

(Continued)

ELECTRIC TABLE OF CONTENTS
RATE SCHEDULES

Sheet 9

(Continued)

PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

1st Light Energy
AT&T
Alcantar & Kahl LLP
Ameresco
Anderson & Poole
BART
Barkovich & Yap, Inc.
Bartle Wells Associates
Bloomberg
Bloomberg New Energy Finance
Boston Properties
Braun Blaising McLaughlin, P.C.
Brookfield Renewable Power
CA Bldg Industry Association
CENERGY POWER
CLECA Law Office
California Cotton Ginners & Growers Assn
California Energy Commission
California League of Food Processors
California Public Utilities Commission
Calpine
Cardinal Cogen
Casner, Steve
Center for Biological Diversity
Chris, King
City of Palo Alto
City of Palo Alto Utilities
City of San Jose
City of Santa Rosa
Clean Energy Fuels
Clean Power
Coast Economic Consulting
Commercial Energy
Consumer Federation of California
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Department of General Services
Department of Water Resources
Dept of General Services
Douglass & Liddell
Downey & Brand
Duke Energy
Economic Sciences Corporation
Ellison Schneider & Harris LLP
Foster Farms
G. A. Krause & Assoc.
GLJ Publications
GenOn Energy Inc.
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
Hitachi
In House Energy
International Power Technology
Intestate Gas Services, Inc.
Lawrence Berkeley National Lab
Los Angeles County Office of Education
Los Angeles Dept of Water & Power
MAC Lighting Consulting
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenna Long & Aldridge LLP
McKenzie & Associates
Merced Irrigation District
Modesto Irrigation District
Morgan Stanley
Morrison & Foerster
Morrison & Foerster LLP
NLine Energy, Inc.
NRG West
NaturEner
Norris & Wong Associates
North America Power Partners
North Coast SolarResources
Northern California Power Association
Occidental Energy Marketing, Inc.
OnGrid Solar
PG&E
Praxair
R. W. Beck & Associates
RCS, Inc.
SCD Energy Solutions
SCE
SMUD
SPURR
San Francisco Public Utilities Commission
Seattle City Light
Sempra Utilities
Sierra Pacific Power Company
Silicon Valley Power
Silo Energy LLC
Southern California Edison Company
Spark Energy, L.P.
Sun Light & Power
Sunrun Inc.
Sunshine Design
Sutherland, Asbill & Brennan
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Turlock Irrigation District
United Cogen
Utility Cost Management
Utility Specialists
Verizon
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
eMeter Corporation