APPENDIX C
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Decision Tables - Test Year 2014

TABLE INDEX

APPENDIX C: Table 1
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC) - Line of Business (LOB) Position Summary
LOB Summary of Adopted Increase Over Authorized 2011 General Rate Case
(Millions of Dollars)

			PG&E Update Testimony Exhibit (PG&E-32)		ORA Comparison Exhibit (PG&E-31)		Adopted			
Line		1/1/2014 Authorized & Pending [(a)]	2014 Proposed	Difference from Authorized	2014 Proposed	Difference from Authorized	2014 Proposed	Difference from Authorized	Reduction from PG&E Proposed	Line
		(a)	(b)	(c)=(b-a)	(d)	(e)=(d-a)	(f)	(g)=(f)-(a)	(h)=(g)-(c)	
	Electric Distribution									
1	Operation and Maintenance	624	619	(5)	514	(111)	613	(11)	(6)	1
2	Customer Services	188	199	10	115	(73)	171	(18)	(28)	2
3	Administrative & General	410	487	77	386	(24)	443	32	(44)	3
4	Less: Revenue Credits (OORs & Wheeling)	(115)	(89)	26	(130)	(16)	(88)	27	1	4
5	FF&U, Other Adjs, Taxes Other than Income	70	95	25	77	7	82	12	(13)	5
6	Return, Taxes, Depreciation, and Amortization	2,471	2,853	382	2,555	84	2,553	82	(300)	6
7	Retail Revenue Requirement	3,650	4,164	514	3,517	(132)	3,775	125	(389)	7
	Gas Distribution									
8	Operation and Maintenance	241	408	168	248	7	357	116	(52)	8
9	Customer Services	146	152	6	113	(33)	131	(15)	(22)	9
10	Administrative & General	199	262	62	207	8	244	45	(17)	10
11	Less: Revenue Credits (OORs & Wheeling)	(23)	(25)	(2)	(22)	1	(25)	(2)	0	11
12	FF&U, Other Adjs, Taxes Other than Income	42	53	11	41	(1)	44	2	(10)	12
13	Return, Taxes, Depreciation, and Amortization	690	891	201	785	95	809	119	(82)	13
14	Retail Revenue Requirement	1,295	1,741	446	1,372	76	1,559	264	(182)	14
	Electric Generation									
15	Operation and Maintenance	558	623	65	500	(59)	599	41	(24)	15
16	Customer Services	0	0	0	0	0	0	0	0	16
17	Administrative & General	197	275	78	218	21	262	65	(13)	17
18	Less: Revenue Credits (OORs & Wheeling)	(12)	(14)	(3)	(18)	(6)	(18)	(6)	(4)	18
19	FF&U, Other Adjs, Taxes Other than Income	43	(67)	(110)	(81)	(124)	(101)	(144)	(35)	19
20	Return, Taxes, Depreciation, and Amortization	903	1,072	169	1,002	99	1,019	116	(53)	20
21	Retail Revenue Requirement	1,689	1,889	199	1,620	(69)	1,761	71	(128)	21
	Total GRC									
22	Operation and Maintenance	1,424	1,651	227	1,261	(163)	1,569	146	(82)	22
23	Customer Services	334	351	17	228	(106)	301	(33)	(49)	23
24	Administrative & General	806	1,023	218	811	5	949	143	(75)	24
25	Less: Revenue Credits (OORs & Wheeling)	(149)	(128)	21	(170)	(21)	(131)	18	(2)	25
26	FF&U, Other Adjs, Taxes Other than Income	155	81	(74)	37	(119)	24	(131)	(57)	26
27	Return, Taxes, Depreciation, and Amortization	4,065	4,816	751	4,343	278	4,382	317	(435)	27
28	Retail Revenue Requirement	6,634	7,794	1,160	6,509	(125)	7,094	460	(700)	28

(a) These amounts include revenues from PG&E's 2011 GRC Decision 11-05-018, adjusted for 2012 and 2013 attrition. Also included are the 2014 revenue requirements associated with the Cornerstone Project, Market Redesign and Technology Upgrade (MRTU), Fuel Cell Project, Vaca-Dixon PV Pilot Project, SmartMeter and Meter Reading. These amounts exclude pension costs. All amounts adjusted for adopted 2013 Cost of Capital consistent with D.12-12-034.

APPENDIX C: Table 2
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC) - Position Summary
Results Of Operations Summary of Adopted Increase Over Authorized 2011 General Rate Case
Results of Operations - Test Year 2014
(Millions of Dollars)

Line No.	Description	1/1/2014 Authorized & Pending [a]	**PG&E** Update Testimony Exhibit (PG&E-32) 2014 Proposed		**ORA** Comparison Exhibit (PG&E-31) 2014 Proposed		Adopted 2014 Proposed		Reduction from PG&E Proposed	Line No.
			2014 Proposed	Difference from Authorized	2014 Proposed	Difference from Authorized	2014 Proposed	Difference from Authorized		
		(a)	(b)	(c)=(b-a)	(d)	(e)=(d-a)	(f)	(g)=(f)-(a)	(h)=(g)-(c)	
	REVENUE:									
1	Revenue Collected in Rates	6,634	7,794	1,160	6,509	(125)	7,094	460	(700)	1
2	Plus Other Operating Revenue	149	128	(21)	170	21	131	(18)	2	2
3	Total Operating Revenue	6,783	7,923	1,139	6,680	(104)	7,225	442	(697)	3
	OPERATING EXPENSES:									
4	Energy Costs	0	0	0	0	0	0	0	0	4
5	Production	552	624	72	498	(53)	600	48	(24)	5
6	Storage	4	0	(4)	0	(4)	0	(4)	0	6
7	Transmission	8	5	(3)	5	(3)	5	(3)	0	7
8	Distribution	860	1,022	162	757	(103)	965	104	(58)	8
9	Customer Accounts	312	344	32	225	(87)	296	(16)	(48)	9
10	Uncollectibles	22	29	7	25	3	23	2	(6)	10
11	Customer Services	22	7	(15)	3	(19)	5	(16)	(1)	11
12	Administrative and General	806	1,023	218	811	5	949	143	(75)	12
13	Franchise Requirements	58	75	18	63	5	69	11	(7)	13
14	Amortization	60	59	(1)	59	(1)	59	(1)	0	14
15	Wage Change Impacts	0	0	0	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	16
17	Other Adjustments	(25)	(137)	(112)	(134)	(109)	(173)	(148)	(36)	17
18	Subtotal Expenses:	2,678	3,051	373	2,313	(365)	2,797	119	(254)	18
	TAXES:									
19	Superfund	0	0	0	0	0	0	0	0	19
20	Property	239	249	10	247	8	249	10	(0)	20
21	Payroll	97	110	13	79	(18)	102	4	(9)	21
22	Business	1	1	(0)	1	(0)	1	(0)	0	22
23	Other	2	3	0	3	0	3	0	0	23
24	State Corporation Franchise	128	140	12	126	(1)	109	(18)	(31)	24
25	Federal Income	565	408	(157)	429	(136)	394	(172)	(15)	25
26	Total Taxes	1,033	911	(121)	885	(147)	857	(176)	(54)	26
27	Depreciation	1,512	2,227	715	1,853	341	1,881	369	(346)	27
28	Fossil Decommissioning	38	36	(2)	36	(2)	36	(2)	0	28
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	29
30	Total Operating Expenses	5,261	6,226	965	5,087	(174)	5,571	310	(655)	30
31	Net for Return	1,523	1,697	174	1,593	70	1,654	131	(43)	31
32	Rate Base	19,538	21,057	1,519	19,762	224	20,529	991	(528)	32
	RATE OF RETURN:									
33	On Rate Base		**8.06%**		**8.06%**		**8.06%**			33
34	On Equity		**10.40%**		**10.40%**		**10.40%**			34

[a] These amounts include revenues from PG&E's 2011 GRC Decision 11-05-018, adjusted for 2012 and 2013 attrition. Also included are the 2014 revenue requirements associated with the Cornerstone Project, Market Redesign and Technology Upgrade (MRTU), Fuel Cell Project, Vaca-Dixon PV Pilot Project, SmartMeter and Meter Reading. These amounts exclude pension costs. All amounts adjusted for adopted 2013 Cost of Capital consistent with D.12-12-034.

APPENDIX C: Table 3

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	PG&E Request *	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
	REVENUE:				
1	Retail Revenue Collected in Rates	7,794,167	7,094,484	(699,683)	1
2	Plus Other Operating Revenue	128,404	130,713	2,309	2
3	Total Operating Revenue	7,922,571	7,225,197	(697,374)	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	623,702	599,767	(23,936)	5
6	Storage	0	0	0	6
7	Transmission	5,100	5,100	0	7
8	Distribution	1,022,134	964,512	(57,622)	8
9	Customer Accounts	344,113	295,834	(48,279)	9
10	Uncollectibles	29,212	23,377	(5,835)	10
11	Customer Services	6,610	5,391	(1,218)	11
12	Administrative and General	1,023,416	948,640	(74,776)	12
13	Franchise Requirements	75,427	68,683	(6,744)	13
14	Amortization	58,975	58,975	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(137,416)	(173,237)	(35,821)	17
18	Subtotal Expenses:	3,051,274	2,797,042	(254,232)	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	249,160	248,686	(474)	20
21	Payroll	110,269	101,664	(8,605)	21
22	Business	926	926	0	22
23	Other	2,939	2,939	0	23
24	State Corporation Franchise	139,788	109,217	(30,572)	24
25	Federal Income	408,261	393,561	(14,700)	25
26	Total Taxes	911,343	856,993	(54,350)	26
27	Depreciation	2,226,997	1,880,768	(346,229)	27
28	Fossil Decommissioning	36,085	36,085	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	6,225,699	5,570,888	(654,811)	30
31	Net for Return	1,696,872	1,654,309	(42,563)	31
32	Rate Base	21,057,183	20,528,996	(528,187)	32
	RATE OF RETURN:				
33	On Rate Base				33
34	On Equity				34

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX C: Table 3-A

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2014
Electric Distribution Summary
(Thousands of Dollars)

Line No.	Description	PG&E Request *	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
	REVENUE:				
1	Retail Revenue Collected in Rates	4,164,033	3,774,649	(389,384)	1
2	Plus Other Operating Revenue	88,788	87,538	(1,250)	2
3	Total Operating Revenue	4,252,820	3,862,187	(390,633)	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	0	0	0	5
6	Storage	0	0	0	6
7	Transmission	1,024	1,024	0	7
8	Distribution	618,225	612,283	(5,942)	8
9	Customer Accounts	194,736	168,086	(26,650)	9
10	Uncollectibles	15,758	12,557	(3,202)	10
11	Customer Services	3,774	2,556	(1,218)	11
12	Administrative and General	487,026	442,610	(44,416)	12
13	Franchise Requirements	35,637	32,378	(3,259)	13
14	Amortization	58,768	58,768	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(1,602)	(4,932)	(3,330)	17
18	Subtotal Expenses:	1,413,347	1,325,330	(88,017)	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	160,005	160,014	8	20
21	Payroll	43,330	40,368	(2,962)	21
22	Business	441	441	0	22
23	Other	1,398	1,398	0	23
24	State Corporation Franchise	89,386	67,267	(22,119)	24
25	Federal Income	216,007	215,697	(310)	25
26	Total Taxes	510,567	485,185	(25,382)	26
27	Depreciation	1,349,822	1,076,793	(273,029)	27
28	Fossil Decommissioning	0	0	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	3,273,736	2,887,308	(386,428)	30
31	Net for Return	979,084	974,879	(4,206)	31
32	Rate Base	12,149,860	12,097,670	(52,190)	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX C: Table 3-B

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2014
Gas Distribution Summary
(Thousands of Dollars)

Line No.	Description	PG&E Request * (A)	Adopted (B)	Difference (C) = (B) - (A)	Line No.
	REVENUE:				
1	Retail Revenue Collected in Rates	1,741,187	1,559,047	(182,140)	1
2	Plus Other Operating Revenue	25,228	25,228	0	2
3	Total Operating Revenue	1,766,416	1,584,276	(182,140)	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	4,575	4,575	0	5
6	Storage	0	0	0	6
7	Transmission	0	0	0	7
8	Distribution	403,908	352,229	(51,680)	8
9	Customer Accounts	149,377	127,748	(21,629)	9
10	Uncollectibles	6,402	5,038	(1,364)	10
11	Customer Services	2,836	2,836	0	11
12	Administrative and General	261,517	244,385	(17,132)	12
13	Franchise Requirements	23,841	21,393	(2,449)	13
14	Amortization	0	0	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(11,207)	(12,997)	(1,790)	17
18	Subtotal Expenses:	841,249	745,206	(96,043)	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	38,614	38,146	(468)	20
21	Payroll	33,221	29,088	(4,133)	21
22	Business	237	237	0	22
23	Other	751	751	0	23
24	State Corporation Franchise	19,375	13,999	(5,376)	24
25	Federal Income	67,134	66,047	(1,087)	25
26	Total Taxes	159,331	148,268	(11,063)	26
27	Depreciation	463,006	392,120	(70,886)	27
28	Fossil Decommissioning	0	0	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	1,463,586	1,285,594	(177,992)	30
31	Net for Return	302,830	298,682	(4,148)	31
32	Rate Base	3,757,938	3,706,468	(51,470)	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX C: Table 3-C

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2014
Electric Generation Summary
(Thousands of Dollars)

Line No.	Description	PG&E Request * (A)	Adopted (B)	Difference (C) = (B) - (A)	Line No.
	REVENUE:				
1	Retail Revenue Collected in Rates	1,888,947	1,760,788	(128,159)	1
2	Plus Other Operating Revenue	14,387	17,946	3,559	2
3	Total Operating Revenue	1,903,335	1,778,734	(124,601)	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	619,127	595,192	(23,936)	5
6	Storage	0	0	0	6
7	Transmission	4,075	4,075	0	7
8	Distribution	0	0	0	8
9	Customer Accounts	0	0	0	9
10	Uncollectibles	7,052	5,783	(1,270)	10
11	Customer Services	0	0	0	11
12	Administrative and General	274,873	261,645	(13,228)	12
13	Franchise Requirements	15,949	14,912	(1,037)	13
14	Amortization	207	207	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(124,607)	(155,308)	(30,701)	17
18	Subtotal Expenses:	796,678	726,506	(70,172)	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	50,540	50,526	(14)	20
21	Payroll	33,719	32,209	(1,510)	21
22	Business	249	249	0	22
23	Other	789	789	0	23
24	State Corporation Franchise	31,028	27,950	(3,078)	24
25	Federal Income	125,121	111,817	(13,304)	25
26	Total Taxes	241,445	223,540	(17,905)	26
27	Depreciation	414,168	411,854	(2,314)	27
28	Fossil Decommissioning	36,085	36,085	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	1,488,376	1,397,986	(90,391)	30
31	Net for Return	414,958	380,748	(34,210)	31
32	Rate Base	5,149,385	4,724,858	(424,527)	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX C: Table 4
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Income Taxes at Proposed Rates - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	PG&E Request *	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
1	Revenues	7,922,571	7,225,197	(697,374)	1
2	O&M Expenses	3,051,274	2,797,042	(254,232)	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	363,294	354,215	(9,079)	5
6	Subtotal	4,508,003	4,073,940	(434,064)	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charges	546,308	532,604	(13,703)	7
8	Fiscal/Calendar Adjustment	9,898	8,952	(946)	8
9	Operating Expense Adjustments	(51,814)	(53,665)	(1,851)	9
10	Capitalized Interest Adjustment	0	0	0	10
11	Removal Costs	189,739	168,949	(20,790)	11
12	Vacation Accrual Reduction	(2,589)	(2,589)	0	12
13	Capitalized Other	107,175	86,451	(20,724)	13
14	Subtotal Deductions	798,716	740,702	(58,014)	14
	CCFT TAXES:				
15	State Operating Expense Adjustment	14,986	14,986	0	15
16	State Tax Depreciation - Declining Balance	0	0	0	16
17	State Tax Depreciation - Fixed Assets	1,607,953	1,592,172	(15,781)	17
18	State Tax Depreciation - Other	0	0	0	18
19	Capitalized Other	76,185	76,185	0	19
20	Repair Allowance	347,404	332,968	(14,437)	20
21	Subtotal Deductions	2,845,244	2,757,013	(88,232)	21
22	Taxable Income for CCFT	1,662,759	1,316,927	(345,832)	22
23	CCFT	146,988	116,416	(30,572)	23
24	State Tax Adjustment	0	0	0	24
25	Current CCFT	146,988	116,416	(30,572)	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	1,325	1,325	0	27
28	Deferred Taxes - Vacation	(229)	(229)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(8,295)	(8,295)	0	30
31	Total CCFT	139,788	109,217	(30,572)	31
	FEDERAL TAXES:				
32	CCFT - Prior Year	83,523	86,658	3,135	32
33	Federal Operating Expense Adjustment	20,470	20,470	0	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	1,356,633	1,305,943	(50,690)	36
37	Federal Tax Depreciation - Other	0	0	0	37
38	Capitalized Other	76,185	76,185	0	38
39	Repair Allowance	347,404	332,968	(14,437)	39
40	Preferred Dividend Credit	2,754	2,754	0	40
41	Subtotal Deductions	2,685,685	2,565,681	(120,005)	41
42	Taxable Income for FIT	1,822,318	1,508,259	(314,059)	42
43	Federal Income Tax	637,811	527,891	(109,921)	43
44	Deferred Taxes - Reg Asset	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	(318)	(318)	0	45
46	Deferred Taxes - Interest	1,456	1,456	0	46
47	Deferred Taxes - Vacation	(826)	(826)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	(229,861)	(134,641)	95,221	49
50	Total Federal Income Tax	408,261	393,561	(14,700)	50

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX C: Table 4-A

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Income Taxes at Proposed Rates - Test Year 2014
Electric Distribution Summary
(Thousands of Dollars)

Line No.	Description	PG&E Request *	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
1	Revenues	4,252,820	3,862,187	(390,633)	1
2	O&M Expenses	1,413,347	1,325,330	(88,017)	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	205,174	202,221	(2,954)	5
6	Subtotal	2,634,299	2,334,636	(299,663)	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charges	315,216	313,862	(1,354)	7
8	Fiscal/Calendar Adjustment	6,168	5,295	(873)	8
9	Operating Expense Adjustments	(32,530)	(33,115)	(586)	9
10	Capitalized Interest Adjustment	0	0	0	10
11	Removal Costs	131,666	117,078	(14,589)	11
12	Vacation Accrual Reduction	(1,205)	(1,205)	0	12
13	Capitalized Other	56,109	43,560	(12,549)	13
14	Subtotal Deductions	475,424	445,474	(29,949)	14
	CCFT TAXES:				
15	State Operating Expense Adjustment	3,502	3,502	0	15
16	State Tax Depreciation - Declining Balance	0	0	0	16
17	State Tax Depreciation - Fixed Assets	848,279	841,126	(7,153)	17
18	State Tax Depreciation - Other	0	0	0	18
19	Capitalized Other	67,180	67,180	0	19
20	Repair Allowance	196,982	184,631	(12,351)	20
21	Subtotal Deductions	1,591,367	1,541,913	(49,453)	21
22	Taxable Income for CCFT	1,042,933	792,723	(250,209)	22
23	CCFT	92,195	70,077	(22,119)	23
24	State Tax Adjustment	0	0	0	24
25	Current CCFT	92,195	70,077	(22,119)	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	310	310	0	27
28	Deferred Taxes - Vacation	(107)	(107)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(3,012)	(3,012)	0	30
31	Total CCFT	89,386	67,267	(22,119)	31
	FEDERAL TAXES:				
32	CCFT - Prior Year	66,627	68,174	1,548	32
33	Federal Operating Expense Adjustment	5,517	5,517	0	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	706,880	676,970	(29,909)	36
37	Federal Tax Depreciation - Other	0	0	0	37
38	Capitalized Other	67,180	67,180	0	38
39	Repair Allowance	196,982	184,631	(12,351)	39
40	Preferred Dividend Credit	319	319	0	40
41	Subtotal Deductions	1,518,929	1,448,267	(70,662)	41
42	Taxable Income for FIT	1,115,371	886,370	(229,001)	42
43	Federal Income Tax	390,380	310,229	(80,150)	43
44	Deferred Taxes - Reg Asset	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	45
46	Deferred Taxes - Interest	597	597	0	46
47	Deferred Taxes - Vacation	(384)	(384)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	(174,585)	(94,745)	79,841	49
50	Total Federal Income Tax	216,007	215,697	(310)	50

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX C: Table 4-B

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Income Taxes at Proposed Rates - Test Year 2014
Gas Distribution Summary
(Thousands of Dollars)

Line No.	Description	PG&E Request *	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
1	Revenues	1,766,416	1,584,276	(182,140)	1
2	O&M Expenses	841,249	745,206	(96,043)	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	72,822	68,222	(4,601)	5
6	Subtotal	852,345	770,848	(81,496)	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charges	97,496	96,161	(1,335)	7
8	Fiscal/Calendar Adjustment	1,987	1,957	(30)	8
9	Operating Expense Adjustments	(14,930)	(15,580)	(650)	9
10	Capitalized Interest Adjustment	0	0	0	10
11	Removal Costs	51,525	45,875	(5,650)	11
12	Vacation Accrual Reduction	(715)	(715)	0	12
13	Capitalized Other	27,476	22,704	(4,772)	13
14	Subtotal Deductions	162,838	150,401	(12,437)	14
	CCFT TAXES:				
15	State Operating Expense Adjustment	581	581	0	15
16	State Tax Depreciation - Declining Balance	0	0	0	16
17	State Tax Depreciation - Fixed Assets	364,061	358,095	(5,966)	17
18	State Tax Depreciation - Other	0	0	0	18
19	Capitalized Other	445	445	0	19
20	Repair Allowance	86,729	84,444	(2,284)	20
21	Subtotal Deductions	614,653	593,967	(20,687)	21
22	Taxable Income for CCFT	237,691	176,882	(60,809)	22
23	CCFT	21,012	15,636	(5,376)	23
24	State Tax Adjustment	0	0	0	24
25	Current CCFT	21,012	15,636	(5,376)	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	51	51	0	27
28	Deferred Taxes - Vacation	(63)	(63)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(1,625)	(1,625)	0	30
31	Total CCFT	19,375	13,999	(5,376)	31
	FEDERAL TAXES:				
32	CCFT - Prior Year	(1,019)	(602)	417	32
33	Federal Operating Expense Adjustment	932	932	0	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	337,265	324,299	(12,966)	36
37	Federal Tax Depreciation - Other	0	0	0	37
38	Capitalized Other	445	445	0	38
39	Repair Allowance	86,729	84,444	(2,284)	39
40	Preferred Dividend Credit	57	57	0	40
41	Subtotal Deductions	587,247	559,976	(27,270)	41
42	Taxable Income for FIT	265,098	210,872	(54,226)	42
43	Federal Income Tax	92,784	73,805	(18,979)	43
44	Deferred Taxes - Reg Asset	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	45
46	Deferred Taxes - Interest	105	105	0	46
47	Deferred Taxes - Vacation	(228)	(228)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	(25,527)	(7,635)	17,892	49
50	Total Federal Income Tax	67,134	66,047	(1,087)	50

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX C: Table 4-C

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Income Taxes at Proposed Rates - Test Year 2014
Electric Generation Summary
(Thousands of Dollars)

Line No.	Description	PG&E Request *	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
1	Revenues	1,903,335	1,778,734	(124,601)	1
2	O&M Expenses	796,678	726,506	(70,172)	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	85,297	83,773	(1,524)	5
6	Subtotal	1,021,360	968,455	(52,905)	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charges	133,596	122,582	(11,014)	7
8	Fiscal/Calendar Adjustment	1,744	1,700	(44)	8
9	Operating Expense Adjustments	(4,355)	(4,969)	(614)	9
10	Capitalized Interest Adjustment	0	0	0	10
11	Removal Costs	6,548	5,997	(552)	11
12	Vacation Accrual Reduction	(669)	(669)	0	12
13	Capitalized Other	23,590	20,187	(3,403)	13
14	Subtotal Deductions	160,454	144,826	(15,627)	14
	CCFT TAXES:				
15	State Operating Expense Adjustment	10,903	10,903	0	15
16	State Tax Depreciation - Declining Balance	0	0	0	16
17	State Tax Depreciation - Fixed Assets	395,614	392,951	(2,663)	17
18	State Tax Depreciation - Other	0	0	0	18
19	Capitalized Other	8,560	8,560	0	19
20	Repair Allowance	63,694	63,893	199	20
21	Subtotal Deductions	639,224	621,133	(18,091)	21
22	Taxable Income for CCFT	382,135	347,322	(34,814)	22
23	CCFT	33,781	30,703	(3,078)	23
24	State Tax Adjustment	0	0	0	24
25	Current CCFT	33,781	30,703	(3,078)	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	964	964	0	27
28	Deferred Taxes - Vacation	(59)	(59)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(3,658)	(3,658)	0	30
31	Total CCFT	31,028	27,950	(3,078)	31
	FEDERAL TAXES:				
32	CCFT - Prior Year	17,916	19,086	1,170	32
33	Federal Operating Expense Adjustment	14,021	14,021	0	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	312,488	304,674	(7,814)	36
37	Federal Tax Depreciation - Other	0	0	0	37
38	Capitalized Other	8,560	8,560	0	38
39	Repair Allowance	63,694	63,893	199	39
40	Preferred Dividend Credit	2,377	2,377	0	40
41	Subtotal Deductions	579,510	557,438	(22,072)	41
42	Taxable Income for FIT	441,850	411,017	(30,832)	42
43	Federal Income Tax	154,647	143,856	(10,791)	43
44	Deferred Taxes - Reg Asset	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	(318)	(318)	0	45
46	Deferred Taxes - Interest	754	754	0	46
47	Deferred Taxes - Vacation	(214)	(214)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	(29,749)	(32,261)	(2,512)	49
50	Total Federal Income Tax	125,121	111,817	(13,304)	50

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX C: Table 5

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Expenses and Escalation - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Electric Distribution	Gas Distribution	Electric Generation	Total Year 2014	Line No.
		(A)	(B)	(C)	(D)	
	Total Escalated					
1	Energy Cost	0	0	0	0	1
2	Production	0	4,575	595,192	599,767	2
3	Storage	0	0	0	0	3
4	Transmission	1,024	0	4,075	5,100	4
5	Distribution	612,283	352,229	0	964,512	5
6	Customer Accounts	168,086	127,748	0	295,834	6
7	Customer Services	2,556	2,836	0	5,391	7
8	Administrative and General	420,777	232,661	249,322	902,760	8
9	Other	(4,932)	(12,997)	(155,308)	(173,237)	9
10	Total Labor Escalated	1,199,793	707,052	693,282	2,600,126	10
11	Wage Related A&G Escalated	21,833	11,724	12,323	45,880	11
	Total Non-Escalated					
12	Energy Cost	0	0	0	0	12
13	Production	0	4,229	560,207	564,436	13
14	Storage	0	0	0	0	14
15	Transmission	959	0	3,815	4,774	15
16	Distribution	569,650	328,526	0	898,177	16
17	Customer Accounts	154,903	117,733	0	272,636	17
18	Customer Services	2,355	2,623	0	4,978	18
19	Administrative and General	401,180	221,949	237,949	861,079	19
20	Other	(4,932)	(12,997)	(155,308)	(173,237)	20
21	Total Labor Non-Escalated	1,124,115	662,063	646,663	2,432,841	21
22	Wage Related A&G Non-Escalated	19,998	10,738	11,287	42,023	22
	Total Escalation					
23	Energy Cost	0	0	0	0	23
24	Production	0	346	34,985	35,331	24
25	Storage	0	0	0	0	25
26	Transmission	65	0	260	325	26
27	Distribution	42,633	23,702	0	66,335	27
28	Customer Accounts	13,183	10,015	0	23,198	28
29	Customer Services	201	213	0	414	29
30	Administrative and General	19,596	10,712	11,373	41,682	30
31	Other	0	0	0	0	31
32	Total Labor Escalation	75,678	44,988	46,618	167,285	32
33	Wage Related A&G Escalation	1,835	985	1,036	3,857	33

APPENDIX C: Table 6

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Franchise Fees and Uncollectibles - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Electric Distribution (A)	Gas Distribution (B)	Electric Generation (C)	Line No.
	Uncollectible Accounts				
1	Rate Case Revenues	3,862,187	1,584,276	1,778,734	1
2	Percent of Revenue from Customers	0.998200	0.976300	0.998200	2
3	Rate Case Revenues from Customers	3,855,235	1,546,729	1,775,532	3
4	Uncollectible Rate	0.003257	0.003257	0.003257	4
5	Uncollectible Accounts Expense	12,557	5,038	5,783	5
	Franchise Fees				
12	Rate Case Revenues from Customers	3,855,235	1,546,729	1,775,532	12
13	Uncollectible Accounts Expense	12,557	5,038	5,783	13
14	Net Rate Case Revenue from Customers	3,842,678	1,541,691	1,769,749	14
15	Franchise Rate	0.008426	0.013876	0.008426	15
16	Franchise Fees Expense	32,378	21,393	14,912	16

APPENDIX C: Table 7

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Taxes Other Than Income - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Electric Distribution	Gas Distribution	Electric Generation	Total Year 2014	Line No.
		(A)	(B)	(C)	(D)	
	Property (Ad Valorem) Tax:					
1	Fiscal Year Tax	165,309	40,103	52,226	257,638	1
2	Calendar Year Tax	160,014	38,146	50,526	248,686	2
	Payroll Taxes					
3	Federal Insurance Contribution Act (FICA)	33,884	24,636	27,397	85,917	3
4	Federal Unemployment Insurance (FUI)	233	169	188	591	4
5	State Unemployment Insurance (SUI)	2,409	1,751	1,948	6,108	5
6	San Francisco Employee Tax	3,842	2,531	2,676	9,048	6
7	Total Payroll Taxes	40,368	29,088	32,209	101,664	7
	Other Taxes					
8	Business	441	237	249	926	8
9	Hazardous Waste	0	0	0	0	9
10	Windfall Profits	0	0	0	0	10
11	Other	1,398	751	789	2,939	11
12	Total Other Taxes	1,839	988	1,038	3,865	12
13	Total Taxes Other Than Income	202,221	68,222	83,773	354,215	13

APPENDIX C: Table 8

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Working Cash Capital - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Electric Distribution	Gas Distribution	Electric Generation	Total Year 2014	Line No.
		(A)	(B)	(C)	(D)	
	Operational Cash Requirements:					
1	Required Bank Balances	0	0	0	0	1
2	Special Deposits and Working Funds	57	30	31	119	2
3	Other Receivables	58,040	30,958	32,003	121,001	3
4	Prepayments	36,540	19,621	20,623	76,783	4
5	Deferred Debits, Company-Wide	750	400	414	1,563	5
	Less:					
6	Working Cash Capital not Supplied by Investors	6,085	3,267	3,434	12,787	6
7	Goods Delivered to Construction Sites	4,588	2,463	2,589	9,640	7
8	Accrued Vacation	63,657	46,283	51,470	161,410	8
	Add:					
9	Prepayment, Departmental	(4,518)	(1,015)	14,865	9,332	9
10	Total Operational Cash Requirement	16,539	(2,020)	10,442	24,962	10
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	130,575	73,758	144,068	348,401	11
12	Working Cash Capital Supplied by Investors	147,114	71,738	154,510	373,362	12

APPENDIX C: Table 9

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Year 2014 Lead Lag Study at Proposed Rates - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.		Amount (A)	Average Daily Amount (B)	Avg No of Days Lag in Paying Expenses (C)	Weighted Average (D)	Rate Base Impact (E)	Line No.
1	Natural Gas Purchased	1,316,858	3,608	39.88	143,862	12,419	1
2	Fuel Oil	1,107	3	35.46	108	24	2
3	Geothermal Steam	0	0	0.00	0	0	3
4	Nuclear Fuel	128,284	351	30.00	10,544	4,680	4
5	Purchased Power	3,601,176	9,866	36.09	356,071	71,306	5
6	Depreciation	1,916,853	5,252	0.00	0	227,487	6
7	Decommissioning	36,085	99	28.97	2,865	1,418	7
8	Federal Income Tax, Current @ Proposed	527,891	1,446	74.52	107,777	(45,128)	8
9	State Corp. Franchise Tax @ Proposed	116,416	319	52.96	16,891	(3,075)	9
10	Income Taxes, Deferred	(132,915)	(364)	0.00	0	(15,774)	10
11	Ad Valorem Tax	248,686	681	42.46	28,930	584	11
12	S.F. Payroll Expense Tax	12,913	35	88.33	3,125	(1,593)	12
13	FICA Tax (net of STIP)	82,304	225	12.59	2,838	6,929	13
14	Federal Unemployment Tax	591	2	74.67	121	(51)	14
15	State Unemployment Tax	6,108	17	74.18	1,241	(517)	15
16	Settlements and Claims	50,032	137	42.95	5,888	50	16
17	Pensions	169,690	465	58.64	27,260	(7,122)	17
18	Savings Fund Plan	44,513	122	11.59	1,413	3,870	18
19	Group Life Insurance	404	1	2.43	3	45	19
20	Health, Vision & Dental Plans	220,737	605	(4.03)	(2,440)	28,636	20
21	Post-Retirement Medical	42,507	116	179.50	20,904	(15,860)	21
22	Franchise Requirements	67,961	186	243.76	45,387	(37,321)	22
23	Payroll (net of STIP)	1,263,948	3,463	11.98	41,484	108,518	23
24	Goods and Services	687,873	1,885	26.00	48,996	32,639	24
25	Materials from Storeroom	34,131	94	0.00	0	4,051	25
26	FICA Tax (STIP)	3,613	10	251.50	2,489	(2,061)	26
27	Short-Term Incentive Plan (STIP)	55,485	152	250.81	38,127	(31,542)	27
28	CPUC Fees	24,140	66	61.63	4,076	(1,211)	28
29	Project Amortization	58,975	162	0.00	0	6,999	29
30	Total	10,586,368	29,004	31.30	907,959	348,401	30
31	Avg No of Days Lag in the Collection of Revenue			43.32			31
32	Less Avg No of Days Lag in the Payment of Exps			31.30			32
33	Excess No. of Days Lag in the Collection of Revenues over the Payment of Expenses			12.01			33
34	Average Daily Operating Expenses		29,004				34
35	Working Cash Capital Requirement Resulting from the Lag in the Collection of Revenues Being Greater than the Lag in the Payment of Expenses					348,401	35

APPENDIX C: Table 9-A

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Year 2014 Lead Lag Study at Proposed Rates - Test Year 2014
Electric Distribution Summary
(Thousands of Dollars)

Line No.		Amount (A)	Average Daily Amount (B)	Avg No of Days Lag in Paying Expenses (C)	Weighted Average (D)	Rate Base Impact (E)	Line No.
1	Natural Gas Purchased	0	0	39.88	0	0	1
2	Fuel Oil	0	0	35.46	0	0	2
3	Geothermal Steam	0	0	0.00	0	0	3
4	Nuclear Fuel	0	0	30.00	0	0	4
5	Purchased Power	0	0	36.09	0	0	5
6	Depreciation	1,076,793	2,950	0.00	0	127,791	6
7	Decommissioning	0	0	28.97	0	0	7
8	Federal Income Tax, Current @ Proposed	310,229	850	74.52	63,338	(26,521)	8
9	State Corp. Franchise Tax @ Proposed	70,077	192	52.96	10,167	(1,851)	9
10	Income Taxes, Deferred	(94,329)	(258)	0.00	0	(11,195)	10
11	Ad Valorem Tax	160,014	438	42.46	18,614	376	11
12	S.F. Payroll Expense Tax	5,681	16	88.33	1,375	(701)	12
13	FICA Tax (net of STIP)	32,165	88	12.59	1,109	2,708	13
14	Federal Unemployment Tax	233	1	74.67	48	(20)	14
15	State Unemployment Tax	2,409	7	74.18	490	(204)	15
16	Settlements and Claims	23,809	65	42.95	2,802	24	16
17	Pensions	80,752	221	58.64	12,973	(3,389)	17
18	Savings Fund Plan	21,183	58	11.59	672	1,842	18
19	Group Life Insurance	192	1	2.43	1	22	19
20	Health, Vision & Dental Plans	105,045	288	(4.03)	(1,161)	13,627	20
21	Post-Retirement Medical	20,228	55	179.50	9,948	(7,547)	21
22	Franchise Requirements	31,613	87	243.76	21,112	(17,361)	22
23	Payroll (net of STIP)	493,954	1,353	11.98	16,212	42,409	23
24	Goods and Services	385,921	1,057	26.00	27,488	18,312	24
25	Materials from Storeroom	19,149	52	0.00	0	2,273	25
26	FICA Tax (STIP)	1,719	5	251.50	1,185	(981)	26
27	Short-Term Incentive Plan (STIP)	26,404	72	250.81	18,144	(15,010)	27
28	CPUC Fees	19,982	55	61.63	3,374	(1,003)	28
29	Project Amortization	58,768	161	0.00	0	6,974	29
30	Total	2,851,993	7,814	26.61	207,892	130,575	30
31	Avg No of Days Lag in the Collection of Revenue			43.32			31
32	Less Avg No of Days Lag in the Payment of Exps			26.61			32
33	Excess No. of Days Lag in the Collection of Revenues over the Payment of Expenses			16.71			33
34	Average Daily Operating Expenses		7,814				34
35	Working Cash Capital Requirement Resulting from the Lag in the Collection of Revenues Being Greater than the Lag in the Payment of Expenses					130,575	35

APPENDIX C: Table 9-B

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Year 2014 Lead Lag Study at Proposed Rates - Test Year 2014
Gas Distribution Summary
(Thousands of Dollars)

Line No.		Amount (A)	Average Daily Amount (B)	Avg No of Days Lag in Paying Expenses (C)	Weighted Average (D)	Rate Base Impact (E)	Line No.
1	Natural Gas Purchased	1,135,500	3,111	39.88	124,050	10,708	1
2	Fuel Oil	0	0	35.46	0	0	2
3	Geothermal Steam	0	0	0.00	0	0	3
4	Nuclear Fuel	0	0	30.00	0	0	4
5	Purchased Power	0	0	36.09	0	0	5
6	Depreciation	392,120	1,074	0.00	0	46,536	6
7	Decommissioning	0	0	28.97	0	0	7
8	Federal Income Tax, Current @ Proposed	73,805	202	74.52	15,068	(6,309)	8
9	State Corp. Franchise Tax @ Proposed	15,636	43	52.96	2,269	(413)	9
10	Income Taxes, Deferred	(7,770)	(21)	0.00	0	(922)	10
11	Ad Valorem Tax	38,146	105	42.46	4,438	90	11
12	S.F. Payroll Expense Tax	3,518	10	88.33	851	(434)	12
13	FICA Tax (net of STIP)	23,713	65	12.59	818	1,996	13
14	Federal Unemployment Tax	169	0	74.67	35	(15)	14
15	State Unemployment Tax	1,751	5	74.18	356	(148)	15
16	Settlements and Claims	12,785	35	42.95	1,504	13	16
17	Pensions	43,361	119	58.64	6,966	(1,820)	17
18	Savings Fund Plan	11,375	31	11.59	361	989	18
19	Group Life Insurance	103	0	2.43	1	12	19
20	Health, Vision & Dental Plans	56,406	155	(4.03)	(623)	7,317	20
21	Post-Retirement Medical	10,862	30	179.50	5,342	(4,053)	21
22	Franchise Requirements	21,508	59	243.76	14,363	(11,811)	22
23	Payroll (net of STIP)	364,160	998	11.98	11,952	31,265	23
24	Goods and Services	179,074	491	26.00	12,755	8,497	24
25	Materials from Storeroom	8,885	24	0.00	0	1,054	25
26	FICA Tax (STIP)	923	3	251.50	636	(527)	26
27	Short-Term Incentive Plan (STIP)	14,178	39	250.81	9,743	(8,060)	27
28	CPUC Fees	4,158	11	61.63	702	(209)	28
29	Project Amortization	0	0	0.00	0	0	29
30	Total	2,404,370	6,587	32.12	211,586	73,758	30
31	Avg No of Days Lag in the Collection of Revenue			43.32			31
32	Less Avg No of Days Lag in the Payment of Exps			32.12			32
33	Excess No. of Days Lag in the Collection of Revenues over the Payment of Expenses			11.20			33
34	Average Daily Operating Expenses		6,587				34
35	Working Cash Capital Requirement Resulting from the Lag in the Collection of Revenues Being Greater than the Lag in the Payment of Expenses					73,758	35

APPENDIX C: Table 9-C

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Year 2014 Lead Lag Study at Proposed Rates - Test Year 2014
Electric Generation Summary
(Thousands of Dollars)

Line No.		Amount (A)	Average Daily Amount (B)	Avg No of Days Lag in Paying Expenses (C)	Weighted Average (D)	Rate Base Impact (E)	Line No.
1	Natural Gas Purchased	181,357	497	39.88	19,813	1,710	1
2	Fuel Oil	1,107	3	35.46	108	24	2
3	Geothermal Steam	0	0	0.00	0	0	3
4	Nuclear Fuel	128,284	351	30.00	10,544	4,680	4
5	Purchased Power	3,601,176	9,866	36.09	356,071	71,306	5
6	Depreciation	447,940	1,227	0.00	0	53,160	6
7	Decommissioning	36,085	99	28.97	2,865	1,418	7
8	Federal Income Tax, Current @ Proposed	143,856	394	74.52	29,370	(12,298)	8
9	State Corp. Franchise Tax @ Proposed	30,703	84	52.96	4,455	(811)	9
10	Income Taxes, Deferred	(30,816)	(84)	0.00	0	(3,657)	10
11	Ad Valorem Tax	50,526	138	42.46	5,878	119	11
12	S.F. Payroll Expense Tax	3,714	10	88.33	899	(458)	12
13	FICA Tax (net of STIP)	26,427	72	12.59	911	2,225	13
14	Federal Unemployment Tax	188	1	74.67	39	(16)	14
15	State Unemployment Tax	1,948	5	74.18	396	(165)	15
16	Settlements and Claims	13,438	37	42.95	1,581	13	16
17	Pensions	45,576	125	58.64	7,322	(1,913)	17
18	Savings Fund Plan	11,956	33	11.59	380	1,039	18
19	Group Life Insurance	109	0	2.43	1	12	19
20	Health, Vision & Dental Plans	59,287	162	(4.03)	(655)	7,691	20
21	Post-Retirement Medical	11,417	31	179.50	5,615	(4,260)	21
22	Franchise Requirements	14,840	41	243.76	9,911	(8,150)	22
23	Payroll (net of STIP)	405,834	1,112	11.98	13,320	34,843	23
24	Goods and Services	122,877	337	26.00	8,752	5,830	24
25	Materials from Storeroom	6,097	17	0.00	0	724	25
26	FICA Tax (STIP)	970	3	251.50	669	(553)	26
27	Short-Term Incentive Plan (STIP)	14,902	41	250.81	10,240	(8,472)	27
28	CPUC Fees	0	0	61.63	0	0	28
29	Project Amortization	207	1	0.00	0	25	29
30	Total	5,330,005	14,603	33.45	488,481	144,068	30
31	Avg No of Days Lag in the Collection of Revenue			43.32			31
32	Less Avg No of Days Lag in the Payment of Exps			33.45			32
33	Excess No. of Days Lag in the Collection of Revenues over the Payment of Expenses			9.87			33
34	Average Daily Operating Expenses		14,603				34
35	Working Cash Capital Requirement Resulting from the Lag in the Collection of Revenues Being Greater than the Lag in the Payment of Expenses					144,068	35

APPENDIX C: Table 10

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Rate Base - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Electric Distribution	Gas Distribution	Electric Generation	Total Year 2014	Line No.
		(A)	(B)	(C)	(D)	
	WEIGHTED AVERAGE PLANT:					
1	Plant Beginning Of Year (BOY)	25,159,013	8,857,514	13,462,357	47,478,884	1
2	Net Additions	622,607	346,441	205,481	1,174,529	2
3	Total Weighted Average Plant	25,781,619	9,203,955	13,667,838	48,653,413	3
	WORKING CAPITAL:					
4	Material and Supplies - Fuel	0	0	0	0	4
5	Material and Supplies - Other	64,127	9,634	132,693	206,453	5
6	Working Cash	147,114	71,738	154,510	373,362	6
7	Total Working Capital	211,241	81,371	287,203	579,815	7
	ADJUSTMENTS FOR TAX REFORM ACT:					
8	Deferred Capitalized Interest	999	608	12,246	13,853	8
9	Deferred Vacation	18,100	10,744	10,051	38,895	9
10	Deferred CIAC Tax Effects	247,864	86,964	0	334,828	10
11	Total Adjustments	266,963	98,315	22,297	387,576	11
12	CUSTOMER ADVANCES	82,789	39,653	0	122,442	12
	DEFERRED TAXES					
13	Accumulated Regulatory Assets	0	0	(19,146)	(19,146)	13
14	Accumulated Fixed Assets	3,166,273	766,411	999,979	4,932,663	14
15	Accumulated Other	0	0	0	0	15
16	Deferred ITC	37,368	18,503	20,570	76,442	16
17	Deferred Tax - Other	0	0	0	0	17
18	Total Deferred Taxes	3,203,642	784,914	1,001,404	4,989,959	18
19	DEPRECIATION RESERVE	10,875,723	4,852,607	8,251,077	23,979,407	19
20	TOTAL Ratebase	12,097,670	3,706,468	4,724,858	20,528,996	20

APPENDIX C: Table 11

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Net-to-Gross Multiplier - Test Year 2014
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Electric Distribution	Gas Distribution	Electric Generation	Line No.
		(A)	(B)	(C)	
1	Revenue Base	1.000000	1.000000	1.000000	1
2	Less Interdepartmental Revenue	0.001800	0.023700	0.001800	2
3	Percent Revenue From Jurisdictional Customers	0.998200	0.976300	0.998200	3
4	Uncollectibles Percentage	0.003251	0.003180	0.003251	4
5	Franchise Requirements	0.008383	0.013503	0.008383	5
6	Total Uncollectibles and Franchise Requirements	0.011635	0.016683	0.011635	6
7	Net For State Income Taxes	0.988365	0.983317	0.988365	7
8	State Income Tax Percentage	0.088400	0.088400	0.088400	8
9	State Income Taxes	0.087372	0.086925	0.087372	9
10	Net For Federal Income Taxes	0.988365	0.983317	0.988365	10
11	Federal Income Tax Percentage	0.350000	0.350000	0.350000	11
12	Federal Income Taxes	0.345928	0.344161	0.345928	12
13	Net Operating Revenue	0.555066	0.552231	0.555066	13
14	Net To Gross Multiplier	1.801587	1.810837	1.801587	14

APPENDIX C: Table 12

Pacific Gas and Electric Company

2014 CPUC General Rate Case (GRC)

Net Salvage Comparison Summary

				Net Salvage		
Line No.	Asset Asset Class	FERC Acct.	Description	PG&E Current Authorized (%)	PG&E Proposed (%)	Adopted (%)
				(A)	(B)	(C)
	ELECTRIC DEPARTMENT					
1	ETC35301	353.01	Station Equipment	(30)	(60)	(55)
2	NTP35301	353.01	Station Equipment	(30)	(60)	(55)
3	ETC35400	354	Towers & Fixtures	(60)	(110)	(75)
4	ETP35401	354.01	Towers & Fixtures (Combined Cycle)	(80)	(110)	(88)
5	EDP36200	362	Station Equipment	(15)	(40)	(21)
6	EDP36400	364	Poles, Towers, & Fixtures	(80)	(150)	(105)
7	EDP36500	365	OH Conductors & Devices	(77)	(200)	(108)
8	EDP36600	366	Underground Conduit	(20)	(100)	(40)
9	EDP36700	367	UG Conductors & Devices	(40)	(50)	(43)
10	EDP36801	368.01	Line Transformers-Overhead	(6)	(25)	(11)
11	EDP36901	369.01	Services-Overhead	(75)	(135)	(90)
12	EDP37000	370	Meters	(15)	(20)	(16)
13	EDP37001	370.01	SmartMeters™	(5)	(20)	(9)
14	EDP37303	373.03	Street Light-Lamps & Equipment	(5)	(65)	(20)
	GAS DEPARTMENT					
15	GDP37601	376	Mains	(52)	(65)	(55)
16	GDP38000	380	Services	(105)	(180)	(124)
17	GDP38100	381	Meters	(5)	(25)	(10)
	COMMON PLANT					
18	CMP39000	390	Structures & Improvements	(10)	(10)	(10)

APPENDIX C: Table 13
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Net Salvage and Accrual Rates

Line No.	Asset Class	FERC Acct.	Description	Avg. Service Life (Yrs) Adopted as Proposed	Curve Type Adopted as Proposed	Net Salvage (%) PG&E Proposed	Net Salvage (%) Adopted	Accrual Rates (%) PG&E Proposed	Accrual Rates (%) Adopted
	ELECTRIC DEPARTMENT								
		INTANGIBLE PLANT							
1	EIP30201	302.01	Franchises and Consents	40	SQ	0	0	2.17	2.17
2	EIP30301	303.01	USBR - Limited Term Electric	Fully Accrued		0	0	0.00	0.00
3	EIP30303	303.03	Software	5	SQ	0	0	9.00	9.00
		STEAM PRODUCTION PLANT							
		Steam Production Plant - Combined Cycle							
4	ESF31103	311.03	Structures & Improvements	75	L0	0	0	3.63	3.63
5	ESF31203	312.03	Boiler Plant Equipment	50	R1	0	0	3.70	3.70
6	ESF31205	312.05	Boiler Plant Equipment	50	R1			3.62	3.62
7	ESF31403	314.03	Turbogenerator Units	40	R2.5	0	0	3.58	3.58
8	ESF31503	315.03	Accessory Electrical Equipment	45	R2.5	0	0	3.51	3.51
9	ESF31603	316.03	Miscellaneous Power Plant Equipment	40	S0.5	0	0	3.76	3.76
		Steam Production Plant - Other Steam Production							
10	ESF31101	311	Structures & Improvements			0	0	8.36	8.36
11	ESF31201	312	Boiler Plant Equipment			0	0	8.36	8.36
12	ESF31301	313	Engines and Engine-Driven Generators			0	0	8.36	8.36
13	ESF31401	314	Turbogenerator Units			0	0	8.36	8.36
14	ESF31501	315	Accessory Electrical Equipment			0	0	8.36	8.36
15	ESF31601	316	Miscellaneous Power Plant Equipment			0	0	8.36	8.36
		NUCLEAR PRODUCTION PLANT							
		Diablo Canyon 2001 & Prior							
16	ENP32100	321	Structures & Improvements	100	R1	(1)	(1)	0.04	0.04
17	ENP32200	322	Reactor Plant Equipment	60	R1	(1)	(1)	0.19	0.19
18	ENP32300	323	Turbogenerator Units	40	R3	(1)	(1)	0.06	0.06
19	ENP32400	324	Accessory Electrical Equipment	75	R1.5	(1)	(1)	0.05	0.05
20	ENP32500	325	Miscellaneous Power Plant Equipment	40	R4	(2)	(2)	0.15	0.15
		Diablo Canyon 2002 & Subsequent							
21	ENP32102	321.02	Structures & Improvements	100	R1	(1)	(1)	7.48	7.48
22	ENP32201	322.01	Reactor Plant Equipment			0	0	6.85	6.85
23	ENP32202	322.02	Reactor Plant Equipment	60	R1	(1)	(1)	6.85	6.85
24	ENP32302	323.02	Turbogenerator Units	40	R3	(1)	(1)	7.27	7.27
25	ENP32402	324.02	Accessory Electrical Equipment	75	R1.5	(1)	(1)	7.58	7.58
26	ENP32502	325.02	Miscellaneous Power Plant Equipment	40	R4	(2)	(2)	7.50	7.50
		HYDRO PRODUCTION PLANT							
		Hydroelectric Production - Excluding Helms Pumped Storage							
27	EHP33101	331	Structures & Improvements					1.48	1.48
28	EHP33102	331	Structures & Improvements					1.48	1.48
29	EHP33103	331	Structures & Improvements	100	S2.5	(1)	(1)	1.48	1.48
30	EHP33201	332	Reservoirs, Dams & Waterways					1.61	1.61
31	EHP33202	332	Reservoirs, Dams & Waterways					1.61	1.61
32	EHP33203	332	Reservoirs, Dams & Waterways	100	S2.5	(2)	(2)	1.61	1.61
33	EHP33300	333	Waterwheels, Turbines & Generators	50	R1.5	(6)	(6)	2.50	2.50
34	EHP33400	334	Accessory Electrical Equipment	50	R1.5	(9)	(9)	3.62	3.62
35	EHP33500	335	Miscellaneous Power Plant Equipment	40	R2	(14)	(14)	4.50	4.50
36	EHP33600	336	Roads, Railroads & Bridges	65	R1.5	(3)	(3)	2.80	2.80
		Hydroelectric Production - Helms Pumped Storage							
37	EHH33101	331	Structures & Improvements	100	S2.5	(1)	(1)	0.17	0.17
38	EHH33201	332	Reservoirs, Dams & Waterways	100	S2.5	(2)	(2)	0.10	0.10
39	EHH33300	333	Waterwheels, Turbines & Generators	50	R1.5	(6)	(6)	1.49	1.49
40	EHH33400	334	Accessory Electrical Equipment	50	R1.5	(9)	(9)	1.77	1.77
41	EHH33500	335	Miscellaneous Power Plant Equipment	40	R2	(14)	(14)	1.25	1.25
42	EHH33600	336	Roads, Railroads & Bridges	65	R1.5	(3)	(3)	0.37	0.37
		OTHER PRODUCTION PLANT							
		Other Production - Combined Cycle							
43	EOP34101	341.01	Structures & Improvements	70	R1	0	0	3.59	3.59
44	EOP34201	342.01	Fuel Holders, Producers and Accessories	50	R1	0	0	3.71	3.71
45	EOP34301	343.01	Prime Movers	40	R2.5	0	0	3.59	3.59
46	EOP34401	344.01	Generators	40	R2.5	0	0	4.05	4.05
47	EOP34501	345.01	Accessory Electrical Equipment	45	R2.5	0	0	3.53	3.53
48	EOP34601	346.01	Miscellaneous Power Plant Equipment	40	S0.5	0	0	3.76	3.76
		Other Production - Solar							
49	EOP34102	341	Solar Struc & Impr			0	0	4.00	4.00
50	EOP34402	344	Solar Gen Equip			0	0	4.00	4.00
51	EOP34403	344	Sol Gen Treas Grants			0	0	4.00	4.00
52	EOP34502	345	Solar Inverter			0	0	4.00	4.00
53	EOP34503	345	Solar Acc Elect Eq			0	0	4.00	4.00
54	EOP34602	346	Miscellaneous Equipment		Square	0	0	3.97	3.97
55									
56		*Other Production - Fuel Cell*							
57	EOP34404	344.04	Generators - Fuel Cell		Square	0	0	10.06	10.06

APPENDIX C: Table 13
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Net Salvage and Accrual Rates

Line No.	Asset Class		FERC Acct.	Description	Avg. Service Life (Yrs) Adopted as Proposed	Curve Type Adopted as Proposed	Net Salvage (%) PG&E Proposed	Net Salvage (%) Adopted	Accrual Rates (%) PG&E Proposed	Accrual Rates (%) Adopted
				TRANSMISSION PLANT						
				Non-Network Transmission Plant (excluding Diablo Canyon) (ETC)						
58	ETC35201		352.01	Structures & Improvements	60	R5	(20)	(20)	1.94	1.94
59	ETC35301	(a)	353.01	Station Equipment	43	R1.5	(60)	(55)	3.88	3.73
60	ETC35302		353.02	Step Up Transformers	43	R5	0	0	1.26	1.26
61	ETC35400	(a)	354	Towers & Fixtures	70	R4	(110)	(75)	3.19	2.41
62	ETC35500		355	Poles & Fixtures	48	R2	(75)	(75)	3.25	3.25
63	ETC35600		356	OH Conductor/Devices - Twr/Pl Ln	55	R3	(80)	(80)	2.92	2.92
64	ETC35700		357	UG Conduit	60	R5	0	0	1.15	1.15
65	ETC35800		358	UG Conductor/Devices	57	R5	0	0	1.01	1.01
66	ETC35900		359	Roads & Trails	57	R2	(10)	(10)	2.20	2.20
				Non-Network Transmission Plant Combined Cycle (excluding Diablo Canyon) (ETCG)						
67	ETP35303		353.03	Station Equipment - Step Up Transformers (Combined Cycle)	43	R5	0	0	3.29	3.29
68	ETP35401	(a)	354.01	Towers and Fixtures (Combined Cycle)	70	R4	(110)	(88)	7.11	6.32
69	ETP35601		356.01	OH Conductors and Devices (Combined Cycle)	55	R3	(80)	(80)	6.10	6.10
				Transmission Plant - Diablo Canyon						
70	NTP35201		352.01	Structures & Improvements	60	R5	(20)	(20)	1.37	1.37
71	NTP35202		352.02	Structures & Improvements-Equipment	60	R5	(20)	(20)	1.37	1.37
72	NTP35301	(a)	353.01	Station Equipment	43	R1.5	(60)	(55)	4.42	4.03
73	NTP35302		353.02	Step-up Transformers	43	R5	0	0	2.88	2.88
				DISTRIBUTION PLANT						
74	EDP36101		361.01	Structures & Improvements	55	S5	(20)	(20)	2.24	2.24
75	EDP36102		361.02	Structures & Improvements - Equipment	55	S5	(20)	(20)	2.30	2.30
76	EDP36200	(a)	362	Station Equipment	42	R2	(40)	(21)	3.52	2.93
77	EDP36300		363	Storage Battery Equipment	20	R2	0	0	5.43	5.43
78	EDP36400	(a)	364	Poles, Towers, & Fixtures	42	R1.5	(150)	(105)	6.47	5.03
79	EDP36500	(a)	365	OH Conductors & Devices	42	R2	(200)	(108)	8.23	5.21
80	EDP36600	(a)	366	Underground Conduit	54	R4	(100)	(40)	4.46	2.91
81	EDP36700	(a)	367	UG Conductors & Devices	42	R3	(50)	(43)	3.35	3.08
82	EDP36801	(a)	368.01	Line Transformers - Overhead	32	R2.5	(25)	(11)	4.29	3.64
83	EDP36802		368.02	Line Transformers - Underground	29	R3	5	5	3.29	3.29
84	EDP36901	(a)	369.01	Services - Overhead	49	R3	(135)	(90)	4.98	3.60
85	EDP36902		369.02	Services - Underground	44	R4	(45)	(45)	3.30	3.30
86	EDP37000		370.00	Meters			(20)	(16)	0.00	0.00
87	EDP37001	(a)	370.01	SmartMeters™	20	R1.5	(20)	(9)	6.36	5.75
88	EDP37100		371	Installations on Customers' Premises	40	S1	0	0	0.00	0.00
89	EDP37200		372	Leased Property on Customers' Premises	16	S1	0	0	0.00	0.00
90	EDP37301		373.01	St. Lighting & Signal Sys. - OH Conductor	30	R0.5	(50)	(50)	3.57	3.57
91	EDP37302		373.02	St. Lighting & Signal Sys. - Conduit & Cable	25	S6	(20)	(20)	5.61	5.61
92	EDP37303	(a)	373.03	St. Lighting & Signal Sys. - Lamps & Equipment	25	L0	(65)	(20)	6.36	3.37
93	EDP37304		373.04	St. Lighting & Signal Sys. - Electroliers	24	L3	(25)	(25)	4.16	4.16
				GENERAL PLANT						
				General Plant (excluding Diablo Canyon)						
94	EGP39000		390	Structures & Improvements	40	R3	(10)	(10)	2.08	2.08
95	EGP39100		391	Office Furniture & Equipment	20	SQ	0	0	7.20	7.20
96	EGP39400		394	Tools, Shop & Garage Equipment	25	SQ	0	0	3.66	3.66
97	EGP39500		395	Laboratory Equipment	20	SQ	0	0	9.49	9.49
98	EGP39600		396	Power Operated Equipment	20	SQ	0	0	6.34	6.34
99	EGP39700		397	Communication Equipment	15	SQ	0	0	5.03	5.03
100	EGP39708		397.08	AMI Communication Network	20	SQ	0	0	5.24	5.24
101	EGP39800		398	Miscellaneous Equipment	20	SQ	0	0	13.75	13.75
				Nuclear General Plant - Diablo Canyon						
102	NGP39100		391	Office Furniture & Equipment	20	SQ	0	0	5.13	5.13
103	NGP39800		398	Miscellaneous Equipment	20	SQ	0	0	5.13	5.13

APPENDIX C: Table 13
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Net Salvage and Accrual Rates

Line No.	Asset Class		FERC Acct.	Description	Avg. Service Life (Yrs) Adopted as Proposed	Curve Type Adopted as Proposed	Net Salvage (%) PG&E Proposed	Net Salvage (%) Adopted	Accrual Rates (%) PG&E Proposed	Accrual Rates (%) Adopted
	GAS DEPARTMENT									
			INTANGIBLE PLANT							
104	GIP30202		302.02	Franchises and Consents	57	SQ	0	0	7.75	7.75
105	GIP30302		303.02	Software	5	SQ	0	0	7.42	7.42
			LOCAL STORAGE PLANT							
106	GLS36101		361.01	Structures & Improvements	31	R1.5	(5)	(5)	2.77	2.77
107	GLS36200		362	Gas Holders	48	S2	(15)	(15)	3.70	3.70
108	GLS36300		363	Purification Equipment	25	S1	0	0	3.13	3.13
109	GLS36330		363.3	Compressor Equipment	25	S1	0	0	1.77	1.77
110	GLS36340		363.4	Measuring & Regulating Equipment	30	R0.5	0	0	3.13	3.13
111	GLS36350		363.5	Other Equipment	26	R0.5	0	0	2.18	2.18
			DISTRIBUTION PLANT							
112	GDP37500		375	Structures & Improvements	60	R3	(5)	(5)	1.74	1.74
113	GDP37601	(a)	376	Mains	57	R3	(65)	(55)	2.75	2.51
114	GDP37700		377	Compressor Station Equipment	32	R2	0	0	3.02	3.02
115	GDP37800		378	Measuring and Regulating Station Equipment	52	R2.5	(35)	(35)	2.13	2.13
116	GDP38000	(a)	380	Services	54	R4	(180)	(124)	5.36	3.84
117	GDP38100	(a)	381	Meters	24	R4	(25)	(10)	6.26	5.29
118	GDP38300		383	House Regulators	25	R2	(5)	(5)	3.69	3.69
119	GDP38500		385	Industrial Measuring and Regulating Equipment	42	R5	(10)	(10)	2.13	2.13
120	GDP38600		386	Other Property on Customer Premises	35	R2	0	0	2.48	2.48
121	GDP38700		387	Other Equipment	29	S1.5	5	5	2.15	2.15
			GENERAL PLANT (EXCLUDING LINE 401 AND STANPAC)							
122	GGP39000		390	Structures & Improvements	40	R3	(10)	(10)	2.44	2.44
123	GGP39100		391	Office Furniture & Equipment	20	SQ	0	0	11.30	11.30
124	GGP39400		394	Tools, Shop and Work Equipment	25	SQ	0	0	4.33	4.33
125	GGP39500		395	Laboratory Equipment	20	SQ	0	0	13.53	13.53
126	GGP39600		396	Power Operated Equipment	20	SQ	0	0	40.82	40.82
127	GGP39708		397.08	Communication Equipment - AMI	20	SQ	0	0	5.04	5.04
128	GGP39800		398	Miscellaneous Equipment	20	SQ	0	0	7.67	7.67
129	GGP39900		399	Other Tangible Property	20	SQ	0	0	56.47	56.47

APPENDIX C: Table 13
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted Net Salvage and Accrual Rates

Line No.	Asset Class	FERC Acct.	Description	Avg. Service Life (Yrs) Adopted as Proposed	Curve Type Adopted as Proposed	Net Salvage (%) PG&E Proposed	Net Salvage (%) Adopted	Accrual Rates (%) PG&E Proposed	Accrual Rates (%) Adopted
	COMMON PLANT								
130	CMP30302	303.02	Software	5	SQ	0	0	24.62	24.62
131	CMP30304	303.04	Software CIS	15	SQ	0	0	6.58	6.58
132	CMP39000	390	Structures & Improvements	40	R3	(10)	(10)	2.74	2.74
133	CMP39101	391.01	Office Machines and Computer Equipment	5	SQ	0	0	18.35	18.35
134	CMP39102	391.02	PC Hardware	5	SQ	0	0	29.63	29.63
135	CMP39103	391.03	Office Furniture & Equipment	20	SQ	0	0	9.66	9.66
136	CMP39104	391.04	Office Machines and Computer Equipment - CIS	15	SQ	0	0	6.49	6.49
137	CMP39201	392.01	Transportation Equipment - Air	13	SQ	50	50	1.46	1.46
138	CMP39202	392.02	Transportatioin Equipment - Class P	8	L3	10	10	7.13	7.13
139	CMP39203	392.03	Transportation Equipment - Class C2	9	S2.5	10	10	6.22	6.22
140	CMP39204	392.04	Transportation Equipment - Class C4	9	S2.5	10	10	7.70	7.70
141	CMP39205	392.05	Transportation Equipment - Class T1	11	S2.5	10	10	9.80	9.80
142	CMP39206	392.06	Transportation Equipment - Class T3	11	S2.5	10	10	8.06	8.06
143	CMP39207	392.07	Transportation Equipment - Class T4	15	L4	10	10	5.50	5.50
144	CMP39208	392.08	Transportation Equipment - Vessels	14	L1	10	10	0.00	0.00
145	CMP39209	392.09	Transportation Equipment - Trailers	21	L1	10	10	1.36	1.36
146	CMP39300	393	Stores Equipment	20	SQ	0	0	8.68	8.68
147	CMP39400	394	Tools, Shop & Garage Equipment	25	SQ	0	0	2.96	2.96
148	CMP39500	395	Laboratory Equipment	20	SQ	0	0	7.64	7.64
149	CMP39600	396	Power Operated Equipment	14	L2	20	20	6.63	6.63
150	CMP39701	397.01	Communications Equipment - Non-Computer	7	SQ	0	0	16.29	16.29
151	CMP39702	397.02	Communications Equipment - Computer	5	SQ	0	0	20.33	20.33
152	CMP39703	397.03	Communications Equipment - Radio Systems	7	SQ	0	0	14.49	14.49
153	CMP39704	397.04	Communications Equipment - Voice Systems	7	SQ	0	0	13.99	13.99
154	CMP39705	397.05	Communications Equipment - Trans Systems	20	SQ	0	0	4.70	4.70
155	CMP39706	397.06	Communication Equipment - Trans Systems, Gas AMI	20	SQ	0	0	5.01	5.01
156	CMP39708	397.08	AMI Communication Network	20	SQ	0	0	5.00	5.00
157	CMP39800	398	Miscellaneous Equipment	20	SQ	0	0	7.33	7.33
158	CMP39900	399	Other Tangible Property	20	SQ	0	0	60.63	60.63
	COMMON NUCLEAR PLANT								
159	CNP30302	303.02	DCPP Software	10	SQ	0	0	13.81	13.81
160	CNP39000	390	Structures & Improvements	40	R3	(10)	(10)	1.67	1.67
161	CNP39101	391.01	Office Machines & Computer Equipment	5	SQ	0	0	43.86	43.86
162	CNP39102	391.02	PC Hardware	5	SQ	0	0	143.58	143.58
163	CNP39103	391.03	Office Furniture & Equipment	20	SQ	0	0	2.82	2.82
164	CNP39202	392.02	Transportation Equipment - Class P	8	L3	10	10	0.00	0.00
165	CNP39203	392.03	Transportation Equipment - Class C2	9	S2.5	10	10	5.50	5.50
166	CNP39204	392.04	Transportation Equipment - Class C4	9	S2.5	10	10	7.52	7.52
167	CNP39205	392.05	Transportation Equipment - Class T1	11	S2.5	10	10	6.39	6.39
168	CNP39206	392.06	Transportation Equipment - Class T3	11	S2.5	10	10	6.73	6.73
169	CNP39207	392.07	Transportation Equipment - Class T4	15	L4	10	10	5.46	5.46
170	CNP39208	392.08	Transportation Equipment - Vessels	14	L1	10	10	0.00	0.00
171	CNP39209	392.09	Transportation Equipment - Trailers	21	L1	10	10	0.02	0.02
172	CNP39300	393	Stores Equipment	20	SQ	0	0	6.32	6.32
173	CNP39400	394	Tools, Shop & Garage Equipment	25	SQ	0	0	0.00	0.00
174	CNP39500	395	Laboratory Equipment	20	SQ	0	0	5.00	5.00
175	CNP39600	396	Power Operated Equipment	14	L2	20	20	5.66	5.66
176	CNP39701	397.01	Communications Equipment - Non-Computer	7	SQ	0	0	18.16	18.16
177	CNP39702	397.02	Communications Equipment - Computer	5	SQ	0	0	664.75	664.75
178	CNP39703	397.03	Communications Equipment - Radio Systems	7	SQ	0	0	23.84	23.84
179	CNP39704	397.04	Communications Equipment - Voice Systems	7	SQ	0	0	14.77	14.77
180	CNP39705	397.05	Communications Equipment - Trans Systems	15	SQ	0	0	0.88	0.88
181	CNP39800	398	Miscellaneous Equipment	20	SQ	0	0	4.86	4.86

Notes:

182 (a) FERC Account with adopted net salvage and accrual rates that are different from those proposed by PG&E in the 2014 GRC Application.

APPENDIX C: Table 14
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted O&M Labor Allocation Factors

Line	Unbundled Cost Category (UCC)	2011 Recorded Adjusted Labor ($000)	2011 Recorded Adjusted Labor %	
	Electric Department			
1	**EG - Power Generation - GRC**	**271,373**	**23.70%**	[1]
2	EG - Fossil Facilities (Incl Gateway, Colusa & Humboldt for 2014 GRC)	11,405	1.00%	
3	EG - Fossil Transmission	118	0.01%	
4	EG - Fuel Cell	22	0.00%	
5	EG - Hydro Facilities (Incl Helms & Hydro Renewables Facilities)	60,668	5.30%	
6	EG - Hydro Transmission (Incl Helms & Hydro Renewables Transmission)	1,940	0.17%	
7	EG - Diablo Canyon Nuclear Generation Facilities (Incl Diablo Steam Generator Replacement)	168,882	14.75%	
8	EG - Electric Procurement (incl. QF & Other Power Payment Admin)	28,331	2.47%	
9	EG - Market Redesign Technology Update - MRTU	6	0.00%	
10	**EG - Power Generation - Non-GRC**	**1,865**	**0.16%**	
11	EG - Humboldt Unit 3 SAFSTOR Costs (Expense)	1,865	0.16%	
12	**ET - Network Transmission**	**70,905**	**6.19%**	
13	**ED - Electric Distribution**	**480,823**	**41.99%**	[1]
14	ED - Wires & Services (& Cornerstone 2014+ & 2011GRC Dynamic(PDP))	402,129	35.12%	
15	ED - Transmission-Level Direct Connects	522	0.05%	
16	ED - Public Purpose Program Administration	70,341	6.14%	
17	ED - SmartMeter Electric (Incl AMI)	7,831	0.68%	
18	**Electric Department Total**	**824,965**	**72.04%**	
	Gas Department			
19	**GT - Gas Transmission and Storage**	**61,963**	**5.41%**	
20	**GD - Gas Distribution[(a)]**	**258,187**	**22.55%**	[1]
21	GD - Pipes and Services	236,646	20.67%	
22	GD - Gas Procurement	2,668	0.23%	
23	GD - Public Purpose Program Administration	15,977	1.40%	
24	GD - SmartMeter Gas (Incl AMI)	2,897	0.25%	
25	**Gas Department Total**	**320,150**	**27.96%**	
26	**PG&E Total Labor**	1,145,115	100.00%	
27	**GRC Total [1]**	1,010,383	88.23%	

Notes:
(a) According to Section 3 of the Decision, the allocation to certain MWC 78 Gas Distribution-related Common Building Capital projects for 2013 and 2014 is 40%.

(END OF APPENDIX C)

APPENDIX D
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Decision Tables - PTYR (2015-2016)

TABLE INDEX

APPENDIX D: Table 1
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
PTYR Revenue Requirement (RRQ) Comparison Summary

2015 RRQ Comparison
Results of Operations at Proposed Rates
(Thousands of Dollars)

Line No.	Description	PG&E Requested Increases* (A)	Adopted Increases (B)	Amount Adopted>Request (B-A) (C)	Percentage Adopted>Request (C/A)% (D)	Line No.
	REVENUE:					
1	**Electric Distribution** Revenue at Effective Rates	220,742	201,966	(18,776)	-8.5%	1
2	**Gas Distribution** Revenue at Effective Rates	177,891	93,827	(84,064)	-47.3%	2
3	**Electric Generation** Revenue at Effective Rates	36,898	28,164	(8,734)	-23.7%	3
4	**Total Retail Revenue Requirement**	435,531	323,957	(111,574)	-25.6%	4

2016 RRQ Comparison
Results of Operations at Proposed Rates
(Thousands of Dollars)

Line No.	Description	PG&E Requested Increases* (A)	Adopted Increases (B)	Amount Adopted>Request (B-A) (C)	Percentage Adopted>Request (C/A)% (D)	Line No.
	REVENUE:					
5	**Electric Distribution** Revenue at Effective Rates	236,053	211,601	(24,453)	-10.4%	5
6	**Gas Distribution** Revenue at Effective Rates	153,082	86,752	(66,330)	-43.3%	6
7	**Electric Generation** Revenue at Effective Rates	97,325	73,094	(24,230)	-24.9%	7
8	**Total Retail Revenue Requirement**	486,460	371,448	(115,013)	-23.6%	8

* Based on PG&E's Update Testimony Exhibit (PG&E-32) filed with the CPUC on October 4, 2013.

APPENDIX D: Table 2
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR End-of-Year (EOY) and Weighted Average (WAVG) Plant Additions

		Capital Expenditures			Retirements[1]		EOY Plant Additions		WAVG Plant Additions		
Line No.	Description	7yr-Average (2008-2014)	2015	2016	2015	2016	2015	2016	2015	2016	Line No.
		(a)	(b)	(c)	(d)	(e)	(f=b-d)	(g=c-e)	(h)	(i)	
1	Electric Generation[2]	621,542	634,642	648,265	151,234	154,942	483,408	493,323	172,006	175,534	1
2	Electric Distribution	1,688,467	1,724,816	1,763,641	242,369	248,516	1,482,448	1,515,125	665,933	680,612	2
3	Gas Distribution	642,700	656,839	671,372	127,886	131,058	528,953	540,314	261,400	267,015	3
4	Total GRC[2]	2,952,709	3,016,298	3,083,278	521,489	534,517	2,494,809	2,548,762	1,099,339	1,123,160	4
							To Attrition RO		*Calculated in RO*		

Note:
[1] PTYR Retirements are based on an escalated 3-year average of Adopted Retirements from 2012-2014.
[2] Electric Generation MWC 2S and MWC 2U correspond to adding several fossil units, which have been started up. There is no attrition effect, so these have been excluded.

APPENDIX D: Table 3

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Results of Operations at Proposed Rates (2014-2016)
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	7,094,484	323,957	7,418,441	371,448	7,789,889	1
2	Plus Other Operating Revenue	130,713	-	130,713	-	130,713	2
3	Total Operating Revenue	7,225,197	323,957	7,549,154	371,448	7,920,602	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	599,767	14,502	614,269	16,544	630,813	5
6	Storage	-	-	-	-	-	6
7	Transmission	5,100	129	5,229	142	5,371	7
8	Distribution	964,512	23,299	987,811	25,251	1,013,063	8
9	Customer Accounts	295,834	8,668	304,502	8,920	313,422	9
10	Uncollectibles	23,377	1,047	24,424	1,201	25,625	10
11	Customer Services	5,391	157	5,549	162	5,711	11
12	Administrative and General	948,640	30,495	979,135	31,612	1,010,747	12
13	Franchise Requirements	68,683	3,196	71,879	3,558	75,437	13
14	Amortization	58,975	5,606	64,581	6,140	70,721	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(173,237)	(25,606)	(198,843)	(6,140)	(204,983)	17
18	Subtotal Expenses:	2,797,042	61,494	2,858,536	87,391	2,945,927	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	248,686	12,787	261,473	13,065	274,538	20
21	Payroll	101,664	3,019	104,684	3,109	107,793	21
22	Business	926	-	926	-	926	22
23	Other	2,939	-	2,939	-	2,939	23
24	State Corporation Franchise	109,217	11,477	120,694	13,408	134,101	24
25	Federal Income	393,561	18,016	411,577	47,128	458,705	25
26	Total Taxes	856,993	45,299	902,292	76,710	979,002	26
27	Depreciation	1,880,768	103,770	1,984,537	101,262	2,085,799	27
28	Fossil Decommissioning	36,085	-	36,085	-	36,085	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	5,570,888	210,562	5,781,451	265,363	6,046,813	30
31	Net for Return	1,654,309	113,395	1,767,703	106,085	1,873,788	31
32	Rate Base	20,528,996	1,407,163	21,936,159	1,316,449	23,252,608	32
	RATE OF RETURN:						
33	On Rate Base						33
34	On Equity						34

APPENDIX D: Table 3-A

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Results of Operations at Proposed Rates (2014-2016)
Electric Distribution Summary
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	3,774,649	201,966	3,976,614	211,601	4,188,215	1
2	Plus Other Operating Revenue	87,538	-	87,538	-	87,538	2
3	Total Operating Revenue	3,862,187	201,966	4,064,153	211,601	4,275,753	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	-	-	-	-	-	5
6	Storage	-	-	-	-	-	6
7	Transmission	1,024	26	1,050	28	1,079	7
8	Distribution	612,283	14,775	627,059	15,933	642,992	8
9	Customer Accounts	168,086	4,925	173,011	5,069	178,079	9
10	Uncollectibles	12,557	657	13,213	688	13,901	10
11	Customer Services	2,556	75	2,631	77	2,708	11
12	Administrative and General	442,610	14,518	457,128	15,049	472,177	12
13	Franchise Requirements	32,378	1,693	34,072	1,774	35,846	13
14	Amortization	58,768	5,606	64,374	6,140	70,514	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(4,932)	(5,606)	(10,538)	(6,140)	(16,678)	17
18	Subtotal Expenses:	1,325,330	36,669	1,361,999	38,619	1,400,617	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	160,014	8,936	168,950	9,133	178,083	20
21	Payroll	40,368	1,199	41,567	1,235	42,801	21
22	Business	441	-	441	-	441	22
23	Other	1,398	-	1,398	-	1,398	23
24	State Corporation Franchise	67,267	7,881	75,148	8,317	83,466	24
25	Federal Income	215,697	28,455	244,152	28,044	272,196	25
26	Total Taxes	485,185	46,471	531,656	46,730	578,385	26
27	Depreciation	1,076,793	59,697	1,136,490	62,529	1,199,019	27
28	Fossil Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	2,887,308	142,837	3,030,145	147,877	3,178,022	30
31	Net for Return	974,879	59,129	1,034,008	63,724	1,097,731	31
32	Rate Base	12,097,670	733,759	12,831,429	790,772	13,622,200	32
	RATE OF RETURN:						
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	34

APPENDIX D: Table 3-B

Pacific Gas and Electric Company

2014 CPUC General Rate Case (GRC)

Adopted PTYR Results of Operations at Proposed Rates (2014-2016)

Gas Distribution Summary

(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	1,559,047	93,827	1,652,875	86,752	1,739,627	1
2	Plus Other Operating Revenue	25,228	-	25,228	-	25,228	2
3	Total Operating Revenue	1,584,276	93,827	1,678,103	86,752	1,764,856	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	4,575	123	4,698	127	4,825	5
6	Storage	-	-	-	-	-	6
7	Transmission	-	-	-	-	-	7
8	Distribution	352,229	8,524	360,753	9,318	370,071	8
9	Customer Accounts	127,748	3,743	131,491	3,852	135,343	9
10	Uncollectibles	5,038	298	5,336	276	5,612	10
11	Customer Services	2,836	82	2,918	85	3,003	11
12	Administrative and General	244,385	7,795	252,181	8,081	260,262	12
13	Franchise Requirements	21,393	1,267	22,659	1,171	23,831	13
14	Amortization	-	-	-	-	-	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(12,997)	-	(12,997)	-	(12,997)	17
18	Subtotal Expenses:	745,206	21,833	767,039	22,910	789,949	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	38,146	2,111	40,257	2,156	42,414	20
21	Payroll	29,088	864	29,952	890	30,841	21
22	Business	237	-	237	-	237	22
23	Other	751	-	751	-	751	23
24	State Corporation Franchise	13,999	3,466	17,466	2,882	20,347	24
25	Federal Income	66,047	8,272	74,319	10,434	84,753	25
26	Total Taxes	148,268	14,713	162,982	16,362	179,343	26
27	Depreciation	392,120	26,244	418,363	22,774	441,138	27
28	Fossil Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	1,285,594	62,790	1,348,384	62,046	1,410,430	30
31	Net for Return	298,682	31,037	329,719	24,706	354,425	31
32	Rate Base	3,706,468	385,152	4,091,620	306,589	4,398,209	32
	RATE OF RETURN:						
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	34

APPENDIX D: Table 3-C

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Results of Operations at Proposed Rates (2014-2016)
Electric Generation Summary
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	1,760,788	28,164	1,788,952	73,094	1,862,046	1
2	Plus Other Operating Revenue	17,946	-	17,946	-	17,946	2
3	Total Operating Revenue	1,778,734	28,164	1,806,898	73,094	1,879,992	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	595,192	14,379	609,570	16,417	625,988	5
6	Storage	-	-	-	-	-	6
7	Transmission	4,075	103	4,179	113	4,292	7
8	Distribution	-	-	-	-	-	8
9	Customer Accounts	-	-	-	-	-	9
10	Uncollectibles	5,783	92	5,874	238	6,112	10
11	Customer Services	-	-	-	-	-	11
12	Administrative and General	261,645	8,182	269,827	8,482	278,309	12
13	Franchise Requirements	14,912	236	15,148	613	15,761	13
14	Amortization	207	-	207	-	207	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(155,308)	(20,000)	(175,308)	-	(175,308)	17
18	Subtotal Expenses:	726,506	2,992	729,498	25,863	755,360	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	50,526	1,740	52,266	1,775	54,041	20
21	Payroll	32,209	957	33,166	985	34,151	21
22	Business	249	-	249	-	249	22
23	Other	789	-	789	-	789	23
24	State Corporation Franchise	27,950	130	28,080	2,208	30,288	24
25	Federal Income	111,817	(18,711)	93,106	8,650	101,756	25
26	Total Taxes	223,540	(15,885)	207,655	13,618	221,273	26
27	Depreciation	411,854	17,829	429,683	15,958	445,642	27
28	Fossil Decommissioning	36,085	-	36,085	-	36,085	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	1,397,986	4,936	1,402,922	55,439	1,458,361	30
31	Net for Return	380,748	23,229	403,977	17,655	421,632	31
32	Rate Base	4,724,858	288,252	5,013,111	219,088	5,232,199	32
	RATE OF RETURN:						
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	34

APPENDIX D: Table 4
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Income Taxes at Proposed Rates (2014-2016)
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
1	Revenues	7,225,197	323,957	7,549,154	371,448	7,920,602	1
2	O&M Expenses	2,797,042	61,494	2,858,536	87,391	2,945,927	2
3	Nuclear Decommissioning Expense	-	-	-	-	-	3
4	Superfund Tax	-	-	-	-	-	4
5	Taxes Other Than Income	354,215	15,806	370,022	16,174	386,196	5
6	Subtotal	4,073,940	246,657	4,320,597	267,882	4,588,479	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	532,604	36,507	569,112	34,154	603,266	7
8	Fiscal/Calendar Adjustment	8,952	-	8,952	-	8,952	8
9	Operating Expense Adjustments	(53,665)	-	(53,665)	-	(53,665)	9
10	Capitalized Interest Adjustment	-	-	-	-	-	10
11	Removal Costs	168,949	-	168,949	-	168,949	11
12	Vacation Accrual Reduction	(2,589)	-	(2,589)	-	(2,589)	12
13	Capitalized Other	86,451	-	86,451	-	86,451	13
14	Subtotal Deductions	740,702	36,507	777,209	34,154	811,363	14
	CCFT TAXES:						
15	State Operating Expense Adjustment	14,986	-	14,986	-	14,986	15
16	State Tax Depreciation - Declining Balance	-	-	-	-	-	16
17	State Tax Depreciation - Fixed Assets	1,592,172	80,320	1,672,492	82,059	1,754,551	17
18	State Tax Depreciation - Other	-	-	-	-	-	18
19	Capitalized Overhead	76,185	-	76,185	-	76,185	19
20	Repair Allowance	332,968	-	332,968	-	332,968	20
21	Subtotal Deductions	2,757,013	116,828	2,873,840	116,213	2,990,053	21
22	Taxable Income for CCFT	1,316,927	129,830	1,446,757	151,670	1,598,426	22
23	CCFT	116,416	11,477	127,893	13,408	141,301	23
24	State Tax Adjustment	-	-	-	-	-	24
25	Current CCFT	116,416	11,477	127,893	13,408	141,301	25
26	Deferred Taxes - Reg Asset	-	-	-	-	-	26
27	Deferred Taxes - Interest	1,325	-	1,325	-	1,325	27
28	Deferred Taxes - Vacation	(229)	-	(229)	-	(229)	28
29	Deferred Taxes - Other	-	-	-	-	-	29
30	Deferred Taxes - Fixed Assets	(8,295)	-	(8,295)	-	(8,295)	30
31	Total CCFT	109,217	11,477	120,694	13,408	134,101	31
	FEDERAL TAXES:						
32	CCFT - Prior Year	86,658	29,758	116,416	11,477	127,893	32
33	Federal Operating Expense Adjustment	20,470	-	20,470	-	20,470	33
34	Fed. Tax Depreciation - Declining Balance	-	-	-	-	-	34
35	Federal Tax Depreciation - SLRL	-	-	-	-	-	35
36	Federal Tax Depreciation - Fixed Assets	1,305,943	66,243	1,372,186	67,677	1,439,863	36
37	Federal Tax Depreciation - Other	-	-	-	-	-	37
38	Capitalized Overhead	76,185	-	76,185	-	76,185	38
39	Repair Allowance	332,968	-	332,968	-	332,968	39
40	Preferred Dividend Credit	2,754	-	2,754	-	2,754	40
41	Subtotal Deductions	2,565,681	132,508	2,698,189	113,308	2,811,497	41
42	Taxable Income for FIT	1,508,259	114,149	1,622,408	154,574	1,776,982	42
43	Federal Income Tax	527,891	39,952	567,843	54,101	621,944	43
44	Deferred Taxes - Reg Asset	-	-	-	-	-	44
45	Tax Effect of MTD & Prod Tax Credits	(318)	(15,112)	(15,430)	-	(15,430)	45
46	Deferred Taxes - Interest	1,456	-	1,456	-	1,456	46
47	Deferred Taxes - Vacation	(826)	-	(826)	-	(826)	47
48	Deferred Taxes - Other	-	-	-	-	-	48
49	Deferred Taxes - Fixed Assets	(134,641)	(6,824)	(141,465)	(6,973)	(148,438)	49
50	Total Federal Income Tax	393,561	18,016	411,577	47,128	458,705	50

APPENDIX D: Table 4-A
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Income Taxes at Proposed Rates (2014-2016)
Electric Distribution Summary
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
1	Revenues	3,862,187	201,966	4,064,153	211,601	4,275,753	1
2	O&M Expenses	1,325,330	36,669	1,361,999	38,619	1,400,617	2
3	Nuclear Decommissioning Expense	-	-	-	-	-	3
4	Superfund Tax	-	-	-	-	-	4
5	Taxes Other Than Income	202,221	10,135	212,356	10,368	222,723	5
6	Subotal	2,334,636	155,162	2,489,798	162,614	2,652,413	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	313,862	19,037	332,899	20,516	353,414	7
8	Fiscal/Calendar Adjustment	5,295	-	5,295	-	5,295	8
9	Operating Expense Adjustments	(33,115)	-	(33,115)	-	(33,115)	9
10	Capitalized Interest Adjustment	-	-	-	-	-	10
11	Removal Costs	117,078	-	117,078	-	117,078	11
12	Vacation Accrual Reduction	(1,205)	-	(1,205)	-	(1,205)	12
13	Capitalized Other	43,560	-	43,560	-	43,560	13
14	Subtotal Deductions	445,474	19,037	464,511	20,516	485,027	14
	CCFT TAXES:						
15	State Operating Expense Adjustment	3,502	-	3,502	-	3,502	15
16	State Tax Depreciation - Declining Balance	-	-	-	-	-	16
17	State Tax Depreciation - Fixed Assets	841,126	46,974	888,100	48,009	936,109	17
18	State Tax Depreciation - Other	-	-	-	-	-	18
19	Capitalized Overhead	67,180	-	67,180	-	67,180	19
20	Repair Allowance	184,631	-	184,631	-	184,631	20
21	Subtotal Deductions	1,541,913	66,011	1,607,924	68,525	1,676,449	21
22	Taxable Income for CCFT	792,723	89,151	881,874	94,089	975,964	22
23	CCFT	70,077	7,881	77,958	8,317	86,275	23
24	State Tax Adjustment	-	-	-	-	-	24
25	Current CCFT	70,077	7,881	77,958	8,317	86,275	25
26	Deferred Taxes - Reg Asset	-	-	-	-	-	26
27	Deferred Taxes - Interest	310	-	310	-	310	27
28	Deferred Taxes - Vacation	(107)	-	(107)	-	(107)	28
29	Deferred Taxes - Other	-	-	-	-	-	29
30	Deferred Taxes - Fixed Assets	(3,012)	-	(3,012)	-	(3,012)	30
31	Total CCFT	67,267	7,881	75,148	8,317	83,466	31
	FEDERAL TAXES:						
32	CCFT - Prior Year	68,174	1,902	70,077	7,881	77,958	32
33	Federal Operating Expense Adjustment	5,517	-	5,517	-	5,517	33
34	Fed. Tax Depreciation - Declining Balance	-	-	-	-	-	34
35	Federal Tax Depreciation - SLRL	-	-	-	-	-	35
36	Federal Tax Depreciation - Fixed Assets	676,970	37,806	714,777	38,640	753,417	36
37	Federal Tax Depreciation - Other	-	-	-	-	-	37
38	Capitalized Overhead	67,180	-	67,180	-	67,180	38
39	Repair Allowance	184,631	-	184,631	-	184,631	39
40	Preferred Dividend Credit	319	-	319	-	319	40
41	Subtotal Deductions	1,448,267	58,745	1,507,012	67,037	1,574,049	41
42	Taxable Income for FIT	886,370	96,416	982,786	95,578	1,078,364	42
43	Federal Income Tax	310,229	33,746	343,975	33,452	377,427	43
44	Deferred Taxes - Reg Asset	-	-	-	-	-	44
45	Tax Effect of MTD & Prod Tax Credits	-	-	-	-	-	45
46	Deferred Taxes - Interest	597	-	597	-	597	46
47	Deferred Taxes - Vacation	(384)	-	(384)	-	(384)	47
48	Deferred Taxes - Other	-	-	-	-	-	48
49	Deferred Taxes - Fixed Assets	(94,745)	(5,291)	(100,036)	(5,408)	(105,444)	49
50	Total Federal Income Tax	215,697	28,455	244,152	28,044	272,196	50

APPENDIX D: Table 4-B
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Income Taxes at Proposed Rates (2014-2016)
Gas Distribution Summary
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
1	Revenues	1,584,276	93,827	1,678,103	86,752	1,764,856	1
2	O&M Expenses	745,206	21,833	767,039	22,910	789,949	2
3	Nuclear Decommissioning Expense	-	-	-	-	-	3
4	Superfund Tax	-	-	-	-	-	4
5	Taxes Other Than Income	68,222	2,975	71,197	3,046	74,242	5
6	Subotal	770,848	69,019	839,868	60,796	900,664	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	96,161	9,992	106,153	7,954	114,107	7
8	Fiscal/Calendar Adjustment	1,957	-	1,957	-	1,957	8
9	Operating Expense Adjustments	(15,580)	-	(15,580)	-	(15,580)	9
10	Capitalized Interest Adjustment	-	-	-	-	-	10
11	Removal Costs	45,875	-	45,875	-	45,875	11
12	Vacation Accrual Reduction	(715)	-	(715)	-	(715)	12
13	Capitalized Other	22,704	-	22,704	-	22,704	13
14	Subtotal Deductions	150,401	9,992	160,394	7,954	168,348	14
	CCFT TAXES:						
15	State Operating Expense Adjustment	581	-	581	-	581	15
16	State Tax Depreciation - Declining Balance	-	-	-	-	-	16
17	State Tax Depreciation - Fixed Assets	358,095	19,816	377,912	20,242	398,154	17
18	State Tax Depreciation - Other	-	-	-	-	-	18
19	Capitalized Overhead	445	-	445	-	445	19
20	Repair Allowance	84,444	-	84,444	-	84,444	20
21	Subtotal Deductions	593,967	29,809	623,775	28,196	651,971	21
22	Taxable Income for CCFT	176,882	39,210	216,092	32,600	248,693	22
23	CCFT	15,636	3,466	19,103	2,882	21,984	23
24	State Tax Adjustment	-	-	-	-	-	24
25	Current CCFT	15,636	3,466	19,103	2,882	21,984	25
26	Deferred Taxes - Reg Asset	-	-	-	-	-	26
27	Deferred Taxes - Interest	51	-	51	-	51	27
28	Deferred Taxes - Vacation	(63)	-	(63)	-	(63)	28
29	Deferred Taxes - Other	-	-	-	-	-	29
30	Deferred Taxes - Fixed Assets	(1,625)	-	(1,625)	-	(1,625)	30
31	Total CCFT	13,999	3,466	17,466	2,882	20,347	31
	FEDERAL TAXES:						
32	CCFT - Prior Year	(602)	16,238	15,636	3,466	19,103	32
33	Federal Operating Expense Adjustment	932	-	932	-	932	33
34	Fed. Tax Depreciation - Declining Balance	-	-	-	-	-	34
35	Federal Tax Depreciation - SLRL	-	-	-	-	-	35
36	Federal Tax Depreciation - Fixed Assets	324,299	17,946	342,245	18,332	360,576	36
37	Federal Tax Depreciation - Other	-	-	-	-	-	37
38	Capitalized Overhead	445	-	445	-	445	38
39	Repair Allowance	84,444	-	84,444	-	84,444	39
40	Preferred Dividend Credit	57	-	57	-	57	40
41	Subtotal Deductions	559,976	44,177	604,153	29,752	633,905	41
42	Taxable Income for FIT	210,872	24,842	235,715	31,045	266,759	42
43	Federal Income Tax	73,805	8,695	82,500	10,866	93,366	43
44	Deferred Taxes - Reg Asset	-	-	-	-	-	44
45	Tax Effect of MTD & Prod Tax Credits	-	-	-	-	-	45
46	Deferred Taxes - Interest	105	-	105	-	105	46
47	Deferred Taxes - Vacation	(228)	-	(228)	-	(228)	47
48	Deferred Taxes - Other	-	-	-	-	-	48
49	Deferred Taxes - Fixed Assets	(7,635)	(422)	(8,057)	(432)	(8,489)	49
50	Total Federal Income Tax	66,047	8,272	74,319	10,434	84,753	50

APPENDIX D: Table 4-C

Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Income Taxes at Proposed Rates (2014-2016)
Electric Generation Summary
(Thousands of Dollars)

Line No.	Description	Test Year 2014	Attrition Year 2015 Increase	Attrition Year 2015 Total	Attrition Year 2016 Increase	Attrition Year 2016 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
1	Revenues	1,778,734	28,164	1,806,898	73,094	1,879,992	1
2	O&M Expenses	726,506	2,992	729,498	25,863	755,360	2
3	Nuclear Decommissioning Expense	-	-	-	-	-	3
4	Superfund Tax	-	-	-	-	-	4
5	Taxes Other Than Income	83,773	2,696	86,469	2,760	89,230	5
6	Subtotal	968,455	22,476	990,931	44,471	1,035,402	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	122,582	7,478	130,060	5,684	135,744	7
8	Fiscal/Calendar Adjustment	1,700	-	1,700	-	1,700	8
9	Operating Expense Adjustments	(4,969)	-	(4,969)	-	(4,969)	9
10	Capitalized Interest Adjustment	-	-	-	-	-	10
11	Removal Costs	5,997	-	5,997	-	5,997	11
12	Vacation Accrual Reduction	(669)	-	(669)	-	(669)	12
13	Capitalized Other	20,187	-	20,187	-	20,187	13
14	Subtotal Deductions	144,826	7,478	152,305	5,684	157,989	14
	CCFT TAXES:						
15	State Operating Expense Adjustment	10,903	-	10,903	-	10,903	15
16	State Tax Depreciation - Declining Balance	-	-	-	-	-	16
17	State Tax Depreciation - Fixed Assets	392,951	13,530	406,481	13,807	420,288	17
18	State Tax Depreciation - Other	-	-	-	-	-	18
19	Capitalized Overhead	8,560	-	8,560	-	8,560	19
20	Repair Allowance	63,893	-	63,893	-	63,893	20
21	Subtotal Deductions	621,133	21,008	642,141	19,491	661,632	21
22	Taxable Income for CCFT	347,322	1,468	348,790	24,980	373,770	22
23	CCFT	30,703	130	30,833	2,208	33,041	23
24	State Tax Adjustment	-	-	-	-	-	24
25	Current CCFT	30,703	130	30,833	2,208	33,041	25
26	Deferred Taxes - Reg Asset	-	-	-	-	-	26
27	Deferred Taxes - Interest	964	-	964	-	964	27
28	Deferred Taxes - Vacation	(59)	-	(59)	-	(59)	28
29	Deferred Taxes - Other	-	-	-	-	-	29
30	Deferred Taxes - Fixed Assets	(3,658)	-	(3,658)	-	(3,658)	30
31	Total CCFT	27,950	130	28,080	2,208	30,288	31
	FEDERAL TAXES:						
32	CCFT - Prior Year	19,086	11,617	30,703	130	30,833	32
33	Federal Operating Expense Adjustment	14,021	-	14,021	-	14,021	33
34	Fed. Tax Depreciation - Declining Balance	-	-	-	-	-	34
35	Federal Tax Depreciation - SLRL	-	-	-	-	-	35
36	Federal Tax Depreciation - Fixed Assets	304,674	10,490	315,165	10,705	325,870	36
37	Federal Tax Depreciation - Other	-	-	-	-	-	37
38	Capitalized Overhead	8,560	-	8,560	-	8,560	38
39	Repair Allowance	63,893	-	63,893	-	63,893	39
40	Preferred Dividend Credit	2,377	-	2,377	-	2,377	40
41	Subtotal Deductions	557,438	29,586	587,024	16,519	603,543	41
42	Taxable Income for FIT	411,017	(7,110)	403,907	27,952	431,859	42
43	Federal Income Tax	143,856	(2,488)	141,368	9,783	151,151	43
44	Deferred Taxes - Reg Asset	-	-	-	-	-	44
45	Tax Effect of MTD & Prod Tax Credits	(318)	(15,112)	(15,430)	-	(15,430)	45
46	Deferred Taxes - Interest	754	-	754	-	754	46
47	Deferred Taxes - Vacation	(214)	-	(214)	-	(214)	47
48	Deferred Taxes - Other	-	-	-	-	-	48
49	Deferred Taxes - Fixed Assets	(32,261)	(1,111)	(33,372)	(1,134)	(34,506)	49
50	Total Federal Income Tax	111,817	(18,711)	93,106	8,650	101,756	50

APPENDIX D: Table 5
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Rate Base (2014-2016)
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.		2014 End Of Year	2014 WAVG Year	2015 End Of Year	2015 WAVG Year	2015 WAVG Increase	2016 End Of Year	2016 WAVG Year	2016 WAVG Increase	Line No.
	PLANT IN SERVICE									
1	Beginning of Year	47,478,884	47,478,884	50,143,407	50,143,407	2,664,523	52,638,216	52,638,216	2,494,809	1
2	Net Additions	2,664,523	1,174,529	2,494,809	1,099,339	(75,190)	2,548,762	1,123,160	23,821	2
3	Total	50,143,407	48,653,413	52,638,216	51,242,746	2,589,333	55,186,978	53,761,376	2,518,630	3
	WORKING CAPITAL									
4	Material & Supplies - Fuel	-	-	-	-	-	-	-	-	4
5	Material & Supplies	206,453	206,453	206,453	206,453	-	206,453	206,453	-	5
6	Working Cash	373,362	373,362	373,362	373,362	-	373,362	373,362	-	6
7	Total	579,815	579,815	579,815	579,815	-	579,815	579,815	-	7
	TRA ADJUSTMENTS									
8	Capitalized Interest	15,243	13,853	15,243	15,243	1,390	15,243	15,243	-	8
9	Deferred Vacation	39,422	38,895	39,422	39,422	528	39,422	39,422	-	9
10	CIAC Deferral	336,534	334,828	336,534	336,534	1,706	336,534	336,534	-	10
11	Total	391,199	387,576	391,199	391,199	3,624	391,199	391,199	-	11
12	CUSTOMER ADVANCES	122,442	122,442	122,442	122,442	-	122,442	122,442	-	12
	DEFERRED TAXES									
13	Accum Def Taxes - Reg Asset	(18,471)	(19,146)	(18,471)	(18,471)	675	(18,471)	(18,471)	-	13
14	Accum Def Taxes - Fixed Assets	4,878,273	4,932,663	4,639,480	4,758,877	(173,787)	4,393,715	4,516,598	(242,279)	14
15	Accum Def Taxes - Other	-	-	-	-	-	-	-	-	15
16	Accum Def ITC	74,477	76,442	74,477	74,477	(1,964)	74,477	74,477	-	16
17	Deferred Taxes-Other	-	-	-	-	-	-	-	-	17
18	Total Deferred Taxes	4,934,278	4,989,959	4,695,486	4,814,882	(175,077)	4,449,721	4,572,603	(242,279)	18
	DEPRECIATION RESERVE									
19	Beginning of Year	23,298,835	23,298,835	24,635,754	24,635,754	1,336,919	26,044,801	26,044,801	1,409,046	19
20	Depreciation Expense	1,916,853	958,426	2,020,623	1,010,311	51,885	2,121,884	1,060,942	50,631	20
21	Net Salvage/Retirements	(579,934)	(277,854)	(611,576)	(305,788)	(27,934)	(642,011)	(321,005)	(15,217)	21
22	Total	24,635,754	23,979,407	26,044,801	25,340,277	1,360,870	27,524,674	26,784,737	1,444,460	22
23	RATE BASE	21,421,948	20,528,996	22,746,503	21,936,159	1,407,163	24,061,156	23,252,608	1,316,449	23
24	Rate Base Increase				1,407,163	1,407,163		1,316,449	1,316,449	24
25	DEPRECIATION EXPENSE		1,916,853		2,020,623	103,770		2,121,884	101,262	25
26	Depreciation Expense Increase					51,885			50,631	26

APPENDIX D: Table 5-A
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Rate Base (2014-2016)
Electric Distribution Summary
(Thousands of Dollars)

Line No.		2014 End Of Year	2014 WAVG Year	2015 End Of Year	2015 WAVG Year	2015 WAVG Increase	2016 End Of Year	2016 WAVG Year	2016 WAVG Increase	Line No.
	PLANT IN SERVICE									
1	Beginning of Year	25,159,013	25,159,013	26,545,011	26,545,011	1,385,998	28,027,459	28,027,459	1,482,448	1
2	Net Additions	1,385,998	622,607	1,482,448	665,933	43,326	1,515,125	680,612	14,679	2
3	Total	26,545,011	25,781,619	28,027,459	27,210,944	1,429,324	29,542,583	28,708,070	1,497,127	3
	WORKING CAPITAL									
4	Material & Supplies - Fuel	-	-	-	-	-	-	-	-	4
5	Material & Supplies	64,127	64,127	64,127	64,127	-	64,127	64,127	-	5
6	Working Cash	147,114	147,114	147,114	147,114	-	147,114	147,114	-	6
7	Total	211,241	211,241	211,241	211,241	-	211,241	211,241	-	7
	TRA ADJUSTMENTS									
8	Capitalized Interest	1,453	999	1,453	1,453	453	1,453	1,453	-	8
9	Deferred Vacation	18,345	18,100	18,345	18,345	245	18,345	18,345	-	9
10	CIAC Deferral	248,846	247,864	248,846	248,846	982	248,846	248,846	-	10
11	Total	268,644	266,963	268,644	268,644	1,681	268,644	268,644	-	11
12	CUSTOMER ADVANCES	82,789	82,789	82,789	82,789	-	82,789	82,789	-	12
	DEFERRED TAXES									
13	Accum Def Taxes - Reg Asset	-	-	-	-	-	-	-	-	13
14	Accum Def Taxes - Fixed Assets	3,126,732	3,166,273	2,974,905	3,050,819	(115,455)	2,817,670	2,896,287	(154,531)	14
15	Accum Def Taxes - Other	-	-	-	-	-	-	-	-	15
16	Accum Def ITC	36,287	37,368	36,287	36,287	(1,081)	36,287	36,287	-	16
17	Deferred Taxes-Other	-	-	-	-	-	-	-	-	17
18	Total Deferred Taxes	3,163,019	3,203,642	3,011,192	3,087,106	(116,536)	2,853,957	2,932,574	(154,531)	18
	DEPRECIATION RESERVE									
19	Beginning of Year	10,476,759	10,476,759	11,270,587	11,270,587	793,828	12,108,424	12,108,424	837,837	19
20	Depreciation Expense	1,076,793	538,397	1,136,490	568,245	29,849	1,199,019	599,510	31,264	20
21	Net Salvage/Retirements	(282,966)	(139,432)	(298,653)	(149,327)	(9,894)	(315,085)	(157,542)	(8,216)	21
22	Total	11,270,587	10,875,723	12,108,424	11,689,505	813,782	12,992,359	12,550,391	860,886	22
23	RATE BASE	12,508,501	12,097,670	13,304,938	12,831,429	733,759	14,093,364	13,622,200	790,772	23
24	Rate Base Increase				733,759	733,759		790,772	790,772	24
25	DEPRECIATION EXPENSE		1,076,793		1,136,490	59,697		1,199,019	62,529	25
26	Depreciation Expense Increase					29,849			31,264	26

APPENDIX D: Table 5-B
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Rate Base (2014-2016)
Gas Distribution Summary
(Thousands of Dollars)

Line No.		2014 End Of Year	2014 WAVG Year	2015 End Of Year	2015 WAVG Year	2015 WAVG Increase	2016 End Of Year	2016 WAVG Year	2016 WAVG Increase	Line No.
	PLANT IN SERVICE									
1	Beginning of Year	8,857,514	8,857,514	9,558,551	9,558,551	701,037	10,087,504	10,087,504	528,953	1
2	Net Additions	701,037	346,441	528,953	261,400	(85,041)	540,314	267,015	5,614	2
3	Total	9,558,551	9,203,955	10,087,504	9,819,951	615,996	10,627,818	10,354,519	534,568	3
	WORKING CAPITAL									
4	Material & Supplies - Fuel	-	-	-	-	-	-	-	-	4
5	Material & Supplies	9,634	9,634	9,634	9,634	-	9,634	9,634	-	5
6	Working Cash	71,738	71,738	71,738	71,738	-	71,738	71,738	-	6
7	Total	81,371	81,371	81,371	81,371	-	81,371	81,371	-	7
	TRA ADJUSTMENTS									
8	Capitalized Interest	686	608	686	686	78	686	686	-	8
9	Deferred Vacation	10,890	10,744	10,890	10,890	146	10,890	10,890	-	9
10	CIAC Deferral	87,688	86,964	87,688	87,688	724	87,688	87,688	-	10
11	Total	99,263	98,315	99,263	99,263	948	99,263	99,263	-	11
12	CUSTOMER ADVANCES	39,653	39,653	39,653	39,653	-	39,653	39,653	-	12
	DEFERRED TAXES									
13	Accum Def Taxes - Reg Asset	-	-	-	-	-	-	-	-	13
14	Accum Def Taxes - Fixed Assets	767,782	766,411	733,302	750,542	(15,869)	698,389	715,845	(34,697)	14
15	Accum Def Taxes - Other	-	-	-	-	-	-	-	-	15
16	Accum Def ITC	18,069	18,503	18,069	18,069	(434)	18,069	18,069	-	16
17	Deferred Taxes-Other	-	-	-	-	-	-	-	-	17
18	Total Deferred Taxes	785,851	784,914	751,371	768,611	(16,303)	716,458	733,914	(34,697)	18
	DEPRECIATION RESERVE									
19	Beginning of Year	4,733,170	4,733,170	4,972,844	4,972,844	239,674	5,228,559	5,228,559	255,715	19
20	Depreciation Expense	392,120	196,060	418,363	209,182	13,122	441,138	220,569	11,387	20
21	Net Salvage/Retirements	(152,446)	(76,623)	(162,649)	(81,324)	(4,702)	(171,503)	(85,751)	(4,427)	21
22	Total	4,972,844	4,852,607	5,228,559	5,100,701	248,094	5,498,194	5,363,376	262,675	22
23	RATE BASE	3,940,837	3,706,468	4,248,556	4,091,620	385,152	4,554,147	4,398,209	306,589	23
24	Rate Base Increase				385,152	385,152		306,589	306,589	24
25	DEPRECIATION EXPENSE		392,120		418,363	26,244		441,138	22,774	25
26	Depreciation Expense Increase					13,122			11,387	26

APPENDIX D: Table 5-C
Pacific Gas and Electric Company
2014 CPUC General Rate Case (GRC)
Adopted PTYR Rate Base (2014-2016)
Electric Generation Summary
(Thousands of Dollars)

Line No.		2014 End Of Year	2014 WAVG Year	2015 End Of Year	2015 WAVG Year	2015 WAVG Increase	2016 End Of Year	2016 WAVG Year	2016 WAVG Increase	Line No.
	PLANT IN SERVICE									
1	Beginning of Year	13,462,357	13,462,357	14,039,845	14,039,845	577,488	14,523,254	14,523,254	483,408	1
2	Net Additions	577,488	205,481	483,408	172,006	(33,475)	493,323	175,534	3,528	2
3	Total	14,039,845	13,667,838	14,523,254	14,211,851	544,013	15,016,576	14,698,787	486,936	3
	WORKING CAPITAL									
4	Material & Supplies - Fuel	-	-	-	-	-	-	-	-	4
5	Material & Supplies	132,693	132,693	132,693	132,693	-	132,693	132,693	-	5
6	Working Cash	154,510	154,510	154,510	154,510	-	154,510	154,510	-	6
7	Total	287,203	287,203	287,203	287,203	-	287,203	287,203	-	7
	TRA ADJUSTMENTS									
8	Capitalized Interest	13,105	12,246	13,105	13,105	859	13,105	13,105	-	8
9	Deferred Vacation	10,188	10,051	10,188	10,188	136	10,188	10,188	-	9
10	CIAC Deferral	0	0	0	0	0	0	0	-	10
11	Total	23,293	22,297	23,293	23,293	995	23,293	23,293	-	11
12	CUSTOMER ADVANCES	-	-	-	-	-	-	-	-	12
	DEFERRED TAXES									
13	Accum Def Taxes - Reg Asset	(18,471)	(19,146)	(18,471)	(18,471)	675	(18,471)	(18,471)	-	13
14	Accum Def Taxes - Fixed Assets	983,758	999,979	931,274	957,516	(42,463)	877,656	904,465	(53,051)	14
15	Accum Def Taxes - Other	-	-	-	-	-	-	-	-	15
16	Accum Def ITC	20,121	20,570	20,121	20,121	(449)	20,121	20,121	-	16
17	Deferred Taxes-Other	-	-	-	-	-	-	-	-	17
18	Total Deferred Taxes	985,408	1,001,404	932,923	959,166	(42,238)	879,306	906,115	(53,051)	18
	DEPRECIATION RESERVE									
19	Beginning of Year	8,088,906	8,088,906	8,392,324	8,392,324	303,417	8,707,818	8,707,818	315,494	19
20	Depreciation Expense	447,940	223,970	465,769	232,884	8,915	481,727	240,864	7,979	20
21	Net Salvage/Retirements	(144,522)	(61,799)	(150,274)	(75,137)	(13,338)	(155,423)	(77,712)	(2,574)	21
22	Total	8,392,324	8,251,077	8,707,818	8,550,071	298,994	9,034,122	8,870,970	320,899	22
23	RATE BASE	4,972,610	4,724,858	5,193,008	5,013,111	288,252	5,413,645	5,232,199	219,088	23
24	Rate Base Increase				288,252	288,252		219,088	219,088	24
25	DEPRECIATION EXPENSE		447,940		465,769	17,829		481,727	15,958	25
26	Depreciation Expense Increase					8,915			7,979	26

(END OF APPENDIX D)

Appendix E-1

Disposition of Net Salvage Parameter Disputes for Specific Accounts

We resolve the disputes between PG&E, DRA, and TURN with respect to depreciation parameters for net salvage value as specified below. Our adopted depreciation parameters by account are set forth in Appendix C on Tables 12 and 13.

1. Station Equipment – Account 353.01

For Station Equipment, PG&E proposes an increase from the current authorized net salvage rate of -30% to -60%, doubling the amount of net salvage collected for this account. DRA recommends a net salvage value of -55% for this account. DRA believes that while the raw data in PG&E's depreciation study lends some support to a -60% rate, PG&E does not fully explain the drivers of the increasing costs in the depreciation study. DRA also claims that PG&E is currently collecting at a higher rate of negative net salvage on this account than the other major IOUs. SCE has a rate of -5%, while SDG&E has a rate of -10%.

We adopt the 55% net salvage estimate for this account proposed by DRA. Adopting DRA's proposed rate represents approximately 90% of the increase forecasted by PG&E, while providing mitigation of the impacts on current customers. By approving this level of increase, we also do not unduly burden future ratepayers with deferred costs.

2. Towers and Fixtures – Account 354 and 354.01

PG&E requests the authorized net salvage rate on Account 354 be increased from -60% to -110%, DRA recommends that net salvage on this account be increased only to -75%, claiming this is in line with the net salvage values for the other major IOUs in their most recent GRCs. PG&E responds that comparisons to other IOUs is not a valid basis to set PG&E's net salvage rate.

The authorized net salvage rate for Account 354.01 (Towers & Fixtures – Combined Cycle) is -80%. Because this account is fairly new and contains assets similar to Account 354, PG&E requests the same rate of -110%. DRA also recommends a net salvage on this account of -75% for this account.

Discussion

We adopt a negative salvage rate of -75% for Account 354. Limiting the rate in this manner is consistent with principle of gradualism. Adopting this allowance provides some recognition of increasing costs, and represents some increase over the existing rate. While the historic 20-year trend indicates that PG&E's costs for this account are rising, the increase requested by PG&E would be too abrupt of a change for current ratepayers. In the interests of gradualism, we limit the adopted rate -75%to which is the rate proposed by DRA. We conclude, however, that a rate higher than -75% is warranted for Account 354.01, since the current rate for Account 354.01 is 25% higher than Account 354. We adopt a negative salvage rate of -88% for Account 354.01, which reflects about 25% of the increase proposed by PG&E, consistent with the principle of gradualism.

3. Distribution Station Equipment – Account 362

PG&E's proposes an increase from -15% to -40% for Account 362- Distribution Station Equipment. This increase would add more than $500 million in depreciation expense over the remaining investment life, increasing 2014 revenue requirement by more than $17 million. PG&E relied on 1990-2009 data showing average net salvage of -39%, and with a most recent 5-year average of -57%.

TURN recommends retaining the 15% rate for Account 362- Distribution Station Equipment. TURN claims that PG&E fails to meet its burden of proof regarding increased removal costs. TURN notes that from 2001 through the present, PG&E recorded no gross salvage value for retirements in this account.[1] To the extent PG&E has not retired transformers during the past decade, the database would be skewed negative. The data would not reflect retirement of transformers, even though a substantial portion of investment in this account is in transformers.

TURN argues that such a negative net salvage is atypical for California utilities, but also for the industry as a whole. SCE relies on a -10% net salvage, and SDG&E relies on a -15% net salvage compared to PG&E's proposed -40%. TURN and DRA also argue that PG&E's proposal also is inconsistent with the concept of gradualism employed in the life analysis portion of the depreciation study.

Discussion

We adopt a net salvage rate of -21% for Account 362. This rate represents some increase over the existing rate, but is also limited to only 25% of the increase proposed by PG&E. PG&E calculates average net salvage for 2007-2009 as -51%. As shown in Table 2-4 of PG&E's rebuttal testimony, inclusion of revised gross salvage amounts lowers average net salvage for this period to -46%. This is still more negative than PG&E's proposed estimate. We conclude that PG&E's proposed negative salvage rate of -40% would cause too abrupt of change for this GRC cycle. We temper the increase in recognition of the large increase in comparison to other sources.

We recognize that each IOU is subject to different conditions and removal costs for each IOU are not necessarily be the same. Nonetheless, extreme variations in comparing PG&E to other IOUs relating to similar types of costs

1 Exhibit (PG&E-2) Chapter 11 workpaper WP 11-918.

highlights the large cost burden reflected in PG&E's request. Also, Gannett Fleming's historical industry database yields an average net salvage of approximately negative 10% and does not identify a single value as negative as it proposes for PG&E out of almost 70 reported values.[2]

We are not persuaded by TURN and DRA, however, to retain a -15% value. Doing so would unduly shift an excessive share of costs to future ratepayers. TURN's estimate of -15% net salvage is below PG&E's actual experience, even when historically high copper prices are considered. Our adopted rate of -21% tempers the extremes on both sides of parties' dispute, and applies the principle of gradualism.

4. Poles Towers and Fixtures – Account 364

PG&E seeks an increase from -80% to -150% in the authorized net salvage rate for Account 364. Based on limiting net salvage increases to 25%, DRA recommends increasing the -80% estimate to no more than-105%. TURN recommends a -100% value. DRA removed two years of recorded data from its analysis, deemed to be outliers, and found that the years 1990-2007 results in a net salvage rate of -122%.

PG&E noted an increase of over 100% in every year in the net salvage analysis 1990-2009 except for six years and over -100% since 2000. In many years it has exceeded -400% and 500.[3] Data from 1990-2009 showed a -149% net salvage which reflects high removal costs in recent years based on PG&E's pole replacement program.

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2 PG&E Response to TURN 6-8 Attachment 1, cited in TURN Opening Brief, at 23.

3 Exhibit (PG&E-2), WP 1-480 and Figure 2-1 of PG&E rebuttal testimony).

TURN claims that PG&E's estimate is overstated in assuming that cost of removal increases in proportion to the cost of a new installation.[4] PG&E increased the normal crew size utilized for pole replacement projects by adding new apprentice and pre-apprentice employees to complement the experienced Journeymen Linemen. The number of complex pole projects has also increased, resulting in higher average costs of pole installations. TURN claims this increased labor costs due to the addition of apprentices and pre-apprentices is temporary.

As explained by PG&E, however, costs of adding an apprentice to a pole replacement crew has a limited impact on removal cost. This practice has been ongoing and costs for apprentice training associated with removal costs are included in historical data. Also, by relying on several years of historic data, removal cost forecasts would reflect the lower levels of hiring and training during earlier periods.

[4] PG&E Response to TURN 46-5(g).

Discussion

We adopt a negative salvage rate of -105% for Account 364 which represents some increase from the existing rate. We decline to grant the full increase sought by PG&E. We are concerned with the growing magnitude of costs relating to this account. Gannett Fleming's database identifies only three values more negative than a -100% out of 65 reported values for this account. Only 5% of the industry reflects values as negative as proposed by PG&E. Gannett Fleming does not report any values more negative than -125%. At the same time, based on historic cost averages, however, a negative salvage rate of -150% appears to be below PG&E's 20-year average for Account 364.[5]

Given these countervailing factors, we conclude that some increase is warranted, but authorizing PG&E's full request of -150% would constitute too abrupt of a change. We thus adopt a negative salvage rate of -105% rate for Account 364, based on DRA's proposed rate. In this way, we mitigate current ratepayers' cost burden, and balance the burden between current and future ratepayers.

5. Overhead Conductors and Devices – Account 365

PG&E proposes a -200% net salvage compared to the existing -77% net salvage for Account 365, which is nearly a threefold increase. PG&E's proposal is based on 1990-2009 data, showing the overall average for this account was -244% and the five-year average was over -500%. PG&E claims that a 200% rate reflects gradualism for this account, considering that five-year averages are over -500%, with the last couple of years being even higher.

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[5] PG&E Rebuttal Testimony (PG&E-17), at 2-17; Figure 2-2.

TURN recommends a rate of 110%. TURN claims that PG&E's database contains errors in the level of reported retirements, and more recent historical periods include much higher labor costs than future amounts likely to be incurred due to increases in crew size performing installation and removal activities to train apprentices and pre-apprentices. PG&E argues, however, that it has not recorded amounts as low as -110% net salvage in this account since 1995, and that every year since has been higher with most years being much higher.

DRA proposes a net salvage value of -90% for this account which is the mean of the net salvage values used by the other major IOUs. DRA believes it should provide a sufficient increase to cover current retirements. DRA notes, however, that the removal costs reflected in PG&E's depreciation study lend some support to PG&E's requested rate. PG&E claims that DRA's estimate is far below actual historical experience

DRA's estimate of a less negative net salvage for this account results in an estimate lower than its estimate for Account 364. Compared to PG&E's experience, however, the data supports a more negative estimate for Account 365 than for Account 364.

Discussion

We conclude that some increase in removal cost for this account is warranted, but decline to adopt PG&E's proposed five-fold increase of -200%. In order to mitigate the rate impacts on current customers, a more modest increase is warranted. We adopt a net salvage rate of 108% for Account 365. The adopted amount still represents an increase of 40%, but is still only approximately 25% of the increase sought by PG&E.

By comparison, in SCE's recent rate proceeding, the utility was granted permission to change from -100% to a -110% net salvage. The substantial difference between PG&E's proposal here versus other utilities calls into question the support for such a large change to -200%.

Based on historical data reflecting an overall net salvage of -102%, and the most recent five years was a -311% net salvage, Gannett Fleming concluded that a more negative net salvage rate was warranted. Gannett Fleming's estimate is 33% higher than the highest value it recommended elsewhere. PG&E's forecast amounts to 16 times the highest level of annual negative net salvage recorded for this account from 1990-2011.

Gannett Fleming's industry database does not contain a value for other utilities more negative than a -100% net salvage for this account, and reflects an overall average of -35%. PG&E is proposing an amount approximately six times the average level that Ganett Fleming proposed for other utilities.

In order to mitigate the impacts on current customers of a five-fold increase, while recognizing the need for some increase, we conclude that a negative salvage rate of -108% for Account 365 is reasonable.

6. Underground Conduit – Account 366

For Account 366, PG&E's net salvage rate is currently -20%. PG&E requests a fivefold increase to -100%. PG&E's depreciation study in the 2011 GRC also yielded the same estimate of -100% for Account 366. PG&E calculates a 20-year average negative salvage of -133% for this account, excluding the effects of large non-recurring gross salvage amounts.

TURN recommends retaining the existing -20% rate. TURN argues that an increase of five times the existing net salvage is not justified, and claims Gannett Fleming did not investigate the impact of emergency retirement situations on the historical database. TURN also believes that PG&E allocates removal costs for replacement work based on a set allocation, thereby tending to overstate costs. PG&E, however, explains that it actually determines the negative salvage percentage of each replacement project's costs separately for each individual project.

Consistent with DRA's recommendation to cap increases to negative net salvage at 25%, DRA recommends net salvage on this account be set at -45%. This value is slightly higher than SDG&E's rate, and more than twice SCE's. TURN proposes to retain the existing rate of -20%.

Discussion

We adopt a negative salvage rate of -40% for this account. We conclude that the current -20% negative salvage rate unduly understates actual costs. We find insufficient basis, therefore, to retain the -20% rate, as proposed by TURN, or to adopt the -45% rate proposed by DRA. Adopting such a negative salvage rate would shift too much cost burden to future customers.

We also conclude, however, that a rate of -100% as proposed by PG&E would be too extreme to impose on current customers. PG&E's request for this account is 16 times the highest level of annual negative net salvage recorded for this account from 1990-2011. It is 50 times the average level of negative net salvage incurred during the last 22 years corresponding to PG&E's historical database.[6] In the interests of gradualism, we conclude that a less extreme change is warranted. We thus adopt net salvage of -40% for Account 366, which reflects doubling of the rate, but is less than half of the increment proposed by PG&E.

7. Underground Conductors and Devices – Account 367

PG&E proposes a -50% net salvage for Account 367 compared to the existing -40%. The average for the period studied is -46% and the most recent five-year average is -60%. Based on recent trends, Gannet Fleming believes the

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[6] Exhibit (PG&E-2) Chapter 11 workpaper WP 11-925.

data suggests a net salvage level more negative than the presently authorized -40%.

The 20-year analysis shows and overall average of -102% net salvage. However, this amount is influenced by large gross salvage amounts in 1991 and 1998. PG&E does not expect the gross salvage amounts to be indicative of future experience, as gross salvage has been close to zero since 1999. Excluding these net salvage amounts, the overall average for this account is -133%.

TURN recommends a -35% net salvage for Account 367. TURN relied on the two years of the 1990-2009 data base which had the largest retirements and developed a net salvage rate of -40 percent.

The four years with the largest level of retirements over the past 10 years yield a -32% net salvage. This value compares to a -152% net salvage for the two years with the lowest level of retirement activity (about half the level of activity in the years with the largest level of retirements). The level of retirement activity varies significantly depending on whether the retirements are due to emergency failure of direct buried underground cable or planned replacement of cable in a conduit. More recent historic trends reflect more emergency replacement situations or potentially a disproportionate level of retirement of direct buried cable, given that many years surrounding these values are in the upper -20% range.

Discussion

We adopt a negative salvage rate of -43% for Account 367 which reflects some increase but less than proposed by PG&E. We are not persuaded by TURN's proposal to reduce the negative salvage rate to -35%. As the basis its figure, TURN relied on a limited number of years of data without explaining why a more expansive time period was not deemed appropriate. TURN states that the experience reflected in PG&E's data base is associated with emergency retirements which are not expected to continue. TURN argues that because underground conduit is retired in place, this will produce less cost of removal in the future. TURN's claims about the effects of emergency retirements are speculative.

Compared to the amounts we are adopting for other asset accounts, and in the interests of gradualism, we find a negative salvage rate of -43% reasonable here.

8. Line Transformers – Overhead -Account 368.01

For Account 368.01, PG&E proposes a -25% net salvage which is more than four times the existing -6% net salvage. The -25% rate is the same amount estimated in PG&E's depreciation study in the 2011 GRC. Gannett Fleming calculated an overall database average of -11% net salvage, and a five-year average of -56%. Based on the most recent years, PG&E proposes that net salvage for Account 368 be increased to -25%.

DRA recommends keeping the current net salvage at -6% consistent with historical net salvage rates in PG&E's depreciation study.

TURN proposes a -15% net salvage, and notes that PG&E's updated database on an overall basis yields -14% net salvage if 2010 and 2011 are included. Gannett Fleming's proposal for a -25% net salvage is at the high end of its own industry database.

Retirements in this account have been due to overload conditions that result in replacements on a preventative basis or in failure mode, as well as due to deterioration and lightning strikes which normally are associated with emergency situations. As previously noted, when plant failures occur in such situations, it is normal to expect that the resulting cost of removal will be more negative in comparison to the planned replacement retirement situation associated with the vast majority of the investment in the future. In planned retirement situations, lower levels of overtime likely will be incurred, the appropriate replacement materials should be available on a timely basis, all of which results in an overall lower replacement cost work order, all else equal.

Discussion

We adopt a negative salvage of -11% for Account 368.01, which reflects some increase but less than PG&E requests. We decline to retain the -6% rate, as proposed by DRA, as doing so would significantly understate costs, and unduly shift deferred costs to future ratepayers. Adopting a -25% rate, as proposed by PG&E, however, would also unduly burden current customers with more than a four-fold increase. Adopting a rate of -11% rate provides a level of gradualism to the extent that increasing cost levels are indicated by the data. A net salvage rate of -11% for Account 368.01 provides a reasonable middle range, which still reflects an increase of almost twice the existing rate, but only 25% of the increase sought by PG&E.

9. Services – Overhead - Account 369.01

PG&E proposes a -135% net salvage for Account 369 compared to the existing -75%. In the most recent five-year period the average had decreased to -177%. Gannett Fleming concludes that net salvage might grow more negative to reflect that change, but determined that a -175% would be a large move. Therefore it recommended an increase limited to -135%.

DRA recommends a net salvage rate of -85% based on the other comparable IOU rates. TURN recommends retaining the -75% negative salvage rate, noting that the -135% net salvage rate requested by PG&E represents the most negative net salvage value identified by Gannett Fleming for this account both in California and in the industry. TURN claims that labor costs reflect a temporary increase in crew size. As junior level employees become journeymen linemen, PG&E plans on reducing crew sizes back to historic levels, thus returning net salvage relationships to prior levels. TURN also believes that disproportionately high levels of negative net salvage were incurred due to emergency situations, particularly due to corresponding overtime charges.

Discussion

We adopt a negative salvage of -90% for Account 369.01 which reflects only 25% of the increase that PG&E estimates. We find insufficient basis to adopt the negative salvage estimates proposed by DRA or TURN. TURN's assumptions are not quantified in most instances. DRA relies on comparisons with other IOUs, but doesn't show that other IOUs face comparable constraints to PG&E. We find a range of potential replacement costs are indicated depending on the period examined. In the past nine years, net salvage exceeded -100% except for one year for this account. PG&E calculated a rate of -100% in its depreciation study for Account 369.01 in the 2011 GRC. In light of the relevant various facts. Although a rate as high as -100% could be arguably defensible, we consider a rate of -90% reasonable for Account 369.01, consistent with our adherence to a principle of gradualism by limiting the increase to 25% of PG&E's request.

10. Legacy Meters/Smart Meters) – Account 370/370.01

PG&E's current authorized net salvage rate for EDP37000 (legacy meters) is15%, and for EDP37001 (smart meters) is -5%. PG&E is requesting a single rate of-20% for both accounts. DRA recommends net salvage on this account remain at -5%. The average net salvage value for combined meters/smart meters is -10% including data for years 2010-11 which PG&E provided in response to a DRA deficiency notice. DRA argues that a rate of -5% is quite close to both the -10% historical average net salvage and the -8% average net salvage since the start of smart meter deployment in 2008. This rate is comparable to the rates at the other major IOUs.

Discussion

We adopt a rate of -16% for EDP37000 (legacy meters) and a rate of -9% for EDP37001 (smart meters), each of which reflect approximately 50% of the net increase requested by PG&E for each account. We are not persuaded by DRA's recommendation to retain net salvage for EDP 37001 at 5%. DRA focused on data from the start of Smart Meter deployment in 2008 through 2011. This period included very few retirements of Smart Meters, but consisted mainly of existing meters. Our adopted negative salvage rates for the legacy meters and smart meters accounts recognizes rising costs, as noted by PG&E, but moderates the impacts on current customers based on our application of gradualism.

11. Street Lighting and Signal Systems – Lamps and Equipment – Account 373.03

PG&E's current authorized net salvage rate on this account is -5%. PG&E is requesting an increase to -65%. DRA recommends that net salvage on this account be increased only to -10%, based on the average net salvage rate shown in the depreciation study from 1990-2009 excluding the outlier year of 1996.

Discussion

Given the large percentage increase in this account, we apply the principle of gradualism and adopt a negative salvage rate of -20%, which is about 23% of the increase requested by PG&E. We decline to adopt DRA's proposal for a -10% negative salvage rate based on historic average costs. As PG&E explains, since 2006, costs increased significantly for this account due to starting a replacement program for center bore word street light poles and related luminaries. PG&E's estimate is based on the more recent data which is expected to be more representative of future activity in this account. The most recent five-year average showed negative salvage of -68%. We conclude, however, that while the existing rate is too low based on increasing cost trends, a change from -5% to -65%, as proposed by PG&E would be too abrupt. Accordingly, we adopt a more gradual increase in the negative salvage rate for Account 37303 from -5% up to -20%.

12. Gas Distribution Mains –Account 376

PG&E proposes a -65% net salvage for Account 376- Gas Distribution Mains which represents a more negative value than the existing -52%. TURN recommends a 50% rate. The average for 1990-2009 was -63% which Gannett Fleming rounded up to -65%. Recent years have shown a -100% cost of removal in a number of years and management confirms that pipe generally is not salvageable. Gannett Fleming further notes that there is very little insertion of pipe in the replacement program and most replacements require an open trench, increasing the cost of retiring the pipe being replaced.

TURN argues that Gannet Fleming fails to recognize corrected data available through 2011, the time period actually reflective of the data in PG&E's depreciation study. When corrected data for the period 1990 through 2011 is reviewed, PG&E's reported level of negative net salvage is reduced to -59%. However, TURN claims there has been no demonstration that the retirement pattern reflected in the overall historical period is representative of future retirement expectations. TURN claims the trend is toward a less negative level of net salvage and is more indicative of -40% net salvage level. TURN notes that based on four years with noticeably higher levels of retirement activity, the average net salvage for those four years was -30%. Also, Gannett Fleming's industry database for Account 376 yields an average negative net salvage of 35%.[7]

Discussion

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7 PG&E Response to TURN 28-3 Attachment 2.

We adopt a negative salvage rate of -55% which represents approximately 25% of the increase sought by PG&E. Our adopted rate reflects a reasonable resolution between the conflicting claims of PG&E and TURN as to whether the cost trend is increasing or not. Our adopted rate is conservative to the extent it remains below the -60% rate that PG&E calculated in its 2011 GRC depreciation study.

13. Services – Gas – Account 380

The PG&E is requesting an increase to -180% in comparison to the current authorized net salvage rate for Account 380 of -105%. During 1990-2009, Gannett Fleming calculates a -182% net salvage average, with five years reporting over -250%.

DRA recommends that the net salvage rate on this account of -130%, consistent with capping increases at no more than 25%. DRA argues it is reasonable to limit increases to the net salvage rate on this account given the increased pace of the Gas Pipeline Replacement Program which DRA believes will have a strong impact on future removal cost levels.

TURN recommends retaining the existing 105% rate. TURN notes that Gannett Fleming's data base industry average for this account is approximately -70%. TURN claims PG&E has not explained why gas service investment or practices underlying recorded removal costs and salvage produced such disparate figures in relation to the major California gas utilities. TURN claims PG&E failed to properly transfer retirements between various software systems, which resulted in erroneously reported lower levels of retirements. Underreporting of retirements inflates the percentage level of negative net salvage for this and other accounts because the retirements are the denominator of the ratio. The database average for the 20-year period reviewed by Gannett Fleming declines by 26% after limited additional retirement activity for 2010 and

2011 are included. The annual level of retirement activity reflected in the database for this account as relied on by Gannett Fleming is small in comparison to the plant in service. Under these circumstances, the recorded retirements may not reach a level of materiality, and any conclusions drawn from the data lack sufficient support as a result.

Discussion

We adopt a negative salvage rate of -124% for Account 380 which represents approximately 25%of the increase forecasted by PG&E. This adopted rate provides some recognition of the increasing removal cost trend for this account based on an overall 20-year average rate of -182%, and -200% for the most recent five-year period. Given these figures, we find insufficient basis to retain the 105% rate, as proposed by TURN. Adopting the TURN proposal would unduly understate removal costs, resulting in excessive costs to be absorbed by future ratepayers. We are concerned, however, that adopting PG&E's full negative salvage proposal for -180%, reflecting a 71% increase, would be too abrupt of a change for current ratepayers to absorb. Our adopted increase of 18% over the adopted rate provides for a more gradual increase for current customers without unduly burdening future customers with excessive deferred removal costs.

14. Meters – Gas – Account 381

The current authorized net salvage rate on this account is -5%. PG&E is requesting an increase to -25% based on the 20-year average cost from 1990-2009. given the numbers provided by PG&E's depreciation study. In light of the results of excluding 2008 and 2009 data as outlier years and net salvage rates on this account for the other major IOUs, DRA recommends that net salvage on this account remain at -5%. TURN does not dispute PG&E's estimate here.

Discussion

We adopt an increase in the net salvage for this account of -10%, representing 25% of the increase requested by PG&E. We conclude that DRA has not justified the continued use of a 5% rate. As a basis for its proposal, DRA is not consistent in its exclusion of outlier years. DRA excluded only 2008 and 2009 data while including years prior to 2004, even though these earlier years are not reflective of more recent levels of activity. Our adopted increase of over the adopted rate provides for a more gradual increase for current customers without unduly burdening them with excessive deferred removal costs.

15. Structures and Improvements -- Account 390

PG&E proposes to retain the existing -10% net salvage for Account 390. DRA has no disagreement here. Gannett Fleming calculated a -25% net salvage based on the historical database. It further noted that more recent years show the net salvage increased (became less negative) to a -17% based on a five-year average, with 5 some years falling below -10%. TURN proposes a net salvage of +25%, which TURN believes reflects the value PGE& is likely to obtain when it ultimately disposes of such facilities. An office complex in downtown San Francisco, with almost two million square feet, is an extremely valuable structure both now and well into the future.

Discussion

We adopt a net salvage of -10% for Account 390, thereby retaining the existing rate. This rate is reasonable in light of recorded costs. We find insufficient basis to adopt TURN's proposed net salvage rate of +25%. TURN's estimate does not account for the value received on the sale of property is related to the land, not to the depreciable structure. Also, TURN's estimate does not account for the cost of removing structural improvements.

(End of Appendix E-1)

Appendix E-2
Disposition of Average Service Life Parameter
Disputes for Specific Asset Accounts

We resolve the disputes between PG&E, DRA, and TURN with respect to depreciation parameters for average service life (ASL) as specified below. Our adopted depreciation parameters are set forth on Appedix C: Table 13.

Distribution Station Equipment -Account 362

PG&E proposes to change the currently authorized life-curve for Account 362 from 40R2 to 42R2. TURN recommends retaining the existing 46S0. We find PG&E's ASL estimate more defensible, and adopt it.

PG&E's Depreciation Study's narrative referred primarily to the results of its SPR analysis, tempered by an observation regarding transformers at indoor substations having shorter anticipated lives. The same observation was contained in the narrative appearing in the 2003, 2007 and 2011 GRC depreciation studies, which are largely identical to narratives here except for omission of an earlier reference to PG&E's proactive program to replace high risk transformers.

TURN basis its recommendations on selecting curves from the SPR analysis, and reducing reliance on long-running observations regarding transformers at indoor substations (in light of the fact that only about 10% of substations are indoor). Industry data reported by Gannett Fleming showed a substantial number of ASLs of 50 years or longer for this account. Yet, as noted by PG&E, SPR results are not as reliable when applied to heterogeneous property, such as is found in Account 362. In such instances, the SPR results can be biased in favor of low mode curves with longer ASLs. In view of these limitations, TURN's estimate of a longer ASL based on its SPR analysis is not defensible.

PG&E and TURN also differ by only 0.2% per year in their simulated balances. This minor difference is statistically insignificant and not sufficient to support TURN's estimated ASL change. Also, based on industry data, we conclude that the estimated ASL from PG&E's depreciation study is more in line with the industry than is that of TURN's.

Poles Towers and Fixtures – Account 364

For Account 364, PG&E relies on a 42R1.5 life-curve combination, representing a two-year increase above the existing 40R2 life-curve combination. Gannett Fleming placed some significance on expectations from PG&E personnel that transformers will have a life around 40 years, and the concept of gradualism. Gannett Fleming limited the increases in ASL to two years or 5% (2/40). TURN argues that such a concept of gradualism is inconsistent with PG&E's proposal for much greater movements in negative net salvage.

TURN proposes an increase to a 46R1 life-curve combination for Account 364 based on SPR results and information applicable to investment in this account. TURN believes a strong case can be made for a 49- or 50-year ASL based on SPR results, but that statistical selection of a 46R1 life-curve combination is superior to PG&E's proposal.

We conclude that PG&E's ASL estimate for Account 364 is reasonable and adopt it. We do not find support for TURN's higher ASL estimate for this account based on relevant historical data or statistical analysis. In rebuttal testimony, PG&E effectively refuted TURN's claim that its statistical selection of a 46R1 life-curve combination is superior to PG&E's proposal.[8] Based on only one additional year of data relative to the 2011 study, TURN proposes a six-year

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[8] PG&E Rebuttal Exh. (PG&E-17), at 2-123 through 2-125.

increase in the ASL. This magnitude of TURN's proposed increase is not consistent with the principle of gradualism.

Overhead Conductors and Devices – Account 365

For Account 365, PG&E proposes a 42R2 life-curve combination, representing an ASL increase of two years from the existing 40R2.5 life-curve combination. Gannett Fleming based its proposal on the indication of a 40- to 45-year life obtained from SPR analysis where it claims good CIs were achieved and the best fit is the 42R2 combination. Gannett Fleming placed significance on the concept of gradualism.

TURN recommends an increase to a 46R1.5 life-curve combination for Account 365, arguing that the best-fitting curves reflect ASLs in the 45-to-55-year range. Gannett Fleming's prior reading of SPR indications resulted in ASLs subsequently demonstrated to be too short. In the 2003 depreciation study, for example, Gannett Fleming believed that SPR based ASL indications were 28- to 38-years. TURN claims that PG&E's forecast is short compared to other California utilities and to industry averages. Gannett Fleming's database reflects an approximate 45-year ASL for the industry, but more reflects numerous recommendations for 55- to 60-year ASLs.

We conclude that PG&E's proposal for Account 365 for a 42R2 life-curve combination is reasonable and adopt it. We do not find support to adopt TURN's proposal for a longer ASL. As noted in PG&E's rebuttal testimony, the simulated balances based on PG&E's and TURN's average survivor curve estimates differ by no more than 0.07% per year. This insignificant difference does not support adopting TURN's proposal for a longer life for Account 365 than is reflected in PG&E's depreciation study.

Underground Conductors and Devices – Account 367

For Account 367, PG&E proposes a 42R3 life-curve combination representing a three-year increase above the existing 39R4 life-curve combination.

Gannett Fleming concludes that very high CIs are obtained from SPR analyses for ASLs around 40 years, and claims that the 42R2 life-curve combination produces the best fitting results.

TURN recommends a 52R2.5 life-curve combination, representing a 13-year increase. TURN disputes PG&E's claim that SPR analysis shows very high CIs for ASLs around 40 years, arguing that even higher CIs correspond to ASLs much greater than 40 years. The CI for TURN's recommendation is 26% to 38% higher than the 40R4 life-curve combination associated with Gannett Fleming's claim. In particular, TURN disputes Gannett Fleming's conclusion that the 42R3 life-curve produces the best-fitting results. The result for each of the R3 curves is either 45 or 46 years – not the claimed 42 years, depending on the band. Gannett Fleming's database yields an average for all companies, without consideration of the mix of investment in the account, at a value greater than that proposed. Gannett Fleming's database reflects many utilities for which it recommended ASLs between 55 and 65 years.

We conclude that PG&E's proposal for Account 367 for a 42R3 life-curve combination is reasonable and adopt it. Although a greater portion of PG&E's investment in the last two decades has been in cable in conduit and newer generation cable that are expected to have longer life than older underground direct buried cable, PG&E explains that the increased service lives for newer cable have been reflected in the increase in service lives in recent studies.

We do not find support to adopt TURN's proposal for a longer ASL. The difference between PG&E's and TURN's estimates of simulated balances based on survivor curves averages no more than 0.7%. This difference is not large enough to justify the significant increase in ASL proposed by TURN. PG&E's proposed three-year ASL increase is in keeping with the rate of increase adopted over the last two GRC cycles. Adopting PG&E's ASL estimate for 2014 is more consistent with the principle of gradualism than is the TURN estimate.

Line Transformers – Overhead -Account 368.01 –

For Account 368.01, PG&E proposes to retain the current 32R2.5 life-curve combination. Gannett Fleming states that a 32-year ASL results in the highest CI and is consistent with the currently authorized ASL. TURN recommends an increased life to 36R0.5. TURN argues that SPR results suggest a more realistic range from 31 to 40 years, with values near the higher end normally exhibiting superior CI values. TURN claims Gannett Fleming's range is understated both on the low and high end by three to four years, based on SPR results.

We conclude that PG&E's proposal to retain the current 32R2.5 life-curve combination for Account 368.01 is reasonable and adopt it. The difference between PG&E's and TURN's estimates of simulated balances based on survivor curves averages differ by no more than 0.7% which is not large enough to justify the increase in ASL proposed by TURN. Also, TURN did not provide a statistical basis for relying on a less common curve type than is normally used for line transformers.

Line Transformers – Underground --Account 368.02 –

For Account 368.02, PG&E proposes to retain the existing 29-year ASL but change the existing S2.5 curve to an R3. Gannett Fleming relies on SPR results, which it claims suggests an ASL range from 24 to 30 years with medium to high modes producing the higher CIs. From these items of information, Gannett Fleming concludes its proposed 29R3 life-curve combination has slightly better conformance with the actual book balances.

TURN recommends a recommend a 31S1.5 life curve combination. TURN claims that not a single resulting value, no matter what the CI or REI values, is as low as 25 years, and the SPR results for life-curve combinations with superior CIs and REIs would realistically yield life values between 29 and 34 years.

We conclude that PG&E's proposal to retain the existing 29-year ASL is reasonable for Account 368.02 and adopt it. Although the S1.5 curve type proposed by TURN has a slightly better Conformance Index, TURN's differences with PG&E are not statistically significant. TURN's estimate also has a lower REI, and thus does not provide a better fit than that of PG&E. We find insufficient basis to change the existing ASL.

Services –Overhead-- Account 369.01 –

PG&E proposes a 49R3 life-curve combination for Account 369.01 which represents a two-year increase from the existing 47R3 life-curve combination. TURN recommends a 56R2 life-curve combination. TURN states that SPR results does not yield a single result as low as 40 years, but yields numerous results in the 50- to mid-60-year range with superior CIs and REIs. TURN claims that Gannett Fleming's reference to medium mode curves being slightly favored is not indicative of actual SPR results. Lower mode curves yield superior CIs with excellent REIs.

TURN disputes Gannett Fleming's statement that the "best-fitting" curve from a statistical analysis is a 49R3 life-curve combination. TURN claims that only one out of four SPR band analyses yielded a 49R3, and such value was not in the top five best-fitting curves. Numerous curves other than the R3 yield superior statistical results. Gannett Fleming's industry database reinforces the concept that a low to mid mode dispersion pattern is more indicative than PG&E's proposed R3 dispersion pattern.

We find PG&E's proposal reasonable for a 49R3 life-curve combination for Account 369.01 which represents a two-year increase from the existing 47R3 life-curve combination. We do not find support for TURN's proposal. The statistical differences between TURN's and PG&E's data of 0.6% per year are too minor to support an ASL increase of seven years. TURN's estimate is higher than the majority of estimates for this type of property and does not reflect the principle of gradualism.

Gas Distribution Mains –Account 376

For Account 376, PG&E proposes a 57R3 life-curve combination which represents a four-year increase from the existing 53S3 life-curve combination. Gannett Fleming states that 57R3 life-curve combination has one for the highest CIs of the "anticipated" modes and reflects an ASL consistent with management's plans.

We decline to adopt TURN's recommended further increase to a 63R2.5 life-curve combination TURN disputes Gannett Fleming's claim that the SPR results suggests an ASL in the 50- to 60-year range. Depending on which SPR based analysis is relied upon, TURN believes the suggested range is more indicative of 50 to 74 years, and the best-fitting curves with excellent CIs and REIs suggest the adoption of an approximate 70-year ASL. Because there is very little statistical difference underlying the basis for TURN's versus PG&E's estimates, we do not find support for the longer life proposed by TURN.

Historically, pipe installation involved cast iron, bare steel, wrought-iron, and problematic first generation plastic pipe. Reduced levels of such pipe are still on the system, while most pipe investment now in service should be newer generation plastic pipe and wrapped steel. Newer generations of plastic pipe no longer have the chemical resin problems previously experienced or the early installation problems that resulted in an unexpectedly short life for first generation plastic mains. Current manufactured steel pipes have superior coatings that should result in a longer service life. Therefore, TURN believes a minimum of 5 to 10 years increase in ASL would be appropriate based on current technology and installation practices. Yet, PG&E has been installing newer technologies of pipe since the 1970s, so PG&E's use of historical data already reflects this effect.

Services – Gas – Account 380

For Account 380, PG&E proposes a 54R4 life-curve combination which represents a slight increase from the existing 53R4 life-curve combination. TURN recommends a 57S2.5 life-curve combination. TURN argues that the indications from SPR analyses are for much higher ASLs than the 50- to 55- year range set forth in Gannett Fleming's depreciation study. The S2.5 curve pattern provides a superior CI value compared to Gannett Fleming's proposal for all bands and reflects an excellent REI in each instance, and produces a 57-year life.

As part of its pipeline replacement program, PG&E retired many services at the same time that mains were retired. The historical database relied upon for SPR purposes thus reflects more retirement activity than it would have absent the pipeline replacement program, which is basically completed. Therefore, in evaluating the statistical results from SPR analysis, a longer ASL can be expected for replacement plant as it provides service going forward.

We find PG&E's proposed a 54R4 life-curve combination reasonable which represents a slight increase from the existing 53R4 life-curve combination. A comparison to the industry is more supportive of a more gradual approach and shorter lives than those proposed by TURN. There are 55 estimates for gas services in Gannett Fleming's database. Of these, all but four are shorter than or equal to 55 years.

Structures and Improvements --Account 390

For Account 390, PG&E proposes to retain the existing 40R3 life-curve combination. TURN recommends a 55R1.5 life-curve combination. We approve PG&E's proposal proposes to retain the existing 40R3 life-curve combination.

TURN claims that the majority of PG&E's investment in this account is associated with just the 10 largest structures owned by PG&E, and that the 10 largest structures have a weighted average installation date of 1960. TURN argues that the majority of the investment in this account (i.e., structures of buildings) indicates exceptionally long life expectancy. The third-largest investment in this account corresponds to the Fresno service center, which was placed in service in 1923 with no plans for retirement.

PG&E's analysis, however, shows that most of the investment has been installed since the original construction of each building. Thus, while some of these buildings were constructed long ago, most of the investment for each building has been added since the original construction. PG&E calculates the dollar weighted installation date for the 10 largest structures as actually 1993. Based on these considerations, we do not find support for assuming a significant increase in life expectancy over existing assumptions. We decline to adopt TURN's proposed extensions in the ASL assumptions for Account 390.

Office Machines and Computer Equipment - Account 391

For Account 391, PG&E proposes retaining the 5SQ life-curve combination for the investment. TURN argues that minimum of a one-year increase to a 6SQ life-curve combination is required. We adopt PG&E's proposal to retain retaining the 5SQ life-curve combination for the investment in Account 391.

TURN believes that based actual operational practices, industry review by outside equipment vendors, or Gannett Fleming's own industry database, a life expectancy greater than five years is appropriate. TURN believes a strong argument could be made for a seven-year or longer life expectancy, but that an increase the 5SQ proposed life-curve combination by only one year to a 6SQ life-curve combination is conservative.

PG&E's IT group has indicated that a five-year average life remains reasonable for the types of property contained in this account. Consistent with FERC 1 Accounting Release 15, PG&E uses amortization accounting for this account. Under amortization, assets are retired once they reach the end of the amortization period. PG&E implemented amortization accounting for this account in the 1996 GRC (D.95-12-055). We do not find support to conclude that any change in the current five-year average life is warranted.

(End of Appendix E-2)

Appendices F-1 to F-5

Approved Settlements and Joint Proposals

1. **Settlement Agreement Among**
   The National Asian American Coalition; The Ecumenical Center for Black Church Studies; The Chinese American Institute for Empowerment; The National Hmong American Farmers; The Burmese American Institute for Corporate Responsibility; and Pacific Gas and Electric Company

2. **Settlement Agreement Among**
   Small Business Advocates and Pacific Gas and Electric Company

3. **Partial Settlement Agreement Between and Among**
   Pacific Gas and Electric Company (U39M), The Utility Reform Network, and the Marin Energy Authority

4. **Joint Proposal of Pacific Gas and Electric Company and the Center for Accessible Technology**

5. **Joint Proposal of Pacific Gas and Electric Company, The Utility Reform Network, and Marin Energy Authority to Credit Customers the Net Proceeds Recorded in the Department of Energy Litigation Balancing Account**

SETTLEMENT AGREEMENT
AMONG
THE NATIONAL ASIAN AMERICAN COALITION;
THE ECUMENICAL CENTER FOR BLACK CHURCH STUDIES;
THE CHINESE AMERICAN INSTITUTE FOR EMPOWERMENT;
THE NATIONAL HMONG AMERICAN FARMERS;
THE BURMESE AMERICAN INSTITUE FOR CORPORATE RESPONSIBILITY; AND PACFIC GAS AND ELECTRIC COMPANY

ARTICLE 1

In accordance with Article 12 of the California Public Utilities Commission's (Commission or CPUC) Rules of Practice and Procedure, the National Asian American Coalition, the Ecumenical Center for Black Church Studies, the Chinese American Institute for Empowerment, the National Hmong American Farmers, the Burmese American Institute for Corporate Responsibility, and Pacific Gas and Electric Company (collectively, the "Settling Parties") hereby enter into this Settlement Agreement (the "Agreement") as a compromise to resolve all disputed issues raised by the Settling Parties in the revenue requirement phase of PG&E's test year 2014 General Rate Case (GRC) A.12-11-009/I.13-03-007.

ARTICLE 2

2.1 On November 15, 2012, PG&E filed its 2014 GRC Application.

2.2 On January 8, 2013, the National Asian American Coalition and the Ecumenical Center for Black Church Studies (as the "Joint Parties") filed a motion in the proceeding seeking party status and raising areas of interest.

2.3 In late 2012, the Joint Parties and PG&E commenced settlement discussions under CPUC Rule 12.

2.4 On January 11, 2013, the Commission convened a prehearing conference before Administrative Law Judge Pulsifer and Assigned Commissioner Florio.

2.5 On January 22, 2013, Commission Florio issued an "Assigned Commissioner's Ruling and Scoping Memo" setting the procedural schedule, as well as addressing the scope of the proceeding and other procedural matters.

2.6 On May 17, 2013, the National Asian American Coalition served its testimony in this proceeding. Prior to serving this testimony, the National Asian American Coalition discussed the testimony with the Ecumenical Center for Black Church Studies, the Chinese American Institute for Empowerment, the National Hmong American Farmers, and the Burmese American Institute for Corporate Responsibility. These other groups concurred with the testimony.

2.7 Also on May 17, 2013, pursuant to Rule 12.1(b), PG&E notified all parties on the service list of a settlement conference to be held on May 24, 2013 to discuss the terms of the Agreement.

2.8 On May 20, 2013, the Chinese American Institute for Empowerment, Burmese American Institute for Corporate Responsibility and the National Hmong American Farmers filed a motion seeking party status. The motion is pending.

2.9 On May 24, 2013, the Settling Parties hosted the afore-mentioned settlement conference at PG&E's offices and this Agreement was executed thereafter.

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ARTICLE 3

SETTLEMENT OF ISSUES

3.1 Customer Outreach

3.1.1 The Settling Parties agree that PG&E will commit, with the assistance of minority organizations, to expand current surveys of its service area that gauge customer understanding of safety and low-income bill assistance programs.

3.1.2 The Settling Parties agree that PG&E will devote 45% of all Customer Care Targeted Residential Rate Education and Outreach funding as authorized in its 2014 GRC up to an amount not to exceed $2.8 million annually (i.e., $8.4 million over the GRC period), toward outreach for communities of color through ethnic media, door-to-door outreach, in-language materials, and partnerships with community-based organizations.

3.1.3 The Settling Parties agree that PG&E will invite low income and community-of-color advocates to participate on an existing customer advisory panel. The scope of the advisory panel includes or will be expanded to include the provision of ongoing guidance relating to PG&E's overall outreach efforts. Meetings of the advisory panel occur on a quarterly basis.

3.1.4 The Settling Parties agree that PG&E will provide testimony in its 2017 GRC on its efforts to engage with community-based organizations on Outreach activities.

3.2 Auditing

3.2.1 The Settling Parties agree that PG&E will provide testimony in its 2017 GRC on its efforts to hire minority-owned businesses for auditing work.

3.2.2 The Settling Parties agree that PG&E will, prior to 2017, put out for bid its overall auditing function.

3.3 Diversity

3.3.1 The Settling Parties agree that PG&E will meet with key diverse business enterprise organizations attending the annual GO 156 *en banc* proceedings, no later than 60 days after the *en banc* hearing, to discuss cooperative methods for achieving GO 156 goals and addressing other issues raised by the CPUC.

3.3.2 The Settling Parties agree that PG&E will provide testimony in its 2017 GRC on its efforts to promote diverse hiring at all levels.

3.4 Economic Circumstances

3.4.1 The Settling Parties agree that, prior to the filing of the 2017 GRC, PG&E will meet with low income minority organizations to discuss the possible impact of economic recovery or lack thereof on any future proposed rate increase.

ARTICLE 4

GENERAL PROVISIONS AND TERM

4.1 The Settling Parties agree that this Agreement shall take effect upon the Commission's approval of this Agreement and shall expire on December 31, 2016.

4.2 The Settling Parties agree that this Agreement resolves all disputed issues with the Settling Parties in this GRC.

4.3 The Settling Parties agree that this Agreement is non-precedential.

4.4 The Settling Parties shall jointly request Commission approval of this Agreement.

4.5 The Settling Parties agree that unless otherwise provided in this Agreement, all proposals and recommendations by the Joint Parties are withdrawn or considered subsumed without adoption by this Agreement.

4.6 The Settling Parties agree that this Agreement represents a compromise, not agreement or endorsement of disputed facts and law presented by the Settling Parties in the 2014 GRC.

4.7 This Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matter described herein, and, except as described herein, supersedes and cancels any and all prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties.

4.8 The Agreement may be amended or changed only by a written agreement signed by the Settling Parties.

4.9 This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

4.10 The Settling Parties intend the Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies the Agreement, the Settling Parties reserve all rights set forth in Rule 12.4 of the Commission's Rules of Practice and Procedure.

In Witness Whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Agreement on behalf of the parties they represent.

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THE NATIONAL ASIAN AMERICAN COALITION By: Faith Bautista Name: FAITH BAUTISTA Date: May 24, 2013	PACIFIC GAS AND ELECTRIC COMPANY By: Trina Horner Name: Trina Horner Date: May 24, 2013
THE ECUMENICAL CENTER FOR BLACK CHURCH STUDIES By: Pastor Mark Whitlock Name: PASTOR MARK WHITLOCK Date: May 24, 2013	THE CHINESE AMERICAN INSTITUTE FOR EMPOWERMENT By: Cathy Zhang Name: Cathy Zhang Date: May 24, 2013
THE NATIONAL HMONG AMERICAN FARMERS By: Name: CHUKOU THAO Date: May 24, 2013	THE BURMESE AMERICAN INSTITUTE FOR CORPORATE RESPONSIBILITY By: V Sheibels Name: Valerie Sheibels Date: May 24, 2013

SETTLEMENT AGREEMENT

AMONG

SMALL BUSINESS UTILITY ADVOCATES

AND

PACFIC GAS AND ELECTRIC COMPANY

In accordance with Article 12 of the California Public Utilities Commission's (Commission or CPUC) Rules of Practice and Procedure, Small Business Utility Advocates (SBUA) and Pacific Gas and Electric Company (PG&E) (collectively, the "Settling Parties") hereby enter into this Settlement Agreement ("Agreement") as a compromise to resolve all disputed issues between the Settling Parties in the revenue requirement phase of PG&E's test year 2014 General Rate Case (GRC) A.12-11-009/I.13-03-007.

ARTICLE 1

RECITALS

1.1 On November 15, 2012, PG&E filed its 2014 GRC Application.

1.2 On January 11, 2013, the Commission convened a prehearing conference before Administrative Law Judge Pulsifer and Assigned Commissioner Florio.

1.3 On January 22, 2013, Commissioner Florio issued an "Assigned Commissioner's Ruling and Scoping Memo" setting the procedural schedule, as well as addressing the scope of the proceeding and other procedural matters.

1.4 On January 25, 2013, SBUA filed a motion in the proceeding seeking party status and raising interests of concern to the small business community.

1.5 On February 6, 2013, Administrative Law Judge Pulsifer granted SBUA's motion for party status.

1.6 On February 11, 2013, SBUA filed a Notice of Intent to claim intervenor compensation.

1.7 On May 17, 2013, SBUA served its expert testimony in this proceeding. SBUA testified that PG&E's revenue requests should give greater consideration to the needs of small businesses in PG&E's service territory. SBUA emphasized that small businesses make critical contributions to the economy in California by adding jobs and creating new industries. SBUA's recommendations centered on increasing services for small businesses, enhancing contract opportunities for small businesses, ensuring economic development efforts did not exclude the small business community, and assisting small electric generators. SBUA also asserted that PG&E could use an improved tracking system to identify small business customers for the purpose of more fully understanding and serving their utility needs.

1.8 In June 2012, SBUA and PG&E commenced settlement discussions under CPUC Rule 12.

1.9 On June 28, 2013, SBUA and PG&E both served rebuttal testimony in this proceeding.

1.10 On July 12, 2013, pursuant to Rule 12.1(b), PG&E notified all parties on the service list of a settlement conference to be held on July 19, 2013 to discuss the terms of the Agreement.

1.11 On July 19, 2013, the Settling Parties hosted the afore-mentioned settlement conference and this Agreement was executed thereafter.

ARTICLE 2

IMPROVED SERVICES TO SMALL BUSINESSES

2.1 Additional Outreach and Support

2.1.1 The Settling Parties agree that PG&E will dedicate 33% of the CPUC-authorized amount of its incremental expense forecast for Customer Energy Solutions, Customer Account Services activity, as described in PG&E's 2014 GRC, Exhibit (PG&E-5), Chapter 7, pp. 7-14 to 7-17, up to an amount not to exceed $8 million annually, to support the needs of Small Businesses. PG&E will target 33% of the additional full time equivalent (FTE) positions funded by the incremental expense forecast for Customer Energy Solutions in Customer Account Services to primarily serve Small Business customers.

2.1.2 The Settling Parties agree that PG&E's continued support for Small Businesses will include but not be limited to: billing issues, new service requests, planned gas or electric shutdowns, as well as providing outage and reliability communications.

2.2 **Tracking Systems**

The Settling Parties agree that PG&E will explore means to track customers that self-identify or are otherwise certified as small businesses in order to provide more tailored services to these customers. Specifically, PG&E will create a plan and/or proposal for such a tracking system, and provide a copy to SBUA, before January 1, 2015.

ARTICLE 3

IMPROVED CONTRACTING OPPORTUNITIES FOR SMALL BUSINESSES

3.1 **Supply Chain Sustainability Program**

3.1.1 In recognition of challenges Small Businesses may have under PG&E's Supply Chain Sustainability Program, the Settling Parties agree that PG&E will dedicate 33% of the CPUC-authorized amount of its incremental expense forecast for the Supply Chain Sustainability Program, as described in its 2014 GRC, for working with small businesses. Such work will include, but not be limited to:

3.1.2 Working with representatives of small businesses to address possible barriers for small businesses to participate in the program. PG&E will host at least one annual workshop each calendar year during the 2014 GRC period to discuss barriers for small businesses and PG&E will take reasonable efforts to identify and invite small businesses, as well as SBUA and other interested parties, to attend this workshop.

3.1.3 Developing training material and making it readily available on PG&E's website to educate small businesses about, and how to participate in, the Sustainability Program.

3.2 **Small Electric Generators**

The Settling Parties agree that as part of the increased number of employees identified for PG&E's Energy Procurement organization in Exhibit (PG&E-6), Chapter 5, PG&E will assign one FTE for the 2014 GRC period to support small electric generators (*i.e.*, generators that are 5 megawatts or less) under the Commission's Renewable Performance Standard (RPS) program or similar mandated procurement programs, such as the Senate Bill 1122 Feed-in Tariff program. PG&E's agreement to assign an FTE as described above is contingent on Commission approval of substantially all of the FTEs under the RPS Contract Administration and GHG requirements, as requested in Exhibit (PG&E-6), Chapter 5, p. 5-20, Table 5-7, Lines 2-3; provided, however, that PG&E will consider this assignment in good faith regardless of the number of FTEs approved by the Commission.

3.3 **Encouraging Small Businesses to Provide Energy Solutions**

The Settling Parties recognize that Small Businesses are capable of providing innovative energy solutions for PG&E's customers; and that such innovations are potentially beneficial for both PG&E and its customers. The Settling Parties agree that PG&E will provide on its website a new dedicated web page with references to resources for Small Businesses who wish to consult with others about creating innovative electricity and natural gas products.

3.4 **Green House Gas and Carbon Offsets**

3.4.1 PG&E currently intends to fulfill work related to GHG compliance and carbon offsets with internal staff. The Settling Parties agree that if and when PG&E determines to outsource this work, PG&E will engage in written outreach and education to alert Small Businesses of such contracting opportunities in advance of issuing any bids or requests for proposals.

3.4.2 The Settling Parties agree that PG&E will require any FTE positions funded for AB 32 compliance and responsible for setting commercial strategies, procuring greenhouse gas emission allowances, and pursing contracts with offset providers, as described in PG&E's 2014 GRC, Exhibit (PG&E-6), p. 5-12, to engage in written outreach and education to alert Small Businesses of any attendant contracting opportunities in advance of issuing any bids or requests for proposals.

ARTICLE 4

ECONOMIC DEVELOPMENT

4.1 The Settling Parties agree that PG&E will continue to work during the 2014 GRC period with local, regional and state officials and economic development organizations to enhance economic development programs that, among other things, support and promote small businesses. As part of this work, PG&E will encourage and work, as appropriate, with recipient organizations that receive ED funds or support from PG&E to develop services that support the needs of small businesses. Such services for Small Businesses may include those already mentioned in PG&E's 2014 GRC, (PG&E-5), Chapter 7, pp. 7-18 through 7-19 such as: (1) estimating costs and responding to customer inquiries associated with new utility services; (2) determining the service reliability and delivery options within a desired area; and (3) presenting other authorized PG&E Demand-Side Management incentives that will help lower the cost of expanding, relocating or continuing a business within PG&E's service area.

4.2 The Settling Parties agree that PG&E's involvement in the above-described Economic Development activities is contingent on the CPUC authorizing funding for PG&E's economic development organization and activities.

ARTICLE 5

IMPLEMENTATION AND MONITORING

5.1 The Settling Parties agree that PG&E will meet with SBUA and other interested persons semi-annually during the 2014 GRC period to discuss progress in all matters relating to this term sheet, as well as what actions PG&E may be taking to provide incentives for its employees, under short term incentive plans and otherwise, to provide improved services to Small Businesses.

5.2 The Settling Parties agree that PG&E will provide testimony in its 2017 GRC on its efforts and progress in implementing each of the provisions of Article 2 through Article 5 of this Agreement.

ARTICLE 6

GENERAL PROVISIONS AND TERM

6.1 For purposes of this Agreement, "Small Businesses" shall mean those businesses that generally are certified or qualify as small businesses under the California Department of Government Services, that are defined as small businesses by the CPUC or that self-identify in good faith as small businesses.

6.2 The Settling Parties agree that this Agreement shall take effect upon the Commission's approval of this Agreement and shall expire on December 31, 2016.

6.3 The Settling Parties agree that this Agreement resolves all disputed issues between the Settling Parties in the revenue requirement phase of PG&E's 2014 GRC (Phase I).

6.4 The Settling Parties agree that this Agreement is non-precedential.

6.5 The Settling Parties shall jointly request Commission approval of this Agreement.

6.6 The Settling Parties agree that unless otherwise provided in this Agreement, all proposals and recommendations by SBUA are withdrawn or considered subsumed without adoption by this Agreement.

6.7 The Settling Parties agree that this Agreement represents a compromise, not agreement or endorsement of disputed facts and law presented by the Settling Parties in the 2014 GRC.

6.8 This Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matter described herein, and, except as described herein, supersedes and cancels any and all prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties.

6.9 The Agreement may be amended or changed only by a written agreement signed by the Settling Parties.

6.10 This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

6.11 The Settling Parties intend the Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies the Agreement, the Settling Parties reserve all rights set forth in Rule 12.4 of the Commission's Rules of Practice and Procedure.

In Witness Whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Agreement on behalf of the parties they represent.

SMALL BUSINESS UTILITY ADVOCATES	PACIFIC GAS AND ELECTRIC COMPANY
By: [signature]	By: [signature]
Name: James Birkelund	Name: Trina Horner
Date: July 19 2013	Date: July 22, 2013

PARTIAL SETTLEMENT AGREEMENT BETWEEN AND AMONG PACIFIC GAS AND ELECTRIC COMPANY (U 39-M), THE UTILITY REFORM NETWORK, AND THE MARIN ENERGY AUTHORITY

I. INTRODUCTION

In accordance with Rule 12.1 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Pacific Gas and Electric Company ("PG&E"), The Utility Reform Network ("TURN"), and the Marin Energy Authority ("MEA") (collectively referred to as "the Parties" or individually as a "Party"), hereby enter into this Partial Settlement Agreement to resolve ratemaking issues raised in PG&E's *Application for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2014* ("Application"). This Partial Settlement Agreement is related to certain Administrative and General ("A&G") expenses that are currently proposed to be included in the distribution function in the General Rate Case ("GRC") for certain programs funded outside of the GRC; specifically Energy Efficiency, Demand Response, Energy Savings Assistance, California Alternate Rates for Energy, Family Electric Rate Assistance, the Self-Generation Incentive Program, California Solar Initiative ("CSI"), and Statewide Marketing, Education and Outreach (collectively "Customer Programs").

The Parties believe that this Partial Settlement Agreement is in the public interest and represents a fair and equitable resolution of the issue raised by TURN and MEA in this proceeding regarding the allocation of Public Purpose Programs ("PPP") charges in the distribution function rates and request that the Commission approve it without modification.

The Partial Settlement Agreement addresses only the allocation of certain A&G items from distribution to PPP and the Customer Programs listed in Table A below. Pension costs, post-retirement benefits and long-term disability, and other A&G expenses not related to the employee benefits and payroll taxes will remain allocated from the Customer Programs to distribution rates in this GRC. Nothing in this proposal precludes revisiting these allocations in future proceedings. This Partial Settlement Agreement does not resolve any other issues raised by the Parties in this proceeding.

II. RECITALS

A. On November 15, 2012, PG&E filed its 2014 GRC Application. PG&E's Application requested, among other relief, certain labor-related costs for the Customer Programs. (Exhibit 4 (PG&E-2), Chapter 7, Section C.)

B. On January 11, 2013, the Commission convened a prehearing conference before Administrative Law Judge Pulsifer and Assigned Commissioner Florio.

C. On January 22, 2013, Commissioner Florio issued an "*Assigned Commissioner's Ruling and Scoping Memo*" setting the procedural schedule, as well as addressing the scope of the proceeding and other procedural matters.

D. On May 17, 2013, MEA served its intervenor testimony which addressed, among other issues, PPP-related labor costs in its "A&G" forecasts. MEA's testimony requests that these PPP-related labor costs be reallocated to the generation function. (Exhibit 157 (MEA Testimony), pp. 2-7.)

E. On June 28, 2013, TURN served its rebuttal testimony of William B. Marcus. In its rebuttal testimony, TURN disagreed with MEA's proposal to allocate the PPP-related labor costs to the generation function and, instead, requests that the incremental A&G costs of PPP programs be unbundled and charged to PPP programs. (Exhibit 138 (TURN Rebuttal Testimony), pp. 2-3.)

F. On June 28, 2013, PG&E served its rebuttal testimony and addressed MEA's cost reallocation proposal. PG&E's rebuttal testimony stated that the labor component of PPP costs are customer service related costs similar to the customer service and customer accounts costs included in the distribution Unbundled Cost Categories ("UCCs") and should not be excluded from the Operations and Maintenance ("O&M") labor allocations or allocated to the transmission and generation function. (Exhibit 58 (PG&E-21), Chapter 6, pp. 6-30 to 6-34.)

G. In August 2013, the Parties conducted settlement negotiations regarding the allocation of the labor-related costs for the Customer Programs.

H. On August 29, 2013, pursuant to Rule 12.1(b), PG&E notified all parties on the service list for this consolidated proceeding, and the services lists for the Customer Program proceedings (A.11-03-001, A.11-05-019, A.12-07-001, R.12-08-007, and A.12-11-005), of the Partial Settlement Agreement and Settlement Conference.

I. On September 5, 2013, the Parties hosted the Settlement Conference at PG&E's offices and this Partial Settlement Agreement was executed thereafter.

III. BACKGROUND

For purposes of determining the GRC revenue requirements, there are certain residual costs such as A&G expenses that cannot be directly assigned to functional categories such as generation or distribution. Since PG&E's 2003 GRC, these residual costs have been allocated to UCCs[1] based on direct labor factors. In determining these labor factors, direct labor for the Customer Programs is included with distribution labor. This method was agreed upon by parties in PG&E's 2003 GRC. One of the goals of allocating residual costs in this manner is to achieve consistent allocations among the various proceedings that are litigated outside of the GRC, including Gas Transmission, Nuclear Decommissioning Cost Triennial Proceeding, Gas PPP and Electric PPP.

IV. ALLOCATION METHOD

A. The Parties agree to a method allocating a portion of A&G expenses from distribution to Customer Program revenues. This will allow Customer Program revenues to more clearly reflect the full costs of providing the services included in this category.

B. The Parties agree that costs associated with certain employee benefits and payroll taxes that are currently allocated to distribution and recovered in the GRC revenue requirement be reallocated to Customer Programs and the balancing accounts attributable to the Customer Programs, and that any necessary modifications or changes to rates and revenue requirements for these programs and balancing accounts be approved by the Commission as part of this Partial Settlement Agreement. These costs include employee benefits (medical, vision, dental,

[1] UCCs are used to assign costs to utility functional categories.

employee healthcare contributions, group life insurance, short-term incentive payments, 401 K expenses, relocation expenses, short-term disability, tuition reimbursement) and payroll taxes.

C. Except as otherwise set forth in this paragraph below, the Parties agree to a reduction to PG&E's requested GRC revenue requirement of $31,716,000 effective January 1, 2014, and an increase in the revenue requirements for the Customer Programs effective January 1, 2014, in an equal amount. The estimated increase in the annual revenue requirements for each Customer Program is set forth in Table 1 below. The actual annual revenue requirement adjustments for the GRC and the balancing accounts will be based on the final decision in this proceeding, which shall authorize the necessary increase in revenue requirements and changes in rates and related Commission decisions necessary for each of the referenced Customer Programs. The amount of the revenue requirement increase for the CSI program is subject to further adjustment based on the spending cap in Public Utilities Code Section 2851, as may be modified.

TABLE 1
REVENUE REQUIREMENT INCREASES CUSTOMER PROGRAMS (THOUSANDS OF DOLLARS)

Energy Efficiency	Electric	PEEBA	PEERAM and PPPRAM	5.64%	23,725
	Gas	PPPEBA	PPP-EE		
Energy Savings Assistance (ESA)	Electric	PPPLIBA	PPPRAM	0.59%	2,495
	Gas		PPP-LIEE		
California Alternate Rates for Energy (CARE)	Electric	NA	CAREA	0.24%	1,027
	Gas	NA	PPP-CARE		
California Solar Initiative (CSI)	Electric	CSIBA	DRAM	0.27%	1,156
Self-Generation Incentive Program (SGIP)	Electric	SGPMA	DRAM	0.04%	156
	Gas		CFCA/NCA		
Demand Response	Electric	DREBA	DRAM	0.69%	2,895
Statewide ME&O	Electric	SWMEO-E	PEERAM and DRAM	0.05%	224
	Gas	SWMEO-G	PPP-EE and PPP-LIEE		
Family Electric Rate Assistance (FERA)	Electric	FERABA	DRAM and UGBA	0.01%	38
TOTAL				7.54%	$31,716

D. Following the issuance of the final decision in this proceeding, PG&E shall increase, effective January 1, 2014, its annual revenue requirement for the Customer Programs set forth in Table 1 above along with the advice letters implementing the final decision in this proceeding. Also, PG&E will include the costs of the employees' benefits and payroll taxes in the balancing and memorandum accounts for each Customer Program effective January 1, 2014.

PG&E shall request its full labor-related expenses, other than pension costs, post-retirement benefits and long-term disability and other A&G expenses not related to the employee benefits and payroll taxes, in subsequent applications for approval of revenue requirements for the Customer Programs at the end of each currently authorized portfolio period, or as otherwise directed by the Commission. A summary of the approved portfolio cycles and associated funding decisions for the Customer Programs is attached hereto as Attachment A. If and when the Commission issues a subsequent decision approving PG&E's annual revenue requirements for a Customer Program listed in Table 1, above, such funding decision shall supersede the approved revenue requirement in this Partial Settlement Agreement on a prospective basis for such program, effective as of the date the new revenue requirement for the Customer Program becomes effective. The Parties commit to discussing the allocation of A&G costs not collected through PPP prior to the submittal of PG&E's next GRC Phase 1 application.

E. Currently distribution revenues are allocated to customer classes using different factors than used for the Customer Program revenues. This Partial Settlement Agreement does not address the factors used to allocate Customer Program revenue requirements to customer classes.

V. COMMISSION APPROVAL.

Commission Approval is a condition precedent to the effectiveness of this Partial Settlement Agreement. This Partial Settlement Agreement is binding on the Parties only if the Commission issues a decision approving it in its entirety and without modification unacceptable to any Party.

VI. EFFECTIVE DATE.

This Partial Settlement Agreement shall become binding on the Parties on the date a final Commission decision approving the terms of this Partial Settlement Agreement without modification unacceptable to any Party is issued by the Commission. Provided Commission Approval is obtained, the Effective Date of this Partial Settlement Agreement is January 1, 2014.

VII. GENERAL TERMS AND CONDITIONS.

1. The Partial Settlement Agreement is intended to be a resolution among the Parties of the allocation of the labor-related costs for the Customer Programs listed in Table 1.

2. The Parties agree to support the Partial Settlement Agreement and perform diligently, and in good faith, all actions required or implied hereunder to obtain Commission approval of the Partial Settlement Agreement, including without limitation, the preparation of written pleadings.

3. The Parties agree by executing and submitting this Partial Settlement Agreement

that the relief requested herein is just, fair and reasonable, and in the public interest.

4. The Partial Settlement Agreement is not intended by the Parties to be precedent regarding any principle or issue. The Parties have assented to the terms of this Partial Settlement Agreement only for the purpose of arriving at the compromise embodied in this Partial Settlement Agreement. Each Party expressly reserves its right to advocate, in current and future proceedings, positions, principles, assumptions, and arguments which may be different than those underlying this Partial Settlement Agreement and each Party declares that this Partial Settlement Agreement should not be considered as precedent for or against it.

5. This Partial Settlement Agreement embodies compromises of the Parties' positions. No individual term of this Partial Settlement Agreement is assented to by any Party, except in consideration of the other Parties' assent to all other terms. Thus the Partial Settlement Agreement is indivisible and each part is interdependent on each and all other parts. Any Party may withdraw from this Partial Settlement Agreement if the Commission modifies, deletes from, or adds to the disposition of the matters stipulated herein. The Parties agree, however, to negotiate in good faith with regard to any Commission-ordered changes in order to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful.

6. The terms and conditions of the Partial Settlement Agreement may only be modified in writing subscribed to by the Parties and approved by a Commission order.

The Parties have caused this Partial Settlement Agreement to be executed by their authorized representatives. By signing this Partial Settlement Agreement, the representatives of the Parties warrant that they have the requisite authority to bind their respective principals.

THE UTILITY REFORM NETWORK

By: ______________________

Hayley Goodson
Staff Attorney

Date: September 6, 2013

PACIFIC GAS AND ELECTRIC COMPANY

By: ______________________

Steven E. Malnight
Vice President, Customer Energy Solutions

Date: September 5, 2013

THE MARIN ENERGY AUTHORITY

By: ______________________

Elizabeth Kelly
Legal Director

Date: September ____, 2013

The Parties have caused this Partial Settlement Agreement to be executed by their authorized representatives. By signing this Partial Settlement Agreement, the representatives of the Parties warrant that they have the requisite authority to bind their respective principals.

THE UTILITY REFORM NETWORK

By:______________________________

Hayley Goodson
Staff Attorney

Date: September ____, 2013

PACIFIC GAS AND ELECTRIC COMPANY

By:______________________________

Steven E. Malnight
Vice President, Customer Energy Solutions

Date: September 5, 2013

THE MARIN ENERGY AUTHORITY

By:______________________________

Elizabeth Kelly
Legal Director

Date: September ____, 2013

The Parties have caused this Partial Settlement Agreement to be executed by their authorized representatives. By signing this Partial Settlement Agreement, the representatives of the Parties warrant that they have the requisite authority to bind their respective principals.

THE UTILITY REFORM NETWORK

By:____________________________

Hayley Goodson
Staff Attorney

Date: September ____, 2013

PACIFIC GAS AND ELECTRIC COMPANY

By:____________________________

Steven E. Malnight
Vice President, Customer Energy Solutions

Date: September 5, 2013

THE MARIN ENERGY AUTHORITY

By:____________________________

Elizabeth Kelly
Legal Director

Date: September 6, 2013

Attachment A to Partial Settlement Agreement

Programs	Type	Expense Accounts	Recovery Accounts	Current Proceeding	Funding Decision	Current Cycle
Energy Efficiency	Electric	PEEBA	PEERAM and PPPRAM	A.12-07-001	D.12-11-015	2013-2014
	Gas	PPPEBA	PPP-EE			
Energy Savings Assistance (ESA)	Electric	PPPLIBA	PPPRAM	A.11-05-019	D.12-08-044	2012-2014
	Gas		PPP-LIEE			
California Alternate Rates for Energy (CARE)	Electric	NA	CAREA	A.11-05-019	D.12-08-044	2012-2014
	Gas	NA	PPP-CARE			
California Solar Initiative (CSI)	Electric	CSIBA	DRAM	R.12-11-005	D.06-12-033	2007-2016
Self Generation Incentive Program (SGIP)	Electric	SGPMA	DRAM	R.12-11-005	D.11-12-030	2001-2016
	Gas		CFCA/NCA			
Demand Response	Electric	DREBA	DRAM	A.11-03-001	D.12-04-045	2012-2014
Statewide ME&O	Electric	SWMEO-E	PEERAM and DRAM	A.12-08-007	D.13-04-021	2013-2014
	Gas	SWMEO-G	PPP-EE and PPP-LIEE			
Family Electric Rate Assistance (FERA)	Electric	FERABA	DRAM and UGBA	A.11-05-019	D.12-08-044	2012-2014

EXHIBIT 2
COMPARISON BETWEEN RATE CASE REQUEST AND SETTLEMENT AGREEMENT
(CPUC RULE 12.1(A))

	GRC Application	Settlement Agreement	Reduction in GRC Request*
Customer Program A&G	31,716,000	0	31,716,000

*The reduction in the GRC revenue request would be wholly or partially offset by increases in the approved revenue requirements for Customer Programs, depending on the outcome of the decision.

APPENDIX F-4

Adopted Provisions of the Joint Proposal of Pacific Gas and Electric Company (PG&E) and the Center for Accessible Technology (C for AT)

The Joint Proposal of PG&E and C for AT as set forth in Exhibit 22 (PG&E-5), Ch. 11, at 11-2 to 4 is hereby adopted, as set forth below:

A. Terms of the Joint Proposal Required

1. **Level of Spending to be Authorized and Tracked**

    PG&E shall spend $1.5 million per year on activities to improve accessibility. Eligible activities shall include those activities set forth in Section B of this appendix.

    The $1.5 million spending target has been included in the revenue requirement forecast through a high-level adjustment in PG&E's Results of Operations (RO) Model. Specifically, the $1.5 million has been entered as an expense item to the "Other Adjustments: line in the RO model.[1] The amount is not included in the totals presented in PG&E's Customer Care exhibit.

    The forecast has been included as a high-level adjustment in the RO Model for two reasons. First, the Center for Accessible Technology and PG&E finalized the joint proposal in October 2012 after the completion of most calculations within the RO Model, including the calculations for the Customer Care exhibit. Second, several possible areas of activity in the joint proposal extend beyond the scope of the Customer Care exhibit, such as the work on utility poles and temporary construction practices.

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[1] Exhibit (PG&E-2), Chapter 18, page 18-6, lines 29-30, page 18-7, lines 1-3.

To track the level of spending, PG&E will create one or more major work categories or planning orders that are specific to the work undertaken under the joint proposal. This will enable clear tracking and reporting of PG&E's spending toward the target.

2. Annual Reporting

PG&E shall prepare and distribute to the Center for Accessible Technology, and any other interested parties, an annual report on its activities and spending to promote accessibility. The annual report shall, among other things, address whether PG&E's spending has met the level set forth above. If PG&E's spending has not met the target level, the annual report shall explain in detail why PG&E has not done so. PG&E shall distribute the annual report by the end of April for the prior calendar year.

3. New Coordinator for Accessibility Issues

PG&E shall hire a new Disability Coordinator. The Disability Coordinator would be responsible for coordinating and shaping Company-wide strategies to improve accessibility. If PG&E is unable to fill this role, PG&E shall explain in detail in the annual report (described above) the efforts that were undertaken by the Company toward this objective.

4. Consultation With Interested Parties

Prior to the start of each calendar year, PG&E shall meet with the Center for Accessible Technology, and any other interested parties, to discuss planned accessibility spending for the upcoming calendar year. Such meetings would typically take place during the fourth quarter of each calendar year. The first such meeting shall take place or within two months of the Commission's matter.

5. Term and Effectiveness

The commitments in this joint proposal shall apply only to the 2014 GRC period and shall only become enforceable upon the Commission's issuance of a final decision in PG&E's 2014 GRC that specifically approves and funds these provisions of the joint proposal.

B. Eligible Activities Under the Joint Proposal

The following types of costs associated with accessibility improvements are eligible for accounting toward the target spending level of $1.5 million per year.

<u>Disability Coordinator and Related Work</u>

- Costs associated with the new coordinator for accessibility issues, including salary and overhead costs.
- Costs associated with the production of the annual report and consultation with interested parties.

<u>Local Offices</u>

- Costs associated with follow-up inspections at local offices to identify remaining or emergent accessibility issues.
- Costs associated with ongoing training for local office personnel in improving accessibility.

<u>Pay Stations</u>

- Costs associated with ongoing survey/alternative efforts to monitor accessibility at Pay Stations.
- Costs associated with the monitoring of ongoing vendor accessibility.
- Costs associated with identifying new accessible locations.
- Costs associated with the ongoing distribution of an up-to-date list of accessible locations.

<u>Temporary Construction Practices</u>

- Costs associated with ongoing training regarding accessibility.
- Equipment maintenance/replacement for use in temporary construction sites.

- Costs associated with the continuing monitoring for compliance with protocols.
- Costs for Audible Alerts at PG&E construction sites.

Utility Poles

- Costs for continued coordination with local governments regarding accessibility issues arising out of the placement of utility poles.
- Costs associated with Rule 20A accessibility issues.

Communications Issues

- Costs associated with maintaining TTY and Relay systems and training personnel at PG&E's Contact Centers.
- Costs associated with Web Accessibility, including the following:
  - Review of work from 2011 Agreement with Disability Rights Advocates
  - Follow up on third-party applications regarding issues identified per 2011 GRC agreement with DisabRA
  - Follow up on any newly identified web accessibility issues
  - Ongoing training and review of accessibility for Information Technology and related personnel
- Costs associated with the ongoing efforts to provide key information in large print on outgoing customer communications.
- Costs to expand the provision of alternative formats for customer information.
- Costs associated with the expansion of efforts around outreach/education regarding customer accessibility issues.
- Costs for continued training on communications issues.
- Cost associated with the identification of disabled customers and use of preferred formats.

(End of Appendix F-4)

APPENDIX F-5

Joint Proposal for Procedure for Crediting to Customers the Net Proceeds Recorded in the Department of Energy Litigation Balancing Account

The Joint Proposal of Pacific Gas and Electric Company (PG&E), Marin Energy Authority (MEA), and The Utility Reform Network (TURN), as set forth in Exhibit 330, for crediting net proceeds recorded in the Department of Energy Litigation Balancing Account is adopted, as prescribed below.

In the fourth quarter of 2012 PG&E received an initial payment of $266,104,245 for spent fuel storage costs and other reimbursable damages incurred through 2010 ("Initial Claims" amount). In the fourth quarter of 2012, PG&E received an additional $28,913,134 for costs incurred in 2011 and through May of 2012, under an administrative claims process. Under the settlement with the Department of Energy (DOE), PG&E expects to receive additional settlement amounts to compensate it for its ongoing costs of storing nuclear fuel on site. These settlement proceeds are estimated to be $20 million per year for 2014 through 2016.

The following method is adopted for crediting Department of Energy Litigation Net Proceeds to customers is as follows:

a) Initial Claim Proceeds

- The Initial Claims amount is $266,104,245.
- Initial Claims proceeds related to costs incurred at the Humboldt Bay Nuclear plant will be credited to the Nuclear Decommissioning Adjustment Mechanism (NDAM), thereby reducing the Nuclear Decommissioning Non-bypassable charge.
- Initial Claims Proceeds related to ISFSI costs incurred after 2001 at Diablo Canyon will be credited to the Utility Generation Balancing Account (UGBA), which will reduce any Power

Charge Indifference Amount paid by non-exempt departing load customers.

- Initial Claims Proceeds related to other costs incurred at DCPP will be credited to the NDAM.
- These credits will be reflected in NDAM and UGBA rates equally over the 2014 GRC period.
- This treatment will be reflected in the advice letters implementing this decision and the Triennial Nuclear Decommissioning Proceeding currently ongoing, and subsequent AET proceedings.

b) 2011 – May 2012 Claim Proceeds

- PG&E received a settlement payment from DOE of $28,913,134 for costs incurred in 2011 through May of 2012.
- Claim proceeds for the period of 2011 through May 2012 will be split with 72% credited to UGBA and 28% credited to NDAM. The proposed split percentages are based on the amount of the claim proceeds related to costs incurred at Diablo Canyon (UGBA) and Humboldt (NDAM). These credits will be reflected in NDAM and UGBA rates equally over the 2014 GRC period.
- This treatment will be reflected in the advice letters implementing this decision and the Triennial Nuclear Decommissioning Proceeding currently ongoing, and subsequent AET proceedings.

c) Future Claims Proceeds

- Future claims proceeds that are received prior to December 31, 2016 will be split using the same percentages as the 2011 – May 2012 Claim proceeds: 72% credited to UGBA and 28% credited to NDAM. Treatment of receipts received after 2016 will be decided in the next General Rate Case, subject to any accounting guidance provided in the current General Rate Case or determinations in the Triennial Nuclear Decommissioning Proceeding regarding future claims and post-2016 spent nuclear fuel storage costs.
- Future Claims Proceeds will be credited to DOELBA as received and transferred to UGBA and NDAM on the January 1st of the following

year. These amounts will be reflected in UGBA and NDAM rates in the AET Advice Letter for the year following receipt.

- The following table summarizes the treatment and the preliminary amount of the claims: The actual amounts as of December 31, 2013 shall be reflected in the advice letter entries submitted by PG&E.

DOE Settlement Proceeds

(in thousands of dollars)

	Amount	UGBA	NDAM
Initial Claim			
Humboldt Bay	$134,669		$134,669
DCPP ISFSI 2002 onward	$108,548	$108,548	
Other DCPP	$22,887		$22,887
Subtotal Net Proceeds	$266,104	$108,548	$157,556
2011-2012 Claim			
Humboldt Bay	$8,161		$8,161
DCPP	$20,752	$20,752	$8,161
Subtotal 2011-2012 Claim	$28,913	$20,752	$8,161
Total Proceeds through 2013	$295,017	$129,300	$165,717
Litigation Costs	($14,958)	($7,479)	($7,479)
Net Proceeds through 2013	$280,059	$121,821	$158,238
Subsequent Claims 2014-2016	-	72%	28%

(End of Appendix F-5)