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Exhibit Number	:	DRA-21
Commissioner	:	Florio
ALJ	:	Pulsifer
Witness	:	K. Lee

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Pacific Gas and Electric Company General Rate Case Test Year 2014

Rate Base (including Working Cash)

San Francisco, California
May 3, 2013

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RATE BASE
(Including Working Cash)

I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Division of Ratepayer Advocates (DRA) regarding Pacific Gas and Electric Company's (PG&E) forecasts of Electric Distribution, Electric Generation, and Gas Distribution Rate Base (including Working Cash) for Test Year (TY) 2014.

Rate Base is the depreciated asset value of a utility's net investments used to provide service to its customers. The major components of Rate Base are Fixed Capital or Utility Plant, Working Capital, which includes Materials and Supplies and Working Cash, Deductions for Deferred Tax, and Deductions for Depreciation Reserves. The Commission allows PG&E the opportunity to earn returns on the sum of these Rate Base components. All Rate Base components are developed on a weighted average basis. DRA's Rate Base estimate reflects adjustments made by several different witnesses. Some of these adjustments are discussed in this exhibit while the others are discussed in the exhibits where they were originally analyzed and developed.

II. SUMMARY OF RECOMMENDATIONS

DRA's recommendations along with PG&E's proposals on rate base and working cash for Electric Distribution, Gas Distribution, and Electric Generation are shown in Tables 21-1 and 21-2 respectively.

For TY2014, DRA recommends that the California Public Utilities Commission (Commission):

- Remove $399 million nuclear fuel inventory and $1.5 million fuel oil inventory from rate base. Fuel inventory carrying cost should continue to be recovered through the Energy Resource Recovery Account (ERRA) proceedings;
- Adopt DRA's recommended working capital of $114 million for Materials and Supplies-Others in rate base instead of PG&E's proposed $133 million;

- Adopt all other DRA rate base recommendations shown in Table 21-1 which were developed by various witnesses and discussed in different DRA exhibits;
- Adopt DRA's recommended company-wide prepayments calculated based on DRA's recommended administrative and general (A&G) escalation rates and insurance growth rate;
- Reduce PG&E's proposed departmental prepayments by $6.3 million to $8.565 million because PG&E already plans to recover part of the cost of the second refueling outage for Diablo Canyon Nuclear Power Plant as an operations and maintenance (O&M) expense;
- Adopt DRA's calculation of deferred debits using an annual average of 6 years, resulting in reducing PG&E's proposed $3.334 million by $2.819 million to $0.515 million;
- Adopt DRA's method of determining accrued vacation deduction by using the 2012 recorded data without accounting adjustments as proposed by PG&E. DRA's method results in a recommended total accrued vacation deduction of $197 million instead of PG&E's proposed $177 million;
- Adopt DRA's recommendation for cash required due to time lags. DRA recommends an expense lag of 132.85 days for State Corporation Franchise Tax, 110.85 days for Federal Income Tax, and 39.64 days for Goods and Services. DRA recommends 40.81 days for revenue collection lag.

Table 21-1
Electric Distribution, Gas Distribution, and Electric Generation
Weighted Average Depreciated Rate Base for TY2014
(In Millions of Dollars)

Description	**DRA Recommended**			**PG&E Proposed**[1]		
	Electric Distribution	Gas Distribution	Electric Generation	Electric Distribution	Gas Distribution	Electric Generation
Wtd Avg Plant						
Plant	$24,995.8	$8,676.5	$13,472.9	$25,196.1	$8,891.9	$13,477.3
Net Additions	$537.3	$219.6	$166.8	$709.0	$383.2	$196.6
Working Capital						
M&S – Fuel	$0.0	$0.0	$0.0	$0.0	$0.0	$400.9
M&S – Other	$64.1	$9.6	$114.0	$64.1	$9.6	$132.7
Working Cash	$58.7	$30.8	$94.0	$157.5	$71.5	$154.4
Adjust Tax Reform Act						
Deferred Cap Interest	$1.0	$0.6	$12.2	$1.0	$0.6	$12.2
Def Vacation	$18.1	$10.7	$10.1	$18.1	$10.7	$10.1
Def CIAC Tax Effects	$247.9	$87.0	$0.0	$247.9	$87.0	$0.0
Customer Advances	$82.6	$40.7	$0.0	$82.6	$40.7	$0.0
Deferred Taxes						
Accum Reg Assets	$0.0	$0.0	($19.1)	$0.0	$0.0	($19.1)
Accum Fixed Assets	$3,177.0	$740.5	$1,005.8	$2,923.2	$684.4	$920.3
Accum Other	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Deferred ITC	$37.4	$18.5	$20.6	$37.4	$18.5	$20.6
Deferred Tax – Other	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Depreciation Reserve	$10,879.6	$4,868.3	$8,250.7	$10,971.1	$4,867.6	$8,246.3
Total Rate Base	**$11,746.4**	**$3,366.8**	**$4,612.2**	**$12,379.4**	**$3,843.3**	**$5,216.0**

1 Ex. PG&E-2 Workpapers, p. WP 14-7 for electric distribution and gas distribution, and p. WP 14-8 for electric generation.

III. DISCUSSION / ANALYSIS OF RATE BASE

Rate base consists of the following components: (1) utility plant; (2) working capital; (3) Tax Reform Act deferrals; (4) customer advances; (5) deferred taxes; and (6) depreciation reserve. Utility plant, Tax Reform Act deferrals, deferred taxes, and depreciation reserve are reviewed and discussed by other DRA witnesses and presented in other exhibits. This exhibit addresses working capital and customer advances.

A. Overview of PG&E's Request

PG&E presents its forecasts on rate base in its direct testimony in Chapter 14 of Ex. PG&E-2[2] and its Workpapers supporting Chapter 14 of Ex. PG&E-2.[3] PG&E's proposed rate base as categorized under the five main components is shown in Table 21-1 for Electric Distribution, Gas Distribution, and Electric Generation. PG&E's proposed rate base is $12,379 million in Electric Distribution, $3,843 million in Gas Distribution, and $5,216 million in Electric Generation.

B. Utility Plant

Utility plant consists of the plant and equipment that is used and useful in rendering service to PG&E's customers. DRA uses capital expenditure estimates to generate utility plant balance estimates through the Results of Operations (RO) model. The discussion and development of these estimates are contained in the various DRA exhibits that address capital expenditures.

C. Working Capital

Working Capital consists of Materials and Supplies–Fuel, Materials and Supplies–Other, and Working Cash.

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[2] Exhibit (Ex.) PG&E-2, Chapter 14, November 15, 2012.

[3] Ex. PG&E-2, Workpapers (WP), November 15, 2012.

1. Materials and Supplies - Fuel

PG&E includes in rate base the weighted average value of Diablo Canyon nuclear fuel inventory in the amount of $399.322 million and $1.533 million for fuel oil inventory for the Humboldt Bay Power Plant. Fuel inventories including nuclear fuel are evaluated annually in Energy Resource Recovery Account (ERRA) proceedings. Carrying costs refer to the cost of holding or storing fuel inventory. Ratepayers pay for the cost of holding or storing fuel until it is consumed.

DRA recommends that the carrying costs for the PG&E fuel inventories continue to be recovered in the ERRA proceedings. DRA removes from rate base the entire $399.322 million of Diablo Canyon nuclear inventory and $1.533 million for fuel oil inventory for the Humboldt Bay Power Plant.

The Commission has made the treatment of fuel inventory very clear in its prior decisions. In Decision (D.) 85-12-107, the Commission first addressed the question of proper rate treatment of fuel inventory for the Southern California Edison Company (SCE) by stating:

> Edison no longer shall be allowed to charge ratepayers the cost of carrying fuel oil in inventory at the authorized rate of return. There are several reasons for this. First, the authorized rate of return includes equity and long-term debt. The cost of using equity rather than debt is higher to the ratepayer because of the income tax that must be recovered with a return on equity. Second, the balancing account associated with the ECAC expense was not designed to reward the company with its rate of return on a non-rate base item but to shield the company from wide swings in fuel expenses. Finally, the low-risk nature of fuel oil inventories call for a different ratemaking approach.[4]

The Commission concluded:

> Fuel oil inventory is low risk. Unlike rate base assets, fuel oil inventory is subject to balancing account treatment. In effect, Edison (SCE) has been guaranteed recovery of its rate of return on a low-risk asset. This result was never intended to occur through ECAC procedures.

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[4] D.85-12-107, 20 CPUC 111,112, as modified in D.86-05-095, slip op. at p.2. 1985 Cal. PUC LEXIS 1129 at *2

In D.87-12-066,[5] the Commission extended the above holding to SCE's coal and fuel inventories. The Commission stated:

> Although Edison (SCE) points out that the operating and life cycle characteristics of nuclear fuel are not the same as coal, gas, and oil, we believe that this is not enough to warrant a different ratemaking treatment. In fact, Edison (SCE) proposes to finance nuclear fuel with a combination of short- and intermediate-term debt. While this might indicate that there is a need to factor in the cost of intermediate debt in deriving the carrying cost associated with nuclear fuel, it does not justify rate base treatment. (Id.)

In the same decision, the Commission further stated it preferred the use of short-term debt instruments to determine carrying charges on fuel. Because fuel "is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land…fuel should not be afforded rate base treatment, regardless of its characteristics." The Commission directed SCE to calculate carrying costs on its unspent nuclear fuel and coal reserves using the cost of short-term debt, and continue to include these costs in its former ECAC (now ERRA) balancing account.[6]

Citing D.85-12-107 as standing for the principle that ratepayer's share of the carrying cost of fuel inventories has been held to be the cost of "short-term debt," the Commission found that SCE's calculation of short-term debt was within the meaning of that term. Thus, the Commission approved the slightly higher yield figure for calculating the forecast and actual carrying costs.

In D.88-09-031,[7] the Commission authorized SCE to finance nuclear fuel with a blend of short and intermediate-term debt. In that case, DRA argued that one short term interest rate should be used to calculate the carrying costs of all fuel inventories, especially since, at the time SCE was not actually financing its nuclear fuel with any intermediate-term debt.

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[5] D.87-12-066, 26 CPUC 2d at 392

[6] D.87-12-066, 26 CPUC 2d at 392

[7] D.88-05-031, 29 CPUC 2d at 314

The Commission agreed with DRA, stating, "[w]e see no difference in the financing of these fuels. SCE and other utilities can use a myriad of borrowing arrangements…including intermediate-term debt …to finance carrying costs."[8] As noted earlier, the utility is free to finance these inventories however it pleases, but the Commission has decided to limit the ratepayer's share in that expense in the short-term interest rate.[9]

In 1985, the Commission established the Energy Cost Adjustment Clause (ECAC now ERRA) mechanism to provide an industry-wide mechanism to provide public utilities with yearly recovery of fuel costs for electric operation. The Commission determined the most cost effective procedure to pay utilities for fuel costs was in this annual proceeding. All California public utilities are currently subject to this fuel cost recovery mechanism.

DRA recommends that the Commission maintain the current fuel cost recovery mechanism, as articulated in D.96-01-011. In that decision, the Commission denied SCE's proposal to split fuel costs into permanent and temporary portions and disagreed with the permanent inventory level concept, stating the increased risk was "insufficient to justify the change in financing."[10] The Commission further stated,

> We believe it more efficient to include determinations of the reasonableness of fuel inventory levels in the ECAC proceedings. That proceeding engages fuel experts who review the utility's fuel purchasing policies as a whole taking out one piece of that puzzle.[11]

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[8] D.93-01-027, 47 CPUC2d at 694.

[9] Id.

[10] D.96-01-011, *mimeo.*, p.226.

[11] D.96-01-011, *mimeo.*, p.227.

In D.06-05-016, the Commission stated "We are not persuaded to change the current ratemaking treatment for fuel inventory. There is a long history to the issue."[12] The Decision then went on to discuss the consistent treatment of fuel inventory, and concluded that,

> Nothing has changed. The reasons why we rejected rate base treatment for fuel inventory has nothing to do with the reasons why we included customer deposits in the operational cash requirement analysis. Fuel inventory was excluded from rate base because of the cost to ratepayers, the balancing account treatment for fuel expenses and the low risk nature of fuel inventories. Inclusion of customer deposits in the operational cash requirement is not new. Non-interest bearing customer deposits have always been included. SCE however pays interest on customer deposits, so prior to D.04-07-022, its customer deposits were excluded in developing the operational cash requirement. The Commission, in D.04-07-022, instead compensated SCE for the interest it pays on customer deposits and estimated a balance of funds that would be available to offset the operational cash requirement. The result was reduced overall costs to ratepayers, while SCE was fully compensated for interest costs it paid.
>
> The Commission's determinations regarding fuel inventory and customer deposits are consistent, in one respect. That is, changes were made to existing practices, which resulted in reduced rates while still providing SCE a fair opportunity to recover its costs. These results are consistent with our responsibilities, in general, and we see no reason to alter the currently adopted ratemaking associated with either issue.[13]

In D.09-03-025, the Commission again reiterated its policy on financing nuclear fuel inventory:

> The Commission has previously determined that nuclear fuel inventory should not be included in rate base and financed through rate of return on rate base but should instead be financed through short-term debt.[14]

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[12] D.06-05-016, *mimeo*., p.271.

[13] D.06-05-016, *mimeo*., pp.274-275.

[14] D.09-03-025, *mimeo*., p.361.

In SCE's 2012 General Rate Case (GRC), Application 10-11-015, SCE did not ask for any carrying costs associated with fuel inventory in the proceeding.

DRA recommends that the carrying costs associated with fuel inventory continue to be recovered through the ERRA consistent with the current Commission policy and numerous past Commission decisions on the matter. PG&E has failed to provide any new evidence in its testimony to modify this long-standing Commission policy on this matter.

2. Materials and Supplies (M&S) - Other

PG&E's proposal on Materials and Supplies – Other is based on forecasted maintenance and construction activities and anticipated changes in commodity costs.[15] D.82-12-045 states that "As long ago as 1923 the Commission clearly stated that an allowance for materials and supplies in inventory should cover only those supplies kept on hand for inventory and not those held for construction work."[16]

DRA reviewed the PG&E testimony and workpapers, and the data responses from PG&E. After the detailed review of the historical trends of the recorded data from 2007 to 2012, and the comparison of PG&E's GRC proposals of 2011 and 2014, DRA turned its focus to PG&E's proposal in the Electric Generation area.

Electric Generation is broken down into Hydro Facilities, Fossil Facilities, and Diablo Canyon Nuclear Generation Facilities. The recorded adjusted weighted average yearly-total Electric Generation M&S for 2007 to 2011 are $68.5 million, $73.8 million, $80.2 million, $85.2 million, and $92.2 million respectively,[17] and approximately $102 million for 2012.[18] The average increase per year over this

[15] Chapter 4, Ex. PG&E-7, Prepared Testimony, November 15, 2002.

[16] D.82-12-045, 10 CPUC 2d at 13.

[17] Data response to DRA-PG&E-143-KCL, Q.2, February 20, 2013.

[18] Data response to DRA-PG&E-240-KCL, Q.1, March 26, 2013.

period is $6.7 million. PG&E proposes $132.7 million for Electric Generation in the current GRC, which is about a $15 million per year increase from 2012 to 2014.

DRA performed linear regression analyses of the recorded data from 2007 to 2012 for Hydro Facilities, Fossil Facilities, and Diablo Canyon Nuclear Generation Facilities. Extrapolations from the resulting trend lines of the regression analyses to 2014 give M&S projections for Hydro Facilities of $1.7 million, Fossil Facilities of $16.5 million, and Nuclear Generation Facilities of $95.8 million for a total of $114.0 million. DRA recommends a $114.0 million working capital for Electric Generation M&S, a reduction of $18.7 million form PG&E's proposed $132.7 million.

3. Working Cash

The working cash discussion appears later in Section IV of this exhibit.

D. Tax Reform Act Deferrals

PG&E's rate base forecast includes certain deferred taxes associated with the 1986 Tax Reform Act. The discussion and development of these deferred taxes can be found in Exhibit DRA-20 (Tax Expenses and Other Financial Matters).

E. Customer Advances

PG&E requires new customers to provide refundable customer advances when PG&E provides services to the new customers. The electric distribution and gas distribution rate base is reduced by the average customer advance balance. PG&E used the recorded 2011 weighted average customer advance balance of $82.6 million for electric distribution and $40.7 million for gas distribution to forecast customer advance for 2012, 2013 and 2014.[19] DRA does not take issue with the methodology and the forecasted amount of customer advances.

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[19] Ex. PG&E-2, p.15-5, lines 24-27. Prepared Testimony, November 15, 2012.

F. Deferred Taxes

PG&E's rate base forecast includes deductions for accumulated deferred taxes resulting from Accelerated Cost Recovery System and Modified Accelerated Cost Recovery System tax depreciation, and deferred Investment Tax Credit. The discussion and development of these deductions can be found in Exhibit DRA-20.

G. Depreciation Reserve

PG&E's rate base forecast includes a deduction for weighted average depreciation reserve. The discussion and development of depreciation reserve can be found in Exhibit DRA-19 (Depreciation Expenses and Reserve).

IV. DISCUSSION / ANALYSIS OF WORKING CASH

Working cash is composed of two basic components: (1) working funds required for day-to-day operations; and (2) funds used to pay operating expenses in advance of receiving customer revenues. Table 21-2 compares DRA's and PG&E's TY2014 forecasts of working cash for Electric Distribution, Gas Distribution, and Electric Generation:

Table 21-2
Electric Distribution, Gas Distribution, and Electric Generation
Working Cash Summary for 2014
(In Thousands of Dollars)

Description	**DRA Recommended**			**PG&E Proposed**[20]		
	Electric Distribution	Gas Distribution	Electric Generation	Electric Distribution	Gas Distribution	Electric Generation
Operational Cash Req'ts						
Cash Balances	$0	$0	$0	$0	$0	$0
Special deposits & working funds	$57	$31	$32	$57	$31	$32
Other Receivables	$59,202	$31,981	$33,478	$59,214	$31,952	$33,455
Prepayments-company-wide	$30,410	$16,325	$17,158	$36,540	$19,621	$20,623
Deferred debits	$245	$132	$138	$1,584	$855	$895
Less						
Working Cash not supplied by Investors	$5,761	$3,093	$3,251	$5,759	$3,092	$3,251
Goods delivered by constr. sites	$4,588	$2,463	$2,589	$4,588	$2,463	$2,589
Accrued Vacation	$93,529	$50,228	$52,790	$69,359	$53,386	$53,929
Add						
SmartMeter Benefits	($4,518)	($1,015)	$0	($4,518)	($1,015)	$0
Prepayments-departmental	$0	$0	$8,565	$0	$0	$14,865
Total Operational Cash Req't	($18,482)	($8,332)	$741	$13,171	($7,499)	$10,102
Lead/Lag Working Capital	$77,201	$39,089	$93,297	$144,336	$79,014	$144,294
Total Working Cash Requirement	**$58,719**	**$30,757**	**$94,038**	**$157,507**	**$71,515**	**$154,396**

[20] Ex. PG&E-2, Prepared Testimony, p. 13-11 for electric distribution and gas distribution, p. 13-14 for electric generation.

A. Overview of PG&E's Request

PG&E presented the working cash forecasts in its direct testimony in Chapter 13 of Ex. PG&E-2[21] and its Workpapers supporting Chapter 13 of Ex. PG&E-2.[22] The proposed working cash are categorized and shown in Table 21-2 for Electric Distribution, Gas Distribution, and Electric Generation. PG&E's proposed working cash in the Electric Distribution area is $157.5 million, in the Gas Distribution area is $71.5 million, and in the Electric Generation area is $154.4 million.

B. Prepayments

Prepayments are presented in two sub-categories. Company-wide Prepayments include prepaid software license fees and prepaid insurance. Departmental Prepayments include a recovery charge for the cost of the second refueling outage for Diablo Canyon Nuclear Power Plant.

1. Company-wide Prepayments

PG&E proposes a total of $76.784 million in company-wide prepayments for Electric Distribution, Gas Distribution, and Electric Generation in 2014, while DRA's forecast is $63.893 million.

Insurance prepayments for PG&E's 2014 GRC are based on the 12-month weighted recorded average unamortized balances adjusted by a percentage of anticipated growth from 2011 to 2014 in Administrative and General (A&G) accounts 924 and 925. The growth factor based on PG&E's anticipated insurance growth to 2014 is 2.063.[23] Software license fee prepayments are based on the 12-month 2011 recorded average adjusted for inflation with A&G escalation rates.

The difference in these prepayments between DRA and PG&E is due to the difference in A&G expense estimates. DRA projects a slower growth of A&G

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[21] Chapter 13, Ex. PG&E-2, Direct Testimony, November 15, 2012.

[22] Chapter 13, Ex. PG&E-2, Workpapers, November 15, 2012.

[23] Ex. PG&E-2, Workpapers, WP 13-20.

accounts 924 and 925. DRA recommends certain adjustments to PG&E's anticipated growth in these two A&G accounts. These discussions can be found in Exhibit DRA-16 (Administrative and General Expenses). As the result of these adjustments, the insurance growth factor is lowered to 1.424. Incorporating this growth factor into the prepayment calculation yields total prepayments of $63.893 million for Electric Distribution, Gas Distribution, and Electric Generation.

2. Departmental Prepayments

PG&E proposes $14.865 million in departmental prepayments in 2014, while DRA's forecast is $8.565 million. There are several components of PG&E's departmental prepayments—one associated with the second refueling outage for the Diablo Canyon Nuclear Power Plant (DCPP), another one for different DCPP functions, plus a credit adjustment of $9.443 million for Long Term Service Agreement for Gateway and Colusa generation plants.[24]

PG&E states that it will pay for the total cost of $56.1 million in 2014 for the second refueling outage at DCPP, and requests cost recovery over three years. The yearly recovered amount would be $18.7 million. However, PG&E has also proposed recovery of $18.7 million as an O&M expense in 2014 in the nuclear O&M testimony.[25] DRA recommends subtracting this O&M expense charge from the $56.1 million before calculating the prepayment amount that should be recovered over the 3-year rate case cycle. Therefore, the prepayment amount should be $12.4 million (one-third of $56.1 million minus $18.7 million) instead of $18.7 million (one third of $56.1 million).

DRA recommends reducing PG&E's proposed total Departmental Prepayments by $6.3 million due to DCPP second refueling outage.

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[24] Ex. PG&E-2, Workpapers, WP 13-21.

[25] Nuclear O&M discussion appears in Ex. PG&E-6.

C. Deferred Debits

Deferred Debits are debits that are still in the process of amortization and are not included in other current asset accounts. PG&E forecasted these deferred debits base on the 12-month weighted 2011 recorded average adjusted with the A&G inflation escalation factors.[26]

The average monthly recorded deferred debits from 2007 to 2012 are shown in Table 21-3. The scattering of these recorded data shows no obvious trend. DRA proposes to use the annual average to derive an amount for 2014. The yearly average of these 6 years (2007-2012) is $515,000. DRA recommends this amount for 2014. The $515,000 is allocated to Electric Distribution, Gas Distribution, and Electric Generation as tabulated in Table 21-2. The DRA recommendation results in a reduction of $2.819 million from PG&E's proposed total of $3.334 million.

Table 21-3
2007-2012 Recorded Monthly Average Data for Deferred Debits
(in Thousands of Dollars)

Description	2007	2008	2009	2010	2011	2012
Deferred Debits	($391)	($399)	($409)	$1,324	$3,508	($543)

Source: 2007-2011 data from Workpapers for Ex. PG&E-2, p. WP-30 to -34. 2012 data from data response to DRA-PG&E-241-KCL, Q.1.

D. Accrued Vacation Deduction

Accrued vacation is a deduction from a utility's operational cash requirement as defined by the Commission's Standard Practice (SP) U-16. The recorded monthly accrued vacation is very stable over 6 years from 2007 to 2012 as shown in Table 21-4. PG&E proposed using the 2011 recorded value and making accounting adjustments of $45.7 million for under-accruals.[27]

DRA does not agree with PG&E that the $45.7 million accounting adjustments are necessary. There are always variations in expenses that may or may not be

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[26] Chapter 13, Ex. PG&E-2 page 13-6. Lines 17 to 20,

[27] Data response to DRA-PG&E-140-KCL, Q.1.

captured in rates in various accounting and regulatory categories. In some instances, the utility may spend more than authorized and in other instances less. It is inappropriate to make an exception with the adjustments in the case of accrued vacation. DRA recommends using the 2012 recorded monthly average for accrued vacation without any accounting adjustments, and allocating this amount in the same manner as shown in the data response[28] to Electric Distribution, Gas Distribution, and Electric Generation. The resulting DRA recommendation is $93.539 million for Electric Distribution, $50.228 million for Gas Distribution, and $52.790 million for Electric Generation.

Table 21-4
2007-2012 Recorded Average Monthly Data for Accrued Vacation
(in Thousands of Dollars)

Description	2007	2008	2009	2010	2011	2012
	$219,420	$209,065	$209,087	$207,018	$219,737	$222,741

Source: 2007-2012 data from data response to DRA-PG&E-241-KCL, Q.2.

E. Cash Required Due to Time Lags

PG&E's proposed working cash requirements due to time lags in revenue collection and expense payment are shown in Table 21-2. PG&E performed lead lag studies to establish revenue and expense lag days for the receipt of revenues and for the payment of each type of expense. The resulting average lag days are shown in Tables 13-4, 13-5, and 13-7 of its Prepared Testimony.[29]

DRA reviewed PG&E's proposed average lag days, compared them to the corresponding ones from the 2011 GRC. DRA recommends adjusting the average lag days for Federal Income Tax (FIT), California State Corporation Franchise Tax (CCFT), Goods and Services, and average lag days for revenue collection.

[28] Attachment GRC2014-Ph-I_DR_DRA_241-Q01Atch01 of data response to DRA-PG&E-241-KCL, Q.1.

[29] Ex. PG&E-2, Pages 13-12, 13-13, 13-15.

Lag days for FIT and CCFT proposed by PG&E were not calculated based on recorded data. They were estimated "Based on 2014 Present Expenses". DRA asked PG&E to calculate the lag days with actual recorded data of years 2007 to 2011 for the PG&E Utility Company. PG&E provided the calculated results for CCFT but stated that PG&E did not make any FIT payments in 2009, 2010, and 2011 because the company reported a net operating loss for taxes.[30] PG&E indicates that the FIT calculation for 2008 is not meaningful, so no lag days were provided. The CCFT lag days for 2007 is much lower than those for 2008 to 2011, and seems to be an aberration. This is similar for the 2007 lag days for FIT.

DRA recommends 132.85 days as the expense lag days for CCFT, which is the average based on PG&E calculated lag days for 2008, 2009, 2010, and 2011.[31] For FIT expense lag days, DRA recommends 110.85 days, which is consistent with PG&E's proposed number in the 2011 GRC.[32] Given that no FIT recorded tax data is available in 2008, 2009, and 2010 to make the calculation, the most recently proposed and adopted figure from PG&E's last GRC is a reasonable FIT expense lag.

PG&E proposed lag days for Goods and Services of 20.56 days, as compare to its proposed 39.64 days in the 2011 GRC[33] and 40.31 days in the 2007 GRC.[34] The 20.56 days is a significant reduction from the two previous GRCs of 39.64 and 40.31 days. DRA requested PG&E to recalculate the lag days based on 2012 recorded data. PG&E responded that it would require an extensive re-calculation and would require relatively costly and time-intensive efforts. The 100 percent reduction in lag days compared to the two most recent GRCs is not reasonable or

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30 Data response to DRA-PG&E-139-KCL, Q.3, February 20, 2013.

31 Id.

32 Chapter 13, PG&E-2, Page 13-9, Direct Testimony for the 2011 GRC.

33 Chapter 13, PG&E-2, Page 13-9, Direct Testimony for the 2011 GRC.

34 Lines 23-24, p. 17-8, DRA-17, DRA Report on GRC TY 2007, Rate Base, April 14, 2006.

supported by recent 2012 data. DRA recommends using the 2011 GRC adopted lag days of 39.64 as the expense lag days for Goods and Services in the current GRC.

PG&E proposed revenue lag day of 43.14 days in the current GRC. It proposed revenue lag day of 40.81 days in the 2011 GRC.[35] With all the money the ratepayers provided PG&E to acquire new computer technology, to make the bill collection system more efficient, to implement SmartMeters, and to improve on other technology systems, the revenue collection lag day should be shorter instead of longer. Therefore, DRA recommends that the average revenue lag day be 40.81 days which is the same one PG&E proposed in the 2011 GRC.

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[35] Chapter 13, PG&E-2, Page 13-9, Direct Testimony for the 2011 GRC.