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

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 August. 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
August 2015

UTILITY NAME: Pacific Gas and Electric Company

Monthly Program Enrollment and Estimated Load Impacts

	January			February			March			April			May			June			
Programs	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**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	1,457	121	128	1,446	121	127	592,761
CBP - Day Ahead	0	0	0	0	0	0	0	0	0	0	0	0	175	21	26	181	21	27	596,779
CBP - Day Of	0	0	0	0	0	0	0	0	0	0	0	0	508	27	10	633	32	12	
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)	2,776	0	5	2,732	0	5	2,707	0	5	2,674	1	5	2,603	1	5	2,563	1	5	62,160
PDP (20 kW or below)	174,503	3	25	173,130	2	25	171,085	2	24	169,496	6	24	168,354	6	24	162,815	7	23	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	42	403	305,159	45	325	301,703	44	324	302,102	75	328	302,519	264	300	296,981	288	295	
Total All Programs	465,830	256	713	463,729	257	619	460,867	259	623	461,319	316	626	461,974	541	598	454,201	614	591	

	July			August			September			October			November			December			
Programs	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**Ex Ante Estimated MW [1]**	**Ex Post Estimated MW [2]**	**Service Accounts**	**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													10,843
OBMC	22	0	0	22	0	0													N/A
SLRP	0	0	0	0	0	0													N/A
SmartAC™ - Commercial	4,555	3	1	4,508	3	1													N/A
SmartAC™ - Residential	151,110	82	79	150,487	79	78													N/A
Sub-Total Interruptible	155,893	329	296	155,225	334	297	0	0	0	0	0	0	0	0	0	0	0	0	
Price Response																			
AMP - Day Of	1,466	120	129	1,434	119	126													592,761
CBP - Day Ahead	200	30	30	198	28	29													596,779
CBP - Day Of	589	20	11	571	19	11													
DBP	513	20	15	508	21	15													10,843
PDP (200 kW or above)	1,869	46	46	1,786	44	44													6,491
PDP (above 20 kW & below 200 kW)	2,525	1	5	2,501	1	4													385,886
PDP (20 kW or below)	160,151	7	23	158,251	7	22													
SmartRate™ - Residential	125,895	37	38	126,778	37	38													N/A
Sub-Total Price Response	293,208	282	296	292,027	275	291	0	0	0	0	0	0	0	0	0	0	0	0	
Total All Programs	449,101	611	592	447,252	609	588	0	0	0	0	0	0	0	0	0	0	0	0	

[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.

[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.

Pacific Gas and Electric Company
Average Ex Ante Load Impact kW / Customer
August 2015

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.

Program Eligibility and Ex Post Average Load Impacts

Program	Average Ex Post Load Impact kW / Customer January	February	March	April	May	June	July	August	September	October	November	December	[1] Eligible Accounts as of Jan 1, 2015	Eligibility Criteria (Refer to tariff for specifics)
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.

Table I-2
Pacific Gas and Electtric Company
Program Subscription Statistics
August 2015

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

2015	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		0.0	0.0	0.0		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		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		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.1	0.0	0.1		0.1	0.0	0.1
CBP - Day Of		3.8	0.0	3.8		3.8	0.0	3.8		3.8	0.0	3.8		4.1	0.0	4.1		4.1	0.0	4.1		4.1	0.0	4.1
DBP		0.0	0.0	0.0		0.0	0.0	0.0		0.1	0.0	0.1		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		0.1	0.0	0.1		0.1	0.0	0.1		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		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		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		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		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		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		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		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		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		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				0.0				0.0				0.0			
Total	0.0				0.0				0.0				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	0.0				0.0	N/A	N/A	N/A	0.0	N/A	N/A	N/A

2015	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		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																
CBP - Day Ahead		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																
DBP		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																
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		5.0	0.0	5.0		5.2	0.0	5.2																
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		5.0	0.0	5.0		5.2	0.0	5.2																
General Program																								
TA (may also be enrolled in TI and AutoDR)	0.0				0.0																			
Total	0.0				0.0																			
Total TA MWs	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-3
Pacific Gas and Electric Company
Demand Response Programs and Activities
2015-2016 Incremental Cost Funding
August 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					$105,794	$537,137		19.7%
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	$1,276	$1,084	$4,139	$2,391	$1,645	($458)	$655	$2,736					$13,469	$304,304		4.4%
Budget Category 1 Total	$15,592	$17,466	$16,446	$16,671	$13,217	$9,040	$13,276	$17,555	$0	$0	$0	$0	$119,263	$841,441	$0	14.2%
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					$171,700	$1,161,150		14.8%
Capacity Bidding Program (CBP)	$22,405	$21,934	$22,215	$28,775	$22,983	$18,680	$23,704	$27,349					$188,044	$4,887,754		3.8%
SmartAC™ [7]	$354,042	($105,497)	$221,492	$211,583	$183,198	$438,497	($334,616)	$1,583,742					$2,552,440	$13,336,338		19.1%
Budget Category 2 Total	$402,811	($64,206)	$265,109	$263,585	$228,882	$478,572	($290,941)	$1,628,372	$0	$0	$0	$0	$2,912,184	$19,385,242	$0	15.0%
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					$211,647	$944,506		22.4%
Budget Category 3 Total	$24,689	$24,692	$25,477	$30,704	$27,926	$22,464	$26,984	$28,711	$0	$0	$0	$0	$211,647	$944,506	$0	22.4%
Category 4: Emerging & Enabling Programs																
Auto DR	$47,963	$142,314	$90,079	$48,782	$294,074	$119,902	$224,114	$123,288					$1,090,515	$17,870,739		6.1%
DR Emerging Technology	$49,984	$124,622	$88,084	$71,000	$52,544	$63,226	$79,406	$104,947					$633,812	$2,809,056		22.6%
Budget Category 4 Total	$97,947	$266,936	$178,163	$119,783	$346,618	$183,128	$303,520	$228,234	$0	$0	$0	$0	$1,724,328	$20,679,795	$0	8.3%
Category 5: Pilots																
Supply Side Pilot	$39,640	$44,845	$29,579	$35,689	$34,825	$74,995	$32,774	$38,139					$330,484	$2,511,198		13.2%
T&D DR[8]	$4,377	$29,878	$211,718	($16,487)	$63,340	$28,191	$20,575	$23,430					$365,023	$1,698,036		21.5%
Excess Supply	$25,736	$31,765	$20,222	$14,073	$11,861	$14,582	$13,836	$23,190					$155,265	$1,199,842		12.9%
Budget Category 5 Total	$69,754	$106,488	$261,519	$33,275	$110,025	$117,768	$67,184	$84,759	$0	$0	$0	$0	$850,771	$5,409,076	$0	15.7%
Category 6: Evaluation, Measurement and Verification																
DRMEC	$23,111	$35,240	$51,664	$39,238	$52,269	$157,284	$114,331	$105,687					$578,824	$8,885,397		6.5%
Budget Category 6 Total	$23,111	$35,240	$51,664	$39,238	$52,269	$157,284	$114,331	$105,687	$0	$0	$0	$0	$578,824	$8,885,397	$0	6.5%
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)					$626,264	$9,142,336		31.0%
SmartAC™ ME&O[2]	$26,787	$61,862	$57,423	$84,374	$356,211	$545,425	$486,891	$589,679					$2,208,654			
Education and Training	$5,243	$5,721	$13,675	$45,787	$8,473	$11,752	$13,346	$8,710					$112,709	$529,889		21.3%
Budget Category 7 Total	$87,740	$131,882	$181,516	$215,140	$437,588	$761,855	$560,775	$571,131	$0	$0	$0	$0	$2,947,626	$9,672,225	$0	30.5%
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					$2,029,028	$9,974,090		20.3%
DR Enrollment & Support	$223,684	$174,511	$223,363	$224,668	$294,135	$159,312	$206,023	$242,842					$1,748,537	$10,874,287		16.1%
Notifications	$309,549	$317,160	$218,851	$242,558	$314,204	$424,941	$275,368	$263,593					$2,366,224	$5,473,744		43.2%
DR Integration Policy & Planning	$53,040	$127,098	$128,979	$138,650	$131,516	$117,578	$108,685	$160,859					$966,406	$3,207,039		30.1%
Budget Category 8 Total	$808,581	$868,027	$931,408	$806,851	$1,059,139	$886,627	$849,537	$900,025	$0	$0	$0	$0	$7,110,195	$29,529,161	$0	24.1%
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					$275,056	$4,051,540		6.8%
Integrated Energy Audits[3]	$5,800	$7,168	$37,312	$168,712	$38,109	$141,981	$10,989	$55,879					$465,949	$2,550,462		18.3%
Budget Category 9 Total	$8,939	$9,927	$39,990	$171,687	$103,062	$208,007	$75,576	$123,815	$0	$0	$0	$0	$741,005	$6,602,002	$0	11.2%
Category 10: Special Projects																
Permanent Load Shifting	$21,065	$29,992	$41,162	$51,341	$38,551	$24,749	$39,662	$48,537					$295,060	$10,128,288	($100,000)	2.9%
Demand Response Auction Mechanism Pilot[9]	$0	$0	$0	$0	$0	$0	$5,699	$6,562					$12,260	$0	$100,000	
Budget Category 10 Total	$21,065	$29,992	$41,162	$51,341	$38,551	$24,749	$45,361	$55,099	$0	$0	$0	$0	$307,320	$10,128,288	$0	3.0%
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					$2,180,625		$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	$0	$0	$0	$0	$19,683,789	$112,077,133	$0	17.6%

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 will be made in August.
[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.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
August 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]	FEBRUARY	System	2/11/2015	1	Day Of	Re-test	15	2:00 PM	4:00 PM	2	Redacted
	Base Interruptible Program (BIP)[1]	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	243.1
	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)	JUNE	System	6/8/2015	1	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	20.5
	Capacity Bidding Program (CBP)	JUNE	Fresno, Humboldt	6/9/2015	2	Day Of	Heat Rate	63	2:00 PM	7:00 PM	5	Redacted
	Capacity Bidding Program (CBP)	JUNE	System	6/12/2015	1	Day Ahead	Heat Rate	175	3:00 PM	7:00 PM	4	14.8
	Capacity Bidding Program (CBP)	JUNE	System	6/12/2015	3	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JUNE	System	6/25/2015	2	Day Ahead	Heat Rate	175	3:00 PM	7:00 PM	4	17.1
	Capacity Bidding Program (CBP)	JUNE	System	6/25/2015	4	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JUNE	System	6/26/2015	3	Day Ahead	Heat Rate	175	3:00 PM	7:00 PM	4	19.7
	Capacity Bidding Program (CBP)	JUNE	System	6/26/2015	5	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JUNE	System	6/30/2015	4	Day Ahead	Heat Rate	175	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JUNE	System	6/30/2015	6	Day Of	Heat Rate	508	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JULY	System	7/1/2015	5	Day Ahead	Heat Rate	181	3:00 PM	7:00 PM	4	11.5
	Capacity Bidding Program (CBP)	JULY	System	7/1/2015	7	Day Of	Heat Rate	633	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	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)	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)	JULY	System	7/28/2015	7	Day Ahead	Heat Rate	181	3:00 PM	7:00 PM	4	13.5
	Capacity Bidding Program (CBP)	JULY	System	7/28/2015	9	Day Of	Heat Rate	633	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JULY	System	7/29/2015	8	Day Ahead	Heat Rate	181	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JULY	System	7/29/2015	10	Day Of	Heat Rate	633	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JULY	System	7/30/2015	9	Day Ahead	Heat Rate	181	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	JULY	System	7/30/2015	11	Day Of	Heat Rate	633	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	AUGUST	System	8/17/2015	10	Day Ahead	Heat Rate	200	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	AUGUST	System	8/17/2015	12	Day Of	Heat Rate	589	3:00 PM	7:00 PM	4	17.5
	Capacity Bidding Program (CBP)	AUGUST	System	8/18/2015	11	Day Ahead	Heat Rate	200	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	AUGUST	System	8/18/2015	13	Day Of	Heat Rate	589	3:00 PM	7:00 PM	4	15.2
	Capacity Bidding Program (CBP)	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)	AUGUST	System	8/26/2015	14	Day Of	Heat Rate	589	3:00 PM	7:00 PM	4	15.4
	Capacity Bidding Program (CBP)	AUGUST	System	8/27/2015	13	Day Ahead	Heat Rate	200	3:00 PM	7:00 PM	4	Redacted
	Capacity Bidding Program (CBP)	AUGUST	System	8/27/2015	15	Day Of	Heat Rate	589	3:00 PM	7:00 PM	4	17.4
	Demand Bidding Program (DBP)	JUNE	System	6/12/2015	1	Day Ahead	Temperature	53	4:00 PM	9:00 PM	5	Redacted
	Demand Bidding Program (DBP)	JUNE	System	6/25/2015	2	Day Ahead	Temperature	66	2:00 PM	10:00 PM	8	Redacted
	Demand Bidding Program (DBP)	JUNE	System	6/26/2015	3	Day Ahead	Temperature	44	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)	JUNE	System	6/30/2015	4	Day Ahead	Temperature	72	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)	JULY	System	7/1/2015	5	Day Ahead	Temperature	61	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)	JULY	System	7/28/2015	6	Day Ahead	Temperature	53	2:00 PM	10:00 PM	8	Redacted
	Demand Bidding Program (DBP)	JULY	System	7/29/2015	7	Day Ahead	Temperature	56	2:00 PM	10:00 PM	8	Redacted
	Demand Bidding Program (DBP)	AUGUST	System	8/17/2015	9	Day Ahead	Temperature	61	2:00 PM	9:00 PM	7	Redacted
	Demand Bidding Program (DBP)	AUGUST	System	8/18/2015	10	Day Ahead	Temperature	55	1:00 PM	9:00 PM	8	Redacted
	Demand Bidding Program (DBP)	AUGUST	Fresno, Los Padres, North Valley, Sacramento Valley, Sierra, San Joaquin, Stockton	8/26/2015	8	Day Ahead	Temperature	15	3:00 PM	9:00 PM	6	Redacted
	Demand Bidding Program (DBP)	AUGUST	System	8/27/2015	9	Day Ahead	Temperature	51	2:00 PM	9:00 PM	7	Redacted
	Demand Bidding Program (DBP)	AUGUST	System	8/28/2015	10	Day Ahead	Temperature	54	3:00 PM	7:00 PM	4	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.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
August 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	**Redacted**
	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
	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
	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
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

[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.

Table I-5
Pacific Gas and Electric Company
2015-2016 Demand Response Programs
Total Embedded Cost and Revenues
August 2015

Annual Total Cost

Cost Item	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-Date 2015 Total Cost
Program Incentives													
Aggregator Managed Portfolio (AMP)[1]	$0	$0	$0	$0	$607,331	$0	$0	$0					$607,331
Automatic Demand Response (AutoDR)	$0	$0	$0	$0	$0	$0	$0	$0					$0
Base Interruptible Program (BIP)[4]	$1,902,132	$2,172,462	$2,157,725	$2,194,550	$2,137,970	$2,250,657	$2,203,402	$2,232,501					$17,251,398
Capacity Bidding Program (CBP)	$0	$0	$0	$0	$0	$349,812	$449,843	$157,740					$957,395
Demand Bidding Program (DBP)	$0	$0	$0	$0	$0	$0	$0	$0					$0
Excess Supply Pilot	$0	$0	$0	$0	$0	$0	$0	$0					$0
Optional Binding Mandatory Curtailment / Scheduled Load Reduction Program (OBMC / SLRP)[1]	$0	$0	$0	$0	$0	$0	$0	$0					$0
SmartAC™[, 3]	$83,738	$89,907	$92,396	$47,989	($120,701)	$12,459	$55,433	$94,404					$355,625
Supply Side Pilot	$0	$0	$0	$0	$0	$0	$6,929	$4,758					$11,687
Technology Incentive (TI)	$0	$0	$0	$0	$0	$0	$0	$28,770					$28,770
Transmission and Distribution Pilot (T&D DR)	$0	$0	$0	$0	$0	$0	$0	$0					$0
Total Cost of Incentives	$1,985,870	$2,262,369	$2,250,120	$2,242,539	$2,624,600	$2,612,928	$2,715,607	$2,518,173	$0	$0	$0	$0	$19,212,206
Revenues from Penalties[2]	$0	$0	$0	$0	$0	$1,098,160	$0	$0	$0	$0	$0	$0	$1,098,160

[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] Revenues from Penalties denote the amounts paid by an aggregator to the utility due to penalties, excluding reduction in incentive payments.
[3] The May credit is attributable to adjustments of prior months' financials.
[4]Amounts reported are for incentive costs that are not recorded in the Demand Response Expenditures Balancing Account.

Table I-7
Pacific Gas and Electric Company
2015-2016 Marketing, Education and Outreach
Actual Expenditures
August 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)					$ 369,486	
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)					$ 147,794	
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)					$ 221,692	
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	$ -	$ -	$ -	$ -	$ 2,208,654	
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					$ 1,761,499	
Labor	$ 26,787	$ 31,985	$ 25,747	$ 49,598	$ 38,621	$ 42,193	$ 51,204	$ 32,396					$ 298,533	
Paid Media	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					$ -	
Other Costs	$ -	$ -	$ 7,500	$ 5,300	$ 9,283	$ 938	$ 41,223	$ 84,379					$ 148,622	
II. TOTAL UTILITY MARKETING BY ACTIVITY	$ 87,740	$ 131,882	$ 181,516	$ 215,140	$ 437,588	$ 761,855	$ 560,775	$ 571,131	$ -	$ -	$ -	$ -	$ 2,947,626	
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					$ 1,972,241	
Labor	$ 82,109	$ 69,463	$ 93,144	$ 147,860	$ 91,171	$ 166,497	$ 91,186	$ 85,189					$ 826,617	
Paid Media	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					$ -	
Other Costs	$ -	$ -	$ 7,500	$ 5,301	$ 9,375	$ 991	$ 41,224	$ 84,379					$ 148,768	
III. TOTAL UTILITY MARKETING BY ITEMIZED COST	$ 87,740	$ 131,882	$ 181,516	$ 215,140	$ 437,588	$ 761,855	$ 560,775	$ 571,131	$ -	$ -	$ -	$ -	$ 2,947,626	
IV. UTILITY MARKETING BY CUSTOMER SEGMENT														
Agricultural	$ 9,143	$ 10,503	$ 18,614	$ 19,615	$ 12,207	$ 32,464	$ 11,083	$ (2,782)					$ 110,846	
Large Commercial and Industrial	$ 51,810	$ 59,517	$ 105,479	$ 111,151	$ 69,171	$ 183,965	$ 62,801	$ (15,766)					$ 628,127	
Small and Medium Commercial	$ 1,339	$ 3,093	$ 2,871	$ 4,219	$ 17,811	$ 27,271	$ 24,345	$ 29,484					$ 110,433	
Residential	$ 25,448	$ 58,769	$ 54,552	$ 80,156	$ 338,400	$ 518,154	$ 462,547	$ 560,195					$ 2,098,221	
IV. TOTAL UTILITY MARKETING BY CUSTOMER SEGMENT	$ 87,740	$ 131,882	$ 181,516	$ 215,140	$ 437,588	$ 761,855	$ 560,775	$ 571,131	$ -	$ -	$ -	$ -	$ 2,947,626	

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.

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	$100,000.00	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.
Total	**$100,000**			