Electric Generation and Other Results of Operations Issues for Pacific Gas and Electric Company

Prepared testimony of
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California Public Utilities Commission

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Table of Contents

List of Tables

List of Figures

I. Introduction and Summary

This testimony is presented by William B. Marcus, Principal Economist of JBS Energy, Inc. on behalf of The Utility Reform Network (TURN). Mr. Marcus has 35 years of experience in energy issues and has appeared before this Commission on many occasions, and has filed testimony or formal comments before about 40 federal, state, provincial, and local courts and regulatory bodies in the U.S. and Canada. Mr. Marcus' qualifications are attached. (Attachment 1)

This testimony addresses a variety of expense and capital-related issues including policy issues, hydroelectric, nuclear, and fossil generation, administrative costs, and cash working capital.

Other testimony is filed in this case for TURN by Gayatri Schilberg (Information Technology capital and O&M); Garrick Jones (electric distribution, HR, and administrative and general costs); Jeffrey Nahigian (customer care and corporate real estate); John Sugar (gas distribution and HR) Jacob Pous (depreciation), Hayley Goodson (uncollectible accounts expenses), Catherine Yap (post-test-year ratemaking) and James Weil (financial health).

This testimony recommends:

- Reducing hydroelectric O&M expenses by at least $32 million, with specific examples identified, and adding $0.9 million to hydro other operating revenue.
- Reducing hydroelectric capital (end of year 2014) by $91 million because of relicensing delays, pursuit of low=priority projects, and inefficient or imprudent specific projects.
- Reducing nuclear O&M expenses (measured using PG&E's ratemaking treatment for comparability) by $46 million for reasons including normalization of new project spending, removing cost of new hires largely covered by embedded costs, reducing forecasts of increased non-outage overtime, removing one of the two steam generator inspections that PG&E requested and normalizing the other one, reducing refueling outage costs,. and adjustments to obsolete inventory, NRC fee escalations, and the Nuclear Energy Institute.

- Changing the ratemaking on refueling outages to "pay as you go" which raises rates in 2014 (but still less than PG&E's request) with substantial reductions in the attrition years and removes the need to collect a prepayment that PG&E requests in rate base.
- Reducing nuclear capital by $7 million, including a project that PG&E expensed in its last rate case.
- Modifying PG&E's ratemaking proposals for Independent Spent Fuel Storage Installation (ISFSI) and money received from the Department of Energy Spent Fuel Settlement.
- Adopting DRA's reductions to fossil O&M expenses, based on DRA's showing and additional information presented here, including a demonstration that new staff hired to reduce overtime, are in fact largely paid for by those overtime reductions.
- Reducing fossil capital by $1.8 million.
- Removing inappropriate expenses of $1.7 million, including websites and blogs that enhance PG&E's image, clothing and other gear, dues to political organizations, and expensive meals and resort costs.
- Reduce income tax expense by $16.8 million and revenue requirement by $26.3 million by applying the income tax deduction for the Employee Stock Ownership Plan.
- Reducing cash working capital by $48 million in other receivables, prepayments, and a longer lag for goods and services.
- Applying customer deposits as an offset to rate base ($137 million to General Rate Case functions).

II. Hydroelectric Costs

A. Introduction – Hydro Is Not So Cheap Anymore

Ratepayers and regulators have generally assumed that hydroelectric costs are relatively inexpensive compared to other generation options and therefore often did not examine those forecasts closely.[1] The real fact is that hydro used to be inexpensive until this rate

[1] There have been notable exceptions, such as the review performed in the two most recent SCE GRCs by a local group concerned about that utility's hydro operations on the eastern side of the Sierras.

case. However, massive increases, particularly in capital spending, have caused PG&E's "going forward" costs of hydro[2] to rise from a PG&E request of 2.4 cents/kWh in the 2007 GRC to 3.5 cents/kWh in the 2011 GRC, to 5.5 cents/kWh in this GRC.[3]

Table 1: PG&E Going Forward Cost Requests for Hydro in Last 3 GRCs

	PG&E 2014 GRC	PG&E 2011 GRC	2014 as % of 2011	PG&E 2007 GRC	2014 as % of 2007
Average capital 5-year rate case cycle ($ millions)	336.8	185.8	181%	102.1	330%
Add 30% to capital for present value of revenue requirement	101.0	55.7		30.6	
Expenses including employee benefits ($ millions)	191.1	159.7	120%	143.9	133%
"Going forward" costs of the hydro system	629.0	401.3	157%	276.6	227%
GWh (1974-1999 average excluding two sold plants)	11,372	11,372		11,372	
Going forward costs (cents/kWh)	0.0553	0.0353		0.0243	

This very large increase in spending requests requires that the Commission take a close look at spending, particularly on capital. Hydropower is an important resource to PG&E, Northern California, and the state. But that does not mean that it is feasible to act like there is a blank check for hydro spending. With PG&E's level of spending, the embedded cost may be inexpensive though rising rapidly, but the going forward costs are no longer substantially cheaper than the market price of energy.

In this context of rising costs, TURN therefore recommends reducing hydro O&M expenses by at least $31.5 million, reducing hydro 2014 end-of-year plant-in-service by $91.1 million, and increasing other operating revenue associated with hydro by $0.9 million.

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[2] Expense including employee benefits plus capital multiplied by the present value of revenue requirements – an adder for income and property taxes. One-time tax breaks from bonus depreciation, which was available for 2008-12, are not considered in this analysis.

[3] Data from 1974-1999 was used to develop average hydro conditions because recent data have become confidential during deregulation. The source of this data is Joint Testimony of Robert Kinosian and William Marcus in CPUC App. 99-09-053 (June 2000) Attachment 2.

B. Hydro Operations and Maintenance Expense

1. Overview – A Top-Down Reduction is Needed

As shown below, PG&E is proposing to raise costs from $133.0 million in 2011 to $191.1 million in 2014.

Table 2: PG&E Hydro O&M Expense Summary

Pacific Gas and Electric Company
2014 GRC
Exhibit (PG&E-6), Chapter 2
Hydro Operations
Expense Summary
(Thousands of Nominal Dollars)

Line No.		2007	2008	2009	2010	2011	2012	2013	2014
1	Base Work	93,588	98,700	101,377	109,162	115,302	123,194	131,257	134,908
2	Projects	12,672	15,707	15,310	12,866	17,726	21,482	38,382	56,236
	Total Expense	106,260	114,407	116,688	122,028	133,028	144,676	169,639	191,144

PG&E is requesting a 31% increase in real terms for hydro O&M expense in 2014 – after accounting for inflation. The amount in excess of inflation is $45.8 million – about 0.4 cents per kWh all by itself. PG&E has overwhelmed the regulatory process with hundreds of projects ranging from the microscopic to the tens of millions of dollars. It is virtually impossible to review all of them. But that does not mean all of them are reasonable. Remember that PG&E's 2011 TY GRC forecast was $159.7 million, and PG&E spent considerably less. Many of the projects that were originally funded in 2011 and have come back in 2014. Many 2014 projects are also non-recurring.

TURN recommends a normalization of spending that allows an increase but limits it. A normalization averaging PG&E's 2011-2014 total forecast spending would recognize that costs are rising but also recognize that there need to be some limits. An average of the four years as forecast by PG&E 2011-2014 would yield $159,622,000. This is the maximum amount that should be allowed, and the Commission could justify further reductions. This figure would be 10% higher in real terms than PG&E's 2011 recorded costs (after adjusting for inflation at 3%) – not 31% as PG&E has requested. The figure is also close to the ratio of 2011 actual expenditures to PG&E's 2011 GRC forecast expenditures (83.30%). This percentage of PG&E's 2014 forecast is $159.2 million.

We point out several illustrative adjustments totaling $5,915,000 that could easily be made as partial justification of the top-down forecast and as recommendations in their own right should the top-down reduction be rejected. These are only a few illustrations out of the over 800 individual planning orders that PG&E has identified!

2. MWC AB (Support)

PG&E asks for more than doubling of expenses in this Major Work Category from $1,404,000 in 2011 to $3,064,000 in 2014. As an alternative to DRA's forecast for this item based on 2011 recorded data ($1,404,000), TURN believes that a reasonable forecast could be 2012 recorded ($2,023,000) plus 5% for inflation or $2,124,000, a figure which is still $940,000 below PG&E.

3. Government Fees (MWC KJ)

PG&E forecasts government fees of $12,245,000 in 2014, including double-digit percentage increases in FERC Fees from 2012-2013 but did not document them. The forecast is spread over 20 separate accounts in MWC KJ, andn PG&E changed accounting in the middle of 2010 combine to make it difficult to discern a trend. TURN obtained aggregate data for these fees in the response to DR 11-04.

FERC Fees are approximately 87% of the total. FERC Fees are based on a unit cost multiplied by a mix of capacity and energy, with a limit on energy. They vary from year to year with water conditions. The unit costs have escalated at about 3.5% per year. Therefore, TURN recommends a five year average of all fees in real 2011 dollars from 2007-2011. This is $10,502,000 in 2011 dollars. It is escalated to $11,409,000 in 2014 nominal dollars, a reduction .of $855,000 from PG&E's request, but an increase of $3,190,000 from the unusually low figures in 2011.

Table 3: Government Fees from TURN DR 11-04 ($'000)

	Actual		Forecast	
	Nominal	Real	Nominal	Real
2007	8,743	10,380		
2008	9,155	10,067		
2009	11,213	12,037		
2010	11,329	11,808		
2011	8,219	8,219		
2012			10,482	10,173
2013			11,967	11,316
2014			12,264	11,289
TURN 5 yr average		10,502		
TURN Escalate to 2014			11,409	
PG&E>TURN			855	

4. Helicopters (MWC KG)

PG&E is doubling the cost of helicopters from 2011 to 2014.[4] PG&E forecasts higher costs in 2013 and 2014 "due to increased use of helicopters for patrols of water conveyance systems which is necessary to ensure public safety."[5] TURN must ask several questions as a result of this explanation.

- Was PG&E degrading or endangering public safety by not spending the money prior to 2013 to patrol these water conveyance systems?"
- Were any people killed or injured because PG&E was not adequately patrolling water conveyance systems prior to 2013?
- Has PG&E balanced the benefits of public safety with the potential cost of worker safety, given that helicopters are necessary but are not the safest form of transportation and not to be used lightly?

If the answers to these questions are no, this becomes yet another unquantified expense to make PG&E feel that it is being safer with a half million dollars of extra costs but no

[4] See planning orders 5011012 and 5011013 in MWC KG, PG&E-6 Workpaper 2-22.

[5] TURN DR 33-11.

demonstrable benefit to ratepayers. TURN recommends 2011 expenses with a 9% increase for inflation, as shown in the table below.

Table 4: Helicopter Costs

	Recorded	PG&E	TURN	PG&E>TURN
	2011	2014	2014	
Shasta	241	488	263	
Desabla	223	591	243	
Subtotal	464	1,079	506	573

5. Duplicative Blanket Infrastructure Projects (MWC KH)

PG&E includes two new blanket projects for infrastructure expenses ($950,000 in Planning Order 5215672) and resurfacing and repairing roads ($347,000 in planning order 5215688).[6] These are small numbers but they demonstrate one element of what is wrong with PG&E's budget process. PG&E has dozens of infrastructure items – including division level budgets for roads and bridges and maintenance of generating structures, as well as individual special projects.

Spending is forecast to increase from $11,150,000 in 2011 to $13,327,000 in 2014 –for infrastructure (in MWC KI) without these two blanket projects. This is a 19.5% increase. PG&E's two new blanket projects top it up to $14,625,000 (31.2% above 2011). These extra new blankets are simply extra money stashed away to make sure PG&E does not run out of its ordinary budgets. TURN proposes removal of $1,297,000 for these projects.

6. Safety – The Word is Everywhere; The Money Was Never Clearly Discussed (MWCs KG and KJ)

PG&E has proposed to increase spending on hydro safety from 2011 to 2014 by $4,325,000 (88%) from a base of $4,933,000 to $9,258,000. Most of this increase is concentrated in three blanket projects.

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[6] PG&E-6, Workpaper 2-30.

Table 5: Safety Spending in 12 Different Planning Orders ($'000)

			2011	2014	increase	% increase
KG	5012419	Public Safety	43	824		
KJ	5004009	HC Facility Safety	432	2692		
KJ	5000143	HC Required Facility Safety	1532	2151		
		subtotal blanket	2007	5667	3660	182%
KG	5008270	KCV Manage Safety	97	100		
KG	5008811	Shasta Manage Safety	95	96		
KG	5008813	DeSabla Manage Safety	57	32		
KJ	5010029	Helms Required Safety	75	158		
KJ	5010030	KCV Required Safety	114	263		
KJ	5010031	ML Required Safety	259	788		
KJ	5010032	Drum Required Safety	175	210		
KJ	5010033	Potter Valley Required Safety	315	263		
KJ	5010034	Shasta Required Safety	1586	1471		
KJ	5010035	DeSabla Required Safety	153	210		
		subtotal specific	2926	3591	665	23%
		TOTAL	4933	9258	4325	88%

While PG&E's testimony mentions safety extensively, it doesn't explain why nearly doubling the safety budget is a better or more reasonable outcome than a smaller increase. It doesn't exen explain that it is doubling the safety budget. It doesn't explain what is being bought with the extra money. Yet the collection of money from ratepayers for projects with "safety" in their name will not necessarily result in actual improvements in safety. Further, PG&E does not acknowledge the two blanket projects that contain $2.8 million of PG&E's safety budget increase in its testimony. This is the problem with a fragmented budgetary process that is not clearly planned and implemented. In light of PG&E's showing, TURN recommends that as part of any other reductions to hydro O&M spending, that safety spending in total be held at no more than $7,258,000, a reduction of $2 million from PG&E's figure and the approximate midpoint between PG&E's request and 2011 escalated with inflation.

7. Project Portfolio Management Tool (5236187)

The project Portfolio Management Tool is discussed in detail in Section C below. As noted there, the PPMT is not being used for prioritizing hydro capital projects. It just describes as low priority a number of projects that PG&E wants to spend money on anyway. It is not being used effectively and the $300,000 of O&M[7] should therefore not be allowed, in addition to the capital disallowance recommended below.

C. Hydro Other Operating Revenue

Timberrr! PG&E says there won't be very much of it in TY 2014, $663,000 as compared to 2011 OOR recorded of $1,063,000 (recorded adjusted $899,000). Historical and forecast timber sales are given below.[8]

Table 6: Timber Sales Revenue

Harvest Year	Actual Revenue	Forecast
2007	$2,440	
2008	$2,297	
2009	$892	
2010	$1,396	
2011	$1,063	$899
2012	$2,099	$1,110
2013		$1,184
2014		$663
TURN 5 year average	2008-2012	$1,550
TURN > PG&E		$887

TURN recommends a five-year average of 2008-2012 given the fluctuations in revenue over time, which increases PG&E's revenue by $887,000.

[7] PG&E-6, Workpaper 2-21.

[8] TURN DR 11-07 for historical data; PG&E forecast from PG&E-2, page 17-9.

D. Hydro Capital

TURN proposes to reduce hydro gross plant in service by $91.1 million ($56.4 million 2014 weighted average).

We move the in-service dates back on a number of projects for which relicensing has been delayed. This reduces 2014 plant in service by $50.6 million (total) or $32.8 million weighted average.

We also reduce spending by $27.6 million ($12.5 million weighted average) on 69 projects that PG&E itself has determined to be of low priority but has proposed to bring into service in 2013-14 anyway.

Finally, we make disallowances for management inefficiency or prudence for several specific projects. These disallowances total $12.9 million of gross plant (all prior to 2014)

1. Relicensing Delays

New relicensing dates for projects expected to be licensed by 2020 are given in Table 8, taken from TURN DR 11-06.These new dates were used directly to calculate changes in capital gross plant for relicensing itself. Ancillary projects to relicensing that were expected to close to plant in 2014 were rescheduled based on information provided by PG&E in DR 33-07. The net result (summarized below) is supported by Table 8 and Table 9 on the next page.

Table 7: TURN Adjustments to PG&E Plant in Service for Relicensing Delays

	EOY 2014 Gross Plant	Wt. Average 2014 Gross Plant
PG&E	$123,747	$88,310
TURN	$ 73,108	$55,490
Difference	$ 50,639	$32,820

Table 8: New Forecasts of Hydroelectric License Issue Dates

FERC LICENSE	PROJECT NAME	NORMAL MW CAPACITY	LICENSE EXPIRES	NOI FILING DEADLINE	APPLICATION FILING DEADLINE	FORECAST LICENSE ISSUANCE RANGE: EARLIEST POSSIBLE	EXPECTED	LATEST LIKELY	LICENSE STATUS
2155	Chili Bar	7	31-Jul-07	31-Jul-02	31-Jul-05	Feb-13	Mar-13	Jun-13	Application filed 7/15/2005
803	DeSabla-Centerville	26.4	11-Oct-09	11-Oct-04	11-Oct-07	Jul-13	Oct-13	Dec-13	Application filed 10/2/2007
2105	Upper NF Feather River	362.3	31-Oct-04	31-Oct-99	31-Oct-02	Jan-14	Apr-14	Jul-14	Application filed 10/23/2002
2107	Poe	120	30-Sep-03	30-Sep-98	02-Jan-04	Feb-14	Apr-14	Jul-14	Application filed 12/16/2003
2106	McCloud - Pit	364	31-Jul-11	31-Jul-06	31-Jul-09	Oct-14	Jan-15	Apr-15	Application filed 7/16/2009
606	Kilarc-Cow Creek Surr.	5	27-Mar-07	27-Mar-02	27-Mar-05	Dec-13	Dec-14	Dec-15	License Surrender Application filed 5/12/2009
2467	Merced Falls	3.5	28-Feb-14	28-Feb-09	28-Feb-12	Jun-14	Feb-16	Feb-19	Application filed 2/18/12
2310	Drum-Spaulding	190.1	30-Apr-13	30-Apr-08	30-Apr-11	Apr-14	Apr-16	Apr-18	Application filed 4/12/11
619	Bucks Creek	65	31-Dec-18	31-Dec-13	31-Dec-16	Feb-19	Dec-20	Dec-23	NOI/PAD to be filed no later than end of 2013

Table 9: 2014 Gross Plant Changes Due to License Delays

Planning Order	Description	Original: Date	Original: Plant	Original: WAVG 2014	Revised: Date	Revised: Plant	Revised: WAVG 2014	
5701979	Poe FERC 2107 Relicense	Dec-2012	14,702	14,702	Apr-14	16,291	11,540	add 8% for AFUDC
5704039	UNFFR FERC 2105 Relicense	Dec-2012	30,675	30,675	Apr-14	33,990	24,076	add 8% for AFUDC
5716718	DeSabla Centerville Relicensing	Dec-2012	18,160	18,160	Dec-13	19,613	19,205	add 8% for AFUDC
5719039	McCloud-Pit FERC 2106 Relicense Cap	Jul-2014	34,015	18,425	Jan-15	0	0	
5720687	DeSablaCentervil LC-Res Elevation M Phil	Oct-2013	1,550	1,550	Oct-14	1,597	333	add 3% for escalation
5741499	DeSabla Centerville LC-FlowMon&Recording	Oct-2013	1,570	1,570	Oct-14	1,617	337	add 3% for escalation
5741503	DeSabla Centerville LC-H2Otemp D forebay	Dec-2014	9,481	395	Dec-15	0	0	
5741504	UNFFR LC-Capital Projects	Oct-2014	13,593	2,832	Feb-16	0	0	
	Subtotal Deferred Projects		123,747	88,310		73,108	55,490	

2. Reduce Spending on Low Priority Projects

PG&E has a Project Portfolio Management Tool (PPMT) "that helps prioritize and manage Hydro's work," which ranks projects from zero to 2000.[9] PG&E provided output from this prioritization tool in its Workpapers 2-107 through 2-121, which it claims "support the capital forecast for Hydro Operations."[10]

PG&E describes the Project Portfolio Management Tool in its testimony as follows:

> **k) Project Portfolio Management Tool – Long-Term Plan and Project Tools**
>
> The PPMT Project will streamline the long-term planning and management of large expense and capital projects, giving leadership a holistic view of the scope, cost and prioritization of the planned work. It will improve project planning and prioritization needed for GRC and annual budget submittals, and will provide the ability to do scenario planning for projects having dependencies with other projects.
>
> PPMT is an SAP module that integrates easily into the 1 PG&E's SAP system and with the Primavera detailed project scheduling program that PG&E uses. PPMT will facilitate the reporting required to track the work and financial aspects of major capital and expense projects at a Work Breakdown Structure (WBS) view.
>
> The project will also, in conjunction with Electric Transmission and Distribution (T&D), bring the currently outsourced implementation of PPMT and Primavera into the PG&E data center.[11]

Leaving aside IT (which doesn't fit in), and license renewal and conditions (which PG&E includes in the system but which are really mandatory, so TURN removed them), and projects the utility hasn't rated (mostly relatively early projects in the rate case cycle), PG&E has ranked and prioritized $1,504 million in projects on which they are proposing to spend capital collars (including capital spending from 2012-2016 plus CWIP in 2011).

However, despite all this prioritization and ranking, PG&E effectively did not use the results of its program. It simply proposes to spent everything on every hydroelectric capital project regardless of priority. Here is a summary of PG&E's spending.

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[9] PG&E-6, p. 2-105; see also TURN DR 11-01.

[10] Liberty DR 1-11. (TURN notes that PG&E has designated as confidential the attachment to this DR, but the quoted material comes from the non-confidential cover page.)

[11] PG&E-6 pp. 2-148 to 2-149.

Table 10: PG&E GRC Spending for Low Priority Projects

Total			1,990,537	
Less IT			38,445	
Less Licensing			347,895	
Less Unrated			99,852	
remaining projects			1,504,345	
Score zero			113,767	7.6%
Score 1-5			65,574	4.4%
Score 5-10			38,866	2.6%
Score 11-20			46,638	3.1%
AM blanket projects Score 1-5			54,050	3.6%
AM blanket projects score 5-10			9,000	0.6%
AM blanket projects Score 11-20			78,680	5.2%
zero			113,767	7.6%
All 1-5			119,624	8.0%
All 5-10			47,866	3.2%
All 11-20			125,318	8.3%
All under 20			406,575	27.0%

On a scale of 1 to 2000, 7.6% of ranked project spending (excluding licensing) had a ranking of ZERO, another 8% had a ranking of 1 to 5 and 27.0% had a ranking of 20 or less.

In other words, PG&E's prioritization tool isn't being used to set priorities for this GRC request.

In light of PG&E's request to spend $2 billion on hydro capital from 2012-2016 plus 2011 CWIP, there needs to be some priority setting in the authorized revenue requirement. TURN recommends removing $27.6 million of costs from 69 low-priority projects with scores below 20 from rates in this rate case. In this case, we removed only half of the cost of blanket projects with scores of 1-20 (recognizing that individual projects within blankets may be of greater and lesser priority than the total score) and half the cost of individual projects with scores of 11-20, in addition to all of the cost of individual projects with scores of zero to ten. The Commission should direct PG&E to make a better showing in its next GRC on how its recommended spending reflects appropriate prioritization. Attachment 2 shows the projects removed from PG&E's capital projects data base.

Many low-priority projects are assumed to come into service in 2015-2016, and our failure to act on them should not be deemed to be approval. If we see them in the next rate case, we will remove them then.

Table 11: TURN Disallowance for Low Priority Projects

TURN Disallowance	EOY Gross Plant	WtAvg Gross Plant
All individual projects with ratings of 0-10	12,385	5,660
Half of cost of individual projects with ratings of 11-20	7,389	3,875
Half of AM blanket costs with ratings of 1-20	7,900	2,963
TURN disallowance	27,674	12,498

3. Expensive or Inefficient Projects: The Context of Rampant Cost Underestimates

Several individual projects should be deleted as well for reasons of prudence or management inefficiency or ineffectiveness. TURN provides an overview of these issues here and provides specific recommendations in Sections 4-8 below.

Management ineffectiveness appears to be rife throughout the area of hydro capital. TURN identified almost a dozen projects whose initial estimates in the 2009 GRC increased by significant amounts in the current GRC, as well as 35 projects completed in 2012 that cost 18% more than their 2012 estimates in this GRC. Because PG&E underestimated costs dramatically, it got committed to the projects before the costs tripled. Had the utility's initial forecast been more accurate, it would have known from the beginning that the projects were going to be much more expensive and, hopefully, might have prioritized and trimmed spending or even redesigned some of the projects.[12]

[12] While an ordinary company with a fixed budget might have cut spending, all the excess spending becomes a 10.4% ROE long-term profit center for PG&E.

We first prepared an analysis of the cost of projects that were carried over from the 2011 to 2014 rate cases. After excluding projects related to relicensing, removing Crane Valley Dam (discussed separately) and three projects where it was clear that the full cost was not included in the TY 2011 rate case (needle valve capital blanket and the Pit 3 and Pit 4 turbine upgrades), there were 33 projects carried over.

Table 12: Projects Carried over from 2011 TY GRC to 2014 TY GRC ($'000)

		2011 TY GRC	2014 TY GRC	2011 TY GRC	2014 TY GRC
5720649	Volta-Lake Nora Intake Walkway	388	1,625	Dec-11	Dec-12
5729759	Tiger Creek Rd - Repave	1,665	3,812	Dec-10	Dec-13
5729770	Haas - Arc Flash Remediation	800	1,586	Dec-11	Dec-12
5728988	Helms TPC System	7,331	3,715	Dec-11	Feb-12
5730440	Rock Creek Arc Flash	2,091	1,753	Dec-10	Nov-13
5730450	Pit 4 Arc Flash Remediation	950	1,082	Dec-12	May-12
5732366	Sand Bar Diversion - Cutoff	1,799	6,350	Sep-12	Oct-15
5720759	Canyon Dam Outlet Lower Gates	2,460	1,777	Oct-12	Dec-12
5729769	Helms 13.8 kV Breaker	4,758	1,813	Jan-11	Feb-12
5715938	South Yuba Canal Gunite	2,020	2,500	Dec-09	Oct-12
5718918	Coal Canyon Miocene Flume Repl.	1,478	1,813	Apr-12	May-12
5720524	Salt Springs Refurbish Wickets	881	3,450	Dec-11	May-15
5720542	Lake Valley Pipe Phase II	1,150	1,700	Oct-11	Jun-13
5720659	Caribou 2-5 rewind	460	1,700	Jun-13	Dec-16
5720685	Pitt 5 U1 BullNose/RiverGate	1,580	2,947	Nov-11	Dec-12
5720731	LimeSaddle Replace Penstock	4,000	1,700	Dec-13	Jun-13
5720733	Replace Pit 6 Trash Rake	775	1,633	Oct-13	Dec-13
5721419	Bear River Gunite	3,200	22,996	Dec-10	Dec-12
5725479	Kern Canyon - Valve/Sluiceway	2,987	5,116	Nov-12	Jun-14
5726821	Helms - Upgrade Cooling Water System	425	2,009	Dec-10	Oct-13
5729550	Electra - Modify Diversion Piping	570	2,209	Mar-12	Oct-13
5729601	Main TuolomneCanal - Shotcrete	1,365	1,350	Dec-10	Oct-13
5728990	Helms - Replace Liquid Rheostat	380	1,619	Dec-11	Sep-13
5729258	Helms - Replace Foxboro/Install DCS	1,000	2,634	Sep-11	Jul-13
5729592	Helms- Replace TSV Control	220	1,507	Nov-11	Oct-13
5729602	Tiger Creek Canal Reline	14,629	1,851	Dec-09	Dec-12
5729667	Drum Canal YB 137- New Gate Controller	350	1,237	Mar-11	Dec-12
5729671	Spaulding 1 - Replace Generator Sw Gear	445	1,404	Dec-11	Dec-13
5730481	Pit 4 Dam drum gate seals	2,120	2,104	Dec-12	Dec-14
5732845	Helms - Replace STP backup generator	400	1,315	Dec-10	Aug-13
5732826	Bear River Canal - Berm Stabilization	470	3,200	Dec-10	Nov-13
5733249	Pit 3 Dam DamCrest Gates	1,497	4,804	Oct-10	Oct-13
	subtotal of projects	66,022	97,427		

The costs of these 33 projects increased from $66 million to $97 million – a 48% increase. Of the 33 projects, 9 were cheaper in this rate case, 3 were less than 25% more expensive, and 21 were at least 25% more expensive.

We asked follow-up data requests (in the TURN DR 33 series) regarding cost increases at a number of projects. The preponderance of the answers on these projects claimed that the estimates were preliminary in the last rate case. A representative answer is this one (for Lake Nora):

> The 2011 GRC forecast of $0.4 million was based on preliminary project scope and cost information available in early 2009. The forecast cost in the 2014 GRC of $1.6 million includes detailed scope, permitting and constructability assessments.[13]

Finally, we compared a number of projects' final costs to their estimates. For all projects except multi-year projects and the Crane Valley Dam completed by March 2013, the Actual Cost was $18 million (18%) higher than the GRC forecast cost; out of 35 projects, 11 projects were less expensive than forecast, 13 had cost overruns of less than 25%, and 11 had cost overruns of more than 25%.

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[13] TURN DR 33-16. See also 33-18 (Haas Arc Flash Remediation), 33-19 (Sand Bar Diversion Cutoff), 33-20 (Lake Valley Pipe Phase II), 33-21 (Pit 5 U1 BullNose/River Gate), 33-22 (Pit 6 Trash Rake), 33-23 (Kern Canyon – Valve Sluiceway); 33-26 (Helms – Replace Foxboro/Install DCS), 33-27 (Helms TSV control); and 33-31 (Pit 3 Dam Crest Gates). All of these data requests had similar answers.

Table 13: Actual and Forecast Costs of Projects Completed by March 2013 ($'000)

Actual and Commitment Cost Details for Major Capital Projects Operative by March 2013
(Thousands of Nominal Dollars)

Line No.	Planning Order Number	Description	Actual Operative Date	Actual Cost	GRC Forecast Cost
	MWC 11 - Relcn Hydro Implt Cap Lic Cond				
1	5720779	Battle Cr Salmon/Steelhead Phase 1	Jan-2013	$ 2,096	$ 3,361
2	5720780	Pit 345 LC Recreation	Mar-2013	$ 7,088	$ 6,165
3	5720793	Pit 1 LC WHIPProperty Improvements	Dec-2012	$ 2,161	$ 1,803
4	5740319	Pit 345 LC Revegetation	Dec-2012	$ 992	$ 1,157
5	5741545	Pit 3 & 4 LC Road Construction	Dec-2012	$ 5,263	$ 3,863
6	5743959	Pit 3 Road Full Section Replacement	Dec-2012	N/A	N/A
	MWC 12 - Implement Environment Projects				
7	5732379	Poe Dam Repl S/B Generator & Batteries	Aug-2012	$ 1,274	$ 1,013
	MWC 2F - Build IT Apps and Infra				
8	5744424	Primavera UAL Licenses	Dec-2012	$ 1,623	$ 2,500
	MWC 2L - Instl/Rpl for Hydro Safety&Reg				
9	5720649	Volta - Lake Nora Intake Walkway	Dec-2012	$ 1,544	$ 1,625
10	5720713	Pit 5 Replace 480V Switchgear	Dec-2012	$ 2,737	$ 2,907
11	5720734	Pit 7 Replace Trash Rake	Feb-2012	$ 1,876	$ 1,615
12	5720759	Almanor Tower Replace Lower Gates	Dec-2012	$ 2,241	$ 1,777
13	5722519	Helms-ReplT1GatehousePenstckProtection	Nov-2012	$ 1,736	$ 1,186
14	5724399	Drum 1&2 Penstock Tunnel Replacement	Nov-2012	$ 9,832	$ 7,380
16	5728988	Helms - Install TPC System	Feb-2012	$ 8,607	$ 3,715
17	5729018	Pit 5 Arc Flash Remediation	Feb-2013	$ 8,961	$ 8,434
18	5729769	Helms - 13.8kV Breaker/Arc Relay Install	Feb-2012	$ 4,696	$ 1,813
19	5735381	PotterVally Instl ScottDamGeotecInstrmts	Dec-2011	$ 1,400	$ 1,373
20	5735794	StanForebay-Install New 480v Sys/Switchs	Nov-2012	$ 2,997	$ 2,367
21	5738060	Kings River PH - Inst Surge Shaff Lining	Jan-2013	$ 2,864	$ 2,811
22	5745688	HC: Hydro Waterwy Public Safety Improv C	Dec-2012	N/A	N/A
	MWC 2M - Instal/Repl Hydro Gneratng Eqp				
24	5720683	Poe U1 Replace Runner, Wickets & FPs	Jul-2012	$ 10,809	$ 8,529
25	5724779	Pit 5 Automate Powerhouse	Jan-2013	$ 1,595	$ 1,841
26	5731362	AM: SCADA RTU Life Cycle Program	Dec-2011	N/A	N/A
27	5736379	Spaulding-ReplaceDischargeLiner/Cauldron	Jun-2012	$ 1,093	$ 1,065
28	5737519	Helms - Replace HPCO HPU	Dec-2012	$ 436	$ 1,580
29	5740890	Kerckhoff 1- U3 Field Poles Refirb/Colla	Jan-2013	$ 2,042	$ 1,107
30	5742178	Project Portfolio Management Tool	Jun-2012	N/A	N/A
31	5744002	Balch 2 U3 - Reinsulate Field Poles	Dec-2012	$ 2,931	$ 2,185
32	5744498	Spaulding 1 PRV Discharge	Dec-2012	$ 6,304	$ 5,643
33	5745701	Narrows Replace Runner	Feb-2013	$ 137	$ 2,150
34	5746203	Helms - U1 Replace Exciter (Restoration)	Dec-2012	$ 1,157	$ 1,295
35	5746659	Helms - U1 Refurbish Rotor Poles	Sept-2012	$ 5,437	$ 5,256
	MWC 2N - Instal/Repl Resv,Dams&Waterway				
36	5704239	Drum Canal/Gunite Work (Cap)	Oct-2012	N/A	N/A
37	5715938	South Yuba Canal Gunite	Dec-2009	N/A	N/A
38	5718918	Coal Canyon Replace M. Miocene 9/1 Flume	May-2012	$ 1,941	$ 1,813
39	5720685	Pit 5 U1 Ins. Bull Nose/River Gate/Clad.	Dec-2012	$ 4,026	$ 2,947
40	5721419	Bear River Canal Gunite	Nov-2012	N/A	N/A
41	5729602	TigerCr Canal-Instl PillasterJointsLiner	Dec-2012	N/A	N/A
42	5730478	McCloud Dam LLO Improvements	Dec-2012	$ 6,715	$ 3,101
43	5734959	Coal Canyon Replace M Mio 6/1 Flume	May-2012	$ 1,806	$ 1,768
44	5735784	Drum - Wise Canal Shotcrete	Nov-2012	N/A	N/A
45	5735785	Drum - South Canal Shotcrete	Nov-2012	N/A	N/A
46	5741532	Towle Canal Shotcrete	Dec-2012	N/A	N/A
47	5744479	Halsey Forebay LLO Assesment	Mar-2013	$ 316	$ 1,113
	MWC 2P - Instl/Rplc Hyd Sctr, Rds&Infst				
48	5734078	Helms - Install Pump/ Load Center at T3A	Mar-2013	$ 843	$ 1,187
Subtotal Completed Projects Except Crane Valley Dam and Multi-Year				**$ 117,573**	**$ 99,445**

In essence, PG&E does not do a good job of estimating costs of hydro projects.

Moreover, several individual projects ranging from the small to the large stand out as at a minimum grossly inefficient if not completely imprudent. Even if not deemed imprudent, management should not get a full 10.4% ROE on this overly expensive work. Here are a few examples:

- PG&E failed to drain Lake Nora properly so that it would dry out enough to construct a 50-foot walkway by the end of the season in 2011. The mistake meant that the walkway took an extra year to build and ended up costing $1.532 million ($31,000 per foot) instead of its original already high estimate of $949,000 ($19,000 per foot), because the lake had to be drained twice – once improperly and a second time properly.

- The failure to measure properly so that the cooling water system upgrade at Helms resulted in the system's rejection because it didn't fit into the space it was designed for.

- A whole series of problems at the $127 million Crane Valley Dam seismic replacement – many of which centered around attempting to build a local quarry without having the expertise to do it correctly, wasted tens of millions of dollars, as well as not hiring experts on other permitting issues.

TURN discusses these troubling projects more in depth in Sections 4-7 below and provides our recommended adjustments.

4. Crane Valley Dam Rebuild

The Crane Valley Dam Seismic Rebuild was identified in the 2011 GRC with a cost of about $63 million. The cost increased to a forecast of $149,784,000 in this rate case.[14] The project ultimately came into service at $127,428,000.[15] It was operational on

[14] The cost is summed over two planning orders, 5724979 and 5746543

[15] TURN DR 33-01.

October 29, 2012. Attachment 3 contains an excerpt from PG&E's workpapers specifically related to this project, and Attachment 4 is the response to TURN DR 33-14 regarding the project.

There were significant problems associated with quarrying 75% of the rock for the project. PG&E identified a number of cost increase drivers that raised the forecast cost by $76.5 million. Approximately $46.8 million of the increases were projected to be related to the quarry. The initial quarry had to be redesigned ($9.4 million original forecast); PG&E's original permit for the project lacked adequate areas to stockpile materials, adding $6.5 million to the cost to re-permit; rock processing was more expensive because more material was rejected and good rock was deeper in the quarry than planned ($12.5 million), and there was a 10 month delay in the construction season (originally 12 months) for a number of reasons, most particularly the quarry issues ($20.0 million). Unforeseen (but apparently not excessive in PG&E's view) regulatory costs contributed $14 million, and the remaining $10 million resulted from other issues.[16]

PG&E identified a potential savings of approximately $20 million by importing additional rock and quarrying less on site.[17] This savings was not included in PG&E's estimate, but was indeed realized and was the major reason for the reduction in cost to $127 million.[18]

Under lessons learned, PG&E stated the following:

1. Lack of experience on quarry development and operation. Our lack of expertise on quarry development and operation, as well as planning decisions made based on limited geotechnical data, resulted in geotechnical findings during the construction phase that caused rock production issues, which translated into costly increases in rock processing and very significant schedule delays:

   Lessons Learned:

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[16] The discussion is summarized from PG&E-6 Workpapers 2-508 to 2-511. The full document is Attachment 3

[17] PG&E-6 Workpaper 2-508.

[18] TURN DR 33-14(f).

Early on, and during both planning and construction, engage expert advise [sic] and consulting, including retaining an Engineering of Record (EOR) firm dedicated to quarry planning and design or negotiate a contracting structure that unequivocally assigns the design and operation of the quarry to the prime contractor.

Conduct a value-engineeering workshop, with participation of expert consultants and practitioners, to analyze and critical [sic] proposed contracting schemen, design of temporary facilities, risks, and potential constructability and operations issues.

2. Available project footprint was very limited. Because the project is located within National Forest lands, the minimum project footprint was developed to reduce the impact on natural resources. However, as the quarry required more land for stockpiling due to increasing waste production factors, additional acreage was necessary, which is requiring a long lead-time for permitting tasks.

Lessons Learned

Permit project area with sufficient spare areas to manage unforeseen footprint needs. Phase footprint development as needed to avoid impacting more areas than necessary.[19]

The reason for PG&E's failure to acquire adequate engineering expertise for the quarry was explained as follows:

> During the planning of the project, the project team, based on available geotechnical information and preliminary discussions with Kiewit and Parsons, did not foresee that the construction and operation of the quarry would turn out to be such a complex task. Thus, the need for additional expert advice during construction planning was not identified. The contractor was expected to have the necessary expertise to manage the temporary quarry facilities. This expectation was not met. [20]

In other words, PG&E thought it did not need expertise to do a job that it was completely unfamiliar with.

[19] PG&E-6 Workpaper 2-512.

[20] TURN DR 33-14(h).

Nevertheless, the actual cost of the quarry turned out to be $22.6 million, as opposed to the $46.8 million originally estimated,[21] in large part due to the rock imports.

Based on all of this information, TURN recommends the following:

1. PG&E's 2014 TY GRC cost for this project should not be based on its forecast of $149,784,000, but should start with actual costs of $127,428,000.
2. TURN recommends a permanent disallowance of $10 million for the project.

This disallowance is based largely on the schedule expansion that arose from problems with the quarry and with the lack of appropriate up-front engineering and oversight admitted by PG&E that caused the quarry problems to have such a large impact. Most of the disallowance should be considered to reflect AFUDC and additional project management and oversight costs resulting from the extended schedule.[22] TURN would have recommended a larger disallowance had PG&E not imported additional rock to regain a portion of the schedule and reduce cost.

We consider the issue of unfamiliarity with regulation that PG&E identified in its workpapers, to be management inefficiency, but it appears to have only caused a low cost estimate rather than an increase to the actual costs incurred or to the duration of the schedule, so we do not propose a disallowance in this area.

Therefore, TURN recommends that this project be allowed at $117,428,000.

5. Lake Nora Walkway (5720649)

One would never think that building a 50 foot walkway out into the middle of a lake to replace an old one would cost $1.5 million. Even at $1.5 million, it is not a large project, by comparison to many of the other hydroelectric projects, much less the range of other generation and electric and gas distribution projects at issue in this GRC. But sometimes,

[21] TURN DR 33-14(d)

[22] See PG&E's estimate of $2 million per month for schedule extension. TURN DR 33-14(f)

we need to use small projects as teachable moments about the relationship of rate of return regulation to value as well as cost.

The original estimate was about $400,000 in the TY 2011 GRC. It was increased to 949,822 in January 2011, and included in PG&E's workpapers in this GRC.[23] The cost was revised to $1,625,000 in PG&E's rate case filing, and the plant was ultimately completed for $1,532,000.

PG&E tells the story as follows:

> Prior to beginning construction, the lake had to be dewatered. Unfortunately, the lake water could not be drained through the penstock due to turbidity concerns. The lake was drained to the maximum extent possible and was allowed to dry over the course of several weeks. Due to the lake draining issues, construction was delayed to the point where there was insufficient time left to replace the walkway before the rainy season. Therefore, the construction had to be postponed to 2012. This delay required notification to all permitting agencies and FERC. In 2012, a different approach was adopted to dewater the lake which included draining the lake through penstock initially to a lower level followed by pumping the residual water into a settling tank prior to sending it down the penstock. This approach was effective in draining and drying the lake in a reasonable timeframe. Construction proceeded as planned and was completed by the end of September 2012.[24]

So PG&E drained the lake but didn't do it the right way. During the winter, the lake of course filled back up again and had to be drained again (including saving the fish and turtles a second time), using a better method. Meanwhile AFUDC accrued on the costs that were incurred in vain, and PG&E wants ratepayers to pay for these excess costs with a return over decades. TURN recognizes that PG&E had to do more work to drain the lake properly than it originally thought, so we allow a figure that is higher than its original $949,000 estimate, but this series of events and decisions cries out for a disallowance.

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[23] PG&E-6, Workpaper 2-460. TURN DR 33-16 indicated that PG&E filed the wrong workpaper and provided information supporting the newest cost estimate in DR 33-16.

[24] TURN DR 33-16. Attachment 5 is the data request and a public excerpt from the confidential attachment to the data request. We conferred with PG&E and agree that the excerpt here does not include material that PG&E believes is confidential.

To figure out the appropriate disallowance, PG&E's workpapers (as documented in TURN DR 33-03 Attachment 1) show CWIP at the end of 2011 as $438,000. A significant portion of this cost was simply lost and done over. TURN recommends starting with the actual cost of $1,533,000[25] and disallowing $375,000 ($350,000 of 2011 costs plus AFUDC). The allowed amount should be $1,158,000, which is $418,000 less than PG&E's forecast. And we still have a walkway that costs an astounding $23,000 per foot – a figure in line with some of the worst of military contracting.

6. Helms – Upgrade Cooling Water System (5726821)

This is a project for $1,389,000 (scheduled for October 14) where PG&E spent an inordinate amount of time and money designing something that didn't fit in its space (a variable frequency drive).

PG&E's business case for this project was authorized for $812,000 in October 2009 for an on-line date at the end of 2010. PG&E has already spent $812,000 as of the end of 2012 and hasn't bought or installed the equipment yet! PG&E has since requested additional money. Attachment 6 provides the relevant excerpt from PG&E's workpapers.

The project is allegedly justified because "The Helms Cooling Water Pump controls are inoperable. Helms powerhouse vibration and time have degraded the controls to a point where they are unusable. Switches have failed in the on position resulting in a continusous run condition on all pumps regardless of cooling loads."[26]

For a project with such a dramatic story as to why it was needed, PG&E appears to have been dilatory throughout the process. TURN DR 33-24 (Attachment 7), and its attachment shows the numbers. PG&E set up a planning order for this project in 2006[27] and by October 2009 had spent $126,000 in bits and pieces over three years. PG&E then spent $135,000 over the two months of November and December of 2009 so that it had

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[25] TURN DR 33-16.

[26] PG&E-6, Workpaper 2-664. (Attachment 6)

[27] TURN DR 33-24 Attachment 1.

spent $261,000 in total. Then PG&E did very little, occasionally spending a few thousand dollars at a time until June 2010. The project was then dormant, accruing AFUDC, until early in 2011, when PG&E rejected the design in March.

In its supplemental response to DR 33-24, PG&E said it spent $392,000 to 90% design and the scope change, which occurred on March 1, 2011. This is consistent with the ledger.

After the rejection, there was a little bit of spending in early 2011, followed by $140,000 in December, for a total of $701,000. But then the project ground to a halt again. PG&E forecast it would spend $144,000 in 2012. It actually spent only $111,000 and 58% of what it spent in 2012 was AFUDC.

PG&E claims that the rejection of the project only added $85,000 to the cost. But the cost started out much higher because of the leisurely nature of project spending. No one seemed to care about it from September 2007 to October 2008, from January to June 2009, and from July 2010 through February 2011. Virtually nothing was spent during those periods. And 2012 spending was extremely low – with AFUDC exceeding direct costs. All for a project justified because the controls had purportedly <u>already</u> failed.

TURN recommends that this project be authorized for $887,000 – the original $812,000 estimate from the end of 2010 plus three years of inflation at 3% - reflective of a more industrious construction schedule rather than an inexplicably leisurely one. Piling up AFUDC, not designing the project to fit the space in the first place, rejecting designs, and generally not getting the work done on something that is allegedly urgent is not prudent. TURN disallows $502,000. A small project, perhaps, but hopefully it is a bigger lesson in inefficiency and imprudence.

7. Project Portfolio Management Tool

Ironically, the last specific project we would remove from service is the Project Portfolio Management Tool (capital plus expense). The software program is projected to cost $2,000,000 in 2014 and is projected to be fully in service in 2015 (though partly in

2014).[28] The PPMT is not being used for its purpose of prioritizing hydro capital projects – which should have had the potential for saving the cost of installing the program – so it is not being used effectively. Ratepayers should not pay for it until it starts saving money for them.

8. Other 2012 Projects

TURN does not recommend truing up other projects completed before March 31, 2013 on Table 13 to actual costs but rather recommends leaving the forecast costs in this rate case. The use of the forecast does not provide a permanent disallowance, but temporarily reduces carrying costs arising from the management inefficiency that allowed the costs of other completed projects to increase by 18% from PG&E's forecasts, which are in turn far above 2011 TY GRC forecasts in many cases.

III. Diablo Canyon

A. Introduction and Summary

PG&E spent $314 million in expenses on Diablo Canyon in 2011. It forecasts an increase to $415 million in TY 2014. TURN has reviewed PG&E's request from a different perspective than PG&E's presentation (individual projects, etc.) and DRA's analysis (at the Major Work Category Level). We recommend an expense level (if PG&E's outage ratemaking were to be used) of $369 million. Note that TURN made no adjustments to the cost of the Fukushima program identified by PG&E.

TURN's first division of costs was between refueling costs (dealt with in Section C below) and other operational costs.

In the operational area, we looked at a few individual items (obsolete inventory, Nuclear Regulatory Commission fees, and the Nuclear Energy Institute), but we focused our

[28] It actually had a 100% cost overrun and came partially into service in June 2012. Our recommendations regarding 2012 forecast cost below would remove that cost as well.

analysis of operational costs at the level of project costs as a whole and labor costs as a whole.

Our review of project costs shows that this is the second rate case when PG&E asked for large amounts of project costs in the Test Year, where they could be escalated over the whole rate case cycle. The requested money was not spent in 2011. We normalized project expense requests over 2011-2014.

Our detailed review of labor costs enabled us to demonstrate that ratepayers do not need to pay for the new staffers that PG&E wants to hire in advance of retirements, because there are embedded costs of vacancies and because new hires would avoid hiring temporary refueling outage workers, and because PG&E is hiring some relatively senior people who do not need long training periods. The labor cost review also revealed a disturbing trend in rising overtime – outside of refueling periods – in TY 2014 relative to earlier years. TURN makes an adjustment of about $7 million for excess overtime.

In refueling, we found completely unexplained increases in costs above those of recent past outages, even while PG&E was claiming that costs were dropping as outage durations were falling. We recommend a reduction based on the average of three recent past refueling outages, rather than PG&E's decision to develop inaccurate forecasts from scratch that are inconsistent with their own witness' testimony. In the process of looking at refueling outages, we also found that PG&E asked for the cost of the TY 2014 steam generator inspection both as part of refueling costs and as a separate line item that would recur throughout the rate case cycle – quadruple counting a single 2014 cost.

TURN's recommended and alternative ratemaking for outage costs are shown in Table 14: Comparison of TURN and PG&E Expenses for Diablo Canyon ($'000)Table 14, along with a comparison of TURN's and PG&E's recommended expenses.

Table 14: Comparison of TURN and PG&E Expenses for Diablo Canyon ($'000)

	Cost $'000		
PG&E recommendation	415,500		
Plus 2/3 of second outage	37,400		
PG&E cost with 2 full outages	452,900		
TURN Adjustments			
normalize new project spending	(16,310)		
remove 58 new hires	(9,437)		
reduce non-outage overtime	(6,925)		
remove double-counted steam generator inspection from second outage refueling cost	(5,000)		
normalize remaining steam generator inspection in base cost	(3,212)		
normalize obsolete inventory	(2,017)		
reduce NRC Fee escalation	(1,326)		
50% of Nuclear Energy institute to shareholders instead of 4%	(429)		
Reduce refueling costs (2 outages)	(7,266)		
Sum of TURN 2014 adjustments	(51,922)		
TURN cost with 2 outages	400,978		
minus 2/3 of second outage (TURN cost)	(31,584)		
TURN with PG&E outage ratemaking	369,394		
PG&E > TURN assuming PG&E Outage ratemaking	46,106		
TURN alternative normalized outage ratemaking	365,446		
PG&E > TURN alternative	50,054		
TURN RECOMMENDED "Pay as you Go" outage ratemaking			
	figures below in 2014 dollars		
	2014	2015	2016
TURN outages in year they happen	400,978	353,602	353,602
PG&E > TURN	14,522	61,898	61,898

TURN recommends a reduction of about $7 million to capital costs to prevent double-recovery of the replacement transformer supercooler as a TY 2011 expense and a TY 2014 capital project and to defer low-priority paving costs until other uncertainties regarding future plant operations are resolved.

Finally TURN proposes a slightly different accounting mechanism for costs of the Independent Spent Fuel Storage Installation (ISFSI), which is similar to but not the same as PG&E's mechanism. We also propose modifications to PG&E's ratemaking mechanism for money received from the Department of Energy spent fuel settlement that balances the interests of bundled service and other PG&E customers appropriately and balances the intergenerational equities of bundled service ratepayers who have been paying for the ISFSI.

B. Diablo Canyon Operational Expenses

1. Project Spending

PG&E's project spending has been concentrated in the Test Year in its last two rate cases. In TY 2011, project spending was forecast to be $21,415,000 in 2009, $7,755,000 in 2010 and $23,590,000 in 2011. Actual project spending in 2011 was $9,978,000 (including IFSFI fuel loading) for comparison to the TY 2011 forecast.[29]

Table 15 shows total project spending from 2011-2014, excluding Fukushima costs and IFSFI expenses (which are proposed to be capitalized starting in 2014 by both PG&E and TURN). (See Section E).

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[29] PG&E-6 Workpaper 3-61.

Table 15: PG&E's Recorded and Forecast Expense Projects and Major Maintenance ($'000)[30]

2011	$ 8,609
2012	$ 5,798
2013	$ 2,400
2014	$ 27,349
TURN recommended normalized average	$ 11,039
TURN increase from 2011	$ 2,430
PG&E increase from 2011	$ 18,740
PG&E>TURN	$ 16,310

PG&E has provided no evidence that the 2014 level of expenditure will recur throughout the rate case cycle,

TURN rtherefore ecommends that project expenses be normalized by averaging PG&E's 2011 recorded and 2012-2014 forecasts. The recommended amount is $11,039,000, a reduction of $16,310,000.[31]

2. Labor Costs

There are considerable problems with PG&E's staffing estimates, which cause TURN to make a significant reduction to personnel costs. TURN asked a series of questions about staffing, vacancies, hours worked, overtime, and similar issues on both a recorded and forecast basis (DRs 58-01 through 58-06 and 76-03). The adjustments are complicated, and we provide a methodological appendix (Attachment 9) explaining how we used all of the data that PG&E gave us to reach our conclusions.

1. There is a small adjustment to outage labor caused by TURN's averaging of the cost of three outages (1R16, 2R16, and 1R17) in real dollars to forecast the 2014

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[30] PG&E-6, Workpaper 3-61.

[31] TURN looked at several specific sub-components of project expenses, including concrete and underground cabling costs (DRs 58-18 and 58-19). The reductions that would be justified using long averages for the fluctuating costs of these types of recurring project-related expenses are consistent with the overall reductions in project costs here.

outage cost and amounts to about $670,000 per outage. This is discussed in Section C below.

2. PG&E claims that it will add 58 new hires in advance of retirements and wants ratepayers to pay $9.4 million. TURN believes that this cost is unjustified and that most is covered by embedded costs of excess staffing in base year 2011 and labor cost savings associated with refueling outages.

3. PG&E's forecast for hours worked shows that overtime spending per employee is expected to burgeon in TY 2014; TURN adjusts overtime during periods unrelated to refueling outages down to 2008-2012 averages of non-refueling periods. This overtime reduction generates an adjustment of $7.1 million.

a. "Me and My Shadow": PG&E's new hires will not really cost more than current rates

First, PG&E claims to add 58 staff people in advance of retirements, but as retirees retire, the 58 staffers effectively do not take their jobs. The 58 extra staffers remain. DRA correctly removes these staffers, but we provide further information in support of this adjustment.

We remove PG&E's upward adjustment because (1) a large portion of the new staff is covered by embedded costs of excess staffing in 2011, (2) since senior staff need less training, fewer than 58 new hires are needed to "shadow" retiring workers, and (3) PG&E's documentation shows that new staffers reduce the embedded cost of temporary outage workers – a fact that PG&E has failed to take into account.

When an existing PG&E staffer retires PG&E's GRC cost-estimation world assumes that either (1) new people are hired to replace the retirees and the "shadows" continue to shadow until "the appropriate level of experience and knowledge transfer is achieved to assure well-trained staff,"[32] (or (2) a "shadow" takes the place of a retiree but a new person is added to "shadow" someone else instead so that the position never goes away.

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[32] TURN DR 58-06e. (included in Attachment 8).

In addition, none of the new hires are assumed to reduce overtime for themselves or other staffers; they are assumed to be totally unproductive in that respect.[33]

All of these conventions for calculating the cost of hiring in advance of attrition make little sense given that PG&E calculates its wages as if 50% of new hires are entry-level but 30% are mid-level and 20% are senior level. (TURN DR 58-06b) It makes no sense to mid-level or senior level staffer would have to "shadow" a near-retiree for years before providing any useful work to the company. Either PG&E's pay estimate is wrong or PG&E's claim about the importance of shadowing for years at a time is wrong, or both are wrong to some degree. TURN recommends removing 25% of the cost because mid-level and senior staff that PG&E assumes that it will hire will need to be trained for shorter periods of time in specific conditions at Diablo Canyon rather than the entire gamut of nuclear plant work.

Furthermore, additional problems with PG&E's analysis are created by the fact that in base year 2011, excluding the outage months, PG&E's vacancy data shows that was overstaffed by 25 positions on average.[34] So PG&E is asking ratepayers to pay for 25 extra employees in the base year and 58 new positions. The general fact that PG&E was overstaffed in 2011 is also confirmed by looking at PG&E's actual staffing for 2011 and forecast hiring data for 2014,[35] though the numbers are slightly different than the 25 extra employees identified in the vacancy analysis. Even assuming that PG&E hires everyone it wants, PG&E's forecast of staff excluding temporary outage workers in 2014 averages only 42 positions above 2011 actual positions instead of 58.

The other fact we find from looking at PG&E's forecast for 2014 employment versus 2011 actual employment is that PG&E forecasts 87 FTE of temporary outage workers in 2014 despite having two outages while hiring 83 FTE in 2011 with one outage –a

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33 TURN DR 58-06f. It is understandable that new staff members require outage experience and might not reduce outage overtime, but routine, non-outage overtime could be reduced.

34 TURN DR 58-04.

35 TURN DR 58-02.

difference of only 4 outage workers. PG&E included 41 FTE for each of the two outages and another 6 FTE for other months (i.e., between the two outages).[36]

While PG&E assumes (in its staffing analysis in TURN DR 58-02 but not in its cost estimation) that the new workers will reduce the need for temporary workers during outages (and thereby lower outage labor costs), the assumption during non-outage periods is the exact opposite -- the only function to be performed by these new workers is to shadow other permanent workers. According to PG&E, the new workers simply stand around watching people and getting no additional work done except during outages when they become productive.

The cost of the temporary workers no longer hired during outages is an embedded cost included in outage labor costs and must be credited against the salaries of the pre-retirement new hires. We have calculated a credit for the outage work that these new hires are doing on a normalized basis (39.96% of days in outage-influenced months). The actual credit in 2014 would be greater with two outages.

When all three of these facts are taken into account, the end result is that PG&E can hire 43.5 workers if it wants (58 workers adjusted downward by 25% to acknowledge that senior workers need a shorter training period), but the ratepayers should not pay a dime for them. And that assumes that the new workers do not do a lick of productive work except during outages. This cost should simply be removed.

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[36] Calculated from DR 58-02.

Table 16: Offsets to Cost of New Hires Proposed by PG&E

58 new workers per PG&E	$	8,700
Escalate to 2014 dollars	$	9,438
25 embedded excess positions in 2011	$	(4,068)
14.5 (25%) of 58 positions because senior hires need less training	$	(2,359)
Less normalized outage work done by remaining 43.5 workers *	$	(3,193)
Reductions	$	(9,620)
Conclusion- no additional costs are needed		
*Normalized to average outages from 2008-2012.		

b. Overtime Is Increasing

In addition to assuming that it has too many staff in its rate case, forecast labor costs are rising in real terms faster than forecast numbers of staff. Table 17 tells the story.

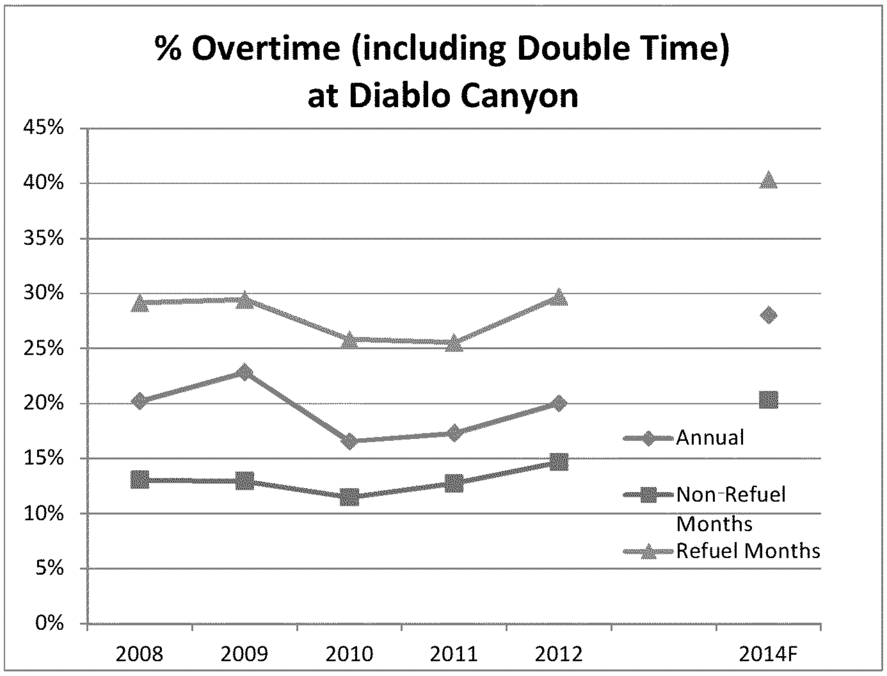
Table 17: Diablo Canyon Labor Costs Rising More Rapidly than Staffing

	2011	2014	Increase
Labor (PG&E)	149,069	208,632	
Remove MWC JV (IT)	(749)	(1,005)	
Remove second outage for comparability		(26,484)	
nominal subtotal	148,320	181,143	
de-escalate to 2011 $	148,320	166,984	12.58%
Employees (PG&E)	1,442.3	1,489.4	3.27%
Remove second outage temporaries		(42.3)	
Adjusted employees	1,442.3	1,447.1	0.33%
Permanent employees (PG&E)	1,359.5	1,402.5	3.16%

Permanent staff increases were 3.2% from 2011 actual to 2014 recorded (from an average of 1360 to 1403) while total staffing rose by even 3.3% despite a second outage or 0.3% if second outage temporary workers are removed. Meanwhile labor costs rise by 12.6%, even subtracting the labor costs of the extra outage.

The reason for labor cost outstripping staffing is PG&E's forecast of growth in overtime from the historical period to TY 2014.

Figure 1: Percentage of Overtime at Diablo Canyon 2008-2012 Actual and 2014 Forecast



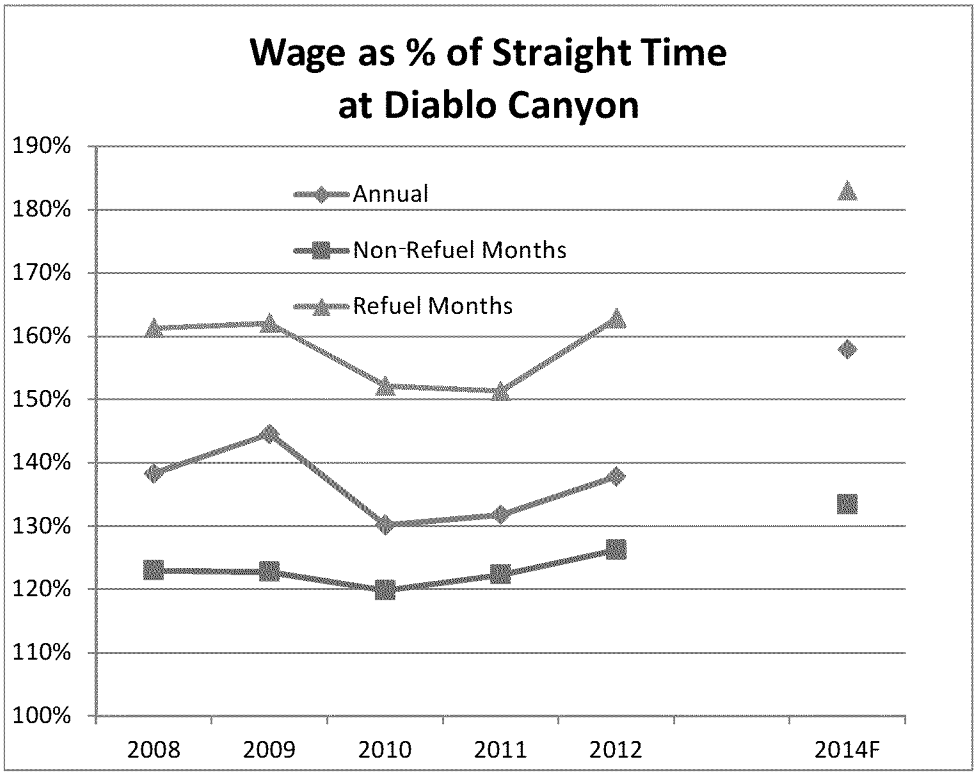
The 2014 forecast has considerably more overtime as a percentage of total hours than in other years. In 2009, the last two-outage year, PG&E experienced 23% annual overtime and 29% overtime during periods influenced by refueling. In 2014, PG&E expects 28% annual overtime and 40% overtime during the refueling period.

Overtime is not all concentrated in the outage months. PG&E's employees worked from from 11-15% overtime and double-time in non-refueling months of 2008-2012. This figure increases to over 20% in PG&E's 2014 forecast.

In other words, PG&E employees were paid for 120-126% of straight time (about 48-50 hours per week straight-time equivalent) in non-outage months of 2009-2012 (assuming each overtime hour at 150% of straight time and each double-time hour at 200% of straight time) versus a forecast that they will be paid for about 133% of straight time (53 hours per week straight-time equivalent) in 2014.[37]

[37] Outage figures are even higher, but we deal with them through a different averaging process in Section C below.

Figure 2: Wages Paid as Percentage of Straight Time at Diablo Canyon 2008-2012 Actual and 2014 Forecast



This extra money amounts to $7.1 million per year (normalized). The calculation is given below.

Table 18: TURN Adjustment for Increased Non-Outage Overtime

All labor per PG&E	$	208,632
2 outages labor per PG&E	$	(52,968)
Non-outage labor per PG&E	$	155,664
Remove MWC JV - not adjusted*	$	(1,005)
New hires per PG&E (adjusted separately)	$	(9,438)
Remainder non-outage labor per PG&E	$	145,221
Adjustment for increased non-outage overtime		4.77%
Reduction for increased non-outage overtime	$	(6,925)
TURN base staff after non-outage overtime	$	138,297
TURN new hires as adjusted	$	-
Add back MWC JV	$	1,005
Non-outage labor per TURN	$	139,302
TURN 2 outages labor	$	51,632
TURN labor 2014	$	190,934
TURN labor reduction	$	17,698
* IT staff largely not at Diablo Canyon, not included		
in non-outage overtime adjustment		

c. Total TURN Labor Adjustments

Table 19 gives TURN's total labor adjustment (except for PG&E labor included in special projects).

Table 19: TURN Total Labor Adjustment ($'000)

Total labor (PG&E)	$	208,632
Minus new hires	$	(9,438)
Minus extra non-outage overtime	$	(6,925)
Minus refueling labor adjustments	$	(1,336)
Total TURN labor adjustments	$	(17,698)
Total TURN labor	$	190,934

To show the relationship of PG&E's original labor costs and TURN's adjustments to 2011 labor, we prepared Table 20.

Table 20: Comparison of TURN and PG&E Labor Forecasts ($'000)

		increase over 2011 escalated	
	$'000	$'000	%
PG&E 2014 less one outage	$ 182,148	$ 20,440	13.7%
TURN 2014 less one outage	$ 165,118	$ 3,409	2.1%
2011 recorded nominal dollars	$ 149,069		
2011 with labor escalation to 2014 $	$ 161,708		

Adjusted for the extra outage, PG&E's labor figures are 13.7% above 2011 escalated to 2014 dollars, while TURN's are 2.1% above 2011 recorded and escalated.

3. Normalize Obsolete Inventory

PG&E has now argued for two rate cases in a row that it will suddenly write off a collection of obsolete inventory worth $3 million in the Test Year (and presumably in the two attrition years as well).[38] The argument was wrong the last time, and it is likely to be wrong this time. PG&E's history of obsolete inventory write-offs is given in Table 21 from TURN DR 11-17).

Table 21: Historical Obsolete Inventory Write-Offs 2007-2012 ($'000)

2007	1,184		
2008	999		
2009	50		
2010	3,275		
2011	33		
2012	557		
TURN Forecast (6-year average)	1,016		
increase from 2011	983		
PG&E Forecast	3,000	increase over 2011	
	3,033	including 2011	
PG&E > TURN	2,017		

DRA recommended zero. TURN agrees that zero could be a reasonable number in light of PG&E's having requested $9 million for obsolete inventory in the last GRC cycle,

[38] TY 2011 GRC, PG&E-5, Workpaper 4-164.

while writing off $0.6 million in 2011-12 and only $6.1 million in the entire period from 2007-2012.

However, TURN offers an alternative recommendation of a six-year average of 2007-2012 recorded, This figure would be $1,016,000, which is an increase of $983,000 over the 2011 recorded amount. PG&E's forecast would be reduced by $2,017,000.

4. Nuclear Regulatory Commission Fee Escalation

PG&E projects an increase in NRC fees by $1,571,000 from $12,242,000 in 2011 to $13,826,000 in 2014. It forecast a 12% increase from 2011 to 2012 based on the escalation rate that was observed from 2007-2010[39] (ignoring the inconvenient fact that 2011 costs were $1 million below 2010). The explanation in DR 58-08 says that costs are raised further in 2013 (when they were in fact not) and raised again in 2014 by 3%.

Table 22 provides historical and PG&E forecast data from TURN DRs 58-08 and 76-01.

Table 22: Nuclear Regulatory Commission Fees and Inspection Costs ($'000)

	Fees	Inspections	Total
2007	8,259	1,307	9,566
2008	8,401	2,135	10,536
2009	9,484	2,321	11,805
2010	9,650	3,615	13,265
2011	9,291	2,951	12,242
2012	9,579	2,676	12,255
4-yr average 2009-2012			12,392
TURN Recommended			12,500
PG&E Forecast			
2012	10,409	3,305	13,714
2013	10,153	3,271	13,424
2014	10,457	3,369	13,826
PG&E>TURN			1,326
Source: TURN DRs 58-08 and 76-01			

[39] TURN DR 58-08

The historical data show very little change from 2009-2012, with the exception of the relatively high number in 2010. The big jump forecast by PG&E in 2012 never occurred. Therefore, TURN recommends $12,500,000 for this cost, a four-year average of 2009-2012 of $12,392,000, rounded up by $108,000 to provide limited escalation. TURN's estimate is $1,326,000 less than PG&E's.

5. Nuclear Energy Institute

PG&E requests 96% of the cost of the NEI in rates for 2014. The only disallowance that PG&E will take is that for direct costs of lobbying. In support of this claim, PG&E states:

> There are significant benefits for customers associated with PG&E's participation in NEI. NEI is a major industry focal point for the multitude of science, technology, emergency planning and security issues facing the nuclear industry. NEI works with the nuclear industry to develop industry standard solutions to regulatory orders that will be acceptable to the NRC. These industry standard industry solutions help provide clarity and consistent implementation of NRC requirements across the industry and, by so doing, helps contain customer costs.[40]

TURN has consistently proposed to allow 50% of the costs of NEI in rates because of the very reasons that PG&E cites here. But TURN opposed allowing the other 50%. Much of NEI's work – beyond what is narrowly described as lobbying – relates to the influencing of public policy through public relations, advertising, and similar advocacy activities that would not be permitted in rates if a California utility did the same work directly rather than through an industry trade association.

Moreover, the Commission has found all the way back to 1992 that organizations that provide information on nuclear power have a significant burden:

> TURN recommended a $62,000 reduction for Edison's membership in the Nuclear Management and resource Council, which TURN characterized as an advocate for nuclear power. … Edison replied to TURN by arguing that the purpose of the NMRC is not to promote nuclear power, but to inform members "on matters pertinent to nuclear power and nuclear energy development." … We

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[40] PG&E-6, page 3-33.

> reject Edison's conclusion that the NMRC's purpose excludes advocacy. The NMRC may say that it only provides information, but the evidence in this proceeding does not overcome our suspicion that the NMRC does encourage nuclear power.[41]

Looking at NEI through this perspective, while PG&E included a letter from NEI in its workpapers referencing the NEI 2011 annual plan deliverables.[42] However, when asked by TURN to provide those deliverables, PG&E has been unable to do so. [43]

NEI explains its own mission succinctly:

> **NEI's Mission:** The Nuclear Energy Institute (NEI) is the policy organization of the nuclear energy and technologies industry and participates in both the national and global policy-making process.
>
> NEI's objective is to ensure the formation of policies that promote the beneficial uses of nuclear energy and technologies in the United States and around the world.[44]

It should first be noted that questions have been raised regarding lobbying disclosure forms. Questions have been raised regarding the method of disclosure used by NEI that focuses on federal lobbying. NEI's method of disclosure excludes "grass-roots" lobbying activities.[45] The Commission has stated in previous cases that it does not want ratepayers to fund these these "grass-roots" activities,[46] even if they are not called "lobbying."

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[41] D. 91-12-076, pp. 66-67.

[42] PG&E-6, Workpaper 3-73.

[43] TURN DR 58-22. This document is included in Attachment 15, which also contains many other documents from NEI's website and other locations referenced in this section.

[44] http://www.nei.org/aboutnei/

[45]Greenwire, Lobbying Disclosure Forms Don't Tell Full Story www.eenews.net 10/26/2009.

[46] D. 96-01-011, p. 154.

The Commission also has a very clear statement dating back to 1996 (in the context of the Edison Electric Institute - EEI) that it does not want to fund institutional advertising and public relations:

> We also exclude the portion of EEI dues related to institutional advertising and public relations, which include activities associated with public opinion research seeking to enhance the image of EEI and its member companies, because this type of advertising does not fall within the types of advertising we permit ratepayers to fund. (See D. 86794 81 CPUC 49, 79 (1976).) We are persuaded by the FEA that we should not indirectly approve ratepayer funding of activities through the EEI which we would not approve if Edison were to directly incur these expenditures.[47]

In fact, NEI engages in significant public relations activities that do not fit a narrow definition of lobbying and has created several "grass-roots" front groups to advance its mission. Funding for NEI supports an array of organizations promoting nuclear power. Three organizations are not mentioned on the NEI website but either identify NEI as a funder or sponsor or have been tied to NEI through other government documentation. These are Clean and Safe Energy Coalition ("founded and solely funded by the Nuclear Energy Institute") , Clean Energy America, and Alliance for Energy and Economic Growth (sponsored jointly by NEI and other organizations such as the US Chamber of Commerce).[48] Given the Commission's past rejection of ratepayer funding for "grass-roots" lobbying, there is little question that the Commission would deny any PG&E request to directly fund similar activities. The NEI should be treated no differently than PG&E or EEI.

In Decision 96-01-011, the Commission specifically said it did not want to fund public opinion research by an organization such as the Edison Electric Institute. There is no

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[47] D. 96-01-011, pp. 154-155.

[48] http://casenergy.org/our-coalition/about-the-coalition/ ; see also http://www.ucsusa.org/news/press_release/christine-todd-whitman-patrick-moore-0415.html; http://www.cleanenergy4america.org/clean-energy-mission.html http://www.yourenergyfuture.org/aboutUs.htm and http://www.yourenergyfuture.org/files/2010/AEEGPrincipals.pdf ; http://www.cleanenergy4america.org/ This web page states: "Clean Energy America is sponsored by the Nuclear Energy Institute."

reason why PG&E ratepayers pay should to conduct polling and opinion research on nuclear power through NEI.[49] Public opinion research is a cornerstone of NEI's activities with surveys conducted on a regular basis about 6 months to a year apart.

PG&E ratepayers should not pay for public relations – glossy flyers to support nuclear power.[50]

PG&E ratepayers should not pay to develop image advertising[51] (print and radio, including past sponsorship of the Washington Capitals National Hockey League team)[52] that the Commission would summarily disallow if PG&E were to directly ask for ratepayer money for such advertising.

TURN opposes the use of ratepayer money to publicize and promote the opinion that nuclear energy is a required piece of any climate change strategy and touting the need for new nuclear plants. [53] It is also inappropriate for PG&E ratepayers to pay for a public

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49 See http://www.nei.org/resourcesandstats/Documentlibrary/Publications/Perspective-on-Public-Opinion/Perspective-on-Public-Opinion,-April-2013. The description of this item on NEI's "Resources and stats" web page says "Latest public opinion data shows an upward trend in public's favorable attitudes toward nuclear energy."

50 http://www.nei.org/resourcesandstats/documentlibrary/protectingtheenvironment/flyers/nuclear-energy-powering-sustainable-economies-worldwide and http://www.nei.org/resourcesandstats/documentlibrary/protectingtheenvironment/flyers/nuclear-energys-indispensable-role-in-global-climate-change-strategy.

51 http://www.nei.org/resourcesandstats/Documentlibrary/Reliable-and-Affordable-Energy/Advertising/Print-Ad,-Clean-Air,-2013,
http://www.nei.org/resourcesandstats/Documentlibrary/Reliable-and-Affordable-Energy/Advertising/Print-Ad,-Jobs,-2013
http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/advertising/ad-on-production-of-nuclear-energy-around-the-clock-2010/

52 Radio Ad, MD and VA, Washington Capitals, 2009-2010 - "MD and VA" is a 30-second ad that will air during the local radio broadcast of all Washington Capitals games in the 2009-2010 season. Game audio will also be streamed live on the team's official Web site, washcaps.com. The ad promotes the "nuclear. clean air energy" message and is part of NEI's corporate sponsorship program with the Washington Capitals. http://www.nei.org/resourcesandstats/documentlibrary/newplants/audio/washington-capitals-radio-ad---md-and-va/

53 http://www.nei.org/publicpolicy/neipolicypositions/ and http://www.nei.org/keyissues/newnuclearplants/needfornewnuclearplants/ and http://www.nei.org/newsandevents/businessleaders (this document not included in attachments because it does not format for printing)

relations campaign, for example, that teaches Belarussian children (who live near the real nuclear disaster of Chernobyl) not to fear nuclear power.[54]

TURN understands that NEI plays a technical role in cost reduction in the industry. That is why we agreed that ratepayers could fund half of its budget despite its rampant advocacy and public relations activities that go beyond PG&E's narrow definition of lobbying and run afoul of Commission decisions and practices dating back 15 to 35 years. But by asking ratepayers to fund 96% of NEI, PG&E is asking the Commission to force ratepayers to subsidize political views repugnant to many ratepayers, through advocacy, public relations, advertising, and other similar activity that the Commission has not allowed for decades.

Therefore, the Commission should maintain its existing policy and only fund half of NEI's costs with ratepayer money. TURN would fund $467,000 (half of the total cost of $933,000 instead of $896,000 – 96% of that cost). TURN's disallowance is $429,000.

C. Refueling Outage Costs

1. Outage Costs

The table below shows nuclear refueling outage costs recorded and forecast (from TURN DRs 58-09 and 11-15 in real and nominal dollars. It shows that there was a period of relatively stable costs in the 16th and 17th refueling periods. However, PG&E's forecast of cost (excluding the steam generator inspection) is almost $1 million higher in 2011 real dollars in 2014 than the highest figure actually experienced in 2009-2012. PG&E claim that it is reducing the forecast in 2014 by $2,939,000 for 10 fewer days of outage than the 1R17 outage in 2012, but even after reduction, the forecast is still higher, and PG&E has never explained why it is higher.

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[54] http://www.nei.org/resourcesandstats/publicationsandmedia/insight/insightaugustseptember2007/belarusianchildrenlearnabcsofnuclearenergy

Table 23: Historical and Forecast Refueling Outage Costs

				Nominal $				2011 $			
Act/Fcst	Outage	Year		Labor	Non-Labor	Total		Labor	Non-Labor	Total	Notes
A	2R15	2009		$18,799	$17,049	$35,848		20,138	18,192	38,330	unspecified amount for SG inspection
A	1R16	2010		$21,539	$23,124	$44,663		22,293	24,003	46,296	includes $4,144 for SG inspection
A	2R16	2011		$23,779	$19,241	$43,020		23,779	19,241	43,020	
A	1R17	2012		$26,020	$21,580	$47,600		25,324	21,054	46,377	add $2,939 to 2R16 for 10 day longer outage
F	2R17	2013		$26,801	$22,227	$49,028		25,386	21,197	46,583	add $2,939 to 2R16 for 10 day longer outage
F	1R18	2014		$26,484	$24,525	$51,009		24,414	22,930	47,344	$2,939 less (10 days shorter)
F	2R18	2014		$26,484	$29,525	$56,009		24,414	27,605	52,019	$2,939 less (10 days shorter), with SG inspection
	average	1R16, 2R16, 1R17						$23,798	$21,432	$45,231	
	TURN average without SG inspection 1R16							$23,798	20,001	43,799	without SG inspection
TURN Forecast											
	1R18			25,816	21,559	47,376					
	2R18			25,816	26,559	52,376					
PG&E > TURN											
	1R18			$668	$2,966	$3,633					
	2R18			$668	$2,966	$3,633					

TURN recommends that the Commission adopt a refueling cost, based on the average of the 1R16, 2R16, and 1R17 actual outage costs in 2011 dollars, excluding the 1R16 steam generator inspection cost. These are the last three recorded refueling outages and include one outage that was 10 days longer than the two earlier ones. The result is a base refueling cost of $47,376,000 before considering the steam generator inspection, which will be subject to normalized accounting.

2. Cost of Steam Generator Inspection; Fix Mathematical Error that Quadruple-Collects the Cost and Normalize Outage Costs

PG&E has two alternative numbers for the cost of the steam generator inspection that will be required in the 2R18 outage. It also included the steam generator inspection cost in two separate places, thereby double-collecting it.

PG&E included the steam generator inspection at a $5.5 million cost as a separate line item applicable to 2014 that would remain in base rates over the entire rate case cycle. However, PG&E also included a $5 million cost of the steam generator as part of its 2R18 outage costs, thus collecting money for four steam generator inspections over this GRC cycle.

We reach the conclusion that PG&E made this mistake by taking an "expense walk"[55] through a number of data requests and workpapers. The cost of the 2R18 outage is $56.0 million according to the response to TURN DR 11-15. One-third of the 2R18 outage (the amount that PG&E is requesting in rates) is $18.7 million according to PG&E's workpapers (PG&E-3, Workpaper 3-11), which ties to the total figure in DR 11-15. PG&E confirms in its response to TURN DR 58-11 that the $56.1 million cost of the 2R18 outage in DR 11-15 includes the cost of the steam generator inspection. However, on the same workpaper that provides for one-third of the 2R18 outage, PG&E includes the full cost of the steam generator inspection in its 2014 request as a separate line item of $5,500,000 applicable to all three years – even though it was also included in the

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[55] Term used by PG&E in PG&E-6, Workpaper 3-11. This workpaper as well as TURN's DRs 11-15, 58-07, 58-09, and 58-11 are included as Attachment 10 (steam generator inspection reference materials). .

outage cost, thus collecting the cost of the one-time event <u>four</u> times over the next three years.

PG&E also presents two different estimates of the cost of the steam generator inspection, $5,500,000 (PG&E-6, Workpaper 3-11) and $5,000,000 (TURN DR 11-15, TURN DR 58-09). We asked for detailed information on steam generator inspections in TURN DR 58-07 Here is PG&E's explanation:

> Total 1R16 cost (includes ECT, data analysis, lancing, manway removal and re-installation, engineering, and nozzle dam scope) was $4,428,086. This cost was reduced to $4,144,465 because of a 3% price reduction with Areva portion of work due to long term contract (contract is now expired). $5.5M cost estimate for 2R18 in 2014 is based on escalating the 1R16 cost ($4,428,086) by about 24% (6% per year).

PG&E provided no explanation as to why escalation of six percent per year was reasonable. We would not even have known that 24% was the escalation amount that PG&E used without asking this data request, because PG&E's application contained nothing but a bare number of $5.5 million. In addition, this is improper double-escalation – increasing the escalation of one item of nuclear non-labor expense more rapidly than general escalation, without reducing escalation on other items that may be rising more slowly. Applying standard nuclear non-labor escalation to the $4,428,000 undiscounted figure from 2010 yields $4,915,000 in 2014 nominal dollars. That figure is close enough to the $5 million estimate in TURN DR 11-15 that we accept the $5 million figure.

TURN recommends normalized accounting for steam generator inspections. Each plant requires an inspection once every three refueling outages, which is once every 4.5 to 5 years with an 18-20-month refueling cycle. With two units at Diablo Canyon, there are two steam generator inspections every 4.5 years, so that ratepayers should be charged for 44.4% of the cost of a steam generator inspection every year. With a $5 million cost, that normalized amount should be $2,222,000, a reduction of $3,278,000 from PG&E's $5.5 million figure. The steam generator inspection cost must also then be removed from the 2R18 cost estimate that PG&E is spreading over 3 years. Removing the steam generator cost from the refueling outage and normalizing it allows TURN to track the main refueling cost outside the normal attrition process, as proposed below and by Ms. Yap.

3. Ratemaking for Refueling Outages

PG&E spreads its version of the second outage cost over 3 years. The net result is a cost of $69.7 million per year for outages in this rate case cycle ($51.0 for the first outage and $18.7 million for the second outage in each of three years). PG&E also credits itself with a prepayment of $18.7 million in rate base (revenue requirement about $2.2 million) because the second outage occurs in year 1. In addition, PG&E erroneously gives itself $5.5 million per year, escalating with attrition, for a second bite at the steam generator inspection (as discussed above).

With TURN's lower outage cost and normalized ratemaking for steam generator inspections, PG&E's ratemaking methodology would yield a figure of $47.376,000 for each outage, and $15,792,000 for one-third of the second outage, yielding a total of $63,068,000. This is a reduction of $6,632,000 from PG&E's figure. The prepayment included in rate base under PG&E's methodology would be $15.792 million. In addition, there would be $2,222,000 instead of $5,500,000 for additional steam generator inspections for a total reduction of $9,410,000 in TY 2014.

TURN offers two other alternatives.

TURN's preferred method would be like the historical treatment of Edison's San Onofre plant. The Commission would set a cost per outage. The cost of one outage would be in base rates, but the cost of two outages would only be allowed in a year when there are actually two outages (2014) and removed from other years in the attrition process. There would be no prepayments, and costs would be reduced when outages are reduced. Assuming a cost in 2014 dollars of $47,376,000, the outage cost would be about $25 million higher than PG&E's in 2014 ($94,752,000). But it would decline by $47.4 million (in 2014 dollars before escalation for attrition) to $47,376,000 in 2015 and 2016. In the next rate case cycle, there would likely be two outages in one of the attrition years. This methodology was adopted in the TY 2007 GRC settlement for PG&E.

The second method would be a fully normalized average. With an 18- 20-month refueling cycle, PG&E routinely has five outages in four years. This is generally consistent with PG&E's performance recently, where the last two-outage year before

2014 was 2009. With an outage cost of $47,376,000, the fully normalized value for PG&E refueling outages would be 125% X 47,376,000 = $59,220,000 in 2014 dollars. This would be a reduction of $10,456,000 from PG&E's refueling figure (which also includes one-third of a steam generator inspection).

D. Diablo Canyon Capital

DRA made no adjustments to Diablo Canyon capital except for its generic reduction for IT.

TURN has identified two projects totaling about $7 million in capital that should be removed, one because PG&E is trying to recover the same cost twice - as an expense in the 2011 TY GRC and (after spending the money in 2010-11) as a capital item in this case; the other because it should be deferred until licensing and once-through cooling (OTC) uncertainties are resolved.

1. Transformer Super Cooler Replacement - Already Expensed; Don't Fund Twice

PG&E spent $3,877,000 to install a replacement transformer super cooler in 2010/2011. The weighted average rate base is $2,794,000 (with $232,000 of depreciation reserve and $850,000 of deferred income taxes).[56] This item was never forecast as a capital item in the 2011 TY General Rate Case, so that this rate case provides the first opportunity to examine the project for prudence. This item should be permanently removed from rate base in 2014 for reasons of accounting.

PG&E's general report states:

> In the area of ES [Energy Supply], PG&E reduced expenses largely as a result of delays impacting the timing of a number of projects … as well as reclassification of some costs from expense to capital."[57]

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[56] TURN DR 66-01 (Attachment 11).

[57] PG&E-10, page 6.

TURN asked which projects were reclassified from expense to capital in DR 66-01, and this plant item appeared. The item was clearly a 2011 expense as shown in PG&E's testimony in the 2011 TY GRC.[58]

The future test year rate process is susceptible to problems when a cost is originally expensed and the utility then proposes to capitalize the same cost. PG&E has already recovered expenses for this cost (forecast in 2009-2011 in its last rate case). Therefore, capitalizing the cost of the same project in this rate case is not reasonable. The capital project should be removed – including gross plant, depreciation reserve, deferred income taxes, depreciation expense, and property taxes.

TURN's recommendation is consistent with the 2006 TY Edison GRC decision which denied funding for capitalized buttress repairs at Florence dam that had previously been included as expenses in the 2003 TY GRC.[59] This expenditure has a nearly identical set of facts and should be treated in the same way.

2. Road Repaving Should Be Deferred Given Operational Uncertainties

In the last rate case, PG&E requested $4 million in expense for road repair and $25 million in capital for road repaving at Diablo Canyon. It spent $1.36 million in 2011-2012 and plans to spend $3.28 million in 2014. (TURN DR 58-16). Additional money may be spent under the Site Modernization Plan. (TURN DR 58-14)

The response to TURN DR 58-16 states that the 2011-12 money was spent "to replace approximately 95,000 square feet of the most degraded sections of the access road." Having done the most urgent work, PG&E should wait to see if the plant is relicensed and can cost-effectively meet Once Through Cooling (OTC) requirements before spending remaining dollars, either here or in the Site Modernization Plan. If the plant will only be used for eight years after the test year, other cheaper options than complete repaving should be considered. In addition, PG&E was fully funded for this work in the

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[58] 2011 TY GRC, Exhibit PG&E-5, page 4-24.

[59] CPUC Dec. No. 06-05-016, pp. 222-225.

last rate case and did not complete it. Therefore, TURN accepts the 2011-2012 spending for this project as fixing the worst part of the problem, but makes an adjustment to remove $3,282,000 from 2014 capital spending.

E. Ratemaking for Independent Spent Fuel Storage Installation (ISFSI) and DOE Settlement

1. Accounting Change for Future ISFSI Expenditures

In 2014, PG&E proposes to change the accounting for filling the Independent Spent Fuel Storage Installation (ISFSI) with spent fuel from expensing prior to 2014 to capitalization starting in 2014. In 2014, there is no spent fuel loading because of two refueling outages; thus the capital item does not appear until 2015, but the expense (estimated at $6.6 million in 2013) is removed from rates.

TURN would agree to capitalize ISFSI fill costs, but not in the same way that PG&E proposes. TURN believes that this change in accounting interacts with the DOE settlement. PG&E proposes to capitalize and depreciate future spent fuel as if it were plant. TURN disagrees. These costs are not plant. Were it not for future spent fuel revenues from DOE, TURN would recommend continuing to treat these costs as expenses. However, in light of the likelihood of continued recovery of funds from DOE, TURN would recommend capitalizing these costs not as plant but as a deferred debit that could be included in rate base but would not be depreciated or amortized at this time. TURN would credit future DOE settlement money received against the deferred debit for ISFSI fill costs for the given years in question. If circumstances change and DOE settlement money is not available, TURN would later allow the deferred debit to be amortized over the remaining life of the plant.

2. Ratemaking for DOE Spent Fuel Settlement

PG&E will receive a settlement of $266,104,245 for spent fuel storage costs through the end of 2010. PG&E proposes to assign costs from the DOE spent fuel settlement (after litigation expense) for Humboldt Bay to the decommissioning fund and for Diablo Canyon as an offset to generation rates.

TURN recommends a more complex treatment of these receipts (again after litigation expenses) to protect the interests of bundled service and DA customers and to provide for improved intergenerational equity among bundled service customers. These recommendations assume that tax treatment can be developed that will not lose any future tax deductibility and that deferred tax assets or liabilities could be created and appropriately dealt with. TURN has submitted a data request to PG&E on the tax implications. TURN's recommendations are as follows.

1. All Humboldt Bay receipts should offset nuclear decommissioning rates.

2. All PG&E costs for ISFSI permitting, construction, operation, and security at Diablo Canyon should be credited to bundled generation customers because (even though all ratepayers paid a portion of the DOE fee through 2000), bundled ratepayers paid for the IFSFI. A different method of crediting the costs would better promote intergenerational equity than PG&E's proposal to reduce rates. All costs reimbursing capital costs of the ISFSI through 2010 should be applied to remove the capital paid prior to 2010 less accumulated depreciation. These past ISFSI costs would no longer be in rate base and would no longer be depreciated. Bundled ratepayers would effectively receive the benefit of reduced ISFSI costs ratably through the end of the life at Diablo Canyon by not paying for a return on capital and a return of capital. A deferred tax asset may need to be established and recovered over the remaining life of the ISFSI.

3. Any additional costs compensating for past ISFSI work that is not currently capitalized or that has already been depreciated should be credited against bundled generation rates.

4. Any additional costs (unrelated to ISFSI work) should be split with 61.5% credited against decommissioning rates (1985-2000) and 38.5% credited to bundled service rates (2001-2010), reflecting the portions of time that all ratepayers paid for the plant versus only bundled service ratepayers.

5. Any additional money compensationg for PG&E for costs incurred after 2010 should be credited to bundled service ratepayers, with costs first used to reduce; ISFSI capital costs and remaining revenues as a credit to bundled service rates.

6. Any receipts for time periods after 2014 should offset IFSFI capital costs less depreciation and the new ISFSI deferred debit account proposed by TURN above,, with any remainder as a credit to bundled service rates. \

IV. Fossil Generation

A. Expense

In the two main major work categories (MWCs) for fossil generation (KK – Operate Fossil Generation and KL – Maintain Fossil Generating Equipment), PG&E requests 46.8 million. DRA recommends $40.0 million. [60] TURN has reviewed these items. Our findings are generally consistent with DRA's with the exception of three items:

- Allow $1,359,000 of additional maintenance at the Humboldt Bay Generating Station (HBGS) in MWC KL which was not present in 2011 because the plant was new, while reducing PG&E's request by $696,000 to average maintenance levels over 2014-2016 and remove the effect of an arbitrary method of calculation of how units of HBGS will operate in the future.

- Impute $90,000 in O&M savings (5% of capital cost) from Gateway Generating Station (GGS) capital project (auxiliary boiler) in MWC KL.

- Remove $128,500 in costs for studies of future fossil plants which should be charged to FERC Account 183 on PG&E's balance sheet rather than expensed. (MWC KK). The reduction is $77,500 if DRA's estimating method for MWC KK (average of 2011-12) is used.

Recommendations are compared below:

[60] PG&E-6, p. 4-5, Table 4-2.

Table 24: TY 2014 Forecasts for Principal Fossil Generation Accounts ($'000)

	PG&E	DRA	TURN
KK - Operate Fossil Generation	$ 14,858	$ 12,935	$ 12,768
KL- Maintain Fossil Generating Equipment	$ 31,942	$ 27,045	$ 28,404
Subtotal	$ 46,800	$ 39,980	$ 41,172

In addition to the fossil generation recommendations that differ from DRA's (discussed above), TURN provides additional information to support points made by DRA.

- TURN demonstrates that the cost of adding two staffers at the Humboldt Bay Generating Station can be fully absorbed through reductions in overtime, with the exception of the cost of the new workers' benefits, which is independently forecast in A&G accounts.

- We provide information obtained from TURN data requests that supports DRA's recommendations to remove PG&E's document storage program in MWC KK and material traceability programs in MWC KL.

1. Additional HBGS Staffing Does Not Require New Funding Except for Staff Benefits

PG&E adds $500,000 to add two staffers at the Humboldt Bay Generating Station. PG&E's justification is given as follows. [61]

> In order to safely and reliably operate 14 HBGS, two PPTs are required on each shift 24 hours a day and 15 seven days a week (24 × 7). These PPTs focus primarily on operations. HBGS currently has enough employees to staff four operator groups of two PPTs each. These four groups are required to work on shifts that cover the 24 × 7 operation at HBGS. In order for a PPT to be able to take his or her vacation time and any necessary sick leave, a PPT from one of the other three groups must work overtime to replace the vacationing or sick PPT in order to keep the required minimum plant operations staffing at two. This situation has created significant overtime and work/life balance issues. PG&E

[61] PG&E-6, p. 4-36.

> plans to hire two additional PPTs to form a fifth operator group. Five operator groups are currently utilized at GGS and CGS with good success.

TURN does not disagree with hiring the two new staff members. However, with the exception of pensions and benefits – forecast separately from plant operations – TURN believes that these staffers can be hired at no net cost, because they will be paid for through reductions of overtime for existing staff.

PG&E came up with a cost of $250,000 per staffer, which is based on standard rate figures of $116.71 (TURN DR 45-04-Supplemental, included here as Attachment 12). However, the supervision and management ($15.73 per hour or 13.5% of the total) is simply inapplicable, because PG&E is not adding any more supervision at HBGS. Many of the non-labor items are also not applicable given the purpose of adding the new staff in large part to reduce overtime. If approximately the same number of people is working at the plant at any given time, more vehicles are not needed, and other items such as materials and contracts are unlikely to increase proportionally with the change in workers.

But PG&E's major error was assuming that all of its existing staffers must still work the same amount of overtime after the addition of the fifth operator group. TURN asked for historical data for hours worked by powerplant technicians at HBGS as well as Colusa and Gateway.

The data from PG&E show that HBGS employees worked almost 53 hours per week – approximately 4 hours per week more than their counterparts at Gateway in 2011-12. There thus appears to be an overtime issue at HBGS that a fifth crew indeed could reduce. HBGS workers worked 32% total overtime of which 9.7% was expensive double-time. By comparison, the average of Gateway in 2011-12 and Colusa in 2012 was 21% total overtime and double-time of which 54% was double-time, based on the five-crew model. Attachment 13 contains calculations of labor costs.

It is also apparent that the staffers to be hired in 2012 were not hired at that point, as there were 12.82 FTE of powerplant technicians at Humboldt in 2011 (straight-time hours divided by 2080) and only 12.07 FTE in 2012.

PG&E's cost analysis assumes that the new staffers work 23% overtime plus double-time, but they add the new staffers on top of the cost of the existing staffers. Thus PG&E assumes that the average staffer still works 52.4 hours per week instead of 52.9 and the total workload per employee at HBGS drops by only 27 hours per week (1%).

TURN prepared two alternative analyses; the first assuming that the fifth crew had the same rate of unproductive time as the existing HBGS employees, and that the required workload was the same number of total productive hours, so that the new staffers largely reduced overtime. The second method of analysis was based on powerplant technician workloads at Gateway which has a similar number of staffers to HBGS (after the addition of two more workers) without the complexity of dry cooling at Colusa. Averaging the two methods means that even though there are 16.1% more staffers (when two are added), the number of paid hours increases by only 4.1%. Because many straight-time hours of the new staffers displace overtime by existing staff, the total cost of wages is actually 1.5% less. In other words, the reduction in overtime pays for the straight time labor – leaving only the benefits. Attachment 13 shows the calculations.

2. New Fossil Generation Studies (MWC KK)

PG&E proposes $128,500 in current expenses for new fossil generation studies in 2014.[62] What new fossil generation is being studied is not clear. Regardless, TURN objects to this cost on the basis of accounting issues. These are studies of projects that are not used and useful. They should be assigned to FERC Account 183 (Preliminary Surveys) or in a CWIP account when projects become more definite. Given that PG&E has treated these costs as an operating expense in past years, we recommend that the change in treatment be effective as of January 1, 2014 rather than making an accounting change between rate cases.

[62]PG&E Workpaper 4-11 (planning order 5222995) shows $155,622 in 2011, nothing in 2012, and $128,500 in 2014. The amount embedded in the DRA forecast (based on the average of 2011-12) is $77,811. This amount should be removed if DRA's forecast is adopted.

3. Normalize Humboldt Major and Minor Maintenance (MWC KL)

PG&E calculates maintenance at Humboldt as $2,715,000 based on scheduling of various types of maintenance in TY 2014.[63] This is an increase of $2,055,000 over 2011 values, which included only minor maintenance and no major maintenance because the units were so new.

TURN believes that some increase in maintenance is necessary from the aging of the units so that some will need more expensive major maintenance, but we recommend a reduction of $696,000 from PG&E's number to $2,019,000 – an increase of only $1,359,000 over PG&E's figures.

Our review of PG&E's workpaper 4-47 revealed two sources of overestimates. First, there is a significant fluctuation in the three forecast years. The cost in 2014 is $2,560,000 (2011 dollars). The average of 2014-2016 is $2,157,000 (2011 dollars), a reduction of $403,000 (real). Because of these fluctuations, TURN believes that the three-year average is more representative of conditions in the rate-effective period.

Second, TURN's review of PG&E's workpaper 4-47, on which PG&E's maintenance expenses are based, assumes that three of the ten units run over 6000 hours per year and one runs 4700 hours per year. PG&E assumes that the others run from only 681 to 1961 hours per year. Increasing the hours run on some units with low utilization, and reducing hours run on units with higher utilization could defer one or more expensive 18,000 hour maintenance events ($760,000 each). We conservatively assume that one of these events is deferred in the three year period (despite developing an illustrative scenario that deferred two of them), creating a further savings of one-third of $760,000 ($253,000 in 2011 dollars), for a total savings of $656,000 (2011 dollars) or $696,000 (nominal dollars).

After adjusting for inflation, TURN's figure is $2,019,000 in 2014 dollars, a reduction of $696,000 from PG&E's 2014 figure of $2,715,000.

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[63] PG&E-6, Workpaper 4-47.

Table 25: Maintenance at HBGS, 2014-2016 ($'000)[64]

	2014	2015	2016	average
2011 $				
minor overhauls	740	660	870	757
major overhauls	1,820	760	1,620	1,400
total	2,560	1,420	2,490	2,157
reduction from averaging				403
remove one 18,000 hour maintenance event				
(running low-use units more)				253
TURN reduction (2011 $)				657
inflation to 2014 $	1.0607			
TURN reduction (nominal dollars)				***697***
	PG&E			TURN
2014 $	2,715			2,019

4. Document Storage (MWC KK) and Material Traceability (MWC KL)

PG&E claims to have proposed these programs in the wake of the San Bruno disaster to assure that it had access to documentary information.[65] The cost of the programs is $240,000 for document storage and $771,000 for material traceability in TY 2014.[66]

These both look like programs designed to spend money, make the public and the Commission feel good about safety, while accomplishing very little.

TURN provides PG&E DRs 45-11 through 45-17 as Attachment 14 Most of these responses are cited below.

When asked whether PG&E could "retrieve plant documents in a timely manner for daily use for its three plants," at the present time, PG&E's answer was "Yes."[67] The project

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[64] PG&E figures from PG&E-6, Workpaper 4-47.

[65] PG&E-6, Workpapers 4-30 and 4-32.

[66] PG&E-6, Workpapers 4-31 and 4-33.

[67] TURN DR 45-11.

was justified because it would "enhance PG&E's ability." When asked to explain and quantify any other benefits of this project, there wasn't a dollar figure anywhere:

> The document storage program supports the companywide effort to modernize PG&E's records and record management practices. This effort includes improving the retrievability of records, confirming their accuracy, and improving the records management systems themselves to help better manage PG&E's operations. This funding provides Fossil operations support to provide attributes to all drawings for the three fossil plants and incorporate these drawings into Documentum.[68]

In response to TURN DR 45-12, PG&E agreed that its construction contractors satisfied contract requirements for delivery of "as built" documentation for each of the three plants that "met the requirement of the contract excerpts." However, PG&E "does not have an opinion on whether the requirements for 'as-built' documentation reflect 'best practices.'"[69]

In both DRs 45-11 and 45-12 PG&E claims that some "attributes" (an undefined term in the data responses) were not provided and would be part of the data storage process. TURN therefore has asked a further data request (DR 86-2) to figure out what the missing "attributes" were and whether public safety or plant reliability was degraded because the "attributes" did not exist.

"Materials traceability" which is integrally linked to "document storage' also appears to be an entirely new concern. In TURN DR 45-13, PG&E admitted that the "[Long-Term Service Agreements] LTSAs for Gateway and Colusa include provisions for adequate documentation of repairs and traceability of materials," but claimed that PG&E needed to trace other materials. In TURN DR 45-14, PG&E stated that at HBGS, which does not have long-term service agreements, "a work management procedure was put in place" but PG&E needed to do "a better job of filling in the gaps in its data," PG&E was not aware of any cases where a materials traceability program would have avoided jeopardy to the public health and safety at modern plants like Gateway, Colusa, and HBGS. (DR 45-16)

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[68] Id.

[69] TURN DR 45-12.

and only came up with a single example for an old-style thermal steam powerplant (DR 45-17).

Therefore, these items, totaling almost $1 million should be deleted from Test Year expenses.

5. Savings from Gateway Capital Project (MWC KL)

The Gateway Generating Station Auxiliary boiler makes the unit more flexible, which is valuable in and of itself, but also reduces wastewater production, as well as wear on several pieces of equipment. PG&E has quantified the cost at $1,798,000 but has failed to provide even nominal savings for maintenance.[70] This appears typical of PG&E's approach in this entire rate case. TURN recommends a small reduction of $90,000 in maintenance and wastewater disposal cost (5% of the cost of the capital project) pending further information.

B. Fossil Generation Capital

TURN has reviewed PG&E's fossil generation capital and makes $3,404,000 in adjustments. This testimony removes $1,786,000 to disallow one project that was not adequately defined and to remove excessive AFUDC on two capital spare parts projects. In addition, Mr. Nahigian's testimony on corporate real estate reduces the forecast cost for the HBGS warehouse project by $1,628,000 because of excessive construction costs. DRA made no changes to fossil capital; thus these are additional reductions.

1. Remove HBGS GHG Reduction Equipment Because No Real Project is Defined

PG&E requests $1.5 million for unspecified equipment, effective in 2015. The amount spent is evenly divided in 2013-2015 ($500,000 each year). Out of an abundance of caution, in case PG&E is attempting to put part of the project in rate base before the project completion date in 2015, TURN recommends deleting this project, since PG&E has not explained what it is. Even if "the cost assumptions used here are based on

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[70] PG&E-6 Workpapers 4-85 to 4-87. A similar project is proposed at Colusa in 2015. This project should generate reduced costs in 2017 based on the actual experience at Gateway.

PG&E's judgment," costs for an unexplained and undefined project are by definition not adequately supported. [71]

2. Excessive AFUDC on Spare Parts Requiring no Construction

There are two projects where PG&E has requested excessive amounts of AFUDC for projects that are simply purchased and put in storage with little or no construction activity.

The first is the spare generator for HBGS. AFUDC at 7.93% of project (equivalent to almost one year of interest on direct cost of the plant) is excessive for an item that will be bought, shipped to the US, and placed into storage with no construction.[72] TURN reduces the AFUDC to 3%, reflecting a shorter time period between when payments are made and the plant is available and in service, which reduces the cost of the spare generator by $81,000 from $1,768,000 to $1,687,000.

The Colusa and Gateway Spare Transformer also has excessive AFUDC of 8.60% (over one year of interest on the direct cost of the plant).[73] This item will be bought and placed into storage with no construction. TURN reduces the AFUDC to 4%,[74] reflecting a shorter time period between when payments are made and the plant is available and in service, which reduces the cost of the spare transformer by $185,000 from $4,374,000 to $4,189,000.

The AFUDC reductions are summarized in Table 26.

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[71] See PG&E-6 Workpapers 4-71 and 4-72. Note that TURN does not take exception to the well-defined GHG reduction project of heat recovery generators at HBGS PG&E-6 Workpapers 4-73 and 4-74.

[72] PG&E-6, Workpaper 4-96.

[73] PG&E-6 Workpaper 4-92

[74] The figure is higher than for the spare generator because there is a limited amount of early engineering on this project.

Table 26: AFUDC Reductions on Capital Spares ($'000)

	Transformer	HBGS Generator	Total
Direct	3,836	1,560	5,396
AFUDC	330	124	454
5% contingency	208	84	292
Total Cost per PG&E	4,374	1,768	6,142
PG&E AFUDC %	8.60%	7.94%	8.41%
TURN AFUDC %	4.00%	3.00%	3.71%
TURN AFUDC	153	47	200
TURN reduction	176	77	253
TURN reduction with 5% contingency	185	81	266
Total Cost per TURN	4,189	1,687	5,876

V. Base Year Adjustments for Inappropriate Expenses

TURN has identified a number of expenses charged to ratepayers for image building and political and social purposes in base year 2011. The expenses constitute base year disallowances which must be escalated to 2014 dollars. They include image-building websites and blogs, political organizations, and various tickets, meals and entertainment expenses. They total $1,676,000 in 2014 dollars across various MWCs and PCCs, mostly related to A&G expenses.

Table 27: Summary of TURN Base Year Expense Adjustments

MWC/PCC	TURN disallowance	2014 $
10311/14	pgecurrents.com and next100.com	888
various	Clothing and other gear	199
various	Tickets, meals and entertainment	148
AB (gen and dist)	Edison Electric Institute	224
various	California Council for Environmental and Economic Balance	134
10404	California Taxpayers Association	61
FK	San Francisco Chamber of Commerce	22
	Total	1,676

A. PG&E's Websites and Blogs pgecurrent.com and next100.com (PCC 10311/10314)

In addition to its main website, PG&E has set up both another website (pgecurrents.com) and a blog (next100.com) to promote its views of the world to its customers and others. The websites call themselves "News and Perspectives from Pacific Gas and Electric Company." They provide a large number of videos as well as other stories. While the website provides some information on programs like energy efficiency and reliability and safety, many of these and other stories are designed to place PG&E in a good light (institutional advertising). Attachment 16 contains materials from www.pgecurrents.com on May 15, 2013, which show that many of the articles do not have to do with safety, reliability, or efficiency [and that, even some of those that do relate to those topics, serve the main purpose of burnishing PG&E's image]

This website is the 2012 version of the old *PG&E Progress* that used to be inserted in customers' bills. About 30 years ago, *PG&E Progress* was a big issue at the Commission. Ultimately courts held that PG&E could not be required to provide space in its own billing envelope to organizations like TURN to present their own views, but the PG&E shareholders paid for the *PG&E Progress* publication, because it presented PG&E's views on controversial issues and polished PG&E's image.

Now, 30 years later, few people would read something like *PG&E Progress* so PG&E's means of communicating with its customers is the Internet.

This website also provides large amounts of video content – mini advertisements, like the advertisements that PG&E's shareholders unquestionably pay for on radio and television.

The upshot of these analogies is that, like *PG&E Progress* in its day and like advertising now, PG&E can polish its image all it wants, but ratepayers should not pay for such image enhancing efforts.

The cost of the website and the videos used on it are $893,000, of which $72,000 was accounted for below the line (San Bruno) and $3,000 is charged to the Smart Meter balancing account, leaving $818,000 charged to ratepayers in base year 2011.[75] The costs are in strategic communications and corporate communications (PCC 10311 and 10314, and MWC LJ). These costs should be removed from the base year from corporate communications as an audit adjustment additional to any other DRA adjustments. The costs that TURN recommends assigning to shareholders are given below.

Table 28: TURN's Disallowance for Cost of pgecurrents.com

	2011
Labor	233
Non-Labor	490
Non-Labor videos	170
Less below-the-line videos	(75)
Subtotal	818
Escalate to 2014 $	888

B. Clothing and other PG&E Gear (Various MWCs and PCCs)

PG&E spent $183,265 on clothing and other gear containing PG&E's name and logo (excluding uniforms, hard hats, etc.) in base year 2011, as shown in TURN DR 49-02. These types of expenses are promotional and image-building (giveaways and other materials) and should not be paid for by ratepayers The expenses should be escalated to 2014 dollars ($199,000) and disallowed as A&G expenses so that the disallowance is spread across all PG&E units.[76] The disallowance should be unbundled by labor to functions.

[75] TURN DRs 49-16 and 49-17.

[76] Because there were 190 data entries totaling only $183,000, the labor spent unbundling each entry would be considerable to achieve a limited gain in accuracy. Nevertheless,TURN could provide unbundled costs at a later time if needed.

C. Tickets, Meals and Entertainment

TURN received information on meals and entertainment in DRs 49-05, 49-09 and 49-10. If, as PG&E intends, ratepayers are to be charged with these expenses, there are a number of very troubling items on this list, including some that appear to constitute waste and abuse of ratepayer funds. Such extravagances should not be charged to ratepayers and should be disallowed. We only identify a few that appear to demonstrate excessive entertainment expenses. The disallowances are small, but the CPUC should investigate further to determine if there is a broader pattern of extravagant entertainment expenses at PG&E that DRA or intervenors would be hard pressed to discover with limited resources.

1. Dardanelles Resort

The Dardanelles Resort is located in the high Sierra 51 miles east of Sonora. Attachment 17 is its home page. PG&E spent $77,274.47 at this resort for purposes that are not at all clear (DR 49-09 "Orders" worksheet). A table of the accounting entries is reproduced below in order of dates. A table in order of accounts billed is in Attachment 18.

Table 29: Sorted Accounting Entries for Dardanelle Resort (from TURN DR 49-09)

End Date	Begin Date		Amount	Billing Code	Description	FERC Acct
6/7/2011	6/3/2011	DARDANELLE RESORT	6,250.00	13004886	10-12 - ETC Stockton - Implementation	908
6/21/2011	6/17/2011	DARDANELLE RESORT	900.00	13004886	Warehouse Mgmt & Meter Inventory - EXP	920
7/12/2011	7/8/2011	DARDANELLE RESORT	3,125.00	13004886	NO-SI-EL DORADO 2/16/201- WIND-LOW SNOW	101
7/12/2011	7/8/2011	DARDANELLE RESORT	3,125.00	13004886	Warehouse Mgmt & Meter Inventory - EXP	920
8/10/2011	8/5/2011	DARDANELLE RESORT	3,125.00	13004886	10-12 - ETC Stockton - Implementation	908
8/10/2011	8/5/2011	DARDANELLE RESORT	3,125.00	13004886	10-12 - ETC Stockton - Implementation	908
8/10/2011	8/5/2011	DARDANELLE RESORT	3,125.00	13004886	10-12 - ETC Stockton - Implementation	908
8/10/2011	8/5/2011	DARDANELLE RESORT	3,125.00	13004886	10-12 - ETC Stockton - Implementation	908
8/30/2011	8/26/2011	DARDANELLE RESORT	1,800.00	13010742	PHASE 1 DATA & MAOP VALIDATION-DV-PRODUC	859
8/30/2011	8/26/2011	DARDANELLE RESORT	900.00	13010742	Wireless BD General Ovhd (NR)	566
9/20/2011	9/16/2011	DARDANELLE RESORT	1,800.00	13010742	10-12 - ETC Stockton - Implementation	908
9/20/2011	9/16/2011	DARDANELLE RESORT	3,125.00	13010742	NO-SI-EL DORADO 2/16/201- WIND-LOW SNOW	101
9/20/2011	9/16/2011	DARDANELLE RESORT	3,125.00	13010742	PHASE 1 DATA & MAOP VALIDATION-DV-PRODUC	859
9/20/2011	9/16/2011	DARDANELLE RESORT	900.00	13010742	PHASE 1 DATA & MAOP VALIDATION-DV-PRODUC	859
9/20/2011	9/16/2011	DARDANELLE RESORT	3,125.00	13010742	PLO-COM:Impl Cyber Security Requirements	101
9/20/2011	9/16/2011	DARDANELLE RESORT	3,125.00	13010742	Warehouse Mgmt & Meter Inventory - CAP	101
10/11/2011	10/7/2011	DARDANELLE RESORT	2,500.00	13010742	10-12 - ETC Stockton - Implementation	908
10/11/2011	10/7/2011	DARDANELLE RESORT	2,500.00	13010742	67-Sychro-phasor technology demo	101
10/11/2011	10/7/2011	DARDANELLE RESORT	3,100.00	13010742	CC-CC SANTA CRUZ CNTY-3/20/11 WIND/RAIN	593
10/11/2011	10/7/2011	DARDANELLE RESORT	3,100.00	13010742	LIEE 11- Stockton Training Center	908
10/11/2011	10/7/2011	DARDANELLE RESORT	2,325.00	13010742	Manage DeSabla Safety Operations	538
10/11/2011	10/7/2011	DARDANELLE RESORT	3,100.00	13010742	NO-NV-BUTTE CO-2/24/11-LOW SNOW	593
10/11/2011	10/7/2011	DARDANELLE RESORT	1,620.00	13010742	NO-SI-EL DORADO 3/18/2011- WIND-RAIN-STO	593
10/11/2011	10/7/2011	DARDANELLE RESORT	2,500.00	13010742	NO-SI-NEVADA-03/18/11-WIND/RAIN STORM	593
10/11/2011	10/7/2011	DARDANELLE RESORT	784.47	13010742	OC4 NO-NV-BUTTE CO-2/24/11-LOW SNOW	101
10/11/2011	10/7/2011	DARDANELLE RESORT	2,500.00	13010742	PHASE 1 DATA & MAOP VALIDATION - DV - NO	859
10/11/2011	10/7/2011	DARDANELLE RESORT	2,325.00	13010742	PHASE 1 DATA & MAOP VALIDATION - DV - NO	859
10/11/2011	10/7/2011	DARDANELLE RESORT	3,100.00	13010742	PHASE 1 DATA & MAOP VALIDATION-DV-PRODUC	859
10/11/2011	10/7/2011	DARDANELLE RESORT	3,100.00	13010742	PHASE 1 DATA & MAOP VALIDATION-DV-PRODUC	859
10/11/2011	10/7/2011	DARDANELLE RESORT	900.00	13010742	Warehouse Mgmt & Meter Inventory - CAP	101
Total			77,254.47			
		Total	CWIP	Expense		
10/7 to 10/11/2011		33,454.47	4,184.47	29,270.00		
9/16 to 9/20/2011		15,200.00	9,375.00	5,825.00		
8/5 to 8/10/2011		12,500.00	4,025.00	8,475.00		
Others (2 or less entries)		16,100.00	3,125.00	12,975.00		
Total		77,254.47	20,709.47	56,545.00		

The table shows numerous expenditures related to activities that often take place far from the site of the resort. Clearly, these were not site visits. For example, it appears there may have been a large conference at the resort in early October (Columbus Day weekend?) in 2011, or maybe it was a coincidence of when invoices were recorded. But the accounting shows the billing parties were not a single group of PG&E employees from a single organization. There were 14 separate billings for that date that include four billings from Phase 1 of PG&E's Gas Pipeline Safety Enhancement Plan ("PSEP"), even though the nearest gas line is at least 50 miles away. It included five billings on storm accounts from February and March – eight months before the October billing date - including accounts in Santa Cruz County and Butte County that are hundreds of miles away. One was to a CWIP account. There were two billings from the Energy Training Center in Stockton (one billed to low income). There was one billing each one from hydro safety at DeSabla (Feather River area), also hundreds of miles away; and two to separate CWIP projects for warehouse management and demonstrating synchro-phasor technology.

A smaller grouping occurred on September 16, with billings to some of the same organizations, warehouse management of meters, the Energy Training Center ("ETC"), PSEP Phase 1, another CWIP billing to a storm account from 8 months earlier, and a CWIP cybersecurity account.

There were several other billings earlier in the summer.

The Energy Training Center was the biggest user of the facility, billing over $23,000 to the Account (see Attachment 18).

PG&E ratepayers should not have to pay for PG&E's employees to be entertained at a High Sierra resort. What does such a resort have to do with MAOP for gas pipelines, or storms eight months earlier, or phasors, or cybersecurity, or safety at DeSabla, or lots of people involved in all these different activities all in the same place together for a long weekend? We can understand that ETC employees might want to hold events for their clients in a nice place in the Sierra, but that is not what the Energy Efficiency budget is for. If PG&E wants to use its shareholders' money for meals and lodging at resorts, that is the company's business. But ratepayers should not pay higher rates to support such entertainment.

TURN recommends disallowing the full $77,254 spent at this resort from Test Year expenses as inappropriate expenses that occurred in the base year. While some of these costs may be in balancing accounts (ETC) or below the line (gas data and Maximum Allowed Operating Pressure work in 2011), it would not serve regulatory economy to force TURN to try to raise the issue in energy efficiency cases where balancing accounts are never audited or to chase down individual storm orders for tiny capital disallowances. There is a The Commission should make clear that it will not allow PG&E to hide behind accounting complexities to impose such extravagant expenses on ratepayers. All of the costs should be disallowed here through the companion Order Instituting Investigation (I. 13-03-007).

2. Other Events

We do not pretend to have found all entertainment expenses that need to be disallowed, but we recommend removing another $71,081 for a variety of meals and entertainment. A couple of these items relate to energy efficiency, but regulatory economy suggests these items should be disallowed here (under the Commission's companion OII) rather than, for example, opening an audit of Energy Efficiency spending to remove a $4100 staff trip to Angel Island.

Among the more egregious expenditures, the Regulatory Affairs Department and the office of the SVP of regulatory affairs spent $22,700 on meals at the St. Francis Yacht Club.[77] And $26,226 was spent on tickets to athletic and cultural events.[78] PG&E says that "eight of the nine transactions involved team building events which … are a normal business practice."[79] However, the Commission recently rejected several of these items in the Sempra rate case:

> We agree with DRA, TURN, and UCAN that the funding requests for retirement activities and special events should not be borne by ratepayers. These two benefits are in the nature of programs that build loyalty and camaraderie between current and former employees with their respective companies, and are not related to any of their companies' job-related activities. For those reasons, we remove the costs of the retirement activities, and special events, from the revenue requirement of both companies.[80]

TURN's recommended additional disallowances are given below.

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[77] $13,063 in PCC 10407 (Regulatory Affairs) and $9637 in PCC 12913 (SVP of regulatory affairs).

[78] TURN DR 49-05 Attachment. PG&E cautioned that some of these costs may be unregulated or below the line, but it provided no information as to where in the company these ticket costs came from, and we found $4110 as a "team building/ recognition events" exercise.

[79] DR 49-05.

[80] D. 13-05-010. p. 888. These recognition costs included trips for employees to Disneyland, Sea World and Knotts Berry Farm among other things. (A. 10-12-006, Exhibit SCG-19R, p. DSR-34. TURN removes these tickets and several "R&R" and employee recognition events in meals and entertainment.

Table 30: Other Disallowances for Meals, Tickets, and Entertainment

Item	MWC/PCC	Amount	Source	
Baseball, football, and symphony tickets	various	26,226	TURN DR 49-05	
St. Francis Yacht Club (3 items reg affairs)	10407	13,063	49-10 Spreadsheet (S)	
St Francis Yacht Club (SVR Reg Affairs)	12913	9,637	49-09 S (PCCs)	
24 Hour Fitness Membership	JV	3,000	49-07	
CES Core Products trip to Angel Island	13775	4,073	49-10 Att. 14 including deposit	
Director of Corporate Accounts team outing	13737	1,354	49-10 Att 5	
Dinner with Best Buy	14455	1,240	49-10 Att 6	
R&R lunch for Staff	11717	1,256	49-10 Att 8	
Campo di Bocce - staff outing	11115	1,383	49-10 Att 15	
San Francisco Sailing	14024	1,886	49-10 S	
Teal Bend Golf	10245	72	49-10 S	
Ristorante Portofino, Pacifica	13891	7,890	49-10 S	
Total Disallowance		**71,081**		

a. Tax Impacts

The $148,000 disallowed for meals and entertainment by TURN (including Dardanelles) is only partially tax deductible. This means that the Schedule M tax increase for meals and entertainment should be decreased by $74,000.

D. Edison Electric Institute

PG&E paid $1,620,719 to the Edison Electric Institute. It assigned 25% below the line ($405,180), and 25% ($405,180) to each of generation, transmission, and distribution.

EEI spends money on many other things that do not fit the narrow definition of lobbying. The Commission has in the past specifically rejected all EEI spending for lobbying, legislative advocacy, regulatory advocacy, marketing, public relations, advertising, donations, and club dues[81].

TURN therefore asked DR 18-15, a question regarding all of these other types of expenses:

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[81] D. 96-01-011 pp. 153-156. Note that the Commission did not adopt an FEA adjustment for donations and club dues because Edison had already adjusted them out, not because such an adjustment was unwarranted.

> Provide the latest available documentation of the Edison Electric Institute identifying funds spend [sic] on lobbying, legislative advocacy, regulatory advocacy, marketing, public relations, advertising, donations, club dues, and any other functions identified by EEI.

We stumped PG&E. All we got back was the invoice from EEI. Not a bit about costs other than "influencing legislation."

It is understandable that PG&E does not know what EEI spends its money on, because EEI has begun to keep this information out of general knowledge. After a series of regulatory disallowances of significant parts of EEI dues across the country, EEI has decided on its own to stop issuing detailed information on its budget that had previously been published for decades under the auspices of NARUC.[82] The last available audited data from 2005 is given below.

Table 31: EEI Spending Data 2005 (Audited)

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues
Legislative Advocacy	20.38%
Legislative Policy Research	6.02%
Regulatory Advocacy	16.49%
Regulatory Policy Research	13.99%
Advertising	1.67%
Marketing	3.68%
Utility Operations and Engineering	11.31%
Finance, Legal, Planning and Customer Service	18.75%
Public Relations	7.71%
Total Expenses	100.00%

JBS was able to obtain a limited amount of additional information from an Oklahoma Gas and Electric rate case in Arkansas, where OG&E filed the following information in response to an Arkansas Public Service Commission (APSC) General Staff data request:

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82 Response to Initial Requests for Information (Question 65) of the Kentucky Attorney General (August 27, 2008) from Kentucky Public Service Commission Case No. 2008-00251 and 2007-00565 for Kentucky Utilities Company, found at http://psc.ky.gov/pscscf/2008%20cases/2008-00251/KU_Response%20to%20AG's%20Requests%20dated%20082708%20(Vol%201of3)_091108.pdf .

Table 32: EEI Spending Data 2005-2009 Arkansas PSC Staff DR 52-03 in Docket No. 10-067-U

Edison Electric Institute Schedule of Expenses

For Core Dues Activities

For the years Ended December 31, 2005 - 2009

(Unaudited)

% of Dues

Operating Expense Category	2005	2006	2007	2008	2009
Legislative Advocacy and Policy Research	26.4%	25.7%	16.2%	14.4%	21.9%
Public Relations	7.7%	8.8%	2.2%	2.0%	2.4%
Advertising	1.7%	1.3%	0.9%	2.3%	2.3%
Marketing	3.7%	3.9%	0.0%	0.0%	0.0%

This document shows that 26.6% of the 2009 EEI budget made available to the APSC Staff is made up of expenses that should be considered as below the line, including legislative advocacy (21.9%), advertising (2.3%), and public relations (2.4%). But that is not all that should be removed. Spending on regulatory advocacy was 16.5% in 2005 – the last year for which that figure has been made available. We add the 2005 regulatory advocacy figure (the latest full audited study available) to the 2009 figures for the other items, since no utility has provided any later data. The total is 43.1% of the $1,441,563 of general dues. EEI states that 35% of Industry Issues program ($144,156) is influencing legislation. There is a small amount for mutual assistance ($5,000), and a $30,000 contribution to the Thomas Alva Edison fund. TURN treats the contribution, like other PG&E donations, as below the line. Table 33compares TURN's and PG&E's calculations. TURN recommends that $702,000 be treated as below the line and agrees with PG&E that it is appropriate to divide the cost remaining above the line one-third each to generation, transmission, and distribution. Note that PG&E used the administrative escalation factor for MWC AB in generation but made up a higher escalation factor (11.1%) for distribution.[83] TURN uses the administrative escalation rate for both.

Table 33: PG&E and TURN Recommendations for EEI

	EEI Invoice	PG&E Below the line		TURN below the line	
	2011	%	$	%	$
Regular Activities	$ 1,441,563			43.10%	$ 621,314
Industry Issues	$ 144,156			35.00%	$ 50,455
Mutual Assistance	$ 5,000			0.00%	$ -
Edison Foundation Contribution	$ 30,000			100.00%	$ 30,000
Total 2011 invoice	$ 1,620,719	25%	$ 405,180	43.30%	$ 701,768
Unbundling and Escalation					
	PG&E	PG&E	TURN	TURN	PG&E>TURN
	2011	2014	2911	2014	2014
Generation MWC AB, PCC 10530	$ 405,180	$ 440,000	$ 306,317	$ 333,000	$ 107,000
Distribution MWC AB	$ 405,180	$ 450,000	$ 306,317	$ 333,000	$ 117,000
Transmission	$ 405,180		$ 306,317		
GRC Functions	$ 810,360	$ 890,000		$ 666,000	$ 224,000

In sum, TURN recommends a further adjustment in this GRC of $224,000 for EEI, $107,000 in generation, and $117,000 in distribution (where PG&E used a different escalation rate).

E. California Council for Environmental and Economic Balance (CCEEB) – Lobbying and Political Organization

This organization is heavily involved in lobbying and support of legislation and initiatives.[84] It is the policy arm associated with the California Foundation for Energy and the Environment, which takes legislators and CPUC commissioners on various junkets.

[83] PG&E-4, page 20-4.

[84] See for example, the "Climate Change Project and "Waste and Water Quality Project" managed by. Robert Lucas of Lucas Advocates, "a lobbying firm" identified as "bob lucas at calobby dot com" http://cceeb.org/projects/climate-project.html

PG&E has charged $123,000 to CCEEB in 2011, an increase of $52,000 from the 2008 base year in the 2011 TY GRC. Not one penny is charged below the line; the costs go to the following organizations, according to TURN DR 49-07 (with $1,000 unallocated):

Table 34: CCEEB Costs by PCC

12076	State Agency Relations	$ 69,500
10449	Director - Environmental Operations	$ 22,000
12636	Environmental Policy	$ 17,500
11707	FS-Fleet Regulatory Compliance	$ 13,000
	Other from GO 77-M Report	$ 1,000
	Subtotal CCEEB	**$ 123,000**
	Escalate to 2014 $	**$ 133,624**

Ratepayers should not pay for PG&E's lobbying and policy advocacy; this audit adjustment should be taken. With non-labor escalation to 2014, the disallowance is $133,624.

F. California Taxpayers Association (CalTax)

PG&E paid $55,821 to the California Taxpayers Association in Base Year 2011 in PCC 10404 (Tax Department).[85] On its webpage, CalTax states:

> CalTax has a strong track record of protecting taxpayers from higher economic burdens. We are leaders in protecting the provisions of Proposition 13, and have scored numerous legislative and regulatory victories for the California taxpayers.[86]

This organization regularly supports and opposes legislation. In the most recent Edison GRC Decision, the Commission charged the costs of this organization to shareholders, stating:

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[85] TURN DR 49-07.

[86] http://caltax.org/about/about.html

> We agree that advancing policies of tax reduction is inherently political and ratepayers should not fund SCE's membership dues in political organizations regardless of some attenuated potential rate benefit.[87]

The Commission should follow the same logic for PG&E and remove the CalTax dues as a base year adjustment to PCC 10404 (PG&E's tax department). The amount is $61,000 after escalation to 2014 dollars.

G. San Francisco Chamber of Commerce

PG&E paid $20,000 to the San Francisco Chamber of Commerce in Base year 2011 in MWC FK (Retain and Grow Customers).[88] PG&E has a long-standing policy of excluding payments to chambers of commerce from rates. If the Commission funds customer retention at all, the Commission should follow the policy on Chamber of Commerce costs and delete these funds ($22,000 with escalation to 2014).

VI. Income Tax Deduction for Employee Stock Ownership Plan Dividends

TURN recommends that PG&E recognize Employee Stock Ownership Plan (ESOP) dividends paid as a tax deduction for ratemaking purposes. This is a case where the Commission has yet again treated PG&E more generously than Edison, to the tune of $33.6 million. ESOP tax deductions benefit ratepayers for Edison, while they benefit shareholders for PG&E. With PG&E's $1.1 billion proposed increase, we cannot afford to continue to give PG&E preferential treatment relative to Edison.

PG&E Corporation operates an ESOP, which is a tax-advantaged way of allowing employees to own shares in the company on a group basis. PG&E's ESOP is part of its Retirement Savings Plan, which is a defined contribution plan partially funded by the company (and thus its ratepayers) and partially funded by employee contributions. Employees may invest their money in three different funds, one of which is limited to PG&E Corporation stock. To the extent that employees invest in PG&E Corporation

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[87] D. 12-11-051, p. 507.

[88] TURN DR 49-07.

stock, they are participants in the ESOP. Dividends paid by a corporation to an employee stock ownership plan (ESOP) are a tax deduction for the dividend payer.

The question that the Commission must address is: who receives the tax deduction for ratemaking purposes – the ratepayers or the shareholders?

The Commission's decision on this issue will not affect employees. The employees will receive the dividends as an addition to their savings plan funds regardless of whether ratepayers or shareholders receive the tax deduction for those ESOP dividends paid.

TURN believes that the portion of the tax deduction allocable to funds associated with utility employees should be flowed through to ratepayers. If the ESOP participants actually received the entire benefit of the tax deduction (through some type of extra matching or dividend reinvestment program funded out of the deduction and not charged to ratepayers, for example), it could potentially be argued that it would be reasonable for those participants, not ratepayers to benefit. But that is not the case. Under PG&E's proposal the deduction is instead flowed to all of its shareholders – ESOP participants and other shareholders alike. The participating employees receive no explicit benefit from the existence of this tax deduction, and the vast majority of PG&E's shares have nothing to do with the ESOP. The general body of shareholders did not contribute the funds and therefore have no equitable right to the deduction.

It is a fundamental ratemaking principle that the after-tax cost of capital should be reflected in rates. The treatment of ESOP dividends is a portion of the cost of capital. It is analogous to the use of special purpose entities to issue a type of preferred stock where the dividends are financed by interest paid on a subordinate debt issue and where a tax deduction is thereby maintained for the preferred dividends.

The ESOP is also distinguishable from other items where deductions have been provided for shareholders, such as political activities, dues, contributions, and institutional or public relations advertising that would otherwise be disallowed. These items are specifically not funded with ratepayer money. The ESOP is different. At its core, it starts with utility ratepayer funding. Ratepayers paid both the wages that gave rise to the workers' contributions and the employers' savings funds matching contributions.

TURN's proposed adjustment for PG&E is presented in Table 35 below. There is a tax deduction of $41,178,000 at the total company level in 2011, including costs associated with gas transmission and storage (separate case) and electric transmission (FERC), as well as the small amount of below-the-line labor. These costs would be allocated by labor expense to the various functional groups of PG&E. Estimates from PG&E-2, Chapter 7 are provided below, but they will change in the ultimate RO model.

PG&E's tax expense should be reduced by $16,778,000 for GRC functions of the company. After gross-up, the revenue requirement is reduced by $26,363,000.

Table 35: Impact of Employee Stock Ownership Plan Tax Deduction for PG&E

	41,178	2011 deduction (assumed the same in 2013 and 2014)
	8.84%	state tax rate
	3,640	state tax reduction (both 2013 and 2014
	35%	federal tax rate
	13,138	federal tax reduction (2014 includes effect of 2013 state tax)
	16,778	total utility-wide tax reduction
23.70%	3,976	Electric Generation
41.99%	7,045	Electric Distribution
22.55%	3,784	Gas GRC (includes Smart Meter labor)
11.77%	1,975	Non-GRC
		With Tax Gross-Up
	7,081	Electric Generation
	12,545	Electric Distribution
	6,737	Gas GRC (includes Smart Meter labor)
Source: TURN DR 20-18.		
Allocation from PG&E-2 page 7-3.		

VII. Cash Working Capital

A. Introduction

PG&E requests $383.4 million in GRC rate base for cash working capital, the sum of $154.4 million (Electric Generation), $157.5 million (Electric Distribution), and $71.5 million (Gas Distribution).[89] TURN recommends four adjustments to Operational Cash (three to Other Receivables, and removal of the Diablo Canyon refueling prepayment, because TURN proposes pay-as-you-go). TURN also recommends adding approximately 6.5 lag days to goods and services to fix only a portion of PG&E's bad sampling of goods and services transactions. TURN also recommends treating customer deposits as an offset to rate base, which reduces GRC costs by $137 million. TURN's position is summarized below. We recommend reducing PG&E's cash working capital request in this GRC by $184.2 million to $198.3 million.

Table 36: Summary of Differences between TURN and PG&E on Cash Working Capital ($'000)

	GRC	Elec Gen	Elec Dist	Gas Dist	Non-GRC
PG&E Request	$ 383,418	$ 154,396	$ 157,507	$ 71,515	
TURN Other Receivables Adjustments	$ (14,972)	$ (4,019)	$ (7,114)	$ (3,839)	$ (2,138)
Less Prepayment Diablo Refueling	$ (18,700)	$ (18,700)			
Effect of Goods and Services Lag	$ (14,474)	$ (3,072)	$ (7,565)	$ (3,837)	
Customer Deposits	$ (137,013)	$ (36,782)	$ (65,102)	$ (35,129)	$ (19,562)
TURN Recommendation	$ 198,259	$ 91,823	$ 77,726	$ 28,710	

B. Other Accounts Receivable

Non-energy accounts receivable are a component of the cash working capital requirement.[90] PG&E requests $142,414,000 in Other Accounts Receivable.[91]. TURN adjusts this figure to $126,797,000.

89 PG&E-2, WP 13-1 (Distribution) and WP 13-5 (Electric Generation).

90 PG&E-2, p. 13-5.

91 PG&E-2, WP 13-14.

Other accounts receivable have been fluctuating erratically in recent years, as described in TURN DR 40-08 (Attachment 19)

It makes sense that many elements of other accounts receivable become part of rate base, because the Company has expended money for goods and services for which it has not been paid. However, other elements of PG&E's calculation appear strange. For example, a government stimulus grant becomes a receivable that must be covered by rate base, even if the construction that the grant would cover is not underway. Similarly, a settlement amount from the energy crisis becomes receivable, and would be included in rate base if in the base year, even if it hasn't been paid out to ratepayers yet. If there is an obligation by the third party to pay the receivable and a subsequent obligation for the utility to spend money, yet there has been no cash outlay by the utility in those cases, the third party obligation should not generate rate base. That is an issue that requires review in future rate cases.

Notwithstanding these broader concerns, however, TURN proposes three adjustments to Other Receivables. The first and smallest is to remove $434,000 from rate base for receivables associated with non-tariffed products and services that do not flow through to ratepayers (the 2011 figure of $400,000 escalated to 2014 dollars).[92] If the revenue is below the line for PG&E, the receivables should also be below the line.

The second removes UEG and Interdepartmental Sales included in error. PG&E agreed that these costs are accounted for through the lead-lag study and do not belong here.[93] This total amount is $1,493,000 ($1,376,000 in 2011 escalated to 2014 dollars).

The third and largest issue relates to the fact that PG&E never declares any non-energy accounts receivable to be uncollectible, so they just stay in rate base.[94] PG&E's is essentially profiting from its diminished ability to collect other accounts receivable in a timely fashion. Amounts outstanding for over a year have more than doubled since 2009,

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[92] TURN DR 40-08(m).

[93] TURN DR 40-08(e).

[94] TURN DR 40-08 (j), (k), and (l).

and those amounts simply pile up in rate base. Competitive businesses don't get more money if they cannot collect what is owed to them. They face unpleasant financial consequences. TURN therefore recommends that the Commission remove $15,143,000 – half of the amount of NEBS and MLX/NEBS receivables outstanding for 366 days or more in 2011.[95] We do not escalate this figure because we hope and expect that the amount of long-duration receivables will not increase as the economy slowly recovers.

PG&E's and TURN's positions are compared below.

Table 37: Effect of TURN Adjustments to Other Receivables ($'000)

	Total	Elec Gen	Elec Dist	Gas Dist	Non-GRC
PG&E Other Receivables	142,414	33,455	59,214	31,952	17,793
non-tariffed P&S below the line	(434)	(102)	(180)	(97)	(54)
UEG and interdepartmental sales	(1,493)	(351)	(621)	(335)	(187)
50% over 365 days	(15,183)	(3,567)	(6,313)	(3,406)	(1,897)
TURN Other Receivables	125,304	29,436	52,100	28,113	15,655

C. Prepayment for Diablo Canyon Refueling

TURN proposes a "pay as you go" plan for Diablo Canyon refueling outages in the nuclear generation section of this testimony, where the 2014 refueling outage is paid entirely in 2014. This is similar to methods used by SCE since the 2003 TY rate case and used for the 2009 refueling outage in the settlement of the 2007 TY PG&E rate case. There is therefore no prepayment to include as PG&E requests.[96] PG&E's inclusion of $18,700,000 for prepayments should therefore be rejected as unnecessary.

95 TURN DR 40-08(i).

96 If PG&E's ratemaking treatment of outages were to be adopted contrary to our recommendation, the prepayment would be $15,792,000 because of TURN's lower estimate of the cost of Diablo Canyon outages ($47,376,000) and TURN's normalization of steam generator inspection costs so that they are excluded from the second outage estimate.

Even if one were to normalize refueling outages (which TURN presents only as an alternative), TURN does not believe a prepayment is warranted, because we are simply attempting to average the cost as it occurs over a reasonable period of time.

D. Goods and Services Lag – Fix PG&E's Bad Sample

PG&E estimates a goods and services lag of 20.56 days (21.22 days minus 0.66 days for items in transit), and provided a model that derived the information in TURN DR 61-01. TURN reviewed the model and found that it was not accurate. Even after PG&E pared the data base down from 175,000 items to approximately 43,000 items and got rid of many costs that are not part of goods and services (see TURN DR 61-02), a number of items simply didn't belong even in the new slimmed down data base. A considerable number of payments for items not included in goods and services (e.g., dental and pharmacy benefits, 401k payments, electricity, nuclear fuel, natural gas and gas transmission services) were included in the data base, as well as internal transfers within PG&E[97] and between PG&E and affiliates such as PG&E Real Estate and PG&ECorporation.).

Given time constraints, TURN could not look at each of the 43,000 invoices and determine if it belonged in goods and services. We were able to review the largest invoices above about $200,000 each (and credit items of equivalent size) to remove items that did not belong in the goods and services lag. Having just corrected those top entries (which amount to 60% of the total dollars in the sample) we now calculate a raw goods and services lag of 27.72 days for the entire sample, with about 1150 items reviewed and corrected as necessary and over 42,000 unreviewed. Subtracting PG&E's transit time of 0.66 days leaves a net lag of 27.06 days, which is 6.50 days more than PG&E's figure. This is still not the right number and is likely to understate the goods and services lag by some amount, but the review of the top entries captures much of the impact and yields a more accurate number than PG&E presented.

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[97] When PG&E writes a check to itself, how does it generate lag days?

With PG&E's underlying costs, TURN's adjustment to add 6.50 lag days for goods and services reduces rate base by $14.4 million.

Table 38: Rate Base Reduction for TURN's Revised Goods and Services Lag ($'000)

	Goods & Services	Rate Base Reduction
Electric Distribution	424,819	7,565
Gas Distribution	215,461	3,837
Electric Generation	172,494	3,072
Subtotal		14,474

E. Customer Deposits Should be an Offset to Rate Base as Capital Not Supplied by Investors

The ratemaking treatment of customer deposits is a multi-million dollar area where PG&E gets a better deal from the CPUC than Edison. In four consecutive Edison general rate case decisions dating back to 2004, the Commission has treated customer deposits as a rate base offset with interest included in operating expenses. PG&E got more favorable treatment than Edison in the last GRC.[98]

The utility is asking for almost $1.3 billion dollars in rate increases. The customer deposit issue is worth just under $20 million. It should be the easiest $20 million for the Commission to cut, not the hardest, as it has nothing to do with the provision of safe and reliable service.

Utilities require an applicant for new service to establish credit with the utility under Rule 6 "Establishment and Reestablishment of Credit." If the customer (whether residential or non-residential) has not qualified for the establishment of credit with the utility, then they are required to submit a deposit to the utility under Rule 7. The utility may additionally require an existing customer to re-establish credit with the utility under

[98] The 2003 TY GRC was an all-party settlement where all parties reached a mutually acceptable agreement in total. The 2007 TY GRC was a DRA/PG&E settlement where the Commission overruled the ALJ and explicitly gave PG&E the money for customer deposits.

certain circumstances by similarly paying a deposit, as provided by Rules 6 and 7.[99] As outlined in Rule 7, the utility must return deposits to the customer with interest (provided the customer's service is not temporarily or permanently discontinued due to nonpayment). According to this rule, the applicable interest rate is the rate on commercial paper (prime, 3 months) reported by the Federal Reserve Statistical Release.

Customer deposits represent a source of working capital to utilities that is not provided by investors. Utilities have a number of sources of permanent capital that "turn over" relatively frequently. The accrued vacation that is outstanding changes every year; accounts payable are generally paid relatively quickly (despite the increase in very long ages in the last few years). The only difference from other sources of permanent capital not supplied by investors (accrued vacation, accounts payable, etc.) is that the utility must pay its deposit-paying customers interest at the Commercial Paper rate. Deposits are also not like short-term debt because they are permanent. By contrast, the utility can borrow and repay short term debt, as it needs cash for short-term purposes such as funding balancing account undercollections, financing risk-free inventories, or as a bridge to fund construction before permanent long-term debt or equity financing is raised.

The amount of customer deposits is substantial, as shown in Figure 5 on the next page, compiled from TURN DR 40-01 in this case, DR 10-01 in the TY 2011 GRC, TURN 4-58 in the TY 2007 GRC, and TURN DR 6-32 in the TY 2003 GRC.

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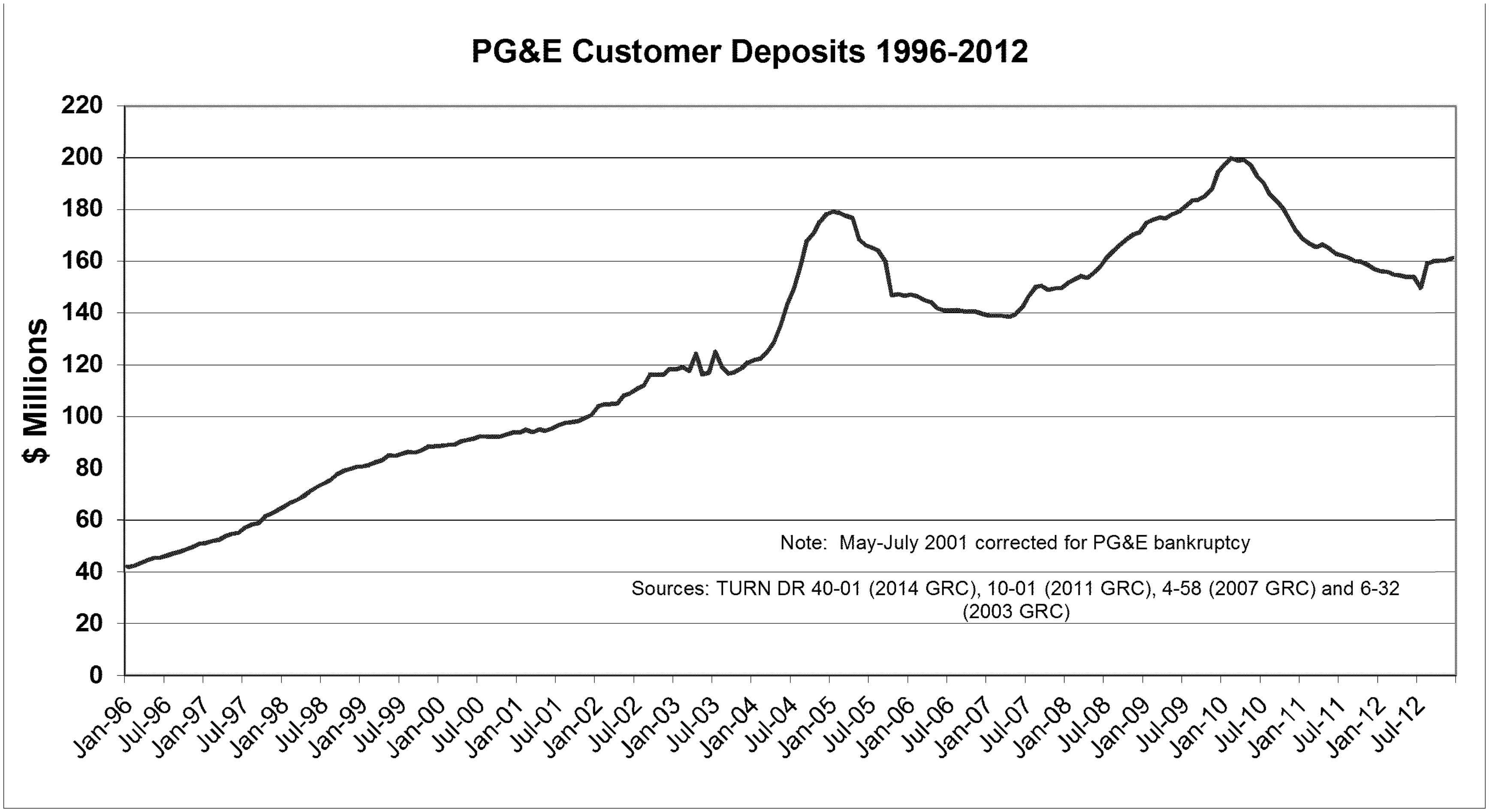
[99] However, in R.10-02-005, the Commission has prohibited the collection of re-establishment of credit deposits from residential customers under certain circumstances, as discussed below.

Figure 3: PG&E Customer Deposits 1996-2012



In recent years, the amount of deposits has fallen as the result of restrictions adopted by the Commission in R. 10-02-005 on the collection of deposits from residential customers, which first took effect in early 2010. The impact of this policy change can be seen clearly in Figure 1. Nevertheless, deposits have stabilized in the range of $150 to $160 million in 2012 – still a substantial amount – and the compound growth rate from 1996 to the present is 8.2%. Furthermore, the deposit restrictions adopted in R. 10-02-005 are set to expire at the end of 2013, including the prohibition on "slow pay" (late payment) deposits for all residential customers and deposits for California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) customers who have not paid or been shut-off for non-payment (SONP) and are seeking to re-establish service.[100] PG&E does not intend to voluntarily extend these restrictions in 2014 but "would consider not charging a reestablishment deposit for slow pay and no pay customers based on a full review of the circumstances" if the Commission adopts the utility's proposed uncollectibles mechanism.[101] Accordingly, it is reasonable to expect that PG&E's deposits will increase starting in 2014 (unless customer payment patterns drastically improve to the extent that PG&E will demand few deposits from slow pay and no pay customers, even though permitted to do so).

In four Edison General Rate Cases where it has made a finding since 2004, the Commission has treated deposits as an offset to rate base. In the most recent Edison case, the Commission made a small exception to allow Edison to offset 90% of deposits against rate base and deposit 10% in minority community banks.[102] The decision states:

> TURN has successfully argued in the past that customer deposits represent a source of capital the utility has on a permanent basis, unlike short-term debt used for certain low-risk inventories, balancing account under-collections, etc. Over time, SCE continually holds a significant block of funds and the only difference is that it must pay short-term interest. SCE's commercial paper rate has been less than 0.5% and has averaged 0.25%. SCE did not rebut TURN's claim that the

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[100] D.12-03-054, Ordering Paragraphs 2, 4.

[101] TURN DR 77-01(b) and -02(b).

[102] D. 12-11-051, p. 629.

policy has not previously impacted SCE's credit rating.[103] [citation omitted from original]

TURN does not believe that there is any significant difference between PG&E and Edison on this issue. Both have similar structures of balancing accounts and similar capitalization. PG&E has slightly more common equity and somewhat more debt, and less preferred stock than Edison. A $150 million item for including deposits in rate base is unlikely to tip the balance on a rating agency decision, given their relatively broad discretion. Both are under the guidance of Standard Practice U-16, a document that was first issued in 1969, when Ronald Reagan was Governor and the witness had not graduated from high school. This document admittedly makes a distinction between interest-bearing and non-interest-bearing deposits, with non-interest-bearing deposits being subtracted from rate base and interest-bearing deposits not being subtracted. Nevertheless, "[a]s the Commission has previously held, U-16 is only a guide, and deviations are appropriate where circumstances warrant." [104] Many other states include deposits either as a rate base offset or as part of the capital structure.

TURN recommends that the Commission adopt a level of deposits as a rate base offset equal to the 2012 weighted average without escalation, given uncertainties in the amount of deposits. That amount is $156,575,000 of which $137.0 million offsets General Rate Case Expenses (Table 36).

Given the Commission's recent Edison decision, TURN would not object to a similar 10% offset tied to community banks. For the amount that offsets rate base, PG&E should be authorized either to recover the actual deposit interest paid in its balancing accounts through this rate case cycle or should be assigned a forecast of deposit interest of about 1% ($1,566,000) to reflect continuing relatively low interest rates during this period.

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[103] Id., p. 628.

[104] D. 04-07-044, p. 253.