Docket:	:	A.09-12-020
Exhibit Number	:	DRA-6
Commissioner	:	Peevey
ALJ	:	Fukutome
Witness	:	Wilson

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Pacific Gas and Electric Company General Rate Case Test Year 2011

Electric Distribution Capital Expenditures
(excluding New Business, Work at the Request of Others, and Rule 20A)

San Francisco, California
May 5, 2010

TABLE OF CONTENTS

ELECTRIC DISTRIBUTION CAPITAL EXPENDITURES
(excluding New Business, Work at the Request of Others, and Rule 20A)

I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Division of Ratepayer Advocates (DRA) regarding Pacific Gas and Electric Company's (PG&E) forecasts of Electric Distribution capital expenditures for 2010 and Test Year (TY) 2011, excluding those associated with New Business, Work at the Request of Others, and Rule 20A, which are addressed in Exhibit DRA-8.

PG&E's electric distribution system serves over 5 million customers. Its service territory stretches from Eureka to Bakersfield, and from the Pacific Coast to the Sierras. To provide electric service to this large geographic area, PG&E maintains approximately 2.3 million poles, 770 substations, 113,500 miles of overhead circuits, 27,500 miles of underground circuits, 330,000 underground locations, and 2,350 distribution substation transformers.[1]

Electric distribution capital expenditures include plant investment in new and/or expanded distribution substations, underground cables, and the replacement/reinforcement of distribution poles. These types of capital expenditures are typically used to construct or modify facilities for the distribution of electricity, to construct or modify substations to transform transmission voltage to a lower distribution voltage, and to improve system reliability (including aging infrastructure issues).

The dollar amounts presented in this exhibit are capital expenditures. As will be discussed later, this exhibit does not specifically address PG&E's capital additions, which are automatically calculated by the Results of Operations (RO) computer model based on the capital expenditures that are loaded into it.

[1] Exhibit PG&E-3, page 1-41, lines 1 through 4.

Section II of this exhibit presents an overview of DRA's recommended adjustments. Section III discusses UCCs (Unbundled Cost Categories) and MWCs (Major Work Categories), and provides some background on how capital expenditures are organized. Section IV discusses DRA's concerns regarding PG&E's deferral of previously authorized capital expenditures. Section V provides detailed discussions of the investigations and analyses that form the basis of DRA's recommendations.

II. SUMMARY OF RECOMMENDATIONS

DRA recommends that the Commission adopt PG&E's recorded 2009 capital expenditures. The following bullets summarize DRA's capital recommendations for 2010 and 2011 by Major Work Category (MWC):

- Expenditures for Preventive Maintenance – Capital (MWC 57) should be reduced by $11.716 million in 2010 and by $46.116 million in 2011.
- Expenditures for Replace/Reinforce Poles (MWC 7) should be reduced by $20.575 million in 2011.
- Expenditures for Replace Substation Equipment (MWC 48) should be reduced by $16.700 million in 2011.
- Expenditures for New Capacity – Line (MWC 6) should be reduced by $0.784 million in 2010 and by $0.630 million in 2011.
- Expenditures for New Capacity – Substations (MWC 46) should be reduced by $5.400 million in 2010 and by $5.350 million in 2011.
- Expenditures for Tools and Equipment – Other (MWC 5) should be reduced by $2.236 million in 2010.
- Expenditures for T&D Mainline Protection and Rebuild (MWC 49) should be reduced by $22.500 million in 2010 and increased by $7.500 million in 2011.
- Expenditures for Automation (MWC 9) should be reduced by $7.600 million in 2011.
- Expenditures for Replace Underground Cable (MWC 56) should be reduced by $33.847 million in 2011.

Table 6-1 (see next page) shows recorded expenditures and compares DRA's recommendations for 2010 and 2011 with PG&E's proposed forecasts:

TABLE 6-1
ELECTRIC DISTRIBUTION CAPITAL EXPENDITURES -- UCC 301 (Functional Only)
Recorded and PG&E's Estimated Data From Page WP 1-19 of Exhibit PG&E-3, Workpapers Supporting Chapter 1
Nominal Dollars ($000)

				1	2	3	4	5	6	7	8	9	10	11	12
Line #	Exhibit PG&E-3	MWC	MWC Description	Recorded						Estimated					
				2004	2005	2006	2007	2008	2009 1/	2010		2011			
										PG&E	DRA	PG&E	DRA	PG&E ≥ DRA	%
1	Chapter 2	57	E Distribution Preventive Maintenance - Capital	58,284	61,591	71,896	72,769	77,934	81,592	74,514	62,798	130,034	83,918	46,116	54.95%
2	Chapter 3	7	E Distribution Replace/Reinforce Poles	59,446	40,134	37,772	28,773	33,292	34,239	37,913	37,913	60,000	39,425	20,575	52.19%
3	Chapter 8	48	E Distribution Replace Substation Equipment	20,679	15,905	20,592	16,994	28,579	29,767	35,521	35,521	72,796	56,096	16,700	29.77%
4		54	E Distribution Replace Substation Transformers	28,025	14,058	17,094	33,239	46,514	52,335	52,606	52,606	79,545	79,545	0	0.00%
5		58	E Distribution Replace Substation Safety	1,261	3,370	2,209	3,341	1,997	788	2,425	2,425	6,360	6,360	0	0.00%
6		59	E Distribution Replace Substation Emergency	16,147	22,165	28,182	32,945	33,060	34,566	23,940	23,940	32,000	32,000	0	0.00%
7	Chapter 9	6	E Distribution New Capacity - Line	28,813	39,639	70,234	75,104	88,699	83,565	82,964	82,180	92,501	91,871	630	0.69%
8		46	E Distribution New Capacity - Substations	16,405	34,800	52,628	73,552	106,621	94,790	77,890	72,490	111,663	106,313	5,350	5.03%
9	Chapter 10	5	E&G Tools & Equipment - Other	(2,090)	(1,432)	(1,640)	230	(1,564)	(2,711)	2,236	0	0	0	0	0.00%
10		8	E Distribution Mitigate Recurring Outages	8,766	9,840	13,054	11,054	9,925	9,268	11,361	11,361	13,300	13,300	0	0.00%
11		49	E T&D Mainline Protection and Rebuild	4,325	6,966	12,139	21,896	30,015	31,851	61,586	39,086	30,000	37,500	(7,500)	(20.00%)
12	Chapter 11	9	E Distribution Automation	4,948	4,605	4,895	8,737	8,605	7,609	9,006	9,006	34,200	26,600	7,600	28.57%
13	Chapter 12	56	E Distribution Replace Underground Cable	16,447	35,102	33,396	30,050	21,883	16,854	17,231	17,231	51,354	17,507	33,847	193.34%
14	Chapter 14	17	E Distribution Emergency Response	64,234	66,428	77,318	80,735	98,301	111,540	109,914	109,914	124,217	124,217	0	0.00%
15		95	E Major Emergency	16,111	15,071	58,140	26,186	69,139	41,396	33,900	33,900	35,995	35,995	0	0.00%
16	Chapter 23	5	E&G Tools & Equipment - ATS	8	44	454	200	438	510	540	540	568	568	0	0.00%
17		78	E Manage Buildings - ATS	0	0	19	66	9	1,101	1,070	1,070	1,000	1,000	0	0.00%
18			**TOTAL**	**341,809**	**368,286**	**498,382**	**515,871**	**653,447**	**629,060**	**634,617**	**591,981**	**875,533**	**752,215**	**123,318**	**16.39%**

1/ NOTE: 2009 Recorded data was obtained from PG&E in an e-mail dated 2/17/10. PG&E's 2009 Forecast was $623,152.

III. DISCUSSION

A. Background for Capital Expenditures

Capital expenditures are cumulative in nature. Expenditures made during one year are added to expenditures that were made in previous years. Therefore, DRA must analyze all of the proposed capital expenditures occurring from the end of the last recorded year (2008) that was provided by PG&E in its application up through the end of the test year (2011). Proposed capital expenditures or additions for the attrition years (2012 and 2013) are also addressed by DRA, but are discussed in another exhibit.

Ideally, DRA tries to obtain an additional recorded year of plant data (in this case 2009) in order to eliminate one year of estimating uncertainty. Fortunately, for this General Rate Case (GRC), DRA was able to obtain recorded 2009 capital expenditure data from PG&E. These data were available at the MWC level of detail and are shown in column 6 of Table 6-1. Some of the tables shown in this exhibit present capital expenditures in finer detail than the MWC level. In those instances, those tables are usually shown with the forecasts for the year 2009 shown as an estimate, as the recorded details necessary to calculate the sub-MWC projects were not available.

In its exhibits and workpapers, PG&E has presented its capital forecasts in nominal dollars. “Nominal” dollars refers to the fact that PG&E’s forecasts are presented with estimates keyed to the year in which they occurred. Put another way, inflation is included in PG&E’s numbers. For example, a 2011 capital expenditure will use 2011 dollars for its estimate, rather than presenting the estimate in constant dollars from a prior year (with inflation added later). Because the exhibits, workpapers, and the computer model are all set up to use nominal dollars, DRA is presenting its capital analyses and estimates in the same manner.

It is important to note the difference between capital expenditures and capital additions. As mentioned previously, PG&E’s capital forecasts are presented as expenditures, not additions. Capital expenditures simply reflect the dollars that are being spent in a given year. Contrast this with capital additions, which reflect the amount of completed capital projects that are being booked to plant in a given year. Capital expenditures may or may not equal additions for any year; more often than not, they will not agree. The reason for this difference is that capital projects that are started in a given year, but not completed until the next, will show up as an expenditure in that first year, but will not be included as an addition until the second. (Since it is not "used and useful," it cannot be considered a plant addition until the second year.) The main reason for making this distinction is to alert the reader that the impact of DRA's proposed capital adjustments may not show up in the year in which they were made.

PG&E's capital exhibits and supporting workpapers (as well as its Results of Operation (RO) computer model) are organized around capital expenditures. PG&E's capital witnesses provide testimony regarding the magnitude of the capital dollars that are estimated to be spent each year, not how much is actually being booked to plant. PG&E relies on its RO computer model to manipulate these capital expenditures; based on when the capital projects are scheduled to be completed, the RO model calculates the corresponding capital additions. Therefore, DRA's analyses and recommended capital adjustments are also stated in terms of capital expenditures.

B. Functional Dollars

In the heading for Table 6-1, the term "Functional" is used in the second line. PG&E uses the term "Functional" to refer to capital costs recorded in the Federal Energy Regulatory Commission (FERC) system of accounts.[2] This category is distinct from other types of capital expenditures, such as Common, General, and Intangible. These other categories of capital expenditures are analyzed and discussed in other DRA exhibits. Unless stated otherwise, all capital amounts shown in this exhibit only contain "Functional" dollars.

[2] Exhibit PG&E-2, page 9-4, footnote 4.

C. Unbundled Cost Categories and Major Work Categories

Consistent with previous Commission decisions, PG&E separates its utility business into numerous Unbundled Cost Categories (UCCs). Each of the 74 UCCs listed in PG&E's RO computer model represents a distinct aspect of PG&E's operations. Many of these UCCs represent facets of PG&E's business that are outside the review of this GRC, including UCCs for the Cornerstone Reliability Projects, Electric Transmission, Gas Storage, etc. As initially received from PG&E, the RO model lists 22 UCCs that are actually included in this GRC. Of those, only four UCCs actually pertain to Electric Distribution:[3]

- UCC 301 – Wires and Services
- UCC 302 – Transmission-Level Direct Connects
- UCC 303 – Public Purpose Program Administration
- UCC 305 – Dynamic Pricing

This DRA exhibit only analyzes capital projects associated with UCC 301. Any capital costs contained in the other three UCCs are discussed in other DRA exhibits.

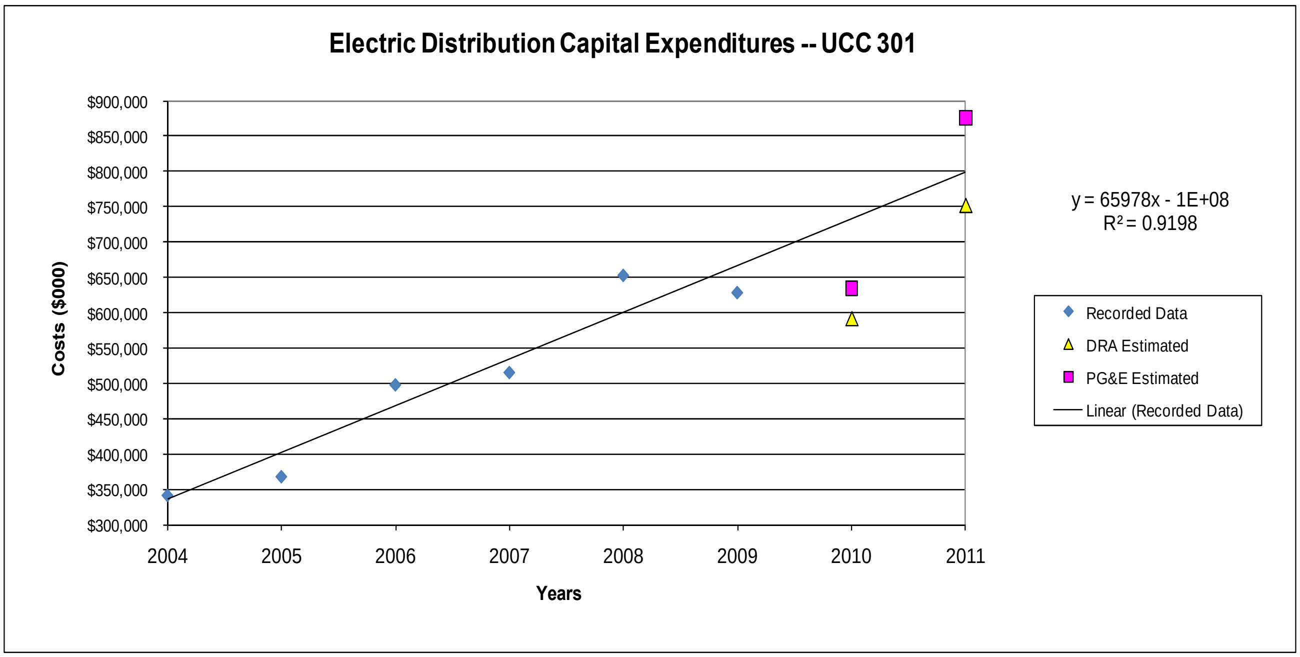
PG&E divides its capital projects into Major Work Categories (MWCs). MWCs are descriptive categories into which are placed the numerous capital projects being proposed by PG&E. Table 6-1 lists the 17 capital MWCs that are being analyzed in this exhibit. These 17 MWCs do not constitute all of the capital MWCs contained in UCC 301. As mentioned in the Introduction of this exhibit, MWCs for New Business, Work at the Request of Others, and Rule 20A are not analyzed here. PG&E has proposed using one-way balancing accounts for these three capital areas, believing that these customer/agency driven expenditures are somewhat uncertain due to the slowdown in the California economy. DRA has elected to discuss and analyze all of the proposed one-way balancing accounts in a separate exhibit.

[3] Exhibit PG&E-2, page 9-4, Table 9-2, line 2.

D. Overview of Electric Distribution Capital Adjustments

Earlier in this exhibit, Table 6-1 presented a detailed look at the capital expenditures being forecasted by PG&E and DRA for the years 2010 and 2011. However, given the level of detail contained in that table, it may be difficult to visualize how the proposed expenditures compare to the recorded data. The following graph compares the overall forecasts with the trend of past recorded expenditures:

Graph 6-1
Electric Distribution Capital – UCC 301
Historical and Forecast Capital Expenditures
Nominal Dollars ($000)



As this graph shows, both PG&E and DRA are forecasting 2010 expenditures that are less than the historical trend. However, 2011 expenditures are projected to increase substantially, with PG&E's forecast being higher than the historical trend. PG&E gives various reasons for this projected accelerated 2011 increase, including catching up on previously deferred capital expenditures, replacing aging infrastructure, and strengthening the distribution system to accommodate increased loads. DRA has analyzed these issues and concluded that in some instances, PG&E’s capital forecasts are reasonable. However, as Table 6-1 indicates, DRA has not agreed with many of PG&E’s forecasts. Section V of this exhibit discusses and analyzes each of DRA’s recommended adjustments.

IV. DEFERRED CAPITAL EXPENDITURES

One of the fundamental principles of utility regulation in California is that revenue requirements resulting from General Rate Cases (GRCs) are not developed using recorded data, but are instead calculated using forecasts of expenses and capital additions for future years. These so-called future test years provide an incentive for utilities to develop new, more efficient ways to run their companies. If a utility can devise more cost-effective ways to do business, it can retain the difference between what it was authorized in the future test year and what it actually spends. Of course, with test year rate making, utilities also run the risk of spending more than what they were authorized if unexpected expenses or capital additions are necessary.

Another fundamental principle of utility regulation is that the California Public Utilities Commission (CPUC) typically does not micromanage the way that utilities spend their dollars. The CPUC assumes that utility managers are in the best position to make the numerous decisions that are required to run a utility efficiently and reliably. If expenditures in one area are less than expected, utility managers can decide to shift those unexpended funds to other areas where expenditures may be higher.

Taken together, these two principles provide a framework for how utilities are expected to operate in California. Since it is never possible to forecast test years with 100% accuracy, utilities can earn more than authorized in some years (when actual expenses/additions are less than forecasted, or if the utility develops a more cost-effective way of doing business), and can earn less than authorized in other years (when actual expenses/additions are greater than forecasted, or the utility is not run efficiently). Utility managers are expected, and even encouraged, to make the decisions necessary to run their utilities in as efficient a manner as possible, consistent with reliable service.

In regards to this particular PG&E GRC, DRA is concerned with PG&E's stated admission that it has deferred certain capital expenditures. In Chapter 1 of Exhibit PG&E-3, PG&E states the following:

> In an effort to remain within the capital and expense expenditure levels imputed from the 2007 GRC Settlement Agreement, PG&E adjusted work where possible by focusing on work in higher priority categories.[4]

Later, in Chapter 3, PG&E states the following:

> The primary driver for the higher level of capital expenditures is the need to address poles rescheduled for replacement due to a reallocation of funds to higher priority work.[5]

Lastly, in explaining why underground cable capital expenditures are lower in 2007 through 2010, PG&E makes the following admission:

> This is because the Company redirected resources originally targeted for underground assets to other higher priority areas. Reallocating resources from underground assets to other higher priority areas is also planned for 2009 and 2010.[6]

What concerns DRA about the above quotations is that PG&E seems to be deferring capital expenditures that have been previously authorized and are ultimately required to be spent. This is not a case of a utility manager shifting authorized expenditures from an area that does not require them to an area that does; this appears to be a case of PG&E shifting authorized expenditures from an area that does need them to an area deemed to be a higher priority. While utility managers are given the authority to transfer/spend company funds as they see fit, that level of authority does not equate to an automatic acceptance of every managerial decision that is made. For example, as recent Commission decisions

---

[4] Exhibit PG&E-3, page 1-35, lines 10 through 13.

[5] Exhibit PG&E-3, page 3-1, lines 26 through 29.

[6] Exhibit PG&E-3, page 12-5, lines 15 through 18.

have ruled, utilities are usually not allowed a second opportunity to recover expenses that were previously authorized but were subsequently deferred. The same should hold true for deferred capital expenditures; DRA does not believe that it is appropriate to defer authorized capital expenditures away from capital projects deemed necessary by the utility, and then seek recovery of the same projects in a later proceeding.

When necessary authorized expenditures are deferred, PG&E appears to be circumventing the fundamental principle of test year ratemaking stated above (i.e., that utilities run the risk of spending more than what they were authorized if unexpected and/or higher than expected expenses or capital additions occur). Taken to an extreme, it is hypothetically possible for a utility to never earn less than what it was authorized; if expenses or capital projects are higher than forecasted, it could theoretically simply defer sufficient expenditures, no matter how essential they may be, to offset the higher expenses/additions. This type of ratemaking philosophy skews the GRC process in the utility's favor (i.e., a utility is free to retain unspent revenues when actual costs are less than authorized, but never spends more than authorized because it is able to defer expense/plant expenditures that exceed what was forecasted). DRA does not believe that this should be a practice that is condoned by the Commission.

As shown on Table 1-1 of Exhibit PG&E-3 (page 1-36), PG&E claims that it spent $139 million more in capital expenditures than was authorized in the 2007 Settlement: $1,099 million actually spent versus $960 million authorized. Table 1-1 must include capital expenditures other than electric distribution, as the Settlement specifically adopts $862.0 million for electric distribution, not the $960 million included in the table.[7] However, whether or not Table 1-1 includes non-electric distribution capital expenditures is of little consequence. As the quotations presented earlier in this section clearly show, PG&E deferred capital expenditures that had previously been authorized "in an effort to remain within the capital and

[7] Decision 07-03-044, page 62.

expense expenditure levels imputed from the 2007 GRC Settlement Agreement." The fact that PG&E claims that it actually spent more than was authorized does not diminish the fact that it engaged in a practice that was designed to ameliorate its higher than expected capital expenditures. As stated previously, DRA believes that expenditures that are higher than authorized are simply the naturally occurring result of test year ratemaking.

Historically, Commission decisions have frequently ruled that utilities should not be permitted to recover expenses that have previously been authorized but were deferred. Recent Commission decisions are starting to take the same position regarding deferred capital expenditures, echoing DRA's concerns expressed above. In the decision for Southern California Edison's (SCE) Test Year 2003 GRC (D.04-07-022), the Commission discussed the need to consider SCE's deferral of pole inspections and stated that:

> This is necessary to ensure that ratepayers are not required to pay a second time for activities explicitly authorized by the Commission in the past …[8]

Later, in the same decision, the Commission stated:

> Based on the foregoing, we will reduce SCE's capital forecast for pole replacements by $3.447 million (68,934 intrusive inspections that were funded by ratepayers but not performed by SCE times $50 per missed inspection).[9]

In the last PG&E GRC decision (D.07-03-044) for Test Year 2007, the Commission stated:

> More recently, the Commission disallowed $1.4 million in annual expenses and $3.4 million in capital costs that SCE requested for

---

[8] Decision 04-07-022, page 106.

[9] Decision 04-07-022, page 110.

> deferred pole maintenance, stating that "ratepayers should not be required to pay twice for the same authorized expense."[10]

Later, in the same decision, the Commission stated:

> The Commission has repeatedly held that it is unjust and unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past. Here, there is no dispute that PG&E received funding for lead paint and PCB abatement in its prior GRC proceeding, and that PG&E seeks funding for these activities a second time in the current proceeding. … In order to find that the Settlement Agreement is consistent with the law, which includes adherence to long-established Commission precedent, we must be satisfied that all of PG&E's lead paint and PCB abatement costs are excluded from the O&M expenses adopted by the Settlement.[11]

Lastly, in D.09-03-025, SCE's Test Year 2009 GRC, the Commission states the following:

> In this proceeding, SCE seeks additional funds for activities explicitly authorized by the Commission in the past. SCE seeks funds to redress maintenance postponed due to unanticipated load and customer growth in 2006-2007. To address this unforeseen customer and load growth, SCE diverted millions of dollars in capital replacements away from its Infrastructure Replacement project … In the past, we have found circumstances, such as the unanticipated scope of Year 2000 (Y2K) projects, to justify deferral of certain maintenance work. The circumstances surrounding Y2K and the related Y2K projects were one-time events and, as such, unique. In contrast, we do not find customer and load growth, even when unanticipated, to create unique circumstances. Load growth and customer growth are routine aspects of any rate case. If the adopted forecast overestimates expenses we do not ask a utility to return funds to ratepayers. Similarly, if an adopted forecast underestimates expenses, we do not go back and give the utility funds to complete projects that should have been addressed in the prior GRC cycle. In short, errors in forecasting occur and we do not go back and fix these errors. Consistent with our policy regarding deferred maintenance, in certain instances in this decision, we adopt reductions to SCE's forecast for operation & maintenance

---

[10] Decision 07-03-044, page 93.

[11] Decision 07-03-044, pages 94 and 95.

and capital expenditures to reflect our finding that unanticipated load and customer growth does not justify SCE's decision to, among other things, defer maintenance.[12]

DRA urges the Commission to continue the practice of not allowing utilities to seek funds for previously authorized capital expenditures that are necessary but have been deferred. In Section V, DRA discusses and analyzes the differences it has with PG&E's capital forecasts. In several of those analyses, the ratemaking concerns raised here play a factor in DRA's recommended adjustments.

V. DISCUSSION / ANALYSIS OF DRA'S ADJUSTMENTS

DRA is recommending adjustments to nine of the 17 MWCs analyzed in this exhibit. DRA has met with PG&E's witnesses and issued numerous data requests in order to get additional information and clarify issues. All of PG&E's proposed expenditures were carefully analyzed. The following nine sections (some with multiple sub-sections) discuss each of the capital MWCs shown in Table 6-1 for which DRA has recommended adjustments.

A. MWC 57 – Preventive Maintenance - Capital

PG&E owns, operates, and maintains a large electric distribution system. The capital expenditures contained in MWC 57 (discussed in Chapter 2 of Exhibit PG&E-3) are designed to replace deteriorated overhead and underground facilities when it is not cost effective to repair them. Typical equipment replacements include corroded transformers, deteriorated cross-arms, inoperative line switches, and damaged underground enclosures.[13] MWC-57 is actually comprised of numerous sub-MWCs. Table 6-2 (see next page) provides details on these various capital areas. The following sub-sections discuss each of the recommended adjustments shown on Table 6-2.

---

[12] Decision 09-03-025, pages 3 through 5.

[13] Exhibit PG&E-3, page 2-42, lines 13 through 15.

TABLE 6-2
MWC 57 -- ELECTRIC DISTRIBUTION PREVENTIVE MAINTENANCE (Functional Only)
Recorded and Forecasted Data From Pages WP 2-3 and WP 2-13 of Workpapers Supporting Exhibit PG&E-3 (Vol 1 of 3)
Nominal Dollars (Shaded Totals in $000)

		1	2	3	4	5	6	7	8	9	10
Line #	**MWC 57 Description**	**Recorded**					**Estimated**				
		2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**		**2011**	
								PG&E	**DRA**	**PG&E**	**DRA**
1	Overhead Notifications	$37,531	$37,475	$40,507	$43,917	$39,095	$41,385	$33,060	$26,038	$42,050	$37,583
2	*# of Notifications*	*12,415*	*13,085*	*12,249*	*12,399*	*8,167*	*9,540*	*6,620*	*6,620*	*9,405*	*9,405*
3	*$ Per Notification*	*$3,023*	*$2,864*	*$3,307*	*$3,542*	*$4,787*	*$4,338*	*$4,994*	*$3,933*	*$4,471*	*$3,996*
4	Underground Notifications	$12,882	$12,060	$12,861	$13,499	$13,235	$16,092	$9,143	$8,297	$11,869	$10,608
5	*# of Notifications*	*1,959*	*1,992*	*1,868*	*1,776*	*1,000*	*1,734*	*983*	*983*	*1,237*	*1,237*
6	*$ Per Notification*	*$6,576*	*$6,054*	*$6,885*	*$7,601*	*$13,235*	*$9,280*	*$9,301*	*$8,440*	*$9,595*	*$8,575*
7	Overhead ERR	$207	$3,507	$4,633	$4,859	$9,320	$17,302	$11,403	$11,403	$6,756	$6,756
8	*# of Repairs*	*8*	*364*	*416*	*366*	*483*	*1,360*	*753*	*753*	*435*	*435*
9	*$ Per Repair*	*$25,858*	*$9,635*	*$11,136*	*$13,276*	*$19,296*	*$12,722*	*$15,143*	*$15,143*	*$15,531*	*$15,531*
10	Underground ERR	$177	$1,413	$1,512	$1,621	$2,167	$3,368	$2,381	$2,381	$1,411	$1,411
11	*# of Repairs*	*7*	*75*	*58*	*73*	*99*	*210*	*149*	*149*	*65*	*65*
12	*$ Per Repair*	*$25,315*	*$18,842*	*$26,062*	*$22,207*	*$21,889*	*$16,038*	*$15,979*	*$15,979*	*$21,706*	*$21,706*
13	Bird Safe	$1,173	$766	$1,521	$2,087	$2,512	$2,168	$2,350	$2,350	$1,704	$1,704
14	*# of Units*	*637*	*481*	*776*	*777*	*1,024*	*942*	*756*	*756*	*731*	*731*
15	*$ Per Unit*	*$1,841*	*$1,593*	*$1,960*	*$2,686*	*$2,453*	*$2,302*	*$3,109*	*$3,109*	*$2,331*	*$2,331*
16	Bird Retrofits	$1,393	$1,715	$2,501	$1,366	$1,965	$1,890	$1,971	$1,971	$2,019	$2,019
17	*# of Units*	*933*	*758*	*932*	*717*	*846*	*966*	*1,000*	*1,000*	*1,000*	*1,000*
18	*$ Per Unit*	*$1,493*	*$2,263*	*$2,683*	*$1,905*	*$2,323*	*$1,957*	*$1,971*	*$1,971*	*$2,019*	*$2,019*
19	Network Work and Projects **(See below)**	$0	$0	$0	$658	$4,476	$4,660	$7,375	$4,839	$21,518	$6,877
20	Idle Facilities Removal	$0	$0	$0	$0	$513	$0	$1,900	$600	$12,500	$600
21	*# of Units*	*0*	*0*	*0*	*0*	*24*	*0*	*76*	*24*	*500*	*24*
22	*$ Per Unit*	*$0*	*$0*	*$0*	*$0*	*$21,375*	*$0*	*$25,000*	*$25,000*	*$25,000*	*$25,000*
23	Notification Major Projects	$4,500	$4,119	$7,666	$3,863	$2,082	$400	$825	$825	$7,600	$3,980
24	*# of Units*	*113*	*133*	*314*	*140*	*96*	*16*	*33*	*33*	*304*	*159*
25	*$ Per Unit*	*$39,820*	*$30,969*	*$24,413*	*$27,593*	*$21,688*	*$25,000*	*$25,000*	*$25,000*	*$25,000*	*$25,000*
26	Other Projects	$424	$536	$690	$895	$2,566	$3,793	$4,094	$4,094	$2,154	$2,154
27	**Subtotal**	**$58,286**	**$61,592**	**$71,890**	**$72,766**	**$77,932**	**$91,058**	**$74,502**	**$62,798**	**$109,581**	**$73,692**
28	Street Light LED Replacement	$0	$0	$0	$0	$0	$0	$0	$0	$20,452	$10,226
29	**Total**	**$58,286**	**$61,592**	**$71,890**	**$72,766**	**$77,932**	**$91,058**	**$74,502**	**$62,798**	**$130,033**	**$83,918**
	Network Work and Projects										
30	Fiber Optics	$0	$0	$0	$120	$676	$800	$2,090	$2,090	$8,694	$2,174
31	*# of Units*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*1*	*4*	*1*
32	*$ Per Unit*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$2,090,000*	*$2,090,000*	*$2,173,600*	*$2,173,600*
33	SCADA Communication Upgrades	$0	$0	$0	$0	$0	$500	$520	$520	$1,622	$541
34	*# of Units*	*0*	*0*	*0*	*0*	*0*	*90*	*90*	*90*	*270*	*90*
35	*$ Per Unit*	*$0*	*$0*	*$0*	*$0*	*$0*	*$5,555*	*$5,777*	*$5,777*	*$6,008*	*$6,008*
36	Network Protector Replacement	$0	$0	$0	$484	$1,224	$1,204	$1,503	$438	$2,995	$456
37	*# of Units*	*0*	*0*	*0*	*0*	*37*	*20*	*24*	*7*	*46*	*7*
38	*$ Per Unit*	*$0*	*$0*	*$0*	*$0*	*$33,081*	*$60,200*	*$62,608*	*$62,608*	*$65,112*	*$65,112*
39	Network Transformer Replacement	$0	$0	$0	$54	$2,576	$1,664	$2,077	$606	$4,139	$630
40	*# of Units*	*0*	*0*	*0*	*0*	*35*	*17*	*24*	*7*	*46*	*7*
41	*$ Per Unit*	*$0*	*$0*	*$0*	*$0*	*$73,600*	*$97,882*	*$86,528*	*$86,528*	*$89,989*	*$89,989*
42	Network Transformer Replacement (High Rise)	$0	$0	$0	$0	$0	$0	$0	$0	$2,880	$1,890
43	*# of Units*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*32*	*21*
44	*$ Per Unit*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$89,989*	*$89,989*
45	*Manhole Covers*	$0	$0	$0	$0	$0	$492	$1,186	$1,186	$1,188	$1,188
46	*# of Units*	*0*	*0*	*0*	*0*	*0*	*205*	*475*	*475*	*475*	*475*
47	*$ Per Unit*	*$0*	*$0*	*$0*	*$0*	*$0*	*$2,400*	*$2,496*	*$2,496*	*$2,500*	*$2,500*
48	**Total Network Work and Projects**	$0	$0	$0	$658	$4,476	$4,660	$7,375	$4,839	$21,518	$6,877

1. Overhead Notifications

As Table 6-2 readily shows, most of the sub-MWCs comprising MWC 57 are themselves made up of forecasts of units of work multiplied by the estimated cost to complete each unit. Such is the case with the Overhead Notifications category, where PG&E has provided forecasts for both the number of notifications each year, as well as the cost for each notification. DRA has not taken issue with the number of notifications being forecasted for 2010 and 2011. However, DRA has recommended lower unit costs.[14]

In Chapter 2 of Exhibit PG&E-3, PG&E describes the four methods it uses to derive its unit cost forecasts. The unit costs for the Overhead Notifications capital category are derived by Unit Cost (UC) Method 3.[15] On page 2-17 of Exhibit PG&E-3, PG&E states the following regarding UC Method 3:

> The forecasted 2011 unit cost [is] based on an escalation of the forecasted 2010 unit cost. The forecasted 2010 unit cost is based on the judgment of EDM Program personnel and is primarily based on 2007 historic unit costs since it was assumed that data more accurately represented the base to determine the 2010 unit cost forecast (as opposed to the 2008 unit cost data).

DRA does not object to the use of UC Method 3 for this capital category. However, since this forecast methodology apparently relies primarily on the escalation of 2007 recorded costs, the escalation factors being used should be current. Consistent with that philosophy, DRA was able to obtain fourth-quarter 2009 escalation data from Global Insight's Power Planner forecast. Included in that forecast are updated escalation factors for Electric Distribution capital plant.[16]

---

[14] Table 6-2, line 3, columns 8 and 10.

[15] Exhibit PG&E-3, page 2-44, Table 2-18, line 1.

[16] The updated Electric Distribution capital escalation factors contained in the Global Insight forecast are as follows: 2008 – 9.4%; 2009 – 1.3%; 2010 – 0.2%; 2011 – 1.6%.

For this sub-MWC capital category, escalation factors are not being used simply to adjust actual costs for inflation; they are being used to derive the actual costs themselves. In DRA's judgment, it makes sense to use these updated escalation factors to derive the 2010 and 2011 unit costs; DRA has done so. By applying these updated factors to the recorded 2007 unit cost, DRA has derived 2010 and 2011 unit costs that are $1,061 lower and $475 lower, respectively, than PG&E's forecasts. After multiplying these updated unit costs by the forecasted number of notification projects, DRA has calculated revised estimates for the Overhead Notifications category that reduces PG&E's forecasts by $7.023 million in 2010, and $4.466 million in 2011.

2. Underground Notifications

The sub-MWC capital category of Underground Notifications is another area that uses UC Method 3 to derive its 2010 and 2011 unit cost estimates. As in the previous sub-section, the unit costs are developed by using the 2007 recorded unit cost, and then escalating that value. These escalated unit costs are then multiplied by the number of notification projects to derive the total yearly estimates. DRA has not taken issue with the number of notifications being forecasted for 2010 and 2011. However, using the same rationale as before, DRA is using updated escalation factors to derive new unit cost forecasts. By applying these updated escalation factors to the recorded 2007 unit cost, DRA has derived 2010 and 2011 unit costs that are $861 lower and $1,020 lower, respectively, than PG&E's forecasts. After multiplying these updated unit costs by the forecasted number of notification projects, DRA has calculated revised estimates for the Underground Notifications category that reduces PG&E's forecasts by $0.846 million in 2010, and $1.261 million in 2011.

3. Idle Facilities Removal

Idle Facilities Removal is another sub-MWC capital area where PG&E derives its forecasts by multiplying an estimate of the number of units (the number of projects being undertaken) by an estimate of the unit cost (the cost of the project). PG&E currently has over 22,000 facilities that are idle and are categorized with a P4 priority code. PG&E describes priority code P4 as follows:

> These are monitor notifications for idle facilities. This is deemed lowest priority and has no impact on safety, reliability, and asset life.[17]

As shown on line 21 of Table 6-2, PG&E is proposing to dramatically increase the number of idle facilities that it forecasts it will review in 2010 and 2011. DRA does not object to the unit cost of $25,000 (line 22 of Table 6-2), but does not believe that dramatic increases in the number of projects are warranted. In its workpapers, PG&E states that prior to 2008, unit cost analyses are not applicable.[18] Therefore, there is little historical data for DRA to analyze.

As PG&E clearly states in its testimony, the review and potential removal of idle facilities "is relatively lower priority work."[19] The previously provided definition of priority P4 goes a step further, stating that it is the "lowest priority" work. Whichever level of non-importance is applied, it is clear that there is no pressing reason to dramatically increase these forecasted numbers in either 2010 or 2011. In fact, DRA sees no need to increase them above the recorded 2008 level. Consequently, DRA is forecasting 24 removals for each of the years 2010 and 2011, a reduction of 52 and 476 removals, respectively, from PG&E's estimates.

In DRA's judgment, PG&E has not shown why an increase over the recorded 2008 level is warranted. In this instance, PG&E has only provided one year of recorded data for DRA to analyze. PG&E has provided no compelling reason to forecast a higher number of removals than what it has done historically in this area. There certainly is no detrimental impact to PG&E's electric distribution system by reducing the number of removals PG&E is forecasting. After multiplying these revised estimates by the forecasted costs, DRA has calculated revised estimates for the Idle Facilities Removal category that reduces PG&E's forecasts by $1.300 million in 2010, and $11.900 million in 2011.

---

[17] Exhibit PG&E-3, page 2-13, lines 1 through 3.

[18] Workpapers Supporting Exhibit PG&E-3, page WP 2-3, footnote D.

[19] Exhibit PG&E-3, page 2-48, lines 20 through 23.

4. Notification Major Projects

Notification Major Projects is yet another instance of a sub-MWC capital area in which the total forecasted expenditure is derived by multiplying the estimate for the number of units (the number of notification projects) by the estimate of the unit cost. Lines 24 and 25 of Table 6-2 show the number of units and the cost per unit for this sub-MWC capital area. As shown on line 24, the number of units in this category has varied considerably, from a recorded low of 96 in 2008 to a recorded high of 314 in 2006; PG&E's forecasts for 2009 and 2010 units are lower than any recorded year. DRA has no objection to PG&E's unit cost forecast of $25,000 for 2010 and 2011, but does not understand why PG&E is forecasting a dramatic increase in the estimated number of units in 2011; PG&E's 2011 forecast of 304 units is more than a 9-fold increase over its 2010 forecast of 33.

There does not appear to be a discernable trend in the number of notification projects that PG&E has done historically; the recorded figures do not appear to be consistently increasing or decreasing. With this type of variability, DRA is recommending that a simple 5-year recorded average of notification projects be used for 2011, which equals 159 units. It should be noted that DRA's forecasted figure of 159 notification projects is greater than all but one of the historical years. It represents nearly a 5-fold increase over PG&E's 2010 forecast. After multiplying this revised estimate by the forecasted unit cost, DRA has calculated a revised estimate for the Notification Major Projects category that reduces PG&E's forecast by $3.620 million in 2011.

5. Streetlight LED Replacement Project

Currently, PG&E owns approximately 162,000 high-pressure sodium vapor and mercury vapor streetlights. PG&E is proposing to replace these streetlights with LED lamps. This project is scheduled to begin in 2011 and is planned to be completed over a 5-year period. PG&E states that it is important to undertake this project in order to save energy (LEDs use approximately 50% less than traditional lamps) as well as to keep PG&E's streetlights current with the technology being installed by cities and counties.[20] In addition, the new LED lights are projected by PG&E to last longer than 10 years, versus four years for a traditional streetlight.[21] PG&E forecasts that this project will cost $20.452 million per year.

In general, DRA agrees that it is reasonable to replace traditional streetlights with more energy efficient LED lights. However, DRA has questions regarding the proposed 5-year schedule for completing the project. Using PG&E's timeframe, the new LED lights would begin to be installed in 2011. The installation would be completed five years later, in 2015. Yet, with a projected life span of at least 10 years, the LED lamps would not begin to need replacing until 2021, ten years after the first lamps were installed. It would appear that PG&E's proposed installation schedule would have PG&E's crews rushing to install LED lights through 2015, and then having no LED-related work until the lights begin "burning out" in 2021.

DRA is proposing that the Streetlight LED Replacement Project be undertaken over a 10-year period. With this schedule, the initial batch of LEDs (installed in 2011) will begin needing replacement in 2021, just as PG&E is finishing the last of the 10-year LED installations. This extended installation schedule is likely to be a more efficient use of resources; it will also result in less annual cost to the ratepayers (albeit over a 10-year period rather than a 5-year period). The result of DRA's recommendation is that the 2011 cost of the Streetlight LED Replacement Project will be cut in half. Instead of a 2011 estimated capital expenditure of $20.452 million, DRA is recommending a $10.226 million expenditure.

6. Fiber Optics

As shown in the bottom half of Table 6-2, the Fiber Optic sub-MWC capital category is one of six capital areas that collectively comprise a work category that PG&E calls Network Work and Projects. DRA is recommending adjustments to five of the six capital areas.

---

[20] Exhibit PG&E-3, page 2-50, lines 12 through 22.

[21] Exhibit PG&E-3, page 2-50, lines 26 through 29.

The Fiber Optics capital area is another instance of a sub-MWC project in which the total forecasted expenditure is derived by multiplying the estimate for the number of units (the number of fiber optic cables) by the estimate of the unit cost. Lines 31 and 32 of Table 6-2 show the number of units and the cost per unit for this sub-MWC capital area. Starting in 2010, PG&E indicates that it plans to expand the number of areas where fiber optic work is performed.

PG&E states that it intends to take advantage of new technologies to establish a real-time condition-based maintenance system.[22] PG&E asserts that such a real-time condition-based system will streamline maintenance and improve overall safety and component reliability.[23] Part of that new system involves fiber optic installations to ensure data capacity.[24] In its workpapers, PG&E states that for 2008 and prior years, unit cost analyses are not available.[25] Therefore, there are no historical unit cost data for DRA to evaluate. Absent any recorded unit cost information, it is difficult for DRA to determine whether or not PG&E's 2010 and 2011 estimates for numbers of units and unit costs are reasonable.

In lieu of a unit cost analysis, DRA compared the recorded total yearly capital expenditures to PG&E's 2010 and 2011 forecasts. As shown on line 30 of Table 6-2, the 2007 and 2008 recorded yearly expenditures for this sub-MWC have been relatively modest. PG&E's forecasted total expenditure for 2010 is $2.090 million, a 3-fold increase over the 2008 recorded level of $0.676 million. In spite of this large increase, DRA agrees that it is reasonable to install one fiber optic project in 2010. DRA also has no reason to dispute the forecasted unit cost of $2.090 million for that installation. Therefore, DRA is not recommending any adjustments to PG&E's 2010 forecast.

---

[22] Exhibit PG&E-3, page 2-46, lines 12 and 13.

[23] Exhibit PG&E-3, page 2-46, lines 25 and 26.

[24] Exhibit PG&E-3, page 2-46, lines 31 and 32.

[25] Workpapers Supporting Exhibit PG&E-3, page WP 2-3, footnote A.

DRA does take exception to PG&E's request for four additional fiber optic installations in 2011. In DRA's judgment, PG&E has not justified such a large increase. In a sense, this is still a pilot project; PG&E has not shown to what degree (if any) this real-time condition-based system "will streamline maintenance and improve overall safety and component reliability." Until such time as PG&E can demonstrate that these improvements actually are occurring, DRA believes that PG&E should not accelerate the fiber optic installations. Therefore, DRA recommends that only one fiber optic project be installed for 2011, the same as the 2010 level. This results in a total Fiber Optic capital expenditure forecast of $2.174 million for 2011, $6.521 million less than PG&E's estimate.

7. SCADA Communication Upgrades

Similar to the previous sub-section, the SCADA Communication Upgrades sub-MWC is a component of PG&E's plan to install a state of the art real-time condition-based maintenance system.[26] As shown on line 33 of Table 6-2, no capital expenditures for this area occurred prior to 2009. Once again, DRA has no recorded information (neither unit cost data nor total yearly expenditure data) with which to analyze PG&E 2010 and 2011 forecasts.

Absent any type of recorded information, DRA's analysis of this area has to rely on judgment. As shown on line 33 of Table 6-2, PG&E's forecasted total expenditure for 2010 is $0.520 million. This figure is derived by multiplying PG&E's estimate of 90 SCADA upgrades by the unit cost estimate of $5,777 per installation. DRA agrees that it is reasonable to proceed with the SCADA upgrades so that PG&E can continue to try to develop its proposed condition-based maintenance system. For 2010, DRA has no reason to dispute either the forecasted unit cost of $5,777 or the forecast of 90 projects. Therefore, DRA is not recommending any adjustments to PG&E's 2010 forecast.

DRA does take exception to PG&E's request for 270 additional SCADA upgrades in 2011. In DRA's judgment, PG&E has not justified such a large increase.

---

[26] Exhibit PG&E-3, page 2-46, lines 12 and 13.

As was the case in the prior sub-section, this sub-MWC is still a pilot project; PG&E has not shown to what degree (if any) this real-time condition-based system "will streamline maintenance and improve overall safety and component reliability." Until such time as PG&E can demonstrate that these improvements actually are occurring (and DRA can verify that the improvements justify the costs), DRA believes that PG&E should not accelerate the SCADA upgrades. Therefore, DRA recommends that 90 SCADA upgrades be installed for 2011, the same as the 2010 level. This results in a total SCADA Communication Upgrade capital expenditure forecast of $0.541 million for 2011, $1.081 million less than PG&E's estimate.

8. Network Protector Replacement

PG&E states that it has a 30-year plan for the Network Protector Replacement sub-MWC capital area. That plan is to replace 24 units in 2010 and 46 units thereafter.[27] In order to capture efficiencies associated with the simultaneous replacement of components, PG&E plans to undertake this project at the same time it replaces its Network Transformers (discussed in the next sub-section). Lines 37 and 38 of Table 6-2 show the number of protector replacements as well as the unit costs for these replacements.

As will be discussed in the next sub-section, DRA is recommending that the number of Network Transformer Replacements be reduced to seven in both 2010 and 2011. DRA believes that the linkage between the number of transformer replacements and protector replacements should be maintained. As stated previously, PG&E believes that there are efficiencies associated with doing both replacements at the same time; DRA agrees. Indicative of these efficiencies, for both sub-MWCs, PG&E has developed 30-year replacement plans based on their 30-year life expectancies, has forecasted 24 replacements for both in 2010, and has forecasted 46 replacements for both in 2011 and beyond. DRA is recommending that the number of Network Protector Replacements be reduced to seven for 2010 and 2011, the same number of

[27] Exhibit PG&E-3, page 2-47, lines 1 through 4.

units being forecasted for the Network Transformer Replacements sub-MWC. DRA does not object to PG&E's estimates for unit costs for 2010 and 2011.

DRA's recommended forecast of seven replacements in 2010 and 2011 is a reduction of 17 replacements and 39 replacements, respectively. This results in a total Network Protector Replacement capital expenditure forecast that is $1.064 million less than PG&E's estimate for 2010, and $2.539 million less for 2011.

9. Network Transformer Replacement

The Network Transformer Replacement capital area is another instance of a sub-MWC project in which the total forecasted expenditure is derived by multiplying the estimate for the number of units (the number of transformer replacements) by the estimate of the unit cost. Lines 40 and 41 of Table 6-2 show the number of units and the cost per unit for this sub-MWC capital area.

Unlike the other sub-MWCs being discussed, PG&E states that the unit cost dollars in this category only represent labor costs.[28] Forecasts for the actual costs of the transformers are included in Chapter 6 of Exhibit PG&E-3.[29] Therefore, the labor dollars analyzed here must be linked to the actual numbers of transformers that are being forecasted in Chapter 6 of Exhibit PG&E-3. The DRA witness responsible for Chapter 6 is using a simple 5-year average of the total recorded transformers (2004 through 2008) to develop the 2010 and 2011 forecasts. The DRA witness is NOT making an independent forecast of the transformers in this capital category; his forecast is for ALL transformers. However, based on the 5-year average forecast methodology, it is possible to derive the impact on this sub-MWC. A simple 5-year average of 2004 through 2008 recorded transformer replacements results in DRA recommending a forecast of seven replacements for 2010 and 2011 for this category. This is simply derived by taking the 35 transformer replacements (the 2008 total) and

[28] Exhibit PG&E-3, page 2-47, line 17.

[29] Exhibit PG&E-3, page 2-47, lines 17 through 19.

dividing that by 5.[30] Obviously, the number of labor units (included here) must agree with the number of transformer units (included in Chapter 6 of Exhibit PG&E-3). Therefore, DRA is forecasting seven replacements for both 2010 and 2011. DRA does not object to PG&E's forecast for unit costs in those years.

DRA's recommended forecast of seven replacements in 2010 and 2011 is a reduction of 17 replacements and 39 replacements, respectively. This results in a total Network Transformer Replacement capital expenditure forecast that is $1.471 million less than PG&E's estimate for 2010, and $3.510 million less for 2011.

10. Network Transformer Replacement (High Rise)

The replacement of network transformers in high rises is a new sub-MWC. As can be seen on lines 42, 43, and 44 on Table 6-2, PG&E proposes to start this program in 2011. Obviously, there are no recorded data for DRA to analyze. PG&E proposes to replace Network Transformers in high rises over a 2-year period – 32 replacements in 2011 and 31 in 2012.

DRA understands the need to replace network transformers in high rises with units that are less susceptible to causing fires. DRA did not undertake an independent investigation regarding the fire risk of the current transformers. DRA can only conclude that the risk is not large or eminent since PG&E is not proposing to replace any of the high rise transformers in either 2009 or 2010. Rather than replacing all 63 transformers over the period 2011 through 2012, DRA is recommending that these replacements be done uniformly over the 3-year period 2011 through 2013. This amounts to 21 replacements per year (63/3 = 21). DRA does not object to PG&E's forecast for unit costs in 2011.

DRA's recommended forecast of 21 high rise transformer replacements in 2011 is a reduction of 11 replacements from PG&E's forecast. This results in a total Network Transformer Replacement (High Rise) capital expenditure forecast that is $0.990 million less than PG&E's estimate for 2011.

---

[30] As shown on line 40 of Table 6-2, no transformers were replaced in the years 2004, 2005, 2006, and 2007. 35 replacements occurred in 2008. The 5-year average of that string of replacements is 7.

B. MWC 7 – Replace/Reinforce Poles

PG&E has full or joint ownership of approximately 2.3 million poles, more than 99% of which are wood.[31] These poles are inspected, and when necessary, restored or replaced. The numbers of poles replaced each year, as well as the unit cost to make the replacements, varies from year to year as well as from division to division.

As seen on line 20 of Table 6-3 (see next page), the number of recorded pole replacements has been decreasing steadily (and dramatically) over the past years. PG&E plans to stop the downward trend starting in 2009. In discussing this reversal, PG&E states:

> The primary driver for the higher level of capital expenditures is the need to address poles rescheduled for replacement due to a reallocation of funds to higher priority work.[32]

DRA is troubled by the above quotation. As discussed in Section IV of this exhibit, the issue of deferred capital expenditures can be problematic. As shown on Table 6-4, D.07-03-044 (the Settlement in the last PG&E GRC) adopted PG&E's request for pole replacement expenditures. As also seen (at the bottom) on Table 6-4, over the 3-year period 2007 through 2009, PG&E actually spent $186.1 million less than was authorized.

PG&E has provided no assurance that pole replacement deferrals will not continue in the future. Equally important, as discussed in Section IV, DRA does not believe that the Commission should authorize an increase in pole replacement expenditures in order to make up for previously authorized replacements that were deferred. Ratepayers should not have to "fund" (i.e., cover the cost of depreciation, return on investment, etc.) the same capital expenditure twice, especially when the second expenditure may itself be deferred. PG&E's 2010 forecast of 3,477 pole replacements appears reasonable, as it is similar in magnitude to the recently recorded replacements. However, DRA does not agree with PG&E's 2011 forecast of 5,000

---

[31] Exhibit PG&E-3, page 3-1, lines 10 and 11.

[32] Exhibit PG&E-3, page 3-1, lines 26 through 29.

TABLE 6-3
MWC 07 - POLE REPLACEMENT UNIT COSTS (Functional Only)
Recorded and Forecasted Data From Pages WP 3-2 and WP 3-7 of Workpapers Supporting Exhibit PG&E-3 (Vol 1 of 3)
Forecast Capital Expenditures (Nominal Dollars)

Line #	Division	2004 Total Poles	2005 Total Poles	2006 Total Poles	2007 Total Poles	2008 Total Poles	2009 Forecasted			2010 Forecasted						2011 Forecasted					
							1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
							Units	Unit Cost	Dollars 1/	Units		Unit Cost		Dollars 1/		Units		Unit Cost		Dollars 1/	
										PG&E	DRA	PG&E	DRA	PG&E	DRA	PG&E	DRA	PG&E	DRA	PG&E	DRA
1	Peninsula						118	$15,206	$1,794	40	40	$15,814	$15,814	$633	$633	78	40	$16,447	$16,447	$1,283	$658
2	San Francisco						19	$17,866	$339	18	18	$18,581	$18,581	$334	$334	71	18	$19,324	$19,324	$1,372	$348
3	Diablo						149	$13,891	$2,070	42	42	$14,447	$14,447	$607	$607	102	42	$15,025	$15,025	$1,533	$631
4	East Bay						182	$15,717	$2,860	34	34	$16,346	$16,346	$556	$556	191	34	$17,000	$17,000	$3,247	$578
5	Mission						65	$14,237	$925	16	16	$14,806	$14,806	$237	$237	123	16	$15,398	$15,398	$1,894	$246
6	Central Coast						146	$12,469	$1,820	283	283	$12,968	$12,968	$3,670	$3,670	480	283	$13,487	$13,487	$6,474	$3,817
7	De Anza						76	$15,206	$1,156	39	39	$15,814	$15,814	$617	$617	123	39	$16,447	$16,447	$2,023	$641
8	San Jose						130	$15,510	$2,016	26	26	$16,130	$16,130	$419	$419	126	26	$16,775	$16,775	$2,114	$436
9	Fresno						454	$8,692	$3,946	194	194	$9,040	$9,040	$1,754	$1,754	161	194	$9,402	$9,402	$1,514	$1,824
10	Kern						83	$8,211	$682	273	273	$8,539	$8,539	$2,331	$2,331	352	273	$8,881	$8,881	$3,126	$2,425
11	Los Padres						237	$10,855	$2,573	49	49	$11,289	$11,289	$553	$553	207	49	$11,741	$11,741	$2,430	$575
12	Stockton						413	$9,500	$3,924	388	388	$9,880	$9,880	$3,833	$3,833	421	388	$10,275	$10,275	$4,326	$3,987
13	Yosemite						233	$9,768	$2,276	500	500	$10,159	$10,159	$5,080	$5,080	301	500	$10,565	$10,565	$3,180	$5,283
14	North Valley						410	$9,130	$3,743	425	425	$9,495	$9,495	$4,035	$4,035	704	425	$9,875	$9,875	$6,952	$4,197
15	Sacramento						62	$9,402	$583	212	212	$9,778	$9,778	$2,073	$2,073	380	212	$10,169	$10,169	$3,864	$2,156
16	Sierra						164	$10,766	$1,766	193	193	$11,197	$11,197	$2,161	$2,161	96	193	$11,645	$11,645	$1,118	$2,247
17	North Bay						521	$12,800	$6,669	235	235	$13,312	$13,312	$3,128	$3,128	292	235	$13,844	$13,844	$4,042	$3,253
18	North Coast						328	$11,100	$3,641	510	510	$11,544	$11,544	$5,887	$5,887	792	510	$12,006	$12,006	$9,509	$6,123
19	General Office						--	--	$13	--	--	--	--	$4	$4	--	--	--	--	--	--
20	**Total**	**10,455**	**6,499**	**5,017**	**3,172**	**2,934**	**3,790**	**$11,292**	**$42,796**	**3,477**	**3,477**	**$10,904**	**$10,904**	**$37,913**	**$37,913**	**5,000**	**3,477**	**$12,000**	**$11,339**	**$60,000**	**$39,425**

1/ The dollar amounts in these columns are shown in thousands.

TABLE 6-4
MWC 7 - POLE REPLACEMENT (Functional Only)
Recorded and Forecast Capital Expenditures (Thousands of Nominal Dollars)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	2004	2005	2006	2007			2008		2009		2010			2011	
Category	Recorded 1/	Recorded 1/	Recorded 1/	PG&E Requested	TY 2007 Settlement Amount 2/	Recorded 1/	TY 2007 Settlement Amount (Attrition) 2/	Recorded 1/	TY 2007 Settlement Amount (Attrition) 2/	Recorded 1/	TY 2007 Settlement Amount (Attrition) 2/	PG&E Forecast	DRA Recommended	PG&E Forecast	DRA Recommended
MWC 7 -- Pole Replacement	$59,446	$40,134	$37,772	$94,137	$94,137	$28,773	$94,137	$33,292	$94,137	$34,239	$94,137	$37,913	$37,913	$60,000	$39,425

1/ NOTE: 2004 through 2008 recorded data come from Table 3-2 of the Workpapers (page WP 3-2). Recorded 2009 was obtained from PG&E in an e-mail dated 2/17/10.

2/ NOTE: 2007 Settlement adopted PG&E's 2007 request. (See page 62 of D.07-03-044 which states that the Settlement adopts PG&E's request.) Attrition years (08, 09, and 10) are assumed to equal TY 2007.

	∑ 07 -09 Authorized	∑ 07 -09 Spent	Δ
2007	$94,137	$28,773	$65,364
2008	$94,137	$33,292	$60,845
2009	$94,137	$34,239	$59,898
Total	**$282,411**	**$96,304**	**$186,107**

replacements. In DRA's opinion, anything appreciably larger than the 3,477 forecasted for 2010 is clearly an effort to make up for the shortfall of previously authorized replacements that were deferred. DRA is recommending that 3,477 replacements be allowed for 2011, a decrease of 1,523 from PG&E's forecast. This decrease in pole replacements results in DRA's 2011 forecast being $20.575 million less than PG&E's estimate.

C. MWC 48 – Replace Substation Equipment

PG&E currently operates 770 distribution substations in its electrical distribution system. MWC 48 includes capital expenditures for all major and minor substation equipment, excluding transformers. MWC 48 is actually comprised of numerous sub-MWCs. Table 6-5 (see next page) provides details on these various capital areas. It should be noted that Table 6-5 attempts to show 2009 recorded data. The difference between the estimated and recorded total 2009 MWC 48 expenditures was a decrease of $4.699 million, which was allocated proportionately to all the expenditures. The following paragraphs discuss each of the differences shown on Table 6-5.

1. Breaker Replacement Program

The Breaker Replacement program forecasts a unit cost of $200,000.[33] Based on PG&E's 2010 forecast of $4.000 million (see line 4, column 7 in Table 6-5), that translates to 20 replacements in 2010. PG&E's forecast of $12.600 million for 2011 equates to the replacement of 63 breakers.[34]

DRA does not believe that such a large change (more than a 3-fold increase over 2010) is justified. In DRA's judgment, an increase of 50% (from 20 replacements in 2010 to 30 in 2011) is more reasonable. Using the unit cost of $200,000, this equates to a 2011 forecast for this sub-MWC of $6.000 million, a decrease of $6.600 million from PG&E's 2011 forecast. Not only does this 2011 recommendation result in

---

[33] Exhibit PG&E-3, page 8-24, lines 24 and 25.

[34] $12.6 million divided by a unit cost of $200,000 equals 63.

TABLE 6-5

MWC 48 - ELECTRIC DISTRIBUTION REPLACEMENT OF SUBSTATION EQUIPMENT (Functional Only)

Recorded and Forecasted Data From Page WP 8-2 of Workpapers Supporting Exhibit PG&E-3 (Vol 2 of 3)

Recorded and Forecast Capital Expenditures (Thousands of Nominal Dollars)

		1	2	3	4	5	6	7	8	9	10
Line	Category	2004	2005	2006	2007	2008	2009	2010 Forecast		2011 Forecast	
#		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded 2/	PG&E	DRA	PG&E	DRA
1	Ancillary Equipment Program	$3,908	$3,882	$4,080	$2,510	$1,285	$1,295	$2,000	$2,000	$3,747	$3,747
2	Insulators Replacement Program	$171	$70	$314	$468	$30	$424	$0	$0	$1,279	$1,279
3	Ground Grids Reinforcement Program	$324	$452	$460	$287	$109	$159	$0	$0	$250	$250
4	Breaker Replacement Program	$1,220	$3,439	$5,473	$4,618	$1,814	$2,777	$4,000	$4,000	$12,600	$6,000
5	Switch Replacement Program	$750	$614	$278	$1,047	$421	$421	$0	$0	$6,750	$2,250
6	Battery Replacement Program	$869	$710	$906	$1,602	$315	$197	$1,300	$1,300	$1,110	$1,110
7	Civil Structure	$316	$97	$465	$3	$78	$146	$0	$0	$1,600	$1,600
8	Switchgear Replacement Program	$12,504	$6,285	$7,613	$5,662	$23,946	$23,778	$28,221	$28,221	$42,100	$38,100
9	Regulator Replacement Program	$240	$38	$821	$684	$284	$303	$602	$602	$602	$602
10	Yard Improvement Program	$344	$315	$182	$51	$113	$179	$258	$258	$258	$258
11	Diagnostics Installation Program	$33	$4	--	$62	$185	$88	$0	$0	$2,000	$400
12	Arc Flash Reduction Program	--	--	--	--	--	$0	$0	$0	$500	$500
13	**Total MWC 48**	$20,679	$15,906	$20,592	$16,994	$28,580	$29,767	$35,521 1/	$35,521	$72,796	$56,096

1/ NOTE: Total does not equal the sum of the 12 expenditures -- one of the expenditures is not correct.
2/ NOTE: Recorded 2009 decrease of $4,699 proportionately allocated to all 12 expenditures.

a 50% higher number of replacements than PG&E is forecasting for 2010, it is also results in a larger expenditure than any of the recorded years going back to 2004.

2. Switch Replacement Program

The switch replacement program has been in existence since 2003. As shown on line 5 of Table 6-5, the highest recorded expenditure occurred in 2007, when $1.047 million was spent. PG&E is not forecasting any capital expenditures in 2010. However, PG&E is proposing to begin replacing 150 switches per year beginning in 2011, with a resulting total expenditure of $6.750 million. This is obviously a dramatic increase, nearly 6.5 times greater than the previous highest expenditure.[35] DRA does not believe that such a large increase is justified. There does not appear to be any urgency to these replacements, given the fact that PG&E does not propose to do any in 2010. In DRA's judgment, 50 replacements in 2011 is a more reasonable forecast. Applying that forecast to the 2011 unit cost figure (of $45,000 per switch[36]) produces a total DRA forecast of $2.250 million, $4.500 million less than PG&E's 2011 forecast. It should be noted that DRA's recommended 2011 forecast is over twice as large as any of the 2004 through 2009 recorded years.

3. Switchgear Replacement Program

PG&E states that its goal for this sub-MWC area is to maximize the overall quality of service and dependability to customers currently being served by obsolete switchgear.[37] In Table 8-3 of Exhibit PG&E-3 (page 8-27), PG&E presents a list of proposed switchgear projects. In 2011, PG&E has proposed to complete or start seven switchgear projects, and conduct a study of one additional project. This is a higher project total than any previous year listed in Table 8-3, with a related higher expenditure total. All of this is being proposed during the costly Hunters Point rebuild.

---

[35] The highest recorded expenditure was $1.047 million in 2007. PG&E's 2011 forecast is $6.750 million. $6.750 million divided by $1.047 million equals 6.447.

[36] Exhibit PG&E-3, page 8-25, line 9.

[37] Exhibit PG&E-3, page 8-26, lines 2 through 4.

DRA does not object to PG&E's 2010 forecast. However, for 2011, DRA recommends that the Oakland D 4-kV study, shown on line 2 of Table 8-3, be postponed, resulting in a $4.000 million reduction. DRA notes that PG&E has not proposed any additional capital expenditures for Oakland D in either 2012 or 2013. This appears to be an exception to PG&E's statement that switchgear replacements typically take one year to scope, followed by a 2-year engineering and construction period.[38] In this instance, any engineering and construction periods that may occur appear to be distantly removed from the "scoping" period.

4. Diagnostics Installation Program

PG&E states that this program involves the installation of diagnostic equipment which will enhance PG&E's ability to identify transformers that are close to failing.[39] PG&E states that it costs $80,000 to install a transformer monitor.[40] Looking at the historical expenditures (line 11 of Table 6-5), it appears that PG&E has only installed one or two monitors per year. In 2010, PG&E does not propose to make any installations. In 2011, PG&E is proposing to install 25 monitors, for a total cost of $2.000 million. DRA recommends installing five. Even at this reduced level of installations, DRA is recommending an expenditure level that is much larger than any previous recorded expenditure going back to 2004. DRA's recommended 2011 expenditure is $1.600 million less than PG&E's forecast.

D. MWC 6 – New Capacity - Line

The DRA witness responsible for this exhibit also worked on PG&E's recent Cornerstone Improvement Project. During the review of the capital projects being proposed for this GRC, DRA has found two capital projects, both of which impact MWC 6, that appear to be common to the GRC and the Cornerstone project. As PG&E

[38] Exhibit PG&E-3, page 8-26, lines 20 and 21.

[39] Exhibit PG&E-3, page 8-28, lines 13 through 15.

[40] Exhibit PG&E-3, page 8-28, lines 16 and 17.

states on page 1-44 of Exhibit PG&E-3 (lines 14 through 16), the capital projects in this GRC are supposed to be separate from the projects in Cornerstone.

The capital projects that appear to be duplicated in this GRC are: (1) the replacement of the Paso Robles Bank #1, and (2) the construction of the new Windsor substation. Appendix A, attached to this exhibit, contains excerpts from PG&E's GRC workpapers that provide more details regarding both of these capital projects. Appendix B contains workpaper excerpts from PG&E's Cornerstone Reliability project which shows the proposed Cornerstone projects. A comparison of these two appendices shows that the Paso Robles and the Windsor projects are common to both.

Because of this apparent duplication, both of these projects are being removed from this GRC. Absent this adjustment, PG&E could conceivably receive authorization for those projects in both applications. Both of these capital projects have capital components in MWC 6. $0.784 million is being deleted in 2010 for the removal of the MWC 6 portion of the Paso Robles project, and $0.630 million is being removed in 2011 for the MWC 6 portion of the Windsor substation. Both of these capital projects also have components that impact MWC 46, which is discussed in the following section.

E. MWC 46 – New Capacity - Substations

As discussed in Section D, DRA has found two capital projects, both of which impact MWC 46, that appear to be common to this GRC and the Cornerstone Improvement Project. The capital projects that appear to be duplicated in this GRC are: (1) the replacement of the Paso Robles Bank #1, and (2) the construction of the new Windsor substation. Because of this apparent duplication, both of these projects are being removed from this GRC. Absent this adjustment, PG&E could conceivably receive authorization for those projects in both applications.

Both of these capital projects have capital components in MWC 46. $3.400 million is being deleted in 2010 for the removal of the MWC 46 portion of the Paso Robles project. Additionally in 2010, $2.000 million is being removed for the MWC 46 portion of the Windsor project. For 2011, $5.350 million is being removed for the MWC 46 portion of the Windsor substation.

F. MWC 5 – Tools and Equipment - Other

Line 9 of Table 6-1 shows the recorded capital expenditures for this MWC over the 6-year period 2004 through 2009. In five of those six years, there was actually a credit for this area. In the sixth year (2007), only $230,000 was spent. PG&E is not forecasting any expenditures in 2011, but for some reason is forecasting $2.236 million for 2010. DRA does not agree with PG&E's 2010 estimate. Instead, DRA is recommending that no dollars be included for 2010, the same forecast as in 2011. This is much more in line with what has occurred historically.

G. MWC 49 – T&D Mainline Protection and Rebuild

Line 11 of Table 6-1 shows the history and forecasts for this MWC. Beginning in 2009, PG&E initiated a new capital program, the Targeted Circuit Initiative.[41] This program is meant to address PG&E's most unreliable circuits. Over the 4-year period 2010 through 2013, PG&E is proposing to spend $70 million for this project. With the exception of 2010 (where PG&E proposes spending $40 million), PG&E forecasts spending $10 million per year for this program.[42] Therefore, in the year 2010, there is an expenditure "spike" where PG&E forecasts spending $30 million more than in the other years.

DRA sees no reason why there should be such a large expenditure in 2010. Instead, DRA is recommending that the $70 million total expenditure be spent uniformly over the 4-year period. This equates to $17.5 million per year.[43] Therefore, for 2010 and 2011, DRA has subtracted PG&E's original forecast for this capital project, and added $17.5 million for each year. The net result of these recommended adjustments is that DRA's forecast for MWC 49 is reduced by $22.500 million in 2010, as compared to PG&E's estimate, and the 2011 forecast is <u>increased</u> by $7.500 million.

---

[41] Exhibit PG&E-3, page 10-9, line 15.

[42] Exhibit PG&E-3, page 10-10, Table 10-4, line 6.

[43] $70 million divided by 4 years equals $17.5 million per year.

H. MWC 9 – Distribution Automation

Line 12 of Table 6-1 shows the history and forecasts for this MWC. One of the capital projects that makes up this MWC is a new program called Fire Risk Management. This new capital program is projected to start in 2011. PG&E forecasts this to be a 3-year project, and plans on spending $15.2 million each year.

PG&E is proposing to reduce the risk of igniting fires due to electrical faults on its distribution system. When a fault is detected, various protective devices (circuit breakers and line reclosers) are activated to protect PG&E's equipment and mitigate the extent of outages. These protective devices can be set to automatically reclose, thereby re-energizing the distribution line, in case the initial fault was temporary. Currently, the number of times that the line is automatically re-energized has to be manually set. In the winter, when there is little risk of starting a fire, PG&E can safely re-energize a line multiple times without risking a fire. However, in the summer, PG&E may not want the line to automatically re-energize at all. Rather than having an employee manually changing the reclosing settings as the weather varies, this new program would allow PG&E to change the reclosing settings automatically. PG&E states that it has not performed a detailed cost comparison of manual versus automatic adjustment of the reclosing settings, but a preliminary estimate indicates it would cost approximately $1.5 to $2.0 million per year to manually adjust these settings (which would presumably be avoided if PG&E could do the resetting automatically).[44]

DRA does not object to the initial implementation of this program, but does not believe that it should be done in three years. DRA considers the Fire Risk Management project to be a pilot program. As mentioned above, PG&E has only been able to develop preliminary potential cost savings estimates. Of more concern to DRA is the following PG&E statement:

> The Company has not been manually changing the reclosing relay settings for the purpose of fire risk management. Consequently, there

---

[44] Exhibit PG&E-3, page 11-13, lines 23 through 28.

> are no historical costs for manually adjusting the relays in the field for the purpose of fire risk management.[45]

In essence, PG&E is trying to automate a procedure that it does not currently use. Since PG&E apparently does not manually change the reclosing settings, DRA wonders whether or not PG&E would actually ever change the settings automatically. Will PG&E utilize this Fire Risk Management program, even if it does work as planned? DRA recognizes that this proposed project has the potential of mitigating outages, while at the same time reducing fire risk. However, since this is clearly a pilot program, and since DRA has no evidence that PG&E will actually utilize the program, DRA is proposing that the Fire Risk Management program be undertaken over a 6-year period, and that the program be immediately cancelled if it does not prove to be used and useful.

Constructing this project over a 6-year period will provide more time for PG&E to evaluate the effectiveness of the program, and also determine whether or not it is being used. If, after initial construction, PG&E determines that the program does not function as planned (or if it is found that the program is not used), the Fire Risk Management program can be cancelled before the bulk of the capital dollars have been spent. Because DRA is recommending that this project be constructed over a 6-year period rather than a 3-year period, the 2011 forecast will be half of what PG&E estimated. DRA's recommendation for the Fire risk Management program reduces the 2011 forecast by $7.600 million.

I. MWC 56 – Replace Underground Cable

PG&E's electric underground distribution system consists of primary distribution cable and associated vaults, enclosures, conduits, splices, cable connectors, and other equipment.[46] In the 2007 GRC, PG&E presented testimony from two outside consultants who had analyzed the underground system. These two consultants, ABB

[45] Exhibit PG&E-3, page 11-13, lines 20 through 23.

[46] Exhibit PG&E-3, page 12-1, lines 12 through 14.

TABLE 6-6
MWC 56 - CABLE REPLACEMENT (Functional Only)
Recorded and Forecast Capital Expenditures (Thousands of Nominal Dollars)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	2004	2005	2006	2007			2008		2009		2010			2011	
Category	Recorded 1/	Recorded 1/	Recorded 1/	PG&E Requested	TY 2007 Settlement Amount 2/	Recorded 1/	TY 2007 Settlement Amount (Attrition) 2/	Recorded 1/	TY 2007 Settlement Amount (Attrition) 2/	Recorded 1/	TY 2007 Settlement Amount (Attrition) 2/	PG&E Forecast	DRA Recommended	PG&E Forecast	DRA Recommended
MWC 56 -- Cable Replacement	$16,447	$35,102	$33,209	$64,150	$64,150	$30,033	$64,150	$21,897	$64,150	$16,854	$64,150	$17,231	$17,231	$51,354	$17,507

1/ NOTE: 2004 through 2008 recorded data come fromm Table 12-1 of the Workpapers (page 12-1). Recorded 2009 comes from a 2/17/10 e-mail from PG&E.

2/ NOTE: 2007 Settlement adopted PG&E's 2007 forecast. (See page 62 of D.07-03-044 which states that the Settlement adopts PG&E's request.) Attrition years (08, 09, and 10) are assumed to equal TY 2007.

	∑ 07 -09 Authorized	∑ 07 -09 Spent	Δ
2007	$64,150	$30,033	$34,117
2008	$64,150	$21,897	$42,253
2009	$64,150	$16,854	$47,296
Total	**$192,450**	**$68,784**	**$123,666**

and KEMA, both concluded that increasing underground failures will negatively impact PG&E's reliability. Therefore, both consultants recommended that PG&E increase its capital expenditures in this area. As shown in Table 6-6 (see previous page), PG&E did increase its requested funding for MWC 56 (the amount requested in Column 4 of Table 6-6 is much higher than the amounts in Columns 1, 2, or 3). In D.07-03-044 (the Settlement in the last PG&E GRC), the Commission adopted PG&E's request.[47]

In discussing the need for increased capital spending for MWC 56 starting in 2011, PG&E makes the following statement:

> This is because the Company redirected resources originally targeted for underground assets to other higher priority areas. Reallocating resources from underground assets to other higher priority areas is also planned for 2009 and 2010.[48]

DRA is troubled by the above quotation. As discussed in Section IV of this exhibit, the issue of deferred capital expenditures can be problematic. As seen (at the bottom) on Table 6-6, over the 3-year period 2007 through 2009, PG&E actually spent $123.7 million less than was authorized.

PG&E has provided no assurance that cable replacement deferrals will not continue in the future. Equally important, as discussed in Section IV, DRA does not believe that the Commission should authorize an increase in cable replacement expenditures in order to make up for previously authorized replacements that were deferred. Ratepayers should not have to "fund" (i.e., cover the cost of depreciation, return on investment, etc.) the same capital expenditure twice, especially when the second expenditure may itself be deferred.

In DRA's judgment, PG&E's 2010 capital forecast of $17.231 million appears reasonable, as it is similar in magnitude to the recently recorded cable replacement expenditures. (See line 13 of Table 6-1). However, DRA does not agree with PG&E's 2011 forecasted expenditure of $51.354 million. In DRA's opinion, any expenditure

---

47 Decision 07-03-044, page 62.

48 Exhibit PG&E-3, page 12-5, lines 15 through 18.

appreciably larger than the $17.231 million forecasted for 2010 is clearly an effort to make up for the shortfall of previously authorized cable replacement expenditures that were deferred. Instead, DRA is recommending that $17.507 million be allowed for 2011. This figure is calculated by increasing DRA's 2010 forecast by an escalation factor of 1.6%, the fourth quarter 2009 Global Insight escalation factor for Distribution Plant. The net result of this recommended adjustment is that DRA's 2011 forecast for Underground Cable Replacement capital expenditures is $33.847 million less than PG&E's forecast.

APPENDIX A

GRC Workpapers

Paso Robles Bank #1 and Windsor Substation

Application: ____________________
(U 39 M)
Exhibit No.: (PG&E-3)
Date: December 21, 2009
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

2011 GENERAL RATE CASE

EXHIBIT (PG&E-3)
GAS AND ELECTRIC DISTRIBUTION

WORKPAPERS SUPPORTING

CHAPTERS 6, 7, 8 AND 9

VOLUME 2 OF 3

PG&E

2011 GENERAL RATE CASE

CAPITAL PROJECT SUMMARY

TITLE: Replace Paso Robles Bank #1
ORDER NO: 5734633 (MWC 06) & 5734017 (MWC 46)
MAJOR WORK CATEGORY: 06 & 46
OPERATIVE DATE: June 2010
AFUDC ELIGIBLE: YES_x_ or NO__
LAND PERCENTAGE: _0_%

ESCALATED CAPITAL EXPENDITURES
($000)

	2009	2010	2011	2012	2013
Total Capital Expenditures:	102	4,184			

To Table 9-4, line 62

DESCRIPTION
Area 4, Los Padres
Replace Paso Robles Bank #1 and install one new feeder.

JUSTIFICATION
Increase distribution capacity in the Paso Robles DPA to alleviate an anticipated 2010 normal overload condition.

2011 GENERAL RATE CASE

CAPITAL PROJECT SUMMARY

TITLE: New Windsor Substation
ORDER NO: 5733965 (MWC 06) & 5707549 (MWC 46)
MAJOR WORK CATEGORY: 06 & 46
OPERATIVE DATE: June 2011
AFUDC ELIGIBLE: YES_x_ or NO__
LAND PERCENTAGE: _0_%

ESCALATED CAPITAL EXPENDITURES
($000)

	2009	2010	2011	2012	2013
Total Capital Expenditures:	2,500	2,000	5,980		

To Table 9-4, line 91

DESCRIPTION
Area 7, North Coast
Build a New Substation in Windsor

JUSTIFICATION
Increase distribution capacity in the Fulton DPA to alleviate an anticipated 2011 normal overload condition.

APPENDIX B

Cornerstone Workpapers

Workpapers Showing Paso Robles Bank #1 and Windsor Substation

Application: 08-05-023
(U 39 M)
Exhibit No.: ____________________
Date: March 17, 2009
Witness: Dan J. Pearson

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRIC DISTRIBUTION RELIABILITY IMPROVEMENT PROGRAM

WORKPAPERS SUPPORTING

CHAPTER 3

ELECTRIC DISTRIBUTION CAPACITY

REDACTED

VOLUME 2 OF 5

UPDATED

Substation Name	Atascadero	Paso Robles	Paso Robles	Paso Robles	San Miguel	Templeton	Templeton	Total
Bank Number	1	1	2	3	1	2	3	
BEFORE WORK								
# Transfers Required to Restore Power	6	3	2	7	4	13	15	
IF DEFICIENT, # MW's Left Out of Service	12.5	3.61	3.61	7.52	5.13	21.04	18.8	
IF DEFICIENT, # Customers Left Out of Service	2460	735	735	701	1175	5178	4642	
WORK REQ'D TO MITIGATE DEFICIENCY								
New Conductor for Feeder or Tie (Ft)								
OH	2600							2600
UG	1250					7300		8550
Reconductor (Ft)								
OH	31400					5600		37000
UG								0
Autotransformers								
OH								0
PM	3					1		4
# Line Regs								0
New Switches								
OH								0
UG								0
New Feeders								
#						4		4
Location						1-12kV CB, 3-21kV CB's at Paso Sub		
New Substation Transformer Capacity								
#						1		1
Location						1-30MVA LTC to replace Paso Bk1		
Comments	Reinforce Templeton 2108 & 2111: Install 1250ft of UG w/ trench, 2600ft of 3-715Al w/ CN. Recond 8500ft to 3-715Al w/ CN to establish new circuit. Also, recond 3800ft to 3-4/0Al on Templeton 2108; 19100ft to 3-715Al w/ CN underbuilt on 70kV on Templeton 2111. Replace **3-3.6 MVA field auto's w/ 7.5MVA.** (1-recl in 1-auto; 0-recl's in 2-auto's).	Same as for Templeton Bk2.	Same as for Templeton Bk2.	Same as for Templeton Bk2.	Same as for Templeton Bk2.	Replace Paso Bk1 w/ 30 MVA 21kV bnk. Route exist'g 1108 fdr, planned 1106 fdr & new 21kV fdr to new bnk. Reroute exist'g 12kV fdrs. Install 7300ft of 3-1100Al UG for new 21kV fdr. Remove 1-station auto; relocate 1-16 MVA auto as tie bet. 21 & 12kV buses. Install 3 new 21kV CB's; 1 new 12kV CB, or move 1 exist'g 12kV CB. Replace 5600ft of OH w/ 715Al on S Vine St in Paso Robles; **replace 1-3.6 MVA field auto (w/ 2 recl's) w/ 7.5 MVA.**	Same as for Templeton Bk2.	

Application: 08-05-023
(U 39 M)
Exhibit No.: ____________
Date: March 17, 2009
Witness: Dan J. Pearson

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRIC DISTRIBUTION RELIABILITY IMPROVEMENT PROGRAM

WORKPAPERS SUPPORTING

CHAPTER 3

ELECTRIC DISTRIBUTION CAPACITY

REDACTED

VOLUME 3 OF 5

UPDATED

Substation Name	Fulton	Fulton	Fitch Mountain	Fitch Mountain	
Bank Number	5	6	1	2	
BEFORE WORK					
# Transfers Required to Restore Power	999	3	5	3	
IF DEFICIENT, # MW's Left Out of Service	26.5	0	0	0	
IF DEFICIENT, # Customers Left Out of Service	5300	0	0	0	
WORK REQ'D TO MITIGATE DEFICIENCY					
New Conductor for Feeder or Tie (Ft)					
OH					
UG					
Reconductor (Ft)					
OH					
UG					
New Capacitors					
OH					
PM					
# Line Regs					
New Switches					
OH					
UG					
New Feeders					
#	3				3
Location	Windsor				
New Substation Transformer Capacity	30				30
#	1				1
Location	Windsor				
Comments	Build Windsor sub and install a 60/12 kV, 30 MVA transformer and 3 feeders to support loss of bank 5 at Fulton.				