Table of Attachments (Updated with Errata)

Attachment C: PG&E Responses to Commercial Energy Data Requests (Updated)

This exhibit includes the following data responses:

Data Request Set 3, Questions 3 and Attachment 1 (attachment has been added), 4 and Attachment 1 (attachment has been added), 5 and Attachment 1 (attachment has been added), 9 and Attachment 1,15, and 25

Data Request Set 3A, Questions 8, 23 and Attachments 1, 2, 3, 4

Data Request Set 7, Questions 6, 7 (response title page has been added) and CONFIDENTIAL Attachments 1 and 2, and Attachment 3, and 8

Data Request Set 9, Question 1

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CommercialEnergy-CA_003-03		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q03		
Request Date:	May 2, 2014	Requester DR No.:	003
Date Sent:	May 29, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:	Jeffrey Swanson	Requester:	Michael B. Day/ Megan Somogyi

QUESTION 3

For each of the last three calendar years (2011-2013), please state the number of natural gas customers served on PG&E Core rate schedules with annual gas usage greater than 200,000 therms per year, but less than 250,000 therms per year. For the purposes of this question treat each meter as a separate customer. Please state the total quantity of gas consumed by all such customers during each calendar year. Please also state the aggregate monthly volume used by all such customers during the 36 month period.

ANSWER 3

Please see GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q03Atch01 for customer counts and associated gas usage for core customers with annual gas usage in excess of 200,000 but less than 250,000 therms.

Customer count data is provided within the context that it would be used for ratemaking. Each customer may have more than one gas meter associated with their account.

GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q03Atch01

Core customers with annual usage between 200,000 and 250,000 therms.

Month	Customers	Therms per Month	Year	Customers	Thousand Decatherms per Year
Jan-11	100	2,199,737	2011	101	2,269
Feb-11	100	2,146,937	2012	108	2,391
Mar-11	101	2,011,520	2013	98	2,241
Apr-11	101	1,891,013			
May-11	101	1,770,859			
Jun-11	101	1,541,392			
Jul-11	101	1,448,420			
Aug-11	101	1,457,020			
Sep-11	100	1,634,230			
Oct-11	100	2,032,195			
Nov-11	100	2,231,892			
Dec-11	100	2,324,330			
Jan-12	107	2,353,275			
Feb-12	107	2,371,447			
Mar-12	108	2,148,893			
Apr-12	108	2,115,105			
May-12	108	1,821,564			
Jun-12	108	1,728,537			
Jul-12	108	1,675,656			
Aug-12	108	1,635,482			
Sep-12	108	1,894,281			
Oct-12	108	1,851,708			
Nov-12	108	2,019,425			
Dec-12	106	2,292,331			
Jan-13	98	2,461,938			
Feb-13	100	2,424,481			
Mar-13	100	2,040,953			
Apr-13	100	1,918,057			
May-13	97	1,568,068			
Jun-13	97	1,470,130			
Jul-13	97	1,485,636			
Aug-13	97	1,481,628			
Sep-13	97	1,600,633			
Oct-13	97	1,858,313			
Nov-13	96	1,946,069			
Dec-13	96	2,157,413			

Customer count data is provided within the context that it would be used for ratemaking. Each customer may have more than one gas meter associated with their account.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CommercialEnergy-CA_003-04		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q04		
Request Date:	May 2, 2014	Requester DR No.:	003
Date Sent:	May 29, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:	Jeffrey Swanson	Requester:	Michael B. Day/ Megan Somogyi

QUESTION 4

For each of the last three calendar years (2011-2013), please state the number of natural gas customers served on PG&E Core rate schedules with annual gas usage greater than 150,000 therms per year, but less than 200,000 therms per year. For the purposes of this question treat each meter as a separate customer. Please state the total quantity of gas consumed by all such customers during each calendar year. Please also state the aggregate monthly volume used by all such customers during the 36 month period.

ANSWER 4

Please see GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q04Atch01 for customer counts and associated gas usage for core customers with annual gas usage in excess of 150,000 but less than 200,000 therms.

Customer count data is provided within the context that it would be used for ratemaking. Each customer may have more than one gas meter associated with their account.

GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q04Atch01

Core customers with annual usage between 150,000 and 200,000 therms.

Month	Customers	Therms per Month	Year	Customers	Thousand Decatherms per Year
Jan-11	177	2,985,124	2011	178	3,166
Feb-11	177	2,901,452	2012	165	2,917
Mar-11	178	2,781,095	2013	170	3,026
Apr-11	180	2,581,888			
May-11	179	2,400,363			
Jun-11	180	2,177,013			
Jul-11	180	2,038,002			
Aug-11	179	2,268,931			
Sep-11	178	3,054,053			
Oct-11	178	2,499,450			
Nov-11	176	3,047,143			
Dec-11	175	2,925,033			
Jan-12	165	2,927,058			
Feb-12	165	2,767,119			
Mar-12	166	2,594,801			
Apr-12	166	2,493,917			
May-12	166	2,099,253			
Jun-12	165	1,954,837			
Jul-12	166	1,919,985			
Aug-12	166	2,055,861			
Sep-12	165	2,403,909			
Oct-12	165	2,495,484			
Nov-12	164	2,764,060			
Dec-12	164	2,698,074			
Jan-13	167	2,989,754			
Feb-13	168	2,851,194			
Mar-13	169	2,575,881			
Apr-13	171	2,448,202			
May-13	172	2,371,366			
Jun-13	173	2,199,443			
Jul-13	173	2,236,597			
Aug-13	172	2,228,573			
Sep-13	170	2,333,591			
Oct-13	169	2,283,598			
Nov-13	169	2,669,885			
Dec-13	169	3,070,650			

Customer count data is provided within the context that it would be used for ratemaking. Each customer may have more than one gas meter associated with their account.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CommercialEnergy-CA_003-05		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q05		
Request Date:	May 2, 2014	Requester DR No.:	003
Date Sent:	May 29, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:	Jeffrey Swanson	Requester:	Michael B. Day/ Megan Somogyi

QUESTION 5

For each of the last three calendar years (2011-2013), please state the number of natural gas customers served on PG&E Core rate schedules with annual gas usage greater than 100,000 therms per year, but less than 150,000 therms per year. For the purposes of this question treat each meter as a separate customer. Please state the total quantity of gas consumed by all such customers during each calendar year. Please also state the aggregate monthly volume used by all such customers during the 36 months.

ANSWER 5

Please see GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q05Atch01 for customer counts and associated gas usage for core customers with annual gas usage in excess of 100,000 but less than 150,000 therms.

Customer count data is provided within the context that it would be used for ratemaking. Each customer may have more than one gas meter associated with their account.

GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q05Atch01

Core customers with annual usage between 100,000 and 150,000 therms.

Month	Customers	Therms per Month	Year	Customers	Thousand Decatherms per Year
Jan-11	403	5,175,859	2011	405	4,935
Feb-11	404	5,077,339	2012	378	4,586
Mar-11	406	4,715,276	2013	394	4,878
Apr-11	406	4,261,086			
May-11	406	3,899,404			
Jun-11	406	3,456,971			
Jul-11	405	2,961,307			
Aug-11	406	3,056,385			
Sep-11	407	3,486,543			
Oct-11	405	3,708,244			
Nov-11	403	4,522,965			
Dec-11	400	5,030,532			
Jan-12	376	4,592,314			
Feb-12	377	4,565,313			
Mar-12	377	4,366,041			
Apr-12	377	3,891,290			
May-12	378	3,423,314			
Jun-12	379	3,189,413			
Jul-12	379	3,029,396			
Aug-12	379	3,106,719			
Sep-12	379	3,835,950			
Oct-12	379	3,630,205			
Nov-12	378	3,900,112			
Dec-12	376	4,326,217			
Jan-13	395	5,624,435			
Feb-13	395	5,261,413			
Mar-13	396	4,416,934			
Apr-13	397	3,813,433			
May-13	396	3,581,312			
Jun-13	395	3,201,962			
Jul-13	393	3,073,959			
Aug-13	394	3,200,160			
Sep-13	393	3,374,613			
Oct-13	393	3,872,633			
Nov-13	391	4,361,073			
Dec-13	391	4,998,646			

Customer count data is provided within the context that it would be used for ratemaking. Each customer may have more than one gas meter associated with their account.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CommercialEnergy-CA_003-09		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q09		
Request Date:	May 2, 2014	Requester DR No.:	003
Date Sent:	May 16, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:	David Elmore	Requester:	Michael B. Day/ Megan Somogyi

QUESTION 9

With respect to Figure 19-2 on page 19-17 of PG&E's Prepared Testimony, please provide a chart with the same horizontal axis, but with the vertical axis variable showing CTA and bundled core loads as volumetric quantities of gas, instead of the ratio of CTA load to core load as shown in the original Figure 19-2. In addition to the chart, please provide the monthly CTA load, expressed as a volumetric quantity of gas, for the same months as Figure 19-2, and also provide the monthly bundled core load, expressed in the same units as the CTA load, for the same months as Figure 19-2.

ANSWER 9

PG&E identified a summation error in the data that produced Figure 19-2 (Row 19 on the Monthly-Calendar tab). This error was corrected in attachment GTS-RateCase2015_DR_IndicatedProducers_002-Q168Atch02.

Please see attachment GTS_RateCase2015_DR_CommercialEnergy-CA_003-Q09Atch01 which uses the data from GTS-RateCase2015_DR_IndicatedProducers_002-Q168Atch02 for the requested chart for CTA and bundled core loads as volumetric quantities of gas.

Base Case Forecast--Calendar Basis
(Average Temperature Year)
November 7, 2013 GT&S Forecast Run (Corrected)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

	Recorded Jan-13	Recorded Feb-13	Recorded Mar-13	Recorded Apr-13	Recorded May-13	Recorded Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13
CORE											
RESIDENTIAL											
RESIDENTIAL IM	33,374	23,561	15,487	10,299	7,456	6,626	6,186	6,306	6,807	9,363	17,989
RES IM TRANS	1,504	1,178	871	667	544	523	411	403	431	586	1,113
RESIDENTIAL MM	1,777	1,483	1,286	1,097	931	863	830	844	885	1,057	1,429
RES MM TRANS	674	576	503	432	379	352	360	362	370	436	575
TOTAL RES	37,329	26,798	18,147	12,495	9,311	8,364	7,786	7,915	8,493	11,442	21,107
COMMERCIAL											
SML COM SALES	6,415	5,117	3,833	3,027	2,535	2,325	2,204	2,184	2,429	3,055	3,828
SML COM TRANS	4,694	3,935	3,192	2,640	2,278	2,124	2,036	2,050	2,200	2,581	3,220
LRG COM SALES	365	335	285	276	265	268	265	335	426	347	337
LRG COM TRANS	374	374	323	303	274	252	291	324	323	394	350
TOTAL COM	11,849	9,761	7,632	6,245	5,352	4,969	4,797	4,893	5,379	6,377	7,734
CTAs	7,247	6,064	4,889	4,042	3,476	3,250	3,098	3,139	3,323	3,997	5,258
Total	49,178	36,560	25,779	18,740	14,663	13,333	12,583	12,809	13,872	17,819	28,841
PG&E Core	41,931	30,496	20,891	14,698	11,187	10,083	9,485	9,669	10,549	13,823	23,583
% CTAs Share	15%	17%	19%	22%	24%	24%	25%	25%	24%	22%	18%
% PG&E Core Share	85%	83%	81%	78%	76%	76%	75%	75%	76%	78%	82%
Jan Cap			15%	15%	15%	15%	15%	15%	15%	15%	15%
Proposed Allocation to CTAs period 1			22%	22%	22%	22%					
Proposed Allocation to CTAs period 2							24%	24%	24%	24%	
Proposed Allocation to CTAs period 3											18%
CTAs Avg. %			20%	20%	20%	20%	20%	20%	20%	20%	20%
CTAs Ave. Volume			4700	4700	4700	4700	4700	4700	4700	4700	4700
INTERDEPT											
GNR1	28	22	14	8	6	5	6	5	5	6	10
GNR2	0	0	0	0	0	0	0	0	0	0	0
TOTAL INTERDEPARTMENTAL	28	22	14	8	6	5	6	5	5	6	10
NATURAL GAS VEHICLE											
NGV1--INTERDEPARTMENTAL	5	5	6	5	7	10	10	10	10	10	10
NGV1--NON-INTERDEPARTMENTAL	159	157	163	169	191	182	156	156	156	156	156
NGV2--NON-INTERDEPARTMENTAL	22	22	22	23	23	21	21	21	21	21	21
TOTAL NGV	185	184	192	197	221	214	186	186	186	186	186
TOTAL CORE	49,391	36,766	25,985	18,946	14,890	13,551	12,776	13,000	14,064	18,012	29,038
Distribution Shrinkage Factor (b)	2.9%	2.9%	2.9%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	2.9%
Total Core @ Citygate (c=a*(1+b))	50,823	37,832	26,738	19,268	15,144	13,782	12,993	13,221	14,303	18,318	29,880
Minimum Transmission Shrinkage (d)	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total Core @ CA Border) (e=c/(1-d))	51,336	38,214	27,008	19,463	15,297	13,921	13,124	13,355	14,447	18,503	30,181

Base Case Forecast--Calendar Basis
(Average Temperature Year)
November 7, 2013 GT&S Forecast Run (Corrected)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

	Dec-13	TOTAL	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
CORE												
RESIDENTIAL												
RESIDENTIAL IM	29,841	173,296	27,507	18,699	16,391	12,288	8,709	6,976	6,250	6,283	6,721	9,203
RES IM TRANS	1,902	10,133	1,828	1,290	1,184	947	695	550	415	402	425	576
RESIDENTIAL MM	1,787	14,270	1,640	1,242	1,261	1,142	1,004	896	838	840	874	1,039
RES MM TRANS	725	5,745	649	499	506	458	412	365	363	361	365	428
TOTAL RES	34,255	203,443	31,624	21,730	19,343	14,835	10,820	8,787	7,867	7,886	8,385	11,247
COMMERCIAL												
SML COM SALES	5,876	42,829	5,655	4,774	4,190	3,520	2,713	2,334	2,178	2,211	2,491	2,602
SML COM TRANS	4,413	35,363	5,133	4,480	3,146	3,195	2,546	2,179	2,044	2,043	1,871	2,430
LRG COM SALES	337	3,841	311	285	268	290	284	282	266	336	427	346
LRG COM TRANS	348	3,930	330	329	311	320	295	275	292	324	324	393
TOTAL COM	10,974	85,963	11,429	9,868	7,915	7,325	5,838	5,070	4,779	4,914	5,113	5,770
CTAs	7,388		7,940	6,598								
Total	45,229		43,053	31,597								
PG&E Core	37,841	0	35,113	24,999								
% CTAs Share	16%		18%	21%								
% PG&E Core Share	84%	100%	82%	79%								
Jan Cap	15%	15%	15%	15%								
Proposed Allocation to CTAs period 1												
Proposed Allocation to CTAs period 2												
Proposed Allocation to CTAs period 3	18%	18%	18%	18%								
CTAs Avg. %	20%	20%	20%	20%								
CTAs Ave. Volume	4700	4700	4700	4700								
INTERDEPT												
GNR1	16	132	27	26	22	16	13	8	6	5	5	6
GNR2	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL INTERDEPARTMENTAL	16	132	27	26	22	16	13	8	6	5	5	6
NATURAL GAS VEHICLE												
NGV1--INTERDEPARTMENTAL	10	96	10	10	10	10	10	10	10	10	10	10
NGV1--NON-INTERDEPARTMENTAL	156	1,956	165	165	165	165	165	165	165	165	165	165
NGV2--NON-INTERDEPARTMENTAL	21	260	22	22	22	22	22	22	22	22	22	22
TOTAL NGV	186	2,311	196	196	196	196	196	196	196	196	196	196
TOTAL CORE	45,432	291,850	43,276	31,819	27,476	22,372	16,867	14,061	12,848	13,001	13,699	17,219
Distribution Shrinkage Factor (b)	2.9%		2.9%	2.9%	2.9%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
Total Core @ Citygate (c=a*(1+b))	46,749	299,051	44,531	32,742	28,273	22,752	17,154	14,300	13,067	13,222	13,932	17,512
Minimum Transmission Shrinkage (d)	1.0%		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total Core @ CA Border) (e=c/(1-d))	47,222	302,071	44,981	33,073	28,559	22,982	17,327	14,445	13,199	13,355	14,073	17,689

Base Case Forecast--Calendar Basis
(Average Temperature Year)
November 7, 2013 GT&S Forecast Run (Corrected)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

	Nov-14	Dec-14	TOTAL	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15
CORE											
RESIDENTIAL											
RESIDENTIAL IM	17,552	29,013	165,592	26,913	18,290	15,930	11,956	8,460	6,792	6,212	6,245
RES IM TRANS	1,086	1,849	11,248	1,788	1,262	1,151	921	675	536	413	399
RESIDENTIAL MM	1,395	1,738	13,909	1,605	1,215	1,226	1,111	975	872	833	835
RES MM TRANS	561	705	5,673	635	488	492	445	400	356	361	359
TOTAL RES	20,593	33,305	196,421	30,940	21,255	18,799	14,434	10,510	8,555	7,819	7,839
COMMERCIAL											
SML COM SALES	3,488	5,293	41,449	5,565	4,638	3,995	3,164	2,526	2,446	2,173	2,182
SML COM TRANS	2,946	4,890	36,903	4,376	4,167	3,617	2,922	2,370	1,923	1,972	1,981
LRG COM SALES	336	336	3,765	307	281	265	288	282	280	264	333
LRG COM TRANS	349	347	3,888	326	325	307	317	293	273	290	322
TOTAL COM	7,118	10,865	86,005	10,574	9,411	8,184	6,692	5,471	4,923	4,699	4,818
CTAs											
Total											
PG&E Core											
% CTAs Share											
% PG&E Core Share											
Jan Cap											
Proposed Allocation to CTAs period 1											
Proposed Allocation to CTAs period 2											
Proposed Allocation to CTAs period 3											
CTAs Avg. %											
CTAs Ave. Volume											
INTERDEPT											
GNR1	10	16	161	27	26	22	16	13	8	6	5
GNR2	0	0	0	0	0	0	0	0	0	0	0
TOTAL INTERDEPARTMENTAL	10	16	161	27	26	22	16	13	8	6	5
NATURAL GAS VEHICLE											
NGV1--INTERDEPARTMENTAL	10	10	115	10	10	10	10	10	10	10	10
NGV1--NON-INTERDEPARTMENTAL	165	165	1,980	174	174	174	174	174	174	174	174
NGV2--NON-INTERDEPARTMENTAL	22	22	259	22	22	22	22	22	22	22	22
TOTAL NGV	196	196	2,354	206	206	206	206	206	206	206	206
TOTAL CORE	27,918	44,383	284,941	41,747	30,898	27,211	21,348	16,200	13,692	12,730	12,868
Distribution Shrinkage Factor (b)	2.9%	2.9%		2.9%	2.9%	2.9%	1.7%	1.7%	1.7%	1.7%	1.7%
Total Core @ Citygate (c=a*(1+b))	28,727	45,670	291,883	42,957	31,794	28,000	21,710	16,476	13,925	12,946	13,087
Minimum Transmission Shrinkage (d)	1.0%	1.0%		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total Core @ CA Border) (e=c/(1-d))	29,017	46,132	294,831	43,391	32,115	28,282	21,930	16,642	14,065	13,077	13,219

Base Case Forecast--Calendar Basis
(Average Temperature Year)
November 7, 2013 GT&S Forecast Run (Corrected)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

	Sep-15	Oct-15	Nov-15	Dec-15	TOTAL	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
CORE											
RESIDENTIAL											
RESIDENTIAL IM	6,676	9,137	17,346	28,408	162,364	26,287	18,303	15,681	11,807	8,418	6,761
RES IM TRANS	422	572	1,073	1,811	11,023	1,747	1,263	1,133	910	671	533
RESIDENTIAL MM	868	1,031	1,378	1,702	13,652	1,567	1,216	1,207	1,097	970	868
RES MM TRANS	362	425	555	690	5,568	620	488	484	440	398	354
TOTAL RES	8,330	11,166	20,352	32,610	192,608	30,220	21,269	18,505	14,253	10,458	8,516
COMMERCIAL											
SML COM SALES	2,450	2,944	3,828	5,554	41,464	5,654	4,261	4,145	3,358	3,043	2,350
SML COM TRANS	1,878	2,315	3,536	4,671	35,731	4,246	3,936	3,486	3,102	2,393	2,206
LRG COM SALES	424	342	331	331	3,730	306	280	264	288	282	280
LRG COM TRANS	322	388	344	343	3,850	325	324	306	317	293	273
TOTAL COM	5,075	5,989	8,040	10,899	84,775	10,531	8,800	8,200	7,065	6,011	5,109
CTAs											
Total											
PG&E Core											
% CTAs Share											
% PG&E Core Share											
Jan Cap											
Proposed Allocation to CTAs period 1											
Proposed Allocation to CTAs period 2											
Proposed Allocation to CTAs period 3											
CTAs Avg. %											
CTAs Ave. Volume											
INTERDEPT											
GNR1	5	6	10	16	161	27	26	22	16	13	8
GNR2	0	0	0	0	0	0	0	0	0	0	0
TOTAL INTERDEPARTMENTAL	5	6	10	16	161	27	26	22	16	13	8
NATURAL GAS VEHICLE											
NGV1--INTERDEPARTMENTAL	10	10	10	10	115	10	10	10	10	10	10
NGV1--NON-INTERDEPARTMENTAL	174	174	174	174	2,088	183	183	183	183	183	183
NGV2--NON-INTERDEPARTMENTAL	22	22	22	22	267	23	23	23	23	23	23
TOTAL NGV	206	206	206	206	2,470	216	216	216	216	216	216
TOTAL CORE	13,615	17,367	28,608	43,731	280,014	40,994	30,311	26,942	21,550	16,698	13,849
Distribution Shrinkage Factor (b)	1.7%	1.7%	2.9%	2.9%		2.9%	2.9%	2.9%	1.7%	1.7%	1.7%
Total Core @ Citygate (c=a*(1+b))	13,847	17,662	29,438	44,999	286,840	42,182	31,190	27,724	21,916	16,982	14,084
Minimum Transmission Shrinkage (d)	1.0%	1.0%	1.0%	1.0%		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total Core @ CA Border) (e=c/(1-d))	13,987	17,841	29,735	45,454	289,738	42,608	31,505	28,004	22,138	17,153	14,227

Base Case Forecast--Calendar Basis
(Average Temperature Year)
November 7, 2013 GT&S Forecast Run (Corrected)

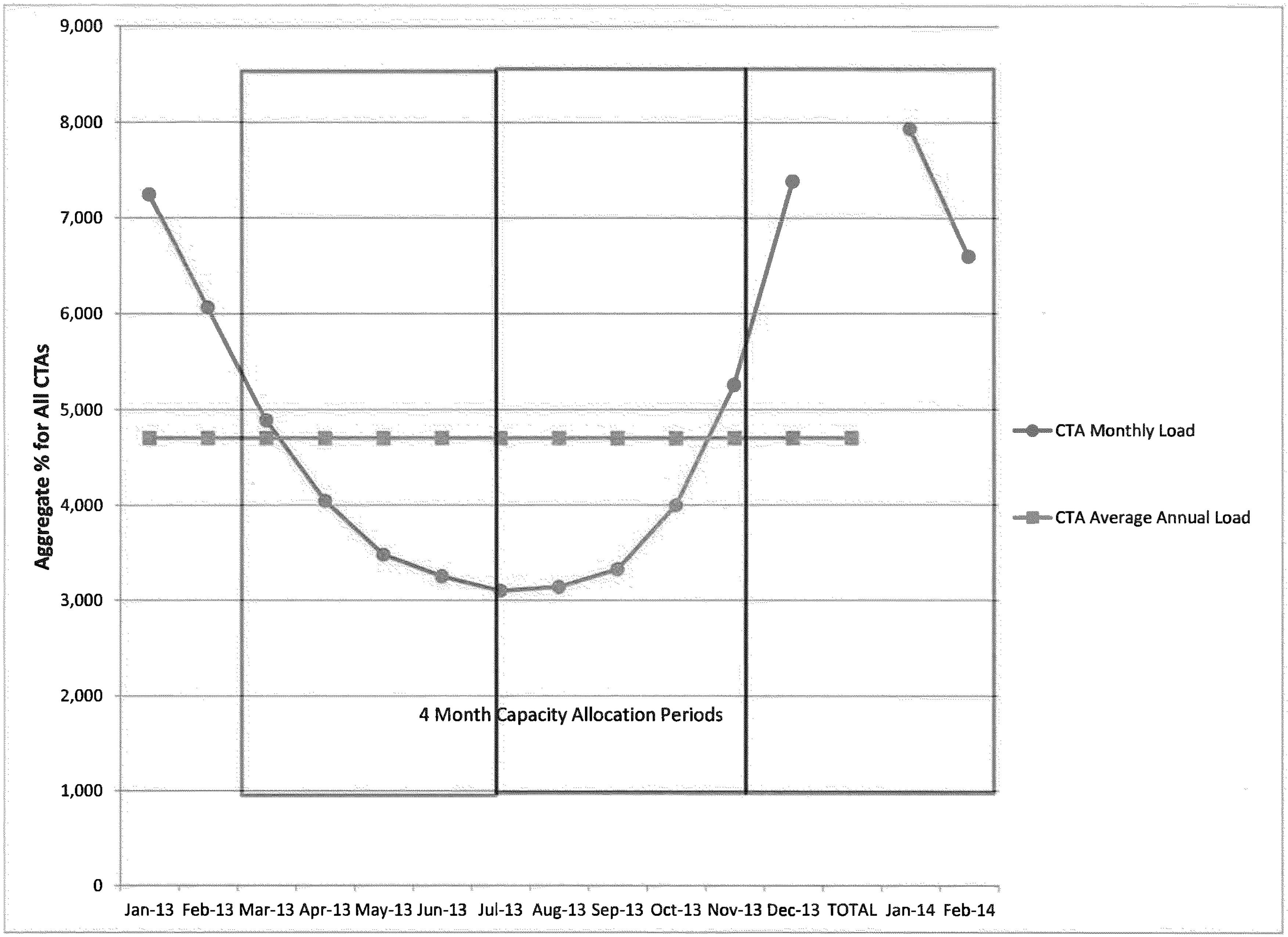
PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	TOTAL	Jan-17	Feb-17	Mar-17	Apr-17
CORE											
RESIDENTIAL											
RESIDENTIAL IM	6,190	6,225	6,663	9,148	17,412	28,546	161,438	26,285	18,068	15,879	11,876
RES IM TRANS	411	398	422	573	1,077	1,819	10,957	1,747	1,247	1,147	915
RESIDENTIAL MM	830	833	867	1,033	1,384	1,710	13,581	1,567	1,200	1,222	1,103
RES MM TRANS	360	358	362	426	557	694	5,540	620	482	490	442
TOTAL RES	7,791	7,813	8,313	11,179	20,429	32,769	191,516	30,219	20,997	18,739	14,337
COMMERCIAL											
SML COM SALES	2,451	2,414	2,403	2,653	3,991	4,900	41,623	5,659	4,583	4,330	3,538
SML COM TRANS	1,879	2,039	2,030	2,451	3,623	4,448	35,838	4,250	4,301	3,799	2,976
LRG COM SALES	265	335	426	345	334	334	3,737	307	281	265	289
LRG COM TRANS	291	323	323	391	347	346	3,858	326	325	307	318
TOTAL COM	4,885	5,111	5,182	5,840	8,296	10,028	85,057	10,543	9,490	8,701	7,120
CTAs											
Total											
PG&E Core											
% CTAs Share											
% PG&E Core Share											
Jan Cap											
Proposed Allocation to CTAs period 1											
Proposed Allocation to CTAs period 2											
Proposed Allocation to CTAs period 3											
CTAs Avg. %											
CTAs Ave. Volume											
INTERDEPT											
GNR1	6	5	5	6	10	16	161	27	26	22	16
GNR2	0	0	0	0	0	0	0	0	0	0	0
TOTAL INTERDEPARTMENTAL	6	5	5	6	10	16	161	27	26	22	16
NATURAL GAS VEHICLE											
NGV1--INTERDEPARTMENTAL	10	10	10	10	10	10	115	10	10	10	10
NGV1--NON-INTERDEPARTMENTAL	183	183	183	183	183	183	2,196	192	192	192	192
NGV2--NON-INTERDEPARTMENTAL	23	23	23	23	23	23	276	24	24	24	24
TOTAL NGV	216	216	216	216	216	216	2,587	225	225	225	225
TOTAL CORE	12,898	13,144	13,715	17,240	28,951	43,029	279,320	41,014	30,738	27,687	21,699
Distribution Shrinkage Factor (b)	1.7%	1.7%	1.7%	1.7%	2.9%	2.9%		2.9%	2.9%	2.9%	1.7%
Total Core @ Citygate (c=a*(1+b))	13,117	13,368	13,948	17,533	29,791	44,277	286,112	42,203	31,629	28,490	22,068
Minimum Transmission Shrinkage (d)	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%		1.0%	1.0%	1.0%	1.0%
Total Core @ CA Border) (e=c/(1-d))	13,250	13,503	14,089	17,710	30,091	44,724	289,002	42,629	31,949	28,778	22,291

Base Case Forecast--Calendar Basis
(Average Temperature Year)
November 7, 2013 GT&S Forecast Run (Corrected)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

		May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL
CORE										
RESIDENTIAL										
	RESIDENTIAL IM	8,420	6,784	6,208	6,242	6,680	9,127	17,336	28,582	161,488
	RES IM TRANS	672	535	413	399	423	572	1,073	1,822	10,962
	RESIDENTIAL MM	971	871	833	835	869	1,030	1,377	1,712	13,591
	RES MM TRANS	399	355	361	359	363	425	554	694	5,544
	TOTAL RES	10,460	8,546	7,815	7,834	8,334	11,154	20,340	32,810	191,585
COMMERCIAL										
	SML COM SALES	2,896	2,549	2,248	2,247	2,368	2,802	4,221	5,297	42,736
	SML COM TRANS	2,704	2,236	2,036	2,035	2,078	2,356	3,550	4,893	37,212
	LRG COM SALES	283	281	265	335	426	344	333	334	3,742
	LRG COM TRANS	293	274	291	324	323	390	346	345	3,863
	TOTAL COM	6,176	5,340	4,840	4,940	5,195	5,892	8,451	10,868	87,554
	CTAs									
	Total									
	PG&E Core									
	% CTAs Share									
	% PG&E Core Share									
	Jan Cap									
	Proposed Allocation to CTAs period 1									
	Proposed Allocation to CTAs period 2									
	Proposed Allocation to CTAs period 3									
	CTAs Avg. %									
	CTAs Ave. Volume									
INTERDEPT										
	GNR1	13	8	6	5	5	6	10	16	161
	GNR2	0	0	0	0	0	0	0	0	0
	TOTAL INTERDEPARTMENTAL	13	8	6	5	5	6	10	16	161
NATURAL GAS VEHICLE										
	NGV1--INTERDEPARTMENTAL	10	10	10	10	10	10	10	10	115
	NGV1--NON-INTERDEPARTMENTAL	192	192	192	192	192	192	192	192	2,305
	NGV2--NON-INTERDEPARTMENTAL	24	24	24	24	24	24	24	24	284
	TOTAL NGV	225	225	225	225	225	225	225	225	2,703
TOTAL CORE		16,874	14,119	12,886	13,005	13,759	17,277	29,026	43,920	282,004
Distribution Shrinkage Factor (b)		1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	2.9%	2.9%	
Total Core @ Citygate (c=a*(1+b))		17,161	14,359	13,105	13,226	13,993	17,571	29,868	45,194	288,866
Minimum Transmission Shrinkage (d)		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
Total Core @ CA Border) (e=c/(1-d))		17,334	14,504	13,237	13,359	14,134	17,749	30,170	45,650	291,784


9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Aggregate % for All CTAs
Jan-13 Feb-13 Mar-13 Apr-13 May-13 Jun-13 Jul-13 Aug-13 Sep-13 Oct-13 Nov-13 Dec-13 TOTAL Jan-14 Feb-14
4 Month Capacity Allocation Periods
CTA Monthly Load
CTA Average Annual Load

PG&E Core Gas Supply
2015 GT&S Rate Case Capacity Recommendation
May 19, 2014

b) Please refer to the Q2 for the information on Tiger Natural Gas

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PG&E Data Request No.:	CommercialEnergy-CA_003-15		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q15		
Request Date:	May 2, 2014	Requester DR No.:	003
Date Sent:	May 15, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:	David Elmore	Requester:	Michael B. Day/ Megan Somogyi

QUESTION 15

Please state the dates that PG&E's contracts for third party storage used to provide core storage are set to expire, and the quantity of inventory, injection, and withdrawal rights that will expire at each such date.

ANSWER 15

PG&E's Core Gas Supply has one third party storage contract:

Inventory: 1,500 MDth.

Injection rights: pro-rata injection of 1,500 MDth from April to October.

Withdrawal rights: 15 days of 100 MDth/d December to February.

Expiration date: February 28, 2015.

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PG&E Data Request No.:	CommercialEnergy-CA_003-25		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q25		
Request Date:	May 2, 2014	Requester DR No.:	003
Date Sent:	June 3, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:	Mel Christopher (a-l)/ David Elmore (l)	Requester:	Michael B. Day/ Megan Somogyi

QUESTION 25

Please answer the following questions with respect to the gas system forecasts and recorded supply and demand on the system peak day of December 9, 2013:

a. Describe how PG&E determined the forecasted System Peak Day volumes on Dec 9, 2013. Please provide the workpapers or other documents that show the calculation.

b. Describe how PG&E determined the actual recorded System Peak Day volumes of Dec 9, 2013 and state the recorded volumes that day by customer class.

c. Does PG&E routinely update its short term daily updated forecasts of gas demand? If so, please state the volume of Core gas demand that PG&E forecast for Dec. 9, 2013 on each of the three days preceding Dec. 9, 2013 days and on Dec. 9, 2013 itself. If such short term forecast updates are distributed in any form of document, correspondence, or email, please provide all such forecast documents for each of the four days listed above, again focusing only on the forecast for Dec. 9, 2013.

d. Please explain the difference between the recorded gas demand on Dec. 9, 2013 and the forecasts issued for expected demand on Dec. 9, 2013, as provide in response to Request 25.c. above. Have the differences between forecast and recorded demand on that high volume day informed PG&E's future forecasting methodology? What steps has PG&E taken or plan to take in the future to improve its forecast accuracy?

e. Did PG&E aggregate smart meter gas data system wide for purposes of making any forecast of Core gas demand for Dec. 9, 2013? Please provide the aggregate core load data provided by smart meters, by the hour, for the day before Dc. 9, 2013, the day after Dec. 9, 2013, and for Dec. 9, 2013 itself. If PG&E did not use smart meter data for purposes of forecasting Core gas demand, what was the reason that such data was not used in the forecasting process?

f. Please state the recorded daily gas demand for each of the following customer classes-- Core, Noncore Industrial, Noncore Electric Generation-- for December 6, 7, 8 and 9, 2013. If PG&E has recorded hourly gas demand data for any or all of these customer classes, please provide that information for each of the four specified days as well.

g. Please state the recorded daily gas demand for each of the following customer classes-- Residential, Master-metered, GNR-1, GNR-2, NGV, Industrial, and Wholesale Generation -- for December 6, 7,8 and 9, 2013. If PG&E has recorded hourly gas demand data for any or all of these customer classes, please provide that information for each of the four specified days as well.

h. Does PG&E determine daily and/or hourly demand for forecasting customer classes demand by aggregating actual meter reads, including smart meters? If not, please describe the method by which daily and hourly forecasts of customer demand are derived for each customer class.

i. Please state the total volume of gas delivered onto the PG&E system from any and all delivery points on December 9, 2013.

j. Please state the volume of gas delivered onto the PG&E system through PG&E Storage withdrawals on December 9, 2013.

k. Please state the volume of gas delivered onto the PG&E system through withdrawals from independent storage providers interconnected to PG&E on December 9, 2013.

l. Was PG&E Core Supply able to provide 100% of the gas demand of core customers on December 9, 2013 through flowing gas supplies, storage withdrawals and curtailments of lower priority customers? If not, please describe how balancing for the Core Supply group was accomplished on Dec. 9, 2013.

ANSWER 25

a. PG&E determined the forecasted volumes for Dec 9, 2013 as it does every day. To forecast industrial gas demand, PG&E uses recent and historical automated meter read (AMR) data from each customer. For electric generation gas demand forecasts, PG&E uses recent and historical customer AMR data, plus information from the California Independent System Operator (CAISO).

To forecast daily core load, the Gas Transmission Control Center uses several sources of information for guidance, similar to the way meteorologists consult multiple sources of information to forecast the weather These sources include a complex model that utilizes an artificial neural network and a regression analysis, a separate trend graph that is based on seasonal core demand, and recent demand information normalized for temperature and day of the week. The forecaster makes the forecast of core demand after reviewing the above models and information sources. The models and trends are based on historical weather and customer usage relationships by day of the week and include adjustments for holidays.

Attached are several pertinent documents from December 9, 2013. GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q25Atch06 has two pages. The first page shows gas sendout for the day per the three customer categories, along with changes in inventory and key temperatures. Key abbreviations are provided below for convenience in review:

Abbreviation	Meaning
Sys Inv	System Inventory
Pk/Dft	Pack/Draft
So Inv	Southern Inventory
Cen Inv	Central Inventory
No Inv	Northern Inventory
Sys S/O	System Sendout
EG RT+M	Electric Generation Real Time Plus Manual. This is the Supervisory Control and Data Acquisition (SCADA)-reported flow volume for certain large electric generators (EGs), plus manually estimated flows for EGs supplied by PG&E but not connected to PG&E's SCADA system.
Ind RT+M	Industrial Real Time Plus Manual. Same as EG RT+M, but for industrial customers.
Cust S/O	Customer Sendout. This is calculated core usage, which is determined by summing all supplies, netting the pack or draft, then backing out the EG and Industrial demands. This leaves the portion of the customer sendout which is considered Core.

The second page of GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q25Atch06 shows the five plans for the day, plus the final, actual figures for the day's system activity. Each of the plans happens successively later, and uses updated data for temperature, nominations, flows, etc. to allow the system operators to manage the system.

GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q25Atch05 shows the hourly sendout details for a six-hour period for the various interconnects to PG&E's gas system and the major customer categories. The units are in millions of cubic feet per hour.

Within this methodology, there are no calculations per se that show how PG&E determines forecasted System Peak Day volumes. The calculations are internal to the system.

b. PG&E determines noncore (industrial and electric generation) sendout by collecting automated meter read (AMR) data for those customers. Core sendout is calculated by totaling the gas supplies brought on to the system, then subtracting noncore on-system, off-system at the various interconnects, fuel usage and estimated lost and unaccounted for (LUAF) gas. The recorded sendout on Dec 9, 2013 is stated below in millions of cubic feet (MMcf).

Recorded Sendout on 12/09/13 by Customer Type			
Date	On-System Demand (MMcf)		
	Core	Industrial	Electric Generation
12/9/2013	2,384	1,032	1,420

c. Yes, PG&E routinely updates its short term daily forecasts in the Daily Plan, which is updated five times a day by the Gas Transmission Control Center. These forecasts, which show the current day and the next three days, are posted on Pipe Ranger as they are updated. See: http://www.pge.com/cgi-bin/pipeline/cgt_pipeline_status.pl#flows. PG&E does not maintain public archives of Daily Plan updates, however, PG&E has provided the Daily Plan Number 1 from December 6, through December 8, 2013, and the Daily Plan Final for December 9, 2013 as GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q25Atch01 through GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q25Atch04.

   Demand forecasts by customer class are also posted on Pipe Ranger, three days after the forecast date. See: http://www.pge.com/pipeline/operations/historical_archives/classarchive.shtml,

   Average monthly end-use demands are also posted on Pipe Ranger. See: http://www.pge.com/pipeline/operations/historical_archives/mo_customer_class.shtml. Historical records of the Daily Plan beyond what is posted to Pipe Ranger are not made available to the market.

d. The primary reason that the recorded gas demand on December 9, 2013 differs from the gas demand forecasts for December 9, 2013 is that the actual December 9 temperatures were different from the forecasted temperatures. Differences between forecasted and actual temperatures will generate differences between core demand forecasts and actual core usage, since core demand is temperature-dependent.

   PG&E continuously incorporates data from historical cold weather events into its forecasting models, and the December 2013 event is just one example of this. PG&E works to ensure that the metering data input to noncore demand forecasts is accurate and that core demand forecasting models are updated annually. Every two years, a study is done to estimate what core demands will be during Abnormal Peak Day (APD) and other cold weather events. This is to incorporate data from recent cold weather events or changes in load characteristics in the estimates. The results of these studies are incorporated into the tools discussed in the response to part (a).

PG&E's 2015 Gas Transmission and Storage (GT&S) Chapter 10 testimony on pages 10-43 and 10-44 makes specific proposals to improve the accuracy of the load forecast.

e. PG&E did not use aggregated, system-wide gas SmartMeter™ data to inform its December 9, 2013 forecast because PG&E had not designed, developed, tested, and deployed the complex data processing system required to do so.

   Gas SmartMeter deployment has proceeded at a slower pace than expected. SmartMeter™ deployment is still not complete system-wide.

   PG&E is developing the capability to use SmartMeter™ data to improve its daily load forecasting, as mentioned in PG&Es 2015 GT&S Rate Case Chapter 10 testimony on page 10-44.

f. The following table shows the recorded daily gas demand for the Core, Industrial (Noncore), and Electric Generation over the four-day period of December 6-9, 2013. PG&E does not have an easily accessible record of hourly demand.

Demand for Cold Event Dec 2013 (MDth)				
Customer	12/6/2013	12/7/2013	12/8/2013	12/9/2013
Core	1,980	2,103	2,257	2,283
Industrial (Noncore)	1,016	959	949	1,016
Electric Generation	1,293	1,180	1,206	1,308

g. PG&E does not forecast or collect gas demand data by the customer classifications requested.

h. PG&E determines daily and/or hourly demand for forecasting customer classes demand as described in the response to part (a), above. The system does use actual meter reads from AMR, but at this time does not use data from SmartMeters™.

i. The total volume of gas delivered onto the PG&E system from any and all delivery points on December 9, 2013, including storage withdrawals from PG&E and third-party facilities, was 4,900 thousand decatherms (MDth).

j. Of the 4,900 MDth of supply delivered onto PG&E's system on December 9, 2013, 1,364 MDth came from PG&E's three traditional storage fields (McDonald Island, Los Medanos, and Pleasant Creek).

k. Of the 4,900 MDth of supply delivered onto PG&E's system on December 9, 2013, 2,236 MDth came from independent storage providers interconnected to PG&E on December 9, 2013. This group comprised Lodi Gas Storage, Wild Goose Gas Storage, Central Valley Gas Storage, and Gill Ranch Storage.

l. To meet Core Gas Supply's (CGS) bundled core customer demand on December 9, 2013, CGS relied on a combination of flowing gas supplies and storage withdrawals to meet 99 percent of its customers' Determined Usage. CGS relied on normal PG&E gas system balancing to provide the remaining 1percent of its determined usage on that date.

To ensure that certain local transmission systems were able to serve all core customers without interruption, PG&E issued curtailment orders to noncore customers within certain curtailment zones on December 9, 2013. Of the 67 noncore customers within the curtailment zones, 27 were seasonal and presumed not operating. The remaining 40 noncore customers receiving curtailment orders were curtailed by an aggregate of 70 percent, meaning that their hourly load could not exceed 30 percent of their Planning Load. The total curtailed load for these customers is estimated to have been 1.6 million cubic feet (approximately 1.6 MDth) across the peak hour.

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Data Response

PG&E Data Request No.:	CommercialEnergy-CA_003A-08		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_003A-Q08		
Request Date:	May 2, 2014	Requester DR No.:	003
Date Sent:	August 1, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:		Requester:	Michael B. Day/ Megan Somogyi

QUESTION 8

What educational or training materials has PG&E provided to its customer service representatives regarding the factors that customers should consider (i.e., pros and cons) when deciding between using Core and Non-core service? Are these the same materials that are presented to the customers? Please provide copies of all documents provided to customer service representatives or trainees regarding these issues, including, but not limited to, emails, electronic files, presentations, class agenda or syllabus, brochures, teaching materials, etc.

a. Has PG&E held training classes for its representatives that covered these issues? Where and when in the past years?

b. Has PG&E held any seminars for its customers that address the issues described in the first paragraph of this Request? Where and when in the past three years? Please provide copies of all documents provided to customers regarding these issues, including, but not limited to, emails, electronic files, presentations, brochures, teaching materials, etc.

ANSWER 8

PG&E has not provided any educational or training materials to its customer service representatives or customers regarding the factors that customers should consider when deciding between Core and Non-core service. PG&E also has not held any training classes for its representatives or any seminars for its customers that address the issues described in the first paragraph of this Request.

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Data Response

PG&E Data Request No.:	CommercialEnergy-CA_003A-23		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_003A-Q23		
Request Date:	May 2, 2014	Requester DR No.:	003
Date Sent:	August 1, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:		Requester:	Michael B. Day/ Megan Somogyi

QUESTION 23

(a.) In any of the cases where bill payment extension periods were granted as set forth in PG&E's answer to Data Request 22 above, did PG&E notify the affected CTA prior to granting the customer an extension? If so, state the number of time such notice was provided to a CTA (b.) Are PG&E customer service representatives instructed to determine if a customer has a CTA agreement prior to granting a bill payment extension request? (c.) Are PG&E customer service representatives instructed to offer other alternative payment arrangements to customers with CTA contracts prior to offering a bill payment extension? If so, what alternative payment arrangements? (d.) Please provide a copy of any customer service representative script or training materials addressing the procedures for dealing with a request for a bill payment extension from a customer with a CTA contract.

ANSWER 23

a) N/A.
b) PG&E customer service representatives are not instructed to determine if a customer has a CTA agreement prior to granting a payment plan.
c) PG&E customer service representatives are not instructed to offer alternative payment arrangements to customers with CTA contracts prior to offering a bill payment extension.
d) None –CTA customers are eligible for the same extensions/arrangements as PG&E bundled service customers. We do not have different offerings for CTAs. Additionally, the Disconnect OIR Settlement Agreement made no reference to CTA vs. non-CTA payment extensions/arrangements; it covers all residential payment extensions/arrangements. GTS-RateCase2015_DR_CommercialEnergy-CA_003A-Q23Atch01 through GTS-RateCase2015_DR_CommercialEnergy-CA_003A-Q23Atch04 provide training material that address pay plan procedures for customers. GTS-RateCase2015_DR_CommercialEnergy-CA_003A-Q23Atch01 and GTS-RateCase2015_DR_CommercialEnergy-CA_003A-Q23Atch02 – Negotiating Pay

Negotiating Pay Plans

- ALWAYS **offer Assistance programs**
- **Opening the negotiation**
    - Listen carefully for the Whys, Wants & Wows
        - Identify the social style - how do you need to respond?
        - Review Payment History
    - Use Judgment & Negotiating Skills
    - Document Actions taken (Create or Deny Pay Plan with reasons)
    - Items to stay away from when speaking to the customer when using the tool
        - DO NOT advise the customer of their risk level
        - DO NOT ask the customer: What can you pay? When can you pay? Will this work for you?
        - DO NOT immediately offer an Authorized Override
        - DO NOT bring up specifics on broken Pay Plans
        - DO NOT proactively offer an SSR or see what they can do
- **Start by collecting as much debt as possible in the shortest amount of time**
    - It is more important to collect debt in a short amount of time
        - Stay within the guidelines of the tool
    - The first payment is the MOST important payment
        - Create a sense of urgency around the first payment
- **Drive the conversation with the Standardized Pay Plan offering from the Assessment Tool**
    - Promote the benefits of paying - What's in it for the customer?
        - "By accepting it now, you will be provided better arrangement terms"
        - "These shorter payment deadlines will ensure the account is moving towards being debt free with PG&E"
        - If the terms agreed upon today are not kept, it will reduce the opportunity for future arrangements"

- **Set up appropriate expectations for the customer when negotiating**
  - Convey to the customer what we are able to offer them:
    - Maintain control of the call: "Here's what we can do....."
  - Drive commitment for the Standardized Pay Plan
    - Longer arrangements have a higher break rate
      - "I can appreciate that, not having finances readily available can be difficult"
  - If a Pay plan breaks, it will affect flexibility on future arrangements
    - Moves the customer Risk Level up
    - Potential need for a 50% Good Faith Payment
      - "If the arrangement is not kept, it will impact the opportunity for future arrangements"
- **Additional expectations for the customer when negotiating the Pay Plan**
  - To respond to a customer who wants to know why their initial offer is so strict:
    - "Based on the account's payment history, this is what the account qualifies for"
    - "We need a Good Faith Payment in order to continue to extend the account balance with us"
    - "Its our goal to continue to provide service at this address, to do so, we need an initial payment"
    - "Bringing the account balance down as quickly as possible will help eliminate any past due balances and bring the account current"
    - "For your convenience, we can offer a payment arrangement for a short time to assist in paying off the balance which will bring the account current"
- **Remember your soft skills**
  - ACKNOWLEDGE
    - Listen to the customer and be aware of their situation
    - Understanding the customer is a sure way to fulfill their needs

- HELP OTHERS
  - Be sure you talk in the first person
  - Customers will listen when you take control in helping them with their debt
  - Demonstrate your knowledge and ability
- EMPATHY
  - Have compassion for the customer's situation
  - Always be sincere with empathy
    - Customers can tell if you are patronizing them

Plans – provide customer service representatives with guidance (e.g., setting expectations, what to say and not to say) on how to negotiate pay plans with customers. GTS-RateCase2015_DR_CommercialEnergy-CA_003A-Q23Atch03 – Pay Plan Standardization – addresses how customer service representatives should assess pay plan options for residential customers, including risk assessment level and demonstrates how the pay plan offerings are the same across all platforms (CSR, online, and IVR) under a Pay Plan Assessment Tool. GTS-RateCase2015_DR_CommercialEnergy-CA_003A-Q23Atch04 – Create Pay Plan – shows how to manually create a pay plan for a customer when the system is down or there is other special circumstance.

Negotiating Guideline

1

a) **Listen** carefully for the **Whys, Wants, and Wows**
b) Identify Social Style –how do you need to respond?
c) Review Payment History

	Low Risk			More Risk
Scenarios	Regular-paying. No history of PP or always kept	Regular-paying. Recent hard times	Irregular-Paying	Irregular-Paying w/med

2

Use Judgment and Negotiating Skills

Examples	Offer PP 1st payment w/in 3 weeks	Offer PP 1st payment w/in 3 weeks	Offer or Deny If offered, 1st payment w/in 1 week	Offer PP 1st payment w/in 1 week

3

Document Your Action, Grant or Deny Reasons

Pay Plan Standardization

- **All RESIDENTIAL customers** are eligible for a Pay Plan EXCEPT for the following situations:
    - Debt outstanding from RTM Payment
    - Severance In Field
    - Severance with Pending SONP FO
    - Stopped or Pending Stop Accounts
- The new Pay Plan Assessment tool will be used to determine the customer risk level
    - Applies to RESIDENTIAL accounts ONLY
    - DOES NOT APPLY to the following situations
        - Assistance Agency Pay Plan
        - Medical Baseline / Life Support Customers
        - Unbilled Deposits
- The system will create an appropriate pay plan based on the result, select the appropriate result to create and negotiate pay plan with the customer
    - Low Risk
    - Medium Risk
    - High Risk
    - Special Handle
- Always show empathy and utilize your soft skills
    - Don't say what we can't do, instead say what we can do
    - Offer up what we can accept:
        - Example: Based on the account's payment history, this is what I can offer you today...
- Promote the benefits of what is being offered:
    - Example: These shorter payment deadlines will ensure the account is moving towards being debt free with PG&E
    - Example: Bringing the account balance down as quickly as possible will help eliminate any past due balances and bring the account current

Create Pay Plan

- For Residential Customers
  - **ALWAYS** offer Assistance programs

- The Pay plan Assessment tool should ALWAYS be used unless any of the following situations exist
  - Agency Pledges
  - CIA account
  - CC&B is down
  - Medical
  - Solar
  - Special Handle situation exists
  - Unbilled Deposits
- For the situations listed above, follow the process below to Create Pay Plan using the Pay Plan + option

Steps to creating a Pay Plan

STEP	ACTION
1	• **Determine Eligibility** ○ **All customers** are eligible for a Pay Plan EXCEPT for the following situations: ▪ Debt outstanding from RTM Payment • Review Payment History for CANCELED payment to determine RTM debt ▪ Severance In Field ▪ Severance with Pending SONP FO ○ Customer DOES NOT meet any of the above ▪ Proceed to the next step ○ Customer MEETS any of the above ▪ Create Deny Pay Plan

2	• **Assess Risk**
	  ○ Review Alerts
	    ▪ Does customer have a Pending Pay Plan case?
	  ○ Review Payment History
	    ▪ Has the customer made consistent payment until now?
	    ▪ Have they made any payments in the last 30 days?
	  ○ Review PRIOR Pay Plans
	    ▪ Do they have 2 or less broken pay plans in the last 12 months? (Low Risk)
	    ▪ Do they have 3 broken pay plans in the last 12 months? (Medium Risk)
	    ▪ Do they have 4 broken pay plans in the last 12 months? (High Risk)
	    ▪ Do they have 5 or more broken pay plans in the last 12 months? (Special Handle)
	  ○ Overall review
	    ▪ Are they about to be billed, creating more debt?
	    ▪ Have they had service less than 1 year?

3	• **Negotiate an appropriate pay plan based on the customer type** ○ **ALWAYS** offer Assistance programs

	LOW RISK
	• **2 broken pay plans in last 12 months**
	  ○ Customer examples: Consistent/Regular Paying, Consistent/Regular Paying customer recently fallen on hard times
	• Begin negotiation for initial payment of NO LESS than 10% of total balance owing within 14 days
	  ○ Use your best judgment
	  ○ Listen to the needs of the customer
	• Go to step 4 to Create Pay Plan

	MEDIUM RISK • **3 broken pay plans in last 12 months** ○ Customer examples: Large outstanding Balance, NO recent payments, Small Partial payments, Unable to make a payment • Try and negotiate for no less than 20% of total balance owing (initial payment) within 10 days

  - Use your best judgment
  - Listen to the needs of the customer
- Customer wants to negotiate a pay plan
  - Initial Payment should be within 10 days
    - DO NOT extend beyond 2 weeks
  - Go to step 4 to Create Pay Plan
    - DO NOT have the customer make the initial payment and then call back to create a pay plan
- If unable to negotiate acceptable pay plan
  - Create Deny Pay Plan
  - Indicate reason for denial

HIGH RISK

- **4 broken pay plans in last 12 months**
  - Customer examples: Large outstanding Balance, NO recent payments, Small Partial payments, Unable to make a payment
- Try and negotiate for no less than 30% of total balance owing (initial payment) within 7 days
  - Use your best judgment
  - Listen to the needs of the customer
- Customer wants to negotiate a pay plan
  - Initial Payment should be within 7 days
    - DO NOT extend beyond 1 week
  - Go to step 4 to Create Pay Plan
    - DO NOT have the customer make the initial payment and then call back to create a pay plan
- If unable to negotiate acceptable pay plan
  - Create Deny Pay Plan
  - Indicate reason for denial

SPECIAL HANDLE

- **5+ broken pay plans in last 12 months / Cash Only**
  - Customer examples: Large outstanding Balance, NO recent payments, Small Partial payments, Unable to make a payment
- Special Handle process

- 1. At a populated Control Central Account Information page, click the Account ID Context

<table>
<tr><td>4</td><td>
Menu button

2. Select Go To Pay Plan in the Add (+) mode from the drop-down list - The Customer Information - Pay Plan page appears
3. Select the appropriate type from the Type drop-down list
Notes:

Revenue Assurance accounts select Residential Revenue Assurance
Ensure Pay Plan type matches customer class or the System will not recognize the Pay Plan

4. Select the appropriate pay method from the Pay Method drop-down list
5. Type the scheduled payment date in the Scheduled Date field
Note: If recent payment was made today, whether posted or not, enter today's date as the first Scheduled Date
6. Type the scheduled payment amount in the Scheduled Amount field
Note: If payment was made today, whether posted or not, enter amount of payment
If more than one payment needs to be scheduled:

Click the Add (+) button. A new row will be added.
Type the next scheduled payment date in the Scheduled Date field.
Type the next scheduled payment amount in the Scheduled Amount field.
Repeat until total amount of the pay plan is scheduled

7. Verify the Total Amount field equals at a minimum the amount in the Delinquent Debt field
Note: Pay Plans less than the Delinquent Debt amount will be automatically canceled by the system
8. Advise customer that future bills must be paid in full by the bill due date or the Pay Plan will automatically be canceled by the system
9. Type applicable comments including notation that customer was advised that bills must be paid in full by due date in the Comments field
10. Click the Save button

</td></tr>
<tr><td>5</td><td>

Recap payment dates and amounts with the customer
Provide the customer with the dates and amounts of agreed upon payments
Customers Wants to update or change existing Pay Plan
<u>Adjusting / Changing / Updating Pay Plan process</u>

</td></tr>
</table>

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CommercialEnergy-CA_007-06		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_007-Q06		
Request Date:	July 15, 2014	Requester DR No.:	007
Date Sent:	July 30, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:		Requester:	Michael B. Day/ Megan Somogyi

QUESTION 6

Has PG&E ever considered developing demand response programs for its gas customers? If so, please describe all such considerations and explain why PG&E has not implemented demand response programs.

ANSWER 6

Yes, PG&E considered using demand response techniques to incentivize the reduction of natural gas usage. In particular, PG&E conducted a study which considered several different approaches to manage gas shortages. PG&E did not move forward with this option as it did not appear to be cost-effective.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CommercialEnergy-CA_007-07		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_007-Q07		
Request Date:	July 15, 2014	Requester DR No.:	007
Date Sent:	July 30, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:		Requester:	Michael B. Day/ Megan Somogyi

QUESTION 7

Please identify any and all studies performed by or on behalf of PG&E related to the development and design of demand response programs for gas customers. For each study identified, please provide a copy of the study.

ANSWER 7

Attachments 01 and 02 to this response have been marked CONFIDENTIAL and are submitted pursuant to a Non-Disclosure Agreement because they include confidential employee information.

PG&E investigated the potential of a gas demand response program in 2009 as part of its Electric Generation Reliability Study. The analysis is provided as GTS-RateCase2015_DR_CommercialEnergy-CA_007-Q07Atch01CONF, GTS-RateCase2015_DR_CommercialEnergy-CA_007-Q07Atch02CONF, and GTS-RateCase2015_DR_CommercialEnergy-CA_007-Q07Atch03.

This Exhibit is confidential and has been redacted.

This Exhibit is confidential and has been redacted.

EG Reliability Project
Options for Modifying Gas Rule 14 to Increase EG Gas Service Priority

Options Considered but Not Recommended

Option 3 – Elevate EG class priority above other noncore customers in Gas Rule 14.

Pros:
- Directly mitigates risk of EG curtailment

Cons:
- Expect a significant negative reaction from non-EG customers, especially refineries
- Good argument can be made to enhance priority of non-EG customers as they are 71% of the noncore customer base if you include cogens (94% if you do not include cogens)
- EG would have to pay a higher rate for higher priority to ensure proper price signals
- No real impetus for making this change (highly reliable gas service and low risk of curtailment)

Criteria:
EG Supply Reliability Impact: high
Likelihood of Success: low
Cost to Customers: medium
Shareholder Risk: low

Option 4 – Elevate EG class priority to parity with core customers in Gas Rule 14.

Pros:
- Mitigates risk of EG curtailment

Cons:
- Expect a significant negative reaction core and noncore customers
- Non-EG would oppose
- Good argument can be made to enhance priority of non-EG customers
- EG would necessarily have to pay the same rate as core for the same priority as core to ensure proper price signals
- No real impetus for making this change (highly reliable gas service and low risk of curtailment)

Criteria:
EG Supply Reliability Impact: high
Likelihood of Success: low
Cost to Customers: high
Shareholder Risk: low

Option 5 (variant of Option 1) – Set EG gas service priority by region in the following order: (i) RMR plants as determined by CAISO; (ii) EG determined by CAISO to be essential for grid reliability; (iii) efficient low heat rate EG (<7,500); and (iv) all other plants.

EG Reliability Project
Options for Modifying Gas Rule 14 to Increase EG Gas Service Priority

EG located on the backbone (BB) system have no gas supply issues. When gas curtailment occurs on the local transmission (LT) system, Gas System Operations (GSO) will contact CAISO to determine which EG are essential to maintain grid stability in the affected region. RMR and essential EG will be given highest priority for gas service, and not be curtailed. Service priority will then be given to efficient EG with heat rates less than 7500. For the remaining EG, the existing Gas Rule 14 procedures will remain in place.

Pros:
- ISO-determined critical plants are not curtailed
- Maintains electric grid stability by region
- CAISO makes the call as to which plants are critical
- Rational argument could be made at the CPUC as rule change will enhance grid reliability
- Promotes efficient use of gas on system
- Supports environmental stewardship

Cons:
- New efficient PG&E EG will be favored by this arrangement
- Opposition from older high heat rate EG
- No real impetus for making this change (highly reliable gas service and low risk of curtailment)

Criteria:
EG Supply Reliability Impact: high
Likelihood of Success: low
Cost to Customers: low
Shareholder Risk: low

Option 6 – For EG identified by ISO as RMR or essential to grid reliability, GSO can grant waivers to exempt these customers from diversion and curtailment.

Pros:
- Mitigates risk of EG curtailment
- Does have to be approved by CPUC

Cons:
- Customers must still pay $50/Dth penalty during curtailment
- Potential for claims of favoritism

Criteria:
EG Supply Reliability Impact: high
Likelihood of Success: low
Cost to Customers: high
Shareholder Risk: low

EG Reliability Project
Options for Modifying Gas Rule 14 to Increase EG Gas Service Priority

Option 7 – Voluntary Demand Response program incentivizing non-EG noncore customers to reduce gas load during curtailment scenario.

Pros:
- Mitigates risk of EG curtailment
- As voluntary program, should not be a litigation problem at the CPUC

Cons:
- Likely will not be cost effective. The incentive to noncore customers will have to be greater than the amount to make them revenue neutral to their voluntary gas "curtailment".

Criteria:
EG Supply Reliability Impact: high
Likelihood of Success: low
Cost to Customers: high
Shareholder Risk: medium

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CommercialEnergy-CA_007-08		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_007-Q08		
Request Date:	July 15, 2014	Requester DR No.:	007
Date Sent:	July 30, 2014	Requesting Party:	Commercial Energy of California
PG&E Witness:	Jeffrey Swanson	Requester:	Michael B. Day/ Megan Somogyi

QUESTION 8

In your response to Commercial Energy of California Data Request Set 3, Question 25(e), you indicate that:

> "PG&E did not use aggregated, system-wide gas SmartMeter™ data to inform its December 9, 2013 forecast because PG&E had not designed, developed, tested, and deployed the complex data processing system required to do so.
>
> Gas SmartMeter deployment has proceeded at a slower pace than expected. SmartMeter™ deployment is still not complete system-wide.
>
> PG&E is developing the capability to use SmartMeter™ data to improve its daily load forecasting, as mentioned in PG&Es 2015 GT&S Rate Case Chapter 10 testimony on page 10-44."

Please respond to the following questions regarding your response:

a. Does PG&E use SmartMeter data of any kind in any of its gas or electric forecasting efforts? For any response other than an unqualified "no," please describe how PG&E uses SmartMeter data in its forecasting efforts, including citations to each and every regulatory proceedings in which these data are used. Please also provide all workpapers related to PG&E's use of SmartMeter data for its forecasting efforts.

b. What are the expected start date and finish date for PG&E to complete its (1) design, (2) development, (3) testing, and (4) deployment of the data processing system required to use SmartMeter data for forecasting? Please provide your best estimate for the timeframe for completion of each of the four steps mentioned in your response.

c. Please provide a description of PG&E's gas load research activities. Please include in this description the number of meters, the history of PG&E's gas load research efforts, and the budget for this activity.

d. Does PG&E have load research meters for use in gas forecasting? If so, how many load research meters does PG&E have that are used in its gas forecasting?

ANSWER 8

a. PG&E objects to this question on the grounds that it is overbroad, unduly burdensome, not reasonably calculated to lead to the discovery of admissible evidence, and outside the scope of this proceeding to the extent that it seeks information regarding PG&E's electric forecasts. Notwithstanding the foregoing objection, PG&E responds as follows:

   PG&E uses SmartMeter™ to bill a large percentage of both its electric and gas customers. Therefore, to the extent that an electric or gas forecast uses billing data as a basis for the forecast, the forecast uses SmartMeter™ data. Please see subpart (b) of this response regarding the use of SmartMeter data in daily gas load forecasting.

b. Presently, SmartMeter™ data is not being used for daily gas forecasting purposes for the reasons described in the response to GTS-RateCase2015_DR_CommercialEnergy-CA_003-Q25 part (e). PG&E is, however, using SmartMeter™ data for local capacity planning purposes. In addition to developing our understanding of (and capability to use) SmartMeter™ data, this effort will likely be informative about future applications.

   There is no current schedule to create the data processing system for transforming SmartMeter™ data for use in daily forecasting. PG&E mentioned using SmartMeter™ data as one of several potential ways of improving the Core Load Forecast Model (CLFM) on page 10-44 of PG&E's 2015 Gas Transmission and Storage (GT&S) Rate Case Chapter 10 testimony. The costs of exploring these options are included in ongoing system maintenance and enhancement costs are described in PG&E's 2015 GT&S Rate Case Chapter 11 testimony on pages 11-37 to 11-38 and in workpapers for Chapter 11 on page WP 11-6, Line 1. The first step is for PG&E to determine which (if any) of these options will lead to more accurate forecasts.

c. PG&E does not currently have an active gas load research program.

d. PG&E does not have any gas load research meters in place.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CommercialEnergy-CA_009-01		
PG&E File Name:	GTS-RateCase2015_DR_CommercialEnergy-CA_009-Q01		
Request Date:	July 29, 2014	Requester DR No.:	009
Date Sent:	August 5, 2015	Requesting Party:	Commercial Energy of California
PG&E Witness:	Mel Christopher	Requester:	Michael B. Day/ Megan Somogyi

QUESTION 1

In its testimony in this proceeding, submitted December 19, 2013, PG&E states the following:

> "Data from gas smart meters is not yet practical for daily gas use forecast because, unlike data for time-of-use electric customers, it is not collected hourly or daily. Rather, a gas smart meter records the rotation of the mechanical meter it is attached to. For a typical residential gas meter, this occurs per each hundred cubic feet. In summer, when space heating loads are sometimes nil, the interval of this rotation may be several days." See PG&E testimony, p. 10-43.

Please respond to the following questions related to this excerpt from the testimony:

a. Does a residential gas meter rotate once per hundred cubic feet? Do PG&E's residential smart meters register each rotation? Please explain your answer.

b. What is the typical gas flow per rotation of PG&E's meters used for its small commercial customers (i.e., customers that use less than 250,000 therms/year)?

c. Do smart meters for PG&E's small commercial customers register for each rotation? If not, how often does the smart meter for such customers register?

d. Would PG&E expect that the interval of rotation for commercial customers would be several days? If so, please provide workpapers supporting your claim. If not, please explain why not.

e. What is the typical gas flow per rotation of PG&E's meters used for its master metered residential customers?

f. Do smart meters for PG&E's master metered residential customers register for each rotation? If not, how often does the smart meter for such customers register?

g. Would PG&E expect that the interval of rotation for master metered residential customers would be several days? If so, please provide workpapers supporting your claim. If not, please explain why not.

ANSWER 1

a. The typical residential gas meter's internal mechanism rotates once per one, two, or five cubic feet of gas. Each rotation creates a pulse, which is recorded in a cache in the meter transmission unit (MTU). When the number of pulses indicates that 100 cubic feet have passed through the meter, the MTU increases the cumulative read stored in its register by 100 cubic feet and transmits the cumulative read to PG&E's database, where it is recorded for billing purposes. The MTU's cache is then cleared and reset to accumulate the next set of pulses to total 100 cubic feet.

b. Commercial meters for customers who use less than 250,000 therms per year typically rotate once per ten cubic feet of gas.

c. The MTUs of small commercial meters work the same as residential MTUs.

d. The rotation interval of the meter's mechanism is a direct function of the rate of gas flowing through it. For residential customers, much of their gas usage is tied to space heating, which allows PG&E to infer that the 100-cubic-foot interval of rotation of a residential meter may take several days. The gas usage of a given commercial customer may not be closely tied to space heating, so PG&E cannot make an equivalent inference. PG&E has no workpapers regarding this inference.

e. Residential master meters, depending on size, may rotate once every two, five, ten, or 100 cubic feet, depending on the model, but report in 100 cubic foot increments.

f. The MTUs of residential master meters work the same as residential MTUs.

g. The more gas a customer uses, the more rotations of the meter. Since master meters serve multiple customers at a time, it is reasonable to infer that the rotation of the internal mechanism and the reporting interval would be more frequent than a stand-alone residential meter serving a single customer. PG&E has no workpapers regarding this inference.

Attachment E: Increase in Costs Based on PG&E's Proposed Capacity Allocation Analysis (Updated)

	Jun 2013	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Totals
[redacted]													
CTA Capacity Costs Using PG&E's Current Methodology													
Total Core Cost ($ millions)	$9.39	$11.56	$11.56	$11.54	$11.65	$11.36	$13.59	$13.62	$13.22	$12.49	$15.33	$15.05	$150.35
CTA%	16.45%	16.45%	16.45%	16.45%	16.45%	16.45%	16.45%	16.45%	16.45%	16.45%	16.45%	16.45%	
Total CTA Cost ($ millions)	$1.55	$1.90	$1.90	$1.90	$1.92	$1.87	$2.24	$2.24	$2.18	$2.06	$2.52	$2.48	$24.73
CTA Capacity Costs Using PG&E's Proposed Methodology													
CTA%	24.54%	26.05%	26.05%	26.05%	26.05%	19.48%	19.48%	19.48%	19.48%	24.54%	25.54%	24.54%	
Total CTA Cost ($ millions)	$2.31	$3.01	$3.01	$3.01	$3.03	$2.21	$2.65	$2.65	$2.58	$3.07	$3.76	$3.69	$34.98
Increase to CTAs ($ millions)	$0.76	$1.11	$1.11	$1.11	$1.12	$0.34	$0.41	$0.41	$0.40	$1.01	$1.24	$1.22	$10.24
CTA Monthly Load MDth	3.48	3.32	3.30	3.45	4.03	5.50	7.87	7.19	6.19	5.31	4.32	3.75	57.72
Increased Cost/MDth	$0.22	$0.33	$0.34	$0.32	$0.28	$0.05	$0.05	$0.06	$0.06	$0.19	$0.29	$0.32	$0.177

Table of Attachments

Attachment N: PG&E Responses to CTAC Data Requests
(Updated)

This exhibit includes the following data responses:

~~Data Request Set 1, Question 5~~

Data Request Set 2, Question 1 and Attachment 1

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CTAC_002-01		
PG&E File Name:	GTS-RateCase2015_DR_CTAC_002-Q01		
Request Date:	June 20, 2014	Requester DR No.:	002
Date Sent:	July 7, 2014	Requesting Party:	Core Transport Agent Consortium
PG&E Witness:	Mel Christopher	Requester:	Mark Fulmer

QUESTION 1

For each month from January 1, 2011 to the present, please provide:

a. Amount of capacity allocated to CTAs on each interstate and intrastate pipeline.

b. The capacity rejected by all CTAs on each interstate and intrastate pipeline.

c. The capacity returned to PG&E Core Gas Service by all CTAs on each interstate and intrastate pipeline.

d. Core Gas Service contract rate for all CTAs in each month.

e. Revenues from auction for all CTAs.

(Please see excerpt from a PG&E Core Capacity stranded cost invoice, below, as a template)

		Unrecovered Capacity	
CTA Allocation Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS by All CTAs (Dth/d)	Remaining Rejected Capacity for All CTAs (Dth/d)
Baja AFT	47,197	13,920	33,277
Baja SFT	0	0	0
Redwood	6,268	6,268	0
El Paso	5,131	1,200	3,931
Transwestern	14,199	3,320	10,879
Ruby	46,679	10,000	36,679
Foothills (GJ/d)	69,411	15,454	53,957
Nova (GJ/d)	70,127	15,613	54,514
GTN	66,926	14,399	52,527
Kern River	1,951	400	1,551
Kern River-Seasonal	0	0	0
Initial Storage (Dth)	4,881,033	1,339,108	3,541,925

				Unrecovered Capacity Cost		
CTA Allocation Capacity	Remaining Rejected Capacity for All CTAs (Dth/d)	CGS Contract Rate for All CTAs ($/Dth/mo)	Contract Cost for All CTAs ($/mo)	Revenues from Auction for All CTAs ($/mo)	Credit from CGS for All CTAs ($/mo)	Unrecovered Costs for All CTAs ($/mo)
Baja AFT	33,277	$5.3466	$177,918.81	$268,040.88	$0.00	$-90,122.07
Baja SFT	0	$0.0000	$0.00	$0.00	$0.00	$0.00
Redwood	0	$0.0000	$0.00	$0.00	$0.00	$0.00
El Paso	3,931	$7.9083	$31,087.53	$15,845.86	$0.00	$15,241.67
Transwestern	10,879	$8.6800	$94,429.72	$51,261.85	$0.00	$43,167.87
Ruby	36,679	$20.6833	$758,642.76	$37,067.80	$0.00	$721,574.96
Foothills (GJ/d)	53,957	$2.6051	$140,563.38	$100,360.02	$0.00	$40,203.36
Nova (GJ/d)	54,514	$4.6600	$254,035.24	$278,839.11	$0.00	$-24,803.87
GTN	52,527	$10.6709	$560,507.79	$63,110.36	$0.00	$497,397.43
Kern River	1,551	$7.4400	$11,539.44	$4,808.10	$0.00	$6,731.34
Kern River-Seasonal Subtotal	0	$0.0000	$0.00	$0.00	$0.00	$0.00
Initial Storage (Dth) Subtotal	3,541,925	$0.1260	$446,282.55	$73,011.19	$0.00	$373,271.36

SB_GT&S_0671810

ANSWER 1

See the attachment GTS-RateCase2015_DR_CTAC_002-Q01Atch01 for the monthly allocations, Core Transport Agents (CTA) rejections, and capacity returned to PG&E Core Gas Supply, for each PG&E intrastate pipeline for each month from January 2011 through May 2014, and the Core Gas Supply contract rates and the revenues from CTA capacity auctions for each month from January 2011 through May 2014.

CTAC 002-01
CTA Unrecovered Capacity Costs (UCC)

For each month from January 1, 2011 to the present, please provide:
a. Amount of capacity allocated to CTAs on each interstate and intrastate pipeline. *(Refer to Pipeline Capacity Allocations tab and Storage Capacity Allocations tab.)*
b. The capacity rejected by all CTAs on each interstate and intrastate pipeline.
c. The capacity returned to PG&E Core Gas Service by all CTAs on each interstate and intrastate pipeline.
d. Core Gas Service contract rate for all CTAs in each month.
e. Revenues from auction for all CTAs.

NOTES:
1. CTA data below does not include unrecovered capacity cost for Mid-Year Storage Adjustment allocation, as they only apply to CTAs that qualified for the additional capacity offering.
2. CTAs were not responsible for the unrecovered capacity cost (UCC) until April 2012 (Gas Accord V). Therefore, no UCC monthly invoices avaiable for January 2011 through March 2012.

Month	CTA Allocation Capacity	Capacity Rejected by All CTAs	Capacity Returned to PG&E CGS by All CTAs	Remaining Rejected Capacity for All CTAs	CGS Contract Rate for All CTAs	Contract Cost for All CTAs	Revenues from Auction for All CTAs	Credit from CGS for All CTAs	Unrecovered Costs for All CTAs
5/2014	Baja AFT	47,197	13,920	33,277	$ 5.3466	$ 177,918.81	$ 268,040.88	$ -	$ (90,122.07)
5/2014	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
5/2014	Redwood	6,268	6,268	-	$ -	$ -	$ -	$ -	$ -
5/2014	El Paso	5,131	1,200	3,931	$ 7.9083	$ 31,087.53	$ 15,845.86	$ -	$ 15,241.67
5/2014	Transwestern	14,199	3,320	10,879	$ 8.6800	$ 94,429.72	$ 51,261.85	$ -	$ 43,167.87
5/2014	Ruby	46,679	10,000	36,679	$ 20.6833	$ 758,642.76	$ 37,067.80	$ -	$ 721,574.96
5/2014	Foothills	69,411	15,454	53,957	$ 2.6051	$ 140,563.38	$ 100,360.02	$ -	$ 40,203.36
5/2014	Nova	70,127	15,613	54,514	$ 4.6600	$ 254,035.24	$ 278,839.11	$ -	$ (24,803.87)
5/2014	GTN	66,926	14,399	52,527	$ 10.6709	$ 560,507.79	$ 63,110.36	$ -	$ 497,397.43
5/2014	Kern River	1,951	400	1,551	$ 7.4400	$ 11,539.44	$ 4,808.10	$ -	$ 6,731.34
5/2014	Kern River-Seasonal	-	-	-	$ -	$ -	$ -	$ -	$ -
5/2014	Subtotal								
5/2014	Initial Storage	4,881,033	1,339,108	3,541,925	$ 0.1260	$ 446,282.55	$ 73,011.19	$ -	$ 373,271.36
5/2014	Subtotal								

Month	CTA Allocation Capacity	Capacity Rejected by All CTAs	Capacity Returned to PG&E CGS by All CTAs	Remaining Rejected Capacity for All CTAs	CGS Contract Rate for All CTAs	Contract Cost for All CTAs	Revenues from Auction for All CTAs	Credit from CGS for All CTAs	Unrecovered Costs for All CTAs
4/2014	Baja AFT	47,197	13,920	33,277	$ 5.3466	$ 177,918.81	$ 239,594.40	$ -	$ (61,675.59)
4/2014	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
4/2014	Redwood	6,268	6,268	-	$ -	$ -	$ -	$ -	$ -
4/2014	El Paso	5,131	1,200	3,931	$ 7.9083	$ 31,087.53	$ 15,334.83	$ -	$ 15,752.70
4/2014	Transwestern	24,804	5,800	19,004	$ 8.4000	$ 159,633.60	$ 80,386.92	$ -	$ 79,246.68
4/2014	Ruby	46,679	10,000	36,679	$ 20.6833	$ 758,642.76	$ 35,872.06	$ -	$ 722,770.70
4/2014	Foothills	69,411	15,454	53,957	$ 2.6051	$ 140,563.38	$ 100,360.02	$ -	$ 40,203.36
4/2014	Nova	70,127	15,613	54,514	$ 4.6600	$ 254,035.24	$ 269,844.30	$ -	$ (15,809.06)
4/2014	GTN	66,926	14,399	52,527	$ 10.3266	$ 542,426.89	$ 80,366.31	$ -	$ 462,060.58
4/2014	Kern River	1,951	400	1,551	$ 7.2000	$ 11,167.20	$ 5,118.30	$ -	$ 6,048.90
4/2014	Kern River-Seasonal	-	-	-	$ -	$ -	$ -	$ -	$ -
4/2014	Subtotal								
4/2014	Initial Storage	4,881,033	1,339,108	3,541,925	$ 0.1260	$ 446,282.55	$ 73,011.19	$ -	$ 373,271.36
4/2014	Subtotal								

Month	CTA Allocation Capacity	Capacity Rejected by All CTAs	Capacity Returned to PG&E CGS by All CTAs	Remaining Rejected Capacity for All CTAs	CGS Contract Rate for All CTAs	Contract Cost for All CTAs	Revenues from Auction for All CTAs	Credit from CGS for All CTAs	Unrecovered Costs for All CTAs
3/2014	Baja AFT	56,992	24,360	32,632	$ 5.3466	$ 174,470.25	$ 119,119.86	$ -	$ 55,350.39
3/2014	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
3/2014	Redwood	13,670	13,670	-	$ -	$ -	$ -	$ -	$ -
3/2014	El Paso	5,131	2,100	3,031	$ 7.9083	$ 23,970.06	$ 15,973.67	$ -	$ 7,996.39
3/2014	Transwestern	37,975	15,540	22,435	$ 8.6800	$ 194,735.80	$ 132,142.15	$ -	$ 62,593.65
3/2014	Ruby	46,679	17,500	29,179	$ 20.6833	$ 603,518.01	$ 34,282.41	$ -	$ 569,235.60
3/2014	Foothills	69,411	27,045	42,366	$ 2.6051	$ 110,367.67	$ 85,367.49	$ -	$ 25,000.18
3/2014	Nova	70,127	27,324	42,803	$ 4.6600	$ 199,461.98	$ 245,475.21	$ -	$ (46,013.23)
3/2014	GTN	66,926	25,198	41,728	$ 10.6709	$ 445,273.27	$ 65,971.97	$ -	$ 379,301.30
3/2014	Kern River	1,951	700	1,251	$ 7.4400	$ 9,307.44	$ 717.45	$ -	$ 8,589.99
3/2014	Kern River-Seasonal	9,568	3,850	5,718	$ 5.2700	$ 30,133.86	$ 8,884.14	$ -	$ 21,249.73
3/2014	Subtotal								
3/2014	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1260	$ 263,776.84	$ 67,997.08	$ -	$ 195,779.77
3/2014	Subtotal								

Month	CTA Allocation Capacity	Capacity Rejected by All CTAs	Capacity Returned to PG&E CGS by All CTAs	Remaining Rejected Capacity for All CTAs	CGS Contract Rate for All CTAs	Contract Cost for All CTAs	Revenues from Auction for All CTAs	Credit from CGS for All CTAs	Unrecovered Costs for All CTAs
2/2014	Baja AFT	62,807	24,360	38,447	$ 5.3466	$ 205,560.73	$ 47,366.70	$ -	$ 158,194.03
2/2014	Baja SFT	58,497	22,470	36,027	$ 6.4159	$ 231,145.63	$ 67,687.53	$ -	$ 163,458.10
2/2014	Redwood	14,253	14,253	-	$ -	$ -	$ -	$ -	$ -
2/2014	El Paso	5,540	2,100	3,440	$ 7.9083	$ 27,204.55	$ 8,765.12	$ -	$ 18,439.43

2/2014	Transwestern	41,657	15,540	26,117	$ 7.8400	$ 204,757.28	$ 71,665.05	$ -	$ 133,092.23
2/2014	Ruby	46,907	17,500	29,407	$ 20.6833	$ 608,233.80	$ 19,926.18	$ -	$ 588,307.62
2/2014	Foothills	52,662	27,045	25,617	$ 2.6051	$ 66,734.85	$ 66,348.03	$ -	$ 386.82
2/2014	Nova	53,206	27,324	25,882	$ 4.6600	$ 120,610.12	$ 153,997.90	$ -	$ (33,387.78)
2/2014	GTN	67,545	25,198	42,347	$ 9.6382	$ 408,148.35	$ 30,655.76	$ -	$ 377,492.59
2/2014	Kern River	1,897	700	1,197	$ 6.7200	$ 8,043.84	$ 1,176.41	$ -	$ 6,867.43
2/2014	Kern River-Seasonal	10,322	3,850	6,472	$ 4.7600	$ 30,806.72	$ 2,736.36	$ -	$ 28,070.36
2/2014	Subtotal								
2/2014	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1260	$ 263,776.84	$ 67,997.08	$ -	$ 195,779.77
2/2014	Subtotal								

Month	CTA Allocation Capacity	Capacity Rejected by All CTAs	Capacity Returned to PG&E CGS by All CTAs	Remaining Rejected Capacity for All CTAs	CGS Contract Rate for All CTAs	Contract Cost for All CTAs	Revenues from Auction for All CTAs	Credit from CGS for All CTAs	Unrecovered Costs for All CTAs
1/2014	Baja AFT	62,807	24,360	38,447	$ 5.3466	$ 205,560.73	$ 50,057.99	$ -	$ 155,502.74
1/2014	Baja SFT	58,497	22,470	36,027	$ 6.2731	$ 226,000.97	$ 79,295.43	$ -	$ 146,705.54
1/2014	Redwood	14,253	14,253	-	$ -	$ -	$ -	$ -	$ -
1/2014	El Paso	5,540	2,100	3,440	$ 7.9083	$ 27,204.55	$ 8,944.00	$ -	$ 18,260.55
1/2014	Transwestern	41,657	15,540	26,117	$ 8.6800	$ 226,695.56	$ 68,818.30	$ -	$ 157,877.27
1/2014	Ruby	46,907	17,500	29,407	$ 20.6833	$ 608,233.80	$ 21,969.97	$ -	$ 586,263.83
1/2014	Foothills	52,662	27,045	25,617	$ 2.6051	$ 66,734.85	$ 73,456.75	$ -	$ (6,721.90)
1/2014	Nova	53,206	27,324	25,882	$ 4.6600	$ 120,610.12	$ 166,485.97	$ -	$ (45,875.85)
1/2014	GTN	67,545	25,198	42,347	$ 10.6709	$ 451,878.53	$ 33,475.30	$ -	$ 418,403.23
1/2014	Kern River	1,897	700	1,197	$ 7.4400	$ 8,905.68	$ 1,302.46	$ -	$ 7,603.22
1/2014	Kern River-Seasonal	10,322	3,850	6,472	$ 5.2700	$ 34,107.44	$ 3,029.54	$ -	$ 31,077.90
1/2014	Subtotal								
1/2014	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1260	$ 263,776.84	$ 67,997.08	$ -	$ 195,779.77
1/2014	Subtotal								

Month	CTA Allocation Capacity	Capacity Rejected by All CTAs	Capacity Returned to PG&E CGS by All CTAs	Remaining Rejected Capacity for All CTAs	CGS Contract Rate for All CTAs	Contract Cost for All CTAs	Revenues from Auction for All CTAs	Credit from CGS for All CTAs	Unrecovered Costs for All CTAs
12/2013	Baja AFT	62,807	24,360	38,447	$ 5.2276	$ 200,985.54	$ 85,813.70	$ -	$ 115,171.84
12/2013	Baja SFT	58,497	22,470	36,027	$ 6.2731	$ 226,000.97	$ 96,606.40	$ -	$ 129,394.57
12/2013	Redwood	14,253	14,253	-	$ -	$ -	$ -	$ -	$ -
12/2013	El Paso	5,540	2,100	3,440	$ 8.0600	$ 27,726.40	$ 12,583.52	$ -	$ 15,142.88
12/2013	Transwestern	41,657	15,540	26,117	$ 8.6800	$ 226,695.56	$ 102,822.63	$ -	$ 123,872.93
12/2013	Ruby	46,907	17,500	29,407	$ 20.6833	$ 608,233.80	$ 23,039.47	$ -	$ 585,194.33
12/2013	Foothills	52,662	27,045	25,617	$ 2.3089	$ 59,147.09	$ 61,941.91	$ -	$ (2,794.82)
12/2013	Nova	53,206	27,324	25,882	$ 5.1700	$ 133,809.94	$ 156,456.69	$ -	$ (22,646.75)
12/2013	GTN	67,545	25,198	42,347	$ 10.6709	$ 451,878.53	$ 26,778.93	$ -	$ 425,099.60
12/2013	Kern River	1,897	700	1,197	$ 7.4400	$ 8,905.68	$ 1,302.46	$ -	$ 7,603.22
12/2013	Kern River-Seasonal	10,322	3,850	6,472	$ 5.2700	$ 34,107.44	$ 6,021.97	$ -	$ 28,085.47
12/2013	Subtotal								
12/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
12/2013	Subtotal								

NOTE: UCC transitioned to CGT Detail Of Bill in Dec 2013

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
11/2013	Baja AFT	52,955	24,360	28,595	$ 5.2276	$ 149,483.22	$ 171,570.00	$ -	$ (22,086.78)
11/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
11/2013	Redwood	15,243	15,243	-	$ -	$ -	$ -	$ -	$ -
11/2013	El Paso	5,540	2,100	3,440	$ 7.8000	$ 26,832.00	$ 6,009.68	$ -	$ 20,822.32
11/2013	Transwestern	35,651	13,300	22,351	$ 8.4000	$ 187,748.40	$ 63,700.35	$ -	$ 124,048.05
11/2013	Ruby	46,907	17,500	29,407	$ 20.6833	$ 608,233.80	$ 28,151.88	$ -	$ 580,081.92
11/2013	Foothills	52,662	27,045	25,617	$ 2.3089	$ 59,147.09	$ 58,406.76	$ -	$ 740.33
11/2013	Nova	53,206	27,324	25,882	$ 5.1700	$ 133,809.94	$ 151,409.70	$ -	$ (17,599.76)
11/2013	GTN	67,545	25,198	42,347	$ 10.3266	$ 437,301.80	$ 26,805.65	$ -	$ 410,496.15
11/2013	Kern River	1,897	700	1,197	$ 7.2000	$ 8,618.40	$ 1,472.31	$ -	$ 7,146.09
11/2013	Subtotal								
11/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
11/2013	Subtotal								

NOTE: UCC invoice sent via E-mail to CTA prior to Nov 2013

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
10/2013	Baja AFT	61,706	24,360	37,346	$ 5.2276	$ 195,229.95	$ 101,937.18	$ -	$ 93,292.77
10/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
10/2013	Redwood	8,168	8,168	-	$ -	$ -	$ -	$ -	$ -
10/2013	El Paso	5,486	2,100	3,386	$ 8.0600	$ 27,291.16	$ 10,208.79	$ -	$ 17,082.37
10/2013	Transwestern	15,179	5,810	9,369	$ 8.6800	$ 81,322.92	$ 26,720.39	$ -	$ 54,602.53
10/2013	Ruby	45,721	17,500	28,221	$ 20.6833	$ 583,703.41	$ 13,122.77	$ -	$ 570,580.64

10/2013	Foothills	70,661	27,045	43,616	$ 2.3089	$ 100,704.98	$ 99,379.06	$ -	$ 1,325.92
10/2013	Nova	71,388	27,324	44,064	$ 5.1700	$ 227,810.88	$ 235,632.24	$ -	$ (7,821.36)
10/2013	GTN	65,834	25,198	40,636	$ 10.6709	$ 433,620.70	$ 83,771.11	$ -	$ 349,849.59
10/2013	Kern River	1,826	700	1,126	$ 7.4400	$ 8,377.44	$ 1,954.74	$ -	$ 6,422.70
10/2013	Subtotal								
10/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
10/2013	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
9/2013	Baja AFT	61,706	24,360	37,346	$ 5.2276	$ 195,229.95	$ 74,343.18	$ -	$ 120,886.77
9/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
9/2013	Redwood	8,168	8,168	-	$ -	$ -	$ -	$ -	$ -
9/2013	El Paso	5,486	2,100	3,386	$ 7.8000	$ 26,410.80	$ 10,207.77	$ -	$ 16,203.03
9/2013	Transwestern	15,179	5,810	9,369	$ 8.4000	$ 78,699.60	$ 24,453.09	$ -	$ 54,246.51
9/2013	Ruby	45,721	17,500	28,221	$ 20.6833	$ 583,703.41	$ 12,699.45	$ -	$ 571,003.96
9/2013	Foothills	70,661	27,045	43,616	$ 2.3089	$ 100,704.98	$ 91,593.60	$ -	$ 9,111.38
9/2013	Nova	71,388	27,324	44,064	$ 5.1700	$ 227,810.88	$ 235,301.76	$ -	$ (7,490.88)
9/2013	GTN	65,834	25,198	40,636	$ 10.3266	$ 419,632.94	$ 97,550.78	$ -	$ 322,082.16
9/2013	Kern River	1,826	700	1,126	$ 7.2000	$ 8,107.20	$ 2,905.08	$ -	$ 5,202.12
9/2013	Subtotal								
9/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
9/2013	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
8/2013	Baja AFT	61,706	24,360	37,346	$ 5.2276	$ 195,229.95	$ 33,612.25	$ -	$ 161,617.70
8/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
8/2013	Redwood	11,451	11,451	-	$ -	$ -	$ -	$ -	$ -
8/2013	El Paso	5,486	2,100	3,386	$ 8.0600	$ 27,291.16	$ 10,207.77	$ -	$ 17,083.39
8/2013	Transwestern	15,179	5,810	9,369	$ 8.6800	$ 81,322.92	$ 25,122.97	$ -	$ 56,199.95
8/2013	Ruby	45,721	17,500	28,221	$ 20.6833	$ 583,703.41	$ 13,122.77	$ -	$ 570,580.64
8/2013	Foothills	70,661	27,045	43,616	$ 2.3089	$ 100,704.98	$ 101,407.20	$ -	$ (702.22)
8/2013	Nova	71,388	27,324	44,064	$ 4.8400	$ 213,269.76	$ 235,632.24	$ -	$ (22,362.48)
8/2013	GTN	65,834	25,198	40,636	$ 10.6709	$ 433,620.70	$ 103,926.57	$ -	$ 329,694.13
8/2013	Kern River	1,826	700	1,126	$ 7.4400	$ 8,377.44	$ 4,363.25	$ -	$ 4,014.19
8/2013	Subtotal								
8/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
8/2013	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
7/2013	Baja AFT	61,706	24,360	37,346	$ 5.2276	$ 195,229.95	$ 47,441.78	$ -	$ 147,788.17
7/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
7/2013	Redwood	11,451	11,451	-	$ -	$ -	$ -	$ -	$ -
7/2013	El Paso	5,486	2,100	3,386	$ 8.0600	$ 27,291.16	$ 10,207.77	$ -	$ 17,083.39
7/2013	Transwestern	15,179	5,810	9,369	$ 8.6800	$ 81,322.92	$ 23,816.00	$ -	$ 57,506.92
7/2013	Ruby	45,721	17,500	28,221	$ 20.6833	$ 583,703.41	$ 13,122.77	$ -	$ 570,580.64
7/2013	Foothills	70,661	27,045	43,616	$ 2.3089	$ 100,704.98	$ 99,379.06	$ -	$ 1,325.92
7/2013	Nova	71,388	27,324	44,064	$ 4.8400	$ 213,269.76	$ 239,047.20	$ -	$ (25,777.44)
7/2013	GTN	65,834	25,198	40,636	$ 10.6709	$ 433,620.70	$ 100,789.88	$ -	$ 332,830.82
7/2013	Kern River	1,826	700	1,126	$ 7.4400	$ 8,377.44	$ 2,513.23	$ -	$ 5,864.21
7/2013	Subtotal								
7/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
7/2013	Subtotal								

NOTE: El Paso: July 2013 UCCI did not reflect the correct CGS Contract Rate, $ 8.06 Dth/mo vs. $0.26 Dth/mo. ($0.26 * 31 days=$8.06 Dth/mo.)
Adjustment was created on the October 2013 bill period.

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
6/2013	Baja AFT	51,652	24,360	27,292	$ 5.2276	$ 142,671.66	$ 67,547.70	$ -	$ 75,123.96
6/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
6/2013	Redwood	5,566	5,566	-	$ -	$ -	$ -	$ -	$ -
6/2013	El Paso	22,789	10,622	12,167	$ 9.5615	$ 116,334.77	$ 40,637.78	$ -	$ 75,696.99
6/2013	Transwestern	12,466	5,810	6,656	$ 8.4000	$ 55,910.40	$ 29,452.80	$ -	$ 26,457.60
6/2013	Ruby	37,548	17,500	20,048	$ 20.6833	$ 414,658.80	$ 15,096.14	$ -	$ 399,562.66
6/2013	Foothills	58,359	27,045	31,314	$ 2.3089	$ 72,300.89	$ 54,486.36	$ -	$ 17,814.53
6/2013	Nova	58,961	27,324	31,637	$ 4.8400	$ 153,123.08	$ 170,175.42	$ -	$ (17,052.34)
6/2013	GTN	54,064	25,198	28,866	$ 10.3266	$ 298,088.50	$ 15,202.28	$ -	$ 282,886.22
6/2013	Kern River	7,558	3,502	4,056	$ 8.4000	$ 34,070.40	$ 17,278.56	$ -	$ 16,791.84
6/2013	Subtotal								

6/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
6/2013	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
5/2013	Baja AFT	51,652	24,360	27,292	$ 5.2276	$ 142,671.66	$ 69,799.29	$ -	$ 72,872.37
5/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
5/2013	Redwood	5,566	5,566	-	$ -	$ -	$ -	$ -	$ -
5/2013	El Paso	22,789	10,622	12,167	$ 9.5615	$ 116,334.77	$ 56,698.22	$ -	$ 59,636.55
5/2013	Transwestern	12,466	5,810	6,656	$ 8.6800	$ 57,771.35	$ 43,536.90	$ -	$ 14,234.45
5/2013	Ruby	37,548	17,500	20,048	$ 20.6833	$ 414,658.80	$ 15,599.35	$ -	$ 399,059.45
5/2013	Foothills	58,359	27,045	31,314	$ 2.3089	$ 72,300.89	$ 56,302.57	$ -	$ 15,998.32
5/2013	Nova	58,961	27,324	31,637	$ 4.8400	$ 153,123.08	$ 170,159.60	$ -	$ (17,036.52)
5/2013	GTN	54,064	25,198	28,866	$ 10.6709	$ 308,024.78	$ 15,709.02	$ -	$ 292,315.76
5/2013	Kern River	7,558	3,502	4,056	$ 8.6800	$ 35,206.08	$ 22,883.95	$ -	$ 12,322.13
5/2013	Subtotal								
5/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
5/2013	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
4/2013	Baja AFT	51,652	24,360	27,292	$ 5.2276	$ 142,671.66	$ 53,219.40	$ -	$ 89,452.26
4/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
4/2013	Redwood	5,566	5,566	-	$ -	$ -	$ -	$ -	$ -
4/2013	El Paso	22,789	10,622	12,167	$ 9.5615	$ 116,334.77	$ 80,314.37	$ -	$ 36,020.40
4/2013	Transwestern	21,779	10,500	11,279	$ 8.4000	$ 94,743.60	$ 71,518.35	$ -	$ 23,225.25
4/2013	Ruby	37,548	17,500	20,048	$ 20.6833	$ 414,658.80	$ 21,050.40	$ -	$ 393,608.40
4/2013	Foothills	58,359	27,045	31,314	$ 2.3089	$ 72,300.89	$ 56,834.91	$ -	$ 15,465.98
4/2013	Nova	58,961	27,324	31,637	$ 4.8400	$ 153,123.08	$ 170,175.42	$ -	$ (17,052.34)
4/2013	GTN	54,064	25,198	28,866	$ 10.3266	$ 298,088.50	$ 16,394.73	$ -	$ 281,693.77
4/2013	Kern River	7,558	3,502	4,056	$ 8.4000	$ 34,070.40	$ 24,542.86	$ -	$ 9,527.54
4/2013	Subtotal								
4/2013	Initial Storage	4,436,906	2,343,439	2,093,467	$ 0.1232	$ 257,915.13	$ 67,997.08	$ -	$ 189,918.06
4/2013	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
3/2013	Baja AFT	51,652	41,760	9,892	$ 5.1362	$ 50,807.29	$ 35,264.98	$ -	$ 15,542.31
3/2013	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
3/2013	Redwood	5,566	5,566	-	$ -	$ -	$ -	$ -	$ -
3/2013	El Paso	22,789	18,209	4,580	$ 9.5615	$ 43,791.67	$ 14,912.48	$ -	$ 28,879.19
3/2013	Transwestern	22,529	18,000	4,529	$ 9.9200	$ 44,927.68	$ 21,200.25	$ -	$ 23,727.43
3/2013	Ruby	37,548	30,000	7,548	$ 20.6833	$ 156,117.55	$ 8,189.58	$ -	$ 147,927.97
3/2013	Foothills	58,359	46,363	11,996	$ 2.3089	$ 27,697.56	$ 26,031.32	$ -	$ 1,666.24
3/2013	Nova	58,961	46,840	12,121	$ 4.8400	$ 58,665.64	$ 65,192.80	$ -	$ (6,527.16)
3/2013	GTN	54,064	43,196	10,868	$ 10.6709	$ 115,970.81	$ 5,798.52	$ -	$ 110,172.29
3/2013	Kern River	7,558	6,004	1,554	$ 8.6800	$ 13,488.72	$ 4,576.53	$ -	$ 8,912.19
3/2013	Subtotal								
3/2013	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1232	$ 26,552.43	$ 16,940.11	$ -	$ 9,612.33
3/2013	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
2/2013	Baja AFT	48,393	41,760	6,633	$ 5.1362	$ 34,068.41	$ 5,757.44	$ -	$ 28,310.97
2/2013	Baja SFT	45,207	38,520	6,687	$ 6.1634	$ 41,214.66	$ 3,931.96	$ -	$ 37,282.70
2/2013	Redwood	6,276	6,276	-	$ -	$ -	$ -	$ -	$ -
2/2013	El Paso	21,371	18,209	3,162	$ 9.5615	$ 30,233.46	$ 10,563.96	$ -	$ 19,669.50
2/2013	Transwestern	21,127	18,000	3,127	$ 8.9600	$ 28,017.92	$ 9,018.27	$ -	$ 18,999.65
2/2013	Ruby	35,208	30,000	5,208	$ 20.6833	$ 107,718.63	$ 32,081.28	$ -	$ 75,637.35
2/2013	Foothills	52,684	46,363	6,321	$ 2.3089	$ 14,594.56	$ 13,716.57	$ -	$ 877.99
2/2013	Nova	54,973	46,840	8,133	$ 4.8400	$ 39,363.72	$ 42,128.94	$ -	$ (2,765.22)
2/2013	GTN	50,697	43,196	7,501	$ 9.6382	$ 72,296.05	$ 3,043.48	$ -	$ 69,252.57
2/2013	KRS	5,529	5,529	-	$ -	$ -	$ -	$ -	$ -
2/2013	Subtotal								
2/2013	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1232	$ 26,552.43	$ 16,940.11	$ -	$ 9,612.33
2/2013	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
1/2013	Baja AFT	48,393	41,760	6,633	$ 5.1362	$ 34,068.41	$ 6,374.31	$ -	$ 27,694.10
1/2013	Baja SFT	45,207	38,520	6,687	$ 6.1634	$ 41,214.66	$ 4,353.24	$ -	$ 36,861.42
1/2013	Redwood	6,276	6,276	-	$ -	$ -	$ -	$ -	$ -
1/2013	*El Paso*	21,371	18,209	3,162	$ 9.5615	$ 30,233.46	$ 10,908.20	$ -	$ 19,325.26
1/2013	Transwestern	21,127	18,000	3,127	$ 9.9200	$ 31,019.84	$ 9,693.70	$ -	$ 21,326.14
1/2013	Ruby	35,208	30,000	5,208	$ 20.6833	$ 107,718.63	$ 35,518.56	$ -	$ 72,200.07
1/2013	Foothills	52,684	46,363	6,321	$ 2.3089	$ 14,594.56	$ 15,186.20	$ -	$ (591.64)
1/2013	Nova	54,973	46,840	8,133	$ 4.8400	$ 39,363.72	$ 44,121.53	$ -	$ (4,757.81)
1/2013	*GTN*	50,697	43,196	7,501	$ 10.6702	$ 80,037.17	$ 3,369.56	$ -	$ 76,667.61
1/2013	KRS	5,529	5,529	-	$ -	$ -	$ -	$ -	$ -
1/2013	Subtotal								
1/2013	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1232	$ 26,552.43	$ 16,940.11	$ -	$ 9,612.33
1/2013	Subtotal								

NOTES:

1) El Paso: invoices in Jan-13 did not include revenues from 662 Dth of capacity sold in 2nd release. Adjustment was created on the February 2013 bill period.

Bill Period	Prior	Revised	Difference
Jan-13	$ 8,525.00	$ 10,908.20	$ (2,383.20)

2) GTN: invoices in Jan-13 did not reflect correct rate for capacity awarded. Adjustment was created on the February 2013 bill period.

Bill Period	Prior	Revised	Difference
Jan-13	$ 9,789.56	$ 3,369.56	$ 6,420.00

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
12/2012	Baja AFT	45,893	41,760	4,133	$ 5.2883	$ 21,856.54	$ 9,096.73	$ -	$ 12,759.81
12/2012	Baja SFT	45,207	38,520	6,687	$ 6.3460	$ 42,435.70	$ 10,572.15	$ -	$ 31,863.56
12/2012	Redwood	6,276	6,276	-	$ -	$ -	$ -	$ -	$ -
12/2012	*El Paso*	21,371	18,209	3,162	$ 9.5615	$ 30,233.46	$ 15,533.20	$ -	$ 14,700.26
12/2012	Transwestern	21,127	18,000	3,127	$ 9.9200	$ 31,019.84	$ 14,637.49	$ -	$ 16,382.35
12/2012	Ruby	35,208	30,000	5,208	$ 20.6833	$ 107,718.63	$ 35,518.56	$ -	$ 72,200.07
12/2012	Foothills	52,684	46,363	6,321	$ 2.8608	$ 18,083.12	$ 15,676.08	$ -	$ 2,407.04
12/2012	Nova	54,973	46,840	8,133	$ 4.9600	$ 40,339.68	$ 44,121.53	$ -	$ (3,781.84)
12/2012	*GTN*	50,697	43,196	7,501	$ 10.6702	$ 80,037.17	$ 3,361.11	$ 0.01	$ 76,676.05
12/2012	KRS	5,529	5,529	-	$ -	$ -	$ -	$ -	$ -
12/2012	Subtotal								
12/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897.27	$ 16,940.11	$ -	$ 9,957.16
12/2012	Subtotal								

NOTES:

1) El Paso: invoices in Dec-12 did not include revenues from 662 Dth of capacity sold in 2nd release. Adjustment was created on the February 2013 bill period.

Bill Period	Prior	Revised	Difference
Dec-12	$ 13,150.00	$ 15,533.20	$ (2,383.20)

2) GTN: invoices in Dec-12 did not reflect correct rate for capacity awarded. Adjustment was created on the February 2013 bill period.

Bill Period	Prior	Revised	Difference
Dec-12	$ 9,765.00	$ 3,361.11	$ 6,403.89

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
11/2012	Baja AFT	37,213	37,213	-	$ -	$ -	$ -	$ -	$ -
11/2012	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
11/2012	Redwood	5,720	5,720	-	$ -	$ -	$ -	$ -	$ -
11/2012	El Paso	21,371	18,209	3,162	$ 9.5615	$ 30,233.46	$ 13,283.56	$ -	$ 16,949.90
11/2012	Transwestern	21,127	18,000	3,127	$ 9.6000	$ 30,019.20	$ 15,197.22	$ -	$ 14,821.98
11/2012	Ruby	35,208	30,000	5,208	$ 20.6833	$ 107,718.63	$ 34,372.80	$ -	$ 73,345.83
11/2012	Foothills	52,684	46,363	6,321	$ 2.8608	$ 18,083.12	$ 15,170.40	$ -	$ 2,912.72
11/2012	Nova	54,973	46,840	8,133	$ 4.9600	$ 40,339.68	$ 43,918.20	$ -	$ (3,578.52)
11/2012	*GTN*	50,697	43,196	7,501	$ 10.3260	$ 77,455.33	$ 3,253.12	$ -	$ 74,202.21
11/2012	KRS	5,529	5,529	-	$ -	$ -	$ -	$ -	$ -
11/2012	Subtotal								
11/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897.27	$ 16,940.11	$ -	$ 9,957.16
11/2012	Subtotal								

NOTES:

GTN: Invoices in Nov-12 did not reflect correct rate for capacity awarded. Adjustment was created on the February 2013 bill period.

Bill Period	Prior	Revised	Difference
Nov-12	$ 9,451.26	$ 3,253.12	$ 6,198.14

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
10/2012	Baja AFT	47,304	41,760	5,544	$ 5.2883	$ 29,318.34	$ 5,637.78	$ -	$ 23,680.55
10/2012	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
10/2012	Redwood	4,788	4,788	-	$ -	$ -	$ -	$ -	$ -
10/2012	El Paso	20,894	18,209	2,685	$ 9.5615	$ 25,672.63	$ 1,342.50	$ -	$ 24,330.13
10/2012	Transwestern	20,651	18,000	2,651	$ 9.9200	$ 26,297.92	$ 12,327.15	$ -	$ 13,970.77

10/2012	Ruby	34,424	30,000	4,424	$ 20.6833	$ 91,502.92	$ 2,194.30	$ -	$ 89,308.62
10/2012	Foothills	53,200	46,363	6,837	$ 2.8608	$ 19,559.29	$ 4,662.83	$ -	$ 14,896.46
10/2012	Nova	53,749	46,840	6,909	$ 4.9600	$ 34,268.64	$ 35,468.04	$ -	$ (1,199.40)
10/2012	GTN	49,566	43,196	6,370	$ 10.6702	$ 67,969.17	$ 7,306.39	$ -	$ 60,662.78
10/2012	KRS	6,889	6,004	885	$ 8.6800	$ 7,681.80	$ 3,017.85	$ -	$ 4,663.95
10/2012	Subtotal								
10/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897.27	$ 16,940.11	$ -	$ 9,957.16
10/2012	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
9/2012	Baja AFT	47,304	41,760	5,544	$ 5.2883	$ 29,318.34	$ 2,494.80	$ -	$ 26,823.54
9/2012	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
9/2012	Redwood	4,788	4,788	-	$ -	$ -	$ -	$ -	$ -
9/2012	El Paso	20,894	18,209	2,685	$ 9.5615	$ 25,672.63	$ 1,342.50	$ -	$ 24,330.13
9/2012	Transwestern	20,651	18,000	2,651	$ 9.6000	$ 25,449.60	$ 11,929.50	$ -	$ 13,520.10
9/2012	Ruby	34,424	30,000	4,424	$ 20.6833	$ 91,502.92	$ 1,327.20	$ -	$ 90,175.72
9/2012	Foothills	53,200	46,363	6,837	$ 2.8608	$ 19,559.29	$ 4,512.42	$ -	$ 15,046.87
9/2012	Nova	53,749	46,840	6,909	$ 4.9600	$ 34,268.64	$ 34,323.91	$ -	$ (55.27)
9/2012	GTN	49,566	43,196	6,370	$ 10.3260	$ 65,776.62	$ 8,790.60	$ -	$ 56,986.02
9/2012	KRS	6,889	6,004	885	$ 8.4000	$ 7,434.00	$ 4,540.05	$ -	$ 2,893.95
9/2012	Subtotal								
9/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897.27	$ 16,940.11	$ -	$ 9,957.16
9/2012	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
8/2012	Baja AFT	47,304	41,760	5,544	$ 5.2883	$ 29,318.34	$ 2,577.96	$ -	$ 26,740.38
8/2012	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
8/2012	Redwood	4,788	4,788	-	$ -	$ -	$ -	$ -	$ -
8/2012	El Paso	20,894	18,209	2,685	$ 9.5615	$ 25,672.63	$ 14,767.50	$ -	$ 10,905.13
8/2012	Transwestern	20,651	18,000	2,651	$ 9.9200	$ 26,297.92	$ 14,792.58	$ -	$ 11,505.34
8/2012	Ruby	34,424	30,000	4,424	$ 20.6833	$ 91,502.92	$ 1,867.44	$ -	$ 89,635.48
8/2012	Foothills	53,200	46,363	6,837	$ 2.8608	$ 19,559.29	$ 4,662.83	$ -	$ 14,896.46
8/2012	Nova	53,749	46,840	6,909	$ 4.9600	$ 34,268.64	$ 35,468.04	$ -	$ (1,199.40)
8/2012	GTN	49,566	43,196	6,370	$ 10.6702	$ 67,969.17	$ 12,638.08	$ -	$ 55,331.09
8/2012	KRS	6,889	6,004	885	$ 8.6800	$ 7,681.80	$ 6,611.84	$ -	$ 1,069.97
8/2012	Subtotal								
8/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897.27	$ 16,940.11	$ -	$ 9,957.16
8/2012	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
7/2012	Baja AFT	47,304	41,760	5,544	$ 5.2883	$ 29,318.34	$ 2,577.96	$ -	$ 26,740.38
7/2012	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
7/2012	Redwood	4,788	4,788	-	$ -	$ -	$ -	$ -	$ -
7/2012	El Paso	20,894	18,209	2,685	$ 9.5615	$ 25,672.63	$ 14,767.50	$ -	$ 10,905.13
7/2012	Transwestern	20,651	18,000	2,651	$ 9.9200	$ 26,297.92	$ 14,792.58	$ -	$ 11,505.34
7/2012	Ruby	34,424	30,000	4,424	$ 20.6833	$ 91,502.92	$ -	$ 44.24	$ 91,458.68
7/2012	Foothills	53,200	46,363	6,837	$ 2.8608	$ 19,559.29	$ 6,358.41	$ -	$ 13,200.88
7/2012	Nova	53,749	46,840	6,909	$ 4.9600	$ 34,268.64	$ 35,468.04	$ -	$ (1,199.40)
7/2012	GTN	49,566	43,196	6,370	$ 10.6702	$ 67,969.17	$ 12,638.08	$ -	$ 55,331.09
7/2012	KRS	6,889	6,004	885	$ 8.6800	$ 7,681.80	$ 7,023.36	$ -	$ 658.44
7/2012	Subtotal								
7/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897.27	$ 16,940.11	$ -	$ 9,957.16
7/2012	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
6/2012	Baja AFT	39,886	39,886	-	$ -	$ -	$ -	$ -	$ -
6/2012	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
6/2012	Redwood	3,005	3,005	-	$ -	$ -	$ -	$ -	$ -
6/2012	El Paso	23,574	23,574	-	$ -	$ -	$ -	$ -	$ -
6/2012	Transwestern	17,525	17,525	-	$ -	$ -	$ -	$ -	$ -
6/2012	Ruby	29,208	29,208	-	$ -	$ -	$ -	$ -	$ -
6/2012	Foothills	50,030	46,363	3,667	$ 2.8608	$ 10,490.55	$ 9,350.85	$ -	$ 1,139.70
6/2012	Nova	50,546	46,840	3,706	$ 4.9600	$ 18,381.76	$ 18,355.82	$ -	$ 25.94
6/2012	GTN	46,613	43,196	3,417	$ 10.3260	$ 35,283.94	$ 5,730.31	$ -	$ 29,553.63
6/2012	Subtotal								
6/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897	$ 16,940.11	$ -	$ 9,957.16
6/2012	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
5/2012	Baja AFT	39,886	39,886	-	$ -	$ -	$ -	$ -	$ -
5/2012	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
5/2012	Redwood	3,005	3,005	-	$ -	$ -	$ -	$ -	$ -
5/2012	El Paso	23,574	23,574	-	$ -	$ -	$ -	$ -	$ -
5/2012	Transwestern	17,525	17,525	-	$ -	$ -	$ -	$ -	$ -
5/2012	Ruby	29,208	29,208	-	$ -	$ -	$ -	$ -	$ -
5/2012	Foothills	50,030	46,363	3,667	$ 2.8608	$ 10,490.55	$ 9,662.55	$ 37	$ 791.34
5/2012	Nova	50,546	46,840	3,706	$ 4.9600	$ 18,381.76	$ 18,967.68	$ 37	$ (622.98)
5/2012	GTN	46,613	43,196	3,417	$ 10.3260	$ 35,283.94	$ 7,700.89	$ 34	$ 27,548.88
5/2012	Subtotal								
5/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897	$ 16,940.11	$ -	$ 9,957.16
5/2012	Subtotal								

Month	Pipeline Capacity	Capacity Rejected by All CTAs (Dth/d)	Capacity Returned to PG&E CGS (Dth/d)	Capacity Offered at Aucton (Dth/d)	CGS Contract Rate ($/Dth/mo)	Contract Cost ($/mo)	Revenues from Auction ($/mo)	Credit from CGS $0.01/Dth/mo ($/mo)	Unrecovered Costs ($/mo)
4/2012	Baja AFT	39,886	39,886	-	$ -	$ -	$ -	$ -	$ -
4/2012	Baja SFT	-	-	-	$ -	$ -	$ -	$ -	$ -
4/2012	Redwood	3,005	3,005	-	$ -	$ -	$ -	$ -	$ -
4/2012	El Paso	23,574	23,574	-	$ -	$ -	$ -	$ -	$ -
4/2012	Transwestern	17,525	17,525	-	$ -	$ -	$ -	$ -	$ -
4/2012	Ruby	29,208	29,208	-	$ -	$ -	$ -	$ -	$ -
4/2012	Foothills	50,030	46,363	3,667	$ 2.8608	$ 10,490.55	$ 9,350.85	$ -	$ 1,139.70
4/2012	Nova	50,546	46,840	3,706	$ 4.9600	$ 18,381.76	$ 18,355.82	$ -	$ 25.94
4/2012	GTN	46,613	43,196	3,417	$ 10.3260	$ 35,283.94	$ 8,600.59	$ -	$ 26,683.35
4/2012	Subtotal								
4/2012	Initial Storage	4,232,847	4,017,324	215,523	$ 0.1248	$ 26,897	$ 16,940.11	$ -	$ 9,957.16
4/2012	Subtotal								

CTAC-CTA Capacity Allocations

a. Amount of capacity allocated to CTAs on each interstate and intrastate pipeline. *(Refer to Pipeline Capacity Allocations tab and Storage Capacity Allocations tab.)*

Pipeline Capacity Offered to CTAs (Dth/day)

Allocation Period	Baja AFT	Baja SFT	Redwood	El Paso	TW	Ruby	Foothills	Nova	GTN	KR	KR-5
Oct 2014	57,388	0	100,393	0	13,687	41,227	63,717	64,373	59,361	0	0
Sep 2014	57,388	0	100,393	0	13,687	41,227	63,717	64,373	59,361	0	0
Aug 2014	57,388	0	100,393	0	13,687	41,227	63,717	64,373	59,361	0	0
Jul 2014	57,388	0	100,393	0	13,687	41,227	63,717	64,373	59,361	0	0
Jun 2014	67,965	0	118,894	5,858	16,212	48,829	75,457	76,235	70,304	1,951	0
May 2014	67,965	0	118,894	5,858	16,212	48,829	75,457	76,235	70,304	1,951	0
Apr 2014	67,965	0	118,894	5,858	28,320	48,829	75,457	76,235	70,304	1,951	0
Mar 2014	67,965	0	118,894	5,858	43,358	48,829	75,457	76,235	70,304	1,951	10,740
Feb 2014	66,058	60,928	115,555	5,694	42,141	47,453	73,337	74,095	68,331	1,897	10,442
Jan 2014	66,058	60,928	115,555	5,694	42,141	47,453	73,337	74,095	68,331	1,897	10,442
Dec 2013	66,058	60,928	115,555	5,694	42,141	47,453	73,337	74,095	68,331	1,897	10,442
Nov 2013	66,058	0	115,555	5,694	36,066	47,453	73,337	74,095	68,331	1,897	N/A
Oct 2013	63,646	0	111,336	5,486	15,179	45,721	70,661	71,388	65,834	1,826	N/A
Sep 2013	63,646	0	111,336	5,486	15,179	45,721	70,661	71,388	65,834	1,826	N/A
Aug 2013	63,646	0	111,336	5,486	15,179	45,721	70,661	71,388	65,834	1,826	N/A
Jul 2013	63,646	0	111,336	5,486	15,179	45,721	70,661	71,388	65,834	1,826	N/A
Jun 2013	52,567	0	91,954	22,920	12,538	37,763	58,359	58,961	54,374	7,558	N/A
May 2013	52,567	0	91,954	22,920	12,538	37,763	58,359	58,961	54,374	7,558	N/A
Apr 2013	52,567	0	91,954	22,920	21,904	37,763	58,359	58,961	54,374	7,558	N/A
Mar 2013	52,567	0	91,954	22,920	22,658	37,763	58,359	58,961	54,374	7,558	N/A
Feb 2013	49,008	45,207	85,735	21,371	21,127	35,208	54,412	54,973	50,697	7,047	N/A
Jan 2013	49,008	45,207	85,735	21,371	21,127	35,208	54,412	54,973	50,697	7,047	N/A
Dec 2012	49,008	45,207	85,735	21,371	21,127	35,208	54,412	54,973	50,697	7,047	N/A
Nov 2012	49,008	0	85,735	21,371	21,127	35,208	54,412	54,973	50,697	7,047	N/A
Oct 2012	47,919	0	83,826	20,894	20,651	34,424	53,200	53,749	49,566	6,889	N/A
Sep 2012	47,919	0	83,826	20,894	20,651	34,424	53,200	53,749	49,566	6,889	N/A
Aug 2012	47,919	0	83,826	20,894	20,651	34,424	53,200	53,749	49,566	6,889	N/A
Jul 2012	47,919	0	83,826	20,894	20,651	34,424	53,200	53,749	49,566	6,889	N/A
Jun 2012	45,064	0	78,831	26,128	19,424	32,372	50,030	50,546	46,613	N/A	N/A
May 2012	45,064	0	78,831	26,128	19,424	32,372	50,030	50,546	46,613	N/A	N/A
Apr 2012	45,064	0	78,831	26,128	19,424	32,372	50,030	50,546	46,613	N/A	N/A
Mar 2012	45,064	N/A	78,831	26,130	19,423	N/A	N/A	N/A	N/A	N/A	N/A
Feb 2012	86,187	N/A	78,427	25,995	19,325	N/A	N/A	N/A	N/A	N/A	N/A
Jan 2012	86,566	N/A	78,770	26,109	19,410	N/A	N/A	N/A	N/A	N/A	N/A
Dec 2011	85,338	N/A	77,655	25,740	19,134	N/A	N/A	N/A	N/A	N/A	N/A
Nov 2011	43,796	N/A	76,612	25,391	18,874	N/A	N/A	N/A	N/A	N/A	N/A
Oct 2011	43,355	N/A	75,846	25,139	18,686	N/A	N/A	N/A	N/A	N/A	N/A
Sep 2011	42,858	N/A	74,975	24,845	18,472	N/A	N/A	N/A	N/A	N/A	N/A
Aug 2011	42,313	N/A	74,021	24,533	18,239	N/A	N/A	N/A	N/A	N/A	N/A
Jul 2011	41,857	N/A	73,224	24,268	18,044	N/A	N/A	N/A	N/A	N/A	N/A
Jun 2011	41,299	N/A	72,247	23,944	17,802	N/A	N/A	N/A	N/A	N/A	N/A
May 2011	40,362	N/A	70,606	23,406	17,398	N/A	N/A	N/A	N/A	N/A	N/A
Apr 2011	38,404	N/A	67,181	22,265	16,553	N/A	N/A	N/A	N/A	N/A	N/A
Mar 2011	38,110	N/A	66,669	22,097	16,428	N/A	N/A	N/A	N/A	N/A	N/A
Feb 2011	71,600	N/A	65,154	21,595	16,054	N/A	N/A	N/A	N/A	N/A	N/A
Jan 2011	72,442	N/A	65,917	21,851	16,241	N/A	N/A	N/A	N/A	N/A	N/A

Pipeline Capacity Accepted by CTA's (Dth/day)

Allocation Period	Baja AFT	Baja SFT	Redwood	El Paso	TW	Ruby	Foothills	Nova	GTN	KR	KR-5
Oct 2014	24,627	0	95,612	0	2,858	2,288	5,109	5,161	8,845	0	0
Sep 2014	24,627	0	95,612	0	2,858	2,288	5,109	5,161	8,845	0	0
Aug 2014	24,627	0	95,612	0	2,858	2,288	5,109	5,161	8,845	0	0
Jul 2014	24,627	0	95,612	0	2,858	2,288	5,109	5,161	8,845	0	0
Jun 2014	20,768	0	112,626	727	2,013	2,150	6,046	6,108	3,378	0	0
May 2014	20,768	0	112,626	727	2,013	2,150	6,046	6,108	3,378	0	0
Apr 2014	20,768	0	112,626	727	3,516	2,150	6,046	6,108	3,378	0	0
Mar 2014	10,973	0	105,224	727	5,383	2,150	6,046	6,108	3,378	0	1,172
Feb 2014	3,251	2,431	101,302	154	485	546	20,675	20,889	786	0	120
Jan 2014	3,251	2,431	101,302	154	484	546	20,675	20,889	786	0	120
Dec 2013	3,251	2,431	101,302	154	484	546	20,675	20,889	786	0	120
Nov 2013	13,103	0	100,312	154	415	546	20,675	20,889	786	0	N/A
Oct 2013	1,940	0	103,168	0	0	0	0	0	0	0	N/A
Sep 2013	1,940	0	103,168	0	0	0	0	0	0	0	N/A
Aug 2013	1,940	0	99,885	0	0	0	0	0	0	0	N/A
Jul 2013	1,940	0	99,885	0	0	0	0	0	0	0	N/A
Jun 2013	915	0	86,388	131	72	215	0	0	310	0	N/A
May 2013	915	0	86,388	131	72	215	0	0	310	0	N/A
Apr 2013	915	0	86,388	131	125	215	0	0	310	0	N/A
Mar 2013	915	0	86,388	131	129	215	0	0	310	0	N/A
Feb 2013	615	0	79,459	0	0	0	1,728	0	0	1,518	N/A
Jan 2013	615	0	79,459	0	0	0	1,728	0	0	1,518	N/A
Dec 2012	3,115	0	79,459	0	0	0	1,728	0	0	1,518	N/A
Nov 2012	11,795	0	80,015	0	0	0	1,728	0	0	1,518	N/A
Oct 2012	615	0	79,038	0	0	0	0	0	0	0	N/A
Sep 2012	615	0	79,038	0	0	0	0	0	0	0	N/A
Aug 2012	615	0	79,038	0	0	0	0	0	0	0	N/A
Jul 2012	615	0	79,038	0	0	0	0	0	0	0	N/A
Jun 2012	5,178	0	75,826	2,554	1,899	3,164	0	0	0	N/A	N/A
May 2012	5,178	0	75,826	2,554	1,899	3,164	0	0	0	N/A	N/A
Apr 2012	5,178	0	75,826	2,554	1,899	3,164	0	0	0	N/A	N/A
Mar 2012	1,031	N/A	75,820	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Feb 2012	1,352	N/A	62,852	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Jan 2012	1,341	N/A	5,236	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Dec 2011	19,402	N/A	53,362	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Nov 2011	3,968	N/A	29,682	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Oct 2011	525	N/A	75,475	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Sep 2011	525	N/A	74,919	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Aug 2011	525	N/A	73,536	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Jul 2011	525	N/A	69,884	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Jun 2011	475	N/A	28,088	0	0	N/A	N/A	N/A	N/A	N/A	N/A
May 2011	499	N/A	34,162	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Apr 2011	3,215	N/A	57,603	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Mar 2011	3,517	N/A	53,180	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Feb 2011	3,688	N/A	54,523	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Jan 2011	3,578	N/A	53,281	0	0	N/A	N/A	N/A	N/A	N/A	N/A

NOTE:
N/A = Not Available.

a. Amount of capacity allocated to CTAs on each interstate and intrastate pipeline. - *Storage Capacity Allocated to CTAs for each storage year.*

PG&E Core Storage Inventory Capacity (MDth)

Year	CTAs
2010/2011	3,056
2011/2012	3,457
2012/2013	4,858
2013/2014	5,550
2014/2015	6,437