Results of Operations Issues for Pacific Gas and Electric Company

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I. Introduction

This testimony is presented by Garrick F. Jones, Economist with JBS Energy, Inc. on behalf of The Utility Reform Network (TURN). Mr. Jones has six years of experience in energy issues, has provided analytical and testimony-writing support in rate cases in 11 jurisdictions, and has filed testimony before this Commission and the Nevada Public Utilities Commission. Mr. Jones's qualifications are attached.[1]

This testimony addresses a variety of expense and capital-related issues within the Electric Distribution portion; Human Resources (HR) portion; and Administrative and General (A&G) portion of PG&E's 2014 General Rate Case (GRC) application.

II. Electric Distribution Issues (PG&E-4)

A. Electric Distribution Maintenance (Chapter 5)

TURN has reviewed PG&E's showing on Electric Distribution Maintenance and has certain recommendations on PG&E's O&M and Capital expense forecasts.

1. *O&M Expenses*

a. Patrols and Inspections (MWC BF)

i. Distribution Line Equipment Inspections and Tests

PG&E forecasts a $1.12 million increase for Distribution Line Equipment Inspections and Tests ($4.289 in 2011 vs. 5.405 million in 2014).[2] PG&E states, "Forecasted units are projected to increase mainly due to new switch installations associated with …FLISR systems resulting from the Cornerstone Project (i.e., FLISR switches installed in 2012 and 2013 as part of the Cornerstone project that will require future inspections and tests)."[3] Specifically, PG&E forecasts a 4,760-unit increase between 2011 (recorded 20,887 units)

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[1] Attachment 1.

[2] PG&E-4 WPs, p. 5-17, p.WP (Workpaper Table 5-13).

[3] PG&E-4, pp. 5-14 (starting at line 31) – 5-15.

and 2014 (forecasted 24,775 units).[4] This is the only reason PG&E provides for the increased expense.

DRA made no reductions to this account.

Table 1 contains PG&E's recorded and forecasted unit counts for this activity.

Table 1: Recorded and Forecasted Unit Count for Overhead Line Equipment Inspected and Tested[5]

	2007 Recorded	2008 Recorded	2009 Recorded	2010 Recorded	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast
Number of Overhead Line Equipment Inspected and Tested	28,066	25,103	28,431	20,331	20,877	22,954	23,855	24,755

PG&E over-forecasted its unit count for Overhead Line Equipment Inspected and Tested in the last GRC, as well. Specifically, the Company forecasted 33,536 units for 2011 in the 2011 GRC,[6] but only performed 20,877 inspections/tests.[7]

Not only did PG&E forecast 33,536 units for 2011 in the 2011 GRC for an increase of more than 6,000 units over that GRC's Base Year recorded count (i.e., 28,431[8]), but PG&E must have known that it would only perform many fewer inspections/tests in 2010 (it ultimately performed inspections/tests on 20,335 units in 2010). PG&E should have known that the number of units would be less than the 33,536 it forecasted because it systematically improved its process in 2010 in order to allow "the frequency of testing for some equipment to be changed from twice a year to once a year."[9] Instead of telling the Commission about the this systematic improvement when it filed its 2011 application in December of 2010, PG&E kept the unreasonably high unit forecast of 33,536 and then only performed inspections/tests on 20,877 units in 2011.

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[4] PG&E-4 WPs, p. WP 5-17 (Workpaper Table 5-13).

[5] PG&E-4 WPs, p. WP 5-17 (line 8).

[6] 2011 GRC, PG&E-3, WPs 2-21 and 39.

[7] PG&E-4 WPs, p. WP 5-17 (line 8).

[8] PG&E-4, p. WP 5-17 (Workpaper Table 5-13).

[9] TURN DR 54-2a.

In any case, PG&E has not sufficiently supported its forecast of all the additional units. It claims that the 900-unit increases from 2012 to 2013 and 2013 to 2014 (i.e., a total increase of 1,800 units for the two years) are from FLISR additions from Cornerstone. However, PG&E also forecasts a 2,077-unit increase from 2011 (20,877 recorded) to 2012 (22,954 forecasted) without providing a reason for the increase. The recorded 2012 unit count was 20,835, about the same as the unit counts for 2010 and 2011 (20,331 and 20,877, respectively) but in line with the general reduction from pre-2010 levels accounting for the "improvements [in 2010] that allowed the frequency of testing for some equipment to be changed from twice a year to once a year." PG&E should recognize those 2010 savings going forward.

Recommendation

In order to account for the improvements that allowed the frequency of testing for some equipment to be changed from twice a year to once a year, the Commission should adopt a lower unit count for 2014 by using the average of 2010-2012 recorded values: 20,681. Using PG&E's forecast of 2014 unit costs ($203, 2011 constant dollars), the forecast should be $4.191 million, a 825K-dollar reduction.

As for the additional units that PG&E forecasts to account for the new equipment related to 2012 and 2013 FLISR units (1,800 in all), these units should be paid for out of the extra money ratepayers paid PG&E during the 2011 rate cycle because of PG&E's failure to inform the Commission that it reduced the inspection rate for some equipment from twice per year to once per year, thereby knowingly over-forecasting the number of pieces of equipment it would need to inspect by 50% (actual about 21,000 pieces versus a knowingly-high estimate of it would only be to inspect equipment on the basis of inflated 33,000-unit 2011 estimate in the 2011 GRC).

2. *Overhead Facilities (MWC KA)*

a. Idle Facilities Investigations

PG&E claims that it has 22,000 pending idle facilities locations for review in its testimony.[10] In its workpapers, PG&E alternatively estimates that it has 20,000 Idle

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[10] PG&E-4, p. 5-21 (lines 8-9).

Facilities Motivations that historically have not been investigated.[11] PG&E also claims that it began the review process of the idle facilities in 2011 and that the "review process for the backlog units is scheduled for completion in 2014."[12]

After having investigated a total of 9,202 units from 2011 to the end of 2013 (at least as recorded in the newly formed MWC KA), PG&E claims that it will investigate 8,468 and 2,330 units, respectively, in 2014 and 2015.[13] The combined, 2-year cost would be $4.870 million ($3.819 million and $1.051 million in the two years, respectively).[14]

This analysis and recommendation needs to be considered in concert with TURN's (and DRA's) analysis and recommendations regarding the actual removal of these facilities, which are recorded and forecasted as capital expenditures in MWC 2A, which I discuss below. There, I recommend that the Commission reduce the number of Idle Facilities Removals, given the large cost they represent, the fact that these facilities do not represent a safety problem or reliability reduction and the overall large rate increase PG&E proposes in this proceeding.

If the Commission adopts all or a portion of TURN's MWC 2A recommendation to dramatically slow down the rate of removals for Idle Facilities, PG&E would have already reviewed enough of these facilities by the end of 2013 to keep it busy in the removal phase. As such, if the Commission does adopt DRA's primary or TURN's maximal MWC 2A recommendation, it should also adopt a Test Year forecast for MWC KA for the review of these facilities of zero.

If the Commission either 1) does not adopt TURN's position in MWC 2A or 2) does adopt TURN's position in MWC 2A but still believes PG&E should move forward to complete its basic review of the facilities, the Commission should reduce the 2014

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[11] PG&E-4 WPs, p. WP 5-26 (FN 1).

[12] PG&E-4, p. 21 (lines 14-15 and 20-21).

[13] PG&E-4 WPs, p. WP 5-26. It is worth noting that PG&E includes the 2015 expense, despite stating on p. 5-21 (lines 20-21) of the testimony that the review would be completed in 2014.

[14] Id.

forecast for MWC KA to normalize the Test Year cost to account for the rapidly diminishing costs through the rest of the rate-effective period.

Specifically, given that PG&E's 2015 forecast is significantly lower than the Test Year forecast and the 2016 forecast is zero, TURN recommends a normalizing adjustment for the test year forecast to conform with the Commission's practice of not including one-time expenses in the test year.

The normalized amount is $1.623 million, which represents a reduction to PG&E's forecast ($3.819 million) of $2.196 million.

Recommendation

TURN recommends that the Commission normalize the forecast for this O&M expense. PG&E's Test Year forecast of $3.819 million would be reduced to $1.623 million, a reduction of $2.196 million.[15]

b. Overhead Transformer Labor Reclassification

PG&E forecasts $1 million for Transformer Labor Reclassification; DRA makes no adjustment.

This is a periodic adjustment where PG&E transfers recorded costs from a capital account (FERC 368) to an expense account (FERC 583) to comply with the FERC Uniform System of Accounts. In making the transfer, PG&E simply determines, on a periodic but not necessarily regimented or annual basis, the number of transformers issued to construction for reinstallation that were previously capitalized and subsequently removed from service and refurbished. PG&E claims that the reclassification varies annually, depending on the number of refurbished transformers installed during a year, and uses 2011 recorded costs as the basis for the 2014 forecast.

However, although the 2011 recorded expense was $974,000, the rest of the four years in the normal five-year recorded period had zero expenses recorded. As such, to assume

[15] PG&E's unit costs for this account were provided as nominal dollars, but the unit costs for each year were $451, with no apparent escalation being included.

that Base Year costs in their entirety should be assumed to occur in the Test Year is unreasonable.

Recommendation

TURN recommends a five-year average for this expense: $325K. This corresponds to a reduction of $675K in the Test Year.

c. Permits

PG&E is forecasting $300,000 in MWC KA (expense)[16] and $200,000 in MWC 2A (capital)[17] in TY 2014, which indicates a total spending forecast (expense plus capital) of $500,000. The Company states in workpapers that the forecast is based on actual 2012 permit costs and that they are "expected to remain constant through the forecast years."[18] In a data request response, however, PG&E states, "permitting costs vary from year to year depending on which projects require use of easements" and that such costs "are charged to capital or expense depending on the nature of the supported project."

Given that expenses vary and are variably charged to either O&M expense or capital expenditures, the proper forecasting method to use is an average of the recorded O&M expense for the expense account (MWC KA) and the recorded capital expenditures for the capital account (MWC 2A). This is especially true on the expense side, where any underspending is still collected and not returned to customers. Whereas, PG&E is forecasting an O&M expense of $300,000 for permits, the average, actual spending during the recorded period (2007-2012) is just $50,000,[19] which means that on average, PG&E would pocket $250,000 per year.

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[16] PG&E-4 Workpapers, p. WP 5-10.

[17] PG&E-4 Workpapers, p. WP 5-25.

[18] Id., pp. WP 5-10 and 5-25, Footnote 7 in both.

[19] Calculated from PG&E-4 Workpapers, p. WP 5-10 (line 39).

Recommendation

The average nominal, O&M expense for permits in MWC KA is $52,000,[20] which is the amount the Commission should adopt. This amount corresponds to a $248,000 reduction to PG&E's $300,000 forecast. Please see the discussion for MWC 2A, below, for the recommendation for the capital side of this expenditure.

3. *Underground Equipment (MWC KB)*

a. Underground Transformer Labor Reclassification

PG&E is requesting $100,000 here; DRA makes no adjustment.

Please see discussion of Transformer Labor Reclassification in the Overhead section for a more in-depth discussion of this topic. While the values in Underground Equipment are much smaller on the Underground side (MWC KB) the concept still applies. The five-year average (recorded expenses for four of the five recorded years is zero) is $32K, which corresponds to a $68K reduction.

Recommendation

TURN recommends a $68K reduction for this activity.

b. Underground Switch Replacement Program

PG&E proposes to perform condition-based assessments of underground oil switches and develop a replacement program, forecasting unit counts for investigations of 2,500 in 2012 and 4,300 in each of 2013-2016 for a total unit count of 19,700 in the five years.[21] The cost for the five years (2012-2016) would be $7 million.[22] With a Test Year forecast of $1.5 million, the cost in the GRC period would be $4.5 million.

It is important to understand that, while PG&E does not have a process for recording the results of the inspections of these units unless those inspections reveal a particular unit where "the condition…will adversely impact safety or reliability," PG&E does inspect

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[20] PG&E claims $300,000 in 2012 recorded expense (DRA DR 128-24) and had zero recorded expenses in every other year (PG&E-4 Workpapers, p. WP 5-10), which produces an average of $49,000 in 2011 dollars or $52,000 in 2014 dollars over the six years.

[21] TURN DR 54-9g.

[22] PG&E-4 WPs, p. WP 5-12.

these units.[23] If PG&E wants to begin a more systematic analysis of its system, it should begin by recording the results of the inspections it is already doing for all units. It does not need to accelerate the inspection and cataloging of all the units within a five-year period. The funding for TURN's recommended, more measured, approach is already in the embedded activities of MWC KB.

Recommendation

The Commission should deny funding for this activity as there is no need to increase the speed of inspections beyond what is embedded in recorded expenses.

4. Capital Expenditures

a. Overhead Facilities (MWC 2A)

i. Idle Facilities

This capital-funded activity is related to the O&M expense in MWC KA, as described in my testimony above. In MWC KA, PG&E describes its efforts to investigate and review the Idle Facilities it has on its system. In this account (MWC 2A), PG&E describes and forecasts the activities it would undertake to actually remove the facilities, a capital expenditure.

Here in MWC 2A, PG&E forecasts spending as shown in Table 2:

Table 2: Recorded and Forecasted Capital Spending for Idle Facilities Removal (MWC 2A)[24]

	2007 Recorded	2008 Recorded	2009 Recorded	2010 Recorded	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Idle Facilities Removal	$ 1,219	$ 466,992	$ (7,827)	$ 9,172	$ 36,443	$ 6,450,000	$ 22,863,975	$ 26,566,875	$ 5,000,499	$ -

PG&E forecasts Test Year capital spending at $26.550 million (which is equivalent to a $3.451 million revenue requirement in the Test Year).[25] Overall, PG&E forecasts capital

[23] PG&E-4, p. 5-26 (lines 13-16).

[24] PG&E-4 WPs, p. 5-25. The 2013-2016 forecasts do not include inflation.

[25] This revenue requirement estimate is based on the inclusion of ROE and taxes, but does not include depreciation because this expenditure acts to reduce ratebase by its amount. Therefore, the revenue requirement can be estimated by: [Revenue Requirement] * 13%, or $26.550 million * 13%, which equals $3.451 million.

spending of $61.1 million over the four years ending in 2015 with just about $50 million in 2013 and 2014, alone. This is despite PG&E's past claims that Idle Facilities designation is the lowest priority and has no impact on safety, reliability, and asset life,"[26] and, "the review and potential removal (if the facilities are deemed to have no reasonable use in the foreseeable future) is relatively lower priority work."[27]

It is unclear why PG&E is in such a hurry to remove Idle Facilities,[28] especially given the fact that these facilities do not represent a safety reliability problem and in light of the fact that PG&E's overall rate-increase proposal in this proceeding is so large.

DRA recommends minimal funding for this program ($102K and $101K in 2013 and 2014, respectively). While TURN agrees with DRA's recommendation, we recommend that the Commission fund this program at no more than $2 million in each year, 2013 and 2014, if the Commission decides to provide PG&E with incremental funding. This represents a modest amount that PG&E can use to remove Idle Facilities as maintenance crews come upon them. In other words, PG&E should not be embarking upon a proactive intensive $64 million program (over 4 years) to remove these facilities. The Company should have a very modest program to remove the facilities as it is convenient for crews already in the field.

Recommendation

TURN recommends that the Commission adopt capital spending forecasts in each year, 2013 and 2014, of no more that $2 million if the Commission decides to adopt a program

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[26] 2011 GRC, PG&E-3, p. 2-13 (lines 1-3). PG&E calls Idle Facilities out as priority code P4 on p. 2-48 (lines19-20) in the same document.

[27] Id., p. 2-48 (lines 21-23).

[28] While there was an agreement between PG&E and Modesto Irrigation District (ModestoID) regarding the identification and removal of idle facilities discussed in the 2011 GRC, the agreement appears not to be any longer in effect. According to PG&E-3 (p. 2-53) in the 2011 GRC application, the agreement between PG&E and ModestoID was to end on December 31, 2011, unless extended by the mutual agreement of PG&E and ModestoID. Given that PG&E did not discuss the agreement in its testimony or workpapers, we assume that the agreement is expired. Even if the agreement is still in effect, PG&E can focus its initial efforts on those items of concern to ModestoID with the funding provided with this recommendation.

larger than DRA recommends. This is a reduction of $20.864 million and $26.5667 million in 2013 and 2014, respectively.

ii. Permits
PG&E forecasts capital expenditures for Permits in MWC 2A of $200,000.

Just as with the Permit-related expenses booked to MWC KA (an O&M account, discussed in Section 2.c, above),, PG&E should take an average of the recorded capital expenditures for this account. The 2011-dollar average is $336,017; the 2014-dollar equivalence is $354,000.[29]

Recommendation

PG&E's forecast for TY 2014 capital spending for permits should be $354,000, an increase of $154,000 over PG&E's stated forecast of $200,000.

b. Underground Facilities (MWC 2B)

i. Underground Oil Switch Replacements
PG&E requests $25 million per year starting in 2014 to perform 1,500 (500 per year) proactive Underground Oil Switch Replacements.[30] DRA reduces the forecast to $5 million for a replacement rate of 100 per year. However, until PG&E proves otherwise, the reasonable replacement rate is contained in PG&E's embedded rate. As such, TURN recommends zero funding for the proactive program; PG&E should continue replacing these items at the same rate it has in the historical period.

PG&E indicates that this initiative is the result of its investigation into underground switch failures. The Company claims that it has 261 reports of failed oil investigations since 2000, of which 61 were violent/catastrophic failures.[31] With 50,391 Underground

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[29] Calculated from information in PG&E-4 Workpapers, p. WP 5-25 (line25) with escalation rates taken from PG&E-10, p. 3-6 (Table 3-4).

[30] PG&E-4 WPs, p. WP 5-39.

[31] TURN DR 54-9h. According to PG&E's response, this is three higher than PG&E reported in its workpapers (PG&E-4, p. WP 5-38) because there were three failures after PG&E developed its workpapers for this case. In TURN DR 54-9c, PG&E states the following regarding "violent/catastrophic failures: Due to their varied nature, PG&E is not aware of a standard definition in the utility industry of violent or catastrophic failures. As used by PG&E here, a violent failure or a catastrophic failure mean the same thing – a sudden and total failure of some

Switches on the system installed by at least 1991, the annual failure rate is 0.04%.[32] The violent/catastrophic failure rate is even smaller: 0.001%.[33] The annual violent/catastrophic failure for 1970s-80s-era switches is 0.016%,[34] which is slightly higher than the 0.007% annual violent/catastrophic failure rate for non-1970s-80s-era switches,[35] but PG&E has produced no evidence that it should spend $75 million because of a 0.009% higher failure rate amongst the 1970-80s population as compared to other pre-2001 switches.

As it is, the rate of failures has not increased since 2000. In fact, it has declined since 2000, per the information in Table 3:

Table 3: Historical Underground Switch Failures[36]

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Failures	34	23	21	29	18	8	20	18	21	22	19	17	12

The average rate of failure from 2000-2003 was 27 failures per year; the average from 2004-2012 was 17. The average of the very recent period (2010-2012) was 16 failures per

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system or device which may lead to cascading power outage events where immediate or routine restoration is not possible. With reference to the underground oil switches discussed on page WP 5-38, this would involve a breach of the switch's containment vessel, followed by a release of flammable fluid and, in some cases, a fire.

[32] TURN calculated this failure rate. With 259 failure in 13 years, the rate is calculated with: 259 switches / [13 years X 50,391 switches/year] = 0.04%. The failure rate for pre-2001 vintage switches would be even less to the extent that any of the 259 failures in the 2000s occurred on 2001 or 2011 switches.

[33] TURN calculated this failure rates. With 61 violent/catastrophic failures in 13 years: 61 switches / [13 years X 50,391 switches/year] = 0.01%.

[34] TURN calculated this failure rates. With 37 violent/catastrophic failures in 13 years: 37 switches / [13 years X 19,692 switches/year] = 0.016%. 37 violent/catastrophic failures comes from PG&E-4 WPs, p. 5-38; 19,692 1970s-80s-era switches comes from DRA DR 41-8a Attachment 1.

[35] TURN calculated this failure rates. With 24 violent/catastrophic failures in 13 years: 24 switches / [13 years X 29,246 switches/year] = 0.007%. 24 violent/catastrophic failures comes from PG&E-4 WPs, p. 5-38 (61 such failures overall, 37 attributed to 1970s-80s-era switches, yields 24 non-1970s-80s violent/catastrophic failures); 29,246 non-1970s-80s-era switches (installed before 2001) comes from DRA DR 41-8a Attachment 1.

[36] TURN DR 54-9h. PG&E notes in TURN DR 54-9h that the response shows 262 failures from 2000-2012, "as there were three additional failures in 2012 since the number 259 was published.

year and in 2012, the period that PG&E says it used to launch this program, there were just 12 failures.

PG&E also claims that the "initiative was the result of PG&E's investigation of various UG switch failures in the past 12 months."[37] However, the "various" UG switch failures that PG&E investigated in the past twelve months comprises just two switches out of the 20,378 that are on the system.[38] PG&E claims that there is a third switch that it has investigated "in the past 12 months", but that switch was returned to the manufacturer for failure analysis on March 14, 2013[39]—three months after PG&E filed this GRC—so it is impossible for the Company to claim that it used its investigation of this unit to inform its launch of the proposed proactive replacement program.

Indeed, despite having 261 failures, 12 of which occurred in 2012, to draw upon to make the decision to launch this program, the Company only provided two incident reports to TURN as support for a program that could cost as much as 7.0 million in expense[40] and $75 million in capital (2014-2016).[41] Two incident reports is not sufficient support to justify this cost.

It is important to recognize that PG&E already inspects this equipment and identifies conditions that might adversely impact safety or reliability.[42] Where inspectors find such conditions, they prepare a notification for repair/replacement.[43] The difference between PG&E's traditional inspection process and the one it proposes going forward is that PG&E would now write down the condition of all of the switches it inspects, rather than just those pieces of equipment that inspectors deem to have reliability or safety

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[37] Id.

[38] TURN DR 54-9a.

[39] Id.

[40] Calculated from PG&E-4 WPs, p. WP 5-12 (line 16). The $7.0 million includes the expenses ratepayers will have to pay in attrition years, even though PG&E does not forecast the attrition years, per se.

[41] PG&E-4 WPs, p. WP 5-27 (line 16).

[42] PG&E-4 WPs, p. WP 5-39.

[43] Id.

issues at the time of the inspection.[44] With the information on all of its switches rather than just those with issues, PG&E claims that it can then perform "a diagnostic-based analysis that determines whether a component has reached the end of its useful life, determined by such factors as age of the equipment, switch location, oil condition, and loading history."[45] PG&E would then use that information to "identify and prioritize switches for replacement."[46] However, PG&E has already determined that it would need to replace 500 switches per year on the basis of the "age and condition of the switches and the number of failures and incident reports" before even doing the analysis.[47] It is unreasonable to expect that PG&E will need to replace these facilities at the rate that it forecasts just because it is now instituting a somewhat more formal procedure than previously used, especially since it has been maintaining these facilities and has experienced a failure rate of just one quarter of one percent.

Spending at a rate of $25.0 million per year ($75 million, total, for the rate-effective period) for large-scale replacements is extraordinarily high. PG&E only spent about $13-$15 million per year for all non-Major Notification-related Underground Maintenance capital from 2007 to 2010. The company then spent $25.5 million in 2011 (and plans to spend $27.3 million and $29.6 million in 2012 and 2013) on non-Major Notification maintenance, and expects such spending to decline back to $16.7 million in 2014.[48] The spike in 2011-2013 owes to PG&E's efforts to eliminate its maintenance backlog.[49]

The fact that PG&E has been inspecting and creating maintenance/replacement notifications throughout the years and has spent on the order of $13-$15 million on steady-state maintenance for all non-Major Notification underground equipment (i.e., not just these oil-filled switches) indicates that a reasonable rate of replacement is far less than the rate PG&E forecasts (i.e., 500 switches per year at $25 million). In other words,

[44] Id.

[45] Id.

[46] Id.

[47] Id., Footnote 4.

[48] Id.

[49] Id.

the reasonable rate of repair/replacement and the associated cost of those activities is already embedded in the PG&E's historical spending. Just because PG&E wants to expand the procedures it wishes to undertake to inspect and record the condition of its switches does not mean that the rate of replacement should change beyond the embedded rate.

I also note that, to the extent this project is related to reliability, PG&E has done no cost-benefit analysis. To the extent that it is related to public safety, beyond the fact that the failure rate on this equipment is so small, PG&E is also installing Swiveloc-brand locking manhole covers on its system at a cost of $24.8 million[50] to improve safety related to underground incidents.

SWIVELOC Manhole Covers

PG&E is taking steps to reduce the risk of the fires, explosions, and manhole projections even in the event of failure.

PG&E began the Network Manhole Cover Replacement program in 2010, in which the Company is replacing in-service manhole covers with hinged venting manhole covers (trade name Swiveloc), which are designed to stay in place in the event of a vault explosion. According to PG&E, these devices "reduce the risks associated with projectile damage and the hot gases released during an event." PG&E also states, "Their design also prevents oxygen from rushing into the vault and potentially igniting a fire."[51]

According to the manufacturer, "The patented SWIVELOC system allows the exploding gases to be vented, while protecting the structural integrity of the manhole structure, and ensuring the safety of nearby people and structures."[52] The manufacturer also

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[50] Calculated from PG&E-4, p. WP 5-28.

[51] PG&E Currents, Innovation: PG&E's New Venting Manhole Covers Stay in Place, Improve Safety. Available: www.pgecurrents.com/2011/10/11/innovation-pge%e2%80%99s-new-venting-manhole-covers-stay-in-place-improve-safety/. Accessed: May 12, 2013. See Attachment 4.

[52] Swiveloc's Website: http://swiveloc.com/products/swiveloc/. Accessed: May 12, 2013. See Attachment 4.

describes the Swiveloc's "ability to form a dynamic air damn, which allows for a controlled pressure release of the exiting diffused gasses while simultaneously preventing the incursion of fresh oxygen into the manhole vault, thereby preventing the more massive secondary explosion."[53]

PG&E claims to have already placed Swivelocs on "the busiest areas of San Francisco" by the end of 2011 and would have started installing them in downtown Oakland during 2012.[54] PG&E will complete the replacement program by 2016.[55]

Recommendation

TURN recommends that the Commission reduce PG&E's capital spending forecast in 2014 by $25 million, the full amount of PG&E's forecast. This recommended reduction is $5 million more than DRA's recommended reduction.

B. Electric Emergency Recovery (Chapter 10)

1. Proactive Outbound Calling During Outage

PG&E forecasts $900,000 annually in order to operate a text-message and voice-based, proactive outbound calling system to notify customers when they experience an outage.[56]

PG&E's stated reason for implementing this program is that it will improve the customer experience, based on the results of a pilot survey.[57]

PG&E's answer to its self-asked question, "Why pilot proactive outage notification?", the Company claims, "Utilities that proactively notify customers of outages score an

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[53] Id., phrase uttered by narrator of the video imbedded at http://swiveloc.com/products/swiveloc/.

[54] PG&E Currents, Innovation: PG&E's New Venting Manhole Covers Stay in Place, Improve Safety.

[55] PG&E-4, p. 5-39.

[56] TURN DR 3-1c.

[57] PG&E-4, p. 10-10 (lines 18-20).

average of 102 points higher on the Power Quality and Reliability section of JD Power."[58]

There are a number of items of note, here:

- As the name of the customer-satisfaction section implies, the *Power Quality and Reliability* section of the J.D. Power customer-satisfaction survey is more expansive than just investigating the difference between those utilities that do and do not offer proactive outage-notification service. In fact, the following criteria and weightings make up the J.D. Power Quality and Reliability score:
    - Supply electricity during very hot or very cold temperatures (22%);
    - Promptly restore power after an outage (18%);
    - Avoid brief interruptions of 5 minutes or less (17%);
    - Quality of electric power in terms of being free from spikes, drops or surges (17%);
    - Avoid lengthy outages of more than 5 minutes (13%);
    - Keep customers informed about an outage (12%).[59]

What if the utilities who offer proactive notification are also much better at "Supplying electricity during very hot or very cold temperatures," especially given that J.D. Power gives that criterion almost twice the weight that it gives "Keep customers informed about an outage?"

Furthermore, the mere association of the use of proactive outage notification with an alleged increase in customer satisfaction does not prove causation, especially when there are myriad inputs into customers' assessment of satisfaction with utility service. As such, nothing can be derived from the over-simplified statement, "Utilities that

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[58] TURN DR 3-1 Attachment 10, p. 8.

[59] TURN DR 3-1a Attachment 4, p. 5.

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proactively notify customers of outages score an average of 102 points higher on the Power Quality and Reliability section of J.D. Power."

- The results of PG&E's pilot indicate that just 1.3 out of 5 customers reported that the outage notification improved their outage experience.[60] That is, just 26% of PG&E's pilot customers perceived a higher outage experience after having received the outage notification.

- The program to proactively call all outage-affected customers has a higher price-tag associated with it (than the *status quo*, where customers must either call in to report an outage or for status information or visit the outage Webpage) because it induces those customers who would normally not make calls that require a live agent at all, to request to speak to a live agent regarding the outage as a result of the proactive call from PG&E.[61]

  On the other hand, the Company has another, albeit cost-lowering option: to call only those customers who are most-likely to be the ones who call the utility themselves when they experience an outage. In fact, such a program would serve to shrink costs (vis-à-vis the *status quo*) by reducing live-agent-directed incoming call volumes.[62]

  In other words, PG&E has chosen to pursue higher perceived customer satisfaction over effective and cost-efficient program management in the face of evidence that just 26% of customers claim their proactive notification improved the outage experience.

- PG&E spent $93,500 on an outage-notification Website in 2012.[63] In an age where mobile access to information is essentially ubiquitous, this Website notification solution is the one that makes sense—particularly for those customers who are

[60] TURN DR 3-1a Attachment 3.

[61] TURN DR 3-1a Attachment 4, pp. 10-11 indicates that when all customers are called, costs increase.

[62] Id., p. 13 indicates that when only those customers within the groups that call in to either report an outage and/or for information regarding the outage (i.e., 31% of residential customers) are proactively called costs decline.

[63] TURN DR 3-1d.

less likely to call in outage notifications to PG&E[64]—and it's already operational and has very little if any ongoing costs.[65]

- The proactive outage communication is linked to PG&E's program to provide outage-affected customers with an Estimated Time of Restoration (ETOR). According to PG&E, J.D. Power indicates that customer satisfaction is relatively equal when power is restored 1-2 hours ahead of ETOR or on time…and, it declines sharply if power is restored even a few minutes after the ETOR."[66] The illuminating conclusion that PG&E takes from this observation is that "[PG&E] should tell Customers a later [ETOR] time than we expect operationally."[67] While this might be a smart choice from the point of view of a utility that is attempting to increase customers' perceived satisfaction, it shows very clearly that the Company focus here is not on the type of performance that would actually improve its product and provide customers with type of information that might be useful. It's a case of "style over substance".

- Related to the last point, where it is clear that PG&E's intention with the ETOR program is to under promise and over deliver, there is a last point that PG&E seems to have failed to consider. There could be unnecessary economic hardship imposed on PG&E's customers if the Company under promises and over delivers.

  As TURN Witness John Sugar discusses in his testimony, for example, if a business owner experiences an outage, they must decide whether to remain open until power is restored, or whether to close. This is especially important if employees are paid on an hourly basis. Staying open if business cannot be transacted or production is halted can be expensive. An accurate estimate of restoration time allows the business owner or manager to make an efficient

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[64] Remember, PG&E can reduce costs for live agents if it only proactively calls those customer groups that are more likely call outages into PG&E.

[65] TURN DR 3-1d.

[66] TURN DR 3-1a Attachment 10, p. 15.

[67] ID.

decision. If the utility systematically overestimates the time until restoration, there is a greater likelihood that businesses will close, when a better decision would have been to remain open.[68]

Even residential customers could be unnecessarily inconvenienced—perhaps being forced into making suboptimal decisions—if they are provided restoration information that is systematically inaccurate from an operational perspective.

PG&E's case for cost recovery for this program has not been made. It is not clear that customers receive significant benefit from proactive calls and it appears to allow and encourage behavior that is aimed at increasing *perceived* customer satisfaction but not *actual* customer experience.

Recommendation

The Commission should not include incremental costs (assumed to be $900,000) for this program in rates.

This program is mentioned on p. 10-10 of PG&E's Electric Distribution testimony. However, the response to TURN DR 3-1d indicates that the costs are charged to a Customer Care Provider Cost Center and are not directly assigned to an MWC. The response also states, "There is no specific line item forecasted in the 2014 GRC Application for this work." While it is impossible to know, based on that information, where to take the reduction we propose, we will request further information from the Company and update this testimony with the correct place to make the reduction when it the additional information becomes available.

[68] Mr. Sugar provides the sample of an auto repair shop that hypothetically loses power. P&E, responding proactively calls the shop, and provides an extended estimate of the time until restoration. The owner decides to close, losing income, leaving customers' cars unrepaired, and leaving hourly employees poorer. When employees have gone, power is restored earlier than the telephone estimate. Depending on how pessimistic the telephoned information was relative to actual restoration, it may have been worthwhile for the shop owner to ride out the outage and remain open.

C. Distribution System Operations (Chapter 11)

1. *Electric Distribution Operation Activities (O&M - MWC BA)*

PG&E is requesting a Test Year forecast of $32.743 million for activities related to the operation of the electric distribution grid.[69]

DRA reduced PG&E's Test Year forecast to $28.729 million, to account for the that fact that PG&E is re-requesting "[Distribution Control Center] pre-consolidation"[70] costs that it received in the 2011 GRC request ($3.785 million in 2010 and $0.709 million in 2011). DRA argued that it is inappropriate to charge ratepayers costs for activities that are already included in its historical costs.[71]

TURN believes the forecast should be reduced further, or at minimum, by the amount discussed below, in the event the Commission does not adopt DRA's position regarding embedded costs.

PG&E is claiming staff counts and overtime reductions as benefits of the Distribution Control Center Consolidation Project.[72] Specifically, it is claiming:

- Reductions of 10 Operators in each year 2013-2015 ($1.870 million per year per 10 employees reduced);
- Reduction of one Support Personnel in 2013 ($150K per year) and five additional Support Personnel reductions in 2014 ($750K per year); and
- Overtime cost reduction in 2016 ($1.500 million in 2016).

PG&E credits the benefits that will inure in 2013 and 2014 to ratepayers, but has not credited the benefits that will inure in 2015 and 2016. In other words, it has not properly

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[69] PG&E-4, p. 11-9 (Table 11-2).

[70] PG&E's forecast includes its proposal to consolidate thirteen existing Distribution Control Centers (DCC) down to one Central DCC and two regional facilities. (PG&E-4, p. 11-7).

[71] DRA-6 Part 2, pp39-41.

[72] For background on the Distribution Control Center Consolidation program, please see pp. 11-12 through 11-15 of PG&E-4 and pp. WP 11-29 through WP 11-30 of the PG&E-4 WPs.

credit the known savings that it will achieve in 2015 and 2016 for the ten Operators that will be eliminated in 2015 or the overtime reduction in 2016.

The known savings that will accrue from the 10-employee reduction in 2015 is $1.870 million, which will continue in 2016. The normalized amount of this reduction that should be applied to the Test Year forecast is $1.247 million (in addition to the $1.870 million that PG&E does credit to ratepayers in WP 11-10 (line 5)).

The known savings from Overtime reduction for Operators is, again, $1.500 million in 2016. Normalized, the per-year reduction would be $500K.

The total reduction to the 2014 forecast to account for these credits that should inure to ratepayers for benefits from the DCC Consolidation Project is $1.597 million.

Recommendation

TURN recommends that the Test Year forecast be reduced by $1.597 million.

If the Commission adopts DRA's position that the Test Year forecast should be reduced to $28.729 to account for the fact that PG&E has embedded costs to rely upon in the "pre-consolidation" period, TURN recommends an additional reduction of $1.597 million to a Test Year forecast of $27.132 million.

If the Commission does not adopt DRA's position, PG&E's forecast of $32.743 million should be reduced by $1.597 million to $31.146 million.

2. *Maintenance of Information Technology Applications (MWC JV)*

DRA recommends that the Commission completely eliminate the Test Year forecast ($877K) because "PG&E does not show any expenses recorded for MWC JV for 2007-2011" even though "PG&E requested ratepayer funding in its 2011 GRC for technology to implement its electronic mapping system."[73] TURN agrees with DRA's analysis and conclusion, but if the Commission does not eliminate this funding as a deferred activity (as DRA recommends), it should at least normalize the $877K, one-time cost over the

[73] DRA-6, Part 2, pp. 47 (line 3) & 48 (lines 1-3).

three years, given that PG&E's 2015 and 2016 forecast for this activity is zero.[74] The resulting 2014 forecast would be $292K, or a $585K reduction to PG&E's forecast.

D. Electric Distribution Reliability (Chapter 15)

1. Base Reliability (MWC 08) and Circuit/Zone Reliability (MWC 49)

PG&E forecasts Test Year spending of $172.026 million for reliability-related programs, or $525.693 million over the three-year, rate-effective period.[75] During the previous three-year period (i.e., 2011-2013), PG&E expects to have spent $513.169 million (average $171.1 million in each year), including Cornerstone-authorized FLISR spending, by the end of 2013.

However, *because* the three-year period of 2011-2013 includes Cornerstone-authorized FLISR spending, it is misleading. Only considering non-FLISR, reliability-related programs in the 2011-2013 period, PG&E will have spent $260.130 million by the end of the 2013. The $345.7 million PG&E proposes to spend on non-FLISR programs during 2014-2016, on the other hand represents a $85.6 million (32%) increase over the previous three years on non-FLISR items. This information illustrates that not only is PG&E proposing to continue its FLISR program past the end of the Cornerstone funding, but it is also proposing to increase non-FLISR reliability-only spending by 32%.[76]

But that is only 32% higher if one considers only those programs designated in MWCs 08 and 49 as reliability-only. The Commission should also consider that the spending in what PG&E designates as "reliability" programs—the items presented here in Chapter 15—are not the only programs that should be considered reliability programs. In fact, in addition to the $525.693 million PG&E plans to spend in 2014-2016 on the programs here in MWCs 08 and 49, PG&E's other reliability-related programs and their related spending proposals include:

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[74] PG&E-4 WPs, p. WP 11-30.

[75] Calculated from PG&E-4 WPs, p. WP 15-4 (line 5).

[76] TURN calculated the values in this paragraph from the information presented in PG&E-4 WPs, p. 15-5.

- Many of the programs described in Chapter 17—Distribution Automation and System Protection—have reliability improvement as their main driver. For example, the primary driver for Substation and Line SCADA installations is reliability.[77] It is interesting, however, that PG&E has not made an estimate of the reliability benefit SCADA offers, even when requested to do so.[78]

  Over the three rate-effective years, Substation and Feeder SCADA installations push PG&E's reliability-related spending up by another $192.5 million[79] on top of the $525.7 million that PG&E explicitly attributes to reliability programs.

- The spending identified explicitly as related to reliability in this case include PG&E's Smart Grid Pilot Program, which the Commission recently authorized. Furthermore, this huge increase in spending is being forecast in isolation from the results of the Smart Grid Pilot Project results. PG&E cannot and is not integrating the results of its Smart Grid Pilot Project activities into any of its $525.7 million (in 2014-2016) reliability spending proposal in this rate case because the Smart Grid Pilot Results will not be available until after PG&E completes its pilot in 2016.[80] Instead of speeding up reliability-related spending, PG&E should be slowing it down until it has results from the Smart Grid Pilot Project and can integrate the technologies from the pilot program into the system in a comprehensive and cost-efficient manner.

- PG&E forecasts Test Year O&M spending of $35.8 million for mapping,[81] which it expects, in part to form the basis for improved reliability.[82]

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[77] PG&E-3 (pp. 11-7 through 11-8 and 11-11 through 11-12) from the 2011 GRC. Please see the discussion of the factors driving SCADA installation in Section II.E, below.

[78] TURN DR 14-4a.

[79] Calculated from PG&E-4, WP p. WP 17-13. Including 2012 and 2013, the total spending for the five years of SCADA installation would be $242.0 million (PG&E-4 WPs, p. WP 17-32.

[80] D.13-03-032, p. 29.

[81] Calculated from information in Table 4-2 and Table 4-3 in PG&E-4.

[82] PG&E states: "Some of the Electric Distribution Mapping and Records Management workload and work management measures include mapping cycle time, map

- PG&E has been implementing a capital program it calls the Animal Abatement Program since 2009. Indicating that contact between animals and electrical substation equipment is "one of the leading causes of substation outages,"[83] PG&E plans to spend $9 million on the program during the GRC cycle.[84]

- Finally, 18 of the 25 programs in Electric Operational Technologies are at least in part reliability related.[85] PG&E forecasts capital spending on the order of $212.0 million for this program during 2014-2016, $91.6 million more than is planned during 2011-2013,[86] although even the 2011-2013 spending will ultimately be $33 million more than PG&E forecasted for 2011-2013 in the last GRC.[87] This is another very large increase to spending that is directly, if not entirely, related to improving reliability.

It is also instructive to consider the cost of each minute of SAIDI that PG&E expects to save with the programs it proposes. We provide a table containing that information for those programs in MWC 08 and MWC 49 for which PG&E provided reliability improvement estimates:

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corrections not associated with a job, post-outage reporting timeliness, and production of inspection and patrol maps. These measures and metrics support the higher-level metrics in the Electric Operations Improvement Plan related to public safety such as number of wire down incidents and reliability metrics such as System Average Interruption Duration Index (SAIDI) because timely reporting of outage and asset performance information is critical to effective corrective action plans for these metrics." (PG&E-4, p. 4-4 (lines 1-10)).

[83] PG&E-4, p. 13-11 (lines 15-17).

[84] Id., lines 28-29.

[85] TURN reviewed PG&E-4, pp. 2-10 through 2-62, which contain descriptions and forecasts of 25 IT projects. TURN count each proposal where the Project Benefits table (there is one for each proposal) mentioned reliability as being one of the benefits.

[86] Calculated from information in PG&E-4, p. 2-62 (Table 2-52).

[87] Calculated from values on lines 27-28 on p. 2-5 of PG&E-4.

Table 4: Calculation and Comparison of the Cost of Reliability ($/Minute of SAIDI Saved) for Capital Proposals in MWC 08 and 49

	Programs in MWC 08 and 49					
	Reclosers	FLISR	OH Fuses	UG Fuse Switches	Targeted Circuits	Overhead Conductor Replacement
SAIDI reduction per year (includes major events)[1]	0.87	11.85	0.49	0.09	0.56	0.63
SAIDI reduction per year (includes major events but assumes 10% reliability overlap factor)[2]	0.78	10.66	0.44	0.08	0.51	0.57
Cost (per year)[3]	3,000,000	60,000,000	3,000,000	1,200,000	26,000,000	34,130,000
Cost of Reliability ($/minute SAIDI Saved)	**3,827,463**	**5,626,311**	**6,786,260**	**15,467,265**	**51,299,269**	**60,294,736**

[1] Values are raw SAIDI values of SAIDI benefits that include major events. See lines 24-29 on p. WP 15-18 in PG&E-4 WPs.

[2] See p. WP 15-18, line 32 and Footnote 4, which indicates that PG&E removes 10% of the expected reliability benefit in all programs to account for the fact that there is "some benefit overlap within each program."

[3] 2015 Capital Expenditure forecasts from PG&E-4 WPs, pp. WP 15-9 (FLISR); WP 15-11 (Reclosers); WP 15-10 (Targeted Circuit Initiative); WP 15-12 (OH Fuses); and WP 15-13 (UG Fuse Switches).
Please note: TURN used SAIDI improvement and investment values from 2015 because of the way PG&E calculates the reliability in any one year, which is 50% of the benefit expected from investments made in the year prior to a given year and 50% of the benefit in the given year, to account for the fact that investments are made throughout the year and, therefore, will not net all of the benefits in the given year, since some of the invesments are made in late fall, for example, and only provide benefits for a few months. 2015 is the correct year to choose because all of the investments in 2014 are forecasted as the same as in 2015, save Overhhead Conductor, which is slightly different at $32.5 million in 2014 and $34.13 million in 2015. As such the 2015 value and SAIDI benefit can be assumed to correspond correctly. See also TURN DR 12-13a.

As the table shows, the programs proposed in MWC 08 and 49 improve SAIDI at costs ranging from $3.827 million per minute of SAIDI saved for Reclosers to $60.295 million per minute for Overhead Conductor Replacement.

For comparison, the Commission adopted spending for distribution automation in PG&E's Cornerstone Project, which included line capacity upgrades, SCADA, switch and FLISR of $181.879 million.[88] This amount, along with the SAIDI improvement that PG&E forecasted for applying FLISR-related improvements to its 400 worst-performing circuits in the Cornerstone Project, was expected to result in a unit-reliability cost of $7.2 million per minute of SAIDI saved.[89]

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[88] D.10-06-048, p. 39.

[89] Id., p. 28. For its development, please see the Direct Testimony of William Marcus and Gayatri Schilberg in A.08-05-023. We note that is not clear how PG&E's SAIDI savings cost in this proceeding for the FLISR program could cost $5.626 million when the cost for the 400 worst circuits at the time Cornerstone was filed was $7.2 million. One would expect the cost to be higher than it was for the worst 400 circuits

These results show that there is room for PG&E to prioritize, just as the Commission directed to do in the Cornerstone decision, D.10-06-048. As a marker, the Commission provided PG&E with the following general guidance as to how the utility should address electric distribution reliability in future Cornerstoneproceedings:

> With respect to future proceedings, PG&E should address all electric distribution reliability matters in an integrated fashion through the GRC process. <u>This will allow consideration and prioritization of all types of reliability programs and projects (existing, expanded or new), not only in the context of reliability but in the context of the overall base revenue requirement</u>. PG&E should implement a process to determine an appropriate path to take with respect providing an appropriate level of reliability to customers. That includes determining whether it would be necessary and appropriate to propose a large scale project such as Cornerstone, something more moderate, or nothing at all. In any case, PG&E should be ready to justify the path it chooses.[90]

The Commission is explicit here. PG&E is required to consider and prioritize all types of reliability. Clearly, with reliability spending programs scattered throughout PG&E's presentation without any comprehensive consideration and analysis of the total spending and benefits, PG&E is not assessing the projects holistically or with any apparent attempt at prioritization. Furthermore, the Commission has directed PG&E to consider its reliability spending in the context of the overall base revenue requirement. Given the large increase PG&E has proposed in this case, it is reasonable to expect that some of its reliability-related spending proposals should be moderated. PG&E does not appear to have shown such restraint.

We recognize that PG&E obtained benefit/cost values for some of its reliability program proposals that were positive, with some of them being very high. However, the VOS results are not the only consideration. As DRA states, "As an extreme example, no one would seriously suggest that all 113,500 miles of overhead conductor be replaced in one year, even assuming the benefit to cost ratio is positive.[91] Furthermore, the Commission was clear in the Cornerstone decision that the VOS was not necessarily the only support PG&E might be require to support its reliability proposals:

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[90] D. 10-06-048, p. 19. Emphasis added.

[91] DRA-7, p. 52 (lines 22-55).

> As part of its next GRC (at this point scheduled for test year 2014) PG&E should conduct a new VOS study for use, at least in part, in determining and justifying its electric distribution reliability needs. We will leave it up to PG&E to determine what other information is necessary to support its position with respect to such needs.[92]

As noted, PG&E does not appear to have prioritized, especially in light of the very large revenue increase it is requesting in this case. As such, TURN makes the recommendation below to prioritize PG&E's reliability-related spending, as the Commission has ordered it to do.

Recommendation

TURN's recommendation applies to the Test Year.

TURN recommends that the Commission consider the 2014 forecasts for Base Reliability (MWC 08) and Circuit/Zone Reliability (MWC 49) as a combined total for ratemaking purposes and make a high-level, downward adjustment to the combined forecast. The purpose of this recommendation is to encourage PG&E to prioritize its investments. As **Error! Reference source not found.** illustrates, there is a wide range in reliability benefit per dollar spent across the reliability-related programs PG&E is proposing in this GRC. This recommendation is similar to decision the Commission issued in the Cornerstone case, where it provided PG&E an amount of money and told the Company to get the most reliability it could for that amount. The recommendation also is in the spirit of the Commission's direction to PG&E in the Cornerstone case regarding prioritization in future cases.

PG&E's combined forecast for MWC 08 and 49 is $172.026 million in 2014. DRA recommended various adjustments which, together, yield a combined 2014 reduction for MWCs 08 and 46 of $53.100 million, which yields a Test Year recommendation of $118.926 million.[93] Again, DRA has recommendations for specific capital programs

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[92] Id., p. 20.

[93] This recommendation is made up of reductions to the following capital programs within MWCs 08 and 49: Overhead Conductor Replacement Program ($16.5 million, MWC 08); Line Recloser Revolving Stock ($6.6 million, MWC 08); and FLISR ($30.0 million, MWC 49).

within MWC 08 and MWC 49, but $118.926 million is the total each DRA's recommendations.

TURN agrees with the sum of DRA's recommendations, and, therefore, recommends that the Commission adopt DRA's total forecast. TURN, however, recommends that the Commission direct PG&E to use that lump sum to derive the most reliability it can for that amount of money.

For context, PG&E will have spent an average of $86.710 million in MWCs 08 and 46 in 2011-2013, excluding Cornerstone (FLISR) investments. DRA's forecast of $118.926 million is $32 million more than that amount. In other words, PG&E has $32 million that it can spend to improve reliability in MWC 06 and 46. If it wishes, $32 million is enough to install FLISR on 107 circuits. Incidentally, the installation of FLISR on 107 circuits would represent seven more than DRA proposes the Commission authorize. It is also about 25% of the number of circuits that the Commission approved for FLISR upgrades in Cornerstone. Again, this information regarding what the additional $32 million above the 2011-2013 average recorded spending is just meant to be an example of what PG&E could do with that additional $32 million. It is not meant to be prescriptive in terms of *what* within MWCs 08 and 46 PG&E should invest in nor is TURN specifically recommending PG&E spend the money in this manner.

2. *Overhead and Underground Fault Indicators*

This is a program to install non-communicating fault indicators that assist troublemen in the field as they attempt to find a fault. These devices basically function to tell the troublemen on which side of the indicator the fault is occurring when the troublemen look at the device in the field. PG&E's forecasts for 2013 and 2014 are $2.5 million and $5.25 million.[94]

PG&E has been installing these devices since 2005[95] and is requesting funding of $5.7 million in each year, 2014-2016, or $17.1 million for the three-year rate-effective period,

[94] PG&E-4 WPs, p. WP 15-14 (line 11).

[95] PG&E-4, p. 15-24 (lines 23-24).

to install 1,500 units (i.e., 500 per year).[96] DRA has accepted PG&E's forecast with no reduction. [97] TURN recommends that the Commission reduce all capital spending forecasts for this program, including for 2013, to zero. This would reduce PG&E's forecast by $2.5 million in 2013 and $5.7 million in the Test Year.

PG&E is now embarking on its Commission-approved Smart Grid Pilot Program in which it will test and pilot communicating fault indicators.[98] If the Company illustrates that the communicating fault indicators are cost effective, it will likely request and may receive Commission approval for wide-spread deployment throughout its service territory. In the case that the Commission approves wide deployment for the communicating fault indicators, PG&E's current expectation is that it would install spend between $93 million and $124 million to install communicating fault indicators.[99] PG&E has no plan for integrating the two technologies (i.e., the non-communicating devices proposed in this GRC and the communicating devices contemplated in the Smart Grid Pilot Project proceeding). In fact, PG&E states:

> PG&E has not made any decisions regarding deployment of non-communicating and communicating Faulted Circuit Indicators; obtaining objective, operating-quality information on which to base these decisions is the main purpose of performing the pilot projects in this application. PG&E plans to evaluate the use of non-communicating and communicating Faulted Circuit Indicators during the analysis, test and pilot phase of Smart Grid Line sensor pilot. PG&E expects that both the communicating and non-communicating fault sensors will have cost-effective and efficient uses on PG&E's system. For example, the communicating fault sensors cannot be installed on portions of the distribution circuits where the line loading is not high enough to charge

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[96] PG&E-4 WPs, p. 15-14 (line 11).

[97] DRA-7, p. 56 (Table 7-13).

[98] Please see A.11-11-017. PG&E proposed and received funding to test and pilot communicating line sensors, which would send a signal to PG&E's operations center, telling central operators on which side of the sensor the fault is occurring. This is opposed to the non-communicating variety, which PG&E is proposing to continue installing in this GRC. PG&E claims that both types of devices have their respective places on its distribution system. It is not clear that this is true. But even if it is, there is no question that if PG&E installs 1,500 non-communicating devices before it has even piloted the communicating devices there is no opportunity for an organized, coherent installation plan that installs the devices in an efficient manner.

[99] R.08-12-009. See PG&E's Smart Grid Deployment Plan, June 30, 2011, p. 163.

> the internal battery which enables communication. In case where the line loading will not support the communicating technologies, PG&E will assess the use of the non-communicating devices for cost-effectiveness. …[T]echnology continues to evolve and PG&E will assess the merits of the different technologies based on cost-effectiveness.[100]

In other words, PG&E will only be able to develop an integrated plan *after* the Smart Grid Pilot Program, which runs through 2016, the last year of the rate-effective period for this GRC.

Furthermore, although PG&E has estimated that the non-communicating fault indicator SAIDI benefit would be about 0.340, 0.476, and 0.526 in 2014, 2015, and 2016, it is not clear that this estimate has any basis in reality, given that PG&E, even after having begun installations in 2005, still has not tested or verified the magnitude of any reliability benefit from these devices.[101]

It would be imprudent to accelerate a program to install non-communicating fault sensors at this juncture, right at the very moment PG&E is testing equipment that would either replace them in some instances, or at the very least, reduce their numbers. The Commission should deny further rate basing of these non-communicating devices until there is clarity about the status and cost-effectiveness of the communicating devices and a comprehensive plan for integrating the installations of communicating and non-communicating fault indicators.

Recommendation

In the event the Commission does not adopt TURN's overall adjustment for MWC 08 and MWC 49, TURN recommends that the Commission reduce PG&E's capital spending forecast specifically by $2.5 million in 2013 and $5.7 million in 2014.

TURN also recommends that the Commission order PG&E to stop installing these units until either the Commission has denied wide deployment of communicating fault indicators or, in the event the Commission approves wide deployment of

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100 TURN DR 12-12.

101 This as of May 4, 2012, when PG&E issued its response to TURN DR 6-10in A.11-11-017 (i.e., PG&E's Smart Grid Pilot Deployment Project). See Attachment 5.

Communicating Fault Indicators, PG&E has developed an installation plan that comprehensively considers both Communicating and Non-Communicating Fault Indicators after the Pilot decision has been issued.

E. Distribution Automation and System Protection (Chapter 17)

1. Distribution Automation and Protection Capital - MWC 09

Work in MWC 09 addresses capital expenditures for Emergency Equipment Replacement, Installation of New Substation and Feeder SCADA, Replacement of (obsolete) Substation and Line SCADA and Deficient protective relays. The program includes a Fire Risk Management (FRM) subprogram which focuses on upgrading the functionality of line recloser controls and the remote operation of their reclosing relays to reduce the likelihood of wildfires.[102]

TURN recommends reductions to the programs to install new Substation SCADA and Feeder SCADA.

Table 5 contains recorded and forecasted expenditures for Distribution Automation and Protection (MWC 09).

[102] PG&E-4, p. 17-7 (lines 5-10).

Table 5: PG&E's MWC 09 Recorded and Forecasted Capital Expenses ($1,000s)[103]

Subprogram/Title	2007 Rec	2008 Rec	2009 Rec	2010 Rec	2011 Rec	2012 Rec (DRA DR 217-1)	2012 FC	2013 FC	2014 FC	2015 FC	2016 FC
Emergency Equipment Replacement	$236	$23	$250	$191	$391	$132	$347	$310	$310	$310	$310
Install of Substation SCADA	$365	$1,393	$3,513	$3,443	$15,699	$32,979	$29,942	$34,650	$58,300	$59,600	$59,600
Replace of Substation SCADA	$1,931	$1,590	$2,127	$2,490	$2,699	$2,963	$3,278	$1,000	$2,000	$2,000	$2,000
Replace of Substation Protective Relays	$211	$24	$50	$434	$354	$323	$318	$2,000	$2,000	$2,000	$2,000
Installation of Feeder SCADA	$2,675	$2,633	$1,688	$1,792	$608	$42	$1,000	$3,000	$5,000	$5,000	$5,000
Replacement of Feeder SCADA	$392	$31	$0	$46	$2,283	$882	$1,100	$3,000	$2,000	$2,000	$2,000
Fire Risk Management (FRM)	$0	$0	$0	$26	$25	$64	$1,200	$2,000	$2,000	$2,000	$1,000
Escalation	$0	$0	$0	$0	$0		$0	$1,313	$1,844	$1,775	$2,003
Distribution SCADA Management System	$3,049	$2,911	$569	-$539	$0		$0	$0	$0	$0	$0
E Dist Automation & Protection	$ 8,858	$ 8,605	$ 8,197	$ 7,883	$ 22,059	$ 37,385	$ 37,185	$ 47,273	$ 73,454	$ 74,685	$ 73,913

DRA reduced PG&E's 2013 and 2014 forecasts for Installing Substation SCADA modestly to $33.1 million (vs. $34.650 million) and $56.8 million (vs. 58.300 million), respectively, to account for the fact that PG&E spent somewhat more in 2012 than it originally forecasted. TURN recommends a larger reduction, with 2013 and 2014 forecasts equal to the recorded expenditure in 2011, $15.699 million, which will allow SCADA installations on about 35 substations per year.[104]

DRA reduces the Feeder SCADA forecast (recommending $1.16 million for 2013 and 2014 vs. $3,000 and $5,000 for the two years respectively). TURN recommends a 2013 and 2014 forecast of $1.573 million, which is the average spending of the 2007-2012

As Table 5 shows, PG&E is forecasting large increases for Substation SCADA and Feeder SCADA spending. Whereas, the average spending for the Installation of Substation SCADA in the years 2007-2011 was $4.883 million, PG&E's 2014 forecast for Installation of Substation SCADA is $58.300 million and its 2014-2016 total spending proposal is $177.500 million. The average spending for Feeder SCADA in 2007-2011 was $1.879 million, but the average forecast in 2014-2016 period is $5.0 million. Together,

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[103] PG&E-4, WPs, Errata p. 17-13. 2012 Recorded are from DRA DR 217-1. The recorded 2012 expenditure for Substation SCADA in DRA DR 217-1 (i.e, $32.979 million) contradicts the value PG&E provided to TURN in TURN DR 14-4b Supplemental 01 Attachment 1, which indicates that the total Substation SCADA expenditure in 2012 was $9.530 million.

[104] On the basis of an average of $452K per installation (PG&E-4 WPs, p. WP 17-32).

Substation and Feeder SCADA installations spending during the GRC period is $192.5 million[105]

Finally, in the five years ending in 2011, PG&E spent $33.808 million on SCADA installations. In the five years starting in 2012, PG&E plans to spend $261.092 million. That is a $227.3 million dollar difference between the two five year periods.

PG&E claims safety, reliability, operability, and Smart Grid benefits for Substation SCADA Installations.[106]

i. Safety

PG&E claims, "During incidents that may expose the public to unsafe conditions, SCADA allows PG&E operators to remotely determine breaker statuses… and remotely open them as necessary."[107] This according to PG&E gives the Company "the ability to de-energize equipment to protect the public and PG&E employees from hazardous conditions that sometimes occur… ."

The traditional drivers for Substation and Line SCADA installations have been reliability. In fact, PG&E did not mention safety as a benefit of SCADA installations once in its last GRC application.[108] However, with PG&E's newly found attention to safety, PG&E has made safety to be a key driver behind SCADA installations.

Finally, PG&E has done no investigations into how numerous or severe the incidents SCADA system would likely avert if it were expanded as proposed in the Electric Operations Improvement Plan.[109] For that matter, there is no record in this proceeding of how many injuries or fatalities have occurred on the PG&E's electric distribution system in general or that PG&E could have averted if SCADA had been available. PG&E indicates that SCADA will make the system safer, but provides no way of

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105 Calculated from PG&E-4, WP p. WP 17-13. Including 2012 and 2013, the total spending for the five years of SCADA installation would be $242.0 million (PG&E-4 WPs, p. WP 17-32.

106 PG&E-4, pp. 17-10 through 17-11.

107 PG&E-4, p. 17-10 (lines 27-30).

108 PG&E 2011 GRC, PG&E-3, pp. 11-7 through 11-8 and 11-11 through 11-12.

109 TURN DR 57-3.

evaluating how dangerous the system is and by how much SCADA expansion can improve the system safety.

ii. Reliability

PG&E states,

> From an outage response perspective, SCADA allows operators to remotely control substation equipment, thereby better utilizing emergency response personnel to perform circuit troubleshooting and sectionalizing out on the distribution feeder.[110]

TURN asked PG&E to "provide business plans, cost-benefit analysis, etc., supporting the increased spending" related to Substation SCADA. In response, PG&E provided benchmarking study (*T&D Benchmarking Final Report 2011*, PA Polaris Consulting).[111] This is the same report that the Company references in its testimony.[112] PG&E claims from the results of the benchmarking,

> The results show that four out of ten North American electric utilities that participated in the survey have 100 percent full SCADA monitoring and control of substation circuit breakers, as shown in Figure 17-1. Furthermore, an additional two utilities have full SCADA supervision greater than 80 percent….. The same utilities that have full SCADA supervision have faster outage restoration times (as reflected by lower CAIDI results) than PG&E.[113]

There are a couple of points about this benchmarking study:

- First, PG&E characterizes this as being a comprehensive study when by stating, "four out ten North American electric utilities that participated in the survey.." This survey appears to have fifteen respondents, one of which was PG&E, out of the thousands of utilities in contained in North America.[114] Furthermore, of fifteen "North American" participants who responded to the survey, only 10

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[110] PG&E-4, p. 17-11 (lines 2-6).

[111] TURN DR 14-3. PG&E provided PA Polaris Consulting report as Confidential Attachment 1.

[112] See PG&E-4, p. 17-12 (Footnote 9).

[113] Id., lines 3-13.

[114] Figure 17-1 p. 17-12 (PG&E-4) contains SADA penetration results for ten utilities. TURN requested that PG&E provide the data that underlies the table (TURN DR 14-6)

responded regarding the percent of SCADA on their respective systems. The study, in other words, is very narrow, and does not account for very many of the utilities in "North America".

- PG&E has no information regarding the relationship between the rate of SCADA penetration among the other utilities in the PA Polaris survey and any other factors other than SCADA that may have had an effect on reliability. In other words, PG&E provided no information regarding the conditions the other utilities face or a catalog of the other measures those utilities take. Just because a certain utility has more SCADA *and* may have better reliability does not necessarily mean that it is SCADA that is providing the additional benefit.

Even if SCADA does have an effect on reliability, PG&E has not quantified an estimated the improvement SCADA might engender. Therefore, it is unclear what the $242.092 million that PG&E plans to spend on this program between 2012 and 2016[115] will buy in terms of reliability improvements.

iii. Operational

PG&E states:

> By allowing operators to remotely switch substation equipment during routine switching and load transfers, field personnel can be reassigned to perform manual field switching operations.[116]

However, PG&E has not quantified the benefits in labor savings, or any other potential benefit, related to the ability to reassign field personnel to perform manual field switching.

PG&E also states:

> SCADA provides comprehensive operational data. The real-time information that SCADA provides allows both operators and engineers to

[115] Calculated from information in PG&E-4 WPs, p. WP 17-13 (Errata Page).

[116] PG&E-4, p. 17-11 (lines 8-11).

> more closely monitor system conditions and take prompt actions to avoid equipment overloads and failures.[117]

And:

> Historical data that SCADA provides is used for determining equipment and line loading trends, forecasting future loading, and even performing outage investigations.

PG&E already forecasts future loading. SCADA may make it easier, but the benefit has not been quantified (in dollars) such that it may be compared to the cost. Moreover, "determining equipment and line loading trends" and performing outage investigations" seem to be things that might be nice to have, but PG&E has not proven their usefulness in the face of the massive spending they'll require.

iv. Smart Grid

PG&E claims:

> SCADA enables PG&E to implement current and anticipated Smart Grid technologies. One of the key benefits of SCADA at a substation is to support the deployment of distribution FLISR systems such as those described in Chapter 15, Electric Distribution Reliability.

If SCADA is needed to support FLISR, SCADA's costs should be incorporated into the cost-benefit review of the FLISR program. PG&E appears to have analyzed the costs of the FLISR program without including the cost of the additional SCADA equipment it would need.

Recommendation

TURN recommends a larger reduction, with 2013 and 2014 forecasts equal to the recorded expenditure in 2011: $15.699 million. This will allow Substation SCADA installations on about 35 substations per year. This indicates reductions in 2013 and 2014 of $18.951 million and $42.601 million. The recommendation for a lower forecast is supported by the testimony in Section D, above, regarding Reliability, where we discuss the Commission's desire that PG&E prioritize and be mindful of the overall base revenue requirement.

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[117] Id., lines 11-14.

Similarly, for Feeder SCADA, TURN recommends $1.573 million in 2013 and 2014. This represents reductions of $1.427 million and $3.427 million, respectively, to the 2013 and 2014 forecasts for this program.

F. Underground Asset Management (Chapter 16)

The Underground Asset Management (UAM) primarily consists of capital investments to replace cable, switches, and other underground assets, which are recorded in MWC 56.[118]

1. *SF Network Cable Replacement (MWC 56)*

PG&E's recorded and forecasted capital spending for the SF Network Cable Replacement Capital is contained in Table 6

Table 6: SF Network Cable Replacement Recorded and Forecasted Expenditures[119]

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast
Network Cable Replacement	$ -	$ -	$ -	$ 16	$ 798	$ 7,000	$ 6,000	$ 21,000	$ 28,000	$ 28,000

PG&E spent $798K on this program in 2011 and forecasts spending of 7.0 million and $6.0 million in 2012 and 2013, respectively. PG&E wants to dramatically ramp the program up starting in 2014 ($21 million) for a total cost of $77 million.

PG&E states:

> The failure of a primary or secondary cable typically does not result in customer interruptions; however, they can pose a public and employee safety hazard, and cause equipment damage. Primary and secondary cable failures can release a significant amount of energy, which can result in explosions and manhole cover displacements. In addition, initial failures can cause fires on the cable insulation, which can fill the vault with gases and result in secondary explosions. These explosions may cause personal injury as well as property damage. The location of these facilities in dense urban environment, combined with failure impacts, increases bystander risk.[120]

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[118] PG&E-4, p. 16-7 (lines 2-4).

[119] PG&E-4 WPs, p. WP 16-33.

[120] PG&E-4, p. 16-11 (lines 11-20).

TURN asked PG&E to "provide copies of all analysis and other materials that PG&E generated and relied upon in making the decision to pro-actively make replacements to [Network Cables]."[121] In response, PG&E pointed to its workpapers, which added to the information in the quote above: "Since 2008, there has been 33 network cable and splice failures in San Francisco. It is expected that [as] these facilities age, the network system will continue to experience cable and splice failures."[122]

This last point, that there have been 33 network cable and splice failures since 2008 (through the end of 2011) appears to be the only support PG&E provides in concluding that the cables have reached the end of their useful lives.

It is worth noting that PG&E does not conclude that it expects the frequency of cable and splice failures to increase, just that they will continue. In fact, PG&E has provided little information about whether and how the failure frequency may have changed over time,[123] and no benchmarking information comparing the failure frequency on PG&E's San Francisco system to the rest of its system or other utilities.

TURN asked PG&E to provide failure counts for the years 1990-2012 in order to assess the amount by which failures may have increased over time as one way of confirming PG&E's claims about the potential aging and deterioration. PG&E, however, did not record these data before 2008 making it impossible to make the assessment.

Table 7: Network Cable Failures in San Francisco

Primary Failure Cause	2008	2009	2010	2011	2012	Total
Cable	2	6	6	5	2	**21**
Splice	1	1	2	5	4	**13**
Secondary	1	0	3	1	3	**8**
Total	**4**	**7**	**11**	**11**	**9**	**42**

Additionally, while the five years that PG&E provides in its testimony make it appear as though the frequency of these failures is increasing (there were four failures in 2008, and

121 TURN DR 56-3a.

122 PG&E-4 WPs, p. WP 16-32.

123 In Table 16-3 on p. 16-12 of PG&E-4, PG&E provided failure counts for the years 2008-2011.

11 in both 2010 and 2011), five years of data are not enough to conclude anything significant. Furthermore, the number of failures in 2012 fell from 11 to 9.[124] But again, with such a short data set—perhaps 2008, at four failures, was an uncharacteristically low—it is difficult to reach any conclusions from these data.

Moreover, there is nothing about the recording of these counts that gives a sense of the severity and consequences of the nominal event. PG&E attempts to characterize the recent failures as more grave than in past years by citing one failure in each of 2010 and 2011 as having "resulted in significant media attention."[125] Those are two events out of the 33 events since 2008 that PG&E pointed to in its testimony (and two of 49 when 2012 is included). When asked to supplement those references with any other events that "resulted in significant media attention," PG&E identified 13 additional such incidents, but since 2000.[126] Regardless, whether an incident reaches the level of "significant media coverage" seems to be arbitrary and insufficient support for investing in a $30 million-per-year capital program.

As stated above, PG&E expresses concern that Network Cable failures in San Francisco can present public safety hazards when fires and explosions occur or manhole covers are blown clear. PG&E, however, is taking steps to reduce the risk of the fires, explosions, and manhole projections even in the event of failure by installing Swiveloc-brand secure manhole covers, PG&E is taking steps to limit the severity of explosions and fires and prevent projectile manhole covers. See the discussion regarding this technology above, in the section on Underground Switch Replacement (MWC 2A), which is discussed in Electric Distribution Maintenance.

Recommendation

PG&E has not provided support for accelerating these replacements. It is not clear that the few incidents it cites in support of the project are sufficient on their own. Add to

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124 TURN DR 56-4.

125 PG&E-4, p. 16-12 (lines 1-9).

126 TURN DR 56-5 Attachment 1. The body of TURN DR 56-5 indicates, "The definition of "significant media coverage" has changed somewhat over time… ."

that PG&E's ongoing program to install Swiveloc manhole covers on its system, and the support is even less sure. TURN recommends reducing the 2014 forecast to $7.0 million, which is PG&E's 2012 forecast and one third of its $21.0 Test Year forecast. This should be enough to continue a reasonable program.

2. *TGRAM/TGRAL Switch Replacement*

a. Introduction

The Transfer Ground Rocker Arm Main/Transfer Ground Rocker Arm Line (TGRAM/TGRAL) Switch Replacement program is a program where PG&E would proactively replace 140 switches a year between 2014 and 2016 (about 420 total during that time). The Company recorded 263 replacements in 2010-2012[127] and forecasts 80 replacements in 2013.

PG&E will have spent $77.192 million between 2010 and 2013 if it spends according to its forecast through 2013 and forecasts Test Year spending of $39.200 million for a three-year 2014-2016 program cost of $117.6 million to complete the remaining units. Overall the proactive TGRAM/TGRAL Switch Replacement program would cost $194.881 million.

DRA recommends that, instead of a program where PG&E completes the remaining 420 switches that PG&E plans to replace in three years, the Commission spread the 420 replacements over four years (one more year that PG&E is proposing) for a Test Year forecast of $28 million instead of PG&E's forecast of $39.2 million.

TURN recommends that the Commission cut this program by more than DRA is recommending. Specifically, TURN recommends that the program from 2014 be limited to 33 replacements in each year for a total of 99 total units. Furthermore, TURN recommends that the Commission deny all further capital expenditures over and above this level for proactive TGRAM/TGRAL switch replacements unless and an until PG&E makes a showing that it is reasonable to proactively replace the switches of least concern

[127] Calculated from TURN DR 79-5 Attachment 1.

(i.e., Priority 8, as explained below).[128] This recommendation results in a 2014 capital spending forecast of $9.124 million, which corresponds to a $30.076 million reduction in the Test Year.

b. Critique of PG&E's support for the TGRAM/TGRAL Switch Replacement Program

The impetus for the wholesale TGRAM/TGRAL Switch Replacement program appears to be the following:

> In June 2009, a cable failure in a manhole at Polk and O'Farrell Streets in San Francisco escalated into a fire that burned through the switch's case. This ignited the oil in the switch and the fire lasted for more than 90 minutes. Shortly after this incident, PG&E determined that the TGRAM/TGRAL switches along with associated equipment should be retired across the entire distribution system through a multi-year program.[129]

TURN requested that PG&E provide "all documentation of analysis, assumptions and/or studies that PG&E used to take this decision." PG&E responded:

> While these devices were once part of PG&E's standard utility designs, they no longer conform to the Company's operating standard utility designs, they no longer conform to the Company's operating standards for new switches, are obsolete, and present potential safety hazards that are known in the industry.[130]

To support this statement, PG&E provided letters from the manufacturer that appear to raise indicate safety concerns and reference the manufacturer's decision to "cease making oil switches on May 27, 1992." The manufacturer ceased its provision of "parts, service, or support for any oil insulated device" by at least March 21, 1997. PG&E first received warnings to remove at least what were referred to "RA switches" for safety reasons as early as <u>1981</u>, with the final warning to remove all oil-filled switches in 1997. PG&E has thus far (at least until 2010) decided to ignore those warnings with very few consequences.

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[128] This recommendation would not apply to those switches that PG&E currently recognizes as Priority 8, but then subsequently determines upon routine inspection should be placed in any of priorities 1-7 and requires replacement.

[129] PG&E-4, p. 16-4 (lines 1-6).

[130] TURN DR 56-6a.

When TURN asked PG&E to identify "all other [than the 2009 cable fire] instances of failures TGRAM/TGRAL switches by their date and their consequences (e.g., outage, explosion, fire, etc.), PG&E could only identify four instances on its distribution system dating all the way back to 1979 (i.e., 1979, 1991 and two in 1997).[131] As such, none has occurred since 1997. The likely reason that so few incidents have occurred overall, and none have since 1997, is that PG&E's safety guidelines appear to have been mostly sufficient and have improved with each incident.[132]

As for PG&E claim that the "devices are no longer part of the Company's operating standards for new switches,"[133] this may or may not be true. However, the reliance upon this reason is belied by the fact that PG&E did not embark upon a wholesale replacement program until 2010, soon after the 2009 cable failure, when the manufacturer had instructed the Company numerous times, starting in 1981, to replace these switches.

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[131] TURN DR 56-6b. PG&E also identified an incident at a generation plant in 1994.

[132] See TURN DR 56-6b, which includes the following:

When an employee mis-operated a TGRAM/TGRAL switch in 1979, which resulted in an explosion that injured three employees, one seriously, "PG&E revised its instructions and operating procedures for TGRAM/TGRAL switches and installed "stop blocks" on TGRAM/TGRAL switches designed to lock the switch in place to prevent similar incidents from happening in the future PG&E provides several alleged benefits of this proposal."

When there was a failure of a TGRAM switch inside of an above-ground transformer in 1991, a combination which PG&E indicates is rare, in any event, which caused an explosion, fire and minor injuries to two employees, the Company "reiterated use of existing requirements that employees wear flash suits when operating this type of pad-mounted switches and/or to use existing remote operating tool for operation of TGRAM/TGRAL switches."

When in January 1997, a "PG&E employee was injured from making contact with test/ground bushings that had become inadvertently energized during switching operation of TGRAL switch, apparently due to misuse of stop blocks and lack of protective bushing cover. After the incident, PG&E redistributed its existing standard regarding proper installation and use of safety blocks to Company personnel. Among other communications, CPUC Safety Branch and PG&E agreed that PG&E would inspect all Electric Distribution TGRAM/TGRAL switches to ensure that all such switches."

The likely cause of the final cited incident, in April 1997, which caused no injuries, included the presence of "contamination of oil in the switch." This possible cause will have already been removed, once PG&E has replaced those units of priorities 1-7.

[133] TURN DR 56-6a.

As for the 2009 fire—the specific event that cause PG&E to launch this program—it was the cable failure that caused the fire, not the switch. The switch did ignite by itself, but only because it was ignited by the fire caused by the failed cable.[134]

Additionally, PG&E is already replacing these switches when it is convenient. The Company states:

> Over the years, PG&E has replaced TGRAM/TGRAL switches in conjunction with urban project work such as system capacity upgrades, reliability-related lead cable replacement, and tie cable replacements, and PG&E continues to replace these switches in conjunction with other work.[135]

Put together, PG&E has already replaced most of the units that were of concern and has continued to replace units when it is convenient. Those items that are replaced in conjunction with other projects are included in the forecasts for those other projects. Furthermore, the replacement costs of those units that are currently in Priority 8, but may need replacement on the basis of routine inspections in the future are embedded in the MWC 2B, Underground Notifications.

PG&E contends that significant operating constraints were placed on the TGRAM/TGRAL Switches after the 2009 San Francisco incident, but indicates that these constraints do not affect power quality and adds that "these operating constraints can sometimes have a reliability impact in the form of longer outage durations and/or more customer interruptions during planned maintenance work."[136] However, PG&E provides no quantification of any such possible impacts and no cost-benefit assessment of reliability benefits vs. cost. Furthermore, PG&E states,

> Although there are operating constraints on TGRAM/TGRAL Switches, these limitations do not impact the ability of the distribution circuits to function normally.[137]

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[134] PG&E-4, p. 16-14 (lines 1-3).

[135] TURN DR 56-6a.

[136] TURN DR 56-10b.

[137] TURN DR 56-10d. TURN DR 56-10d also states, "The switch constraints impact the procedures that must be followed when operating the switches during sectionalizing work." But

Finally, PG&E, however, is taking steps to reduce the risk of the fires, explosions, and manhole projections even in the event of failure by installing Swiveloc-brand secure manhole covers, PG&E is taking steps to limit the severity of explosions and fires and prevent projectile manhole covers. See the discussion regarding this technology above, in the section on Underground Switch Replacement (MWC 2A), which is discussed in Electric Distribution Maintenance.

c. Steps PG&.E has already taken

As noted, PG&E has set up a priority system to catalog its TGRAM/TGRAL switch fleet. It is shown in Table 8:

Table 8: PG&E's TGRAM/TGRAL Switch Priority System[138]

Priority / Tier	Units Completed EOY 2011	Units Remaining as of YE 2011	Tier Description	Details
1	13	0	Tier 1 = Oil clarity, oil leak, corrosion, cracks in lead sheath, condition at cable entry	
2	3	1	Tier 2 = Oil clarity/leak and corrosion	
3	5	2	Tier 3 = Oil leak and corrosion/other condition	
4	21	39	Tier 4 = Oil clarity and/or oil leak	
5	10	8	Tier 5 = Oil clarity and corrosion	
6	1	5	Tier 6 = Oil clarity or oil leak (no corrosion)	
7	39	120	Tier 7 = Other conditions (no oil conditions)	
8	63	441	Tier 8 = No significant visible oil leaks or corrosion conditions identified. Continued inspection is required to monitor future conditions	
Total	**155**	**616**		(2)

Forecast Assumptions and Details(as stated by PG&E in Workpaper Table 16-9)

(1) Please refer to WP 16-27 "Forecasted TGRAM/TGRAL Switch Replacement Expenditures" for details on the forecasted amounts of units to be completed for 2012-2016.

(2) It is forecasted that a total of 16 units will be completed in conjunction with other program work from 2012 thru 2016

The information in the table shows that there are 441 units remaining in Priority/Tier 8. However, PG&E stated as of April 25, 2013, PG&E claims that most of the seven highest priority tier units have been completed:

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again, PG&E has not quantified this effect or analyzed the reliability reduction against the cost of these replacements.

138 This table is an exact copy of PG&E's Workpaper Table 16-9 in PG&E-4.

> To date, PG&E has replaced most of the TGRAM/TGRAL switches in the seven highest priority tiers (of eight tiers total), and most of the remaining switches are in the lowest priority tier, i.e. the tier for which "no visible oil leaks or corrosion conditions" were identified.[139]

Furthermore, "most of the remaining switches are in the lowest priority tier, i.e., the tier for which "no visible oil leaks or corrosion conditions" were identified."[140] PG&E responded to a late-filed TURN DR that indicated as of the end of 2013 there were 103 non-Tier 8 and 405 Tier 8 TGRAM/TGRAL Switches left on the system.[141]

As noted above, TURN recommends that the Commission authorize pre-emptive, systematic replacements for only those units that are not in the lowest priority tier (i.e., Priority Tier 8). TURN proposes that the Commission should be conservative and approve a replacement count that is slightly more than 20% of the replacements that PG&E is forecasting in the 2014-2016 period, even though PG&E has replaced "most" of the switches. That is, PG&E should replace 33 units per year (99 for the 2014-2016 period), instead of the 140 it is requesting funding for.[142]

TURN recommends that the Commission adopt a capital forecast on the basis of 33 TGRAM/TGRAL switch replacements, which at $280 per unit[143] is $9.124 million. This should be more than enough, given that PG&E already has TGRAM/TGRAL replacements embedded in its work on other equipment, as well as, in Underground Notifications (MWC KB).

Ideally, PG&E would have replaced these switches in order of priority and all of the high priority units would have been replaced by now. If this was truly a safety issue,

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139 TURN DR 56-6a.

140 TURN DR 56-10c.

141 Calculated from TURN DR 79-5 Attachment 1.

142 TURN generated the 33 replacements using the following: the total non-Priority 8 units remaining as of YE 2011 was 175 (see Table 8, above), but PG&E forecasts a total of 180 units would be replaced in 2012 and 2013 (combined). Assuming that PG&E replaced the highest priority units 2013, the units remaining for 2014 would be 23 because PG&E plans to do 80 replaements in 2013 and there were 103 high-priority units left at the end of 2012, per TURN DR 79-5 Attachment 1.

143 PG&E-4 WPs, p. WP 16-27.

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one would think this is the way it would have been accomplished. By limiting the replacements to those units that are not in the lowest priority tier, the Commission will, at least, ensure that PG&E is focusing on higher priority replacements, and limit spending on low-priority equipment replacements.

Recommendation

TURN recommends that the Commission reduce the TGRAM/TGRAL Switch Replacement program forecast from 140 replacements per year to 33. This will reduce the forecast from $39.2 million per year to $9.124 million, a $30.076 million reduction. Further, the Commission should order PG&E not to proactively replace anymore TGRAM/TGRAL Switches than these 99 units in a wholesale manner. Further replacements should only be made on the basis of individual inspections.

3. Tie Cable Replacement

PG&E's 2014 capital expenditure forecast for Tie-Cable Replacements—i.e., ties connecting substations, not serving customers—is $7.4 million with a three-year expenditure of $21.2 million.[144] DRA made not adjustment to this program.

It's not clear, however, whether PG&E either needs to or will spend that amount given the company's history of forecasted and recorded expenditures for this activity since 2005.

PG&E forecasted $25.7 million for Tie-Cable Replacements over five years (i.e., 2009-2013) in the 2011 GRC.[145] However, the Company only spent and plans to spend a total of $9.3 million during that 2009-2013 timeframe.[146] Worse, PG&E forecasted $85.8 million over five years (2005-2009) in the 2007 GRC,[147] but only spent $59.5 million during that timeframe, a $26.3 million difference.[148]

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[144] PG&E-4, p. 16-8 (Table 16-1).

[145] 2011 GRC, PG&E-3, p. 12-8 (Table 12-2).

[146] PG&E-4, p. 16-8 (Table 12-2).

[147] 2007 GRC, PG&E-4 Workpapers, p. WP 6-7.

[148] 2011 GRC, PG&E-3, p. 12-8 (Table 12-2).

Table 9 is a tabular illustration of PG&E's practice:

Table 9: Historical and Future Capital Expenditures for Tie-cable Replacements

2007 GRC Forecast			2011 GRC Forecast			2014 GRC Forecast		
Forcasted (2005-2009)	Recorded (2005-2009)	**Underspend**	Forcasted (2009-2013)	Recorded (2009-2013)*	**Underspend**	Forcasted (2012-2016)	Recorded (2012-2016)	**Underspend**
85,799	59,525	**26,274**	25,969	9,281	**16,688**	23,800	????	**????**

* Recorded in 2009-2011, forecasted in 2012-2013.

This clearly illustrates a pattern of either underspending or over-forecasting.

Furthermore, PG&E claims that the spending forecast accounts for the need to replace tie-cable in the East Bay Division because it is aging. The Company also claims in the instant case that it was by 2013 that it originally planned to complete the East Bay Division Tie-Cable Replacements, but that this task went undone because the Company was forced to focus on TGRAM/TGRAL switch replacement.[149] This is not correct characterization, however: the East Bay Division tie-cable replacements were originally forecasted—in 2005 when it prepared the 2007 GRC application—to be completed by 2009.[150] That represents more than a decade of either deferred maintenance or a decade of consistent, over forecasting. The Company has, in the intervening years, earned profit through ROE payments and income taxes on that over-forecast. Ratepayers should not continually pay for a program that is systematically and indefinitely over-forecasted.

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149 PG&E-4, p. 16-16 (lines 11-14).

150 PG&E stated in the 2007 GRC, "There are 47 tie cable circuits in PG&E's San Francisco and East Bay Divisions (PG&E-4, p. 6-21 (lines 9-10). … Between 2002 and 2004 PG&E spent $8.4 million to replace aging tie-cables. PG&E's forecast for MWC 56 includes a total of $85.8 million to replace aging tie cables million between 2005 and 2009 (see the workpapers supporting this chapter for details). Considering the age of the cables (over 70 years old in some instances), the increasing failure rates, and the number of customers these facilities serve in densely populated urban areas (tens of thousands customers in San Francisco, Oakland and Berkeley), refurbishing the tie-cable systems is a reasonable and necessary first step to address aging underground assets in a significant manner (Id., p. 6-24 (lines 6-16)."

PG&E, therefore, applied the $85.8 million forecast to the period 2005-2009 (Id., p. 6-19 (Table 6-2)), planned to have completed the tie-cable replacement program by 2009, implicitly.

Recommendation

TURN recommends that the Commission decline to adopt PG&E's forecast, and instead adopt Test Year 2014 capital forecast of the average of PG&E's recorded 2009-2011 and forecasted 2011 and 2012: $3.7 million. If the Company ultimately implements a program that is more ambitious than one made possible by $3.7 million, the higher spending will be trued-up in the 2017 GRC.

G. LED Streetlight Program

PG&E is requesting a Test Year capital spending forecast of $18.6 million and is forecasting a total, three-year (2014-2016) spending program of $59.5 million. DRA recommends a much more limited program costing $2.468 million per year,[151] where LED lights are installed at the rate of 7,000 per year for 24 years.[152] DRA's recommendation is reasonable.

TURN points out that PG&E forecasted a five-year, $102.5 million LED Streetlight Replacement program in its 2011 GRC filing.[153] The Commission approved a 2011 capital spending forecast of $18.5 million,[154] yet PG&E spent nothing on the program in any of 2011-2013.[155]

Recommendation

The Commission should adopt DRA's recommendation of $2.467 million for this account.

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151 DRA-8, p. 18 (Table 8-12).

152 Id., p. 25 (lines 10-12).

153 PG&E's 2011 GRC, PG&E-3, pp. 2-50 and 2-51.

154 PG&E's 2011 GRC, PG&E-3, pp. 2-50 and 2-51 contains PG&E's 2011 forecast of $20.5. D.11-05-018, Attachment 1, p. 1-4 states that the Commission reduced this forecast by $2 million.

155 PG&E-4, p. 19-10 (Table 19-5).

H. Electric Distribution Support Activities (PG&E-4, Chapter 20)

PG&E is removing the escalation in certain Electric Distribution O&M accounts in 2012-2014 to account for the efficiency savings it expects from the Electric Operations Improvement Plan (EOIP).[156] However, through the EOIP, PG&E expects to also save an amount equal to escalation in 2015.[157] The Company has not made an adjustment to reflect those savings.[158] We note that the savings PG&E is providing to ratepayers through escalation reductions are the <u>minimum savings</u> PG&E expects its EOIP implementation to net.[159]

DRA accepts PG&E's productivity improvement-resultant escalation savings values of $10.191.

TURN believes the value should be higher by the amount of the savings PG&E expects in 2015, normalized over the two years of the rate cycle (2015 and 2016) that PG&E would benefit from 2015 efficiencies. Based on the escalation offset values included in PG&E-4, WP 20-17, the 2015 escalation value would be about $10.7 million. Normalized over the three-year rate cycle, the 2014 forecast should be reduced by $6.8 million more than the $10.7 million PG&E forecasts. The total productivity improvement savings applied to the Test Year should be $17.5 million.

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[156] PG&E-4 WPs, p. 20-17.

[157] PG&E-4, p. 20-6 (lines 20-22), which state: "…Electric Operations has committed to offset escalation for 2012 through 2015."

[158] See PG&E-4 WPs, p. WP 20-17 and the discussion on pp. 2-4 through 2-6 and Table 2-1 in PG&E-11 (the Post Test Year Ratemaking exhibit). Table 2-1 indicates that PG&E's 2015 escalation forecast for all of Electric Distribution is $42.712 million and there is no mention of an efficiency adjustment.

[159] EOIP, p. 34. Provided in TURN DR 10-1 Attachment 1. This document states: "Financial benefits [of the work efficiency programs described in the EOIP] will (at a minimum) fully offset inflation over the 2012-2015 time period; additional upside will be quantified as initiatives are developed. TURN DR 10-3 shows that PG&E did not achieve the entire $10.5 million in savings that it expected in 2012, instead only achieving $3.3 million. However, PG&E indicates that this is not because it will fail to achieve the savings, but because the EOIP program was a little slow getting off the ground. Specifically, in TURN DR 57-8, PG&E states. "With respect to why PG&E did not achieve the forecasted savings in 2012 this was due to this being the first year of the work efficiency improvement plan and the initial traction of getting the effort established."

III. Human Resources (HR) Issues (PG&E-8)

A. Benefits, Health and Insurance

1. Medical Program Costs

PG&E's Medical Program Costs are composed of several items, including actual Healthcare Costs, in addition to other items, such as Fiduciary Compliance and Administration, and Flexible Benefits. DRA made no adjustment to the Medical Program forecast.[160]

PG&E engaged Tower Watson to develop its Healthcare Cost forecast.[161] Towers Watson provided its report to PG&E on October 5, 2012, but used stale national forecasts when making its forecast for PG&E. Specifically, Towers Watson used national forecasts from a September 2010 document called the *National Health Expenditure Projections 2009 – 2019 Report*.[162] While it was not available when Towers Watson did its analysis in 2012,[163] a more recent version of the National Health Expenditure Projections (from 2011, called *National Health Expenditure Projections 2011-2021*) is available.[164]

The more recent projections (i.e., 2013-2016) show lower cost increases than those that Towers Watson originally used to inform its PG&E trend analysis, as shown in Lines 1 to 4 of Table 10:

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[160] DRA did make an adjustment to Employee Contributions (DRA-14, 1 of 2, p. 17), but that is a separate line item from Medical Program costs (see PG&E-8, p. 6-1).

[161] See Tower Watson's analysis starting on p. WP 6-8 of PG&E-8.

[162] TURN DR 27-6. These documents are produced by the Centers for Medicare and Medicaid Services (CMS). CMS is a branch of the U.S. Department of Health and Human Services. For more information, see questions.cms.gov/faq.php?id=5005&faqId=1779

[163] TURN DR 27-6.

[164] See: www.cms.gov/Research-Statistics-Data-and-Systems/Statistics-Trends-and-Reports/NationalHealthExpendData/Downloads/Proj2011PDF.pdf.

Table 10: Comparison of the 2010 and 2011 CSM Forecasts of Healthcare Costs and Adjustment to PG&E Forecasts [165]

Line	Category	2012	2013	2014	2015	2016
(1)	Medical Baseline Year-over-Year Change (Towers Watson; PG&E's forecast)	5.4%	8.1%	8.2%	8.3%	8.4%
(2)	CMS infation values from 2010 Report	3.60%	5.40%	12.80%	9.10%	8.30%
(3)	CMS inflation values from 2011 Report	4.70%	4.00%	9.60%	6.10%	6.80%
(4)	Difference between 2010 and 2011 Inflation	-1.10%	1.40%	3.20%	3.00%	1.50%
(5)	Adjustment Factor	75%	75%	75%	75%	75%
(6)	Adjusment to Towers Watson Values	-0.83%	1.05%	2.40%	2.25%	1.13%
(7)	Medical Baseline Year-over-Year Change (TURN's forecast). Compare to line 2 in the next table.	6.2%	7.1%	5.8%	6.1%	7.3%

In Lines 5 to 7 of Table 10, TURN reduced the Baseline Medical Forecast inflation by 75% of the difference between the 2010 and 2011 CSM forecasts to align them with the most recent information.[166]

In Table 11 below (Line 2), TURN uses the adjusted Baseline inflation rates from Line 7 in Table 10 to adjust PG&E's Healthcare forecasts.

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165 See Attachment 6, contains the CMS documents for inflation values for both the 2010 and 2011 reports. As noted, Towers Watson used the CMS document from 2010.

166 TURN did not apply the full amount of the difference between the 2010 and 2011 forecasts of inflation to account for other information that Towers Watson likely relies on other information than just those inflation figures. To be conservative, therefore, TURN adjusted the difference by a judgmental 75%.

Table 11: **Calculation of TURN's Recommendation for Medical Program Costs**
(1000s$)

	Category	2011 Rec Adj	2012	2013	2014	2015	2016
	Medical Baseline Forecast (**PG&E**, based on PG&E's 2011 Recorded Adj from PG&E-9, WP 6-4 (line 1a) and forecasted inflation from Towers Watson, p. WP 6-10 of PG&E-8 (2010 calculated inflation))	286,927	302,421	326,917	353,724	383,083	415,263
	Year over Year Increase (**PG&E**, based on Towers Watson, p. WP 6-10 of PG&E-8, which relies on the 2010 CMS Report)		5.4%	8.1%	8.2%	8.3%	8.4%
(1)	Medical Baseline Forecast (**TURN**, based on PG&E's 2011 Recorded Adj from PG&E-9, WP 6-4 (line 1a) and forecasted inflation from Towers Watson, p. WP 6-10 of PG&E-8 (but adjusted to indlude the updated 2011 inflation forecast))	286,927	304,788	326,276	345,200	366,084	392,717
(2)	Year over Year Increase (TURN, based on Towers Watson, p. WP 6-10 of PG&E-8), but adjusted for updated, lower inflation figures from CMS Report)		6.2%	7.1%	5.8%	6.1%	7.3%
(3)	Net Med Plan Savings (PG&E, p. WP 6-10 of PG&E-8)	0	0	(7,229)	(20,672)	(21,719)	(23,694)
(4)	Health Incentive Credits (PG&E, p. WP 6-10 of PG&E-8)	0	0	2,021	5,682	5,682	5,682
(5)	**TURN** Healthcare Forecast (values **TURN** recommends be substituted for the values on Line 1a. on PG&E-8, p. WP 6-4; this is an intermediate step to get to the ratemaking forcast, below)		304,788	321,067	330,210	350,047	374,704
(6)	Plan Year over Year Increase (**TURN** Calculation)		6.2%	5.3%	2.8%	6.0%	7.0%
(7)	PG&E's Healthcare Forecast (line 1a. from PG&E-8, p. WP 6-4)		303,400	322,915	340,341	368,963	399,352
(8)	Difference (TURN < PG&E)		(1,388)	1,848	10,131	18,916	24,648
(9)	TURN Total Medical Program Forecast (values that TURN recommends be substituted for the values on Line 1 of PG&E-8, p. WP 6-1. These values include the non-Healthcare costs, such as, Administration, DOT and Flexible Benefits, etc., costs that are on PG&E-8, p. WP 6-4)		311,458	329,821	339,933	359,770	384,480
(10)	PG&E Total Medical Program Forecast		310,069	331,670	350,064	378,685	409,127
(11)	Difference (TURN < PG&E)		1,389	(1,849)	(10,132)	(18,915)	(24,647)

The table shows the amount the Commission should adopt for PG&E's Medical Program forecasts in Line 9, and the amount of TURN's recommended reduction in Line 11. This is the rare expense where the amount of the reduction forecasted in 2015 and 2016 matters; PG&E is forecasting inflation outside of the normal procedure for Medical

Program expenses because of the recent trend where Medical Expenses have outpaced general inflation.[167]

Recommendation

TURN recommends that the Commission reduce PG&E's Medical Program costs to reflect an update to a source that PG&E's medical cost consultant used in estimating PG&E's medical inflation. The forecasts for 2014, 2015, and 2016 should be $339.933 million, $359.770 million, and $384.480 million, respectively. In addition, the forecasts for 2015 and 2016 should be recognized in the Medical Plan Cost Adjustments portion of Post Test Year Ratemaking, presented in Exhibit 11 on p. 2-5.

B. Retirement Savings Plan Benefit

PG&E calls its 401K plan the "Retirement Savings Plan."

Table 12 indicates PG&E's unescalated, Base Year-dollar recorded and forecasted costs, which for the 2012-2014 years do not include increases for employee count forecast increases. PG&E forecasts the employee counts separately on p. WP 7-2 in the PG&E-8 workpapers. DRA made no adjustments regarding the Base forecast (i.e., the forecast before employee counts are considered).[168]

Table 12: Recorded and Forecasted Retirement Savings Plan Costs (1000s of Base Year Dollars; Forecast Values Exclude Employee Count Growth)[169]

Base Forecast (Base year Dollars)									
		Recorded Adjusted					Forecast		
Line	Department/Description	2007	2008	2009	2010	2011	2012	2013	2014
9	Retirement Savings Plan	53,391	51,863	55,677	56,728	64,123	63,495	64,635	71,426

TURN's Base Year dollar recommended forecast is $63.148 million compared to PG&E's forecast of $71.426 million. In nominal dollars, TURN's forecast would be $68.943

[167] See Exhibit 11, p. 2-5, which indicates that PG&E applies special inflation rates to the Test Year forecast for medical expenses in order to calculate the Post Test Year amounts for medical expenses.

[168] See DRA-14, p. 27 (p. 3-7). DRA did make an adjustment related to headcount, but not to the underlying, forecasted increase for the Base plan costs..

[169] PG&E-8 WPs, p. WP 7-2. The nominal-dollar values are presented on p. WP 7-1.

million vs. PG&E's nominal-dollar forecast of $77.981 million. TURN bases its forecast on the five-year average of costs from 2007 to 2011, plus an increment related to a new plan to be available to employees in 2014.

As shown in Table 3 above, PG&E is forecasting a substantial increase in 2014 ($71.426 million in 2014 vs. $64.123 million in 2011). PG&E's forecast for 2014 is sharply higher than the five-year average of 2007-2011 recorded values, $56.356 million.

In support of its 2014 forecast, PG&E's states:

> PG&E will introduce a new retirement income program beginning in 2013 through implementation of a new cash balance pension formula. The new program will apply to all new hires beginning January 2013, and will be offered to existing employees effective January 2014.[170]

The basis for PG&E's forecast is recorded 2011 data with an adjustment in 2014 to reflect the effect of the "new retirement income program", when existing employees are given an enrollment option. PG&E makes no adjustment for 2013 because it does not expect the 2013 forecast to be affected by the new program because it assumes new employees (who are the only employees to have access to the new program in 2013) will replace employees who leave the Company.[171]

TURN does not take issue with the component of PG&E's forecasted increase in 2014 to incorporate the likely cost impacts of its "new retirement income program", which will increase the Company's contribution. However, TURN disputes PG&E's use of the 2011 Base Year recorded cost as the starting point from which to increase the 2014 expenses. PG&E should have used a five-year average of Company contribution costs (from 2007-2011), given that the nature of 401K contributions is variable and there is no clear trend

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170 PG&E-8, p. 7-18 (lines 4-8).

171 See the discussion on p. 7-19 (lines 7-16) of PG&E-8, which states: "[The 2014] estimate includes employer matching contributions based on 2011 participant data and forecast salary growth to the test year, plus recordkeeping, administrative and trustee fees required to operate the plan. This forecast also reflects the January 2013 changes to employer match provisions and the addition of automatic enrollment for new hires that will be covered by the new cash balance pension formula. For purposes of this portion of the forecast, it is assumed that new hires replace employees who leave the Company, such that the forecast population of employees is held constant with base year 2011."

from 2007 to 2011. While 2011 is higher than the average, that is just one year, and PG&E provides no justification as to why 2011 costs are not just an anomaly that in 2012 will return to the mean. Furthermore, PG&E undertook a substantially larger planned layoff program in 2012/2013 than is normal, making it likely that the base level of 401K contributions will have declined as a result.[172]

As such, TURN believes a conservative estimate for 2014 would start with the average of the 2007-2011 costs and be adjusted in 2014 to reflect the "new retirement income program."

Recommendation

TURN recommends that the Commission adopt a Base Year constant dollar forecast of $63.148 million.[173] The corresponding nominal-dollar forecast is $68.943 million.[174] Respectively, the reductions from PG&E's Base Year constant dollar and nominal-dollar forecasts are $8.279 million and $9.038 million.

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[172] PG&E let 298 employees go in 2012 (TURN DR 16-2b), resulting in Severance Program costs of $39.918 million, substantially higher than the average from 2007-2011 ($13.071 million), indicating that more employees left the company in 2012 than normal and that, correspondingly, the Company's matching contribution for the 401K Retirement Plan will likely be less than the 2011 recorded data would indicate.

[173] $63.148 million = $56.356 million (the five-year average (2007-2011)) + [$71.426 million (the 2014 value) - $64.635 million (the 2013 value)]. In other words, it is the average of 2007-2011 plus the difference between the 2014 value and the 2013 value in order to add the increment related to the higher contribution in 2014 resulting from the onset of the "new retirement income" for existing employees.

[174] TURN applied an escalation rate of 2.97% in each year, following PG&E's method of escalating the Base Year-dollar forecast to the nominal dollar forecast (see pp. WP 7-1 and WP 7-2 of PG&E-8 WPs).

IV. Administration & General (A&G) (PG&E-8)

A. Regulatory Relations Organization (Chapter 5)

1. Regulation and Rates Department (VP Regulation Rates)

a. FERC and ISO Relations Department (PCCs 12864, 12916)

PG&E forecasts $829,831 for the FERC and ISO Relations Department in its Test Year 2014 GRC.[175] The FERC and ISO Relations Department supports PG&E's Electric Transmission, Energy Procurement, Power Generation, and Gas Transmission Lines of Business.[176]

DRA does not make a recommended adjustment. TURN does not dispute the amount of the cost, either. However, given that FERC and ISO relations are only related to transmission and generation, and not distribution, this expense should be directly assigned to transmission and generation at 50% each, with none allocated to distribution.

Recommendation

The expenses for the FERC and ISO Relations Department (forecast of $829.8K in the Test Year) should be directly assigned at 50% each to transmission and generation.

b. Regulatory Relations Department

DRA recommends that the Commission reject PG&E's request for the incremental $1.4 million for nine new employees in 2014. DRA argues that PG&E already added nine new fulltime-equivalent (FTE) employees in 2012 and that PG&E has not shown there is an immediate need and/or urgency to hire another nine new employees in 2014.[177]

TURN agrees with DRA's assessment and adds the following argument to support DRA's recommendation.

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[175] PG&E-9 WPs, p. WP 5-2.

[176] PG&E-9, pp. 5-11.

[177] DRA 17, p. 42 (lines 13-18).

The Operations Proceedings Department, which is a sub-department within the Regulatory Relations Department, is responsible for supporting regulatory proceedings in which PG&E seeks recovery of operations-related costs. PG&E notes an apparent increase in the regulatory focus on its operations as one of the reasons for an increase to its forecasted number of FTEs, citing the Pipeline Safety Enhancement Plan (PSEP) and Safety of Electric Utility Facilities OIR as examples of the increased focus. PG&E also implies that increased scrutiny of operational initiatives are driven by business needs and regulatory mandates and cites to Modifications to SmartMeter; Alternative Fuel Vehicles OIR; Smart Grid OIR; Competitive Bidding Rule OIR; and the Customer Data Access Project as examples of the reasons PG&E requires increased staffing.[178]

PG&E's rationale is faulty. All of these cases have begun, many are well underway, and some of them have even had a decision rendered and are no longer relevant. If this is the expected caseload it appears that the Company is managing with the staffing levels it currently has. Thus, it makes little sense that the Company would need to increase its staffing levels in 2014, after most of these cases will have run their course.

If it needed the extra FTE employees to deal with the cases it cites in its testimony—again, cases that are already ongoing--PG&E would already have made the required hires. As DRA notes, the Company has made nine hires in 2012. It is those nine, 2012 hires that will assist PG&E with those ongoing caseloads. Since PG&E has not explained why it expects the caseload to be higher in 2014, the Commission should deny funding for the 2014 staff members.

Recommendation

TURN supports DRA's recommendation that the Commission deny the $1.4 million for nine new FTE employees in 2014.

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[178] PG&E-9, p. 5-10 (lines 24-29).