Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for December 2015

Changed the initial posting date from January 21, 2015 to January 21, 2016

Revised October 10, 2016

Added Carry-Over Expenditures and Funding, Page 7b

Replaced and changed title to Customer Program Incentives and Penalties, Table I-5a, Page 9

and converted AMP/BIP to accrual basis

Added Carry-Over Incentives and Funding, Table I-5b, Page 9b

Pacific Gas and Electric Company®

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Pacific Gas and Electric Company ("PG&E") hereby submits this report on Interruptible Load and Demand Response Programs for December. 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/

NOTE:

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Table I-1
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Subscription Statistics - Enrolled MW
December 2015

UTILITY NAME: Pacific Gas and Electric Company

Monthly Program Enrollment and Estimated Load Impacts

	January			February			March			April			May			June			
Programs	**Service Accounts [4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3, 4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3, 4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**[4] Eligible Accounts as of Jan 1, 2015**
Interruptible/Reliability																			
BIP - Day Of	219	214	229	203	212	212	207	215	217	207	241	217	207	223	217	206	240	216	10,843
OBMC	24	0	0	24	0	0	24	0	0	23	0	0	23	0	0	22	0	0	N/A
SLRP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	N/A
SmartAC™ - Commercial	4,833	0	1	4,796	0	1	4,760	0	1	4,730	0	1	4,710	2	1	4,612	3	1	N/A
SmartAC™ - Residential	152,200	0	79	153,547	0	80	154,173	0	80	154,257	0	80	154,515	52	80	152,380	83	79	N/A
Sub-Total Interruptible	157,276	214	310	158,570	212	294	159,164	215	298	159,217	241	298	159,455	277	298	157,220	326	296	
Price Response																			
AMP - Day Of	3,036	0	267	2,167	0	190	2,160	0	190	2,169	0	191	1,287	151	113	1,457	121	128	592,761
CBP - Day Ahead	0	0	0	0	0	0	0	0	0	0	0	0	204	21	30	175	21	26	596,779
CBP - Day Of	0	0	0	0	0	0	0	0	0	0	0	0	587	26	11	508	27	10	
DBP	794	23	24	790	27	23	784	25	23	767	31	23	767	28	23	570	23	17	10,843
PDP (200 kW or above)	1,846	15	46	1,811	15	45	1,838	16	45	1,939	37	48	1,893	37	47	1,866	46	46	6,491
PDP (above 20 kW & below 200 kW)	26,141	2	47	25,889	2	46	25,600	2	46	25,307	6	45	25,132	7	45	24,549	7	44	62,160
PDP (20 kW or below)	151,138	2	21	149,973	2	21	148,192	2	21	146,863	5	21	145,825	5	21	140,829	6	20	323,726
SmartRate™ - Residential	125,599	0	38	124,529	0	37	123,129	0	37	125,057	0	38	126,762	22	38	126,907	38	38	N/A
Sub-Total Price Response	308,554	43	442	305,159	47	363	301,703	46	362	302,102	80	365	302,457	297	328	296,861	289	329	
Total All Programs	465,830	258	751	463,729	259	657	460,867	260	660	461,319	321	663	461,912	574	626	454,081	615	625	

	July			August			September			October			November			December			
Programs	**Service Accounts [3, 4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3, 4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3, 4]**	**Ex Ante Estimate MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [3, 4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts [4]**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**[4] Eligible Accounts as of Jan 1, 2015**
Interruptible/Reliability																			
BIP - Day of	206	244	216	208	252	218	209	245	219	210	240	220	210	220	220	210	212	220	10,843
OBMC	22	0	0	22	0	0	22	0	0	22	0	0	22	0	0	22	0	0	N/A
SLRP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	N/A
SmartAC™ - Commercial	4,555	3	1	4,508	3	1	4,476	2	1	4,430	1	1	4,403	0	1	4,373	0	1	N/A
SmartAC™ - Residential	151,110	82	79	150,487	79	78	151,580	73	79	151,898	37	79	153,537	0	80	153,686	0	80	N/A
Sub-Total Interruptible	155,893	329	296	155,225	334	297	156,287	320	299	156,560	278	300	158,172	220	301	158,291	212	301	
Price Response																			
AMP - Day Of	1,446	121	127	1,466	120	129	1,434	119	126	1,452	119	128	2,684	0	236	2,661	0	234	592,761
CBP - Day Ahead	181	21	27	200	30	30	198	28	29	164	27	24	0	0	0	0	0	0	596,779
CBP - Day Of	633	32	12	589	20	11	571	19	11	523	18	10	0	0	0	0	0	0	
DBP	513	20	15	508	21	15	503	20	15	502	19	15	495	18	15	495	16	15	10,843
PDP (200 kW or above)	1,865	46	46	1,786	44	44	1,790	42	44	1,796	35	44	1,782	17	44	2,086	17	52	6,491
PDP (above 20 kW & below 200 kW)	24,184	7	43	23,772	7	42	23,603	7	42	23,308	6	42	24,295	2	43	33,652	3	60	385,886
PDP (20 kW or below)	138,492	6	20	136,980	6	19	135,821	6	19	133,921	5	19	138,462	2	20	187,441	3	27	
SmartRate™ - Residential	125,895	37	38	126,778	37	38	132,779	36	40	134,405	17	40	137,690	0	0	143,593	0	0	N/A
Sub-Total Price Response	293,209	290	328	292,079	285	329	296,699	276	327	296,071	245	322	305,408	39	357	369,928	39	387	
Total All Programs	449,102	620	624	447,304	619	626	452,986	596	626	452,631	524	622	463,580	258	658	528,219	251	688	

[1] Ex Ante Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 1, 2015 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 during the event season May through October.

[2] Ex Post Estimated MW = In compliance with Decision 08-04-050, the values presented herein are based on the April 1, 2015 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 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

NOTE: There is also another group of customers on the Critical Peak Pricing (CPP also known as PDP) rate, e.g., small business and medium C&I customers, who are enrolled on CPP on a purely voluntary basis. This group of customers is referred to as the voluntary CPP customers. The great majority of these service accounts are associated with a single business entity and do not respond on event days. These voluntary CPP participants inflate the enrollment number because they are not representative of the small business or medium C&I populations that will continue to default onto CPP in coming years. Load impacts for these customers are presented in the PG&E electronic ex post load impact table generator; but it is important to remember that their load impacts do not reflect what would be expected from the small business and medium C&I customer classes in the future under default CPP.

NOTE: The April 2015 ILP provides update to the AMP available 2015-2016 data for Eligible Accounts and Program Eligibility for Ex Ante and Ex Post Average Load Impacts. This updates the January, February and March data for the Ex Ante and Ex Post estimated MW and eliminates AMP-DA since it's no longer offered.

NOTE: The April 2015 ILP provides update to the PDP Eligible Accounts and Program Eligibility for Ex Ante and Ex Post Average Load Impacts. This updates the January, February and March data for the Ex Ante and Ex Post estimated MW and further differentiates the PDP customer size.

3 AMP and CBP values for the event season (May - October) have been updated based on new inputs.

[4] PDP Service Accounts have been corrected to reflect the enrollment counts by customer size.

Program Eligibility and Ex Ante Average Load Impacts

Program	Average Ex Ante Load Impact kW / Customer												[1] Eligible Accounts as of Jan 1, 2015	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - Day Of	979.39	1045.67	1037.94	1165.99	1075.80	1165.67	1184.85	1211.97	1171.07	1142.09	1046.04	1008.01	10,843	This schedule is available to bundled-service, Community Choice Aggregation (CCA) Service, and Direct Access (DA) commercial, industrial, and agricultural customers. Each customer, both directly enrolled and those enrolled in an aggregator's portfolio, must take service under the provisions of a demand time-of-use rate schedule to participate in the Program and have at least an average monthly demand of 100 kilowatt (kW). Customers being served under Schedules AG-R or AG-V are not eligible for this program. Customers taking service under DA must meet the metering requirements prescribed in the Metering Equipment section of this rate schedule.
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	Not Available	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	Not Available	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	N/A	N/A	N/A	N/A	0.39	0.62	0.62	0.61	0.53	0.29	N/A	N/A	Not Available	Small and medium business customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment. Closed to new enrollment.
SmartAC™ - Residential	N/A	N/A	N/A	N/A	0.34	0.54	0.54	0.52	0.48	0.24	N/A	N/A	Not Available	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
AMP - Day Of	N/A	N/A	N/A	N/A	84.87	84.87	84.87	84.87	84.87	84.87	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	148.54	153.00	158.86	147.37	137.79	140.95	N/A	N/A	596,779	A customer may participate in either the Day-Ahead or Day-Of option. A customer with multiple service agreements (SA) may nominate demand reductions from a single SA to either the Day-of option or Day-ahead option. A SA may not be nominated to both the Day-of and Day-ahead option during a single program month. Customers that receive electric power from third parties (other than through direct access and Community Choice Aggregation) and customers billed for standby service are not eligible for Schedule E-CBP. Eligible customers include those receiving partial standby service or services pursuant to one or more of the Net Energy Metering Service schedules except NEMCCSF.
CBP - Day Of	N/A	N/A	N/A	N/A	16.81	18.07	18.94	18.76	18.62	16.39	N/A	N/A		A customer may participate in either the Day-Ahead or Day-Of option. A customer with multiple service agreements (SA) may nominate demand reductions from a single SA to either the Day-of option or Day-ahead option. A SA may not be nominated to both the Day-of and Day-ahead option during a single program month. Customers that receive electric power from third parties (other than through direct access and Community Choice Aggregation) and customers billed for standby service are not eligible for Schedule E-CBP. Eligible customers include those receiving partial standby service or services pursuant to one or more of the Net Energy Metering Service schedules except NEMCCSF.
DBP	29.38	34.42	32.50	40.88	37.06	39.75	39.52	41.33	39.07	38.11	35.95	32.78	10,843	This schedule is available to individual PG&E bundled-service customers, Community Choice Aggregation Service (CCA Service) customers, and Direct Access (DA) customers. Each customer must take service under the provisions of their otherwiseapplicable rate schedule. Customers participating in the Program must be on an eligible rate schedule and able to reduce load by at least 10 kW during an E-DBP event. Prior to May 1, 2013, customers with SAs throughout PG&E's electric service territory with individual meters with demands less than 200 kW (as described in the Applicability Section) had the option to participate in this Program under the provisions stated in the Aggregated Group Section of this rate schedule. Those SAs participating as an Aggregated Group as of May 1, 2013, may continue to participate as an Aggregated Group.
PDP (200 kW or above)	8.35	8.40	8.70	19.34	19.52	24.42	24.46	24.37	23.50	19.64	9.34	8.31	6,491	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 (above 20 kW & below 200 kW)	0.09	0.09	0.09	0.23	0.26	0.30	0.30	0.30	0.29	0.24	0.10	0.09	62,160	
PDP (20 kW or below)	0.01	0.01	0.01	0.03	0.04	0.05	0.05	0.05	0.04	0.03	0.01	0.01	323,726	
SmartRate™ - Residential	N/A	N/A	N/A	N/A	0.17	0.30	0.30	0.29	0.27	0.13	N/A	N/A	Not Available	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 1, 2015 (R.13-09-011). 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 for April through October, and 4 - 9 pm for November through March, on the PG&E system peak day of the month.

NOTE: The April 2015 ILP provides update to the PDP Eligible Accounts and Program Eligibility for Ex Ante and Expost Average Load Impacts.

Pacific Gas and Electric Company
Average Ex Post Load Impact kW / Customer
December 2015

Program Eligibility and Ex Post Average Load Impacts

Program	Average Ex Post Load Impact kW / Customer												[1] Eligible Accounts as of Jan 1, 2015	Eligibility Criteria (Refer to tariff for specifics)
	January	February	March	April	May	June	July	August	September	October	November	December		
BIP - Day Of	1046.7	1046.7	1046.7	1046.7	1046.7	1046.7	1046.7	1046.7	1046.7	1046.7	1046.7	1046.7	10,843	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	Not Available	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	Not Available	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	Not Available	Small and medium business customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment. Closed to new enrollment.
SmartAC™ - Residential	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	Not Available	Residential customers taking service under applicable rate schedules equipped with central or packaged DX air conditioning equipment.
AMP - Day Of	87.9	87.9	87.9	87.9	87.9	87.9	87.9	87.9	87.9	87.9	87.9	87.9	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	148.3	148.3	148.3	148.3	148.3	148.3	148.3	148.3	148.3	148.3	148.3	148.3	596,779	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	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5		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	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	10,843	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)	24.7	24.7	24.7	24.7	24.7	24.7	24.7	24.7	24.7	24.7	24.7	24.7	6,491	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 (above 20 kW & below 200 kW)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	62,160	
PDP (20 kW or below)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	323,726	
SmartRate™ - Residential	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	Not Available	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 1, 2015 (R.13-09-011). 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 SA_ID remains constant across all months. The average load impact is "N/A" for programs having no prior events. Commercial SmartAC was not called in 2014; its average-customer impact reported here is from the April 2, 2012 filing.

NOTE: The April 2015 ILP provides update to the PDP Eligible Accounts and Program Eligibility for Ex Ante and Expost Average Load Impacts.

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

2015	January				February				March			
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
AMP - Day Ahead		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
AMP - Day Of		0.3	0.0	0.3		0.3	0.0	0.3		0.3	0.0	0.3
CBP - Day Ahead		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
CBP - Day Of		3.8	0.0	3.8		3.8	0.0	3.8		3.8	0.0	3.8
DBP		0.0	0.0	0.0		0.0	0.0	0.0		0.1	0.0	0.1
PDP		0.1	0.0	0.1		0.1	0.0	0.1		0.1	0.0	0.1
SmartRate™ - Residential		0.0	0.0	0.0		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		0.0	0.0	0.0
SmartAC™ - Residential		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
Total		4.1	0.0	4.1		4.1	0.0	4.1		4.2	0.0	4.2
Interruptible/Reliability												
BIP - Day of		0.0	0.0	0.0		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		0.0	0.0	0.0
SLRP		0.0	0.0	0.0		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		0.0	0.0	0.0
Total Technology MWs		4.1	0.0	4.1		4.1	0.0	4.1		4.2	0.0	4.2
General Program												
TA (may also be enrolled in TI and AutoDR)	0.0				0.0				0.0			
Total	0.0				0.0				0.0			
Total TA MWs	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A

2015	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
AMP - Day Ahead		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
AMP - Day Of		0.6	0.0	0.6		0.6	0.0	0.6		0.6	0.0	0.6
CBP - Day Ahead		0.0	0.0	0.0		0.1	0.0	0.1		0.1	0.0	0.1
CBP - Day Of		4.1	0.0	4.1		4.1	0.0	4.1		4.1	0.0	4.1
DBP		0.1	0.0	0.1		0.1	0.0	0.1		0.1	0.0	0.1
PDP		0.1	0.0	0.1		0.2	0.0	0.2		0.2	0.0	0.2
SmartRate™ - Residential		0.0	0.0	0.0		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		0.0	0.0	0.0
SmartAC™ - Residential		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
Total		4.9	0.0	4.9		5.0	0.0	5.0		5.0	0.0	5.0
Interruptible/Reliability												
BIP - Day of		0.0	0.0	0.0		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		0.0	0.0	0.0
SLRP		0.0	0.0	0.0		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		0.0	0.0	0.0
Total Technology MWs		4.9	0.0	4.9		5.0	0.0	5.0		5.0	0.0	5.0
General Program												
TA (may also be enrolled in TI and AutoDR)	0.0				0.0				0.0			
Total	0.0				0.0				0.0			
Total TA MWs	0.0				0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A

2015	July				August				September			
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
AMP - Day Ahead		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
AMP - Day Of		0.6	0.0	0.6		0.6	0.0	0.6		0.6	0.0	0.6
CBP - Day Ahead		0.1	0.0	0.1		0.1	0.0	0.1		0.1	0.0	0.1
CBP - Day Of		4.1	0.0	4.1		4.1	0.0	4.1		4.8	0.0	4.8
DBP		0.1	0.0	0.1		0.1	0.0	0.1		0.1	0.0	0.1
PDP		0.2	0.0	0.2		0.3	0.0	0.3		0.3	0.0	0.3
SmartRate™ - Residential		0.0	0.0	0.0		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		0.0	0.0	0.0
SmartAC™ - Residential		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
Total		5.0	0.0	5.0		5.2	0.0	5.2		5.8	0.0	5.8
Interruptible/Reliability												
BIP - Day of		0.0	0.0	0.0		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		0.0	0.0	0.0
SLRP		0.0	0.0	0.0		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		0.0	0.0	0.0
Total Technology MWs		5.0	0.0	5.0		5.2	0.0	5.2		5.8	0.0	5.8
General Program												
TA (may also be enrolled in TI and AutoDR)	0.0				0.0				0.0			
Total	0.0				0.0				0.0			
Total TA MWs	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A

2015	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
AMP - Day Ahead		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
AMP - Day Of		0.7	0.0	0.7		0.7	0.0	0.7		0.7	0.0	0.7
CBP - Day Ahead		0.1	0.0	0.1		0.1	0.0	0.1		0.1	0.0	0.1
CBP - Day Of		4.8	0.0	4.8		4.8	0.0	4.8		4.8	0.0	4.8
DBP		0.1	0.0	0.1		0.1	0.0	0.1		0.1	0.0	0.1
PDP		0.3	0.0	0.3		0.3	0.0	0.3		0.3	0.0	0.3
SmartRate™ - Residential		0.0	0.0	0.0		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		0.0	0.0	0.0
SmartAC™ - Residential		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
Total		5.9	0.0	5.9		5.9	0.0	5.9		5.9	0.0	5.9
Interruptible/Reliability												
BIP - Day of		0.0	0.0	0.0		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		0.0	0.0	0.0
SLRP		0.0	0.0	0.0		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				0.0
Total Technology MWs		5.9	0.0	5.9		5.9	0.0	5.9		5.9	0.0	5.9
General Program												
TA (may also be enrolled in TI and AutoDR)	0.0				0.0				0.0			
Total	0.0				0.0				0.0			
Total TA MWs	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A

NOTE: Projects for which applications were approved in the previous funding cycle are charged to that funding cycle; however, installed megawatts are at the time of installation regardless of funding cycle.

Table I-3a
Pacific Gas and Electric Company
Demand Response Programs and Activities
2015-2016 Incremental Cost Funding
December 2015

2015-2016 Program Expenditures

Cost Item	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date 2015 Expenditures	2-Year Funding[5]	Fundshift Adjustments[6]	Percent Funding
Category 1: Reliability Programs																
Base Interruptible Program (BIP)	$14,316	$16,382	$12,307	$14,280	$11,572	$9,498	$12,620	$14,819	$2,488	$14,269	$7,552	$9,365	$139,467	$537,137		26.0%
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)[10]	$1,276	$1,084	$4,139	$2,391	$1,645	($458)	$655	$2,736	($437)	$1,458	$419	$613	$15,522	$304,304		5.1%
Budget Category 1 Total	$15,592	$17,466	$16,446	$16,671	$13,217	$9,040	$13,276	$17,555	$2,051	$15,727	$7,971	$9,978	$154,989	$841,441	$0	18.4%
Category 2: Price-Responsive Programs																
Demand Bidding Program (DBP)	$26,364	$19,357	$21,401	$23,228	$22,702	$21,395	$19,971	$17,282	$5,322	$13,209	$6,931	$9,052	$206,215	$1,161,150		17.8%
Capacity Bidding Program (CBP)	$22,405	$21,934	$22,215	$28,775	$22,983	$18,680	$23,704	$27,349	$12,517	$21,426	$14,742	$12,927	$249,657	$4,887,754		5.1%
SmartAC™ [7]	$354,042	($105,497)	$221,492	$211,583	$183,198	$438,497	($334,616)	$1,583,742	$452,397	$832,406	($248,572)	$305,024	$3,893,694	$13,336,338		29.2%
Budget Category 2 Total	$402,811	($64,206)	$265,109	$263,585	$228,882	$478,572	($290,941)	$1,628,372	$470,236	$867,041	($226,899)	$327,003	$4,349,566	$19,385,242	$0	22.4%
Category 3: DR Provider/Aggregator Managed Programs																
Aggregator Managed Portfolio (AMP)	$24,689	$24,692	$25,477	$30,704	$27,926	$22,464	$26,984	$28,711	$15,298	$24,928	$16,743	$15,260	$283,875	$944,506		30.1%
Budget Category 3 Total	$24,689	$24,692	$25,477	$30,704	$27,926	$22,464	$26,984	$28,711	$15,298	$24,928	$16,743	$15,260	$283,875	$944,506	$0	30.1%
Category 4: Emerging & Enabling Programs																
Auto DR	$47,963	$142,314	$90,079	$48,782	$294,074	$119,902	$224,114	$123,288	$390,581	$199,503	$127,493	$181,814	$1,989,906	$17,870,739		11.1%
DR Emerging Technology	$49,984	$124,622	$88,084	$71,000	$52,544	$63,226	$79,406	$104,947	$53,305	$79,987	$48,683	$96,033	$911,820	$2,809,056		32.5%
Budget Category 4 Total	$97,947	$266,936	$178,163	$119,783	$346,618	$183,128	$303,520	$228,234	$443,886	$279,489	$176,176	$277,847	$2,901,727	$20,679,795	$0	14.0%
Category 5: Pilots																
Supply Side Pilot	$39,640	$44,845	$29,579	$35,689	$34,825	$74,995	$32,774	$38,139	$165,991	$105,841	$62,822	$91,171	$756,309	$2,511,198		30.1%
T&D DR[8]	$4,377	$29,878	$211,718	($16,487)	$63,340	$28,191	$20,575	$23,430	$18,403	$20,212	$20,186	$70,033	$493,857	$1,698,036		29.1%
Excess Supply	$25,736	$31,765	$20,222	$14,073	$11,861	$14,582	$13,836	$23,190	$9,417	$20,635	$18,464	$181,499	$385,279	$1,199,842		32.1%
Budget Category 5 Total	$69,754	$106,488	$261,519	$33,275	$110,025	$117,768	$67,184	$84,759	$193,811	$146,688	$101,472	$342,703	$1,635,446	$5,409,076	$0	30.2%
Category 6: Evaluation, Measurement and Verification																
DRMEC	$23,111	$35,240	$51,664	$39,238	$52,269	$157,284	$114,331	$105,687	$147,370	$126,031	$228,161	$265,041	$1,345,427	$8,885,397		15.1%
Budget Category 6 Total	$23,111	$35,240	$51,664	$39,238	$52,269	$157,284	$114,331	$105,687	$147,370	$126,031	$228,161	$265,041	$1,345,427	$8,885,397	$0	15.1%
Category 7: Marketing, Education and Outreach																
DR Core Marketing and Outreach[1]	$55,709	$64,299	$110,417	$84,978	$72,904	$204,677	$60,537	($27,259)	$225,858	$36,390	$90,428	$78,437	$1,057,377	$9,142,336		45.6%
SmartAC™ ME&O[2]	$26,787	$61,862	$57,423	$84,374	$356,211	$545,425	$486,891	$589,679	$483,872	$197,443	$117,436	$102,199	$3,109,604			
Education and Training	$5,243	$5,721	$13,675	$45,787	$8,473	$11,752	$13,346	$8,710	$7,855	$3,356	$4,117	$3,628	$131,663	$529,889		24.8%
Budget Category 7 Total	$87,740	$131,882	$181,516	$215,140	$437,588	$761,855	$560,775	$571,131	$717,585	$237,189	$211,981	$184,264	$4,298,644	$9,672,225	$0	44.4%
Category 8: DR System Support Activities																
InterAct / DR Forecasting Tool	$222,309	$249,258	$360,215	$200,974	$319,285	$184,796	$259,460	$232,732	$234,253	$251,028	$210,361	$197,813	$2,922,482	$9,974,090		29.3%
DR Enrollment & Support	$223,684	$174,511	$223,363	$224,668	$294,135	$159,312	$206,023	$242,842	$350,867	$463,507	$574,689	$319,926	$3,457,527	$10,874,287		31.8%
Notifications[10]	$309,549	$317,160	$218,851	$242,558	$314,204	$424,941	$275,368	$263,593	($2,379)	$60,328	$8,150	$58,882	$2,491,204	$5,473,744		45.5%
DR Integration Policy & Planning	$53,040	$127,098	$128,979	$138,650	$131,516	$117,578	$108,685	$160,859	$67,899	$89,852	$143,407	$98,530	$1,366,095	$3,207,039		42.6%
Budget Category 8 Total	$808,581	$868,027	$931,408	$806,851	$1,059,139	$886,627	$849,537	$900,025	$650,640	$864,715	$936,606	$675,151	$10,237,307	$29,529,161	$0	34.7%
Category 9: Integrated Programs and Activities (Including Technical Assistance)																
Technology Incentives - IDSM[3]	$3,140	$2,759	$2,679	$2,975	$64,953	$66,026	$64,587	$67,936	$61,964	$63,550	$62,213	$58,933	$521,715	$4,051,540		12.9%
Integrated Energy Audits[3]	$5,800	$7,168	$37,312	$168,712	$38,109	$141,981	$10,989	$55,879	$207,843	$78,013	$99,315	$41,386	$892,506	$2,550,462		35.0%
Budget Category 9 Total	$8,939	$9,927	$39,990	$171,687	$103,062	$208,007	$75,576	$123,815	$269,807	$141,563	$161,528	$100,318	$1,414,221	$6,602,002	$0	21.4%
Category 10: Special Projects																
Permanent Load Shifting	$21,065	$29,992	$41,162	$51,341	$38,551	$24,749	$39,662	$48,537	$47,039	$26,340	$55,428	$7,263	$431,129	$10,128,288	($300,000)	4.3%
Demand Response Auction Mechanism Pilot[9]	$0	$0	$0	$0	$0	$0	$5,699	$6,562	$5,592	$8,893	$39,959	$37,851	$104,556	$0	$300,000	
Budget Category 10 Total	$21,065	$29,992	$41,162	$51,341	$38,551	$24,749	$45,361	$55,099	$52,631	$35,233	$95,387	$45,114	$535,685	$10,128,288	$0	5.3%
Recovery of DR-related capital costs prior to 2009 (for interval metering as authorized in D.06-03-024/D.06-11-049); and, additionally, for the HAN Integration project (as authorized in D.12-04-045).	$264,020	$261,814	$293,341	$270,988	$270,250	$269,465	$275,754	$274,993	$274,231	$273,469	$272,708	$271,946	$3,272,979		$0	N/A
Total Incremental Cost[4]	$1,824,250	$1,688,258	$2,285,795	$2,019,263	$2,687,529	$3,118,957	$2,041,357	$4,018,381	$3,237,545	$3,012,073	$1,981,834	$2,514,626	$30,429,866	$112,077,133	$0	27.2%

Technical Assistance & Technology Incentives (TA&TI) Identified as of August 2015.	$0

[1] 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 2015-16 approved budget for DR Core Marketing and Outreach includes funding for SmartAC marketing, education and outreach activities. August credit is due to reclassification of contracts.
[2] The budget for SmartAC marketing, education, and outreach costs are included in the 2015-16 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 now closed to non-residential customers. The "percent funding" calculation shown on the DR Core Marketing and Outreach line includes SmartAC marketing expenditures.
[3] Additional funding for Technology Incentives and Integrated Energy Audits was approved in Energy Efficiency Decision 14-10-046. This funding will continue through 2025 unless the Commission issues a superseding funding decision.
[4] Total Incremental Cost excludes incentives. Incentives are reported on Table I-5.
[5] Program budgets include employee benefits costs approved in the GRC (D.14-08-032) – Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016, issued on August 20, 2014.
[6] See the Fund Shift Log 2015-16 for explanations.
[7] February credit is the result of a reversal of an accrual made in January. July credit is due to erroneous accrual reversals; adjustments made in August. November credit is due to true-up of actuals.
[8] The April credit is attributable to adjustments of prior months' financials.
[9] Resolution E-4728 provides approval with modification, to the Advice Letter 4618-E, which proposes DRAM cost cap to $4 Million.
[10] September credit is attributable to adjustments of prior month's financials.

Table I-3b
Pacific Gas and Electric Company
Demand Response Programs and Activities
Carry-Over Expenditures and Funding
2015-2016

Cost Item [1]	January	February	March	April	May	June	July	August	September	October	November	December	Carry-Over Expenditures incurred in 2015	Carry-Over Expenditures incurred in 2015-2016
Category 1: Reliability Programs														
Base Interruptible Program (BIP)	$299	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$297	$297
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	$294	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$294	$294
Budget Category 1 Total	**$593**	**($3)**	**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$590**	**$590**
Category 2: Price-Responsive Programs														
Demand Bidding Program (DBP)	$284	($11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$272	$272
Capacity Bidding Program (CBP)	$473	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$431	$431
Peak Choice	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SmartAC™	$64,989	$366,621	$50,575	($169,978)	($25)	($50)	$95,000	($11,988)	($2,559)	$0	$0	$0	$392,585	$392,585
Critical Peak Pricing (CPP)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Budget Category 2 Total	**$65,745**	**$366,568**	**$50,575**	**($169,978)**	**($25)**	**($50)**	**$95,000**	**($11,988)**	**($2,559)**	**$0**	**$0**	**$0**	**$393,289**	**$393,289**
Category 3: DR Provider/Aggregator Managed Programs														
Aggregator Managed Portfolio (AMP)	$307	($4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$303	$303
Budget Category 3 Total	**$307**	**($4)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$303**	**$303**
Category 4: Emerging & Enabling Programs														
Auto DR	$198,728	$179,470	$143,825	$198,180	$44,477	$4,359	$0	$0	$0	$0	$0	$231	$769,269	$769,269
DR Emerging Technology	$89,074	($16,587)	($4,907)	($355)	($161)	$1,152	$0	$0	($93)	$0	$0	$0	$68,122	$68,122
Budget Category 4 Total	**$287,802**	**$162,882**	**$138,918**	**$197,825**	**$44,316**	**$5,511**	**$0**	**$0**	**($93)**	**$0**	**$0**	**$231**	**$837,391**	**$837,391**
Category 5: Pilots														
IRR Phase 2	($6,806)	$9,198	$0	$10,000	($400)	$5,627	$0	$0	$0	$0	$0	$0	$17,619	$17,619
T&D DR	($80)	$35,006	($31,575)	$61,418	$0	$0	$0	$0	$0	$0	$0	$0	$64,769	$64,769
Plug-in Hybrid EV/EV (incl. HAN-EV)	$3,004	$9,402	$0	$20,372	$150,329	$28,646	$171,237	$530,064	$16,831	$26,859	$23,991	$52,832	$1,033,567	$1,033,567
Budget Category 5 Total	**($3,882)**	**$53,606**	**($31,575)**	**$91,790**	**$149,929**	**$34,273**	**$171,237**	**$530,064**	**$16,831**	**$26,859**	**$23,991**	**$52,832**	**$1,115,955**	**$1,115,955**
Category 6: Evaluation, Measurement and Verification														
DRMEC	$671,365	$479,347	$250,618	$144,878	$163,977	$333,434	$214,896	$62,086	($255,735)	$128,362	($25,056)	$141,576	$2,309,747	$2,309,747
DR Research Studies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Budget Category 6 Total	**$671,365**	**$479,347**	**$250,618**	**$144,878**	**$163,977**	**$333,434**	**$214,896**	**$62,086**	**($255,735)**	**$128,362**	**($25,056)**	**$141,576**	**$2,309,747**	**$2,309,747**
Category 7: Marketing, Education and Outreach														
DR Core Marketing and Outreach	($3,618)	$2,615	($3,487)	$5,859	($765)	$0	($26)	($35)	($22)	($20)	$0	$1,378	$1,879	$1,879
SmartAC™ ME&O	($93,410)	$126,749	$4,787	($4,369)	$1,508	($48,095)	($50,525)	($2,367)	$0	$0	$0	$90	($65,632)	($65,632)
Education and Training	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Budget Category 7 Total	**($97,027)**	**$129,363**	**$1,300**	**$1,491**	**$743**	**($48,095)**	**($50,551)**	**($2,402)**	**($22)**	**($20)**	**$0**	**$1,468**	**($63,753)**	**($63,753)**
Category 8: DR System Support Activities														
InterAct / DR Forecasting Tool	($38,588)	$2,112	$11,900	$57,381	$0	$0	$0	$0	$0	$0	$0	$0	$32,805	$32,805
DR Enrollment & Support	($21,312)	$181,581	$57,808	$57,808	$57,808	$113,416	$57,808	$55,170	$57,808	($94,500)	$0	$0	$523,395	$523,395
Notifications	$157,309	($106,977)	$137,646	$146,458	$76,351	($35,420)	$165,278	($48,163)	$0	($90,000)	$0	($48,659)	$353,822	$353,822
DR Integration Policy & Planning	$17,252	$18,790	$0	$0	$3,862	($4,262)	$0	$0	$0	$0	$0	$0	$35,642	$35,642
Budget Category 8 Total	**$114,661**	**$95,505**	**$207,354**	**$261,647**	**$138,021**	**$73,734**	**$223,086**	**$7,007**	**$57,808**	**($184,500)**	**$0**	**($48,659)**	**$945,664**	**$945,664**
Category 9: Integrated Programs and Activities (Including Technical Assistance)														
Technology Incentives - IDSM	($9,921)	($1,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10,921)	($10,921)
PEAK	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Integrated Marketing & Outreach	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Integrated Education & Training	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Integrated Sales Training	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Integrated Energy Audits	$28,399	$50,572	$12,567	($81,683)	$0	$264	$0	$0	$0	$0	$0	($10,118)	$0	$0
Integrated Emerging Technology	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Budget Category 9 Total	**$18,477**	**$49,572**	**$12,567**	**($81,683)**	**$0**	**$264**	**$0**	**$0**	**$0**	**$0**	**$0**	**($10,118)**	**($10,921)**	**($10,921)**
Category 10: Special Projects														
DR-HAN Integration (excl. HAN-EV)	($73,666)	($9,922)	($2,987)	$1,242	($1,215)	$8,537	($94)	$0	$0	$7,780	$0	$0	($70,326)	($70,326)
Permanent Load Shifting	$44,842	($32,444)	$9,683	$2,197	$394	($961)	$2,530	($690)	$2,088	($1,553)	$5,157	$2,585	$33,827	$33,827
Budget Category 10 Total	**($28,824)**	**($42,367)**	**$6,695**	**$3,440**	**($821)**	**$7,576**	**$2,437**	**($690)**	**$2,088**	**$6,227**	**$5,157**	**$2,585**	**($36,499)**	**($36,499)**
Total Incremental Cost	**$1,029,216**	**$1,294,470**	**$636,454**	**$449,409**	**$496,139**	**$406,645**	**$656,104**	**$584,076**	**($181,682)**	**($23,072)**	**$4,091**	**$139,915**	**$5,491,766**	**$5,491,766**

Notes:

[1] Expenditures on this page reflect expenses incurred in 2015 from all prior funding cycles.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
December 2015

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)[2,3]
Category 1: Reliability Programs												
	Base Interruptible Program (BIP)[1,3]	FEBRUARY	System	2/11/2015	1	Day Of	Re-test	15	2:00 PM	4:00 PM	2	Redacted
	Base Interruptible Program (BIP)[1,3]	APRIL	System	4/23/2015	2	Day Of	Re-test	3	2:00 PM	4:00 PM	2	Redacted
	Base Interruptible Program (BIP)[1]	JULY	System	7/30/2015	3	Day Of	Test	204	3:00 PM	7:00 PM	4	243.2
	Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Category 2: Price-Responsive Programs												
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/8/2015	1	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	Fresno, Humboldt	6/9/2015	2	Day Of	Heat Rate	63	2:00 PM	7:00 PM	5	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/12/2015	1	Day Ahead	Heat Rate	175	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/12/2015	3	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/25/2015	2	Day Ahead	Heat Rate	175	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/25/2015	4	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/26/2015	3	Day Ahead	Heat Rate	175	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/26/2015	5	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/30/2015	4	Day Ahead	Heat Rate	175	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JUNE	System	6/30/2015	6	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	System	7/1/2015	5	Day Ahead	Heat Rate	181	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	System	7/1/2015	7	Day Of	Heat Rate	633	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	Central Coast, East Bay (Bay Area), Fresno, Los Padres, North Coast, San Francisco (Bay Area), Peninsula (Bay Area), South Bay (Bay Area)	7/16/2015	6	Day Ahead	Heat Rate	126	4:00 PM	7:00 PM	3	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	Central Coast, East Bay (Bay Area), Fresno, Los Padres, North Coast, San Francisco (Bay Area), Peninsula (Bay Area), South Bay (Bay Area)	7/16/2015	8	Day Of	Heat Rate	450	4:00 PM	7:00 PM	3	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	System	7/28/2015	7	Day Ahead	Heat Rate	181	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	System	7/28/2015	9	Day Of	Heat Rate	633	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	System	7/29/2015	8	Day Ahead	Heat Rate	181	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	System	7/29/2015	10	Day Of	Heat Rate	633	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	System	7/30/2015	9	Day Ahead	Heat Rate	181	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	JULY	System	7/30/2015	11	Day Of	Heat Rate	633	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	AUGUST	System	8/17/2015	10	Day Ahead	Heat Rate	200	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	AUGUST	System	8/17/2015	12	Day Of	Heat Rate	589	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	AUGUST	System	8/18/2015	11	Day Ahead	Heat Rate	200	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	AUGUST	System	8/18/2015	13	Day Of	Heat Rate	589	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	AUGUST	Fresno, Los Padres, North Valley, Sacramento Valley, Sierra, San Joaquin, Stockton	8/26/2015	12	Day Ahead	Heat Rate	96	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	AUGUST	System	8/26/2015	14	Day Of	Heat Rate	589	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	AUGUST	System	8/27/2015	13	Day Ahead	Heat Rate	200	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	AUGUST	System	8/27/2015	15	Day Of	Heat Rate	589	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	SEPTEMBER	System	9/9/2015	16	Day Ahead	Heat Rate	198	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	SEPTEMBER	System	9/9/2015	16	Day Of	Heat Rate	571	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	SEPTEMBER	System	9/10/2015	17	Day Ahead	Heat Rate	198	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	SEPTEMBER	System	9/10/2015	17	Day Of	Heat Rate	571	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	SEPTEMBER	System	9/11/2015	18	Day Ahead	Heat Rate	198	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)[3]	SEPTEMBER	System	9/11/2015	18	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Demand Bidding Program (DBP)[3]	JUNE	System	6/12/2015	1	Day Ahead	Temperature	53	4:00 PM	9:00 PM	5	Redacted
	Demand Bidding Program (DBP)[3]	JUNE	System	6/25/2015	2	Day Ahead	Temperature	66	2:00 PM	10:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	JUNE	System	6/26/2015	3	Day Ahead	Temperature	44	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	JUNE	System	6/30/2015	4	Day Ahead	Temperature	72	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	JULY	System	7/1/2015	5	Day Ahead	Temperature	61	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	JULY	System	7/28/2015	6	Day Ahead	Temperature	53	2:00 PM	10:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	JULY	System	7/29/2015	7	Day Ahead	Temperature	56	2:00 PM	10:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	AUGUST	System	8/17/2015	9	Day Ahead	Temperature	61	2:00 PM	9:00 PM	7	Redacted
	Demand Bidding Program (DBP)[3]	AUGUST	System	8/18/2015	10	Day Ahead	Temperature	55	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	AUGUST	Fresno, Los Padres, North Valley, Sacramento Valley, Sierra, San Joaquin, Stockton	8/26/2015	8	Day Ahead	Temperature	19	3:00 PM	9:00 PM	6	Redacted
	Demand Bidding Program (DBP)[3]	AUGUST	System	8/27/2015	9	Day Ahead	Temperature	51	2:00 PM	9:00 PM	7	Redacted
	Demand Bidding Program (DBP)[3]	AUGUST	System	8/28/2015	10	Day Ahead	Temperature	54	3:00 PM	7:00 PM	4	Redacted
	Demand Bidding Program (DBP)[3]	SEPTEMBER	System	9/9/15	11	Day Ahead	Temperature	53	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	SEPTEMBER	System	9/10/15	12	Day Ahead	Temperature	53	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)[3]	SEPTEMBER	System	9/11/15	13	Day Ahead	Temperature	57	2:00 PM	8:00 PM	6	Redacted

[1] Both the February and April 2015 events are re-tests resulting from the 9/11/2014 BIP event and included only a subset of the program's enrollment.

[2] Load reduction amount is based on available meter data and may vary by month pending the collection of all data.

[3] Pursuant to Commission guidance in D.14-05-016, p.118 and Finding of Fact 17, PG&E will redact-the load reduction MW (Max Hourly) in the Public Version due to having less than 15 customers involved or a single customer in the group account for more than 15 percent of the aggregated total. CBP events are listed as Redacted.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
December 2015

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)[2,3]
Category 2: Price-Responsive Programs **(Cont'd)**												
	Peak Day Pricing (PDP)	JUNE	System	6/12/2015	1	Day Ahead	Temperature	164,000	2:00 PM	6:00 PM	4	35.0
	Peak Day Pricing (PDP)	JUNE	System	6/25/2015	2	Day Ahead	Temperature	164,000	2:00 PM	6:00 PM	4	27.7
	Peak Day Pricing (PDP)	JUNE	System	6/26/2015	3	Day Ahead	Temperature	164,000	2:00 PM	6:00 PM	4	54.4
	Peak Day Pricing (PDP)	JUNE	System	6/30/2015	4	Day Ahead	Temperature	164,000	2:00 PM	6:00 PM	4	28.1
	Peak Day Pricing (PDP)	JULY	System	7/1/2015	5	Day Ahead	Temperature	164,000	2:00 PM	6:00 PM	4	83.9
	Peak Day Pricing (PDP)	JULY	System	7/28/2015	6	Day Ahead	Temperature	163,000	2:00 PM	6:00 PM	4	24.6
	Peak Day Pricing (PDP)	JULY	System	7/29/2015	7	Day Ahead	Temperature	163,000	2:00 PM	6:00 PM	4	25.7
	Peak Day Pricing (PDP)	JULY	System	7/30/2015	8	Day Ahead	Temperature	163,000	2:00 PM	6:00 PM	4	23.7
	Peak Day Pricing (PDP)	AUGUST	System	8/17/2015	9	Day Ahead	Temperature	162,000	2:00 PM	6:00 PM	4	19.5
	Peak Day Pricing (PDP)	AUGUST	System	8/18/2015	10	Day Ahead	Temperature	163,000	2:00 PM	6:00 PM	4	14.5
	Peak Day Pricing (PDP)	AUGUST	System	8/27/2015	11	Day Ahead	Temperature	161,422	2:00 PM	6:00 PM	4	31.5
	Peak Day Pricing (PDP)	AUGUST	System	8/28/2015	12	Day Ahead	Temperature	161,000	2:00 PM	6:00 PM	4	54.3
	Peak Day Pricing (PDP)	SEPTEMBER	System	9/9/15	13	Day Ahead	Temperature	161,000	2:00 PM	6:00 PM	4	48
	Peak Day Pricing (PDP)	SEPTEMBER	System	9/10/15	14	Day Ahead	Temperature	160,500	2:00 PM	6:00 PM	4	51
	Peak Day Pricing (PDP)	SEPTEMBER	System	9/11/15	15	Day Ahead	Temperature	161,000	2:00 PM	6:00 PM	4	52
	SmartAC	JUNE	System	6/25/2015	1	Day Of	Test	12,500	12:30 PM	6:00 PM	5.5	7.2
	SmartAC	JUNE	System	6/30/2015	2	Day Of	Test	12,534	6:30 PM	8:00 PM	1	6.9
	SmartAC	JUNE	System	7/1/2015	3	Day Of	Test	12,532	3:30 PM	7:00 PM	3.5	4.7
	SmartAC	JUNE	System	7/28/2015	4	Day Of	Test	48,336	3:30 PM	7:00 PM	3.5	26.1
	SmartAC	JUNE	System	7/29/2015	5	Day Of	Test	12,478	12:30 PM	5:00 PM	4.5	8.1
	SmartAC	AUGUST	System	8/15/2015	6	Day Of	Test	15,000	3:30 PM	6:00 PM	2.5	6.4
	SmartAC	AUGUST	System	8/17/2015	7	Day Of	Test	12,000	11:30 AM	9:00 PM	9.5	7.4
	SmartAC	SEPTEMBER	System	9/8/15	8	Day Of	Test	15,860	12:30 PM	3:00 PM	2.5	2
	SmartAC	SEPTEMBER	System	9/9/15	9	Day Of	Test	46,936	3:30 PM	7:00 PM	3.5	27
	SmartAC	SEPTEMBER	System	9/10/15	10	Day Of	Test	12,219	3:30 PM	7:00 PM	3.5	7
	SmartAC	SEPTEMBER	System	9/11/15	11	Day Of	Test	11,975	2:30 PM	6:00 PM	3.5	5
	SmartRate (SR)	JUNE	System	6/12/2015	1	Day Ahead	Temperature	126,896	2:00 PM	7:00 PM	5	44.7
	SmartRate (SR)	JUNE	System	6/25/2015	2	Day Ahead	Temperature	126,349	2:00 PM	7:00 PM	5	51.4
	SmartRate (SR)	JUNE	System	6/26/2015	3	Day Ahead	Temperature	126,349	2:00 PM	7:00 PM	5	50.3
	SmartRate (SR)	JUNE	System	6/30/2015	4	Day Ahead	Temperature	126,050	2:00 PM	7:00 PM	5	57.2
	SmartRate (SR)	JULY	System	7/1/2015	5	Day Ahead	Temperature	126,050	2:00 PM	7:00 PM	5	45.7
	SmartRate (SR)	JULY	System	7/28/2015	6	Day Ahead	Temperature	126,000	2:00 PM	7:00 PM	5	55.4
	SmartRate (SR)	JULY	System	7/29/2015	7	Day Ahead	Temperature	126,000	2:00 PM	7:00 PM	5	59.6
	SmartRate (SR)	JULY	System	7/30/2015	8	Day Ahead	Temperature	126,000	2:00 PM	7:00 PM	5	44.8
	SmartRate (SR)	AUGUST	System	8/17/2015	9	Day Ahead	Temperature	129,000	2:00 PM	7:00 PM	5	57.5
	SmartRate (SR)	AUGUST	System	8/18/2015	10	Day Ahead	Temperature	126,000	2:00 PM	7:00 PM	5	38.8
	SmartRate (SR)	AUGUST	System	8/27/2015	11	Day Ahead	Temperature	131,000	2:00 PM	7:00 PM	5	48.7
	SmartRate (SR)	AUGUST	System	8/28/2015	12	Day Ahead	Temperature	131,000	2:00 PM	7:00 PM	5	49.4
	SmartRate (SR)	SEPTEMBER	System	9/9/15	13	Day Ahead	Temperature	133,000	2:00 PM	7:00 PM	5	56
	SmartRate (SR)	SEPTEMBER	System	9/10/15	14	Day Ahead	Temperature	133,000	2:00 PM	7:00 PM	5	54
	SmartRate (SR)	SEPTEMBER	System	9/11/15	15	Day Ahead	Temperature	133,000	2:00 PM	7:00 PM	5	44
Category 3: DR Provider/Aggregator Managed Programs												
	Aggregator Managed Portfolio (AMP)	JUNE	System	6/8/2015	1	Day Of	Heat Rate	1,457	3:00 PM	7:00 PM	4	96.7
	Aggregator Managed Portfolio (AMP)	JUNE	Fresno, Humboldt	6/9/2015	2	Day Of	Heat Rate	213	1:00 PM	7:00 PM	6	15.2
	Aggregator Managed Portfolio (AMP)	JUNE	System	6/12/2015	3	Day Of	Heat Rate	1,457	3:00 PM	7:00 PM	4	104.2
	Aggregator Managed Portfolio (AMP)	JUNE	System	6/25/2015	4	Day Of	Heat Rate	1,457	3:00 PM	7:00 PM	4	105.3
	Aggregator Managed Portfolio (AMP)	JUNE	System	6/26/2015	5	Day Of	Heat Rate	1,457	3:00 PM	7:00 PM	4	102.8
	Aggregator Managed Portfolio (AMP)	JUNE	System	6/30/2015	6	Day Of	Heat Rate	1,457	3:00 PM	7:00 PM	4	92.1
	Aggregator Managed Portfolio (AMP)	JULY	System	7/1/2015	7	Day Of	Heat Rate	1,446	3:00 PM	7:00 PM	4	107.5
	Aggregator Managed Portfolio (AMP)	JULY	Central Coast ,East Bay (Bay Area), Fresno, Los Padres, North Coast, San Francisco (Bay Area)	7/16/2015	8	Day Of	Heat Rate	686	3:00 PM	7:00 PM	4	56.1
	Aggregator Managed Portfolio (AMP)	JULY	System	7/28/2015	9	Day Of	Heat Rate	1,446	3:00 PM	7:00 PM	4	103.7
	Aggregator Managed Portfolio (AMP)	JULY	System	7/29/2015	10	Day Of	Heat Rate	1,446	3:00 PM	7:00 PM	4	100.9
	Aggregator Managed Portfolio (AMP)	JULY	System	7/30/2015	11	Day Of	Heat Rate	1,446	3:00 PM	7:00 PM	4	92.8
	Aggregator Managed Portfolio (AMP)	AUGUST	System	8/17/2015	12	Day Of	Heat Rate	1,446	3:00 PM	7:00 PM	4	93.6
	Aggregator Managed Portfolio (AMP)	AUGUST	System	8/18/2015	13	Day Of	Heat Rate	1,446	3:00 PM	7:00 PM	4	84.7
	Aggregator Managed Portfolio (AMP)	AUGUST	System	8/26/2015	14	Day Of	Heat Rate	1,446	3:00 PM	7:00 PM	4	93.5
	Aggregator Managed Portfolio (AMP)	AUGUST	System	8/27/2015	15	Day Of	Heat Rate	1,446	3:00 PM	7:00 PM	4	85.8
	Aggregator Managed Portfolio (AMP)	SEPTEMBER	System	9/9/2015	16	Day Of	Heat Rate	1,434	2:00 PM	7:00 PM	5	85.0
	Aggregator Managed Portfolio (AMP)	SEPTEMBER	System	9/10/2015	17	Day Of	Heat Rate	1,434	2:00 PM	7:00 PM	5	83.0
	Aggregator Managed Portfolio (AMP)	SEPTEMBER	System	9/11/2015	18	Day Of	Heat Rate	1,457	3:00 PM	7:00 PM	4	81.0

[1] Both the February and April 2015 events are re-tests resulting from the 9/11/2014 BIP event and included only a subset of the program's enrollment.

[2] Load reduction amount is based on available meter data and may vary by month pending the collection of all data. For PDP, small and medium customer load reduction was calculated using a control group. For large customers, a 10-in-10 baseline with day-of adjustment was used.

[3] Pursuant to Commission guidance in D.14-05-016, p.118 and Finding of Fact 17, PG&E will redact the load reduction MW (Max Hourly) in the Public Version due to having less than 15 customers involved or a single customer in the group account for more than 15 percent of the aggregated total.

Table I-5a
Pacific Gas and Electric Company
2015-2016 Demand Response Programs
Customer Program Incentives and Penalties
December 2015
(Revised October 2016 - Accrual Basis)

Cost Item	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date 2015 Total Cost
Annual Total Cost													
Program Incentives													
Aggregator Managed Portfolio (AMP)[1]	$0	$0	$0	$0	$607,331	$764,582	$2,046,612	$2,518,905	$1,463,326	$384,536	$0	$0	$7,785,291
Automatic Demand Response (AutoDR)	$0	$0	$0	$0	$0	$0	$0	$0	$33,870	$0	$12,600	$0	$46,470
Base Interruptible Program (BIP)[2]	$1,902,132	$2,172,462	$2,157,725	$2,195,711	$2,135,348	$2,250,657	$2,203,402	$2,324,487	$2,291,691	$2,231,027	$2,194,584	$2,025,030	$26,084,254
Capacity Bidding Program (CBP)[3]	$0	$0	$0	$0	$0	$349,812	$449,843	$157,740	$706,606	($250,973)	$333,904	($4,712)	$1,742,221
Demand Bidding Program (DBP)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,022,581	$0	$1,022,581
Excess Supply Pilot	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Optional Binding Mandatory Curtailment / Scheduled Load Reduction Program (OBMC / SLRP)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SmartAC™ [4]	$83,738	$89,907	$92,396	$47,989	($120,701)	$12,459	$55,433	$94,404	$102,681	$135,110	$70,642	$36,591	$700,649
Supply Side Pilot	$0	$0	$0	$0	$0	$0	$6,929	$4,758	$5,000	$9,000	$9,000	$11,000	$45,687
Technology Incentive (TI)	$0	$0	$0	$0	$0	$0	$0	$28,770	$43,920	$15,330	$0	$0	$88,020
Transmission and Distribution Pilot (T&D DR)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,150	$5,150
Total Cost of Incentives	**$1,985,870**	**$2,262,369**	**$2,250,120**	**$2,243,700**	**$2,621,979**	**$3,377,510**	**$4,762,219**	**$5,129,064**	**$4,647,094**	**$2,524,029**	**$3,643,311**	**$2,073,059**	**$37,520,323**
Revenues from Penalties[5]	$0	($1,254)	$0	($1,390)	$0	($1,177,221)	($234,946)	($209,016)	($27,518)	$0	($2,570)	$0	($1,653,915)

[1] Amounts reported are for incentive costs that are not recorded in the Demand Response Expenditures Balancing Account. Incentives have been converted to the accrual basis.
[2] Amounts reported are for incentive costs that are not recorded in the Demand Response Expenditures Balancing Account. Incentives have been converted to the accrual basis.
[3] Incentives reported are net of penalties paid by the aggregators. October credit is attributable to accrual reversals. December credit is due to true up of actuals and accruals.
[4] The May credit is attributable to adjustments of prior months' financials.
[5] Revenues from Penalties denote penalty payments made by aggregators and charges to full service customers enrolled in AMP and BIP programs.

Table I-5b
Pacific Gas and Electric Company
Demand Response Programs and Activities
Carry-Over Incentives and Funding
2015-2016

Annual Total Cost														
Cost Item [1]	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Carry-Over Incentives incurred in 2015**	**Carry-Over Incentives incurred in 2015-2016**
Program Incentives														
Aggregator Managed Portfolio (AMP)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Automatic Demand Response (AutoDR)	$2,566	$0	($2,093)	$109,230	$18,960	$0	$0	$0	$0	$30,940	$265,440	$249,216	$674,260	$674,260
Base Interruptible Program (BIP)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Bidding Program (CBP)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Bidding Program (DBP)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Permanent Load Shift	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PHEV/EV Pilots	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,800	$0	$13,800	$13,800
SmartAC™	$36,278	($50,000)	($50)	$100	$156,475	$50	$50	$16,650	$200	$0	($50)	$50	$159,753	$159,753
Technology Incentive (TI)	$967	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$967	$967
Transmission and Distribution Pilot (T&D DR)	$0	($11,600)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11,600)	($11,600)
Total Cost of Incentives	**$39,811**	**($61,600)**	**($2,143)**	**$109,330**	**$175,435**	**$50**	**$50**	**$16,650**	**$200**	**$30,940**	**$279,190**	**$249,266**	**$837,180**	**$837,180**
Revenues from Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

[1] Incentives on this page reflect expenses incurred in 2015 from all prior funding cycles.

Table I-7
Pacific Gas and Electric Company
2015-2016 Marketing, Education and Outreach
Actual Expenditures
December 2015

PG&E's ME&O Actual Expenditures	2015-2016 Funding Cycle Customer Communication, Marketing, and Outreach												Year-to-Date 2015 Expenditures	2015-2016 Authorized Budget (if Applicable)
	January	February	March	April	May	June	July	August	September	October	November	December		
I. STATEWIDE MARKETING														
IOU Administrative Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Statewide ME&O contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
I. TOTAL STATEWIDE MARKETING	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
II. UTILITY MARKETING BY ACTIVITY[1]														
TOTAL AUTHORIZED UTILITY MARKETING BUDGET FOR 2015-2016	[redacted]													
PROGRAMS, RATES & ACTIVITES WHICH DO NOT REQUIRE ITEMIZED ACCOUNTING														
Integrated Demand Side Marketing	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	
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	
Demand Bidding Program	$ 30,476	$ 35,010	$ 62,046	$ 65,383	$ 40,689	$ 108,215	$ 36,942	$ (9,274)	$ 116,856	$ 19,873	$ 47,272	$ 41,033	$ 594,520	
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	
Permanent Load Shifting	$ 12,190	$ 14,004	$ 24,819	$ 26,153	$ 16,275	$ 43,286	$ 14,777	$ (3,710)	$ 46,742	$ 7,949	$ 18,909	$ 16,413	$ 237,808	
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	
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	
Enabling Technologies (e.g., AutoDR, TI)	$ 18,286	$ 21,006	$ 37,228	$ 39,230	$ 24,413	$ 64,929	$ 22,165	$ (5,565)	$ 70,114	$ 11,924	$ 28,363	$ 24,620	$ 356,712	
PeakChoice	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	$ 9,672,225
Customer Awareness, Education and Outreach	$ -												$ -	
PROGRAMS & RATES WHICH REQUIRE ITEMIZED ACCOUNTING														
SmartAC	$ 26,787	$ 61,862	$ 57,423	$ 84,374	$ 356,211	$ 545,425	$ 486,891	$ 589,679	$ 483,872	$ 197,443	$ 117,436	$ 102,199	$ 3,109,604	
Customer Research	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ -	$ 29,877	$ 24,176	$ 29,476	$ 308,307	$ 502,295	$ 394,464	$ 472,904	$ 448,746	$ 140,531	$ 43,805	$ 98,354	$ 2,492,934	
Labor	$ 26,787	$ 31,985	$ 25,747	$ 49,598	$ 38,621	$ 42,193	$ 51,204	$ 32,396	$ 35,127	$ 45,259	$ 73,631	$ (7,273)	$ 445,276	
Paid Media	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		-	$ -	$ -	
Other Costs	$ -	$ -	$ 7,500	$ 5,300	$ 9,283	$ 938	$ 41,223	$ 84,379	$ -	$ 11,653	-	$ 11,118	$ 171,393	
II. TOTAL UTILITY MARKETING BY ACTIVITY	$ 87,740	$ 131,882	$ 181,516	$ 215,140	$ 437,588	$ 761,855	$ 560,775	$ 571,131	$ 717,585	$ 237,189	$ 211,981	$ 184,264	$ 4,298,644	
III. UTILITY MARKETING BY ITEMIZED COST														
Customer Research	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 5,631	$ 62,420	$ 80,873	$ 61,978	$ 337,043	$ 594,367	$ 428,366	$ 401,564	$ 630,193	$ 124,997	$ 71,550	$ 143,638	$ 2,942,619	
Labor	$ 82,109	$ 69,463	$ 93,144	$ 147,860	$ 91,171	$ 166,497	$ 91,186	$ 85,189	$ 87,392	$ 100,539	$ 140,431	$ 29,508	$ 1,184,486	
Paid Media	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other Costs	$ -	$ -	$ 7,500	$ 5,301	$ 9,375	$ 991	$ 41,224	$ 84,379	$ -	$ 11,653	$ -	$ 11,118	$ 171,539	
III. TOTAL UTILITY MARKETING BY ITEMIZED COST	$ 87,740	$ 131,882	$ 181,516	$ 215,140	$ 437,588	$ 761,855	$ 560,775	$ 571,131	$ 717,585	$ 237,189	$ 211,981	$ 184,264	$ 4,298,644	
IV. UTILITY MARKETING BY CUSTOMER SEGMENT														
Agricultural	$ 9,143	$ 10,503	$ 18,614	$ 19,615	$ 12,207	$ 32,464	$ 11,083	$ (2,782)	$ 35,057	$ 5,962	$ 14,182	$ 12,310	$ 178,356	
Large Commercial and Industrial	$ 51,810	$ 59,517	$ 105,479	$ 111,151	$ 69,171	$ 183,965	$ 62,801	$ (15,766)	$ 198,655	$ 33,784	$ 80,363	$ 69,755	$ 1,010,684	
Small and Medium Commercial	$ 1,339	$ 3,093	$ 2,871	$ 4,219	$ 17,811	$ 27,271	$ 24,345	$ 29,484	$ 24,194	$ 9,872	$ 5,872	$ 5,110	$ 155,480	
Residential	$ 25,448	$ 58,769	$ 54,552	$ 80,156	$ 338,400	$ 518,154	$ 462,547	$ 560,195	$ 459,679	$ 187,571	$ 111,564	$ 97,089	$ 2,954,124	
IV. TOTAL UTILITY MARKETING BY CUSTOMER SEGMENT	$ 87,740	$ 131,882	$ 181,516	$ 215,140	$ 437,588	$ 761,855	$ 560,775	$ 571,131	$ 717,585	$ 237,189	$ 211,981	$ 184,264	$ 4,298,644	

Notes:

[1]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 14-05-025, 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 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.

Pacific Gas and Electric Company
2015-2016 Fund Shifting Documentation
December 2015

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	$0.00			
Category 10: Special Projects	$100,000	Permanent Load Shifting to Demand Response Auction Mechanism Pilot	8/14/2015	The transferred funds support Demand Response Auction Mechanism pilot pursuant to Ordering Paragraph 5 of Decision 14-12-014.
	$200,000	Permanent Load Shifting to Demand Response Auction Mechanism Pilot	12/16/2015	The transferred funds support Demand Response Auction Mechanism pilot pursuant to Ordering Paragraph 5 of Decision 14-12-014.
Total	**$300,000**			