Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for February 2014

Pacific Gas and Electric Company®

March 21, 2014

Pacific Gas and Electric Company ("PG&E") hereby submits this report on Interruptible Load and Demand Response Programs for February 2014. This report is being served on the Energy Division Director and the service list for A.11-03-001.

http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/cs/

Table I-1
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Subscription Statistics - Enrolled MW
February 2014

UTILITY NAME: Pacific Gas and Electric Company

Monthly Program Enrollment and Estimated Load Impacts

Programs	January Service Accounts	January Ex Ante Estimated MW [1]	January Ex Post Estimated MW [2]	February Service Accounts	February Ex Ante Estimated MW [1]	February Ex Post Estimated MW [2]	March Service Accounts	March Ex Ante Estimated MW [1]	March Ex Post Estimated MW [2]	April Service Accounts	April Ex Ante Estimated MW [1]	April Ex Post Estimated MW [2]	May Service Accounts	May Ex Ante Estimated MW [1]	May Ex Post Estimated MW [2]	June Service Accounts	June Ex Ante Estimated MW [1]	June Ex Post Estimated MW [2]	[4]Eligible Accounts as of Jan 1, 2013
Interruptible/Reliability																			
BIP - Day Of	249	184	218	218	166	191													10,424
OBMC	25	0	0	25	0	0													N/A
SLRP	0	0	0	0	0	0													N/A
SmartAC™ - Commercial	5,762	0	2	5,760	0	2													N/A
SmartAC™ - Residential	154,398	0	88	154,529	0	88													N/A
Sub-Total Interruptible	160,434	184	308	160,532	166	281													
Price Response																			
AMP - Day Ahead	680	0	146	675	0	145													592,761
AMP - Day Of	1952	0	223	1,941	0	222													592,761
CBP - Day Ahead	0	0	0	0	0	0													592,761
CBP - Day Of	0	0	0	0	0	0													592,761
DBP	940	37	36	930	38	35													10,424
PDP (200 kW or above)	1,814	49	34	1,796	48	33													387,153
PDP (<200 kW)	4,490	21	2	4,559	21	2													
SmartRate™ - Residential	118,053	0	33	118,441	0	33													N/A
Sub-Total Price Response	127,929	107	473	128,342	107	470													
Total All Programs	288,363	291	781	288,874	272	751													

Programs	July Service Accounts	July Ex Ante Estimated MW [1]	July Ex Post Estimated MW [2]	August Service Accounts	August Ex Ante Estimated MW [1]	August Ex Post Estimated MW [2]	September Service Accounts	September Ex Ante Estimated MW [1]	September Ex Post Estimated MW [2]	October Service Accounts	October Ex Ante Estimated MW [1]	October Ex Post Estimated MW [2]	November Service Accounts	November Ex Ante Estimated MW [1]	November Ex Post Estimated MW [2]	December Service Accounts	December Ex Ante Estimated MW [1]	December Ex Post Estimated MW [2]	[4]Eligible Accounts as of Jan 1, 2013
Interruptible/Reliability																			
BIP - Day of																			10,424
OBMC																			N/A
SLRP																			N/A
SmartAC - Commercial																			N/A
SmartAC - Residential																			N/A
Sub-Total Interruptible																			
Price Response																			
AMP - Day Ahead																			592,761
AMP - Day Of																			592,761
CBP - Day Ahead																			592,761
CBP - Day Of																			592,761
DBP																			10,424
PDP (200 kW or above)																			387,153
PDP (<200 kW)																			
SmartRate™ - Residential																			N/A
Sub-Total Price Response																			
Total All Programs																			

[1] Ex Ante Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 2, 2013 Load Impact Report for Demand Response. The values reported are calculated by using the monthly ex ante average load impact per customer multiplied by the number of currently enrolled service accounts for the reporting month, where the ex ante average load impact is the average hourly load impact for an event that would occur from 1 - 6 pm on the system peak day of the month. The Ex Ante Estimated MW value for the aggregator programs, e.g., AMP and CBP are the monthly nominated MW.

[2] Ex Post Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 2, 2013 Load Impact Report for Demand Response. The values reported are calculated by using the annual ex post average load impact per customer multiplied by the number of currently enrolled service accounts for the reporting month, where the ex post load impact per customer is the average load impact per customer for those customers that may have participated in an event(s) during all actual event hours in the preceding year when or if events occurred. New programs report "n/a", as there were no prior events.

NOTE: Readers should exercise caution in interpreting or using the estimated MW values found in this report in either the ex post or ex ante columns. Ex post estimates reflect historic event(s) that have taken place during specific time periods and actual weather conditions by a mix of customers that participated on event day(s). Ex ante forecasts account for variables not included in the Ex post estimate such as normalized weather conditions, expected customer mix during events, expected time of day which events occur, expected days of the week which events occur, and other lesser effects etc. An Ex ante forecast reflects forecast impact estimates that would occur between 1 pm and 6pm during a specific DR program's operating season, based on 1-in-2 (normal) weather conditions if all DR programs were called simultaneously on the system peak day. In either case, MW estimates in this report will vary from estimates filed in the PG&E's annual April 1st Compliance Filing pursuant to Decision D.08-04-050 and reporting documents that may be supplied to other agencies e.g. CAISO, FERC, NERC, etc. MW estimates found in the Monthly ILP Report are not used by PG&E for operational reporting, resource planning, and cost effectiveness analysis or in developing regulatory filings.

[4] The updated customer counts and impact data will be available in the March, 2014 ILP.

Program Eligibility and Average Load Impacts

Program	January	February	March	April	May	June	July	August	September	October	November	December	[1]Eligible Accounts as of Jan 1, 2013	Eligibility Criteria (Refer to tariff for specifics)
	Average Ex Ante Load Impact kW / Customer													
BIP - Day Of	740.42	760.09	748.56	861.83	842.17	895.97	870.06	897.95	884.24	842.82	807.72	805.61	10,424	Bundled, DA and CCA non-residential customer service accounts that have at least an average monthly demand of 100 kW.
OBMC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Bundled, DA and CCA non-residential customer accounts with interval meters that must be able to reduce electric load such that the entire load on the PG&E circuit or dedicated substation that provides service to that customer is reduced to or below Maximum Load Levels (MLLs) for the entire duration of each and every RO operation.
SLRP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Bundled-service customers taking service under Schedules A-10, E-19 or E-20 & minimum <u>*average monthly demand of 100 kilowatts*</u> (kW). Customers must commit to minimum 15% of baseline usage, with a minimum load reduction of 100 kW.
SmartAC™ - Commercial	N/A	N/A	N/A	N/A	0.37	0.47	0.69	0.55	0.51	0.32	N/A	N/A	N/A	Small and medium business customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
SmartAC™ - Residential	N/A	N/A	N/A	N/A	0.38	0.45	0.66	0.52	0.53	0.29	N/A	N/A	N/A	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
AMP - Day Ahead	N/A	N/A	N/A	N/A	157.27	157.27	157.27	157.27	157.27	157.27	N/A	N/A	592,761	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
AMP - Day Of	N/A	N/A	N/A	N/A	99.77	102.89	105.63	107.07	105.69	101.91	N/A	N/A	592,761	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
CBP - Day Ahead	N/A	N/A	N/A	N/A	109.42	131.45	140.98	116.76	95.38	107.48	N/A	N/A	592,761	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
CBP - Day Of	N/A	N/A	N/A	N/A	71.02	75.88	74.99	77.35	68.79	77.48	N/A	N/A	592,761	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
DBP	39.79	40.50	38.51	43.39	49.30	50.24	46.19	49.18	51.60	49.16	38.78	40.48	10,424	Non-residential Customers 200 kW or above on a demand TOU rate schedule, not on rate schedule AG-R, AG-V or S. Eligible customers include PG&E Bundled, Direct Access (DA; ESP), and Community Choice Aggregation Service. Non-residential Customers' accounts < 200 kW may participate as aggregated group for service accounts with same Federal Taxpayer ID Number.
PDP (200 kW or above)	26.84	26.84	26.84	27.04	26.74	25.14	23.79	26.06	24.88	26.90	27.08	27.08	387,153	Default beginning on: May 1, 2010 for bundled C&I Customers >200kW Maximum Demand; February 1st, 2011 for large bundled Ag customers; November 2014 for bundled C&I Customers with <200 kW Maximum Demand and 12 consecutive months of interval data.
PDP (<200 kW)	4.57	4.57	4.57	4.50	4.88	3.81	4.74	3.95	4.33	4.07	4.57	4.57		
SmartRate™ - Residential	N/A	N/A	N/A	N/A	0.16	0.22	0.31	0.25	0.24	0.14	N/A	N/A	N/A	A voluntary rate supplement to residential customers' otherwise applicable schedule. Available to Bundled-Service customers served on a single family residential electric rate schedule.

The average ex ante load impacts per customer are based on the load impacts filing on April 2, 2013 (D.08-04-050). Estimated Average Ex Ante Load Impact kW/Customer = Average kW / Customer, under 1-in-2 weather conditions, of an event that would occur from 1 - 6 pm (or 2 - 6 pm for PDP) for April through October, and 4 - 9 pm for November through March, on the system peak day of the month.

[1]The updated customer counts and impact data will be available in the March, 2014 ILP.

Pacific Gas and Electric Company
Average Ex Post Load Impact kW / Customer
February 2014

Program Eligibility and Average Load Impacts

	Average Ex Post Load Impact kW / Customer													
Program	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**[1]Eligible Accounts as of**	**Eligibility Criteria (Refer to tariff for specifics)**
BIP - Day Of	877.0	877.0	877.0	877.0	877.0	877.0	877.0	877.02	877.0	877.0	877.0	877.0	10,424	Bundled, DA and CCA non-residential customer service accounts that have at least an average monthly demand of 100 kW.
OBMC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Bundled, DA and CCA non-residential customer accounts with interval meters that must be able to reduce electric load such that the entire load on the PG&E circuit or dedicated substation that provides service to that customer is reduced to or below Maximum Load Levels (MLLs) for the entire duration of each and every RO operation.
SLRP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Bundled-service customers taking service under Schedules A-10, E-19 or E-20 & minimum *average monthly demand of 100 kilowatts* (kW). Customers must commit to minimum 15% of baseline usage, with a minimum load reduction of 100 kW.
SmartAC™ - Commercial	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	N/A	Small and medium business customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
SmartAC™ - Residential	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	N/A	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
AMP - Day Ahead	214.40	214.40	214.40	214.40	214.40	214.40	214.40	214.40	214.40	214.40	214.40	214.40	592,761	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
AMP - Day Of	114.20	114.20	114.20	114.20	114.20	114.20	114.20	114.20	114.20	114.20	114.20	114.20	592,761	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
CBP - Day Ahead	121.50	121.50	121.50	121.50	121.50	121.50	121.50	121.50	121.50	121.50	121.50	121.50	592,761	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
CBP - Day Of	62.80	62.80	62.80	62.80	62.80	62.80	62.80	62.80	62.80	62.80	62.80	62.80	592,761	Non-residential customers on commercial, industrial, partial standby, or agricultural rate schedules, except those who receive electric power from third parties (other than DA), billed via net metering or full standby services.
DBP	37.88	37.88	37.88	37.88	37.88	37.88	37.88	37.88	37.88	37.88	37.88	37.88	10,424	Non-residential Customers 200 kW or above on a demand TOU rate schedule, not on rate schedule AG-R, AG-V or S. Eligible customers include PG&E Bundled, Direct Access (DA; ESP), and Community Choice Aggregation Service. Non-residential Customers' accounts < 200 kW may participate as aggregated group for service accounts with same Federal Taxpayer ID Number.
PDP (200 kW or above)	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	387,153	Default beginning on: May 1, 2010 for bundled C&I Customers >200kW Maximum Demand; February 1st, 2011 for large bundled Ag customers; November 2014 for bundled C&I Customers with <200 kW Maximum Demand
PDP (<200 kW)	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36		
SmartRate™ - Residential	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	N/A	A voluntary rate supplement to residential customers' otherwise applicable schedule. Available to Bundled-Service customers served on a single family residential electric rate schedule.

The average ex post load impacts per customer are based on the load impacts filing on April 2, 2013 (D.08-04-050). Estimated Average Ex Post Load Impact kW / Customer = Average kW / Customer service account over all actual event hours for the preceeding year when or if events occurred. Some programs may experience no events or few events while other programs may operate regularly depending on event triggers. For existing programs, the average ex post load impact per customer SAID remains constant across all months. The average load impact is "N/A" for programs having no prior events. Commercial SmartAC was not called in 2012; its average-customer impact reported here is from the April 2, 2012 filing.

[1]The updated customer counts and impact data will be available in the March, 2014 ILP.

Table I-2
Pacific Gas and Electtric Company
Program Subscription Statistics
February 2014

Detailed Breakdown of MWs To Date in TA/Auto DR/TI Programs

2014	January				February				March				April				May				June			
Price Responsive	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs
AMP - Day Ahead		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
AMP - Day Of		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
CBP - Day Ahead		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
CBP - Day Of		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
DBP		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
PDP		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
SmartRate™ - Residential		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
SmartAC™ - Commercial		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
SmartAC™ - Residential		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
Total		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**																
Interruptible/Reliability																								
BIP - Day of		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
OBMC		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
SLRP		0.0	0.0	**0.0**		0.0	0.0	**0.0**																
Total		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**																
Total Technology MWs		**0.0**	**0.0**	**0.0**		**0.0**	**0.0**	**0.0**																
General Program																								
TA (may also be enrolled in TI and AutoDR)	0.4				0.4																			
Total	**0.4**				**0.4**																			
Total TA MWs	**0.4**	N/A	N/A	N/A	**0.4**	N/A	N/A	N/A		N/A	N/A	N/A		N/A	N/A	N/A		N/A	N/A	N/A		N/A	N/A	N/A

2014	July				August				September				October				November				December			
Price Responsive	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs	TA Identified MWs	Auto DR Verified MWs	TI Verified MWs	Total Technology MWs
AMP - Day Ahead																								
AMP - Day Of																								
CBP - Day Ahead																								
CBP - Day Of																								
DBP																								
PDP																								
SmartRate™ - Residential																								
SmartAC™ - Commercial																								
SmartAC™ - Residential																								
Total																								
Interruptible/Reliability																								
BIP - Day of																								
OBMC																								
SLRP																								
Total																								
Total Technology MWs																								
General Program																								
TA (may also be enrolled in TI and AutoDR)																								
Total																								
Total TA MWs		N/A	N/A	N/A		N/A	N/A	N/A		N/A	N/A	N/A		N/A	N/A	N/A		**N/A**	**N/A**	**N/A**		**N/A**	**N/A**	**N/A**

Beginning August 2013, the SmartAC program has been moved from the Interruptible/Reliability to Price Responsive Category per D.12-04-045.

Table I-3
Pacific Gas and Electric Company
Demand Response Programs and Activities
2012-2014 Incremental Cost Funding
February 2014

2012-2014 Program Expenditures

Cost Item	2012 and 2013 Expenditures	January	February	March	April	May	June	July	August	September	October	November	December	Year-to Date 2014 Expenditures	Program-to-Date Total Expenditures 2012-2014	3-Year Funding	Fundshift Adjustments [4]	Percent Funding
Category 1: Reliability Programs																		
Base Interruptible Program (BIP)	$451,829	$9,630	$14,854											$24,484	$476,312	$666,349		71.5%
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	$159,363	$1,121	$1,854											$2,975	$162,338	$413,532		39.3%
Budget Category 1 Total	$611,192	$10,750	$16,708	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,458	$638,650	$1,079,881	$0	59.1%
Category 2: Price-Responsive Programs																		
Demand Bidding Program (DBP)	$498,460	$13,416	$16,415											$29,831	$528,291	$3,216,000		16.4%
Capacity Bidding Program (CBP)	$662,889	$23,045	$30,178											$53,223	$716,112	$11,563,485		6.2%
Peak Choice [1]	$843,326	$156	$119											$275	$843,601	$1,750,000		48.2%
SmartAC™	$6,929,374	$161,983	$276,486											$438,469	$7,367,843	$19,353,335		38.1%
Budget Category 2 Total	$8,934,048	$198,600	$323,198	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$521,798	$9,455,846	$35,882,820	$0	26.4%
Category 3: DR Provider/Aggregator Managed Programs																		
Aggregator Managed Portfolio (AMP)	$620,347	$23,348	$21,629											$44,978	$665,324	$1,187,700		56.0%
Budget Category 3 Total	$620,347	$23,348	$21,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$44,978	$665,324	$1,187,700	$0	56.0%
Category 4: Emerging & Enabling Programs																		
Auto DR	$3,429,791	$47,920	$157,568											$205,489	$3,635,279	$26,297,459		13.8%
DR Emerging Technology	$638,142	$89,921	$100,104											$190,026	$828,167	$3,749,238		22.1%
Budget Category 4 Total	$4,067,932	$137,842	$257,673	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$395,514	$4,463,446	$30,046,697	$0	14.9%
Category 5: Pilots																		
IRR Phase 2	$489,707	$81,891	$47,199											$129,089	$618,796	$2,458,336		25.2%
T&D DR	$156,168	$13,466	$14,544											$28,010	$184,178	$2,458,336		7.5%
Plug-in Hybrid EV/EV (incl. HAN-EV)	$110,937	$4,631	$2,507											$7,138	$118,075	$3,000,000		3.9%
Budget Category 5 Total	$756,812	$99,988	$64,249	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$164,237	$921,049	$7,916,672	$0	11.6%
Category 6: Evaluation, Measurement and Verification																		
DRMEC	$3,690,348	$329,776	$214,082											$543,858	$4,234,206	$14,520,981		29.2%
DR Research Studies	-	-	-											-	-	$1,200,000		0.0%
Budget Category 6 Total	$3,690,348	$329,776	$214,082	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$543,858	$4,234,206	$15,720,981	$0	26.9%
Category 7: Marketing, Education and Outreach																		
Statewide Marketing [1]	$3,360,000	-	-											-	$3,360,000	$3,500,000		96.0%
DR Core Marketing and Outreach [2]	$1,819,726	$29,920	$43,609											$73,529	$1,893,255	$13,000,000		46.9%
SmartAC™ ME&O [3]	$4,021,452	$51,154	$132,493											$183,647	$4,205,099	$0		
Education and Training	$146,896	$2,461	$4,398											$6,859	$153,755	$771,993		19.9%
Budget Category 7 Total	$9,348,074	$83,536	$180,499	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$264,035	$9,612,109	$17,271,993	$0	55.7%
Category 8: DR System Support Activities																		
InterAct / DR Forecasting Tool	$6,777,573	$892,009	$249,639											$1,141,648	$7,919,222	$14,407,887		55.0%
DR Enrollment & Support	$6,744,848	($450,046)	$722,043											$271,997	$7,016,845	$15,787,400		44.4%
Notifications	$562,647	$1,875	$5,268											$7,143	$569,791	$7,427,715		7.7%
DR Integration Policy & Planning	$1,340,078	$83,299	$138,984											$222,283	$1,562,362	$3,893,342		40.1%
Budget Category 8 Total	$15,425,146	$527,138	$1,115,935	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,643,072	$17,068,219	$41,516,344	$0	41.1%
Category 9: Integrated Programs and Activities (Including Technical Assistance)																		
Technology Incentives - IDSM [5]	$1,000,994	($115,661)	$231,348											$115,688	$1,116,682	$7,538,000		14.8%
PEAK [1]	$541,609	-	-											-	$541,609	$560,000		96.7%
Integrated Marketing & Outreach [1]	$359,406	-	$0											$0	$359,406	$377,500	$73,000	95.2%
Integrated Education & Training [1]	$15,181	$39	$30											$68	$15,249	$61,000		25.0%
Integrated Sales Training [1]	$14,507	-	-											-	$14,507	$76,000		19.1%
Integrated Energy Audits [5]	$1,028,451	$10,470	$20,768											$31,239	$1,059,690	$3,719,000	($73,000)	28.5%
Integrated Emerging Technology [1]	$427,248	($158)	-											($158)	$427,090	$440,000		97.1%
Budget Category 9 Total	$3,387,396	($105,310)	$252,146	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$146,836	$3,534,232	$12,771,500	$0	27.7%
Category 10: Special Projects																		
DR-HAN Integration (excl. HAN-EV) [6]																$11,941,000		35.5%
HAN Integration Expense	$39,915	$47,631	$22,697											$70,328	$110,243			
HAN Integration Capital [8]	$2,935,105	$591,328	$608,016											$1,199,344	$4,134,449			
Permanent Load Shifting	$608,747	$45,277	$62,162											$107,439	$716,186	$15,000,000		4.8%
Budget Category 10 Total	$3,583,767	$684,236	$692,875	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,377,111	$4,960,878	$26,941,000	$0	18.4%
Recovery of Capital Costs Authorized Prior to 2009	$1,675,359	$64,449	$64,449											$128,898	$1,804,257	$0	$0	N/A
Total Incremental Cost [7]	$52,100,423	$2,054,352	$3,203,443	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,257,795	$57,358,218	$190,335,588	$0	30.1%

Technical Assistance & Technology Incentives (TA&TI) Identified as of FEBRUARY 2014.	$0

[1] Authorized funding for 2012 only.
[2] The expenditures listed are in support of PG&E's DR programs for large commercial, industrial and agricultural customers, excluding the aggregator-managed programs. Disclosure complies with OP 24 of D.12-04-045. The 2012-14 approved budget for DR Core Marketing and Outreach
[3] The budget for SmartAC marketing, education, and outreach costs are included in the 2012-14 approved budget for DR Core Marketing and Outreach; however, the expenses are separated to differentiate the ME&O efforts targeting residential and small commercial customers. SmartAC is
[4] See the Fund Shift Log 2012-14 for explanations.
[5] Additional funding for Technology Incentives and Integrated Energy Audits was approved in Energy Efficiency Decision 12-11-015 for 2013 and 2014.
[6] The CPUC authorized the HAN Integration Project in the amount of $11,941,000 on April 8, 2013 per Advice Letter 4119-E/E-A.
[7] Total Incremental Cost excludes incentives. Incentives are reported on Table I-5.
[8] The HAN Integration capital expenditures are for informational purpose only, that is, the capital revenue requirement will not be recorded in DREBA until the assets are operational.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
February 2014

Program Category	Program Name	Month	Zones (1)	Event Date	Event No. (by Program Type)	Program Type	Trigger	# of Accounts	Event Start Time (PDT)	Event End Time (PDT)	Program Tolled Hours	Load Reduction MW (Max Hourly) (2)
Category 1: Reliability Programs												
	Base Interruptible Program (BIP)	FEBRUARY	System, All SubLaps	2/6/14		Day Of	Ordered by ISO	220	3:15 PM	7:15 PM	4	189.3
	Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)											
Category 2: Price-Responsive Programs												
	Capacity Bidding Program (CBP)											
	Demand Bidding Program (DBP)											
	Peak Day Pricing (PDP)											
	SmartAC™											
	SmartRate™											
Category 3: DR Provider/Aggregator Managed Programs												
	Aggregator Managed Portfolio (AMP)											

Table I-5
Pacific Gas and Electric Company
2012-2014 Demand Response Programs
Total Embedded Cost and Revenues
February 2014

Annual Total Cost															
Cost Item	**2012 and 2013 Cost of Incentives**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Year-to-Date 2014 Total Cost**	**Program-to-Date Total Cost**
Program Incentives															
Automatic Demand Response (AutoDR)	$94,906	$0	$0											$0	$94,906
Aggregator Managed Portfolio (AMP)[1]	$27,419,047	$0	$0											$0	$27,419,047
Base Interruptible Program (BIP)[1]	$47,541,369	$1,843,389	1,943,367											$3,786,756	$51,328,125
Capacity Bidding Program (CBP)	$3,201,084	($15)	($4)											($19)	$3,201,065
Demand Bidding Program (DBP)	$975,678	$0	$0											$0	$975,678
Optional Binding Mandatory Curtailment / Scheduled Load Reduction Program (OBMC / SLRP)[1]	$0	$0	$0											$0	$0
Technology Incentive (TI)	$567,000	$0	$0											$0	$567,000
PeakChoice	$139,230	$0	$0											$0	$139,230
Commercial and Industrial Based Intermittent Resource Management Pilot 2	$100,000	$0	$0											$0	$100,000
SmartAC™	$1,223,030	$27,099	$72,159											$99,258	$1,322,288
Total Cost of Incentives	$81,261,343	$1,870,473	$2,015,522	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,885,995	$85,147,338
Revenues from Penalties[2]	$71,863	$0	$0										$0	$0	$71,863

[1]Amounts reported are for incentive costs that are not recorded in the Demand Response Expenditures Balancing Account. Incentives are recorded at the time of payment.
[2] The amount reported for November 2013 represents the termination fee received from an AMP aggregator who defaulted on Product B (Day-Ahead with Local Dispatch). As per D.13-01-024, which authorized the cost recovery of agreement costs for the AMP program in the Energy Resource Recovery Account (ERRA), the termination fee received was posted in ERRA.

Table I-7
Pacific Gas and Electric Company
2012-2014 Marketing, Education and Outreach
Actual Expenditures
February 2014

PG&E's ME&O Actual Expenditures	2012- 2014 Funding Cycle Customer Communication, Marketing, and Outreach													Year-to Date 2014 Expenditures	2012-2014 Total Expenditures	Authorized Budget (if Applicable)
	2012 and 2013 Expenditures	January	February	March	April	May	June	July	August	September	October	November	December			
I. STATEWIDE MARKETING[1]																
IOU Administrative Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Statewide ME&O contract	$ 3,360,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,360,000	
I. TOTAL STATEWIDE MARKETING		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,360,000	$ 3,500,000
II. UTILITY MARKETING BY ACTIVITY[2,3,4]																
TOTAL AUTHORIZED UTILITY MARKETING BUDGET FOR 2012-2014																
PROGRAMS, RATES & ACTIVITES WHICH DO NOT REQUIRE ITEMIZED ACCOUNTING																
Integrated Demand Side Marketing[5]	$ 374,586	$ 39	$ 30											$ 68	$ 374,655	$ 438,500
Marketing My Account/Energy and Integrated Online Audit Tools	$ -	$ -	$ -											$ -	$ -	
Critical Peak Pricing > 200 kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Demand Bidding Program	$ 633,948	$ 16,191	$ 24,003											$ 40,194	$ 674,142	
Real Time Pricing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Permanent Load Shifting	$ 276,870	$ 6,476	$ 9,601											$ 16,078	$ 292,948	
Circuit Savers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Small Commercial Technology Deployment	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Enabling Technologies (e.g., AutoDR, TI)	$ 589,987	$ 9,714	$ 14,402											$ 24,116	$ 614,103	
PeakChoice	$ 465,817	$ -	$ -											$ -	$ 465,817	
Customer Awareness, Education and Outreach	$ -	$ -	$ -											$ -	$ -	
PROGRAMS & RATES WHICH REQUIRE ITEMIZED ACCOUNTING																
SmartAC	$ 4,021,452	$ 51,154	$ 132,493	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 183,647	$ 4,205,099	
Customer Research	$ -	$ -	$ -											$ -	$ -	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 3,438,383	$ 39,469	$ 89,746											$ 129,215	$ 3,567,598	
Labor	$ 516,395	$ 11,686	$ 32,422											$ 44,107	$ 560,502	
Paid Media	$ -	$ -	$ -											$ -	$ -	
Other Costs	$ 66,674	$ -	$ 10,325											$ 10,325	$ 76,999	
II. TOTAL UTILITY MARKETING BY ACTIVITY	$ 6,362,661	$ 83,575	$ 180,529	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 264,104	$ 6,626,764	$ 14,210,493
III. UTILITY MARKETING BY ITEMIZED COST																
Customer Research	$ 37,290	$ -	$ -											$ -	$ 37,290	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 3,986,335	$ 39,093	$ 89,746											$ 128,839	$ 4,115,174	
Labor	$ 2,229,975	$ 44,482	$ 80,458											$ 124,939	$ 2,354,914	
Paid Media	$ -	$ -	$ -											$ -	$ -	
Other Costs	$ 109,061	$ -	$ 10,325											$ 10,325	$ 119,386	
III. TOTAL UTILITY MARKETING BY ITEMIZED COST	$ 6,362,661	$ 83,575	$ 180,529	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 264,104	$ 6,626,764	
IV. UTILITY MARKETING BY CUSTOMER SEGMENT																
Agricultural	$ 351,181	$ 4,863	$ 7,205											$ 12,068	$ 363,250	
Large Commercial and Industrial	$ 1,990,027	$ 27,557	$ 40,831											$ 68,388	$ 2,058,415	
Small and Medium Commercial	$ 201,073	$ 2,558	$ 6,625											$ 9,182	$ 210,255	
Residential	$ 3,820,380	$ 48,597	$ 125,868											$ 174,465	$ 3,994,844	
IV. TOTAL UTILITY MARKETING BY CUSTOMER SEGMENT	$ 6,362,661	$ 83,575	$ 180,529	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 264,104	$ 6,626,764	

Notes:

[1]Statewide Marketing refers to the one year of funding, which is equal to $3.5 million, to be used for an emergency alert campaign as per D.12-04-045 Ordering Paragraph 19.

[2]Utility Marketing includes all activities to market individual utility programs or rates, demand response concepts, and customer tools, that were approved or directed by Decision 12-04-045, whether or not the marketing budget was approved as a line item in the Decision. For example, PG&E should not include marketing for TOU and PDP because funding was authorized in another proceeding. However, PG&E must document all amounts spent on marketing individual demand response programs such as Peak Choice even though a specific marketing budget was not approved for the program. This example applies to all of the utilities. The programs and activities listed in item II of the template are meant as examples, and may not be exhaustive. However, the utilities must include all programs or rates that meet this description. The totals for Items II, III and IV should be equal.

[3]The 2012 Authorized Budget for Integrated Demand Side Marketing includes the budget for Integrated Marketing & Outreach ($304,500) and Integrated Education & Training ($61,000).

[4]The Total Authorized Budget for Utility Marketing includes the Integrated Demand Side Marketing budget for 2012 and the local ME&O (DR Core Marketing & Outreach and Education &Training) budget for 2012-14.

[5]See the Fund Shift Log 2012-14 for explanations.

FUND SHIFTING DOCUMENTATION PER DECISION 12-04-045 ORDERING PARAGRAPH 4

OP 4:

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company:
May not shift funds between categories with two exceptions as stated in Ordering Paragraphs 4 and 5;
May continue to shift up to 50 percent of a Demand Response program's funds to another program within the same budget category, with proper monthly reporting;
Shall not shift funds within the "Pilots" or "Special Projects" categories without submitting a Tier 2 Advice Letter filing;
May shift funds for pilots in the Enabling or Emerging Technologies category;
Shall continue to submit a Tier 2 Advice Letter to eliminate a Demand Response program;
Shall not eliminate a program through multiple fund shifting events or for any other reason without prior authorization from the Commission; and
Shall submit a Tier 2 Advice Letter before shifting more than 50 percent of a program's funds to a different program within the same budget category.

Program Category	Fund Shift Amount	Programs Impacted	Date	Rationale for Fundshift
Category 1: Reliability Programs	$0.00			
Category 2: Price-Responsive Programs	$0.00			
Category 3: DR Provider/Aggregator Managed Programs	$0.00			
Category 4: Emerging & Enabling Programs	$0.00			
Category 5: Pilots	$0.00			
Category 6: Evaluation, Measurement and Verification	$0.00			
Category 7: Marketing, Education and Outreach	$0.00			
Category 8: DR System Support Activities	$0.00			
Category 9: Integrated Programs and Activities	$73,000	Integrated Energy Audits to Integrated Marketing & Outreach	12/1/2012	The transferred funds support the expanded effort to increase adoption of energy management solutions, which integrate DR with other PG&E programs.
Category 10: Special Projects	$0.00			
Total	**$73,000**			