Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for March 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 March. 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
March 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										10,843
OBMC	24	0	0	24	0	0	24	0	0										N/A
SLRP	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										N/A
SmartAC™ - Residential	152,200	0	79	153,547	0	80	154,173	0	80										N/A
Sub-Total Interruptible	157,276	214	310	158,570	212	294	159,164	215	298	0	0	0	0	0	0	0	0	0	
Price Response																			
AMP - Day Of	2,167	0	190	2,160	0	190	2,169	0	191										592,761
CBP - Day Ahead	0	0	0	0	0	0	0	0	0										596,779
CBP - Day Of	0	0	0	0	0	0	0	0	0										
DBP	794	23	24	790	27	23	784	25	23										10,843
PDP (200 kW or above)	1,846	15	46	1,811	15	45	1,838	16	45										6,491
PDP (<200 kW)	177,279	4	811	175,862	4	805	173,792	4	796										385,886
SmartRate™ - Residential	125,599	0	38	124,529	0	37	123,129	0	37										N/A
Sub-Total Price Response	307,685	43	1,109	305,152	46	1,100	301,712	45	1,092	0	0	0	0	0	0	0	0	0	
Total All Programs	464,961	257	1,419	463,722	259	1,394	460,876	260	1,390	0	0	0	0	0	0	0	0	0	

	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																			10,843
OBMC																			N/A
SLRP																			N/A
SmartAC™ - Commercial																			N/A
SmartAC™ - Residential																			N/A
Sub-Total Interruptible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Price Response																			
AMP - Day Of																			592,761
CBP - Day Ahead																			596,779
CBP - Day Of																			
DBP																			10,843
PDP (200 kW or above)																			6,491
PDP (<200 kW)																			385,886
SmartRate™ - Residential																			N/A
Sub-Total Price Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total All Programs	0	0	0	0	0	0	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.

[3] 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 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.

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

NOTE: The number of SmartRate Service Accounts in January has been updated in the February 2015 ILP. The January 2015 ILP incorrectly restated the December 2014 numbers.

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 operational reporting, resource planning, and cost effectiveness analysis or in developing regulatory filings.

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 (<200 kW)	0.02	0.02	0.02	0.06	0.06	0.08	0.08	0.08	0.07	0.06	0.02	0.02	385,886	
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.

[1] The March 2015 ILP provides the available 2015-2016 data for 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
March 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 (<200 kW)	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	385,886	
SmartRate™ - Residentia	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.

[1] The March 2015 ILP provides the available 2015-2016 data for Eligible Accounts and Program Eligibility for Ex Ante and Expost Average Load Impacts.

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

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		0.1	0.0	0.1
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		0.1	0.0	0.1
Total Technology MWs		4.1	0.0	4.1		4.1	0.0	4.1		4.3	0.0	4.3
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												
AMP - Day Of												
CBP - Day Ahead												
CBP - Day Of												
DBP												
PDP												
SmartRate™ - Residential												
SmartAC™ - Commercial												
SmartAC™ - Residential												
Total												
Interruptible/Reliability												
BIP - Day of												
OBMC												
SLRP												
Total												
Total Technology MWs												
General Program												
TA (may also be enrolled in TI and AutoDR)												
Total												
Total TA MWs												

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												
AMP - Day Of												
CBP - Day Ahead												
CBP - Day Of												
DBP												
PDP												
SmartRate™ - Residential												
SmartAC™ - Commercial												
SmartAC™ - Residential												
Total												
Interruptible/Reliability												
BIP - Day of												
OBMC												
SLRP												
SmartAC™ - Commercial												
Total												
Total Technology MWs												
General Program												
TA (may also be enrolled in TI and AutoDR)												
Total												
Total TA MWs												

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												
AMP - Day Of												
CBP - Day Ahead												
CBP - Day Of												
DBP												
PDP												
SmartRate™ - Residential												
SmartAC™ - Commercial												
SmartAC™ - Residential												
Total												
Interruptible/Reliability												
BIP - Day of												
OBMC												
SLRP												
SmartAC™ - Commercial												
Total												
Total Technology MWs												
General Program												
TA (may also be enrolled in TI and AutoDR)												
Total												
Total TA MWs												

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
March 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										$43,005	$537,137		8.0%
Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)	$1,276	$1,084	$4,139										$6,499	$304,304		2.1%
Budget Category 1 Total	$15,592	$17,466	$16,446	$0	$0	$0	$0	$0	$0	$0	$0	$0	$49,504	$841,441	$0	5.9%
Category 2: Price-Responsive Programs																
Demand Bidding Program (DBP)	$26,364	$19,357	$21,401										$67,123	$1,161,150		5.8%
Capacity Bidding Program (CBP)	$22,405	$21,934	$22,215										$66,554	$4,887,754		1.4%
SmartAC™ [7]	$354,042	($105,497)	$221,492										$470,037	$13,336,338		3.5%
Budget Category 2 Total	$402,811	($64,206)	$265,109	$0	$0	$0	$0	$0	$0	$0	$0	$0	$603,714	$19,385,242	$0	3.1%
Category 3: DR Provider/Aggregator Managed Programs																
Aggregator Managed Portfolio (AMP)	$24,689	$24,692	$25,477										$74,858	$944,506		7.9%
Budget Category 3 Total	$24,689	$24,692	$25,477	$0	$0	$0	$0	$0	$0	$0	$0	$0	$74,858	$944,506	$0	7.9%
Category 4: Emerging & Enabling Programs																
Auto DR	$47,963	$142,314	$90,079										$280,356	$17,870,739		1.6%
DR Emerging Technology	$49,984	$124,622	$88,084										$262,690	$2,809,056		9.4%
Budget Category 4 Total	$97,947	$266,936	$178,163	$0	$0	$0	$0	$0	$0	$0	$0	$0	$543,046	$20,679,795	$0	2.6%
Category 5: Pilots																
Supply Side Pilot	$39,640	$44,845	$29,579										$114,064	$2,511,198		4.5%
T&D DR	$4,377	$29,878	$211,718										$245,973	$1,698,036		14.5%
Excess Supply	$25,736	$31,765	$20,222										$77,723	$1,199,842		6.5%
Budget Category 5 Total	$69,754	$106,488	$261,519	$0	$0	$0	$0	$0	$0	$0	$0	$0	$437,760	$5,409,076	$0	8.1%
Category 6: Evaluation, Measurement and Verification																
DRMEC	$23,111	$35,240	$51,664										$110,015	$8,885,397		1.2%
Budget Category 6 Total	$23,111	$35,240	$51,664	$0	$0	$0	$0	$0	$0	$0	$0	$0	$110,015	$8,885,397	$0	1.2%
Category 7: Marketing, Education and Outreach																
DR Core Marketing and Outreach[1]	$55,709	$64,299	$110,417										$230,425	$9,142,336		4.1%
SmartAC™ ME&O[2]	$26,787	$61,862	$57,423										$146,073			
Education and Training	$5,243	$5,721	$13,675										$24,640	$529,889		4.7%
Budget Category 7 Total	$87,740	$131,882	$181,516	$0	$0	$0	$0	$0	$0	$0	$0	$0	$401,138	$9,672,225	$0	4.1%
Category 8: DR System Support Activities																
InterAct / DR Forecasting Tool	$222,309	$249,258	$360,215										$831,781	$9,974,090		8.3%
DR Enrollment & Support	$223,684	$174,511	$223,363										$621,558	$10,874,287		5.7%
Notifications	$309,549	$317,160	$218,851										$845,560	$5,473,744		15.4%
DR Integration Policy & Planning	$53,040	$127,098	$128,979										$309,118	$3,207,039		9.6%
Budget Category 8 Total	$808,581	$868,027	$931,408	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,608,016	$29,529,161	$0	8.8%
Category 9: Integrated Programs and Activities (Including Technical Assistance)																
Technology Incentives - IDSM[3]	$3,140	$2,759	$2,679										$8,578	$4,051,540		0.2%
Integrated Energy Audits[3]	$5,800	$7,168	$37,312										$50,280	$2,550,462		2.0%
Budget Category 9 Total	$8,939	$9,927	$39,990	$0	$0	$0	$0	$0	$0	$0	$0	$0	$58,857	$6,602,002	$0	0.9%
Category 10: Special Projects																
Permanent Load Shifting	$21,065	$29,992	$41,162										$92,219	$10,128,288		0.9%
Budget Category 10 Total	$21,065	$29,992	$41,162	$0	$0	$0	$0	$0	$0	$0	$0	$0	$92,219	$10,128,288	$0	0.9%
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										$819,175		$0	N/A
Total Incremental Cost[4]	$1,824,250	$1,688,258	$2,285,795	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,798,302	$112,077,133	$0	5.2%

Technical Assistance & Technology Incentives (TA&TI) Identified as of MARCH 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.

[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.

Table I-4
Pacific Gas and Electric Company
Interruptible and Price Responsive Programs
Year-to-Date Event Summary
March 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)[3]	FEBRUARY	System	2/11/2015		Day Of	Re-test	15	2:00 PM	4:00 PM	2	**Redacted**
	Optional Bidding Mandatory Curtailment / Scheduled Load Reduction (OBMC / SLRP)											
Category 2: Price-Responsive Programs												
	Capacity Bidding Program (CBP)											
	Peak Day Pricing (PDP)											
	SmartAC™ [4]											
	SmartRate™											
Category 3: DR Provider/Aggregator Managed Programs												
	Aggregator Managed Portfolio (AMP)											

[1] Identifies location of event (SubLAP) for locally-dispatchable programs. Non-locally-dispatchable programs are listed as System.

[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.

NOTE: The 2/11/2015 BIP event was a re-test resulting from the 9/11/2014 BIP event. It included only a subset of the program's enrollment.

Table I-5
Pacific Gas and Electric Company
2015-2016 Demand Response Programs
Total Embedded Cost and Revenues
March 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
Automatic Demand Response (AutoDR)	$0	$0	$0										$0
Base Interruptible Program (BIP)[1]	$1,902,132	$2,172,462	$2,157,725										$6,232,318
Capacity Bidding Program (CBP)	$0	$0	$0										$0
Demand Bidding Program (DBP)	$0	$0	$0										$0
Excess Supply Pilot	$0	$0	$0										$0
Optional Binding Mandatory Curtailment / Scheduled Load Reduction Program (OBMC / SLRP)[1]	$0	$0	$0										$0
SmartAC™	$83,738	$89,907	$92,396										$266,041
Supply Side Pilot	$0	$0	$0										$0
Technology Incentive (TI)	$0	$0	$0										$0
Transmission and Distribution Pilot (T&D DR)	$0	$0	$0										$0
Total Cost of Incentives	$1,985,870	$2,262,369	$2,250,120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,498,359
Revenues from Penalties[2]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

[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.

Table I-7
Pacific Gas and Electric Company
2015-2016 Marketing, Education and Outreach
Actual Expenditures
March 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										$ 127,533	
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										$ 51,013	
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										$ 76,520	
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 146,073	
Customer Research	$ -	$ -	$ -										$ -	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ -	$ 29,877	$ 24,176										$ 54,053	
Labor	$ 26,787	$ 31,985	$ 25,747										$ 84,520	
Paid Media	$ -	$ -	$ -										$ -	
Other Costs	$ -	$ -	$ 7,500										$ 7,500	
II. TOTAL UTILITY MARKETING BY ACTIVITY	$ 87,740	$ 131,882	$ 181,516	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 401,138	
III. UTILITY MARKETING BY ITEMIZED COST														
Customer Research	$ -	$ -	$ -										$ -	
Collateral- Development, Printing, Distribution etc. (all non-labor costs)	$ 5,631	$ 62,420	$ 80,873										$ 148,923	
Labor	$ 82,109	$ 69,463	$ 93,144										$ 244,715	
Paid Media	$ -	$ -	$ -										$ -	
Other Costs	$ -	$ -	$ 7,500										$ 7,500	
III. TOTAL UTILITY MARKETING BY ITEMIZED COST	$ 87,740	$ 131,882	$ 181,516	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 401,138	
IV. UTILITY MARKETING BY CUSTOMER SEGMENT														
Agricultural	$ 9,143	$ 10,503	$ 18,614										$ 38,260	
Large Commercial and Industrial	$ 51,810	$ 59,517	$ 105,479										$ 216,805	
Small and Medium Commercial	$ 1,339	$ 3,093	$ 2,871										$ 7,304	
Residential	$ 25,448	$ 58,769	$ 54,552										$ 138,769	
IV. TOTAL UTILITY MARKETING BY CUSTOMER SEGMENT	$ 87,740	$ 131,882	$ 181,516	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 401,138	

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	$0.00			
Total	**$0**			